2013 Asset Management Plan

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TOP ENERGY®
Te Puna Hihiko

Introduction

It gives me great pleasure to present Top Energy's 2013-2023 Network Asset Management Plan (AMP).

The 2013 plan follows on from the 2012 plan, addressing the key issues of reliability, security of supply and capacity. In this plan, we detail our reliability improvement programme as well as a significant transmission and sub-transmission investment plan over the next decade.

This AMP is the core asset management planning and operations document for Top Energy and details inspection, maintenance and capital replacement strategies, as well as the service level targets that we intend to deliver to our customers.

The Commerce Commission requires that electricity distribution businesses (EDBs) publicly disclose an AMP each year that provides information on how the EDB intends to manage its network assets to meet the requirements of its consumers. In compiling this plan, emphasis has been given to ensuring compliance with the Commerce Commission's Disclosure Requirements, whilst also providing detailed information about Top Energy's asset management and planning processes.

In 2009, we introduced a major reliability programme which has targeted the clearance of trees near lines, the installation of automated switches and re-closers in strategic locations, and the use of specialised equipment to reduce the impacts of lightning strikes. This programme resulted in a significant improvement in the performance of the network in the last two years.

At the time of writing, customers in the Far North have experienced 254 SAIDI minutes without power (on average) since the beginning of April 2012; a 28% improvement on the performance for the same period last year. It is planned that reliability improvement will continue and deliver an average reliability of less than 200 SAIDI minutes by the year 2020.

The 2010 Top Energy AMP announced a 10-year sub-transmission development plan aimed at improving quality of supply by providing more points of injection into the distribution network. Building upon those plans, the 2011 AMP announced Top Energy's plan to supplement the sub-transmission development plan with a transmission development plan, designed to address the 110kV security of supply issues to the Kaitaia region. I am pleased to report that we assumed ownership of the majority of the Transpower transmission assets in the Far North from 1st April 2012.

The investment in the region's 110kV assets is critical to our network expansion and reliability plans, between now and 2022. It includes ownership of both the substations in Kaikohe and Kaitaia and more than 50km of connecting 110kV line between them; it is Top Energy's largest network asset acquisition to date.

This AMP details our plans for managing these newly acquired assets over the next decade.

We believe that having the entire local lines network operated by just one company will result in savings and efficiencies worth $10 million, helping to keep power bills down in the long-term. In addition, the investment increases security of supply and long-term electricity capacity for the whole of the Far North. The purchase of Transpower's Far North assets puts all maintenance and investment decisions into the hands of people who live and work in our own community. It's a really positive move for the Far North.

Top Energy also has a number of other projects underway to help improve the reliability and security of the local electricity supply. These include:

- modernising infrastructure to improve reliability;
- doubling the size and capacity of the existing 33kV network by 2020; including new lines to Kerikeri and Waipapa
- building a back-up 110kV line to Kaitaia to enhance security of supply to East Coast communities (including Kerikeri and Taipa);
- substation construction right across the region to reduce the number and duration of outages;
- back-up infrastructure to reduce the number of outages even further; including short-term back-up diesel generation in Taipa, and
- trialling a new solar power project.

INTRODUCTION

A more stable and widespread electricity supply has financial benefits for the region. It makes the Far North a more attractive place to do business and 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 Top Energy invest a total of almost $190 million on network capital expenditure and almost $54 million in network maintenance expenditure over the ten-year period of this AMP. The Board is confident that this expenditure will improve service outcomes to levels comparable to that experienced by consumers supplied by comparable rural networks within New Zealand and that this expenditure is necessary if the long term economic development of the Far North community is to be assured. Nevertheless, it also recognises the potential pricing impact of expenditure on this scale and will focus on achieving a price-quality balance that is affordable and in the best interests of the communities that it serves.

In addition to the technical development of the network assets, we also continue to develop the safety and asset management culture within Top Energy.

In 2010, we received the Electricity Engineer's Association (EEA) Public Safety Award for our Close Approach Consent Process, which provides on-site safety advice and guidance for contractors and members of the public, when working within 4 metres of our lines.

In 2011, we beat six other companies to win the industry's top award for workplace safety. The EEA Workplace Safety Award recognised our safety-focused culture and significant reduction of lost time injuries (LTI's) from a historical high of 16 LTI's in 2004 to just one in the last twelve months.

We followed this up in 2012 jointly winning the EEA Workplace Safety Award for an educational video for employees on the dangers of drugs and alcohol in the workplace. This featured members of staff from the participating businesses and was completed in partnership with the EPMU. We also jointly won the EEA Engineering Excellence Award with Transpower for the transfer of the Far North transmission assets, which is the largest asset transfer of its type. And most importantly we were the recipient of the Deloitte Lines Company of the Year for 2012, the premier award for lines companies in the energy sector. These awards provide external recognition of the excellent work the staff at Top Energy have undertaken. We are extremely proud of our staff and their achievements.

To improve our asset management processes, we have chosen to develop a framework approach that aligns to the UK Publicly Available Specification for Asset Management (PAS55), which was adopted by the UK electricity supply industry in 2004. We have been steadily improving our processes over the past three years, including our alignment with the PAS55 asset management standard. We have now embarked on formal certification to demonstrate continual improvement and comparability against international best practice, as part of our annual disclosures.

Certification to PAS55 will provide assurance to our stakeholders that the asset management processes within Top Energy meet international best-practice and are continuously monitored and improved.

We hope that you find this Asset Management Plan both informative and comprehensive. 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

Russell Shaw

Chief Executive, Top Energy Ltd

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1 Executive Summary

1.1 Company Background

Top Energy Limited is part of the Top Energy group of companies and is wholly owned, for the benefit of its consumers, by the Top Energy Consumer Trust. The group has four divisions:

- **Ngawha Generation**, which operates the 25MW Ngawha geothermal power plant;
- **Top Energy Networks (TEN)**, 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.

Top Energy Limited is the local electricity distribution lines business that distributes electricity to more than 31,000 electricity consumers in the Mid and Far North of the Northland region, New Zealand. It employs around 200 people and is one of the largest employers in the Far North.

Top Energy was first established in 1935 as the Bay of Islands Electric Power Board. The company is registered under the Companies Act 1993 and is governed by an independent Board of Directors appointed by the Trust.

1.2 Network Description

Top Energy's electricity network begins in Hukerenui, approximately 25km north of Whangarei and ends at Te Paki, 20 km south of Cape Reinga. It spans from the East coast to the West coast. The supply area is sparsely populated with no dominant urban centre and is recognised as one of the more economically depressed areas of the country.

Figure 1.1: Top Energy Sub-transmission lines (33kV) and transmission Transpower (110kV)

The existing network infrastructure was developed at a time when Kaikohe and Kaitaia were the dominant urban centres. This is no longer the case; most economic growth is now occurring in the Bay of Islands and Kerikeri areas, as well as the east cost peninsulas, areas where the existing infrastructure is weak. Other weaknesses include the reliance on a single transmission circuit to supply Kaitaia and the northern part of the supply area, and the distribution feeders supplied from a limited number of zone substations. These are legacies of a network design focused on providing electricity to a sparsely populated, economically deprived area at a time when cost rather than reliability was the main driver for network development.

DESCRIPTION	QUANTITY
Area Covered	$6{,}822km^2$
Customer Connection Points	31,217
Grid Exit Point	Kaikohe[1]
Embedded Generator Injection Point	Ngawha Geothermal
Network Peak Demand (FYE2012)	64MW
Electricity Delivered to Customers (FYE2012)	333GWh
Number of Distribution Feeders	47
Distribution Transformer Capacity	257MVA
Sub-transmission Cables (33kV)	1 km
Sub-transmission Lines (33kV)	266km
HV Distribution Cables (22, 11 and 6.35kV)	167km
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,562km

Note 1: Following the transfer of the Kaikohe and Kaitaia transmission substations to Top Energy on 1 April 2012, the 110kV incoming circuit breakers at Kaikohe form the boundary between the Top Energy network and Transpower's transmission grid.

Table 1.1: Network Summary (as at 31 March 2012 unless otherwise shown)

1.3 Value of Network

In accordance with the Commerce Commission's Electricity Distribution Information Disclosure Requirements 2008, Top Energy disclosed that its system fixed assets were valued at $154,207,000 as at 31 March 2012; an increase of $10,233,000 since 31 March 2011. This total does not include transmission assets that Top Energy acquired from Transpower on 1 April 2012, valued at around $6.0 million.

This increase in asset value was derived as follows:

	$000
Asset Value at 31 March 2011	**143,974**
Add:	
New assets	13,832
Indexed inflation adjustment	2,261
Less:	
Depreciation	5,860
Asset value at 31 March 2012	**154,207**

Table 1.2: Value of System Fixed Assets

1.4 Areas of Uneconomic Supply

Over 35% of Top Energy's 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 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, Top Energy is obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers supplied from existing lines.

The Electricity Networks Association (ENA) created a working party to review the implications of this obligation, particularly for distribution businesses that include a large rural network component. To assist this review, in April 2009 Top Energy engaged Intergraph to create a trace within its GIS system to identify uneconomic lines based on the Ministry of Economic Development (MED) suggested test scenarios.

This trace stepped through each piece of equipment within the GIS, feeder by feeder and identified where uneconomic lines begun. The start points were individually recorded and each of these start points became the beginning point of a further trace. This in turn identified all downstream equipment, therefore summing the length of uneconomic conductors.

The results revealed that 32% of Top Energy lines were uneconomic, based on MED criteria. However, these lines feed only 8% of Top Energy's consumer base. The high proportion of uneconomic lines in Top Energy's supply area is a continuing financial burden on all Top Energy consumers.

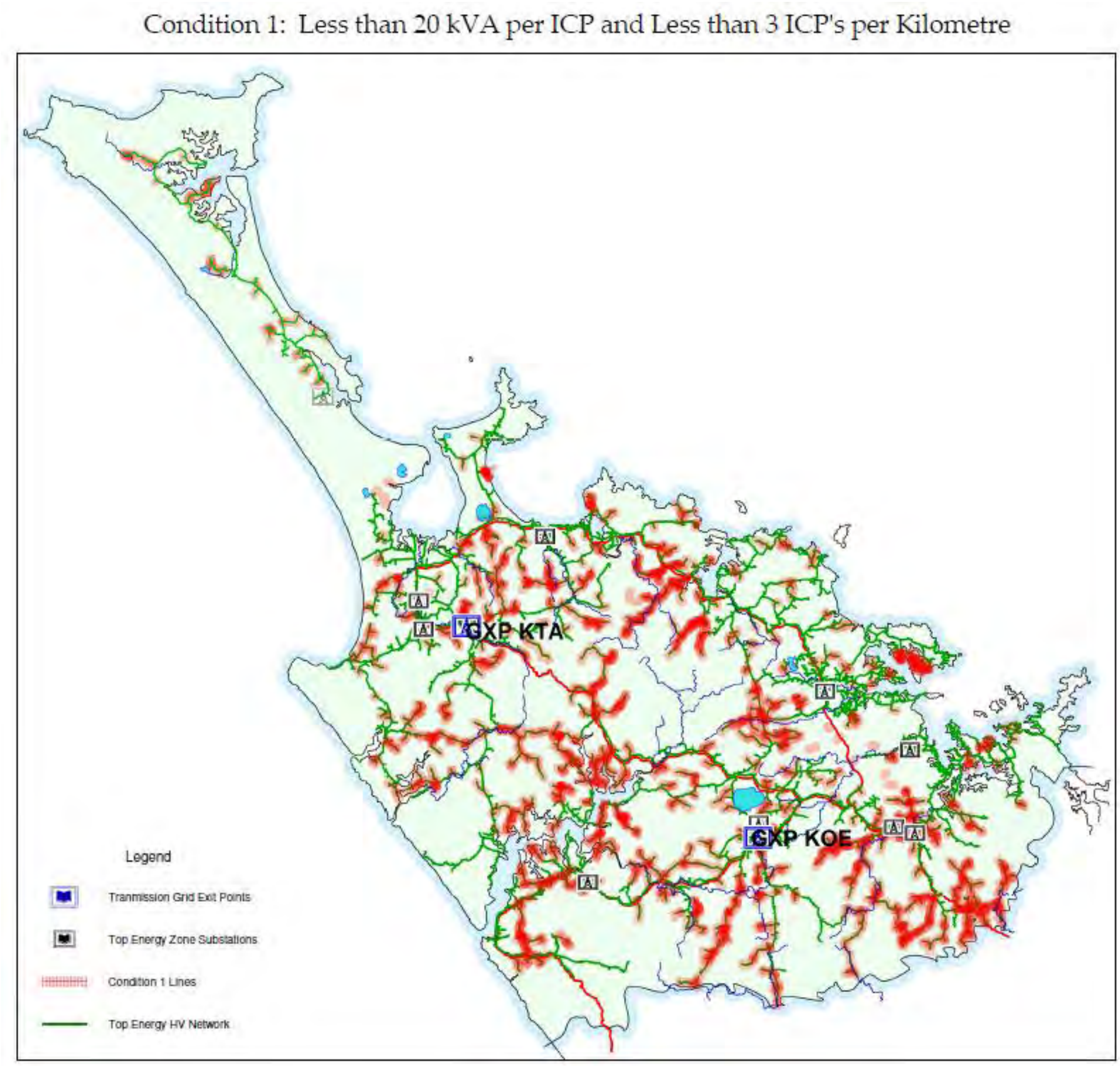

Figure 1.2: **Map of uneconomic lines**

1.5 Asset Management Strategy

Top Energy has commenced a significant investment programme in its aging and historically unreliable electricity network assets, including the transmission assets that it acquired from Transpower on 1 April 2012. The key drivers are to improve:

- operational performance;
- security of supply; and
- service provision to electricity consumers on the Top Energy electricity network.

Network Reliability

In spite of recent improvements in performance, Top Energy remains the worst performing electricity distribution business in New Zealand for network reliability. During the financial year ending 31 March 2012, (FYE2012), on average, each consumer experienced six outages and more than seven hours without electricity. Whilst this performance was once viewed as the result of a complex mix of historical design, investment, ecological and climatic factors, it is now recognised that with suitable strategies and funding, the effects of these factors can be mitigated. Therefore, this asset management plan (AMP) identifies the strategies that will be applied to mitigate the factors to the extent economically practicable.

Demographic Challenges

The challenges that Top Energy currently face in improving security of supply and network performance can partly be explained by the fringe location of its network and the location of the 110kV infrastructure, relative to the major population centres. This latter problem is a legacy of an era when the inland urban centres of Kaikohe and Kaitaia were the hubs of both economic and population growth in the Far North region.

Over the last twenty years, there has been a steady decline in the growth of Kaikohe and significant expansion in the areas of Kerikeri, the Bay of Islands and the Eastern coastal peninsulas. Parts of the network that previously supplied fringe coastal communities are now operating at over 90% capacity during peak periods. This demographic change limits the ability of the existing network to accommodate the connection of new customers in many areas and makes it more difficult to restore supply when a fault occurs.

Network Expansion

To address these issues and improve security of supply, Top Energy will invest around $185 million by FYE2023 to complete what will be the single largest expansion in the history of the Top Energy electricity network.

Within the next five years, Top Energy will construct a new 110 kV transmission line over a coastal route between Kaikohe and Kaitaia, to improve the security of supply to the Northern region. This will enable the construction of a new 110kV transmission substation at Wiroa, to serve customers in Kerikeri and the coastal regions in the North East of Top Energy's supply area.

The expansion will also strengthen the 33kV sub-transmission system, increasing the number of points at which power is injected into the older distribution network. It will also significantly increase the long-term security and reliability of the network to support future economic growth.

Key sub-transmission projects include four new transmission to sub-transmission substations and substantial 110kV and 33kV line construction. These will replace short-term measures currently in place. For example, in FYE2012 Top Energy installed diesel generation at Taipa to provide a backup power supply to cover the loss of the incoming 33kV supply.

Vegetation control and strengthening the distribution's network's ability to withstand adverse weather events is also a focus for strategic investment and presents additional opportunities for significant performance improvement.

In April 2009, TEN began a major reliability programme addressing the clearance of trees and vegetation near our lines. It has also installed specialist equipment to reduce the number of faults that were caused by lightning and over 200 automated switches and re-closers in strategic locations to limit the number of customers affected by a fault event and, in many cases, the time required to restore supply. Overall, the results have been excellent and the investment has more than halved the total time that the average consumer went without electricity (from over 900 SAIDI minutes in FYE2009 to 440 SAIDI minutes in FYE2011 and 435 minute in FYE2012). Further, the number of outages experienced by our consumers was also more than halved during the same period.

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

1.6 Reliability

In FYE2012, TEN's SAIDI was 435 minutes a small improvement in the 440 minutes the previous year. SAIDI is the System Average Interruption Duration Index, a measure of the total number of minutes in a year that the average consumer is without electricity. This was a marked improvement from 2009, when there were 932 SAIDI minutes.

In addition to measuring the accumulated total time the average consumer is without supply, Top Energy also measures the System Average Interruption Frequency Index (SAIFI) average number of interruptions experienced by consumers in any year. The SAIFI in FYE2012 was 6.4, significantly higher than the average of 4.9 interruptions in FYE2011. This was because the weather experienced in 2011 and early in 2012 was significantly worse than normally experienced, causing a higher number of faults. In spite of this, TEN was able to improve on its previous year's SAIDI. This is testimony to the success of the reliability improvement initiatives that TEN has been putting in place since FYE2010.

The levels of service experienced by any individual consumer (as distinct from the average) are the result of many factors, with perhaps location being the most critical. In general, consumers in remote locations, well away from zone substations, will experience lower reliability than those in the larger urban locations. This is true of all networks.

With the acquisition of the Transpower assets on 1 April 2012 outages of these assets, in particular the single 110kV line supplying customers in the north of the supply area, are now included in the measures of network reliability. As of the middle of February 2013 TEN is on track to meet its FYE2013 SAIDI target of 402 minutes and its SAIFI target of 5.0. This is notwithstanding a planned nine hour maintenance outage of the Kaitaia line, scheduled for March 17 2013, which is expected to add 56 SAIDI minutes and 0.4 interruptions to the measured reliability.

As a result of the network development plan, which is discussed in Section 1.7, and the maintenance initiatives that TEN has put in place, the network reliability is expected to improve significantly over the ten-year period of this AMP. This is reflected in TEN's forward reliability targets, which are shown in Figure 1.3 and Figure 1.4 below, which also compare the current and target levels of reliability with the historical performance of the network.

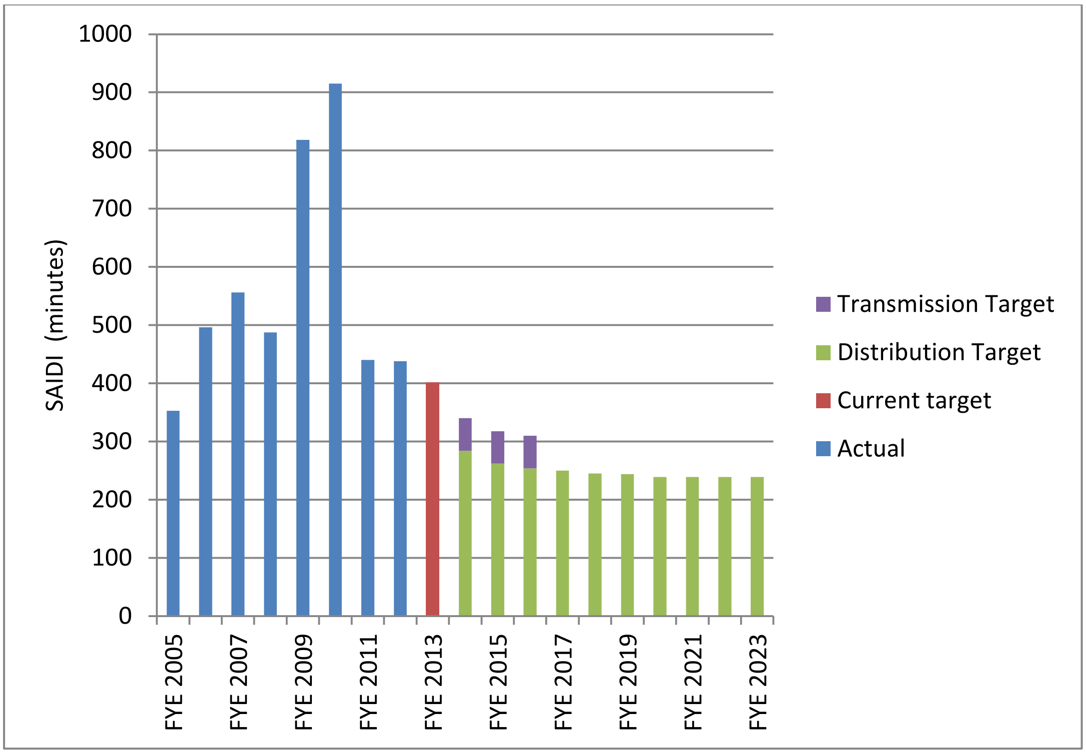

Figure 1.3: **Historical and Target SAIDI**

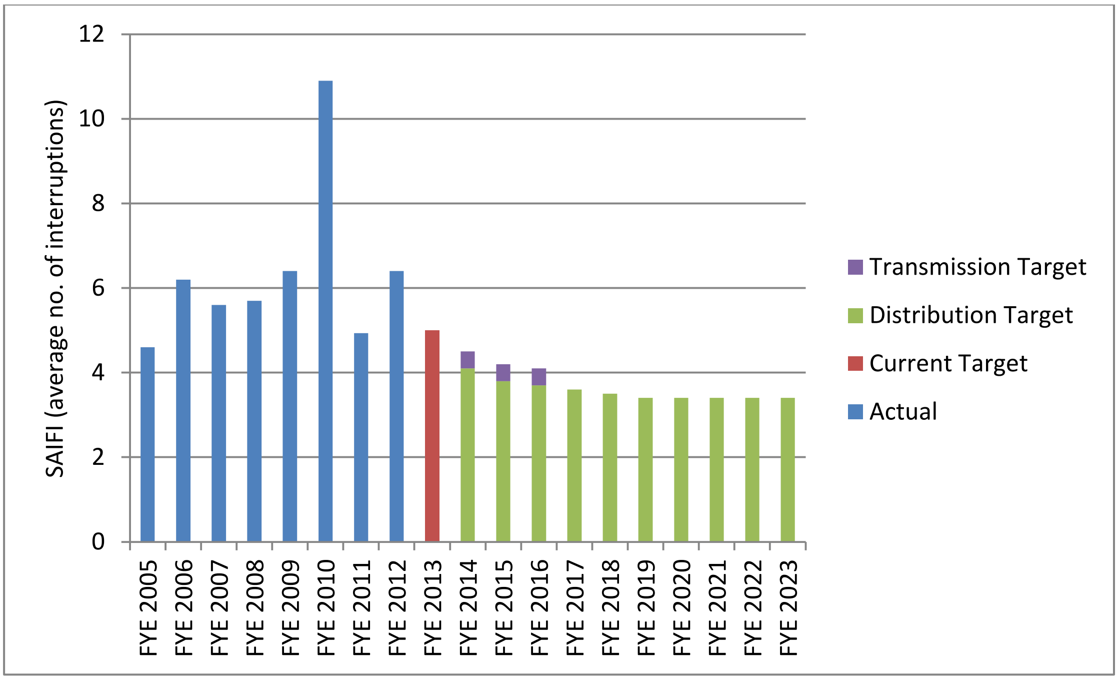

Figure 1.4: Historical and Target SAIFI

1.7 Network Development Plan

Over the next ten years a significant number of major capital projects have been identified in the Network Development Plan, which will deliver the security and capacity improvements required to meet the forecast growth in electricity demand and the reliability improvements shown in Figures 1.3 and 1.4.

Project staging has been determined by a number of factors. Most critical were the security and capacity constraints on the network, which require much of the development plan to be implemented as soon as practical. However, resource availability (human and financial) was also considered and projects moved appropriately. The result is a work plan which will produce the desired performance outcomes in an affordable and sustainable manner.

The integrated network development plan detailed in this AMP is designed to address the following key network constraints:

- around 10,000 consumers in Top Energy's Northern area are 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 an annual maintenance interruption that can last more than nine hours, as well as an elevated risk of unplanned fault interruptions;

- the sub-transmission system serving consumers in the Kerikeri area is already loaded to its full design capacity at times of peak network demand. In the event of an unplanned outage of a sub-transmission element, the network voltage could drop to an unacceptable level and this problem could only be addressed by shedding load;

- while in relatively good condition, many of the assets purchased from Transpower are old and present safety and reliability risks. A major problem is the capacity and condition of the existing transformers at Kaitaia. These are old, single phase units that testing has indicated are in poor condition. They are also rated at 22MVA, which is less than the current peak load at the substation. The condition of the 33kV outdoor switchgear at both substations, which have been built to a design that is now accepted as a safety risk, is also an issue;

- load growth in some areas that are not well-served by existing zone substations is exceeding the capacity of the 11kV distribution system. The areas of particular concern are Kerikeri, the Whangaroa-Kaeo-Matauri Bay area and Russell;

- apart from Haruru, all zone substations are currently operated in a split bus, radial configuration in order to manage protection constraints. This does not meet Top Energy's security requirements for larger, two transformer substations; as it means that supply interruptions are inevitable, whenever a sub-transmission fault occurs;

- outdoor switchgear at some substations is in poor condition and requires replacement; in particular Moerewa and Waipapa; and
- the single phase transformer bank at Omanaia is now 58 years old and approaching the end of its economic life.

The plan includes:

- construction of a new 110kV transmission line between Kaikohe and Kaitaia using a route around the east coast. This line will provide an alternative incoming transmission circuit to the Northern region; it will also be used to supply Kerikeri and the coastal belt in the north east of the supply area. It will be commissioned as far as Wiroa in FYE2016 and through to Kaitaia in FYE2017;
- construction of a new transmission substation at Wiroa to supply the Kerikeri, Waipapa, Matauri Bay and Kaeo areas. This will be commissioned at 33kV in FYE2014 and 110kV in FYE2016;
- construction of new 33/11kV zone substations in Kerikeri and Martins Rd, Kaeo. The Kerikeri substation will be commissioned early in FYE2014 and the Kaeo substation in FYE2019;
- replacement of the two 110/33kV transformers at Kaitaia in with new larger units. The first transformer will be replaced in FYE2015 and replacement of the second transformer will follow in FYE2020.
- replacement of the outdoor 33kV switchyards with new indoor switchboards at Kaikohe and Kaitaia transmission substations. The Kaikohe switchboard is planned for FYE2014 and the Kaitaia switchboard for FYE2020;
- refurbishment of the existing 110kV line between Kaikohe and Kaitaia during the period 2018-2022;
- reinforcement of the supply to Taipa through the construction of a new 110kV substation with larger transformers by FYE2019;
- installation of a newer, larger transformer at Omanaia by FYE2019;
- reinforcement of the supply to the Russell Peninsula, either through the installation of a third submarine cable from Paihia or possibly, as a temporary measure, the construction of a small power station;
- installation of a new fibre-optic communications system across the network to replace the existing, obsolete infrastructure and enable the use of modern protection and control technology; and
- upgrades to the 11kV distribution network to relieve localized overloads and to interface it to the new 33kV zone substations.

Figure 1.5 shows the total capital expenditure (CAPEX) forecast for the 10-year planning period of this AMP, while Table 1.4 provides more detail on the first five year period, highlighting in particular the major projects. With the new Kerikeri zone substation due for commissioning in early FYE2014, the key objective in the short term will be to deliver the second 110kV circuit through to Kaitaia, and this accounts for the substantial reliability, safety and environment CAPEX through to FYE 2017. The focus will then switch to leveraging off this project to increase the capacity of supply into the north east of the supply area, through the construction of the new zone substations in Kaeo and Taipa. Once these major reliability and growth projects are completed, the focus will be on asset replacement through rebuilds of the Moerewa and Waipapa zone substations, asset replacements at the Kaitaia transmission substation and the refurbishment of the existing 110kV line to Kaitaia.

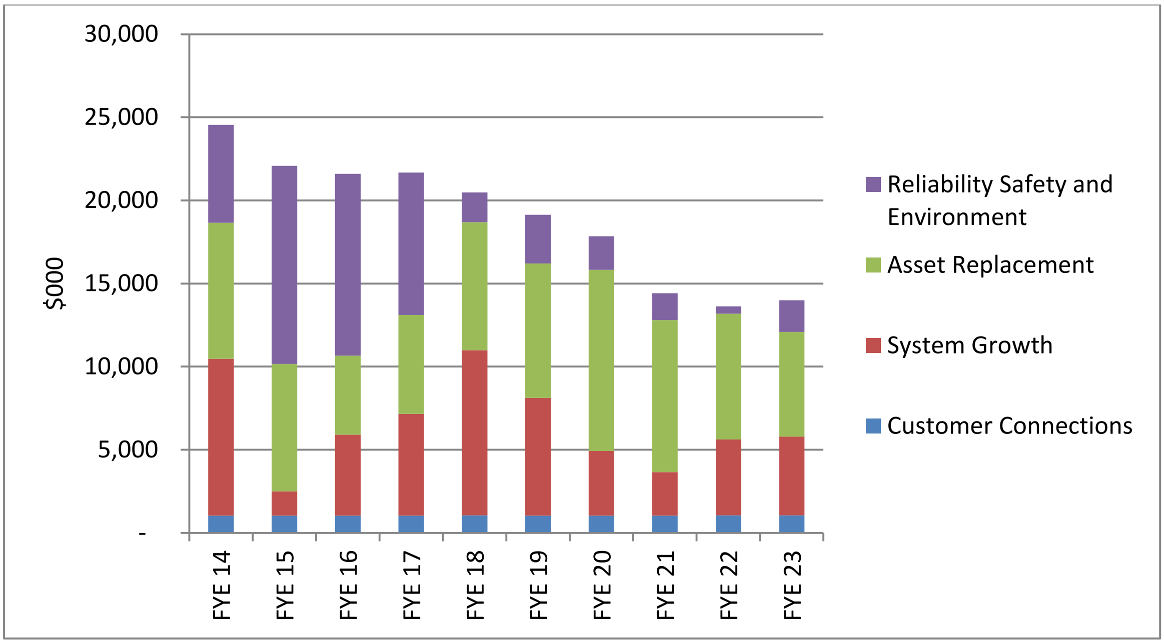

Figure 1.5: **Capital Expenditure Forecast Profile FYE2014 to FYE2023**

$ million (real)	Category	Major Project Cost	FYE				
			2014	2015	2016	2017	2018
System Growth							
110kV line Kaikohe-Wiroa		**6.1**	1.8	0.8	-	-	-
110kV Wiroa substation		**9.7**	2.6		3.4	2.3	0.9
Kerikeri substation - incoming 33 kV cable		**4.5**	1.6	-	-	-	-
Taipa 110 kV line deviation		**3.2**	0.2	-	1.0	2.0	-
Taipa 110 kV substation		**5.2**	0.4	0.5	-	1.0	3.3
Kaeo 33 kV lines		**4.9**	1.3	-	0.3	-	2.6
Kaeo 33 kV substation		**4.4**	0.1	-	-	-	1.7
Other			1.4	0.2	0.2	0.8	2.5
Total			**9.4**	**1.5**	**4.9**	**6.1**	**9.9**
Reliability, Safety and Environment							
110kV line Wiroa-Kaitaia		**34.2**	3.4	10.7	10.7	6.0	
Protection and communications			1.5	0.2		0.8	0.1
Feeder interconnections				0.2	0.1	1.2	0.9
Remote control switches						0.2	0.7
Other			1.0	0.8	0.1	0.4	0.1
Total			**5.9**	**11.9**	**10.9**	**8.6**	**1.8**
Asset Replacement and Renewal							
Kaikohe 33 kV outdoor-indoor conversion.		**3.5**	3.5				
Kaitaia 110/33 kV T1 transformer replacement		**2.0**	0.1	1.8			

Moerewa outdoor-indoor conversions	**3.1**		1.7	1.4		
Waipapa outdoor-indoor conversion	**2.2**					1.7
Transmission substation asset replacement			1.0	0.7	0.6	
Kaikohe-Kaitaia 110kV line rebuild	**6.0**				0.4	1.1
Other		4.6	3.2	2.7	5.0	4.9
Total		**8.2**	**7.7**	**4.8**	**6.0**	**7.7**

Table 1.3: Network CAPEX FYE2014 to FYE2018.

1.8 Maintenance Expenditure

Figure 1.6 shows the forecast maintenance expenditure (excluding capitalised asset replacements) over the ten-year planning period. It shows that some increase in maintenance is planned in the later years of the period, after capital expenditure on network development has reduced. Table 1.3 presents this information in numerical format for the FYE 2014 to FYE 2018 period.

In November 2012, Top Energy introduced the SAP asset management software modules as the tool for managing its asset inspection programme and recording, prioritising and clearing identified asset defects. SAP also allows asset condition data to be recorded in a more structured way and to be more readily retrievable for future reference. Over time this should lead to significant efficiencies in the management of the maintenance effort.

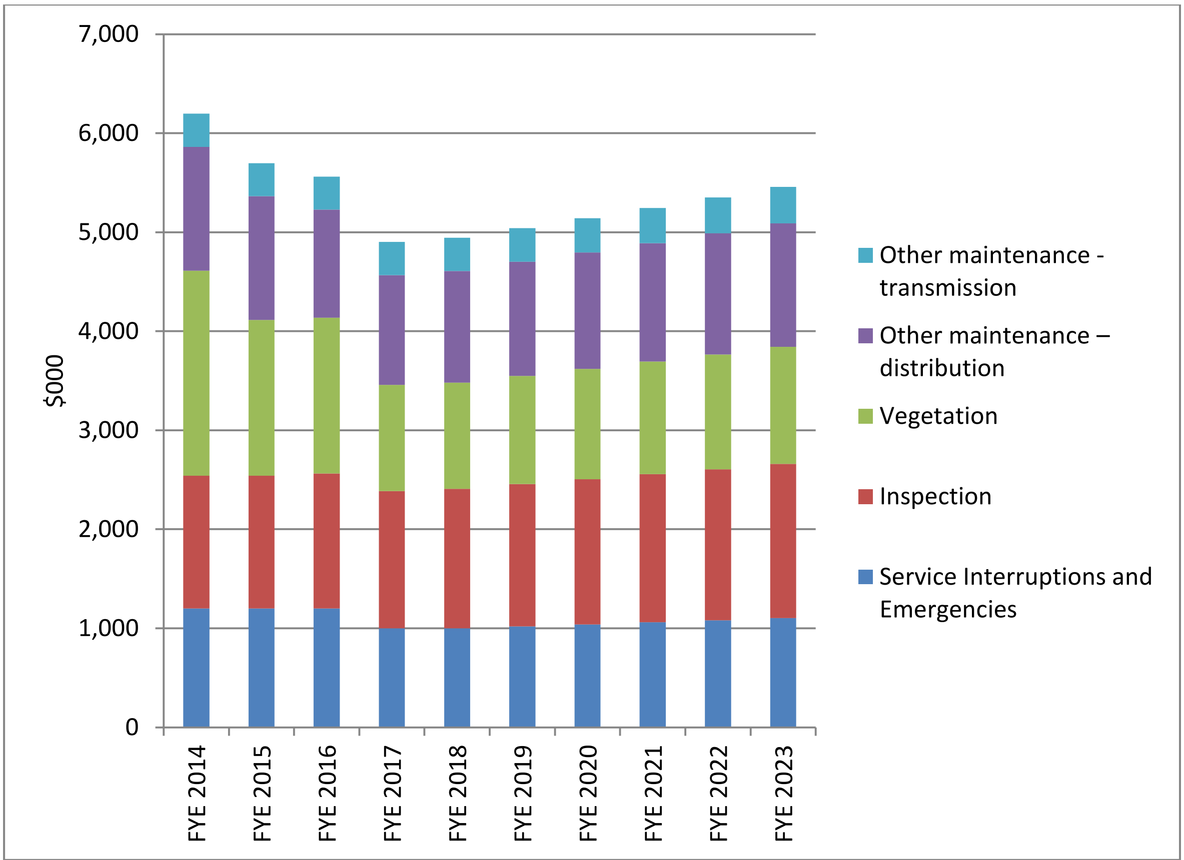

Figure 1.6: Forecast Maintenance Expenditure (FYE2014 to FYE2023)

$000	FYE				
	2014	2015	2016	2017	2018
Service Interruptions and Emergencies	1,200	1,200	1,200	1,000	1,000
Inspection	1,341	1,341	1,363	1,385	1,408
Vegetation	2,072	1,572	1,572	1,072	1,072
Other maintenance – distribution	1,250	1,250	1,093	1,110	1,129
Other maintenance - transmission	334	334	334	334	334
Total	**6,197**	**5,697**	**5,562**	**4,902**	**4,943**

Table 1.4: Forecast Maintenance Expenditure (FYE2014 to FYE2018)

1.9 Conclusion

The asset management strategies and plans set out in this AMP are a continuation of the network development programme that commenced in FYE2011 and constitute what will be the largest investment in the history of the Top Energy network. The objective of this programme is to position the network to meet a continuing increase in the demand for electricity and to improve the reliability of electricity supply from the worst in the country to one that is comparable to, or even better than, that currently experienced by consumers in other parts of rural New Zealand.

This investment programme has been developed in full consultation with the Far North community and with the full support of the Top Energy Consumer Trust, the Board of Directors and the Executive Management Team. This support is provided because a more reliable supply of electricity is needed to underpin the economic development of the area, which in turn will increase the employment opportunities and living standards of those who choose to live in one of the more remote and economically deprived parts of New Zealand.

While the challenges of this 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, are testimony to this.

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 region. The business comprises four divisions:

- **Ngawha Generation**, which operates the 25MW Ngawha geothermal power plant;
- **Top Energy Networks (TEN)**, 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.

Top Energy 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 TEN's electricity distribution network. Top Energy is a major contributor to the community's financial well-being and employs more than 200 staff. The company is one of the largest in the region and is uniquely placed to act as a catalyst for developing the region's economic potential.

TEN's electricity transmission and distribution network distributes electricity, sourced from the Transpower grid and the Ngawha power plant, to more than 31,000 electricity consumers. This Asset Management Plan (AMP) covers the management of TEN's network and non-network assets, which currently have a book value in excess of $150 million. (This figure excludes Top Energy's three other operating divisions).

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 sub-transmission network. Table 2.1 below shows the key network parameters.

DESCRIPTION	QUANTITY
Area Covered	6,822km^2
Customer Connection Points	31,217
Grid Exit Point	Kaikohe[1]
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HV Distribution Cables (22, 11 and 6.35kV)	167km
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,562km

Note 1: Following the transfer of the Kaikohe and Kaitaia transmission substations to Top Energy on 1 April 2012, the 110 kV incoming circuit breakers at Kaikohe form the boundary between the Top Energy network and Transpower's transmission grid.

Table 2.1: Network parameters (as of 31 March 2012 unless otherwise shown)

2.2 Purpose of this Plan

Top Energy's Statement of Corporate Intent (SCI) describes the AMP as the defining document for the group's network business, TEN. The AMP lies at the heart of TEN's asset management process and is the primary tool for planning the long-term capital and maintenance activities of the electricity network. This AMP documents the processes and activities planned by TEN to develop, maintain and operate its 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 TEN's asset management strategies and action plans for its transmission and distribution network, within the context of Top Energy's mission statement and corporate strategy;
- define the services to be provided, the measures used to monitor the quality of these services, and 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 customer expectations; and
- comply with clause 2.6.1 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012.

2.3 Asset Management Objectives

Top Energy's corporate mission statement is outlined in the Statement of Corporate Intent (SCI) and is:

To operate a successful and responsible business and to maximise the value of the Group in the long term for the benefit of the Shareholders.

In respect of Top Energy's network assets, the SCI states that this will be achieved by:

- investing in business activities that enhance the security of power supply in the Far North District;
- achieving network service quality standards acceptable to the community and deliverable from future maintainable earnings of the network business;
- developing and utilising staff skills and the Group's intellectual property, while providing a safe environment for staff, contractors and the public;
- operating in accordance with the principles of environmentally sustainable management; and
- acting responsibly and co-operatively in the community and adopting a responsible approach to social and cultural issues.

TEN's asset management and planning processes have been developed to ensure that these high level network objectives are achieved as efficiently and effectively as possible, notwithstanding the constraints imposed by the environment within which Top Energy must operate.

2.4 Rationale for Asset Ownership

The assets covered by this AMP are used to deliver electricity to consumers within Top Energy's supply area, the Far North District of New Zealand. The majority of these 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 and economically deprived area.

At the time, supply availability was considered more important than reliability and cost was an overriding consideration. Hence, the network is characterised by a small number of long distribution feeders, supplied from a limited number of zone substations, and two wire and single wire earth return (SWER) lines are used extensively.

The existing network was never designed to supply the level of reliability required in modern, developed economy and that consumers now expect. While there have been modest improvements in supply reliability as a result of better maintenance practices and the installation of strategically targeted network automation and remote control devices, the overall supply reliability remains the lowest in the country.

In order to significantly improve supply reliability, the network architecture needs to be upgraded; firstly, by providing a second high capacity incoming transmission line to serve customers in the North of the supply area; and secondly, by providing more points of injection into the medium voltage distribution system. These improvements would have the following benefits:

- customers in the Northern region would 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;
- increased utilisation of the existing high voltage distribution network assets;
- improved reliability of supply by providing for an increased number of shorter distribution feeders, each supplying fewer consumers. This would reduce the average number of consumers affected by a single fault and often allow earlier restoration of supply to customers not directly affected; and
- improved network voltages, increasing the quality of supply to customers located in remote areas.

2.5 Framework for Asset Management Planning

Consistent with the high level strategies set out in the SCI, the Board has approved a set of detailed business objectives against which the AMP has been developed:

- Top Energy maintains a good relationship with its external stakeholders, including its owner and consumers;
- the network return on investment (ROI) is maintained within the acceptable regulatory band, which reflects the cost of capital;
- the network is developed according to the network development plan detailed in this AMP;
- the network is maintained according to the maintenance plan detailed in this AMP;
- asset and business risks are understood, communicated and controlled;
- reliability is within realistic expectations, relative to an appropriate peer group;
- supply capacity is available to allow economic growth in the Far North;
- security of supply standards are met or the risks inherent in a less secure network are understood and a plan is in place to deal with loss of supply contingencies;
- capabilities are increased in people, process and systems;
- standards are defined across the network; and
- there is an aligned team of high performers who are proud to work for Top Energy.

Within this business framework, the detailed strategies and plans in this AMP are designed to ensure that:

- the management of network assets is consistent with the corporate mission statement in the SCI and the business objectives approved by the Top Energy Board;
- capital expenditure decisions are prudent and provide value to consumers;
- asset replacement and network augmentation is undertaken with appropriate timing;
- an ‘optimal life cycle’ approach is taken to managing network assets;
- asset management strategies reflect the expectations of stakeholders, including customers;
- TEN meets legal and regulatory requirements;
- a long term view is taken to developing annual budgets and work plans;
- asset management strategies reflect revenue availability and deliver a reasonable profit in keeping with both shareholder expectations and regulatory constraints;
- best practice performance in the management of direct and indirect operating and maintenance costs is achieved;
- appropriate risk management practices form an integral part of normal business activities; and
- ethical behaviour is practised in all business activities, including stakeholder interactions.

At an asset specific level, this AMP includes:

- a network development strategy designed to provide both sufficient capacity to supply the growth in electricity demand forecast over the planning period and a quantum improvement in supply reliability by addressing the network limitations described in Section 2.4;
- a strategy to maintain and upgrade the transmission assets acquired from Transpower on 1 April 2012. Many of these assets operate at a higher voltage than the rest of the network and require the application of new and unfamiliar work practices. Furthermore, many of these assets are nearing the end of their useful life and will require replacement or refurbishment during the planning period;

- a strategy to improve the efficiency and effectiveness of the maintenance effort by leveraging the data warehousing and life cycle asset management capabilities of SAP business management software; and
- a strategy to improve the overall quality of asset management planning and implementation through the development and implementation of a PAS 55 compliant asset management system, leading to PAS 55 certification (targeted FYE2015).

2.6 Asset Management Planning

The key internal planning documents that directly connect with the AMP are the:

- Statement of Corporate Intent (SCI), which outlines Top Energy's 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 budgets 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 on how budget funding will be used than set out in this AMP. 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 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 the:

- Risk Register, which identifies key risks that the business faces, given the architecture and condition of the network fixed assets. Mitigation of these risks is a key driver of the capital expenditure (CAPEX), and operations and maintenance expenditure (OPEX) on network assets;
- Emergency Preparedness Plan, detailing Top Energy's network management and associated practices adopted to ensure electricity supply is maintained or quickly restored following emergency circumstances and events;
- Safety Management System, detailing the processes and procedures in place to ensure the safety of employees and contractors working on the network;
- Public Safety Management System, which specifies the processes and procedures put in place by Top Energy to ensure that its 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 the 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

2012[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 TEN's 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 Top Energy's 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 FYE2014. Hence for the first year of the planning period, the AMP content is purely operational. In subsequent years the content becomes progressively more strategic to the extent that in the later years of the planning period the AMP content is entirely strategic.

The SCI provides the context for the AMP, which in turn provides the context for the Annual Plans. All three 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 the business is expected 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 the TEN's 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 TEN's 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 Top Energy's strategic corporate objectives. It also includes a review of TEN's forecast of the demand for electricity and the performance of the existing network asset base. As a result of this review, TEN prioritises its capital, operations and maintenance expenditure requirements. These activities lead to the development of initial plans that consider operational constraints at a surface 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 the SCI and Annual Plans are considered, which may result in further adjustments. The iterative process continues until a set of plans result that are consistent with one another, align with Top Energy's mission, and accommodate all key constraints.

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

[I] Commerce Commission Decision NZCC35, dated 30 November 2012.

2.6.1 Planning Periods Adopted

This AMP is dated 1 April 2013 and relates to the period from 1 April 2013 to 31 March 2023. It was approved by the Top Energy Board on 26 March 2013 and replaces all previously published AMPs.

2.6.2 Key Stakeholders

Engagement with stakeholders is ongoing throughout the year and the outcomes of this engagement provide critical inputs to the development of asset management plans at all levels. Top Energy engages with stakeholders through the following forums:

- meetings and informal discussions;
- discussions with major customers;
- industrial seminars and conferences;
- customer surveys;
- enquiries and/or complaints;
- discussions with the Trust;
- reviews of major events (e.g. storms);
- specific project consultation (e.g. capital projects);
- 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, Top Energy will engage the affected stakeholders and attempt to achieve an acceptable outcome. In these situations, the following considerations apply:

- safety is always the 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, an appropriate resolution process is adopted 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, Top Energy 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 Top Energy’s 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
CUSTOMERS	Fair Price	Commerce Commission, Pricing Spread sheets/ Budgets	Price-Quality Regulatory Threshold	Expenditure is controlled and managed against the Annual Plans to ensure profitability and service levels are maintained with prices allowed under the price-quality threshold.
		Billing System, DigSilent (Network Analysis Software)	Loss Factors	Network losses are measured, and planning and design activities ensure they are maintained at an optimum level. Loss factors for different parts of the network are calculated in accordance with the methodology approved by the Electricity Authority.
		SCADA, GIS, DigSilent	Asset Utilisation	Planning and design activities ensure optimum asset utilisation.
		Financial System, SCADA System, DigSilent	Transpower Costs	GXP demand is actively managed to ensure connection costs are controlled.
		PriceWaterhouseCoopers and Commerce Commission performance analysis	Lines Business Rankings	Network performance is assessed through comparison with peer group EDBs with similar operating characteristics to TEN.
	Reliability	Reliability Database, SCADA, GIS, Defects Management System	SAIDI, SAIFI	Reliability is continually measured and reviewed against the targets detailed in the AMP. Work aimed at improving reliability is targeted at known causes of poor reliability.
		GIS, DigSilent	Security Standards	Projects are identified and implemented to address present and future non-compliance.
	Quality	Faults Register	Voltage Complaints	Modelling and actual customer complaints identify problem areas within the network and voltage improvement projects are implemented as a result.
	Communications	CMS System (Call Management System)	Call Centre Statistics	The Top Energy owned contact centre (Phone Plus) ensures customers are directed to the appropriate point of contact within TEN for quick and efficient service.
RETAILERS	Communications	Fault records, SCADA and GIS	Outage data transfers	TEN shares information with retailers in accordance with standard industry protocols.
		Use of Systems Agreement and Industry Regulations	Tariff Changes	Top Energy coordinates 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	The current tariff structure has been 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	Top Energy has a transparent pricing structure that is explained clearly.
	Allocation of Losses	Monthly Loss Data and Network Analysis Software	12 month rolling losses	Loss factors for different parts of the network are calculated 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	Top Energy relies on retailers' systems to reconcile revenue.
BOARD	Safety	Industry Regulations and Standards	Accident Report Statistics and Non-Compliances	Safety is accorded the highest priority. TEN operates a safety management system that has received recognition of excellence from the industry and is being further developed to meet the requirements of the Electricity Regulations 2010. Safety outcomes are actively monitored and reported monthly to the Board.
	Profit	Financial System	Audited Financial Reports	Financial outcomes are reported monthly to the Board. This report includes a comparison against the approved budgets in this AMP.
	Reliability	Reliability Database, SCADA, GIS	Fault Statistics	Expenditure is targeted at initiatives that are expected to improve reliability of supply.
	Accountability	Key Performance Indicators	Annual Staff and Plan Performance Reviews	TEN employees' key performance indicators are linked to asset management service levels.
	Compliance	Correspondence and Board reports	Legal and Statutory Compliance	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	Equitable sharing of the costs of new construction installed for the benefit of individual customers.
TOP ENERGY CONSUMER TRUST	Dividend	Financial System	Audited Financial Reporting	Operating and capital expenditure is controlled and managed against Annual Plans to ensure profitability and service levels are maintained.
	Grow Asset Value	Financial System, GIS Asset Database	Annually Disclosed Asset Valuation	Timely investments are made to meet customer needs with long-term value-adding assets.
	Retain Ownership	Survey Report	Ownership Reviews as per Trust Deed requirement	Combine the desire of the shareholder 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	Forms an integral part of monthly reports to the Board.
STAFF	Health and Safety	Safety Database	Accident Statistics	Internal standards, procedures and policies.
	Job Security and Satisfaction	Administration Spreadsheet	Staff Survey Results, Staff Turnover Figures	Ensures that a succession plan is in place so that relevant skill sets will be available when required.
	Training	Administration Spreadsheet	Agreed Professional Development	The AMP reflects the skill set required of the TEN workforce, which inputs to the Training and Development Plan. Staff training hours are monitored.
	Safety	Industry Regulations and Standards	Accident Report stats and Non-Compliances	TEN operates a safety management system that has received recognition of excellence from the industry. Only pre-qualified contractors are permitted to work on the network.

STAKEHOLDER	EXPECTATIONS	CURRENT DATA SOURCE	MEASURES	ACTIONS
PUBLIC	Vegetation Control is Fair	Spread sheet, GIS	Complaints and Service Levels	Targeted vegetation control expenditure in accordance with the defined service levels and Tree Regulations.
		Reliability Database, SCADA, GIS	Fault Statistics	Expenditure is targeted at vegetation control on the basis of the expected improvements in reliability of supply.
	Safety	Public Safety Management System	Non-conformance records	The public safety management system has been implemented to ensure that operation of TEN's system assets does not pose risk or hazard to the general public.
	Land access rights upheld	CMS system, GIS	Complaints	The AMP identifies future work that requires access to landowners' property. This allows Top Energy to comply with relevant regulations and consult with stakeholders as appropriate.
COUNCIL	Resource Management	Legislation, GIS	Consents for Work	The network development plan within the AMP acknowledges time frames for consent processes.
	Road Management	Procedures, GIS	Consents for Work	The network development plan within the AMP acknowledges time frames for consent processes.
	Marine Crossings	Procedures, GIS	Consents for Work	The network development plan within the AMP acknowledges time frames for consent processes and on-going costs

Table 2.2: Relationship between Stakeholders and AMP

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 the asset management effort through the development of the Top Energy strategy, approval of this AMP and individual project approval papers. It also actively monitors the ongoing operation of TEN and TECS. The Board also provides input into development of the strategic performance targets in the SCI and approves all capital expenditure projects with an estimated cost of $500,000 or more.

The Top Energy Group structure is shown in Figure 2.1.

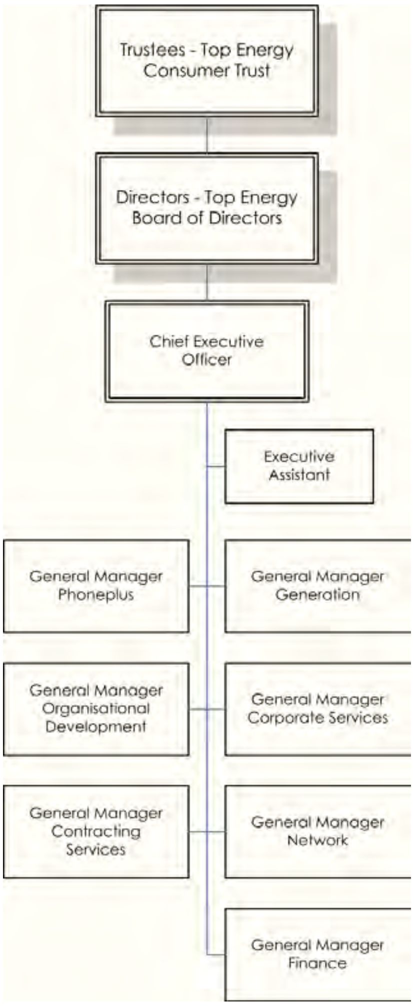

Figure 2.1: Top Energy Structure

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

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

- determining expenditure requirements;

- maintaining asset records, developing and setting standards;
- operating the network in a safe manner to minimise outages;
- monitoring performance;
- making investment recommendations;
- managing risk; and
- the ongoing management of the network assets within approved renewal, maintenance, capital and operational expenditure budgets.

In particular, TEN is responsible for updating this AMP and implementing the network Annual Plans. TEN is required to report any material variances from the Annual Plans in terms of both scope and financial variances 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 Networks and the CEO, and may be raised for Board approval if they are considered significant.

Apart from specialist activities, work on the network, including major construction projects, 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. For example, the Kerikeri zone substation currently under construction is outsourced to external contractors.

TECS operates from purpose-built depots in Kaitaia and Puketona. While TECS is also a division of Top Energy, work contracted-out to TECS is managed by TEN as if TECS was an external contractor operating under an arms-length relationship. The nature of the formal relationship between TEN and TECS is discussed further in Section 2.13.4. 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 TEN staff. However, TECS is able to prioritise routine maintenance activities and minor capital works, provided it works within the criteria set out in the relevant Annual Plan. TEN monitors the work undertaken by TECS through regular reports on work progress and financial performance against budget. 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 TEN maintenance, planning or operations managers. TEN operates a safety management plan and in 2011 won the Electricity Engineers' Association (EEA) Workplace Safety Award.

Consistent with the requirements in "Safety Manual – Electricity Industry (SM-EI)", TEN implements 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 Networks.

The structure of TEN's asset management team is outlined in Figure 2.2 below.

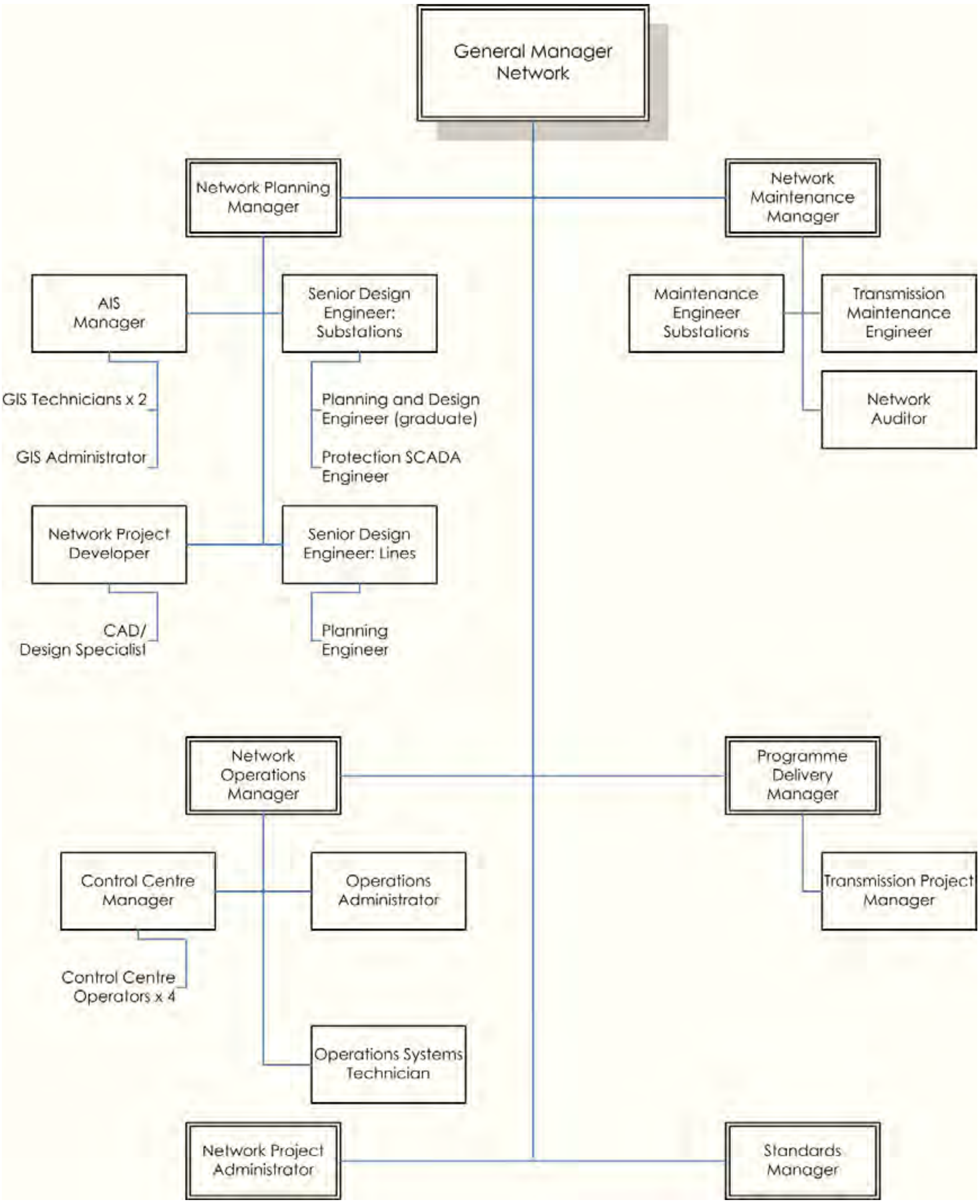

Figure 2.2: **Top Energy Network Division - Structure**

The key responsibilities of TEN senior management are:

Position	Accountability
General Manager Networks	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.
Standards Manager	To manage the development of standardised policies, procedures and specifications.
Engineers	Delegated authority to manage projects to individual budgets.

Table 2.3: Top Energy Network 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

TEN uses a range of information and telecommunications systems critical to the asset management process. This section outlines Top Energy's present and future development plans for information systems.

2.7.1 System Control and Data Acquisition

TEN uses 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 all TEN zone substations, as well as the 33kV feeder circuit breakers at Kaikohe and Kaitaia transmission substations, to be remotely operated from the central control room at Kaikohe. In addition, it is possible to remotely operate switches and reclosers situated at strategic locations throughout the sub-transmission and distribution networks.

SCADA monitoring and control of the transmission (110 kV) circuit breakers and ancillary equipment in the Kaikohe and Kaitaia transmission substations is still undertaken through Transpower's Northern Regional Control Centre in Auckland. It is planned to transfer this function to Top Energy's SCADA system in FYE2014.

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

Reporting of actual versus budget performance occurs on a monthly basis by general ledger category and individual projects. The senior management team also receive monthly reports of:

- profit and loss reconciliation by division;

- consolidated profit and loss;
- consolidated balance sheet;
- consolidated cash flow; and
- capital and maintenance expenditure.

Top Energy staff 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 base and overlaid with raster images from aerial photography.

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

ICP Application

An application that is integrated into the national registry to manage and report on consumers' Installation Control Points (ICPs). Supplementary information is included to facilitate Top Energy's management of customer connections; including safety and pre-connection status.

Permission Applications

Used 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 customers affected under different switching configurations. This is used to generate the network's SAIDI and SAIFI reliability reporting.

2.7.4 Network Analysis System

A DigSilent power systems analysis package is used 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. The DigSilent package directly interfaces with the GIS system to ensure that the analysis uses an accurate network model. This provides a powerful tool for the analysis of load growth, development options and the impact of unusual switching operations.

2.7.5 Customer Management System

Top Energy's subsidiary Phone Plus is contracted to handle customer calls and uses its Customer Management System (CMS) to provide Top Energy with details about specific customer calls and call statistics.

2.7.6 Drawing Management System

Top Energy uses 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

Since November 1 2012, Top Energy has been using the SAP asset management software modules as a repository for asset condition data and the basis for its maintenance planning and management, replacing the in-house developed maintenance management databases previously used to manage the maintenance effort. The SAP asset database was initially populated by downloading asset records from GIS. 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. TECS 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 into the SAP database using hand held data input devices.

Reports on assets with defects requiring remediation are downloaded by TECS for action.

2.8 Asset Data Accuracy

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

GIS data now 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;
- 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 in FYE2015.

2.9 Asset Management Systems

2.9.1 Asset Inspections and Maintenance Management

TEN has developed a time-based asset inspection programme, which is uploaded into and managed through SAP. The programme covers all system assets and is implemented by TECS asset inspectors. 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). The systematic network-wide inspection programme commenced in 2010 and since inspection cycles for some asset classes are as long as five years, not all assets have been inspected under this programme. A more detailed description of the different maintenance policies for specific asset types is provided in Chapter 6 of this AMP.

As discussed in Section 2.7.7, since November 2012 inspections have been managed through the implementation maintenance plans within the SAP asset management database. This has resulted in a review of some asset inspection cycles, which have also been revised for consistency with Top Energy's public safety management plan. This requires more frequent inspections near sensitive areas such as public parks and schools.

Defects identified during asset inspections and condition assessments are prioritised and actioned directly by TECS within approved budgets and performance targets. This allows TEN's maintenance management section to focus on strategic maintenance issues. Quality and efficiency is monitored through selective auditing and monthly reporting.

TEN receives regular reports from TECS on maintenance work undertaken. These are used by the General Manager Networks as the basis for Board reporting on maintenance work undertaken and expenditure against the maintenance budget.

TECS also operates 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

During 2009, TEN undertook a review of the risks associated with the available network capacity, performance and security of supply levels. This review identified a significant mismatch between the capacity of the network and forecast growth in electricity demand. It also identified a number of issues that limited the operation and reliability of the network, such as protection limitations that prevented sub-transmission lines and zone substation transformers being operated in parallel. As a result of this review, the 10-year network development plan described in Chapter 5 of this AMP was developed.

As part of this review, an interface was developed between the GIS system and the DigSilent network analysis software, which has allowed the development of a detailed and accurate model of the network for system analysis. This model, together with recorded SCADA information, future load growth predictions and asset defect, condition and attribute data, is used to determine the present utilisation of network assets and to identify areas of the present network unable to meet forecast load growth with an acceptable security of supply.

The network development plan is reviewed on an annual basis after the load forecast is updated, taking into account the actual peak demand on the network, which normally occurs in 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. The fundamental assumptions made in the formulation of the Network Development Plan are also reviewed for their on-going validity.

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. The reassessment may result in adjustments to the timing of planned development projects, but it may also result in the redesign of some projects to accommodate new block loads that have not previously been provided for or to accommodate developments that have been accelerated, cancelled or deferred. Project budget estimates are also reviewed annually and adjusted for changes in construction cost and the impact of more accurate resource consenting and easement costs.

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

Top Energy has developed an internal real time fault management system called Whiteboard. Once a call is received by the control room staff, a fault job is raised within Whiteboard. 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. Whiteboard also provides a list of faults with active or incomplete status, so that Top Energy 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 customers 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 audit consultant.

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.

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, which has involved discussions with the Commerce Commission on the need for a price path that will deliver the revenues needed to support the plan. As reported in Top Energy's 2012 Annual Report, debt funding has now been secured to insure 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
GROWTH FUNDING	This AMP assumes that the forecast growth in demand will materialise. The network development plan has been prepared on the basis that, in addition to debt and inter-group transfers, the cost of developing the network can be partly financed by the additional revenue from new network customers and contributions from customers for new connections.	Top Energy has developed a funding plan based on a combination of increased bank borrowings, the sale and lease back of buildings, inter-group transfer of funds from the profits of Ngawha Generation, new revenues from demand growth and line charge increases. This funding strategy is designed to keep increases in line charges as low as possible. Increases in transmission and sub-transmission 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 allowing for the load growth, over time the level of network investment will reduce and this should assist in stabilising future pricing.	If the assumed growth in electricity demand is lower than forecast, it will be difficult to cancel or defer the larger projects in the development plan. This is because much of the network currently does not meet accepted industry standards for security of supply. For example, the purpose of the second 110kV line to Kaitaia is to increase network reliability for existing consumers rather than to increase capacity to accommodate new load. The project cannot be deferred if targeted improvements in the reliability of supply are to be achieved. Achieving these reliability improvements without increasing line charges more than currently planned will therefore be difficult if the forecast demand growth does not eventuate.
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 investment in infrastructure.	The 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.
DEMAND SIDE MANAGEMENT AND PEAK CONTROL	The industry 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 for 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. This assumption is based on the information that suggests investors will want to minimise the cost of network development. All stakeholders want costs controlled and environmental lobbies want losses minimised. Power factor and changing demand behaviour affects losses.	The network development plan focuses on the transmission and sub-transmission network and, apart from increasing the points of injection, largely overlooks the distribution network. Without the ability to effectively control peak load, Top Energy may need to reinforce the distribution network more than currently planned and this would utilise funds intended to finance improvements to the transmission and sub-transmission network.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
RELIABILITY AND QUALITY	Customers want an improvement in the reliability and quality of electricity supply.	Top Energy's current supply reliability is the worst in the country. The Trust and Board both consider that improving the reliability of supply is consistent with its SCI objective of investing in activities that contribute to economic development within the Far North District. 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. Top Energy has consulted widely with the local community and received strong support for its proposals, notwithstanding the significant increase in line charges that will be necessary to fund the investment.	There is a risk that the current support 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. Top Energy has tried to mitigate this risk by returning profits to consumers by means of a rebate on electricity prices rather than a one-off annual dividend. Furthermore, it is anticipated that future increases in line charges will be significantly lower than those that have recently been implemented.
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 that age profile of assets in a specific category. The introduction of a formalised asset condition assessment in the Commerce Commission's Commerce Act (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 will be supported by the introduction of SAP which will permit the collection of more useful information on the condition of individual assets and also allow asset maintenance (including replacement and renewal) expenditure to be better targeted at assets known to be in poor condition.	Defective equipment currently causes more than 25% of unplanned supply interruptions and approximately 40% of Top Energy's measured SAIDI. However it is a fault cause that is difficult to target through a reliability improvement programme, since equipment failures 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 should reduce the SAIDI impact by allowing supply to be restored sooner; particularly to customers upstream of a fault location. The installation of diesel generators at Taipa should also result in SAIDI improvements. In the medium-term, the network development plan will also provide SAIDI improvements, because most transmission and sub-transmission 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 customers affected by a specific distribution network fault will be reduced.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
			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 therefore limits the extent to which supply reliability can be 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 the TEN 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.
INFLATION	Except where otherwise shown, cost estimates in the AMP are presented in real New Zealand dollars as at 31 March 2013. Where these cost estimates are expressed in nominal New Zealand dollars, an annual inflation rate of 2.5% is assumed for the whole of the planning period.	This is the approximate mid-point of the inflation forecasts for the years 2013-16 provided by Treasury in its Budget Economic and Fiscal Update 2012, published on 24 May 2012. It is also the mid-point of the Reserve Bank's target inflation rate of 2-3%.	

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 TEN's existing 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 to have a documented asset management strategy. The key element of this strategy is to improve the reliability of supply provided to 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 to be done by:

- construction of a second 110 kV 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 existing sub-transmission capacity issues and reduce the number of long, heavily-loaded distribution feeders;
- installation of new protection systems on the sub-transmission network to allow circuits to operate in parallel, so that the majority of sub-transmission 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; and
- improving the efficiency of the maintenance effort through the introduction of a state-of-the-art 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 this strategy will be implemented.

The strategy is consistent with the overarching corporate mission statement described in Section 2.3 and, in the opinion of both the 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. Top Energy's new 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

Top Energy has a documented Emergency Preparedness Plan detailing its response and management of serious incidents and events. However, AMCL found that this plan was not formally rehearsed, although it noted that lower level emergency events (due, for example, to adverse weather events) were relatively common and the response to these provided relevant staff training. Top Energy also tries to 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.

2.11.4 Implementation of Asset Management Plans

AMCL found that TEN has processes, but not necessarily documented procedures, for the implementation of its 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. These weaknesses are being addressed through the introduction of SAP, which was subsequent to 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.

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.

Top Energy was 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. At the time of writing this AMP, the new enterprise-wide system was still being bedded-in, but over time it is expected that more useful asset condition data will be recorded and made available to those who may need it within the organisation. The use of hand-held devices is also allowing defect remediation to be directly recorded in real-time without relying on a separate data entry process.

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 is SAP are less mature, although the use of hand held field input devices is facilitating this. 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

TEN uses the following documents and processes to control its asset management activities:

2.13.1 Asset Management Policy

An asset management policy has been prepared in accordance with the requirements of PAS 55. However, the policy document is still only a draft and has still to be formally signed-off by the CEO and communicated to stakeholders. It also needs further review to confirm that it is fully aligned with the higher level corporate strategy set out in the SCI and meets all requirements of clause 4.2 of PAS 55.

2.13.2 Asset Management Plan

This AMP is the document central to the implementation of TEN's 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 states:

> *…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 TEN's 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 TEN's asset management performance – these could include indicators relating to the completion of planned asset inspections and the level of defect backlogs. TEN already has internal measures and targets relating to health and safety but leading indicators of its asset management performance have still to be developed.

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 TEN and TECS and so are critical to the implementation of the action plans within this AMP. The Interface Agreement defines the pseudo-contractual relationship between the two business units based on an asset owner–service delivery model. The Sourcing Strategy, which was developed with the assistance of external consultant, Marchment Hill, provides for all TEN work to be undertaken by TECS, but allows TECS to outsource to external contractors as required. This is particularly applicable to the large, one-off capital transmission and sub-transmission projects included in the network development plan.

AMCL assesses Top Energy's outsourcing strategy to be borderline and almost compliant with clause 4.4.2 of PAS 55. The main issue is the management of the interface between TEN and TECS, which is still transitioning to an arm's length pseudo-contractual relationship. AMCL considers that, while this relationship is nominally formalised, it is often not so in actuality. This would suggest that the accountabilities and responsibilities of the staff involved may not always be clearly acknowledged.

2.13.5 Documentation of the Asset Management System

TEN is in the process of creating the policies, procedures and work instructions for its public safety management system in accordance with the requirements of the Electricity Regulations 2010. When this work is complete, attention will move to documenting the asset management system in accordance with the requirements of PAS 55. AMCL noted that many of the safety management system procedures and work instructions documented what was already occurring within TEN and TECS and it is anticipated that this will also be true of the PAS 55 Asset Management System documentation requirements. It is also anticipated that some procedures and work instructions will be included in both systems.

2.13.6 Legal Compliance Database

Ensuring that TEN complies with all legal obligations is the responsibility of the General Manager Corporate Services and is explicitly identified in the job description for 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.

2.13.7 Network Development Procedures and Controls

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

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 is well intentioned, but ineffective. The lack of a clear "line of sight" into TECS suggests that accountability for implementation of the maintenance plan was unclear or not well understood.

It is anticipated that over time these issues will be addressed as SAP (introduced in November 2012) becomes the repository for asset condition data and the tool used for managing the maintenance effort.

2.13.9 Performance and Condition Monitoring

Top Energy has 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, should assist in addressing these deficiencies.

2.13.10 Audit

The AMCL report noted that no formal audit procedures exist, although there was informal auditing of asset management activities; particularly field activities undertaken within TECS or by its subcontractors. It noted that the most developed audit element within Top Energy related to safety and that the new safety management system will require an audit process to be structured and formalised. TEN expects that this safety management audit process will in time form the basis of a more developed asset management audit system that complies with PAS 55 requirements.

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 have 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.

However, the report also noted that continual improvement of the core asset management system documentation such as the asset management system, policy and plans is not yet formalised. Nevertheless, the preparation and ongoing improvement of this AMP is accorded a high priority within TEN, which over the last few years has engaged an external consultant to assist with this process. The need to extend this improvement process to cover all asset management activities is recognised and TEN is intending to formalise its asset management system following the implementation of the safety management system, with the aim of achieving PAS 55 certification during FYE2015.

2.14 Communication and Participation Processes

2.14.1 Communication of the AMP to Stakeholders

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

2.14.2 Top Management Communication and Support

Top Energy's 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 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 is its proven functionality as an asset management tool.

2.14.3 Communication, Participation and Consultation

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

This issue is recognised by executive management and a new General Manager position focused on organisational development has been established. This position was taken up at the beginning of FYE2013.

2.15 Capability to Deliver

The investment programme set out in later sections of this AMP is more ambitious than any previous investment in Top Energy's electricity distribution network. Top Energy has 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, are testimony to this.

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:

- new revenues from line charges and demand growth. Line charges from 1 April 2013 will comply with the Commerce Commission's final determination *Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors,* published on 30 November 2012; and
- increased bank borrowings. Top Energy announced in 2012 that it had secured the bank funding needed to fund the investment.

Top Energy's Board and executive management are confident of their ability to fund the network development plan without jeopardising the long term financial security of the business.

2.15.2 Line Routes

The ability to secure line routes, in particular the route for the new 110kV transmission line between Kaikohe and Kaitaia, is perhaps the biggest risk to the timely delivery of the investment programme. Delays to the construction of the section of this line between Hariru Rd and Wiroa have already been caused by difficulties in securing the agreement of affected landowners.

Top Energy has identified a line route between Wiroa and Kaitaia and has commenced negotiations with affected landowners. It has a dedicated team working on this and will use its best endeavours to find a route that is acceptable to all stakeholders. However, the cooperation of all concerned will be necessary if construction is to be completed in accordance with the schedule set out in this AMP.

2.15.3 Engineering

The design of the network development works set out in this AMP requires engineering skills and resources beyond TEN's in-house capabilities. This applies in particular to the design of the new transmission lines and the protection systems needed to enable the sub-transmission lines and power transformers to operate in parallel. TEN plans to outsource the skills and engineering resources that it cannot provide in-house and has allowed for this in estimating the costs of the various projects.

2.15.4 Construction

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

Top Energy provided services to 31,217 connection points as of 31 March 2012.

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 FYE2011, the average quantity of electricity supplied to each connection point was again the second lowest in the country; notwithstanding the impact of the large Juken Nissho triboard mill load. Almost 20% of the energy delivered through the TEN distribution network is provided to the five largest consumers.

3.1.2 Load characteristics and large users

For FYE2012, the maximum demand was 64MW and the total energy delivered to consumers was 333 GWh. The majority of electrical load is residential, small commercial and agricultural. There are only five large users:

- Juken Nissho Mill near Kaitaia (≈ 10.6MVA);

- AFFCO Meat Works near Moerewa (≈ 2.4MVA);
- Mt Pokaka Timber Products Ltd, south of Kerikeri (≈ 1.2MVA);
- Immery's Tableware near Matauri Bay (≈ 1.1MVA); and
- Northern Regional Corrections Facility at Ngawha (≈ 0.6MVA).

Top Energy's three largest consumers have dedicated supply feeders from a local zone substation. However, Immery's Tableware and the Ngawha Corrections Facility are supplied at 11kV from their local distribution feeder.

Maintenance, renewal and replacement strategies for assets that affect the operations of major consumers are discussed and negotiated with each individual company. As a result, maintenance work affecting these consumers is usually scheduled for their off-peak or non-operational periods. Top Energy also works closely with its major customers to ensure that the service it provides aligns with their requirements, to the extent feasible on a shared network.

Approximately 20% of the energy delivered through the network supplies these five 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 the supply area.

3.1.3 Network Characteristics

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

Top Energy's supply area is separated into two distinct geographic areas. The Northern area including Kaitaia, Taipa; and the Far North peninsular is supplied from a 110kV transmission substation located at Pamapuria, approximately 10km east of Kaitaia. The more heavily loaded Southern area (including Rawene, Kaikohe 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 sub-transmission voltage.

A 33kV sub-transmission network supplies eleven zone substations; four in the Northern area and seven in the Southern. The zone substations in turn supply a total of 47 distribution feeders, which generally 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 3-phase, 480/240V 2-phase and 240V single phase.

The key weaknesses of the current network are:

- the single 110kV circuit between Kaikohe and Kaitaia, which means that all supply to consumers in the Northern area is lost when this circuit is not available. During the annual maintenance shutdown of this circuit, no grid electricity is available in the Northern area and approximately one third of TEN's consumers are without power during this time;
- transformer banks at Kaitaia substation are under-sized and in poor condition. In the event of a loss of one of these banks at times of peak load, supply to consumers in the Northern area may need to be rationed;
- capacity constraint issues at Waipapa substation. The ability to maintain an acceptable voltage level in the Kerikeri area is marginal if one of the two sub-transmission lines supplying the Waipapa zone substation is lost; and
- protection constraints that currently require all 33kV lines and substations to operate in a radial configuration. This results in an unavoidable loss of supply to some customers if any sub-transmission element should fail.

3.1.4 Grid Exit Point

With the acquisition of the transmission assets from Transpower in 2012, Top Energy's 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 consideration of the need for thermal upgrades to the incoming Transpower circuits can therefore be deferred to beyond the planning period.

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. Even at current loads, support from Ngawha generation may be required should either of these transformer banks be out of service at times of peak demand.

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

There are two single phase 110/33kV transformer banks at Kaitaia, each rated at 22MVA. As the capacity is insufficient to provide N-1 security, in the event of failure of a transformer unit supply might need to be rationed until a replacement unit (provided by Transpower) is transported to site and installed. Condition assessment indicates that both transformer banks have limited remaining life and replacement of one bank with a new 40/60MVA unit is planned for FYE2015. The second bank is scheduled for replacement in FYE2020.

The condition of the 33kV circuit breakers and outdoor 33kV switchyards at both substations, particularly Kaikohe, is a concern and these assets pose both reliability and safety issues. Outdoor 33kV switchyards are no longer considered good industry practice and outdoor-indoor conversions are planned at Kaikohe in FYE2014 and Kaitaia in FYE2020.

A further issue is low 110kV voltage at Kaikohe, which can be a concern when Ngawha generation is not operating. This is primarily a Transpower problem, which should be alleviated with the commissioning of a new STATCOM at Marsden and the commissioning of a third 220kV circuit through the Auckland isthmus in 2013.

3.1.6 Sub-transmission system

A geographic diagram of TEN's 33kV sub-transmission network is shown in Figure 3.1.

Table 3.1 below shows TEN's existing zone substation transformers. TEN generally purchases transformers that can be upgraded by the addition of cooling systems to suit increasing load growth.

Historically, Top Energy has standardised on an 11.5/23MVA design for its larger load substations, to allow the relocation of transformers in case of an emergency if a single unit should fail. However, the tap changer range in some of the zone transformers limits the ability to maintain acceptable voltage levels. To allow transformer maintenance and to provide backup to locations where only a single 33/11kV transformer is installed, Top Energy has a 7.5MVA mobile transformer unit.

SUBSTATION	UNIT	NOMINAL ONAN/ ONAF OR OFAF MVA RATINGS WITH EXISTING COOLING	PRESENT MAXIMUM MVA RATING
Southern GXP			
Kaikohe	T1	11.5/23 MVA ONAN/OFAN (Has pumps but no fans)	11.50
	T2	11.5/23 MVA ONAN/OFAN (Has pumps but no fans)	11.50
Kawakawa	T1	5 MVA ONAN (Has no pumps or fans)	5.00
	T2	5 MVA ONAN (Has no pumps or fans)	5.00
Moerewa	T1	11.5/23 MVA ONAN/OFAN (Has pumps but no fans)	11.50
	MOB	5/7.5 MVA ONAN/ONAF (Has no pumps but fans are fitted)	7.50
Waipapa	T1	11.5/23 MVA ONAN/OFAF (Has both pumps and fans)	23.00
	T2	11.5/23 MVA ONAN/OFAF (Has both pumps and fans)	23.00
Omanaia	T1-1 R	0.917 MVA ONAN (Has no pumps or fans)	2.75
	T1-2 Y	0.917 MVA ONAN (Has no pumps or fans)	
	T1-3 B	0.917 MVA ONAN (Has no pumps or fans)	
Haruru	T1	11.5/23 MVA ONAN/OFAF (Has pumps and one fan)	23.00
	T2	11.5/23 MVA ONAN/OFAF (Has pumps and one fan)	23.00
Mt Pokaka	T1	3/5 MVA ONAN/ONAF (Has no pumps but has fans)	3.00
Northern GXP			
Okahu Rd	T1	11.5 MVA ONAN (Has no pumps or fans)	11.50
	T2	11.5 MVA ONAN (Has no pumps or fans)	11.50
Taipa	T1	5/6.25 MVA ONAN/ONAF (Has no pumps, but fans are fitted	6.25
Pukenui	T1	5 MVA ONAN (Has no pumps or fans)	5.00
NPL	T1	11.5/23 MVA ONAN/OFAF (Has both pumps and fans)	23.00
	T2	11.5/23 MVA ONAN/OFAF (Has both pumps and fans)	23.00

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 sub-transmission network only; there is not full N-1 supply to the Northern area, as there is only one incoming 110kV circuit.

As can be seen from the table, the Waipapa 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 Top Energy's security standard. In addition, all zone substations operate in an open bus position, due to transformer protection constraints. This means that, even where sufficient capacity exists to meet the N-1 criterion, in the event of a sub-transmission fault there will be a loss of supply until the network is reconfigured (generally through remote control from the Kaikohe control room) to utilise the available spare capacity. Protection modifications, which will allow the Haruru

Falls substation to operate in a closed bus configuration, are expected to be completed by the beginning of FYE2014.

SUBSTATION	UNIT	PRESENT RATING (MVA)	SUBSTATION PRESENT CAPACITY (MVA)		
Southern Area			Firm (N-1)	11kV feeder Switched Capacity	Year Substation N-1 Exceeded
Kaikohe	T1	11.50	11.50	1.00	>FYE2023
	T2	11.50			
Kawakawa	T1	5.00	5.00	2.50	>FYE2023[1]
	T2	5.00			
Moerewa	T1	11.50	7.50[2]	2.10	>FYE2023[3]
Waipapa	T1	23.00	23.00	1.50	Current[4]
	T2	23.00			
Omanaia	T1	2.75	0.00	0.30	Current
Haruru	T1	23.00	23.00	0.45	>FYE2023
	T2	23.00			
Mt Pokaka	T1	3	0.0	1.50	>FYE2023
Northern Area			Firm (N-1)	11kV feeder Switched Capacity	Year Substation N-1 Exceeded
Okahu	T1	11.50	11.50	3.70	>FYE2023
	T2	11.50			
Taipa	T1	6.25	0.00	3.6[5]	2017[6]
Pukenui	T1	5.00	0.00	0.24	Current
NPL	T1	23.00	23.00	1.10	>FYE2023
	T2	23.00			

Table 3.2: Present Zone Substation Transfer/Switching Capabilities

Note 1: The current load exceeds the capacity of a single transformer, but the switched 11 kV transfer capacity is sufficient to allow supply to all consumers to be restored before the mobile transformer is relocated. This situation is expected to continue through the planning period.
Note 2: Mobile substation, which is currently connected at the Moerewa substation.
Note 3: Provided the mobile substation continues to be located at Moerewa.
Note 4: While the peak demand at Waipapa is well within the rating of a single transformer, the network has insufficient capacity to maintain voltage within prescribed limits in an N-1 contingency situation.
Note 5: Diesel generation.
Note 6: Assuming that the generators' condition does not deteriorate and the generators continue to be able to produce their rated power output.

3.1.7 Distribution system

TEN's distribution system consists of 47 predominantly overhead rural feeders, which supply almost 6,000 transformers. The system operates at 11kV except for about 20km of the Rangiahua feeder, which had been upgraded to 22kV. Figures 3.2 to 3.12 show the distribution system for each of TEN's zone substations.

The percentages of underground to overhead line are as follows:

Sub-transmission	-	overhead 100% (except for three short cable lengths at substation exits)
Distribution	-	overhead 94%, underground 6%
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 30 years, Top Energy has 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.

TEN's 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.

Distribution transformers follow the ISO standard sizing and 87% of distribution transformers are pole mounted. Pole mounting of transformers is now limited to ratings up to 100kVA for seismic purposes. Transformers may be 1, 2 or 3 phase according to customer or load requirements, although 3 phase is not available to customers supplied from a SWER line.

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

Transformer size kVA	Number Pole Mounts	Number of Pad Mounts
Under 10	194	-
10	184	1
15	2,753	19
20	2	-
25	51	-
30	1,340	89
50	384	153
75	23	-
100	156	176
150	21	50
200	29	165
300	-	75
400	-	9
500	16	26
750	-	11
1000	-	4
1500	-	2
2000	-	1
3000	-	1

Table 3.3: Distribution Transformer Population

Figures 3.2 – 3.12 below show the coverage of the distribution feeders supplied from each of Top Energy's zone substations. Not shown are four NPL feeders supplying the Juken Nissho tri-board mill and one Mt Pokaka feeder supplying the Mt Pokaka Timber Products mill.

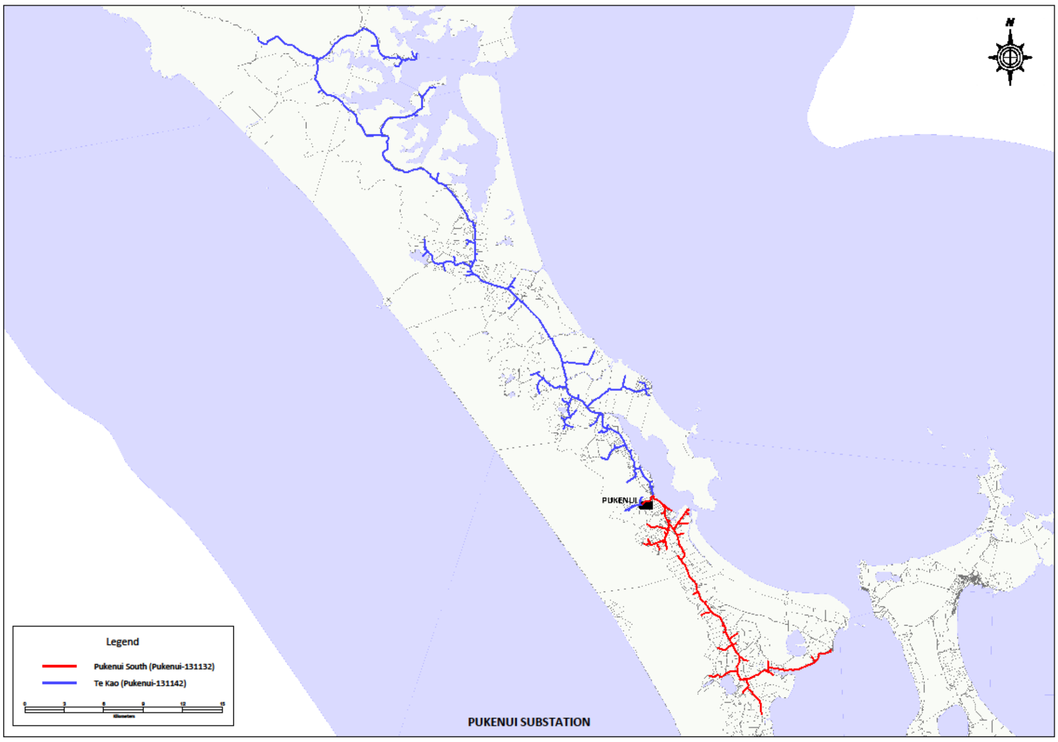

Figure 3.2: Geographic diagram of the Pukenui zone substation

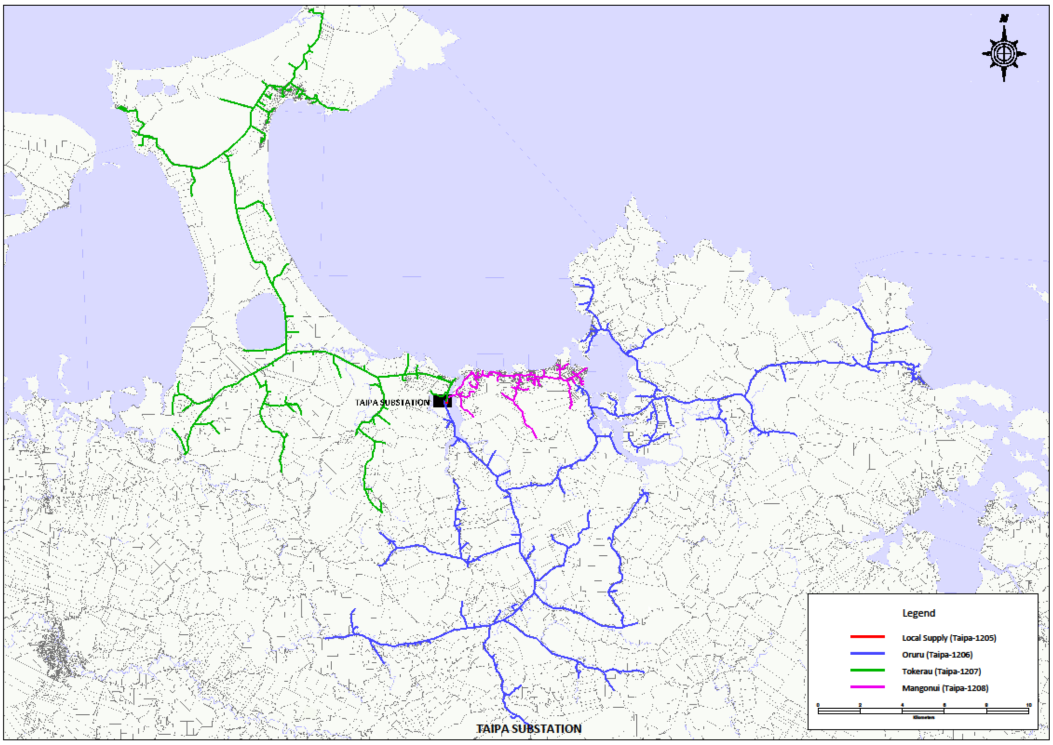

Figure 3.3: Geographic diagram of the Taipa zone substation

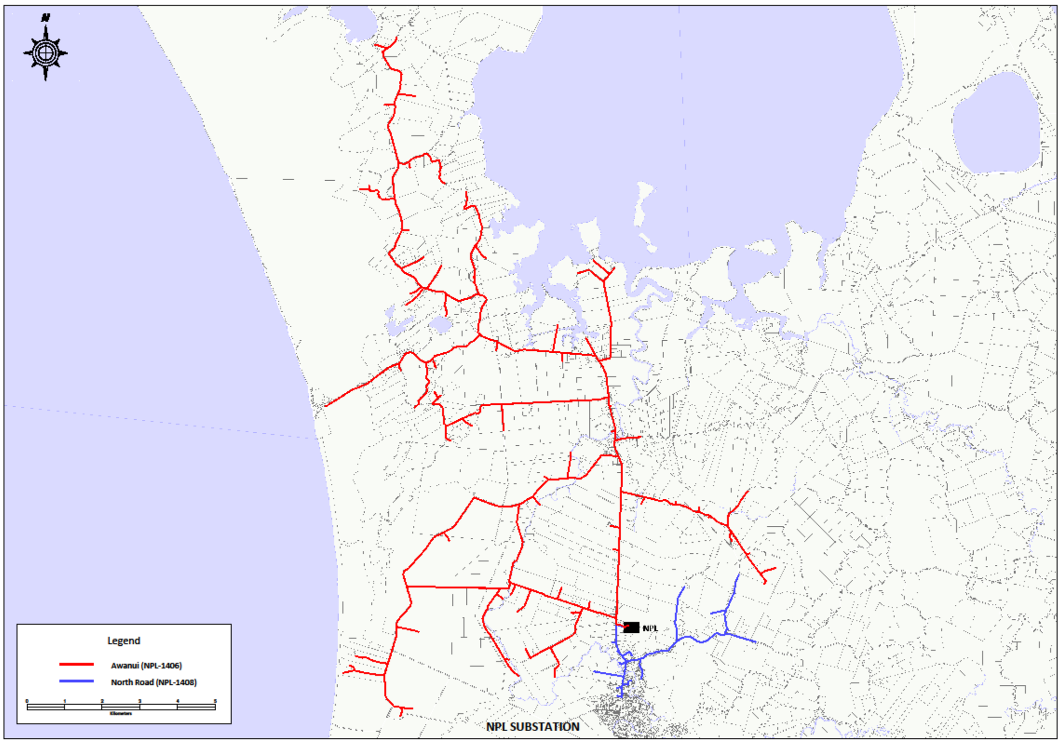

Figure 3.4: **Geographic diagram of the NPL zone substation**

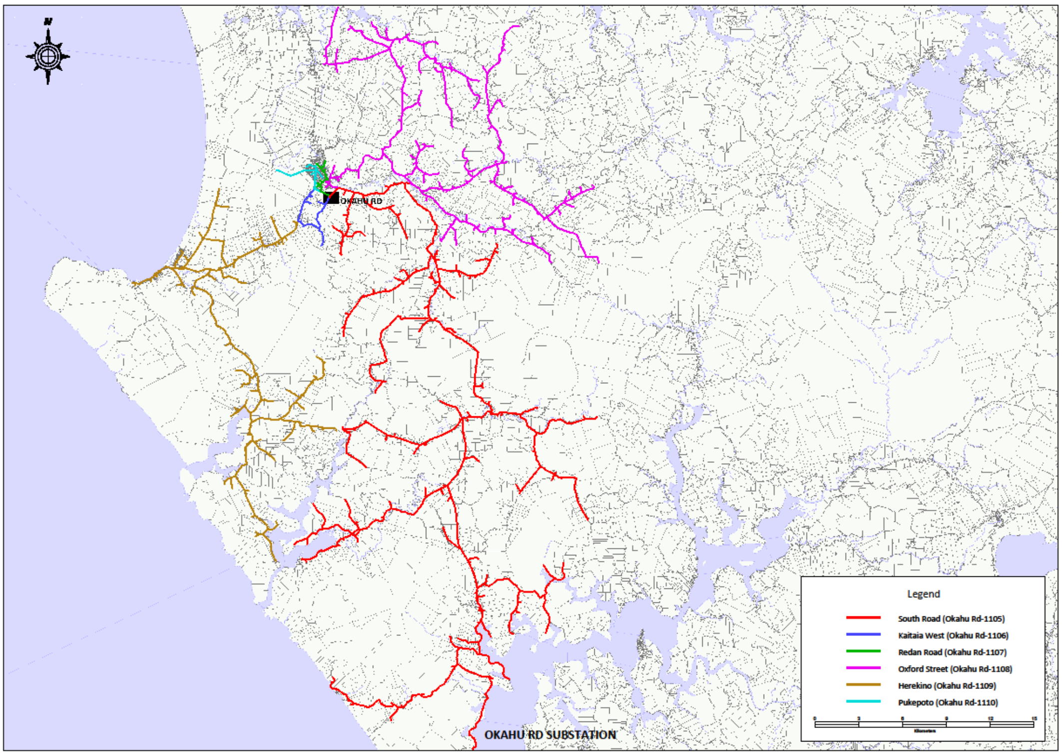

Figure 3.5: **Geographic diagram of the 33kV Okahu Road zone substation**

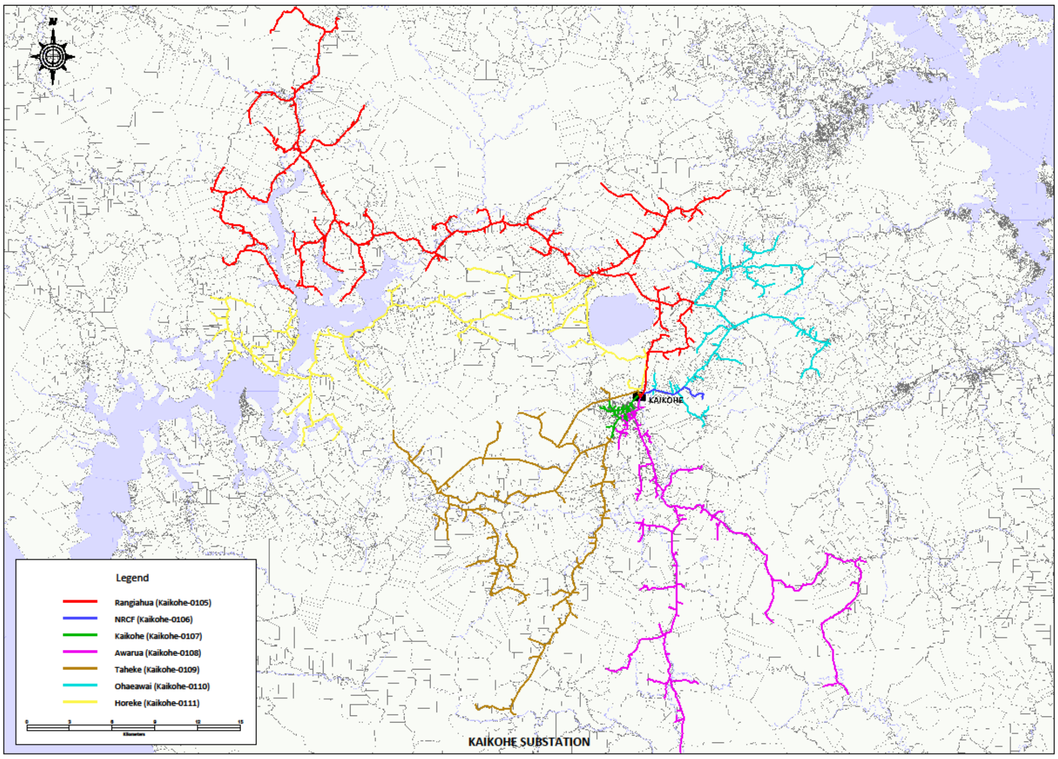

Figure 3.6: **Geographic diagram of the Kaikohe zone substation**

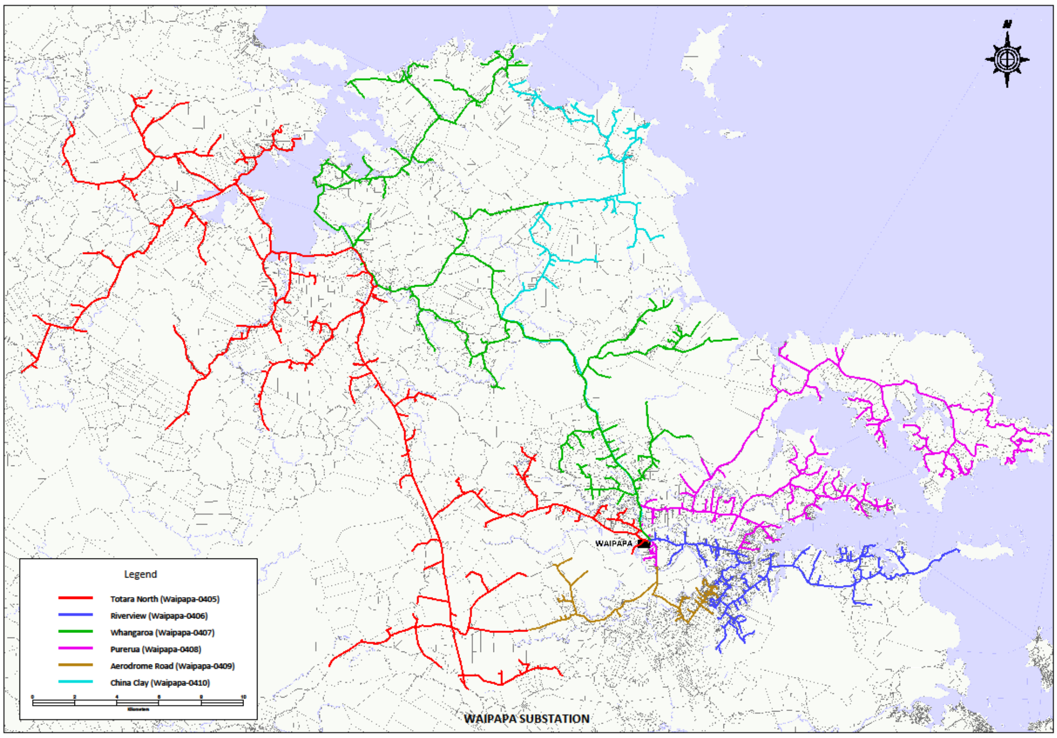

Figure 3.7: **Geographic diagram of the Waipapa zone substation**

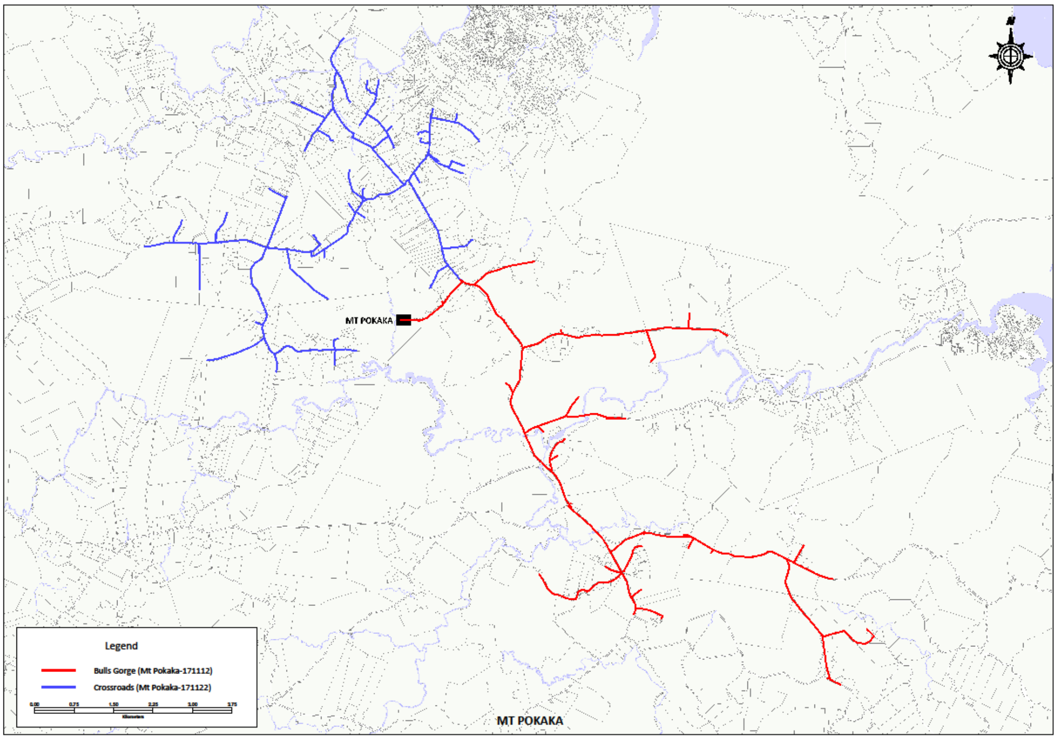

Figure 3.8: **Geographic diagram of the Mt Pokaka zone substation**

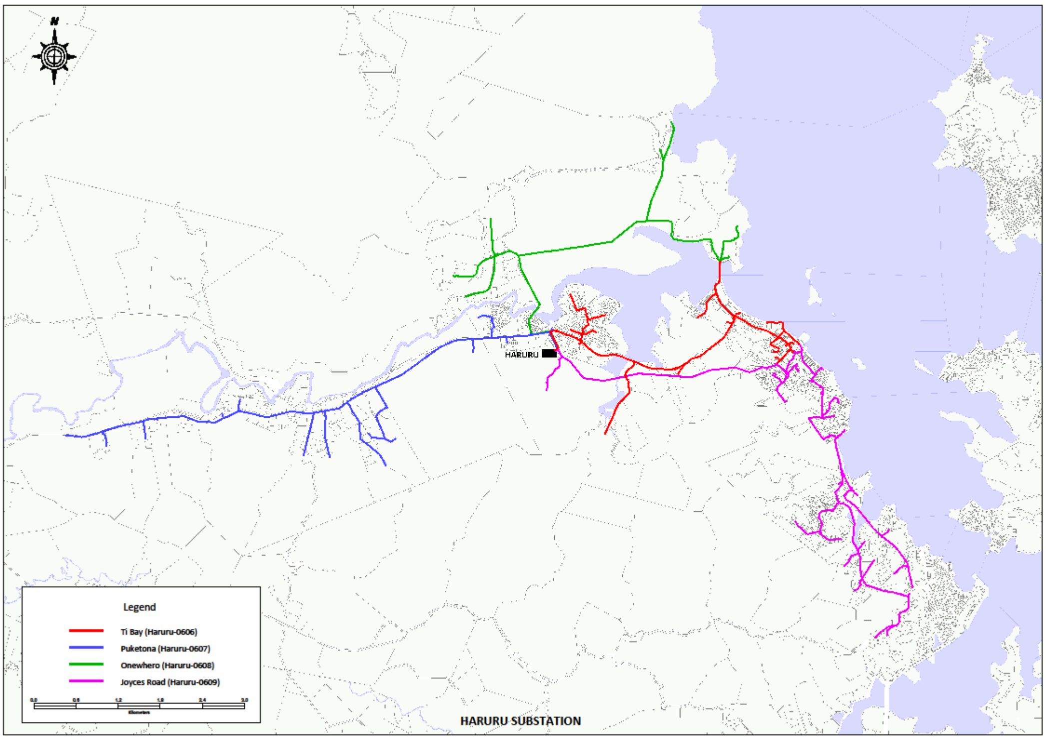

Figure 3.9: **Geographic diagram of the Haruru zone substation**

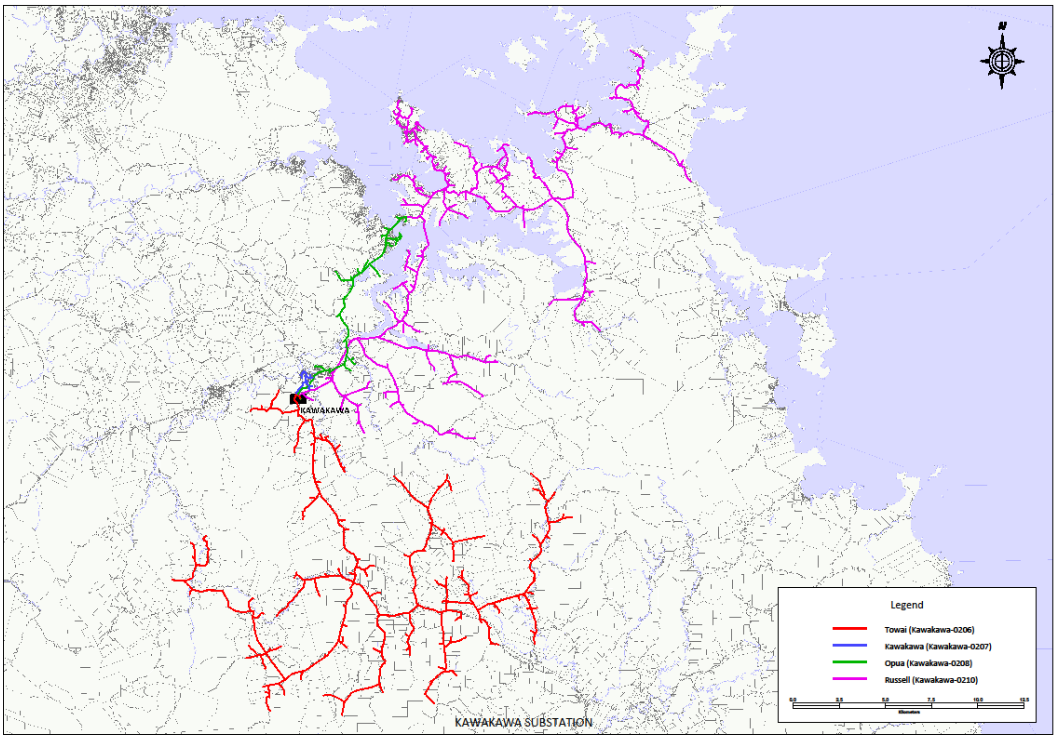

Figure 3.10: Geographic diagram of the Kawakawa zone substation

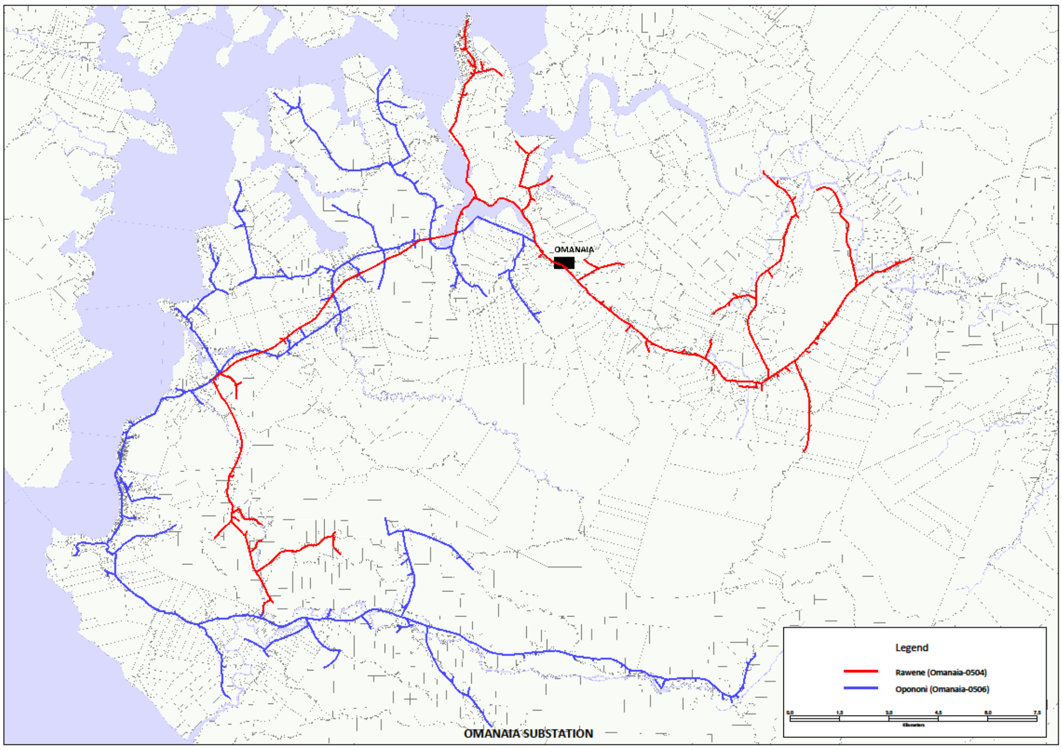

Figure 3.11: Geographic diagram of the Omanaia zone substation

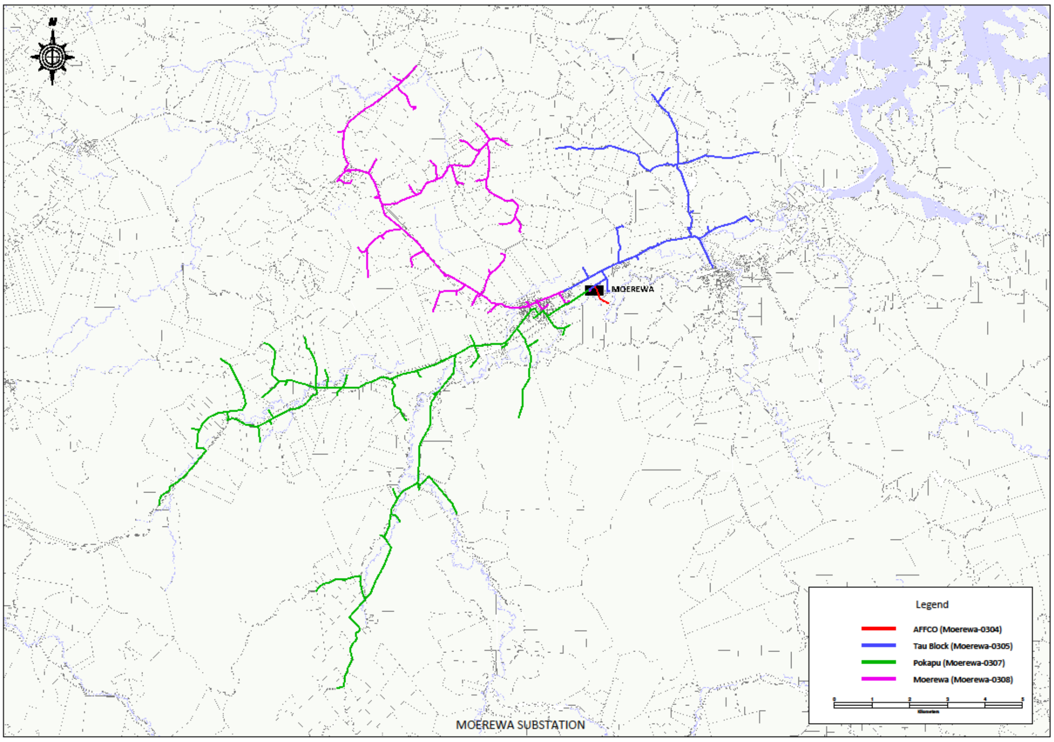

Figure 3.12: Geographic diagram of the Moerewa zone substation

Over 35% of Top Energy's 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, Top Energy is obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers supplied from existing lines.

The Electricity Networks Association (ENA) created a working party to review the implications of this obligation, particularly within distribution companies that include a large rural network component. To assist this review, in April 2009, Top Energy engaged Intergraph to create a trace within its GIS system to identify uneconomic lines using data based on the Ministry of Economic Development (MED) test scenarios. This trace stepped through each piece of equipment within the GIS, feeder-by-feeder and identified where uneconomic lines began. The start points were individually recorded and each of these start points became the beginning point of a further trace; which in turn identified all downstream equipment, therefore summing the length of uneconomic conductors. The results revealed that 32% of Top Energy lines were uneconomic, based on MED criteria. However, these lines fed only 8% of Top Energy's consumer base. The high proportion of uneconomic lines in Top Energy's supply area presents a burden for all Top Energy consumers.

3.1.8 Secondary assets

3.1.8.1 Protection

The company uses a mixture of protective devices on its network including:

- electromechanical relays;
- numerical relays;
- integrated protective devices such as 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.

The TEN network is on the fringe of the transmission grid and is characterised by very low fault levels. This affects the reliability of protection, particularly where traditional electromechanical protection relays are used. These protection limitations mean that the sub-transmission network is currently operated in a radial configuration, making uninterrupted N-1 security impossible. Top Energy has commenced a programme to progressively replace the electromechanical protection relays in its zone substations in order to improve the detection and discrimination of faults and to permit the parallel operation of sub-transmission assets. Furthermore, as the communications infrastructure is upgraded through the installation of fibre-optic cable, the existing overcurrent protection on 33kV lines will be changed to differential protection, which is expected to provide superior performance in TEN's low fault level environment.

3.1.8.2 SCADA and communications

TEN's system control and data acquisition (SCADA) system operates out of TEN's control room in Kaikohe. It uses iPower SCADA systems to operate its electricity network.

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. TEN uses multiple communication protocols over its own VHF network and a leased UHF broadband network. The existing data communications system is nearing the end of its useful life and does not provide for new requirements, such as protection signalling. A modern system, primarily utilising fibre optic cable, will be progressively installed over the period of this plan.

3.1.8.3 Load control system

TEN owns and operates static ripple control plants via its SCADA system and injection is made at 317Hz onto its 33kV sub-transmission system. The plants are located at TEN's Kaikohe and Okahu Road substations, with a standby plant at Waipapa substation.

The load management plants are used to control demand by allowing the organisation to control a range of load types to actively manage its 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 rather than Top Energy.

3.2 Asset Details by Category

In accordance with the Commerce Commission's Electricity Distribution Information Disclosure Requirements 2008, Top Energy disclosed that its system fixed assets were valued at $154,207,000 as at 31 March 2012; an increase of $10,233,000 since 31 March 2011. This total does not include the transmission assets that Top Energy acquired from Transpower on 1 April 2012, which were valued at approximately $6.7 million. This increase in asset value is derived as follows:

	$000
Asset Value at 31 March 2011	**143,974**
Add:	
New assets	13,832
Indexed inflation adjustment	2,261
Less:	
Depreciation	5,860
Asset value at 31 March 2012	**154,207**

Table 3.4: Value of System Fixed Assets

The disclosed regulatory asset value of non-network assets was $2,438,000.

The different assets that make up TEN's system fixed asset base are discussed in the sections below.

3.3 Transmission Assets

TEN's transmission assets include transmission substations at Kaikohe and Pamapuria, 10km east of Kaitaia, and a single circuit 110kV transmission line that is approximately 54km long. The transmission line uses Coyote ACSR conductor and is wood pole, except for the section over the Maungataniwha Range, which has steel towers. The two transformers at each substation are all single phase units.

The 33kV switchyards are outdoor, with oil-filled circuit breakers.

3.4 Distribution Assets

3.4.1 Overhead conductors

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

The types of overhead conductor known to be installed on Top Energy's Network includes 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.

TEN's network is in close proximity to the sea at certain locations, where there is salt content in the atmosphere; this causes corrosion of ACSR conductor. To overcome this, TEN now uses all aluminium alloy conductor (AAAC) on new transmission and sub-transmission lines, except for very long spans that require the additional strength of ACSR.

3.4.1.1 Sub-transmission

Figure 3.13 shows the age profile of sub-transmission overhead conductors.

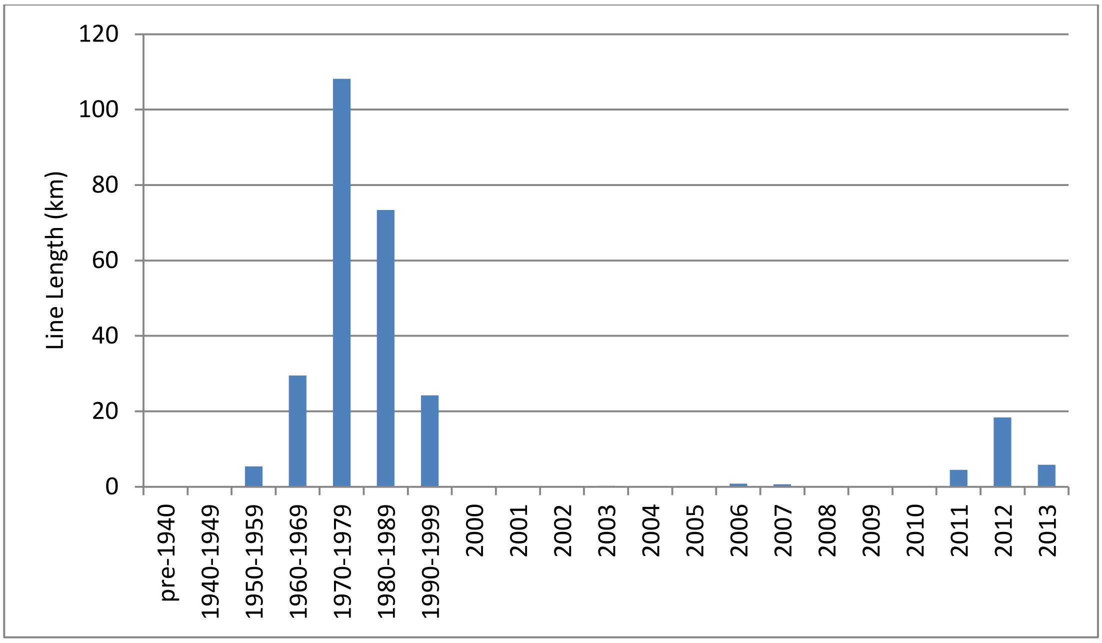

Figure 3.13: Age profile of sub-transmission overhead conductors

There is a total of 271km circuit length of sub-transmission overhead conductor, which is generally in an acceptable condition.

3.4.1.2 Distribution

Figure 3.14 below shows the age profile of distribution overhead conductors.

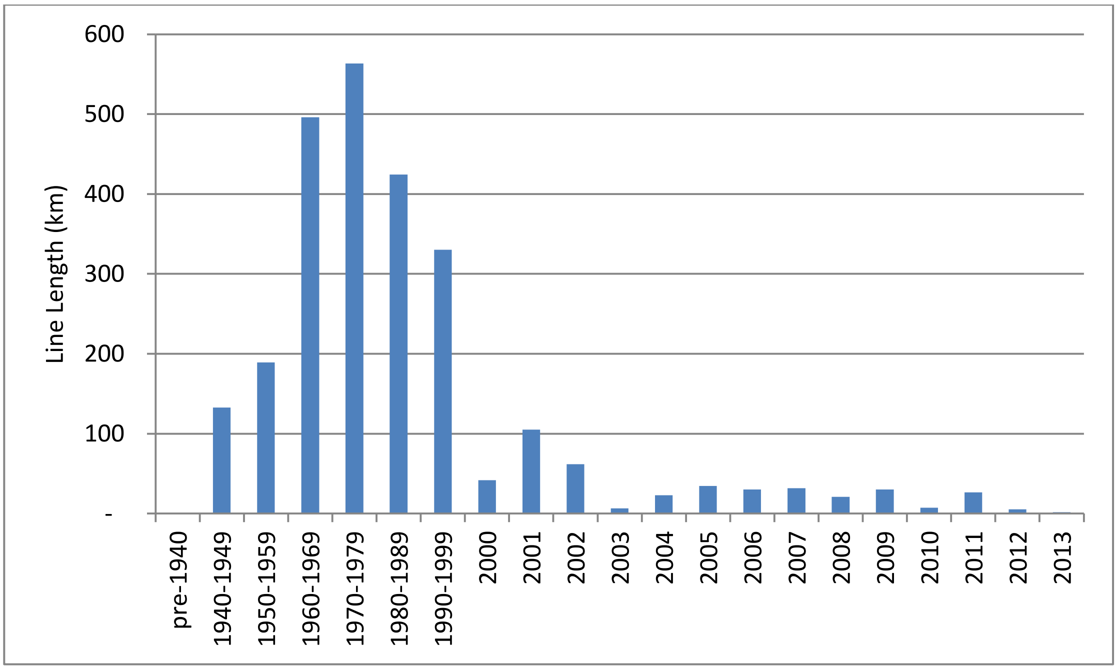

Figure 3.14: Age profile of distribution overhead conductors

There is a total of 2,560km 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 3.15 below shows the age profile of low voltage overhead conductors.

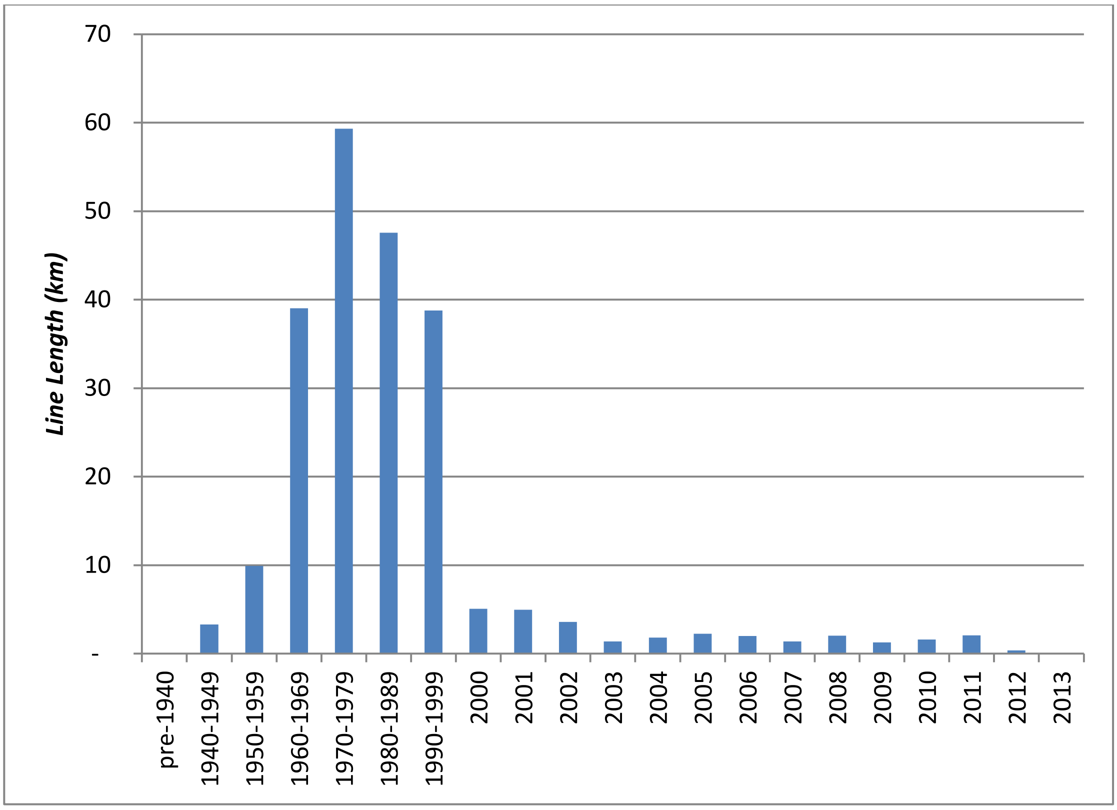

Figure 3.15: Age profile of low voltage overhead conductors

There is a total of 228km 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 three categories: sub-transmission, distribution and low voltage. Four types of poles and structures have been used: hardwood, softwood, steel and concrete. TEN was 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 Sub-transmission

The sub-transmission network has been built sporadically over the last 60 years and poles have been mainly concrete, since the 1960's.

Figure 3.16 shows the age profile of sub-transmission poles.

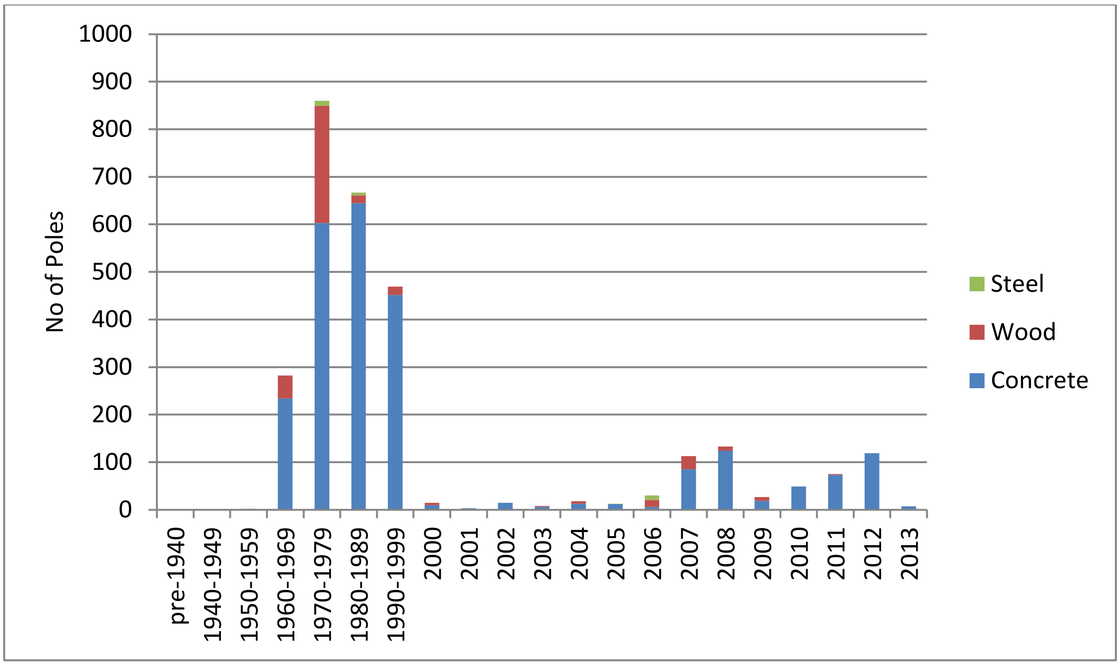

Figure 3.16: Age profile of sub-transmission poles

There are just over 2,900 sub-transmission poles, of which over 85% are concrete. These are inspected annually.

3.4.2.2 Distribution

Figure 3.17 shows the age profile of distribution poles.

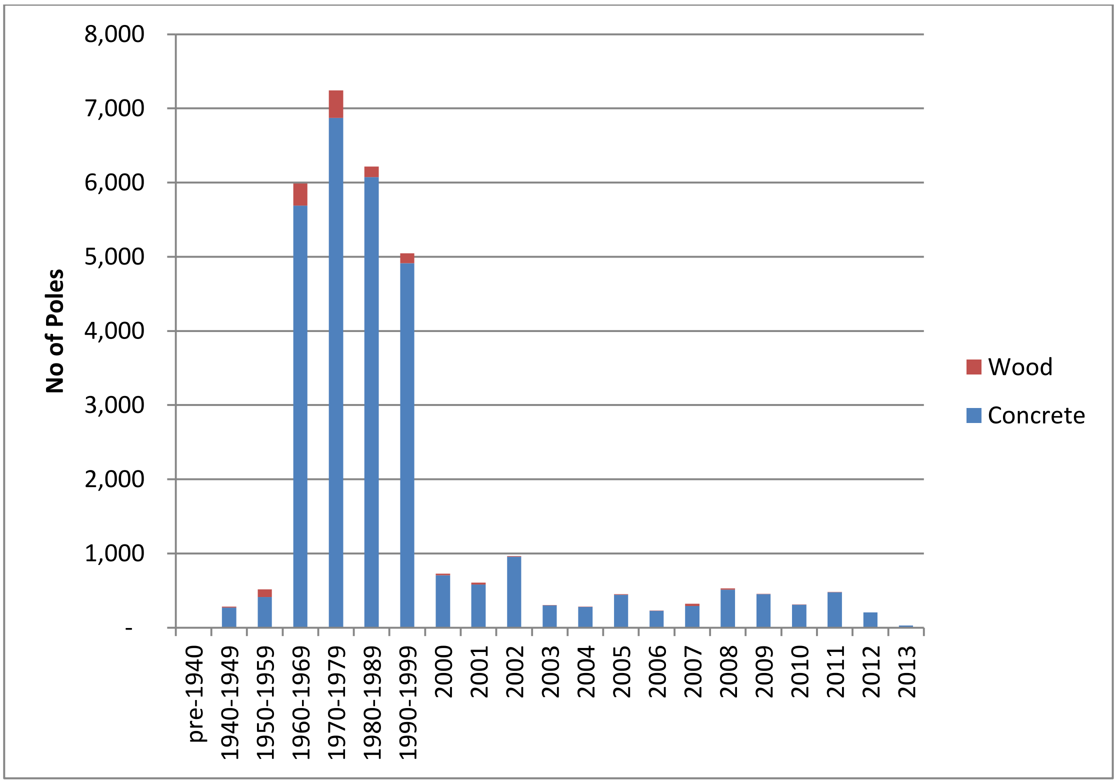

Figure 3.17 Age profile of distribution poles

There are approximately 31,200 distribution poles, of which 96% are concrete. Although TEN's 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 20 years.

3.4.2.3 Low Voltage

Figure 3.18 below shows the age profile of low voltage poles.

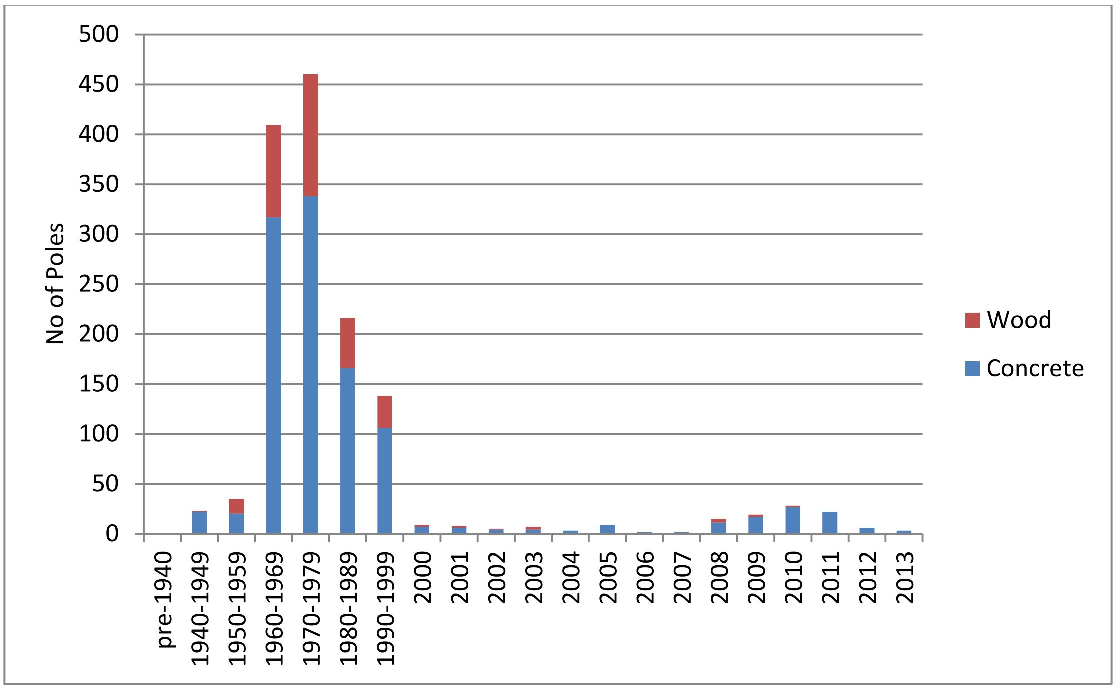

Figure 3.18 Age profile of low voltage poles

There are just over 1,400 low voltage poles, of which 77% are concrete. TEN has built very little LV overhead line since around 1995 and this is reflected in the graph. 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 20 years.

3.4.3 Underground Cables

Similar to overhead lines, underground cables are split into three main categories: sub-transmission, 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 TEN used imperial sized single core and metric 4 core PVC cables until 2008.

TEN has now introduced the use of metric-sized single and four-core aluminium low voltage cables, which will replace the existing single-core imperial range.

3.4.3.1 Sub-transmission

Top Energy's first sub-transmission cable was 0.5km of 33kV Al XLPE 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. These cables are all in good condition.

3.4.3.2 Distribution

Figure 3.19 below shows the age profile of distribution underground cables.

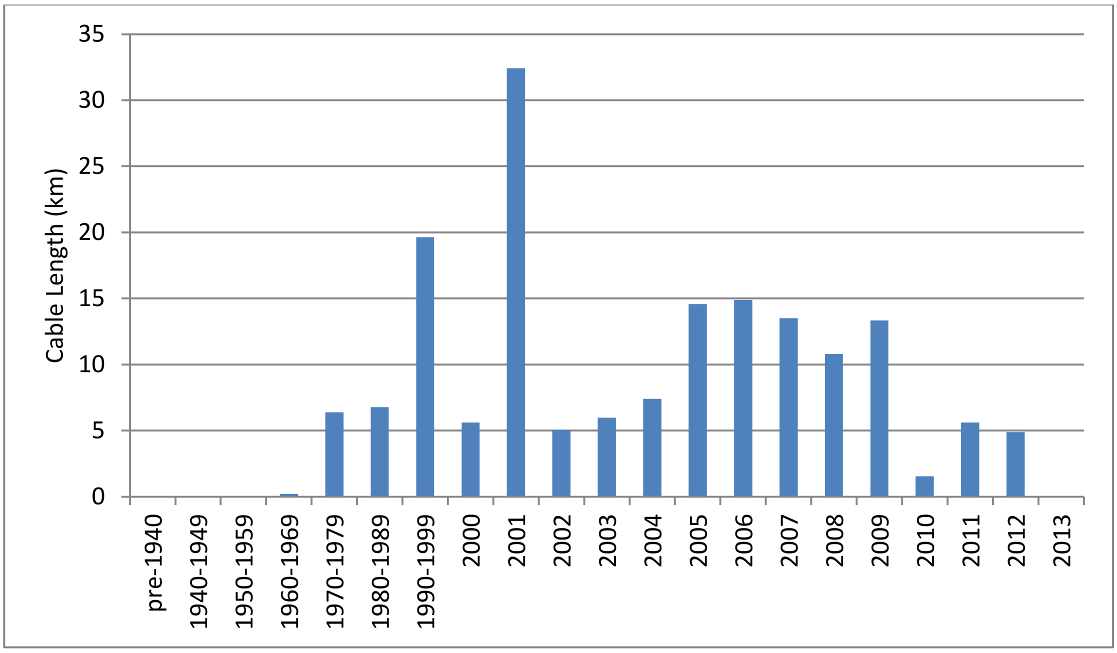

Figure 3.19: Age profile of distribution underground cables

There is a total of 169km of distribution underground cable, which is generally in good condition, with 82% of the in-service cable being less than 15 years old. Historically, TEN has experienced, on average, one underground high voltage 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 TEN's underground distribution system. Ongoing monitoring of system loadings and fault trends will continue through the planning period of the AMP.

Since the installation of ground fault neutraliser systems at Waipapa, Kawakawa and Okahu Rd substations, there has been an increase in the number of distribution cable faults and this programme has now been discontinued, pending further review of its effectiveness.

3.4.3.3 Low Voltage

Figure 3.20 below shows the age profile of low voltage underground cables.

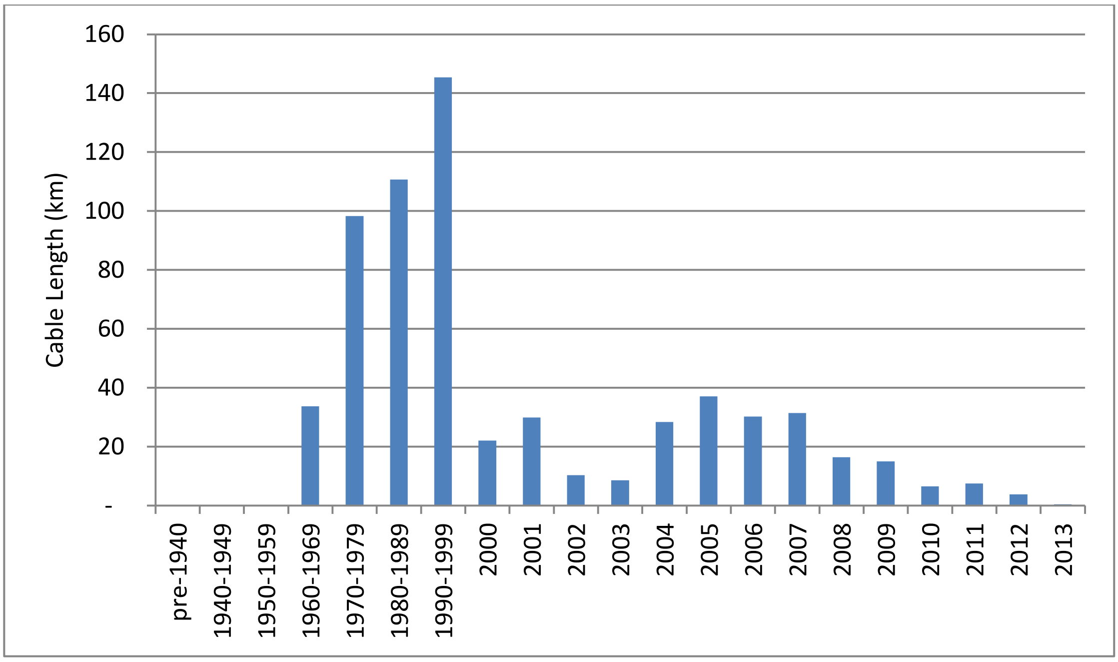

Figure 3.20: Age profile of low voltage cables

There is a total of 636km 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

There are two 11kV submarine cables feeding the Russell Peninsula. The first cable is laid across the Waikare Inlet and is a single circuit, three-core 70 mm^2 copper cable, around 1.5 km long and was livened in 1975. It has been through 33 years of its nominal 70 years 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.

3.4.3.5 Streetlight Cables

Street light cable (222 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.

3.4.4 Distribution Transformer and SWER Transformers

The age profiles of TEN's in-service distribution and SWER isolating transformers are shown in Figure 3.21 and Figure 3.22 below.

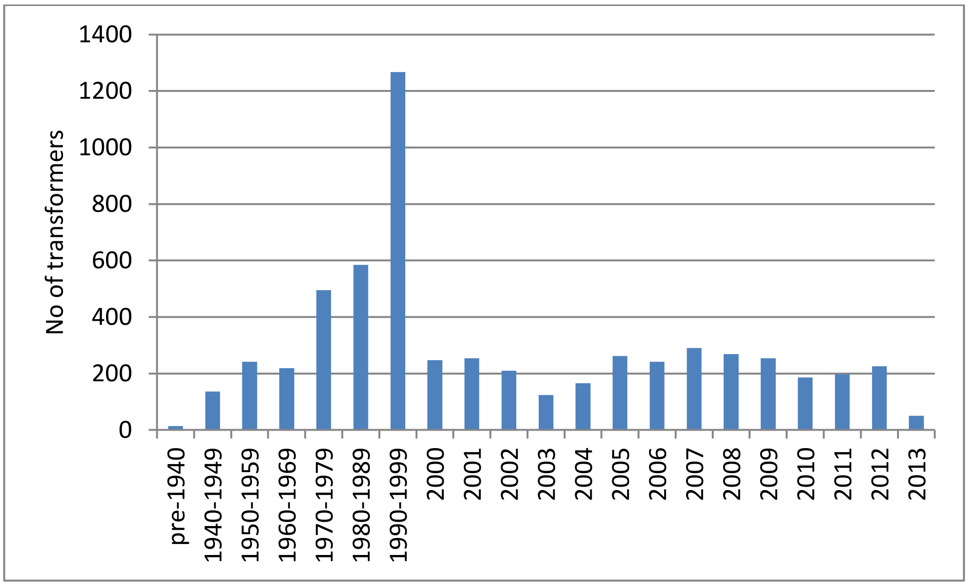

Figure 3.21: Age profile of distribution transformers (all capacities)

There are almost 5,950 distribution transformers of various capacities with an aggregated capacity of 267 MVA. While a small number of transformers installed prior to 1940 are still in service, the fleet is relatively young with over 75% being less than 20 years old.

In general, TEN's transformer population is of average condition. TEN considers 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, environment or property are proactively replaced.

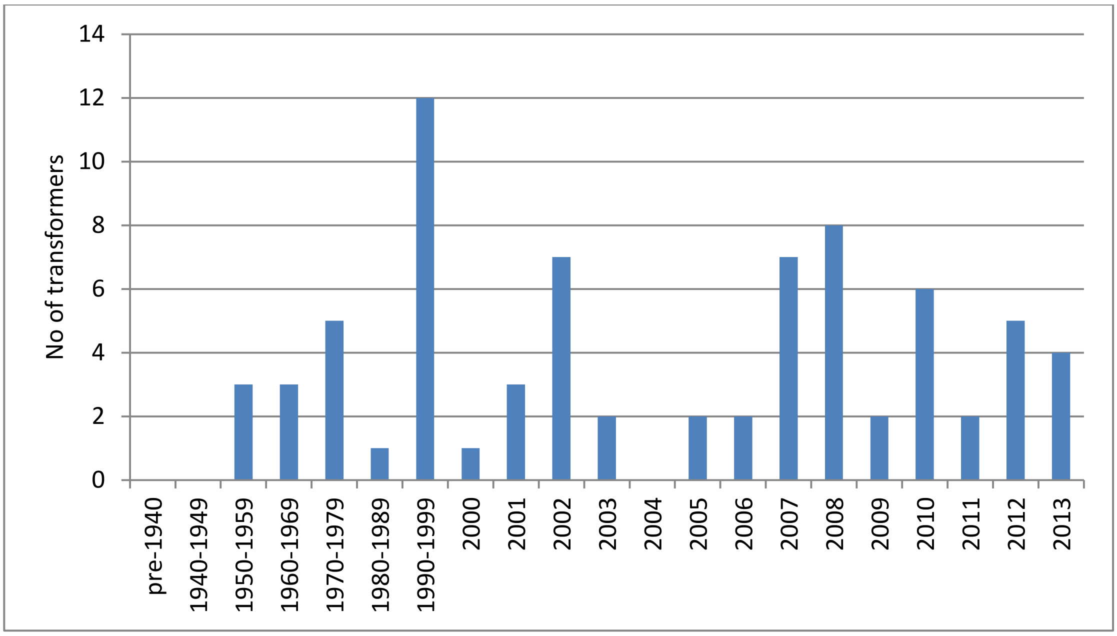

Figure3.22: Age profile of SWER isolating transformers

There are a total of 75 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 50% of the fleet is now less than 10 years old.

3.4.5 Reclosers

Figure 3.23 below shows the age profile of reclosers on Top Energy's Network.

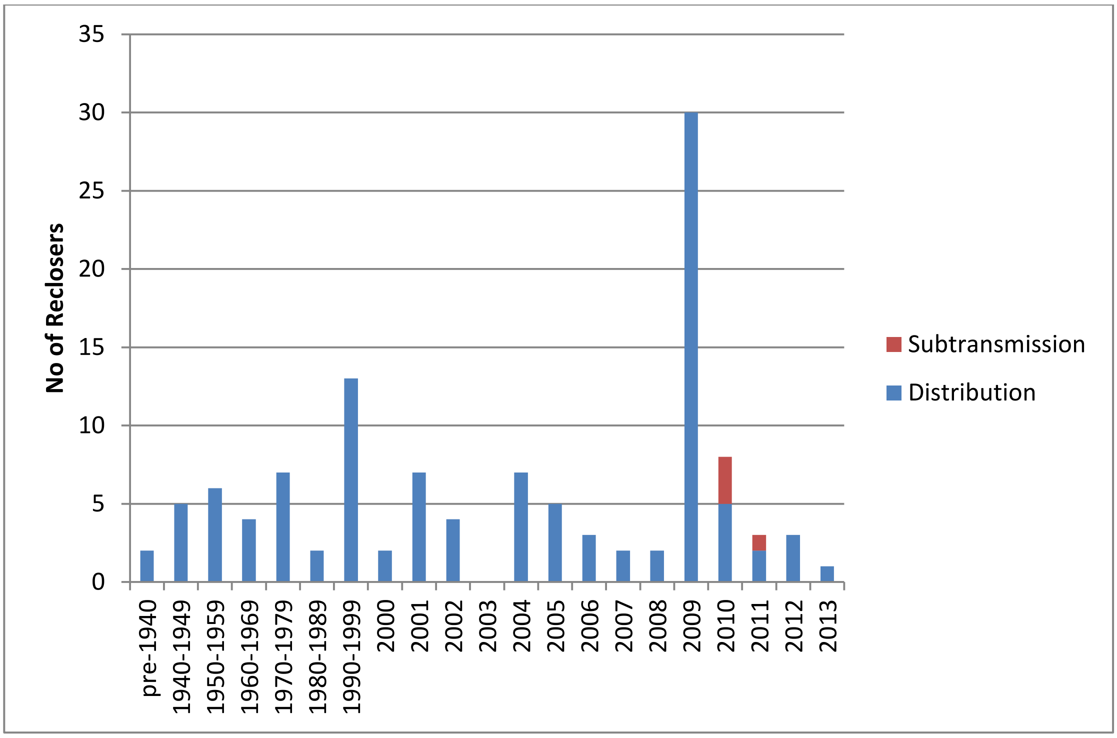

Figure 3.23: Age profile of reclosers

There are a total of 4 sub-transmission and 112 distribution voltage reclosers on the network, 45 of which (including all the sub-transmission units) were installed as part the network automation project that commenced in FYE2009. 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

Figure 3.24 below shows the age profile of the voltage regulators on TEN's network.

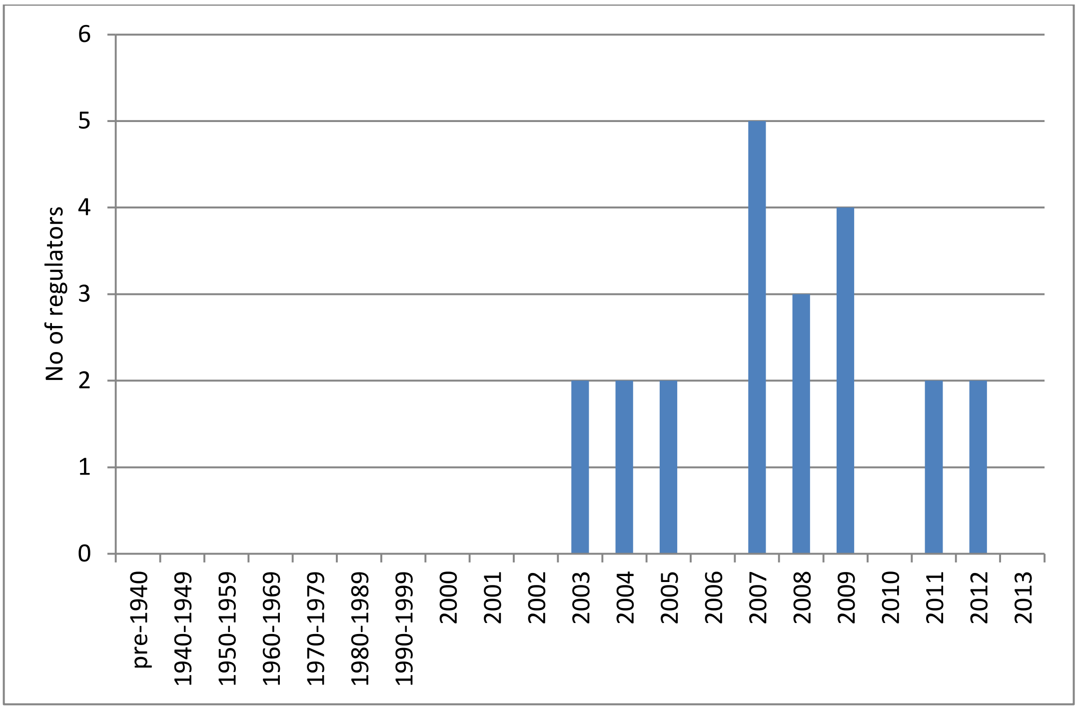

Figure 3.24 Age profile of voltage regulators

There are a total of 22 voltage regulators, all of which are less than ten years old and in good condition. An annual condition inspection is carried out to identify maintenance requirements.

3.4.7 Ring Main Units (RMU)

Figure 3.25 below shows the age profile of RMUs on TEN's network.

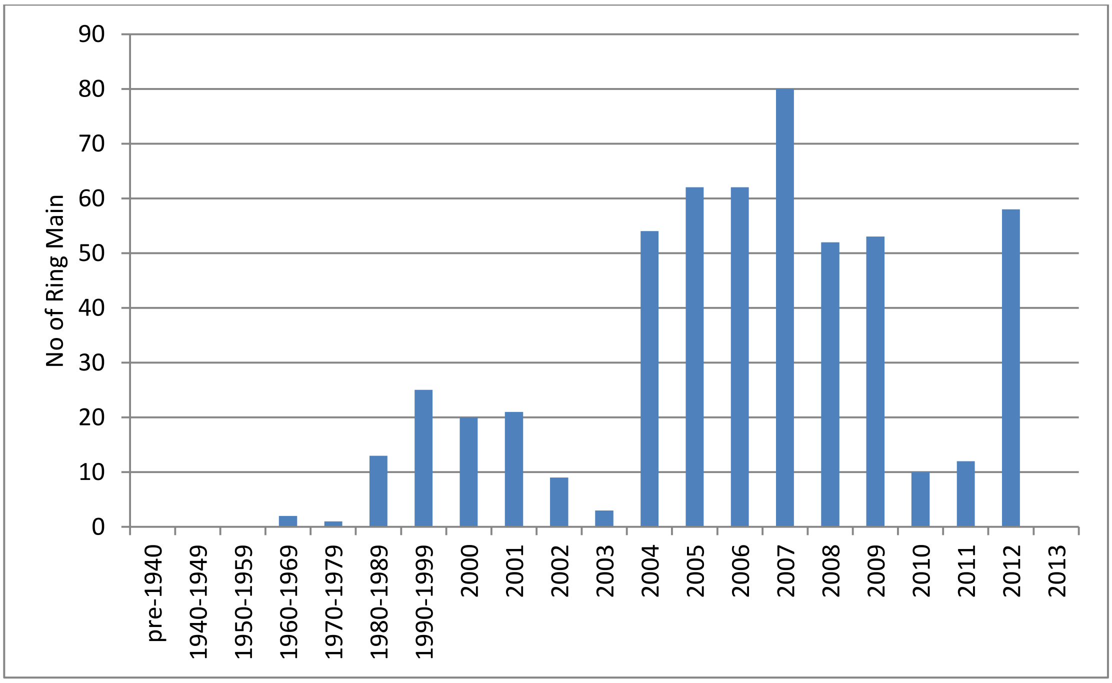

Figure 3.25: Age profile of ring main units

There are a total of 537 RMUs on TEN's 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 will be non-oil filled units.

3.4.8 Sectionalisers

Figure 3.26 below shows the age profile of sectionalisers on TEN's network.

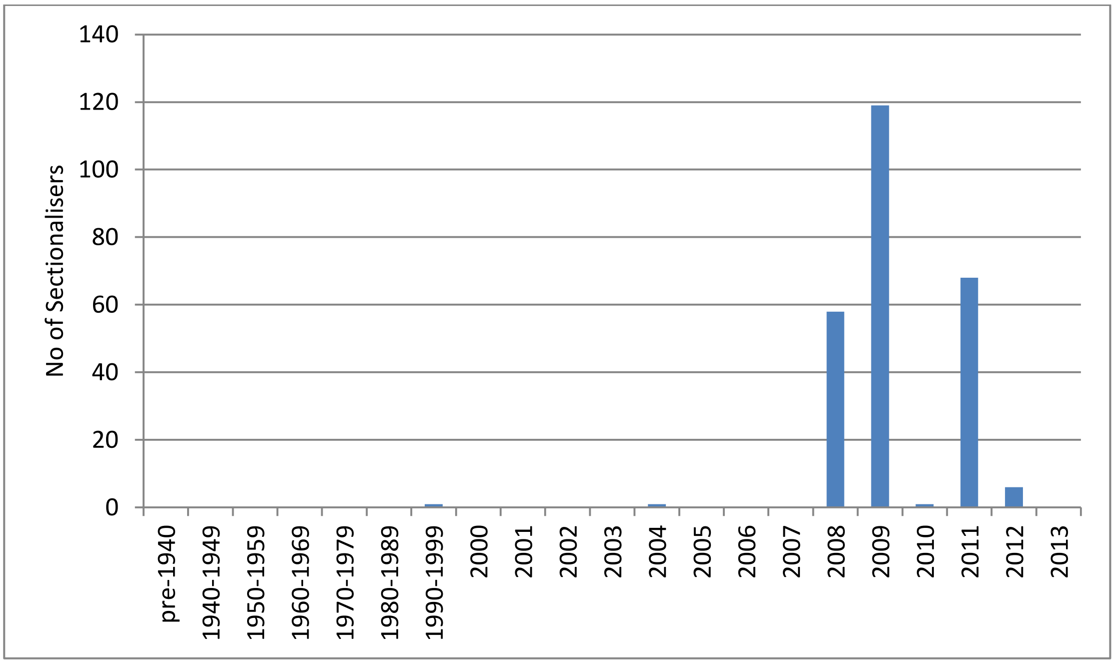

Figure 3.26 Age profile of sectionalisers

There are a total of 254 sectionalisers on TEN's network, most of which are configured as remote controlled switches. Sectionalisers are a relatively new asset on the network and 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 TEN's network.

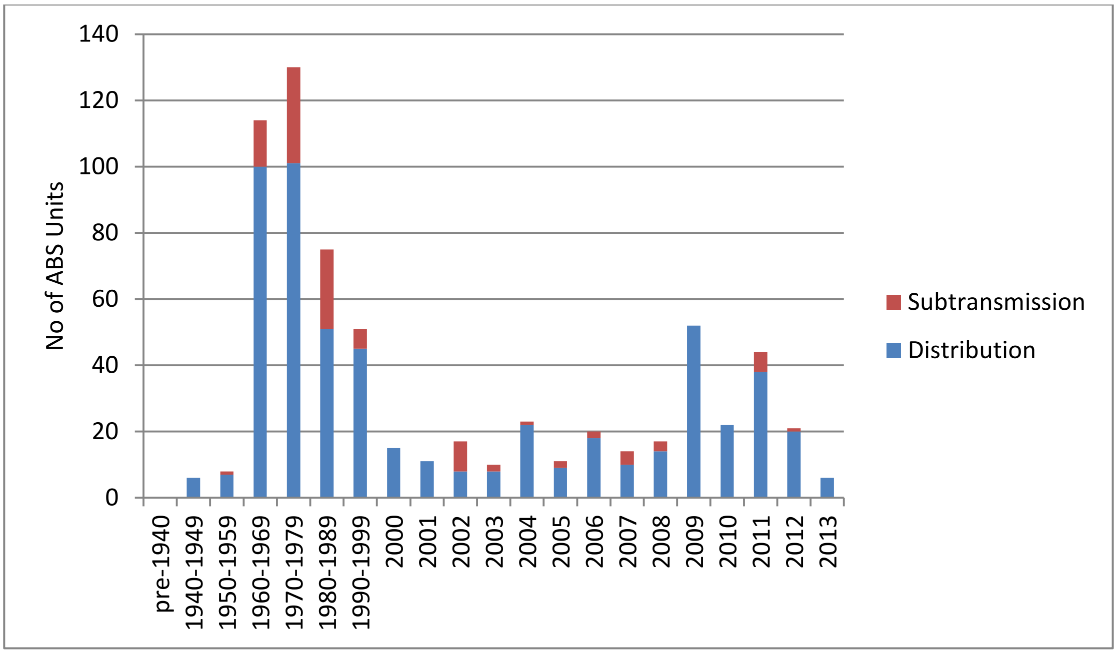

Figure 3.27: Age profile of air break switches

There are a total of 676 switches on the network, of which a little over 100 are sub-transmission. TEN has a programme in place during the planning period to proactively replace older and unserviceable units. This is discussed in Section 6.11.

3.4.10 Capacitors

Figure 3.28 below shows the age profile of capacitors on TEN's network

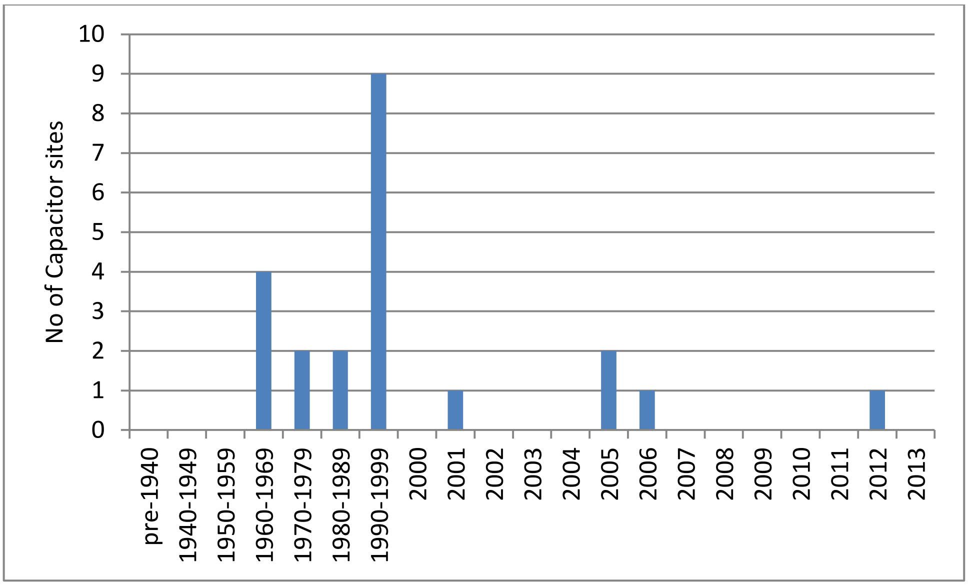

Figure 3.28 Age profile of capacitors

There are a total of 22 capacitors and they are in average-to-fair condition. One new unit was installed in FYE2012. 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 TEN's zone substations.

PRESENT SUBSTATION	UNIT	DESIGN RATING MVA	PRESENT RATING MVA	AGE[1]
Southern				
Kaikohe	T1	11.5/23.0	11.5	43
Kaikohe	T2	11.5/23.0	11.5	43
Kawakawa	T1	5	5	51
Kawakawa	T2	5	5	51
Moerewa	T1	11.5/23.0	11.5	43
Waipapa	T1	11.5/23.0	23	29
Waipapa	T2	11.5/23.0	23	29
Omanaia	T1-1 R	0.9		59
Omanaia	T1-2 Y	0.9	2.75	59
Omanaia	T1-3 B	0.9		59
Haruru	T1	11.5/23.0	23	25
Haruru	T2	11.5/23.0	23	5
Mt Pokaka	T1	3/5	3	3
Northern				
Okahu Rd	T1	11.5	11.5	34
Okahu Rd	T2	11.5	11.5	34
Taipa	T1	5/6.25	6.25	48
Pukenui	T1	5/6.25	5	48
NPL	T1	11.5/23.0	23	26
NPL	T2	11.5/23.0	23	26
Mobile Substation				
Mobile Substation	T1	5/7.5	7.5	10

Note 1: As at 31 March 2012

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 TEN's fleet. The actual age at which a power transformer will be replaced will depend on its condition, loading, history and design; TEN expects that most of its 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 58 years old, are closer to end of life at 274-465. These transformers will be replaced by the existing Taipa unit 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) Sub-transmission circuit breakers

Figure 3.29 below shows the quantities and age profile of TEN's sub-transmission circuit breakers installed within its zone substations.

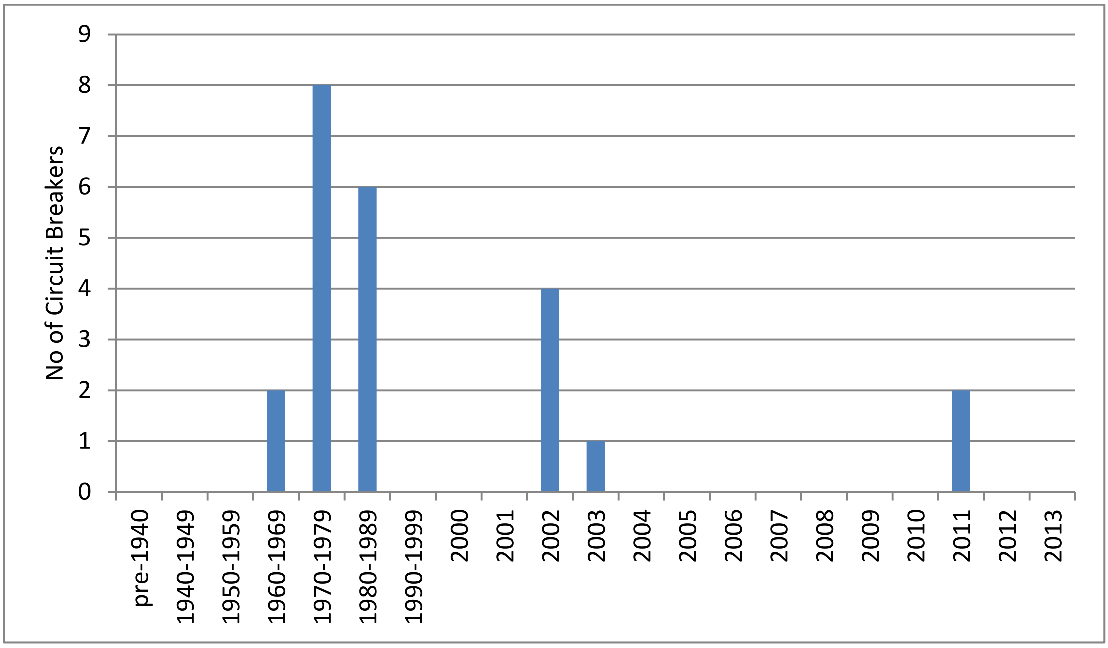

Figure 3.29: Age profile of sub-transmission circuit breakers

TEN has a relatively small number of sub-transmission circuit breakers (CBs) and, as a result, there is a concentration of types.

There are 10 English Electric OKW3 minimum oil outdoor 33kV CBs, all of which are more than 35 years old. Minimum oil CBs are noted 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. Extension of service beyond their standard lives is expected to be achieved through regular maintenance and testing practices, to manage the risk of a failure. Until replacement of these circuit breakers occurs, TEN 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 the TEN network.

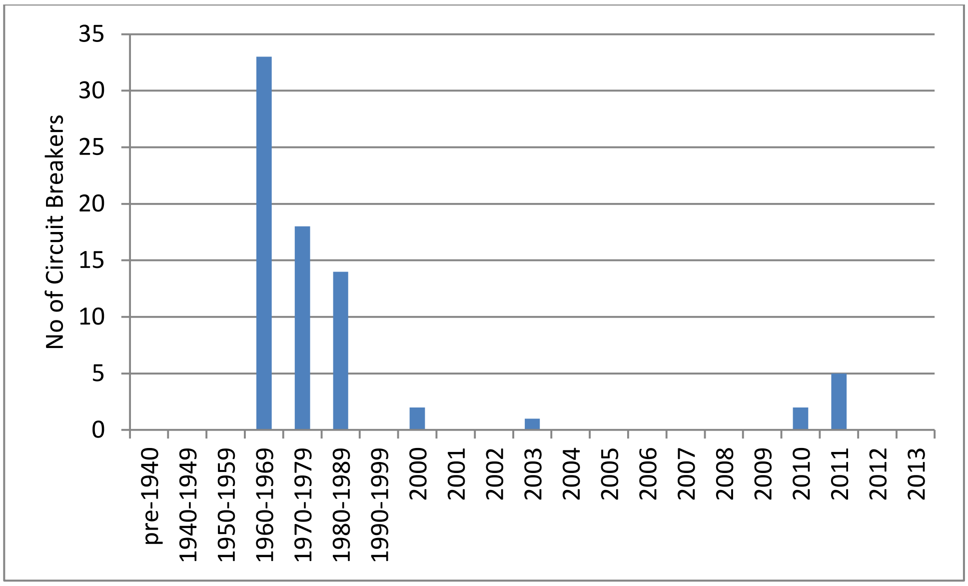

Figure 3.30: Age profile of distribution voltage circuit breakers

The condition of these 75 circuit breakers is considered sound, with a thorough testing and condition-based maintenance programme in place. No age-based replacements are planned in the planning period; however, some oil breakers may be relocated to a lesser duty site to reduce maintenance costs. While the low fault levels in the TEN's 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).

3.4.11.3 Zone Substation Structures

TEN's 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. TEN inspects and tests the battery banks monthly and replaces the whole bank at the end of its economic life. Batteries at Kawakawa and Haruru were replaced during FYE2013.

3.4.11.5 Zone Substation Protection

At present, TEN has a variety of relay classes including electromechanical, solid state electronic and modern microprocessor relays. Their ages generally correspond to the age of the substation concerned. The exceptions are Okahu Road and NPL, which have had replacement relays installed since 2000.

An upgrade of all zone substation protection relays has commenced, moving to a numerical type with improved discrimination and capable of data logging. The low fault levels in TEN's supply area complicate protection design and as a result, the sub-transmission network is currently in a radial configuration to mitigate the potential for, and consequences of, mal-operation.

Unfortunately this means that all sub-transmission faults will cause a supply interruption, even where capacity is sufficient to provide N-1 supply security. The new protection relays will allow sub-transmission lines and zone substation transformers to be operated in parallel, meaning that most faults on the sub-transmission system should not result in a supply interruption.

Over time, this should 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.

Haruru is the first substation where the new relays will be installed and installation of new protection schemes at this substation is currently in progress. Installation of these relays at other zone substations will follow progressively.

3.4.11.6 Zone Substation Grounds and Buildings

TEN's substation buildings are listed in the Table 3.6 below.

SUBSTATION NAME	CONSTRUCTED
Kaikohe	1971
Kawakawa	1961
Moerewa	1970
Waipapa	1965
Omanaia	1983
Haruru Falls	1988
Mt Pokaka	2010
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 Customer Service Pillars

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

Figure 3.31 below depicts the age profile of customer service pillars in service. There are more than 11,900 pillars installed on the network.

Customer 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.

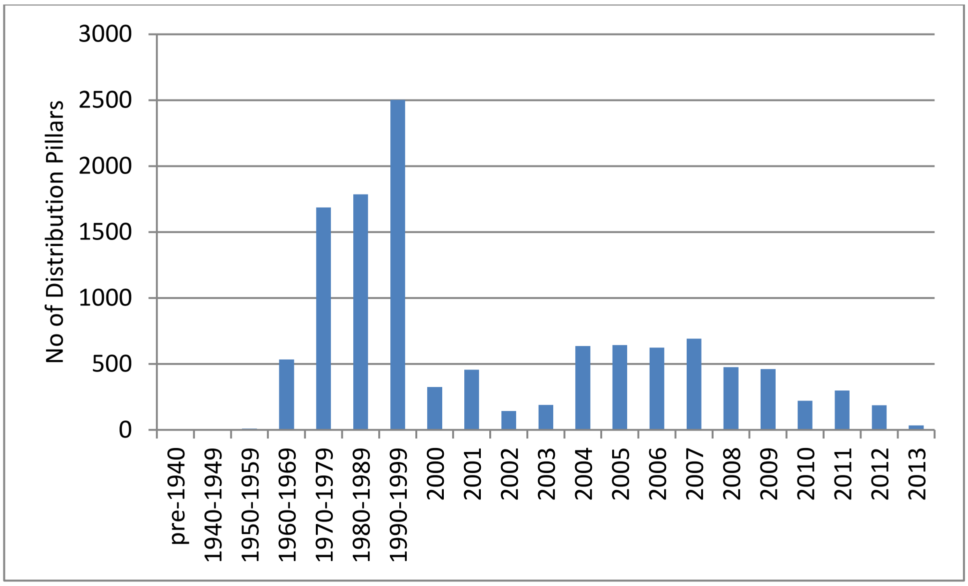

Figure 3.31: Age profile of customer service pillars

3.4.13 SCADA and Communications

TEN's 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; and
- a front end in the control centre comprising of an iPower HMI system and backup servers at an alternate location, connected via the Ethernet WAN.

Figure 3.32 below shows the location of communications repeater sites.

The existing 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. It will be progressively replaced by a modern system, primarily using fibre-optic cable, as part of the network development plan. This is discussed further in Section 5.

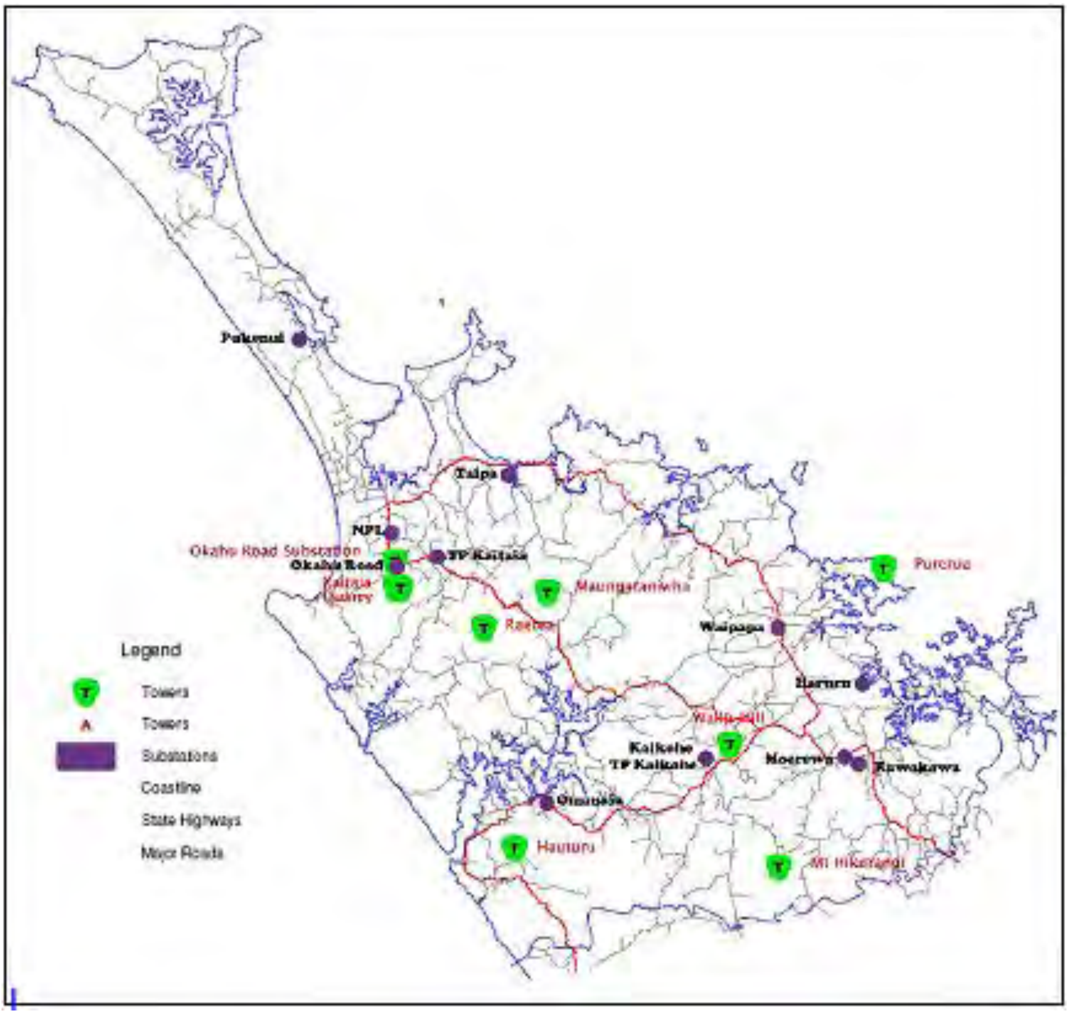

Figure 3.32: Repeater tower sites

TEN is 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. There are currently around 150 field located control and monitoring points.

3.4.14 Load Control Plant

TEN has three Zellweger decabit type injection plants operating at 317Hz connected to its 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 Top Energy presently uses 45 of these.

3.4.15 Mobile Substations and Emergency Generation

Top Energy owns a 33/11kV, 7.5MVA mobile substation that was commissioned in FYE2003. It is currently located at the Moerewa zone substation where it is in service as the second transformer. However, its main function is to mitigate the risk of a transformer failure at one of Top Energy's single-transformer zone substations, Taipa, Pukenui, Omanaia and Mt Pokaka. Relocation of the substation and renenergisation at its new site could take up to ten hours, depending on the travel time required.

TEN also installed two 2.5MVA 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 sub-transmission line or substation transformer. The generators will also be used during maintenance shutdowns of the Kaikohe-Kaitaia 110kV transmission line. The load and the number of customers 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 of diesel generation.

3.4.16 Other Assets

TEN's non-system assets include computer hardware and software, motor vehicles assigned to TEN staff, office equipment and miscellaneous equipment such as survey equipment. TEN staff operate out of buildings that are owned by Top Energy Group and are not considered part of the TEN fixed asset base. 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 economic life in the Commerce Commission's ODV Handbook. 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 is high and, as noted above, Top Energy is 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, except possibly for sub-transmission air break switches.

Asset Class	Average Age	ODV Handbook Age
Sub-transmission conductors	31	-
Distribution conductors	34	-
LV conductors	32	-
Sub-transmission poles - concrete	25	60
Sub-transmission poles - wood	31	45
Distribution poles – concrete	30	60
Distribution poles - wood	37	45
LV poles - concrete	36	60
LV poles - wood	39	45
Distribution cable - PILC	17	70
Distribution cable - XLPE	9	45
LV cable	20	45
Air break switches – sub-transmission	28	35
Air break switches – distribution	24	35
Ring main units	8	40
SWER transformers	15	45
Distribution transformers	19	45
Distribution pillars	29	45

Table 3.7: Average Age of Sub-transmission and Distribution Assets

3.5 Justification for Assets

TEN's 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 its supply area.

ASSET DESCRIPTION

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, as noted in Section 2.4. TEN is therefore implementing a network development plan (described in Section 5), which will put an augmented transmission and sub-transmission 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 from which this higher capacity network will be developed.

The current network is essentially radial in nature and includes a 110 kV transmission line, 33 kV sub-transmission lines, 22/11 kV distribution lines and a 415/240 V 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 Top Energy's sub-transmission network, which supplies the zone substations. The 33/11kV zone substations are configured with either dual transformer banks or a single transformer bank depending upon the security and load requirements of the area and inject the electricity into a network of 47 distribution feeders. These generally operate at 11kV and are long for this voltage.

TEN believes this asset base is no longer adequate to provide acceptable supply reliability to consumers and comply with statutory requirements related to delivery voltages. In addition, the overall network capacity is insufficient to underpin the continued economic development of its supply area.

Identification of 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. This analysis (discussed below) identified a small number of assets for optimisation; the majority being for capacity reasons rather than for being superfluous.

Load growth since 2004 has 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

The 110kV transmission substations at Kaikohe and Kaitaia are approximately 50km 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 TEN's Northern and Southern area networks could not be practically interconnected using 33kV sub-transmission 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 up to the Kaikohe substation; power is injected into TEN's 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 consumers connected to the Northern distribution network if this circuit is out of service for any reason.

Ngawha generation also provides 25MW injection into the Top Energy sub-transmission 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 Sub-transmission 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 sub-transmission network. As noted above, TEN now believes the existing sub-transmission 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 and by a recently completed back-up circuit into NPL, which is teed into 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

Waipapa substation is supplied using two dedicated 33kV lines. The existing load in the Waipapa substation area would result in excessive voltage drop under N-1 contingent operation precluding any reduction in the conductor size.

Haruru, Kawakawa and Moerewa substations are all supplied using two shared 33kV circuits and operate on a radial, split bus arrangement, due to load and protection constraints. 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 using a single 33kV tie line from Kaikohe GXP.

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

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

Top Energy also owns a 7.5MVA 33/11kV mobile substation that was commissioned in FYE2003 and provides back-up for all single bank substations. There is some back-up 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 TEN's 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 has been optimised to 5/10MVA. 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 TEN's 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 11 kV 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 now precludes 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 some zone substations. It is planned to install bunding at the Kawakawa and Waipapa zone substations during the planning period and bunding will be installed at Moerewa when the existing transformers are replaced.

3.5.4 Distribution network

Factors such as current rating, losses and voltage drop are considered to decide whether distribution network conductors could be optimised to smaller size. Although Top Energy does not specify an N-1 criterion for feeders, due to the mainly rural nature of the network and therefore the impracticality of providing full back-up, it does make use of feeder interconnections close to the substations to reduce the number of outages required for planned substation maintenance. This is standard industry practice.

To achieve the security criteria set out in this AMP, the feeder current rating has to be adequate to carry its own load and that of any feeder it backs 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 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.

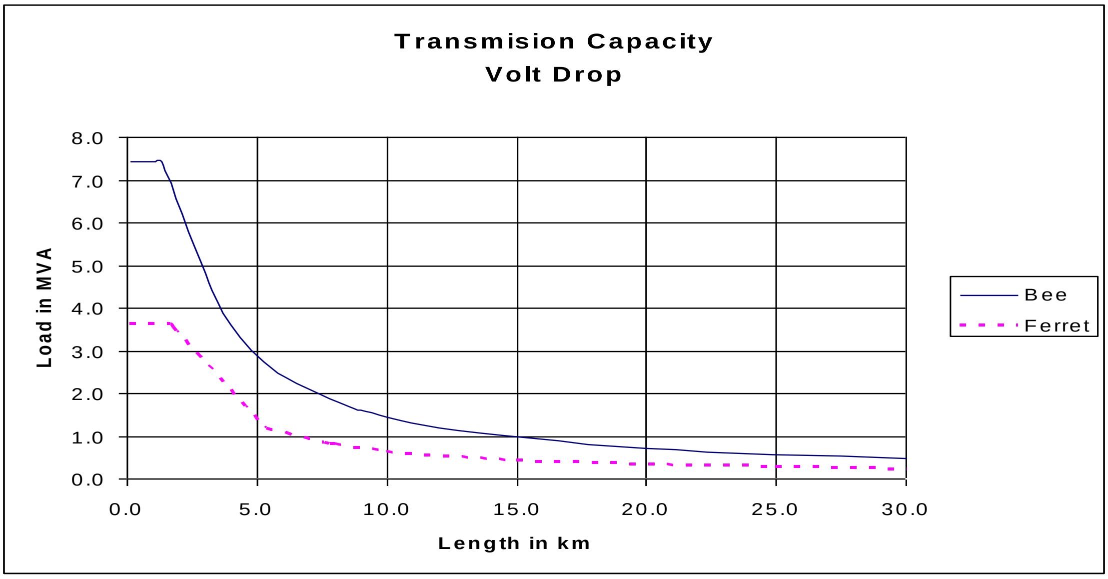

Figure 3.33: Conductor transmission capacity vs. distance

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 preclude 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 is possible. This lack of optimisation is indicative of the relatively high loading on the distribution system and the very long feeder lengths that currently exist. This will be alleviated by the network development plan, which will increase the number of points at which electricity is injected into the distribution network. This in turn will reduce the load on many existing heavily-loaded feeders.

3.5.5 Distribution transformers

The optimisation review undertaken in 2011 determined that the utilisation of distribution transformers is now above 30%, so the current distribution transformer capacity installed on the network is not excessive.

3.5.6 Low voltage network

TEN provides 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 Top Energy was 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 consists entirely 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 customers' 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, TEN has 22 voltage regulators 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.

TEN has a small number of fixed capacitor banks attached to the 11kV. 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 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

TEN uses 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

TEN uses SCADA to monitor and control its zone substations, GXPs and remote control equipment on the network.

TEN has installed remote control equipment such as motorised switches, reclosers and circuit breakers at both sub-transmission and distribution voltage level, in order to improve reliability. With only 42 non-industrial distribution feeders and more than 2,500km of overhead HV line, 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 customer 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 a specific agreement with the TECS store in addition to the normal construction stocks. No optimisation is possible.

Section 4 Level of Service

4 Level of Service

4.1 Introduction

TEN distributed electricity to 31,217 consumers as at 31 March 2012 via 3,858km of lines and cables, of which 79% are overhead. This gives an average consumer density of 8.1 consumers per km. This groups TEN with a peer group of companies that includes MainPower, Eastland Network and Alpine Energy; electricity distribution businesses (EDBs) that also have significant areas of rural supply.

TEN has the worst supply reliability of any EDB in New Zealand. During FYE2012, on average, each customer experienced six outages and more than seven hours without electricity. This is the result of a complex mix of historical design, investment, ecological and climatic factors. It is now recognised that, with suitable development and maintenance strategies and adequate funding, the effects of these factors on supply can largely be mitigated.

The poor network reliability is, in some part, a consequence of the fringe location of the network 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 the 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 and inadequate sub-transmission support.

To address these legacy issues and to improve security of supply, Top Energy will invest almost $190 million CAPEX during the ten year period between FYE 2014 and FYE 2023 in what will be the single largest expansion in the history of the network. To this end, it has already acquired the region's transmission assets from Transpower and will invest in improving and upgrading these assets. It will also construct a second 110kV transmission circuit between Kaikohe and Kaitaia, so that supply to consumers in the Northern area will no longer depend on a single transmission circuit. Furthermore, it will expand and strengthen the 33kV sub-transmission system in order to increase the number of bulk supply points at which power is injected into the existing distribution network. The result of this expansion will be a significantly more secure and reliable network to support the future economic growth of the Far North.

Bulk supply capacity is not the only focus of 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, TEN began a major reliability programme targeting the clearance of trees and vegetation near lines. It also installed equipment to reduce the number of faults caused by lightning and over 200 automated switches and re-closers in strategic locations to limit the number of customers affected by many fault events. Overall, the result has been excellent. The average total minutes off supply per customer, as measured by network SAIDI, reduced from 924 minutes in FYE2009 to 435 minutes in FYE2012. This programme, assisted by relatively mild weather, reduced the average number of outages consumers experienced (as measured by network SAIFI) from more than ten in FYE2010 to less than five in FYE2011. Unfortunately, adverse weather conditions saw the network SAIFI increase again to over six in FYE2012. In spite of this 28% increase in SAIFI, TEN's network SAIDI showed a marginal improvement over the level experienced the previous year. This was because TEN was able to significantly reduce the average length of each interruption. This is testimony to the success of this reliability programme. In addition, the increased management focus on network reliability has undoubtedly improved the quality of the TEN and TECS response to the faults that do occur.

TEN will continue to invest in technologies and strategies that offer the best performance gains when compared to the cost of implementation. The work planned over the next decade will also have a significant impact on the human resource requirement at Top Energy, creating new job opportunities in the Top Energy area. A recruitment campaign for planners, project managers, electrical lines engineers and other staff continues. It is expected that more than 20 new permanent positions will arise from the investment in the electricity network operation over the planning period.

Top Energy performs regular customer research to inform, educate and seek feedback from customers on what is an appropriate level of service. The results of this customer research have been incorporated in the strategies discussed in this AMP and has guided development of the service target levels proposed within this chapter.

4.2 Customer Orientated Service Levels

4.2.1 Measures and Targets

The customer service targets included in this AMP are limited to the industry performance measures used by the Commerce Commission to monitor the reliability of the electrical network under the price-quality regime. The Commission has chosen these measures because it believes they are effective indicators of how well an electricity distribution business provides a reliable electricity supply to consumers. Top Energy agrees with this. However, it has set itself much more challenging targets than the benchmark service levels used by the Commission in monitoring TEN’s supply reliability, in order to ensure that the targets capture the benefits of its planned investment programme. The Commission’s benchmarks are based solely on historic performance and therefore don’t account for planned improvements.

The two measures that TEN will use for the development of customer service targets are:

- SAIDI: System Average Interruption Duration Index. This is the accumulated total time that the average consumer connected to the network will be without supply in any measurement year as a result of faults and planned outages on the Top Energy 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 the network will experience in a measurement year as a result of faults and planned outages on the Top Energy network. The units are outages per customer 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 TEN’s transmission, sub-transmission and distribution networks. The inclusion of the transmission assets in the measure can be expected to decrease the measured reliability when compared to past years, because interruptions that have previously been excluded are now included in the measure.

In measuring its performance against these targets, Top Energy will adopt the normalising approach that is now being taken by the Commerce Commission in measuring the reliability of supply provided by all the electricity distribution business that it regulates. Normalisation of the raw performance measure is designed to exclude the impact of events that are outside TEN’s reasonable control. Top Energy believes that setting targets using normalised measures provides a better indication of the success of its asset management strategies, by limiting the extent to which events outside TEN’s control impact the measured performance.

The normalisation process will have two effects. First, and as at present, interruptions due an event originating outside of the TEN network will not be counted. TEN has no control over these outages and their impact on measured performance can be substantial.

Second, the impact of interruptions occurring on “major event days” will be limited to an “interruption envelope”, where the measured reliability for the day will be replaced by a lower “interruption threshold”. The value of the SAIDI and SAIFI interruption thresholds have been determined by a statistical analysis of actual daily interruptions over the period 1 April 2004 – 31 March 2009, 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 that is outside the ability of TEN and TECS resources 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 to TEN.

The 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 threshold level, rather than allowing major event days to be ignored altogether.

The service level targets set out in this AMP include the transmission assets that were transferred from Transpower to Top Energy ownership on 1 April 2012. Prior to the transfer, a customer interruption caused by these assets had no impact on TEN's reported reliability. These assets are subject to an annual planned maintenance shutdown, affecting all customers in the TEN Northern area and usually occurring in March.

The SAIDI and SAIFI normalisation thresholds that apply from 1 April 2012, which include the impact of faults and planned outages on the transmission assets acquired from Transpower, are shown in Table 4.1 below.

Indicator	Threshold
SAIDI	55.91
SAIFI	0.83

Table 4.1: SAIDI and SAIFI Thresholds for Major Event Days

An interruption of the Kaikohe-Kaitaia transmission will result in a loss of supply to approximately 10,000 consumers or one third of TEN's total consumer base. This will have a significant impact on reported reliability – SAIFI will increase by about 0.4 and SAIDI will increase by approximately one minute for each three minutes of outage duration. Hence a planned interruption lasting 8 hours will have an actual SAIDI impact of around 160 minutes. In measuring SAIDI for reliability monitoring, this 160 minutes will be replaced by the SAIDI threshold of 56 minutes. However, the SAIFI impact of the interruption will not exceed the threshold and so will not be capped for measurement purposes.

In resetting the targets to accommodate the impact of these transmission assets it has been assumed that:

- there will be one planned transmission related interruption each year;
- these planned interruptions will result in a SAIDI "major event day" where the impact of the interruption on TEN's reported SAIDI will be limited by the Commission's normalising threshold, as discussed above;
- the new 110 kV Kaikohe-Wiroa-Taipa-Kaitaia circuit will be commissioned during FYE2017. After this time an alternative supply will be available and outages of the transmission system will not cause supply interruptions. TEN's reliability will then revert to the levels that would have been reported had the impact of transmission assets not been included. It has been assumed that there will be no planned interruption in FYE2017 as this can be deferred until after the commissioning of the second transmission line;
- that weather conditions will be average for the area. The reliability of an overhead distribution network is strongly influenced by the weather. The targets set in this AMP may

not be met in years where storm activity is significantly greater than normal. As discussed in Chapter 8, FYE2012 was such a year and as a result the SAIFI target was not met;

- there are no unplanned outages of the existing 110kV Kaikohe-Kaitaia transmission lines. In the last 10 years there have been only two unplanned outages of this circuit, neither of which have been the result of weather event or equipment failure. The measured reliability of the network is very sensitive to the performance of this line, as an outage will affect all consumers in the Northern region. Hence, should an unplanned transmission outage interrupt supply to all consumers in the Northern area, the reliability targets may not be met.

The SAIDI and SAIFI targets for each year of the planning period are shown in Table 4.2 below. The target reliability for the distribution network in FYE2014 and FYE2015 is consistent with the targets set out in the FYE2013 SCI.

The impact of the planned transmission system outage has been superimposed on the distribution network reliability. Should the completion of the second 110kV circuit to Kaitaia be delayed beyond FYE2017, the reliability targets for the succeeding years until completion may need to be adjusted to accommodate additional planned network outages. However, all else being equal, this should not impact the reliability of the distribution network.

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
SAIDI										
Distribution Related	284	262	254	250	245	244	239	239	239	239
Transmission Related	56	56	56							
Target	**340**	**318**	**310**	**246**	**245**	**244**	**239**	**239**	**239**	**239**
SAIFI										
Distribution Related	4.1	3.8	3.7	3.6	3.5	3.4	3.4	3.4	3.4	3.4
Transmission Related	0.4	0.4	0.4							
Target	**4.5**	**4.2**	**4.1**	**3.6**	**3.5**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**

Table 4.2: Customer 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. It should be noted that the historical performance is not directly comparable to the performance targets going forward. Firstly, performance prior to FYE2008 was estimated rather than directly measured. Furthermore the reported actual performance prior to FYE2010 has not been normalised in accordance with the Commerce Commission's current measurement methodology.

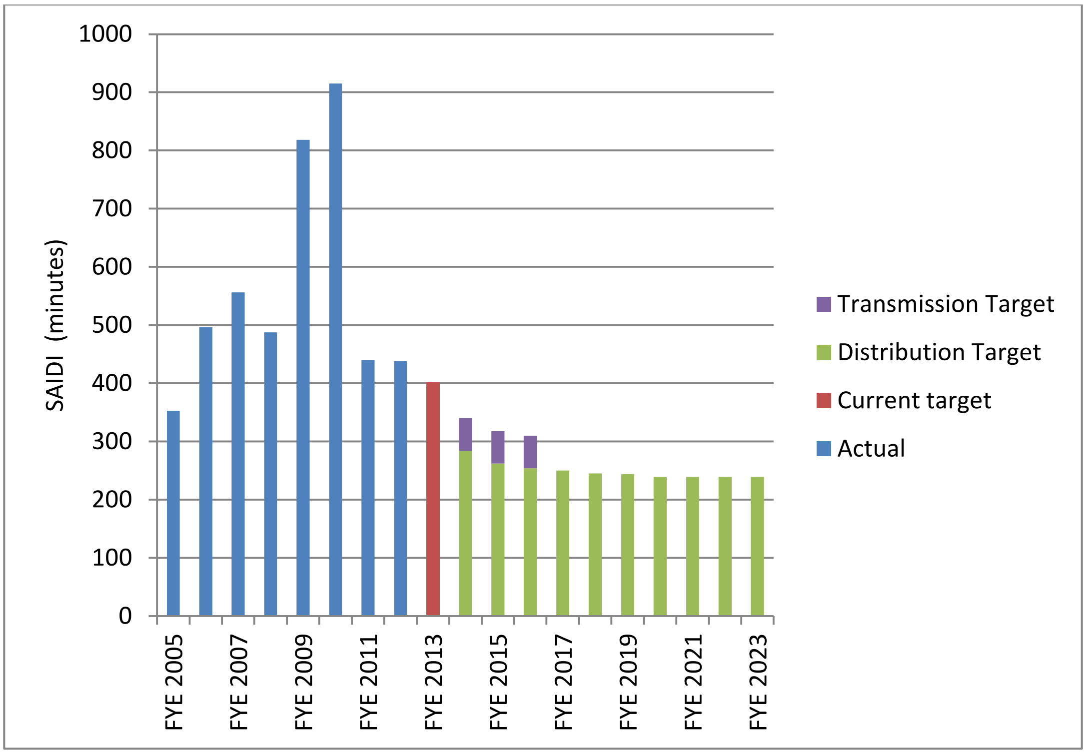

Figure 4.1: **Historical and Target SAIDI**

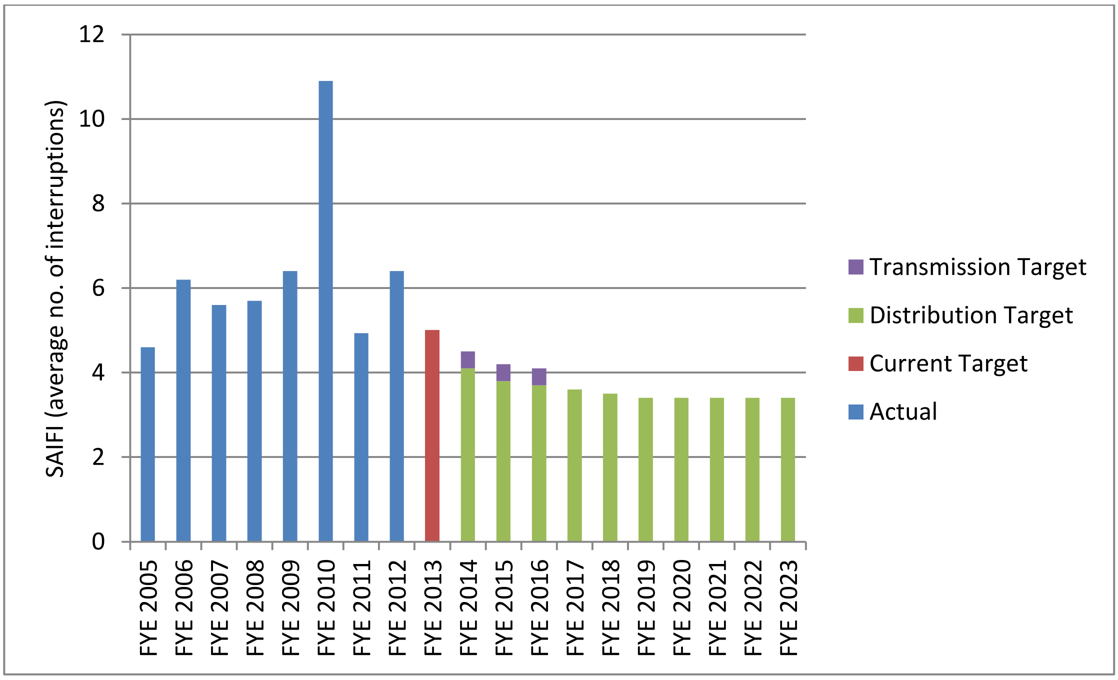

Figure 4.2: **Historical and Target SAIFI**

The actual reliability of all electricity networks is in part determined by the actual weather conditions experienced over a measurement year, and will be worse in a year of adverse weather than in one that is relatively benign. Given this uncertainty, the above reliability targets have been set at a level that TEN would expect to achieve in most measurement years, given the network development and maintenance strategies set out in this AMP. This means that:

- following completion of the network development plan, the long term average reliability should trend just below the upper level reliability represented by the targets.

- it can be expected that in the occasional year when weather conditions are particularly unfavourable, the actual measured reliability will be worse than the above targets. Management intervention to correct such a situation would only be considered if the targets were consistently not met or if they were not met in a year when the weather was unusually benign.

4.2.2 Strategies to improve the reliability of supply

The poor FYE2009 SAIDI performance prompted a review of interruption causes and maintenance practices in 2009, identifying the major reasons for the poor network reliability. Following this analysis, Top Energy has developed strategies to mitigate the predominant causes of the poor non-storm related SAIDI (as shown in Table 4.3). These strategies have already had a significant impact and are expected to result in even further improvement by 2015.

Table 4.3 also shows the progress that has been made towards meeting the 2015 targets. The increase in faults due to weather related causes reflected in the table shows the impact of the adverse weather experienced in FYE2012.

INTERRUPTION CAUSE	ACTUAL FYE2009	ACTUAL FYE2011	ACTUAL FYE2012	TARGET FYE2016
Vegetation	52%	10.4%	18.4%	5%
Lightning	21%	0.8%	6.2%	2.5%
Equipment Failure	9%	40.3%	33.3%	5%
Foreign Interference	4%	21.7%	18.5%	2.5%
Planned	9%	4.8%	4.9%	50%
Human Element	4%	1.8%	1.4%	15%
Transmission (unplanned)	1%	-	-	20%
Unknown or other	-	6.8%	16.3%	-

Table 4.3 Breakdown of Non-Storm SAIDI Causes

Internal targets have been set to:

- Reduce vegetation faults to < 30 Faults per year (currently 61)
- Reduce lightning faults to < 5 per year (currently 26)
- Reduce equipment failure faults to < 25 (currently 113)
- Monitor and target performance in line with the Identified industry peer group of companies

A review of Table 4.3 indicates that, notwithstanding the setback in FYE2012, progress has been made in reducing the number of unplanned interruptions due to vegetation contact and lightning, but the high number of equipment failure faults remains a significant concern. There is no 'quick fix' for this issue, as equipment failures can occur anywhere on the network and are difficult to target in the short-term. The high number of equipment failures is indicative of the overall condition of the existing asset base, particularly in the distribution network. This problem has historically been overshadowed by the high number of faults due to environmental causes but, now that these faults have been reduced by targeted maintenance strategies, it is exposed as a significant issue. In the short-term, the equipment failure problem is likely to limit the rate at which reliability can be improved beyond current levels. Over time, the problem should reduce as improved maintenance strategies have an impact and the network becomes more robust as a result of network development plan initiatives.

Strategies that are being employed by Top Energy to improve levels of service include:

- Vegetation control. Vegetation related outages in FYE2009 contributed 52% to the total SAIDI performance figure. Actively applying the NZ Tree Regulations provides an opportunity for Top Energy to make progress with what has been a difficult problem, because of the growth rate of vegetation locally and the high proportion of native trees.

  The regulations place the onus of responsibility with the tree owner; however there is initially a high expenditure by the network owner in the early years to initiate the process. In March 2012, Top Energy completed a three year programme that invested around $3 million per annum on vegetation management to reduce the vegetation problem to a manageable level. The above table indicates the success of this initiative.

  Expenditure on vegetation management of the sub-transmission and distribution network in FYE2014 is budgeted at $2 million and is focused on the least reliable distribution feeders.

- the use of automatic switching devices and line fault indicators, (i.e. distribution automation);
- sub-transmission protection upgrades. Currently all sub-transmission faults cause a supply interruption that affects a large number of consumers. After completion of the sub-transmission protection upgrade programme, sub-transmission circuits can be operated in parallel and sub-transmission faults will no longer cause interruptions to supply.
- the remote control of switches;
- the use of live line work;
- the installation of diesel generators at Taipa to be used when there is an incoming supply interruption;
- extensive data capture to obtain a better understanding of the asset base, so that Top Energy can improve the effectiveness of its condition-based replacement programme; and
- over the longer term the installation of more interconnections between feeders to enable faster restoration of supply to consumers not directly affected after a fault occurs.

A factor that limits the achievable performance is the geographic spread of the network and the location of staff. It is necessary to have substantial depots from which teams or individuals work for logistical reasons and for backup during emergencies. TECS has two field staff depots, one at Puketona (equidistant from the urban centres of Kaikohe, Kerikeri and Paihia) and the second at Kaitaia. The travel time from these locations to remote areas significantly impacts fault response times.

4.3 Asset Performance and Efficiency Targets

In order to ensure that its asset management strategies result in effective utilisation of its asset base, TEN has developed targets to reflect its asset performance and efficiency.

The targets for loss ratio and operational expenditure ratio are based on indicators that reflect the effectiveness the management of the network assets for the benefit of electricity consumers in the Far North. TEN also considered including a target based on its capital expenditure ratio, but the implementation of the network development programme is likely to result in a volatile capital expenditure ratio of the planning period. This will limit the usefulness of this indicator as a measure of business performance.

4.3.1 Loss ratio

TEN has 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 other factors such as incorrect metering installations, meter errors and theft. In TEN’s 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 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, TEN considers 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 TEN has 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, Top Energy's low consumer density necessitates a high total transformer capacity to provide individual transformers for rural customers, which in turn sets a higher level of standing losses than is typical for less rural networks.

From 1996 to 2001 TEN's network high loss ratio was approximately 10%. In recent years, the loss ratio has improved somewhat to between 8% and 9%. TEN is targeting losses of 6.5% by FYE2022, which is a level reflective of the average for rural networks in NZ. However, in the short-term the network loss ratio is expected to increase from its current level as losses in the transmission assets are included. Transmission losses should decrease once the second transmission circuit is commissioned and new, lower loss transformers are installed at Kaitaia. Over time, distribution losses should also decrease as new sub-transmission circuits are completed and the installation of new zone substations reduces distribution system losses. Nevertheless, there is a limit to the extent the losses can be mitigated. Typically, up to 30-40% of losses are on the low voltage network and these losses cannot easily be reduced. Also, rural networks with low loss ratios tend to have a higher number of injection or grid exit points.

TEN's loss ratio targets for the planning period are shown in Table 4.4 and Figure 4.3 compares these target levels with the recent historical performance. Target loss ratios for FYE2017 and beyond may need to be adjusted if there is a delay in the completion of the second 110kV circuit to Kaitaia.

The FYE2012 target shown in Figure 4.3 is the 8.0% target set in the 2011 AMP. A similar target was set for FYE2013 in the 2012 AMP.

FYE 2014	FYE 2015	FYE 2016	FYE 2017	FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023
9.0%	8.7%	8.4%	8.4%	7.5%	7.3%	7.0%	6.7%	6.5%	6.5%

Table 4.4: Target Loss Ratios

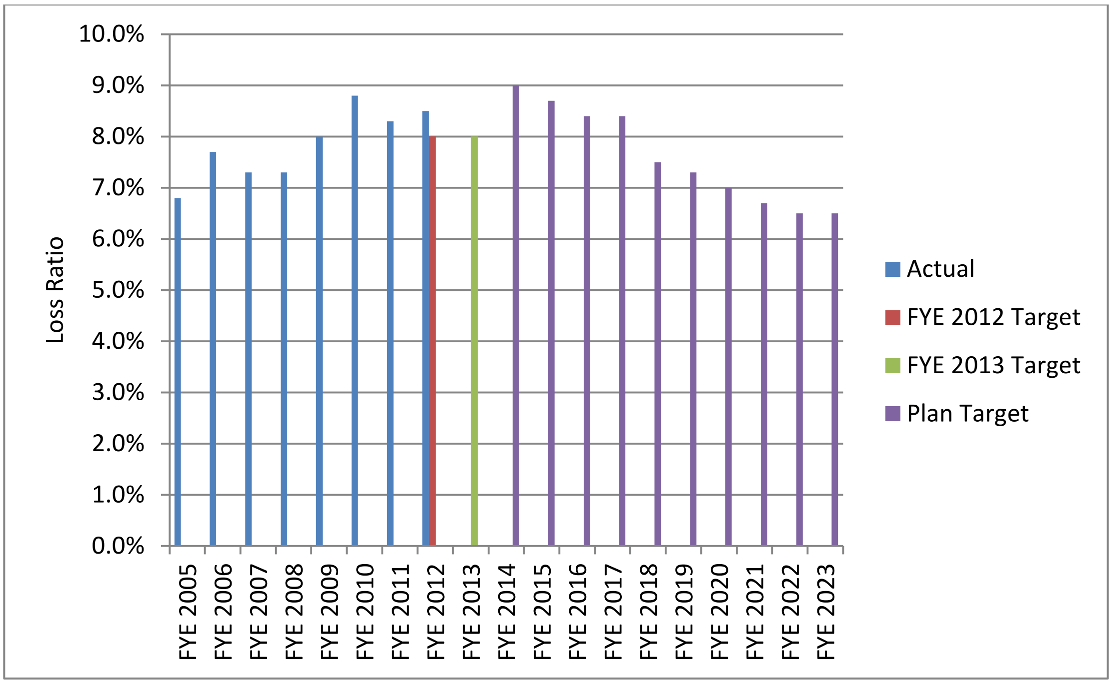

Figure 4.3: Loss Ratios of Top Energy since FYE2004

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. TEN has selected its operational expenditure ratio as an appropriate indicator of the financial effectiveness of its asset management efforts. The operational expenditure ratio is defined as the ratio of TEN's total operational expenditure during a measurement year to the replacement cost of TEN's system fixed assets at the end of the measurement year. It is a key financial performance indicator used by the Commerce Commission in its information disclosure regime, which was developed after extensive public consultation at a national level. Hence TEN's performance is directly comparable with the disclosed performance of its peer distribution utilities.

As shown in Figure 4.4, TEN's historic operational expenditure ratio has risen progressively since the measure was first introduced by the Commerce Commission in FYE2008. It was expected to rise to approximately 4.75% in FYE2012 and FYE2013, due to the additional operational expenditure required to maintain the recently acquired transmission assets and the relatively poor condition of these assets. It is expected that, from FYE2014 and beyond, the operational expenditure ratio should reduce significantly, due to the reduced maintenance requirements of newer assets and the progressive reduction in the average age of network assets as the network development plan is implemented. This will result in a higher replacement cost, which will tend to reduce the ratio. It has therefore been decided to target a modest improvement in the operational expenditure ratio over the remaining years of the planning period. However these targets will need to be kept under review and may need to be reset as Top Energy gains experience in the operation and maintenance of its new 110kV transmission assets

The proposed targets for the planning period are shown in Table 4.5 and a comparison of these targets with TEN's historic performance is shown in Figure 4.4.

The FYE2012 target shown in Figure 4.4 is the 4.75% target set in the 2011 AMP. A similar target was set for FYE2013 in the 2012 AMP.

FYE 2014	FYE 2015	FYE 2016	FYE 2017	FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023
4.70%	4.64%	4.59%	4.53%	4.48%	4.42%	4.37%	4.31%	4.26%	4.25%

Table 4.5: Operational Expenditure Ratio Targets

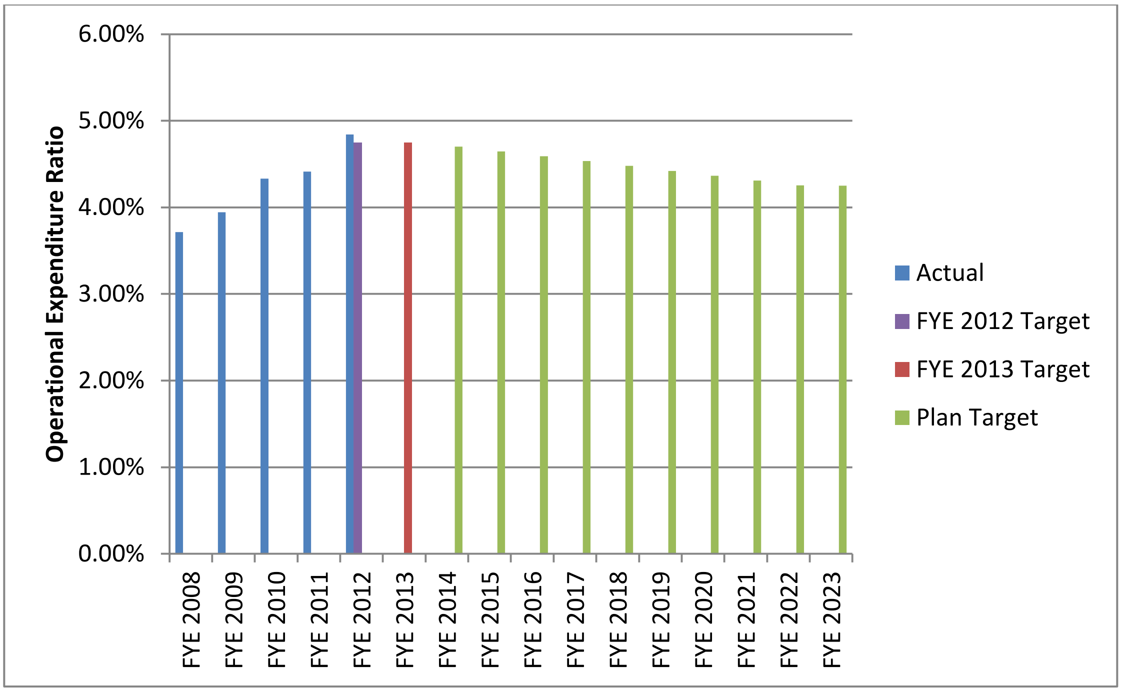

Figure 4.4: **TEN's Operational Expenditure Ratio since FYE 2008**

4.4 Justification for Service Level Targets

TEN's service level indicators are designed to measure the effectiveness of TEN's asset management strategies, which have been developed to reflect the outcome of its stakeholder consultation process and other internal business drivers. An important economic consideration for TEN in setting service level targets is affordability of services, as the supply area covered by TEN is one of the poorest socio-economic areas in New Zealand.

As discussed in Section 3.1.4, over 35% of TEN's 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 32% of TEN's lines, which supply just 8% of its consumer base, are considered uneconomic.

Accordingly, the service level targets must ultimately reflect the Top Energy Board's views on affordability, given this high proportion of uneconomic lines. This view was informed by the results of the customer consultation process described in Section 4.4.1 below.

It should be noted that the underlying service levels delivered by TEN to most of its customers FYE2011 and FYE2012 were a significant improvement on earlier years, as a result of several initiatives and targeted investment strategies discussed in Section 4.2.2. This is largely a response to a strong message from our consumers that the earlier network performance levels are not acceptable. As demonstrated in this AMP, TEN continues to explore and implement suitable strategies for performance improvement.

4.4.1 Formal Customer Consultation

Top Energy has:

- advised its 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.

Top Energy undertook a comprehensive consumer telephone survey and one-on-one discussions with major power users in 2009 to assist it formulate relevant asset management strategies, including the network development plan and to set appropriate performance targets. In Top Energy's experience, customer views do not normally change significantly over time; therefore, the results of this survey are considered to remain relevant during this planning period.

4.4.1.1 2009 telephone survey

An independent review was carried out of a random sample of 1,000 small use consumers. The breakdown by supply area and market segment is shown in the table below.

MARKET SEGMENT	BAY OF ISLANDS	NORTH	SOUTH	SUB-TOTAL
Rural commercial	14	10	5	29
Rural residential	173	246	117	536
Urban commercial	33	12	10	55
Urban residential	202	98	62	362
Not disclosed	6	10	2	18
Total	428	376	196	1,000

Table 4.6: Customer survey

The questionnaire incorporated questions intended to inform, educate and elicit feedback useful to Top Energy in defining and setting target levels of service. The key conclusions drawn from the 2009 survey are:

- most customers recalled having a power cut within the last few weeks or months of the survey;
- 86% of customers consider Top Energy's supply reliability to be either acceptable or more than acceptable;
- 88% of customers' recollections of changes in supply reliability were incorrect;
- when told that supply reliability had actually declined, 54% of customers indicated that this was unacceptable (despite 86% of customers indicating that reliability was either acceptable or more than acceptable);
- 80% of customers wished to see an improvement in reliability (despite 86% of customers indicating that reliability was either acceptable or more than acceptable);
- expectations of prompt restoration appear high, with 64% of customers expecting power to be restored with 2 hours. The rural segment seems to be an exception with an even spread between 'less than 2 hours' and '2 to 6 hours';
- expectations of continuity also appear high, with 25% of customers believing that the power should never go off;
- 62% of customers recall having a power cut of less than 1 minute, with only 10% considering this to be a major inconvenience;
- consumer preferences for fewer but longer outages, as opposed to more but shorter outages, revealed a slight skew towards the latter. This seems at odds with the derived preferences for SAIFI, which indicate a preference for a low number of outages;
- consumers' perceptions of an acceptable SAIDI level were approximately 346 minutes. This is significantly lower than both TEN's historical performance and the regulatory threshold;
- 66% of customers would not be prepared to pay any more for a second 110kV line to the Kaitaia GXP; and

- only 52% of those customers surveyed believed that a business setting up in the Far North should have access to a reliable electricity supply.

The results of the 2009 consultation, and those undertaken in previous years, gave Top Energy the following objectives:

- to focus on improving service continuity and restoration as priorities;
- to improve the provision of restoration information in parallel with the fault restoration work;
- to educate consumers to complete basic checks before they call and inform TEN of a fault;
- to reduce flicker and surge where practical and where resources are available; and
- to educate consumers on the causes of flicker and surge, and how hard it is to reduce flicker.

Examining the customer responses to the questions relating to reliability of service and the length of outages, it is possible to draw direct conclusions as to customer expectations relating to SAIDI and SAIFI performance measures.

- **Perceptions of acceptable SAIDI**: Average customer perceptions of an acceptable SAIDI is about 346 minutes, which is lower than what Top Energy had achieved in the years prior to the survey and significantly lower than the regulatory threshold. These perceptions are shown in more detail in Table 4.7.

MARKET SEGMENT	BAY OF ISLANDS	NORTH	SOUTH
Rural commercial	403	468	450
Rural residential	345	379	434
Urban commercial	355	248	117
Urban residential	307	345	306

Table 4.7: Customer expectations - SAIDI

The following conclusions were drawn from the table above

- in the Bay of Island area, rural and urban customers seem to have a similar perception of an acceptable SAIDI;
- in the Northern area there is a gap between what rural commercial and urban commercial customers believe is an acceptable SAIDI; and
- expectations around rural reliability appear to be greater in the Bay of Islands than in the broader North and South areas.

- **Perceptions of acceptable SAIFI:** Average customer expectations of acceptable perceived SAIFI is 2.4, which was significantly lower than Top Energy' historical performance.

MARKET SEGMENT	BAY OF ISLANDS	NORTH	SOUTH
Rural commercial	2.3	2.3	3.0
Rural residential	2.4	2.5	2.9
Urban commercial	2.2	2.3	1.5
Urban residential	2.5	2.4	2.2

Table 4.8: Customer expectations - SAIFI

The survey identified continuity of supply and prompt restoration of service to be the most important aspects of service; TEN interprets 'quality' as synonymous with reliability (i.e. continuity and restoration). The customer service indicators adopted reflect this interpretation.

The very high percentage of customers indicating that the current reliability of the network is acceptable and the majority expectation that power is restored within two hours, suggests that the recent SAIDI performance (which is at the top end of the TEN peer group and considerably higher than preferred) is acceptable. In spite of this, 80% of respondents indicated a desire to see reliability improved. TEN has adopted forward service targets that are markedly lower than present.

4.4.1.2 High user consultation

In 2008, TEN engaged a specialist energy consultant to contact (by phone) the 12 largest consumers (the same consumer group TEN surveyed in 2006) and an additional 15 randomly selected commercial customers from the top 100 commercial consumer group. TEN holds detailed discussions with each of its four major industrial customers on an annual basis about the form and content of their charges, with a view to ensuring that the costs are fairly allocated and to consider options to improve service and reduce costs. In all cases, no immediate growth was forecast and the current level of reliability and security is considered acceptable.

4.4.2 Community Engagement

Notwithstanding the results of the formal customer consultation process a number of factors led the 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 the TEN 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 sub-transmission capacity bringing power into the area could no longer be deferred;
- There was ongoing community concern at the lack of security in the supply to the Northern area and the fact that one third of the supply area was denied an electricity supply for extended periods during annual maintenance shutdowns. Furthermore, there was little likelihood of local generation materializing that would alleviate this problem; and
- The low levels of supply reliability experienced in FYE2009 and FYE2010 were unsustainable in the regulatory environment within which TEN operates. In fact, the reliability experienced by customers in the Northern region was understated by these measures, since they did not include transmission driven interruptions.

Top Energy 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. It engaged in an extensive community consultation process to determine the standard of electricity supply required to underpin the economic development of the Far North over the next two decades and, importantly, the amount its customers are prepared to pay to secure an electricity supply of the quality that other rural New Zealanders have come to expect.

The engagement has 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 is 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 Top Energy has undertaken to implement the extensive network development and maintenance improvement programmes described in Sections 5 and 6 of this AMP. Over the last two years it has also implemented the significant price increases needed to fund the programmes with little overt community opposition. The plans described in this AMP are ambitious, but Top Energy's Board and management strongly believe that they are consistent with the long-term interests of its local community. Top Energy looks forward to continuing to work with its community to successfully implement these plans in a timely manner.

4.4.3 Justification for Asset Performance and Efficiency Targets

4.4.3.1 Loss Ratio

The short-term loss ratio targets in Table 24 reflect a short-term deterioration in loss ratio to take into account the inclusion of local transmission losses in the loss ratio measurement. Loss reductions from the following projects have been allowed for setting the targets for the subsequent years of the planning period:

- the commissioning of the double circuit 110 kV line between Kaikohe and Wiroa at 33kV in FYE2015;
- the replacement of the Kaitaia 110/33kV transformers in FYE2015 and FYE2020 with lower loss units; and
- the commissioning of the 110kV line between Wiroa and Kaitaia in FYE 2017.

Overlaid on this are smaller, but nevertheless significant, reductions in network losses as a result of the installation of the Kerikeri, Taipa and Kaeo substations. These capacity expansions will reduce sub-transmission losses through the addition of new sub-transmission lines carrying lower currents. They will also reduce distribution network losses through the introduction of additional injection points, which will in turn reduce distribution network loadings from current levels. Distribution loss reductions will also arise from reconductoring initiatives during the planning period.

4.4.3.2 Operational Expenditure Ratio

TEN’s operational expenditure ratio is likely remain at approximately 4.75% in the current year (FYE2013), due to the impact of a continuing high level of expenditure on vegetation management and other maintenance initiatives. It was expected that, from FYE2014 and beyond, the operational expenditure ratio would gradually reduce, as maintenance stabilises and an increased level of asset replacement (resulting from the network development plan) increases the total asset replacement cost.

However, the acquisition of the Transpower assets on 1 April 2012 will impact Top Energy’s operational expenditure ratio and, at this stage, it is not clear what the appropriate targets should be for the planning period. Notwithstanding the actual increase in the operational expenditure ratio in FYE2012, in the absence of better information it has been decided to retain the 2012 AMP FYE2014 target of 4.70% and to continue to target a modest improvement in the operational expenditure ratio over the remaining years of the planning period. However, these targets will be kept under review and may need to be reset over the next two or three years, as TEN gains experience in the operation and maintenance of its new 110kV transmission assets.

Section 5 Network Development Planning

5 Network Development Planning

5.1 Planning Criteria

Planning criteria for 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 is the main factor that drives these requirements, network development is also driven by a need to improve the reliability of supply to consumers.

5.1.1 Voltage Criteria

Top Energy uses the following design voltage limits.

- 33kV sub-transmission: +4.5%, -10% of nominal voltage;
- 11kV distribution: +2%, -5% of nominal voltage; and
- 400V LV network: ±4% of nominal voltage up to legal point of supply.

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

TEN's 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 and voltage is therefore the most common driver for augmentation projects.

5.1.1.1 Voltage Control Options

a) Zone sub and Distribution Transformer

In order to control the system voltage within the specified limit, TEN purchases 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 Regulator

TEN uses 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, TEN has connected voltage regulators in an open delta configuration to obtain 10% voltage regulation on two phases. As TEN has 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

TEN typically purchases 200kVAr fixed tap capacitor banks to use on rural distribution feeders, but also has 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

TEN's network is predominantly rural, with long radial feeders and significant lengths of two wire and SWER lines. Therefore, to address voltage and capacity problems, TEN investigates 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 e.g. from 11kV to 22kV;

5.1.2 Security of Supply

TEN's 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 operation 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 TEN's 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, all consumers supplied from that substation will experience an interruption that could last for up to 10 hours; depending on the cause of the fault and the location of the substation. In most situations, some power transfer capacity within the distribution network will be available, allowing power to be restored to some consumers well before this.

TEN owns and operates 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.

The network does not currently conform to the security of supply criteria, due mainly to protection constraints that limit the way the 33kV sub-transmission network can be operated. The sub-transmission system is currently run in a radial, split bus arrangement with one line feeding each half of a substation. This means that, in the event of a fault on the incoming line, supply to approximately half of the customers supplied from the substation would be interrupted until the network can be reconfigured by switching.

This inability to maintain uninterrupted supply from large zone substations in the event of a single sub-transmission element fault is a significant concern and is being addressed as part of the network development plan detailed later in this chapter. This will involve an upgrade of the protection system at each substation and, in some cases, circuit breaker replacement. The first zone substation to be upgraded to achieve full uninterrupted N-1 security will be Haruru, where the upgrade will be completed by the commencement of FYE2014.

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

Table 5.1 shows the level of security currently provided at all Top Energy's zone substations.

SUBSTATION	TRANSFORMER FAILURE	BACK UP TO AFFECTED TRANSFORMER	TIME REQUIRED TO RESTORE SUPPLY (HRS)
Southern Area			
Kaikohe	T1	T2	Switching Time
	T2	T1	Switching Time
Kawakawa	T1	T2	Switching Time
	T2	T1	Switching Time
Moerewa	T1	Mobile Substation	Switching Time[1]
Waipapa	T1	T2	Switching Time
	T2	T1	Switching Time
Omanaia	T1-1 R	Mobile Substation	9.5
	T1-2 Y		
	T1-3 B		
Mt Pokaka	T1	Mobile Substation	9.0
Haruru	T1	T2	Switching Time
	T2	T1	Switching Time
Northern Area			
Okahu Rd	T1	T2	Switching Time
	T2	T1	Switching Time
Taipa	T1	Mobile Substation	9.5
Pukenui	T1	Mobile Substation	10.0
NPL	T1	T2	Switching Time
	T2	T1	Switching Time

Note 1: This is assuming that the mobile substation continues to be located at Moerewa.

Table 5.1: Zone Substation Security

5.1.3 Network Capacity Requirements

With ever-increasing load growth on the distribution network, some of the existing network assets need to be upgraded, or new assets need to be introduced to supply the forecast load growth.

For design purposes, TEN considers the different capacity constraint levels on primary assets for normal operation and contingent operation, and applies 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: Top Energy Design Capacity Limits

5.1.4 Network Protection Requirements

Modern protection systems offer features not available from Top Energy's mechanical protection relays. Top Energy plans to replace the existing relays with relays that will facilitate utilisation of interties at sub-transmission level and allow more sophisticated meshed switching arrangements at zone substation and distribution levels. This will reduce the number and duration of outages, as well as meet the requirements of TEN's security standards.

The new systems also provide improved data on asset utilisation and will allow improved modelling of the network over time. Improved modelling will mean improved asset management.

Protection upgrades are required at all dual transformer zone substations (except Haruru, where the upgrade has already been completed) before they can provide uninterrupted N-1 security. The upgraded sub-transmission line protection schemes will rely on a comparison of the amount of power entering and leaving each line. This requires a high speed, fibre-optic communication path linking the two ends of each line.

5.1.5 New Equipment Standards

In order to maximise cost efficiencies and reduce the required number of spares, TEN has 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 customer 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 customer 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 sub-transmission voltage and below. Steel poles will be used for 110kV transmission lines and will also be used for new sub-transmission lines in locations where Top Energy's 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 sub-transmission 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 and where 5/10MVA and 3/5MVA transformers are used. Transmission transformers rated at 110/33kV are standardised at 40/60MVA, except for Taipa where a smaller transformer size will likely be used. In TEN's 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. However, it does increase the risk of over-capacity. An example of where this has occurred is Moerewa, where the closure of the diary factory and the downsizing and modernisation of the freezing works means that a load where the FYE2013 peak was just 1.7MW is supplied through an 11.5/23MVA transformer. Nevertheless, while the possibility of new industrial development in or around Moerewa remains, it would be unwise to relocate the existing transformer at this stage. This illustrates the high level of uncertainty in which network development decisions must be made.

Network development is planned around TEN's standard asset sizes. In selecting the appropriate asset size, the forecast peak load under contingency conditions at the end of what TEN considers 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, TEN prefers 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

TEN's network is predominantly rural and radial with many long feeders, often with a low number of customers per kilometre. This means that the limiting factor determining the size of conductor will be the voltage drop along the line, rather than the thermal current carrying capacity. TEN monitors the voltage level along its feeders by using sophisticated computer models and by 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, use of voltage regulators, and the use of both fixed and switched capacitors.

Load growth in many areas has now reached the stage where incremental augmentation of this nature is no longer sufficient. The network development plan will address this issue by increasing the number of points at which power is injected into the distribution network. This will allow the use of shorter feeders, which will limit voltage drops and allow higher current loadings of existing conductors (as well as reducing the number of consumers affected by an HV fault).

TEN is also planning to install more interconnections between distribution feeders to permit more operating flexibility during faults. This will improve reliability by allowing supply to be restored sooner for many customers after a fault occurs.

TEN also monitors the thermal current ratings of feeders, which can be a limiting factor for shorter, urban feeders.

5.3 Energy Efficiency

Given the current electricity industry structure, TEN is not responsible for the cost of losses on its network. Nevertheless, as a responsible service provider, it recognises that the energy efficient operation of its network is in the long-term interests of all stakeholders. The following initiatives are in place to promote energy efficiency:

- Currently, TEN's network losses are the highest in the country. However, as discussed in Section 4.3.1, TEN has set a target of reducing network losses by more than 25% over the planning period. While loss minimization is not the primary objective of the network development plan, the reduction of network losses should be a positive outcome from the implementation of this plan.
- The Ngawha geothermal power station provides approximately 70% of the energy requirements of TEN 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. Sub-transmission losses incurred in transmitting the energy generated at Ngawha to the Kaikohe substation will be further reduced now the second 33kV circuit between Ngawha and Kaikohe is finally commissioned. TEN's internal analysis has shown that the reduction in the cost of these sub-transmission losses, as a result of the commissioning of this line, will be substantial.
- As discussed in Section 5.9, TEN actively controls 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 TEN's network maximum demand by approximately 10MW.
- TEN is 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.

- TEN's 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

The company maintains 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

The 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 significant load growth in the Kerikeri area and the consequent development of a voltage constraint under certain N-1 contingency situations;
- the condition of the 33kV switchgear at both the Kaikohe and 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 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.

The Top Energy Board and the 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 capacity to the Northern and Eastern parts of the supply area. As discussed in Section 4.4.2, Top Energy has the support of its community for this investment. The major projects planned for the next 10 years and the basis for their prioritisation are discussed in Sections 5.10-5.12. 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 as soon as realistically possible is central to Top Energy's network development strategy. Improvement of the supply capacity into Kerikeri leverages off this project, but also addresses an existing network limitation. Hence, this project is committed for implementation as soon as possible with no scope for timing adjustments.

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 and the outdoor-indoor switchyard conversions). While there may be scope for some timing or prioritisation adjustments and minor design changes, all major projects must proceed if the Board's overarching strategy of delivering a quantum improvement in the level of service to customers is to be achieved. Hence, implementation of the programme is not dependent on demand growth, but could be constrained by funding and deliverability limitations. Difficulty in securing new transmission line routes is a recurring problem for network service providers and this has already caused some delay in the construction of the new 110kV line between Kaikohe and Wiroa.

5.5.2 Incremental Capital Upgrades

Incremental capital upgrades generally have short lead-times and are managed within budget envelopes in the Annual Plan. They include asset replacements undertaken as a consequence of condition assessments and asset inspections. They also include refurbishment projects targeted at assets (often sub-transmission or distribution lines) 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 only those that provide the greatest benefits are implemented.

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

- TEN staff;
- Top Energy control centre;
- TECS;
- Network asset inspection reports;
- Maintenance Manager;
- Network modelling and study;
- Analysis of fault statistics and causes;
- Consumers; and
- Far North District Council plans.

This information is used by TEN staff 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.

The need to meet challenging short-term SAIDI and SAIFI targets is accorded a high priority by Top Energy and the potential of a project to improve network reliability is therefore weighted highly in TEN's prioritisation process. In the shorter-term, there has therefore been a high priority given to projects that will improve the reliability of the transmission and sub-transmission networks, as outages of these networks affect a large number of customers and all sub-transmission faults at present result in a supply interruption. Programmes involving the installation of further remote controlled switches and interconnections between neighbouring feeders have also been prioritised for a similar reason.

In the first five years of the planning period, the focus of the incremental capital expenditure forecast is on the replacement of high-risk sub-transmission assets and on the delivery of distribution network programmes that will improve reliability. Hence, the installation of remote controlled switches will continue and a programme to install more interconnections between neighbouring feeders is being initiated. In the later years of the planning period, the focus on increasing network capacity and improving reliability will diminish, while expenditure on asset replacement and renewal is expected to increase. These trends can be seen from the CAPEX forecasts in Section 5.14.

5.6 Demand Forecasting Methodology

5.6.1 Overview

Load forecasting is performed to provide an estimate of future loads, 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. heat pumps, electric cars, etc.).

Historically, the methodology used for forecasting demand was based on linear trending of historical data (with the addition of new loads), based on ICP numbers and associated load per customer. The methodology used for the 2012 AMP varied from that used previously, as it used historical base load projections based on the average changes in the past three years. For the reasons discussed in Section 5.6.4, the load forecast developed for the 2012 AMP has been retained for this 2013 AMP.

The financially restrained economy has resulted in unpredictable and somewhat subdued growth and demand. Therefore, the period 2009 to 2011 was used as a historical footprint for future load growth, as it provided a more realistic indication of a recovering economy post the 2008 financial recession.

The methodology used to prepare the 2012 AMP load forecast is summarised in Figure 5.1.

In projecting future growth rates based on the 2009 to 2011 historical footprint, the following factors are reviewed and considered as appropriate:

- **Energy Sales Records:** Energy sales records for the network, mainly by industrial and domestic customer classes, were reviewed. As detailed energy sales records are not available for small commercial customers, they were considered as domestic customers.
- **Demand Records:** Daily half-hourly average demand data for each feeder on the network was obtained from the SCADA system. The half-hourly data for each feeder (with all switching aberrations removed) was correlated with zone and transmission substation demand data to calculate the diversity factors that were used in the forecast. Diversity is discussed in more detail below.
- **Subdivision activity:** Potential subdivision activity for the planning period was identified from information provided by different resources such as TECS, subdivision developers, real estate agents and TEN's own local knowledge of the region. In cases where the total load requirements for any subdivision is not available, the values of 4kW/unit after diversity maximum demand (ADMD) and 8kW/unit ADMD are used for domestic and small commercial subdivisions respectively, as per TEN's design standard. These loads were attributed to the relevant feeders with due allowance being made for the potential delays between the reticulation of a new subdivision and the new load materialising. These delays tend to lengthen when economic activity is weak.
- **Industrial and large commercial growth:** TEN consults with its major industrial customers regarding any future expansion and change in load demand for the planning period. It also acquires the information on any known industrial and/or major commercial development on the network in near future by consulting TECS and other developers in the region. The demand of these existing large customers is not currently expected to increase above existing levels.
- **General demographic and economic trends:** TEN uses general knowledge gained from demographic trend information. This information is collected from both publicly available census data and from the data gathered by TEN through its daily operations.
- **Diversity Factor:** Diversity factor is the ratio of non-coincident maximum demand (∑ feeder maximum demand) to coincident demand (zone substation maximum demand). Maximum demand for different supply points (GXPs, zone substations or feeders) do not necessarily occur at the same time. This suggests that the zone substation maximum demand will be less than the sum of individual feeder maximum demands supplied from it. This also applies at the transmission substation and also at GXP level. Diversity factors at transmission and zone substation levels are calculated using historical data. The

average of historical diversity factors is applied at appropriate level to forecast maximum demands at zone substation and GXP level.

- **Demand Side Management (DSM) Plan:** Peak demand is limited by hot water storage system ripple relays. The reality is that the majority of consumers do not have sufficient price incentives to modify their demand themselves. However, the three largest industrial consumers are given the opportunity and a direct financial incentive within their tariff structure to contribute to a reduction of grid exit point costs, by controlling their coincident peak loads. Thus far, a more sophisticated real-time monitoring and demand side dispatch system is not considered worthwhile. TEN's demand management plan is discussed in detail in Section 5.9. The load forecast in this AMP includes the impact of these demand management initiatives. This impact is significant and TEN estimates that its load control reduced its actual peak demand by at least 10MW.
- **Supply-Side Options:** Potentially, new large generators have an opportunity to share the benefits of reducing grid exit point charges and this will be negotiated with proponents on a case-by-case basis. The connection requirements for distributed generation and the approval process are described in Section 5.8 and TEN's distributed generation policy is available on the Top Energy website. TEN also encourages the connection of small generation plant such as small 2-5kW generators, solar panels, small wind turbines and consumer-owned stand-by generators (<300kW) to its network. TEN has received a number of enquiries about distributed generation proposals, but economically the schemes have not been viable to-date and therefore are not included within the forecasts included in this AMP.
- **Impact of Uncertain Projects:** There are three projects that have the potential to significantly change the load forecasts projected within this AMP. These are discussed in Section 5.7.2.

5.6.2 Data on Historic Demand

Historic demand data for the Kaikohe and Kaitaia transmission substations, as well as the injection into the network from the Ngawha power station, was obtained from the Electricity Authority's centralised data set. Data was also obtained from TEN's SCADA system. Adjustments were made to eliminate false peaks caused by network aberrations and also to account for discrepancies between TEN and Transpower data, which occurred as a result of a combination of:

- losses within the network;
- inaccuracy in zone substation measurement instruments (as these are not metering class);
- inaccuracy in time stamps; and
- inaccuracy in the power factor and voltage assumed for converting GXP data to kVA.

5.6.3 Forecast Methodology

5.6.3.1 Feeder Demand Growth

Actual growth rates for each feeder over the period 2009 -2011 were assessed on the basis of the average of the top 20 normalised feeder peaks for each year. These growth rates were used as the basis for forecasting the underlying growth on each feeder with the base load for the projection being the average of the top 20 feeder peaks in 2011. Where the average growth rate over the period 2009-11 was negative, a zero growth rate was assumed.

Economic development in the area is still relatively subdued and, while TEN is aware of a number of potential new block loads, none have progressed to the stage where it has been considered prudent to include them in the forecast. There are also a number of recently completed subdivisions, generally in areas where demand growth is already relatively high. These subdivisions are relatively small and no specific provision has been made for this new load, as new subdivisions can take some years to be fully occupied. It is recognised that, historically, growth rates have been higher in areas where there have been higher levels of subdivision activity and in general it has been assumed that the effect of new subdivision development is to make land available so that load growth can be sustained in more rapidly developing areas.

5.6.3.2 Zone and Transmission Substation Demand Growth

A feeder to zone substation diversity factor was calculated for each feeder, based on the average contribution of that feeder (relative to peak feeder load) to the zone substation peak load for each year of the three year period 2009-11. The demand at each zone substation was the aggregate of the diversified feeder loads for each year of the forecast period. The individual zone substation growth rates were then 'cross checked' at a high level and adjustments were made where it was considered appropriate.

In particular, the forecast growth rate at Taipa was increased to 1.25%. This is a popular holiday and retirement area that has historically experienced high growth rates, but which was particularly hard hit by the global financial crisis and has still to fully recover. There are a large number of vacant housing lots in the area and TEN expects that the current rate of growth in electricity demand will increase as economic conditions improve. The zone substation demand forecasts calculated in this manner were then calibrated against the actual peak substation demands in 2011 (FYE2012), in order to produce the demand forecasts in the tables below.

Zone substation to transmission substation diversities were similarly calculated and used to calculate transmission substation and network peak demands. A similar approach was also used to estimate the overall network peak demand.

Forecast peaks for Kaikohe transmission substation do not take account of whether or not Ngawha is operating; the peak shown is the potential demand on the grid if Ngawha was not operating at the time of the peak. Under normal circumstances, Ngawha would be operating at time of peak demand and the actual peak demand on the Kaikohe 110kV transformers would be up to 25MW lower than shown in Table 5.5.

5.6.4 Update for 2013 AMP

For this AMP TEN did not undertake a full revision of the load forecast using the approach described above. Instead, TEN compared the actual peak demand at each zone substation in FYE2013 with that forecast in the 2012 AMP. This comparison is shown in Table 5.3 below.

Overall, the aggregated peak demand at zone substations across the network was marginally lower than forecast. However, the variance at individual substations was significant, although in many cases these variances related to substations where there is sufficient capacity for the planning period and no new capacity is required. While the population of Moerewa is in decline, the significant reduction at this site is due to lower than expected demand from the AFFCO Freezing Works, the major industrial customer supplied from the substation, which was affected by extended industrial action during the early part of the year. The significant increase in demand above forecast at Kawakawa substation is of concern, although this was largely offset by reduced demand at Haruru. These substations together supply the Bay of Islands tourist area and, significantly, both peaks were registered during the Queen's birthday winter holiday weekend. While there is ample transformer capacity at Haruru, transformer capacity at Kawakawa is limited, although there is some ability to redistribute demand between the two substations. However, load growth on the Russell Peninsular (supplied from Kawakawa via two submarine cables) will continue to be monitored, as this is a high growth area with a large number of vacant subdivision lots still available.

Overall, the variances between the 2012 forecast and actual zone substation peak demands do not justify a revision of the 2012 peak demand forecast and the demand forecast in Section 5.7 is based on the forecast in the 2012 AMP. The forecast demand for FYE2023 was not shown in the 2012 AMP, as it was outside the planning period. For this AMP, it has been derived by extrapolation. TEN will continue to monitor this variance on an annual basis and modify this forecast, should a significant trend become apparent.

There was an error in the transmission substation and network peak demands forecast in the 2012 AMP as these were extrapolated from the disclosed FYE2011 network peak demand of 70.0MW. However, this was an outlier that does not reflect the peak demands that Top Energy normally experienced, as reflected in disclosures for other years. This error has been corrected in Table 5.5.

Substation	Peak Demand (MW)		Date of Actual Peak	Variance
	AMP Forecast	Actual		
Kaikohe	9.71	9.15	31/07/12	-5.8%
Kawakawa	5.08	5.87	02/06/12	15.6%
Moerewa	3.02	1.69	25/07/12	-44.0%
Waipapa	17.24	17.14	21/05/12	-0.6%
Omanaia	2.24	2.27	02/07/12	1.3%
Haruru	5.87	5.23	03/06/12	-10.9%
Mt Pokaka	2.59	2.33	31/07/12	-10.0%
Okahu Rd	9.12	9.36	31/07/12	2.6%
Taipa	4.80	4.61	02/06/12	-4.0%
Pukenui	1.53	1.87	02/07/12	22.2%
NPL	11.50	11.24	29/06/12	-2.3%

Note 1: Peak demands at the two transmission substations have not been recorded since their acquisition from Transpower. This will be addressed in FYE2014.

Table 5.3: Comparison of Actual and Forecast Zone Substation Peak Demands

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 5.4 below. The peak demands shown in the tables are net of the peak demand reductions that TEN is able to achieve though the operation of its load control system. At present, there is no embedded generation within the TEN network that supplies an internal consumer load and therefore has the potential to reduce peak network demand.

	FYE 2014	FYE 2015	FYE 2016	FYE 2017	FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023
Southern Area										
Kaikohe	9.81	9.86	9.92	9.97	10.02	10.08	10.13	10.19	10.25	10.31
Kawakawa	5.16	5.20	5.25	5.29	5.34	5.39	5.44	5.49	5.53	5.57
Moerewa	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02
Waipapa	12.10	12.31	12.52	12.75	12.98	9.01	9.19	9.38	9.57	9.76
Omanaia	2.28	2.31	2.33	2.35	2.38	2.40	2.42	2.45	2.48	2.51
Haruru	5.98	6.03	6.09	6.15	6.21	6.26	6.32	6.38	6.44	6.50
Mt Pokaka	2.66	2.69	2.74	2.78	2.82	2.85	2.89	2.92	2.95	2.98
Kerikeri (new)	6.71	6.75	6.80	6.84	6.89	6.94	6.99	7.04	7.09	7.14
Kaeo	-	-	-	-	-	4.20	4.26	4.32	4.38	4.44
Northern Area										
Okahu Rd	9.27	9.35	9.43	9.51	9.59	9.68	9.76	9.84	9.92	10.00
Taipa	4.91	4.98	5.04	5.10	5.17	5.23	5.30	5.36	5.42	5.48
Pukenui	1.53	1.54	1.54	1.54	1.54	1.54	1.55	1.56	1.57	1.58
NPL	11.54	11.56	11.59	11.61	11.63	11.65	11.67	11.69	11.71	11.73

Table 5.4: Zone Substation Demand Forecast (MW)

The demand forecasts for the two transmission substations and for the total network are shown in Table 5.5 below.

	FYE 2014	FYE 2015	FYE 2016	FYE 2017	FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023
Kaikohe	44.7	45.2	45.8	46.4	47.0	47.6	48.2	48.8	49.4	50.0
Kaitaia	23.3	23.4	23.6	23.7	23.8	24.0	24.1	24.3	24.4	24.6
Network[1]	65.4	66.0	66.7	67.4	68.2	68.9	69.6	70.3	71.1	71.8

Note 1: Peak demands at the two transmission substations have not been recorded since their acquisition from Transpower. This will be addressed in FYE2014.

Table 5.5: Transmission Substation and Network Demand Forecast (MW)

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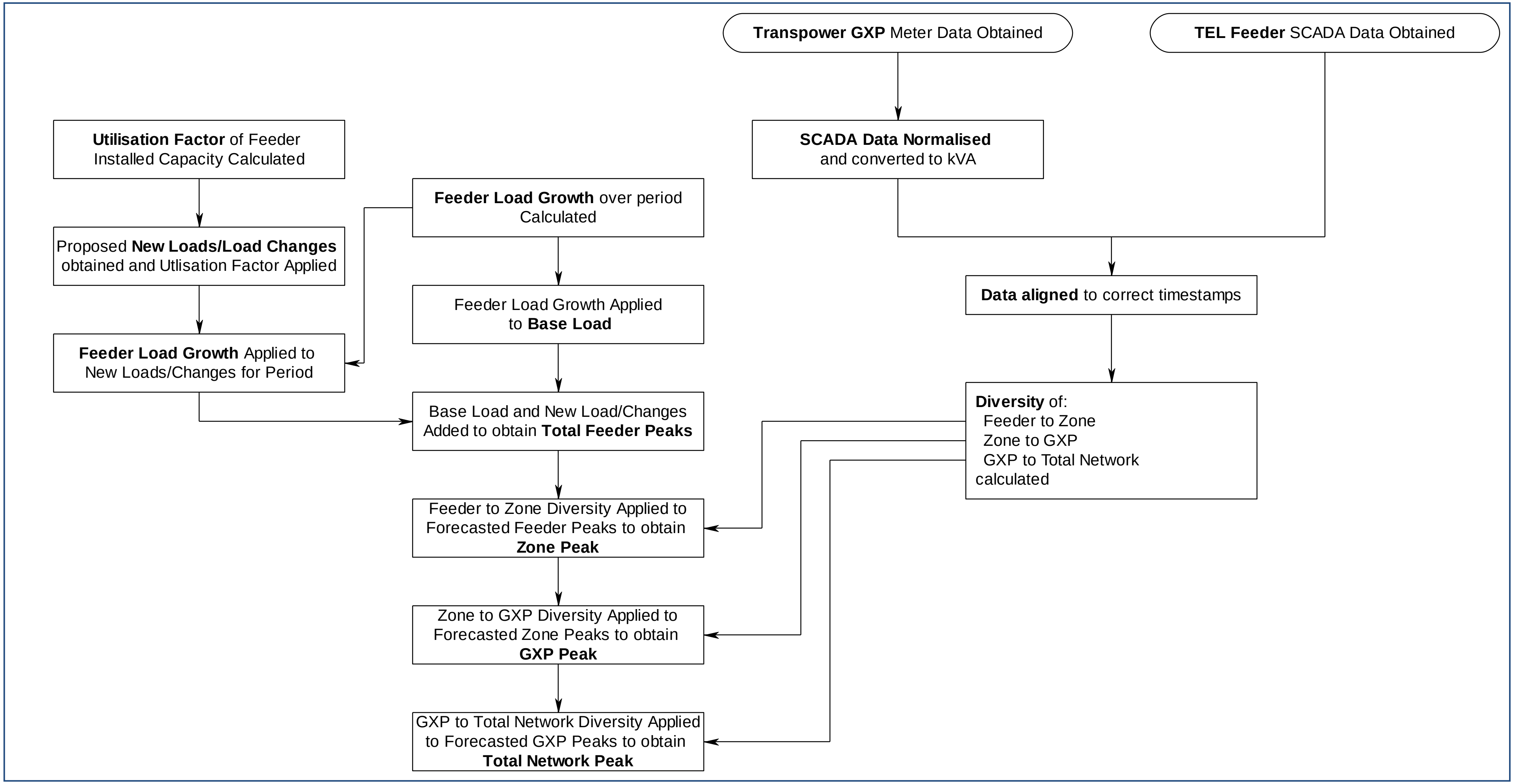


Figure 5.1: Load Forecast Methodology Overview

5.7.2 Uncertainties in the demand forecast

There are three known projects that have the potential to impact the load forecasts projected in this AMP.

Both the areas of Purerua and Karikari are subject to potential large subdivision developments that are equivalent to small-to-medium size townships. Should the subdivisions proceed, a new zone substation will be required in each area. Both developments are currently on hold due to the recession and the current state of the property market. Development of the Karikari peninsular, in particular, has been mooted over an extended period and has still to come to fruition. The number of vacant lots in the Cable Bay and Taipa area would suggest that the market is still not conducive to this development. Neither load is included in the demand forecast, although the CAPEX forecast provides for construction of the Purerua substation to commence at the very end of the planning period.

The third major uncertainty is potential agricultural processing at Moerewa, which could increase the load at Moerewa substation by up to 4MVA above the forecast level. This depends on both the resource planning process and the overseas market for agricultural products. At this stage, the chances of such processing proceeding are considered most uncertain; therefore the load is not included in the forecast.

In the Southern network, TEN is aware of other smaller potential subdivisions and industrial loads especially on Aerodrome feeder (800kVA) and Riverview feeder (900kVA). In the Northern network, there are also potential subdivision loads on Te Kao feeder (200kVA), North Rd feeder (800kVA supermarket), Herekino feeder (300kVA) and Redan Rd (300kVA). There are also a significant number of subdivision developments already in progress or completed that have not yet resulted in connected load, but which could very quickly add to the present demand once the recession lifts in the region and building recommences. These developments could result in some increase in growth rates above the forecast levels, but can be accommodated by the network development plan as formulated in this AMP.

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 and at distribution rather than transmission voltage. Top Energy's approach to DG is based on the following key principles:

- DG is able to connect to Top Energy's electricity distribution 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;
- TEN reserves the right to limit the total capacity of DG connected to different parts of its 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.

TEN has 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.

Top Energy's policy and requirements for the connection of DG rated at less than 10 kW is available on its website. Proponents seeking to connect higher rated DG to the network are invited to contact Top Energy to discuss their specific requirements.

The process involved in connecting DG to the TEN network is shown in Figure 5.2 below.

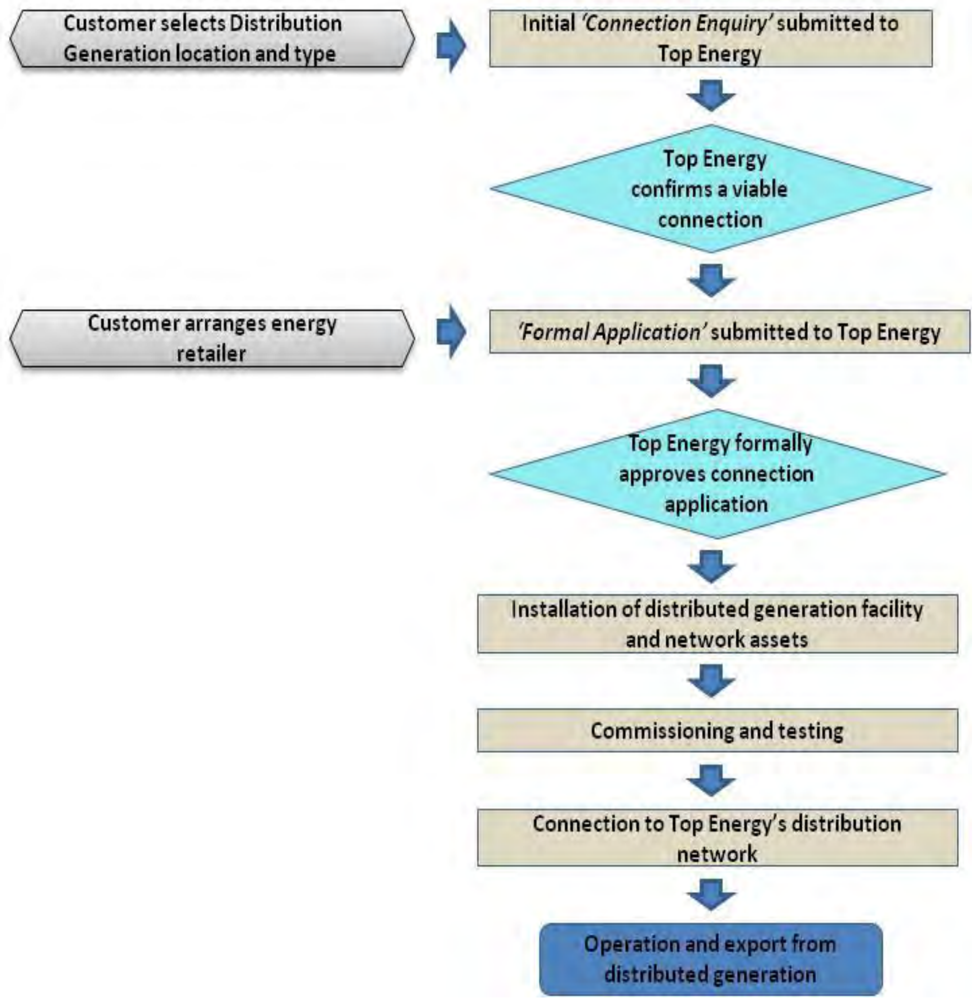


Figure 5.2: Distributed generation connection process

TEN considers potential supply-side options as an integral part of its 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 Top Energy's policies for supply-side options.

- **Embedded Generation (>5MW):** Top Energy encourages 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, Top Energy has demonstrated its own commitment to embedded generation by establishing the 25MW Ngawha Power Station.

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

The following options have potential for dispersed generation;

- small thermal generators. Generators installed as standby units in hospitals or industrial installations could potentially be synchronized to the network and used as part of a strategy to manage network peaks;
- solar panels (with or without battery storage). Solar panels connected through an inverter to the network have proved popular in Australia as a result of government subsidy programmes. Similar subsidies are not available in New Zealand and the high cost and low output of solar panels means they are currently uneconomic, except in situations where the peak demand at a connection point is below about 1kW;
- mini and micro- hydroelectric; and
- wind power.

Top Energy has received a number of enquiries about small distributed generation proposals ranging from photovoltaic panels to 1-2MW generator sets; however the schemes have not been economically viable to date. TEN uses solar panels for some of its remotely controlled equipment to avoid the cost of a dedicated transformer and on a number of occasions has used mobile generators to provide supply to customers when the network is not available. However, in most instances the costs to implement a micro-generation option mean that it is not an economic alternative to a standard network supply.

While there have been no installations to date, alternative generation sources are nevertheless an integral part of TEN's planning and prioritisation process, especially when security projects are being considered. The Taipa generators are an example of this.

Top Energy is aware that the cost of supplying uneconomic customers may create a business opportunity to establish distributed generation solutions in place of upgrading old lines. The viability of distributed generation in these circumstances will likely depend on the technology available, the cost of any required line upgrade and the life cycle costs of operating and maintaining the plant to ensure reliable and safe operation.

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. 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 the ripple control system. As yet, TEN does not participate in this demand side management market opportunity, due to the limited load available to be shed within the response time required. However, Top Energy offers different DSM options to its major industrial customers, but is currently unable to provide sufficient price incentives for them to modify their demand.

Top Energy uses the following DSM options to manage customer's demand in different operating conditions.

- **Direct Load Management (DLM):** TEN routinely controls water heating load through its 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, TEN also uses the system to reduce load and maintain supply for as many customers 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. TEN estimates 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, the TEN 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. Tables 5.6 and 5.7 show the operating arrangements of these two load blocks.

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

Table 5.6: Emergency Load Shedding Specification

In terms of the quantity of load interrupted, Block 1 equals approximately 34% of the TEN network maximum demand and Block 2 equals approximately a further 21% of the maximum demand. Table 5.7 identifies the feeders disconnected by each of the two blocks of emergency load shedding.

SUBSTATION	BLOCK 1 FEEDER	BLOCK 2 FEEDER
SOUTHERN NETWORK		
Kaikohe	Horeke	
	Taheke	
	Rangiahua	
		Ohaeawai
Kawakawa	Towai	
	Opua	
Moerewa		Tau Block
		Pokapu
		Moerewa
Waipapa	Totara North	
	Purerua	
	Riverview	
Haruru		Puketona
		Onewhero
Omanaia	Rawene	
	Opononi	
NORTHERN NETWORK		
Okahu	South Road	
	Kaitaia West	
	Herekino	
NPL	Awanui	
TAIPA		Oruru

SUBSTATION	BLOCK 1 FEEDER	BLOCK 2 FEEDER
		Tokarau
		Mangonui
PUKENUI		Te Kao
		Pukenui South

Table 5.7: Top Energy Emergency Load Shedding Feeder Identification

5.9.1 Green energy research project

In addition to the above, and with a focus on new ways to meet future power demands on heavily loaded sections of the electricity network, Top Energy is also working on a green energy research project. If successful, this could see the roll-out of solar power and hot water systems across some targeted areas of the Far North.

The project is trialling a combination of solar photovoltaic panels, solar hot water and battery storage systems to assess the impacts on domestic electricity consumption during peak evening periods. Ten houses in Kerikeri have been identified with the trial sites selected based on the best mix of exposure to the sun, the number of people in the home, including whether there are couples or families with children. The project's ultimate objective is to ease the pressure on the network in the evenings, when consumption is at its peak.

The solar panels will generate electricity from the sun during the day and store it in the batteries. Using a localised PLC Controller with connection through to the network control centre in Kaikohe, TEN will then be able to switch-in this power supply to supplement the grid supplies during evening peak load periods.

As far as Top Energy is aware, this is the first time that solar micro generation at a domestic level has been used in New Zealand for load management purposes. The system could also prove useful when electric cars become more popular in the future, as it will allow people to charge their cars in the evening using energy collected from the sun during the day. Electricity stored in these batteries could also feed back into the network and reduce peaks.

The solar initiative will also enable people to have greater control over their energy consumption. As part of the project, Top Energy will be studying not only the effects of micro-solar generation systems connected to the electricity network, but also any sociological or behavioural aspects. It is interested to see if people change their living patterns to maximise the benefits from generating electricity or heating water from the sun their homes. For example, people may choose to have showers in the evening rather than in the mornings, or run appliances such as dishwashers and washing machines during the day when the sun is shining.

The peak consumption and social behavioural effects will be monitored over an extended period to identify if further installations could be rolled out on other areas of the network and defer future investment in traditional, but more expensive, system upgrades.

5.10 Network Development Plan

5.10.1 Network Development Plan Objectives

Top Energy's integrated network development plan is designed to address the following key network constraints.

- Approximately 10,000 consumers in Top Energy's Northern area are reliant on a non-secure supply, due to the fact that there is only one transmission line between Kaikohe and Kaitaia. The consumers are subjected to annual maintenance interruptions lasting approximately nine hours, as well as an elevated risk of unplanned fault interruptions.

- At times of peak demand, the sub-transmission system serving consumers in the Kerikeri area is 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 is being utilised to supply normal demand. The network is therefore operating at a reduced level of security and, in the event of an unplanned outage of a sub-transmission element, the network voltage could drop to an unacceptable level. Without increasing the available capacity, this problem can only be addressed by shedding load.
- Many of the assets purchased from Transpower are old and present safety and reliability risks. A particular problem is the capacity and condition of the existing transformers at Kaitaia. These are old, single phase units that testing has indicated are in poor condition. They are also rated at 22MVA, which is less than the current load at the substation. The condition of the 33kV outdoor switchgear at both substations is also a concern.
- Load growth in some areas not well served by existing zone substations is exceeding the capacity of the existing 11kV distribution system. Areas of particular concern are Paihia and Opua, Kerikeri, the Whangaroa-Kaeo-Matauri Bay area and the Russell peninsular.
- Zone substations are currently operated in a split bus, radial configuration in order to manage protection constraints. This does not meet Top Energy's security requirements for larger, two-transformer substations, as it means that supply interruptions are inevitable whenever a sub-transmission fault occurs. This has a significant adverse impact on the reliability of supply.
- Outdoor switchgear at some substations is in poor condition and requires replacement. Moerewa and Waipapa are of particular concern.
- The single phase transformer bank at Omanaia is now 58 years old and approaching the end of its economic life.

Solutions to these constraints are discussed in the sections below.

5.10.2 Work Recently Completed or Underway

The following components of the network development plan announced in 2010 have either been completed or are nearing completion.

- Stage 1 (Kaikohe–Hariru Rd) of the new 110kV double circuit transmission line between Kaikohe and Wiroa was completed during FYE2013. As a temporary measure, this has been livened at 33kV to allow the section of the Waipapa No 1 feeder that the line was built alongside to be demolished. After some delay in finalising the route between Hariru Rd and Waipapa, construction of the remainder of this line has commenced. Purchase of the site for the new Wiroa 110/33kV substation has been completed.
- A route for the 110kV line between Wiroa and Kaitaia has been identified and the line has been surveyed. Negotiations have commenced with affected landowners.
- The section of the new 33kV Wiroa-Kerikeri cable between the airport and Hall Rd on the outskirts of Kerikeri township has been completed and the sections of cable at either end will be completed during FYE2014. Construction of the Kerikeri zone substation commenced in November 2012. Initially, the substation will be supplied from Waipapa from an overhead 33kV line that was constructed along Waipapa Rd in 2009. Installation of the cable between the end of this line and the substation, as well as the modifications necessary to divert the 11kV network into this substation, are in progress and will be completed in time for commissioning.
- A new 33kV sub-transmission line between the Ngawha power station and the Kaikohe zone substation has recently been completed. This line is intended to address operating and protection constraints inherent in the current configuration and also to provide N-1 redundancy in the connection between the power station and the Top Energy network. It will also reduce the technical line losses between the power station and the point of injection into the rest of the TEN network.

- A major protection upgrade of the Haruru zone substation was completed in late FYE2013 and the transformers are now operated in parallel. Haruru has therefore become TEN's first zone substation to provide full, uninterrupted N-1 security.
- The existing 33kV lines between Kaikohe and Waipapa are routed close to the Wiroa site and the Wiroa-Waipapa sections of these lines will be used to supply Waipapa. Upgrading of the older No. 1 line into Waipapa was completed in FYE2013.
- The older No. 1 33kV line between Kaikohe and Kawakawa is being reconductored to secure the incoming supply to Kawakawa, Moerewa, Paihia and Russell. Work has been completed between Kaikohe and Hupara. In addition, the reconductoring of 20km of conductor in the No. 2 line to cockroach to ensure that the line impedance is such that differential protection is assured has been completed.
- An alternative incoming supply to the Northern Pulp substation by teeing a new 33kV line to the substation off the nearby Kaitaia-Pukenui 33kV line has been completed. Northern Pulp substation is supplied from a double circuit 33kV line that also supplied Okahu Rd and it is possible that a single pole failure could result in a loss of supply to both substations, which together supply more than 75% of the load in the Northern region. The alternative supply into Northern Pulp will fully mitigate this risk, as it can also be used to supply Okahu Rd.
- A new underground 11kV distribution feeder between the Haruru zone substation and Te Tii Bay in Paihia has been completed and will be commissioned in FYE2014. This will reinforce the supply to Paihia and allow some of the Opua feeder load to be transferred to Haruru. This will in turn free-up capacity on the Opua feeder, which will be available to reinforce the supply into Russell. Reconductoring of parts of the Joyces Rd and Opua feeders is planned to increase the distribution network transfer capacity between Haruru and Kawakawa zone substations.
- Two 2.5MVA diesel generators have been installed at Taipa zone substation to provide backup in the event of a sub-transmission fault. The Taipa substation consists of a single transformer and incoming line (notwithstanding a current peak load of almost 5MVA) and this arrangement will remain until the incoming 110kV supply is available.
- Ground fault neutralisers have been installed at Waipapa, Kawakawa and Okahu Rd substations. While they have achieved their primary objective of reducing outages due to earth faults, there has been an increase in 11kV cable failures in networks supplied from these substations. The application of the technology at these substations will be optimised in FYE 2014. However, no further ground fault neutraliser installations are currently planned although their use remains under review.

5.10.3 Work in Progress or Planned in the next Five Years

5.10.3.1 Kaikohe-Wiroa-Kaitaia 110kV Circuit

The dependence of the Northern area on a single 110kV line from Kaikohe has been a source of concern to Top Energy 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 1980's, 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 region. 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 attractive option is currently wind generation and Top Energy is 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 by Transpower over the direct route has also been a continuing possibility. However, this option is expensive and difficult to justify when its only benefit would be to provide a supply when the existing line is out of service.

Incremental demand growth is rapidly occurring around the coastal belt in the East and North East of Top Energy's supply area. The need to reinforce the network supplying this area has created an opportunity that has not previously existed, as it has made the construction of the second line over a longer, but more accessible coastal route, economically feasible. This is because the line can also supply these coastal communities; and in particular the Kerikeri area, where additional capacity is now urgently required. Transpower's agreement to transfer its assets to Top Energy 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 operated as part of the Transpower grid.

In accordance with its 2010 sub-transmission development plan, Top Energy has already commenced construction of a double circuit line between Kaikohe and a new substation at Wiroa. While it was planned to operate this line at 33kV for approximately 25 years, the line will now likely be operated at 110kV from FYE2016.

The new 110kV line to Kaitaia will be a new single circuit line from Wiroa to the existing transmission substation at Pamapuria, south of Kaitaia and will be completed during FYE2017. A potential line route has been identified and landowner discussions have commenced. The line will have an underbuilt 33kV circuit over the Southern part of its route to supply the new Kaeo substation. As discussed in Section 5.10.3.5, the line will also be diverted to the site of a new 110/11kV substation at Taipa.

Following completion of the new 110kV line between Kaikohe and Kaitaia, it will be possible to take the existing 110kV line out of service without disrupting the supply to Kaitaia. TEN is then planning to refurbish the old line. This is a major project that is expected to be spread over five years, involving the replacement of poles and other equipment that exhibit significant levels of deterioration.

Estimated expenditure from FYE2013 on the Wiroa 110kV line is $6.1 million, while the estimated cost of the Wiroa-Kaitaia line is $34.2 million.

5.10.3.2 Wiroa 110 kV Substation

Under the 2010 sub-transmission development plan, TEN had committed to building a new double circuit line, designed for operation at 110kV, to a new 33kV switching station at Wiroa. As noted above, it was intended to operate the line at 33kV until the load in the Kerikeri area had grown to the point where a 110kV supply was required. The construction of a new switching station at Wiroa was preferred to an earlier plan to upgrade the Waipapa substation, because of difficulty in finding a 110kV line route into Waipapa that complied with Civil Aviation requirements in relation to the construction of transmission lines close to the Kerikeri Airport. The need to operate this line at 110kV to provide a second supply to Kaitaia has changed this plan and it is now intended to energise Wiroa at 110kV in FYE2016.

Prior to this, the Kaikohe-Wiroa section of the 110kV line will be operated at 33kV and Wiroa will be used as a 33kV switching station. The 33kV indoor switchboard is planned for completion in FYE2014. There will be five outgoing circuits. The existing 33kV circuits to Waipapa will be diverted into this switchboard, providing two outgoing circuits to Waipapa and one to Mt Pokaka. A new underground 33kV circuit will supply the new Kerikeri zone substation, while the new underbuilt circuit to Kaeo will also be supplied from Wiroa.

Construction of the 110kV switchyard is currently planned with one transformer to be energised in FYE2016, prior to the completion of the 110kV circuit through to Kaitaia by 2017. This will have two 40/60MVA (110/33kV) transformers, which will provide sufficient capacity to supply the coastal region between Kerikeri and Kaeo (including the rapidly growing commercial and industrial area at Waipapa) for the longer-term. Installation of the second Wiroa transformer and the new load control plant will be undertaken in FYE 2017.

TEN has considered the potential to defer construction of the 110kV Wiroa switchyard by operating one circuit of the new 110kV line at 33kV upon commissioning. However, load flow studies have indicated potential for 33kV voltage collapse in a high load situation when Ngawha is not operating and TEN is reliant on the national grid for its incoming supply. Nevertheless, TEN will continue to explore options for deferring the Wiroa 110kV upgrade. Transpower's installation of a third 220kV circuit through the Auckland isthmus and the installation of a new STATCOM at Marsden should improve the incoming voltage at Kaikohe. TEN is also reviewing the accuracy of its load flow model; a more accurate model may indicate that the issue is not as critical as currently believed.

The estimated total cost of this project is $9.7 million. This includes the 33kV switchboard, the 110kV switchyard and transformers, the new ripple injection plant and switched capacitor banks.

5.10.3.3 Kerikeri 33kV Substation

Supply to Kerikeri, one of the fastest growing areas in the country, is currently reliant on two heavily loaded 11kV feeders supplied from the Waipapa zone substation. This situation has become untenable for a town of this size. In the event of the loss of one of these feeders it would not be possible to maintain supply to all customers, particularly if the loss was to occur at a time of peak load. Some support is now available from Mt Pokaka, but this is limited.

The construction of a new zone substation with two 11/23 MVA transformers within the industrial part of the Kerikeri urban area is in progress and is scheduled for completion early in FYE2014. In order to supply this new substation, TEN completed construction of a new overhead 33kV circuit between Waipapa and the outskirts of the town in FYE2010 and in FYE2014 this circuit will be extended 3.5km to the new substation using underground cable. An underground cable will also be installed constructed under State Highway 10 between the Waipapa zone substation and the Waipapa end of the overhead line to complete the circuit between Waipapa and the new substation.

Construction of a second underground 33kV circuit between the Wiroa substation site and the Kerikeri substation has been completed and the substation will be livened early in FYE2014 from this circuit. Prior to completion of the 33kV switchroom at Waipapa, this circuit will be energised by a temporary connection to the existing Mt Pokaka-Waipapa 33kV line.

The estimated cost of this project from FYE2013 is $8.7 million, comprising $4.2 million for the substation and $4.5 million for the incoming 33kV cables. Most of this is being spent in the current year (FYE2013) and only $1.5 million is budgeted for FYE2014. The reconfiguration of the distribution network to connect into the new substation is provided for in the distribution network growth budget.

5.10.3.4 Upgrading and Replacement of Transmission Assets

As noted earlier, some transmission assets being acquired from Transpower are in poor condition. Particularly critical are the Kaitaia transformers, which are old single phase 22MVA banks that do not have sufficient capacity to carry the full 25MW Northern area demand under contingency conditions. Tests also show the transformers are producing excessive amounts of gas, which is an indicator of insulation deterioration. Replacement of transformer T1 (which is in the worst condition) with a 20/40 MVA three phase unit is planned in FYE2015 and replacement of transformer T2 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 doing maintenance in Transpower's outdoor 33kV switchyards. The Kaikohe switchyard is now more than 50 years old and replacement of much of the equipment is overdue.

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, Top Energy will replace the 33kV switchyards at both Kaikohe and Kaitaia substations with indoor switchboards. The replacement of the Kaikohe switchyard is programmed for FYE2014. This project will also make the 33kV outdoor switchgear at the adjoining Kaikohe zone substation redundant. Two outgoing 33kV circuit breakers on the new switchboard will connect directly to the high voltage side of the existing supply transformers at the zone substation through short lengths of 33kV cable.

The 33kV outdoor switchyard at Kaitaia was constructed in time for the commissioning of the Pukenui zone substation in 1976. While the asset is not as old as Kaikohe and is in better condition, the safety and reliability concerns remain and the circuit breakers are nearing the age where replacement will be required. A conversion of these assets from outdoors to indoors is currently expected to be required around FYE2020.

The estimated cost of replacing the two Kaitaia transformers is $3.7 million and the estimated cost of the outdoor-indoor circuit breaker conversion at Kaikohe is $3.4 million.

5.10.3.5 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 is already approaching the natural cooling capacity of the transformer and the level at which TEN's 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, TEN has now installed 5MVA of diesel generation at the site. This will provide some back-up in the event of a loss of supply, but is not a long-term solution.

Top Energy's original network development plan envisaged upgrading the substation to a dual 11/23MVA facility and construction of a new 33kV circuit between Kaeo 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 possibility was to construct a second 33kV circuit from Kaitaia, with the circuit being underbuilt on 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. The new substation would use zigzag transformers to ensure that the 11kV phasing was the same as the rest of the network. This work is planned for completion by FYE2019, although the new substation will be livened with one transformer in service in FYE2018. Livening of the second transformer will release the existing transformer for relocation to Omanaia and replace the existing 2.75 MVA single phase transformer bank, which will then be well over 60 years old.

Construction of the 110kV line deviation is estimated to cost $3.2 million and construction of the substation $6.2 million. Of this latter cost $1.0 million for the second transformer will be incurred in FYE2019.

5.10.3.6 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. 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.

Top Energy has purchased land for a new 33kV zone substation on Martins Rd in the Kaeo area. 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 from the Gun Club. The second circuit will be a new circuit from Wiroa, which will be underbuilt on the Wiroa-Kaitaia 110kV line for much of its route.

Extension of the existing 33kV line to the new substation site is in progress and will be completed in FYE2014. Construction of the second line to the site from the underbuilt circuit on the Wiroa-Kaitaia 110kV line is planned for FYE2018. Site works will start in FYE2018 and commissioning of the substation is planned for FYE2019.

The total estimated cost of the incoming sub-transmission line works is $4.9 million and the substation is $4.4 million. $2.7 million of the substation cost is programmed for FYE2019.

5.10.3.7 Other Growth CAPEX

The major projects discussed above account for about 75% of planned growth-related expenditure over the FYE2014 to FYE2018 period. Much of the remaining expenditure is expected to be allocated to the upgrading of undersized conductors on distribution feeders. Planned work includes:

- Reconductoring and rearrangement of the 11kV distribution system in the vicinity of the new Kaeo and Taipa substation sites, in preparation for the commissioning of the new substations; and
- Reconductoring of a number of under-rated sections of the 11kV distribution system in other parts of the network.

5.10.3.8 Other Reliability, Safety and Environment CAPEX

The Wiroa-Kaitaia line is expected to account for almost 80% of the forecast reliability safety and environment CAPEX over the FYE2014 to FYE2018 periods. Other initiatives, which are primarily intended to improve the quality of supply to consumers, include:

- the installation of additional interconnections between neighbouring feeders. Interconnections between the Rangiahua and Horeke, and also between the Puketona and Moerewa feeders are planned; and
- continuation of the programme to install remote controlled reclosers on strategic points on the network;
- sub-transmission line and power transformer protection upgrades and the installation of fibre-optic cable to utilise the full functionality of the new line protection relays;
- reconductoring of parts of the Opua and Joyces Rd feeders to increase the distribution network transfer capacity between the Haruru and Kawakawa zone substations; and
- installation on surge arrestors in the Kawakawa area to reduce the incidence of lighting initiated faults during storm conditions.

5.10.3.9 Other Replacement and Renewal CAPEX

The replacement of aging outdoor circuit breakers with indoor switchboards, not only at the Kaikohe transmission substation, but also at Waipapa and Moerewa zone substations is provided for in the asset replacement budget over the planning period. There is also a provision for the replacement of assets at the Kaikohe and Kaitaia transmission substations acquired from Transpower. Some of these assets are known to have reached the end of their economic life, but further investigation and condition assessment is required before a prioritised replacement programme is finalised. A pole replacement programme on the Kaitaia-Pukenui 33kV line has also been provided for.

Following commissioning of the new Wiroa-Kaitaia 110kV circuit, TEN is planning a major refurbishment of the existing circuit over the Maungataniwha ranges. This is expected to take five years and cost $6.0 million. $1.5 million has been provided in the FYE2017 and FYE2018 forecasts for the commencement of this work.

Many of the network assets are approaching the end of their useful lives and provision has been made to replace assets that are prioritised for replacement as a result of the asset inspection programme or as part of a more proactive asset replacement effort. For example, it is planned to phase out the use of wood poles on the network over a period of 20 years.

5.10.3.10 Implementation Timeline and Costs

The implementation schedule for the network development plan over the first five years of the planning period is shown in Table 5.8 below. Commissioning of the Kerikeri substation from Waipapa will occur in FYE2014, the first year of the planning period. Then the focus will be on the construction of the 110kV line to Kaitaia, with the Kaikohe-Wiroa section scheduled for commissioning in FYE2015 and the Wiroa-Kaitaia section in FYE2017. Commissioning of the first transformer at Taipa will follow in FYE2018 and commissioning of the second Taipa transformer and the Kaeo substation are currently planned for FYE2019.

$ million (real)	Category	Major Project Cost[1]	FYE				
			2014	2015	2016	2017	2018
System Growth							
110kV line Kaikohe-Wiroa		**6.1**	1.8	0.8	-	-	-
110kV Wiroa substation		**9.7**	2.6		3.4	2.3	0.9
Kerikeri substation - incoming 33 kV cable		**4.5**	1.6	-	-	-	-
Taipa 110 kV line deviation		**3.2**	0.2	-	1.0	2.0	-
Taipa 110 kV substation		**5.2**	0.4	0.5	-	1.0	3.3
Kaeo 33 kV lines		**4.9**	1.3	-	0.3	-	2.6
Kaeo 33 kV substation		**4.4**	0.1	-	-	-	1.7
Other			1.4	0.2	0.2	0.8	2.5
Total			**9.4**	**1.5**	**4.9**	**6.1**	**9.9**
Reliability, Safety and Environment							
110kV line Wiroa-Kaitaia		**34.2**	3.4	10.7	10.7	6.0	
Protection and communications			1.5	0.2		0.8	0.1
Feeder interconnections				0.2	0.1	1.2	0.9
Remote control switches						0.2	0.7
Other			1.0	0.8	0.1	0.4	0.1
Total			**5.9**	**11.9**	**10.9**	**8.6**	**1.8**
Asset Replacement and Renewal							
Kaikohe 33 kV outdoor-indoor conversion.		**3.5**	3.5				
Kaitaia 110/33 kV T1 transformer replacement		**2.0**	0.1	1.8			
Moerewa outdoor-indoor conversions		**3.1**		1.7	1.4		
Waipapa outdoor-indoor conversion		**2.2**					1.7
Transmission substation asset replacement				1.0	0.7	0.6	
Kaikohe-Kaitaia 110kV line rebuild		**6.0**				0.4	1.1
Other			4.6	3.2	2.7	5.0	4.9
Total			**8.2**	**7.7**	**4.8**	**6.0**	**7.7**

Note 1: Includes costs outside the period shown

Table 5.8 **CAPEX Forecast and Timeline FYE2013 to FYE2018**

5.11 FYE2014 Capital Expenditure Work Plan

The tables in this section provide a more detailed breakdown of the FYE2014 CAPEX budget, as approved by the Board.

5.11.1 System Growth Expenditure

Project	Description	Budget ($000)
Taipa substation incoming supply	Detailed design of the double-circuit 110kV line from the Peria tee-off point to the location of the new 110kV substation.. Negotiation of easements for the line is required plus transaction costs.	180
Taipa substation	Purchase of land for Taipa substation in the upper Peria valley	275
Taipa substation	Design and planning for Taipa 110kV/11kV substation in the upper Peria valley - outdoor hybrid 110kV switchgear, indoor 11kV switchgear, switch/control room and civil works.	95
Kaikohe-Wiroa 110 kV line	Completion of Stage 2 of the Kaikohe to Wiroa 110kV line, including stringing of conductor and OPGW.	1,820
Kaeo substation – incoming line from Wiroa	Design of the 33kV overhead line from the new 110kV Wiroa to Kaitaia line into the Martins Rd substation site, including property, consenting and transaction costs. The proposal is that 18.5m poles be utilised and may involve overbuilding existing 11kV.	340
Kaeo substation incoming line from Waipapa	Construction of the second stage of the 33kV line from the China Clay feeder to the Kaeo substation site on Martins Rd.	950
Kerikeri substation distribution network terminations	Remove the redundant 11kV overhead left as a consequence of the 11kV underground interconnections for Kerikeri substation.	65
Kaeo substation incoming line from Waipapa	Design of the underground circuit from the China Clay 33kV feeder into Waipapa substation, plus the new 33kV circuit breaker bay	10
Kerikeri substation – incoming line from Waipapa	Construction of the underground 33kV and 11kV circuits for KER1 33kV line (Stages 2 and 3) through Quail Ridge, along Rainbow Falls Rd, and across the Kerikeri Domain	1,105
Kerikeri substation – incoming line from Waipapa	Construction of the underground cable circuit from the existing 33kV overhead KER1 circuit on Waipapa Rd, under SH10 and into Waipapa Substation, including: reconfiguration of the 11kV overhead along Waipapa Rd; a new CB bay in Waipapa substation; and underground fibre connection from end of overhead circuit on Waipapa Rd.	517
Hokianga distribution network upgrade	11kV upgrade in the Opononi and Omapere areas. The conductor will be upgraded to Bee to improve capacity. The poles will be replaced as they have deteriorated due to being exposed to coastal conditions (6km approx.)	640
Kawakawa substation	Reconfiguration of the Panaru and Waikare Rd feeders	495
Kaeo substation.	Design and planning of the new substation in Martins Rd Kaeo. Design to be based on Kerikeri, including switchgear and control building, indoor 33kV and 11kV switchgear and two 33kV/ 11kV transformers	50

Project	Description	Budget ($000)
Wiroa substation	Design and planning for the installation of switched capacitor banks at Wiroa for voltage support. It is anticipated that the required capacitors and associated reactors for up to 20MVAr will fit into the 110kV switchyard without additional civil works being required. Indoor 33kV switching has been allowed for in the building design	80
Wiroa substation	Construction of the Wiroa 33kV switching substation, including switch/control room building, indoor 33kV switchgear, civil works and cabling	2,528
Kawakawa substation feeder termination upgrade	Design work for the upgrade of the two remaining feeder cables at Kawakawa substation. Cables upgraded to 185mm^2 aluminium	10
Waimate North line deviation.	Construction of line deviation along Waimate North Rd in preparation for the utilization of part of the existing 33kV Kaikohe-Waipapa No 1 line as a distribution feeder after commissioning of the Wiroa substation	260
TOTAL		**9,420**

Table 5.9: Breakdown of System Growth CAPEX Budget FYE2014

5.11.2 Reliability, Safety and Environment Expenditure

Project	Description	Budget ($000)
Wiroa-Kaitaia 110kV line	Construction of a 6km section of the Wiroa to Kaitaia 110kV line. The precise location of the line section will depend on property consents being secured. In anticipation, SKM is providing detailed design for a 11km stretch of line from Wiroa substation to Pungaere Rd (structures WRA1 - WRA 48)	2,000
Wiroa-Kaitaia 110kV line	Design of the overhead circuits into Kaitaia substation from the new 110kV single circuit line into the 110kV structure and terminations into a new 110kV circuit breaker (CB) bay. Design of 110kV switchgear requirements for the line termination and a new bus tie CB is required. Hybrid CBs are proposed	20
SCADA	Upgrade of remote terminal units at 15 recloser sites	98
Omanaia substation	Design work for the upgrade of the feeder protection at the substation	32
Optical fibre installation	Fibre installation beneath the Kawakawa 2 33kV line from Kaikohe substation to Kawakawa (stage 2 and 3)	389
Optical fibre installation	Fibre installation beneath the Pukenui 33kV line from Kaitaia substation to NPL substation via Church Rd Tee (8.9km)	183
Optical fibre installation	Fibre installation beneath the Pukenui 33kV line from Kaitaia Substation to NPL Substation via Okahu Rd (13.2km)	269
Optical fibre installation	Fibre installation along Waipapa Rd underneath the 33kV/ 11kV line from Waipapa substation to Rainbow Falls Rd	53

Project	Description	Budget ($000)
Optical fibre installation	Fibre installation beneath the Haruru 33kV line from Pakaraka to Haruru (14.3km)	349
Ground fault neutralizer (GFN) improvements	The GFN installations require additional minor works to complete, including: remote actuators on the neutral switches; protection enhancements; acoustic damping to reduce noise levels; the remaining work involved in stressing feeders; and investigations into 5th harmonic or another form of fault detection	105
Horeke feeder – remote controlled switches	Installation of remote controlled switches in place of 365 and 292 at pole locations 420332 and 420329 on the Kokukohu (Northern) side of the Narrows on the Horeke feeder. Leads to improved responses to outages on the Northern Hokianga and the ability to isolate these faults from the upstream section of the feeder	57
Kawakawa substation	Design work for the upgrade of protection systems at Kawakawa substation	65
Okahu Rd recloser installations	Okahu Rd installation of three 33kV reclosers, one in each line and one from the substation bus to enable directional protection and remote isolation of line sections to be implemented	535
Moerewa substation	Design work for upgrade of protection systems at Moerewa substation	12
SCADA	Design work for the installation of SCADA communications links to feeder voltage regulators	5
SCADA	Replacement of 3 SCADA remote terminal unit cabinets at different zone substations	40
Substation security	Design and planning new security systems for substations, based on Kerikeri substation	15
Metering	Installation of check metering at Kaikohe and Kaitaia transmission substations and at Transpower, Maungatapere	85
33kV sub-transmission reconfiguration	Reconfigure Warsnops 33kV switching station to provide dedicated supply to Ngawha; break line sections, install new jumpers, install VT, install communications/protection cabinet, procure and install differential relays. Modify protection on CBs 1192 and 1172 at Kaikohe, install new differential relays	235
Wiroa-Kaitaia 110kV line	Detailed design of the 110kV line from Wiroa to Kaitaia. SKM will undertake the design work. Negotiation of easements for the line is required plus transaction costs	1,339
TOTAL		**5,885**

Table 5.10: Breakdown of Reliability, Safety and Environment CAPEX Budget FYE2014

5.11.3 Asset Replacement and Renewal Expenditure

Project	Description	Budget ($000)
Kaitaia transmission substation	Design work for the replacement of 110/33kV T1 transformer	100
Surge arrestor replacement	Replacement of lightning arrestors in the Kawakawa area. Arrestors will be chosen according to priority	400
Okahu Rd-NPL 33kV line refurbishment	Refurbishment of the Okahu to NPL 33kV line; pole crossarm and insulator replacements as required and selected structures on a priority basis. Poles changed to Busck concrete 15.5m poles, unless otherwise specified. Specific design undertaken on critical structure locations. Existing conductor to be re-used	100
Kaikohe transmission substation outdoor indoor conversion	Construction of new terminal poles/gantry and re-termination of 33kV lines ready for cables from new substation	165
Kaikohe transmission substation outdoor-indoor conversion	Rebuilding of the 33kV switchyards in both ex Transpower and TEN yards as indoor switchgear, including new building, 33kV switchgear, provision for 11kV indoor equipment, relocation of both existing transformers onto ground mount pads, 33kV cabling and associated civil works	3,475
Transmission asset replacements - Kaikohe	Identification of transmission equipment requiring replacement, and the planning and design involved (Kaikohe transmission substation)	5
Transmission asset replacements - Kaitaia	Identification of transmission equipment requiring replacement and the planning and design involved (Kaitaia transmission substation)	5
Moerewa outdoor-indoor conversion	Moerewa substation is in very poor condition. It will be rebuilt with Schneider indoor switchgear in a new switchroom. 33kV equipment will be done first followed by the 11kV. Subsequently, a second transformer will be added for security and to release the mobile sub for other duties. This is the planning and design phase	45
Okahu Rd-NPL 33kV line refurbishment	Refurbishment of the Okahu to NPL 33kV line; pole crossarm and insulator replacements as required and selected structures on a priority basis. Poles changed to Busck concrete 15.5m poles, unless otherwise specified. Specific design undertaken on critical structure locations. Existing conductor to be re-used	100
Peria SWER line refurbishment	SWER refurbishment. Valley Peria to Mangatoitoi and Mangamuka	150
Pukenui 33kV line refurbishment	Refurbishment of the Pukenui 33kV line - pole crossarm and insulator replacements as required; selected structures on a priority basis. Poles changed to Busck concrete 15.5m poles unless otherwise specified. Specific design undertaken on critical structure locations. Existing conductor to be re-used	340
Distribution network asset replacement	Replacement of steel structures and conductor (Horeke feeder at the Narrows Crossing North side)	125

Project	Description	Budget ($000)
Distribution network asset replacement	Replacement of steel structures and conductor (Horeke feeder at the Narrows Crossing South side)	125
Kaikohe-Kaitaia 110kV line	Rectification of defects found during asset inspections	160
Waipapa outdoor-indoor conversion	Design and planning for rebuild Waipapa 33kV/11kV substation 33kV and 11kV indoor switchgear, switch/control room and civil works	40
Non-project asset replacement	Rectification of defects found during asset inspection programme	2,860
Total		**8,195**

Table 5.11: Breakdown of Asset Replacement and Renewal CAPEX Budget FYE2014

5.12 Capital Expenditure FYE2019 to FYE2023

TEN has prepared an indicative forecast of its 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. These projects including: the completion of the Taipa and Kaeo substations, the refurbishment of the existing Kaikohe-Kaitaia 110kV line and the Kaitaia 33kV outdoor-indoor conversion and the replacement of the 110/33kV T2 transformer at Kaitaia are likely to proceed. The need for, and timing of, other projects (e.g. the Purerua and Whatuwhiwhi substations) is less certain and will depend on factors that include the rate and location of demand growth and the rate of deterioration of the asset base.

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 FYE2019-FYE2023 and may not represent the total cost of a particular project or programme.

5.12.1 System Growth Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Taipa substation, Transformer 2	1.0	2019	Completion of this project will provide N-1 security at Taipa and release the existing transformer for relocation to Omanaia.
Kaeo substation	2.7	2019	Construction of this substation is scheduled to commence in FYE2018.
Omanaia substation transformers	0.2	2019	The existing transformers at Omanaia will be more than 60 years old and are in poor condition. Relocation of the existing Taipa transformer will provide capacity for future growth in demand and significantly reduce the risk of a transformer failure.

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Whatuwhiwhi line	2.8	2019-2020	Electricity demand on the Karikari peninsular is reaching the capacity of the existing 11kV circuit. The new circuit will be constructed at 33kV and initially operated at either 11kV or 22kV. It will provide additional capacity until a new zone substation is required.
Purerua line	3.3	2022	Electricity demand on the Purerua peninsular is reaching the capacity of the existing 11kV circuit. The new circuit will be constructed at 33kV and initially operated at either 11kV or 22kV. It will provide additional capacity until a new zone substation is required.
Purerua substation	3.0	2023	The timing for the new substation is uncertain, however it has been provided for at the end of the AMP planning period.
Russell submarine cable	1.0	2023	Demand growth is high on the Russell peninsular as a result of new subdivision development and a third submarine cable will eventually be required. It will be rated at 33kV in preparation for the installation of a new zone substation in the longer-term, but will initially be operated at either 11kV or 22kV. The cable, which will run from Paihia to the Russell foreshore, will also offload the Kawakawa substation by transferring load to the larger Haruru substation. Once the Taipa substation is complete, it is likely that the existing generators will be transferred to Russell to provide interim load support.
Other	8.9	2019-2023	Approximately $1.8 million per year is expected to be required for other work, in particular strategic load-driven upgrades to the distribution network
Total	**22.9**		

Table 5.12: Breakdown of System Growth CAPEX Forecast FYE2019 to FYE2023

5.12.2 Reliability, Safety and Environment Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Feeder interconnections	2.8	2019-2020	This will complete the ongoing programme of installing additional interconnections between neighbouring feeders in order to allow earlier restoration of supply to many customers following a feeder fault. Interconnections between the following feeders are planned: • Inlet Road and Onewhero; • Rangiahua and South Road; and • Rawene and Horeke.

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
33kV sub-transmission	0.8	2019-2020	This will allow the completion of a 33kV switching station at Hupara, which is needed to provide uninterrupted sub-transmission security to consumers supplied from the Moerewa, Kawakawa and Haruru substations. There is also provision for design work for a second 33kV line to Omanaia, although this may not be built until after the end of the planning period.
Optical fibre installation	1.0	2021	This will provide for additional fibre along existing sub-transmission lines. This is needed for improved communication and, importantly, to take advantage of the full functionality of modern protection relays.
Other	4.3	2019-2023	Approximately $0.9 million per year has been provided in the budget for other network reliability and safety improvements.
Total	**8.9**		

Table 5.13: Breakdown of System Reliability, Safety and Environment CAPEX Forecast FYE2019 to FYE2023

5.12.3 Asset Replacement and Renewal Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Kaitaia outdoor-indoor conversion	2.0	2020	Rebuilding of the 33kV switchyard with indoor switchgear, including new building and 33kV switchgear.
Kaitaia T2 transformer	1.2	2020	Replacement of the 110/33kV transformer T2 at Kaitaia
Other transmission substation replacements	3.4	2019-2023	Provision for unspecified asset replacements in the transmission substations acquired from Transpower.
Kaikohe-Kaitaia line rebuild	6.5	2019-2022	Continuation of the refurbishment of the existing Kaikohe-Kaitaia 110kV circuit, which is scheduled to commence in FYE2018.
Waipapa outdoor-indoor conversion	0.5	2019	Completion of the replacement project scheduled to commence in FYE2018.
Other asset replacements	21.9	2019-23	Approximately $4.4 million per year is expected to be required for other proactive network asset replacements projects, as well as reactive asset replacement, as a result of asset failing in service and defects identified during the asset inspection programme.
Total	**42.0**		

Table 5.14: Breakdown of System Replacement and Renewal CAPEX Forecast FYE2019 to FYE2023

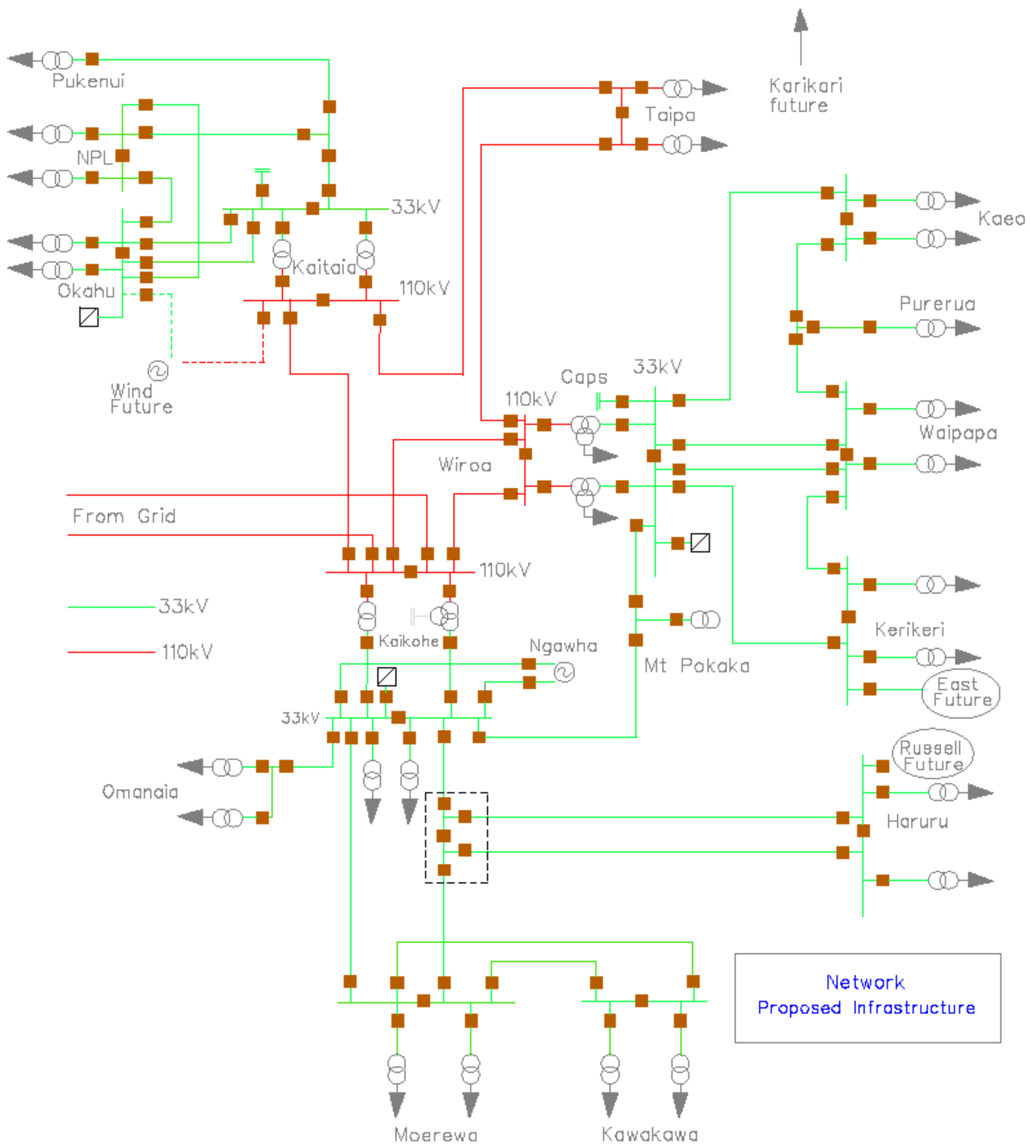
5.12.4 Customer Connections

Approximately $1.05 million per year 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. Some of this CAPEX is recovered through capital contributions.

5.13 Future Network

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

Figure 5.3: Possible Infrastructure FYE2023



5.14 Breakdown of the Capital Expenditure Forecast

A summary of forecast CAPEX on network assets for the full 10-year planning period is shown in Table 5-15 below and shown graphically in Figure 5.4. There forecast categories map directly into the corresponding forecast CAPEX categories in Schedule 11a of Appendix A.

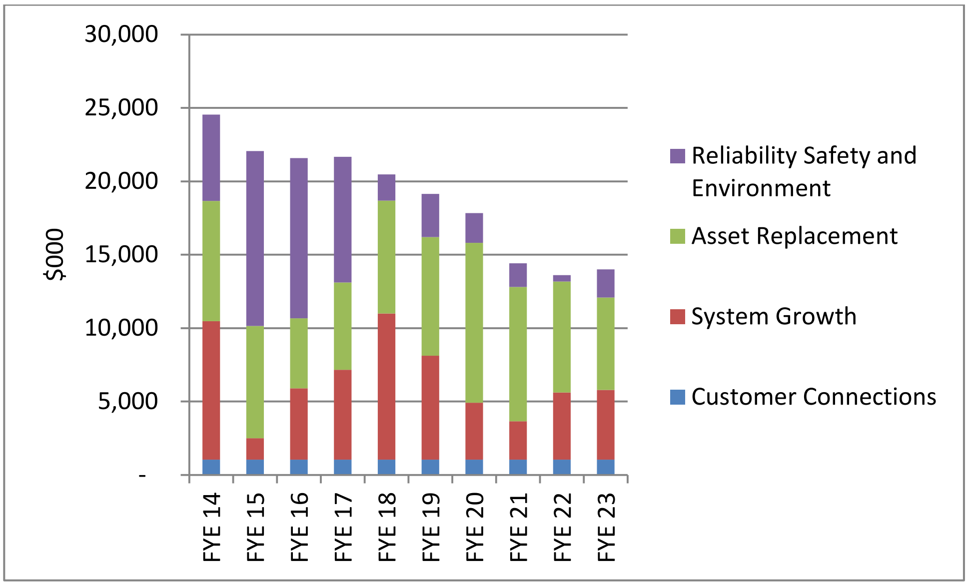


Figure 5.4 Capital Expenditure Forecast Profile FYE2014 to FYE2023

($000,real) FOR YEAR ENDED	YEAR 1 2014	YEAR 2 2015	YEAR 3 2016	YEAR 4 2017	YEAR 5 2018	YEAR 6 2019	YEAR 7 2020	YEAR 8 20210	YEAR 9 2022	YEAR 10 2023
Capital Expenditure: Customer Connections	1,045	1,045	1,045	1,045	1,050	1,045	1,045	1,045	1,050	1,050
Capital Expenditure: System Growth	9,420	1,455	4,852	6,117	9,946	7,080	3,880	2,617	4,568	4,748
Capital Expenditure: Reliability, Safety and Environment	5,885	11,913	10,928	8,563	1,790	2,930	2,031	1,607	440	1,905
Capital Expenditure: Asset Replacement and Renewal	8,195	7,658	4,766	5,950	7,687	8,084	10,888	9,144	7,564	6,296
Capital Expenditure: Asset Relocations	-	-	-	-	-	-	-	-	-	-
Subtotal – Capital Expenditure on asset management	**24,546**	**22,071**	**21,591**	**21,674**	**20,473**	**19,139**	**17,843**	**14,413**	**13,622**	**13,999**

Table 5.15: Forecast Annual CAPEX FYE2014 to FYE2023

Section 6 Life Cycle Asset Management

6 Lifecycle Asset Management

This section of the AMP outlines Top Energy's maintenance and renewals policies, strategies and practices. TEN uses these to ensure that assets are utilised efficiently during their service life.

6.1 Maintenance and Renewal Planning Criteria and Assumptions

6.1.1 Maintenance and Renewal Criteria

The overall objective of TEN's asset management practices is to deliver the agreed level of service whilst achieving the lowest possible lifecycle cost for its assets. This means that the initial costs, the maintenance costs, any mid-life refurbishment and end-of-life replacement costs need to be considered holistically to achieve the best outcome for key stakeholders.

A risk-based approach is adopted 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.

Economic analysis is undertaken for significant decisions related to lifecycle optimisation (e.g. operations, planned/reactive maintenance, renewals) and prioritisation of projects required to mitigate unacceptable risks.

Top Energy has introduced a focus on the continuous improvement of asset management practices, processes, systems and plans in accordance with the improvement plan, which is reviewed annually.

Top Energy's life cycle expenditure is split into three different categories. These are:

Planned Maintenance:

- **Routine and Preventative Maintenance –** TEN operates a time-based asset inspection and maintenance programme, whereby all assets are regularly inspected to identify defects that require repair. This routine inspection programme includes non-invasive condition assessments that are implemented on a regular time-based cycle to identify faults in key assets that cannot be identified by visual inspection. It also includes maintenance activities, such as vegetation management, which are undertaken on a time-based cycle and are considered necessary to maintain the reliability of the network and to ensure that assets continue to function as designed.
- **Renewal Maintenance –** Condition-based maintenance is based on an assessment of an asset's physical condition and is usually triggered by the findings of the routine inspection and condition assessment programmes. TEN's 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 TEN assess and budget future renewal maintenance and asset replacement requirements.

Reactive 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 generally based on actual reactive maintenance costs in previous years.

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. Short-term renewal plans are based upon condition assessment.

Asset replacement falls into two separate categories:

- **Proactive replacement projects and programmes –** These are managed and budgeted for as separate stand-alone projects. Examples of such programmes and projects included in this AMP are outdoor-indoor switchgear replacements and major line refurbishment projects, such as the refurbishment of the Kaikohe-Kaitaia 110kV line and the pole replacement programme on the Pukenui 33kV line, which are not driven by demand growth. Proactive asset replacement projects and programmes are discussed in Chapter 5.
- **Reactive asset replacements –** These are unplanned asset replacements resulting from defects identified through the asset inspection programme or following a network fault. Asset replacement occurs when it is considered that replacement is more economic than repair. Provisions for proactive asset replacements have been made in the CAPEX budgets discussed in Section 5.

6.1.2 Routine and Preventative Maintenance Programme

TEN implements a routine inspection and maintenance programme to ensure continuing network safety and reliability. This strategy uses the asset's criticality, serviceability, safety, performance, economic viability and the environmental consequences of failure to justify this expenditure. 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 TEN's public safety management programme.

TEN uses specialist TECS field inspectors to implement the programme. Asset inspection schedules are resident in SAP and used to 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. The quality of the asset data reported from these field inspections is proving to be of a good standard and it is anticipated that the quality will improve over time with experience and continuous improvement to methodology.

Overlaid on the inspection programme are a separate vegetation management programme and a condition monitoring programme for key assets involving testing for defects that are not apparent from a visual inspection. Tests include oil sampling of zone substation transformers and other programmes such as thermographic surveys to test for hot spots caused by poor connections.

GROUP	ASSET	VOLTAGE	TYPE
Field Equipment	Poles/Conductors/Cables	33kV	Annual
		≤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	≤33kV	4 Year
	Earths	≤33kV	6 Monthly
	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: TEN's asset inspection programme

6.1.3 Renewal Maintenance Programme

TEN implements a renewal maintenance programme to ensure that assets continue to function satisfactorily over their economic life. This strategy uses asset criticality, serviceability, safety, performance, economic viability and the environmental consequences of failure to determine when a maintenance intervention is required. Both age and condition are considered in determining the timing of treatment, but the latter is given priority. This condition-based maintenance is driven out of the preventative maintenance programme.

6.1.4 Reactive Maintenance

TEN maintains a 24 hour fault service providing prompt and effective response to asset failures, supply interruptions and asset failures causing supply interruptions or a major safety risk are attended to immediately they are reported.

TEN and TECS maintenance staff are able to download schedules of defects identified during routine asset inspections as requiring remediation and TECS uses these to prepare its 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 able to produce reports of defect backlogs.

It is also a requirement that employees report asset defects identified as requiring attention and the public are encouraged to do the same.

Asset conditions reported outside of preventative maintenance are rated as summarised in Table 68 and the appropriate action is taken.

Table 6.2 illustrates how defects are prioritised in the reactive maintenance programme.

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

6.1.5 Asset Replacement

The general strategy for the replacement of assets is to consider the following justifications:

- **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).

6.2 Transmission Assets

TEN purchased its 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[2].

6.2.1 Transmission Line

A full condition assessment of the lines asset was undertaken in December 2012. 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 condition of the steel towers has still to be fully assessed, but a preliminary assessment does not indicate that there is a cause for concern regarding tower condition.

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2 The total acquisition price for the Transpower assets was less than 70% of the estimated cost of building the new Wiroa substation.

There are a total of 301 structures on the line comprising: 14 steel towers, 117 wood structures and 170 concrete structures. The assessment of the wooden poles revealed that 31 poles are in need of attention due to reduced cross-sectional area from decay. TEN is presently in the process of establishing a programme to manage these structures to ensure continuing reliability of supply.

6.2.2 Substations

The overall condition of the substation assets was generally good at the time of the acquisition, apart from the issues with the Kaitaia transformers and the Kaikohe circuit breakers discussed in Section 5. The substation equipment has been regularly checked by TEN since the asset transfer and there have been no issues identified other than a need to clean insulators and treat minor rust.

Recently, TEN has engaged an external contractor to provide the preventive maintenance servicing and testing of the substation electrical equipment. The long-term objective of this arrangement is to provide training and experience to TEN and TECS staff for the eventual transition of the full maintenance function back to Top Energy.

6.3 Overhead Conductors

6.3.1 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. binder, ‘dead end’ and ‘armour rod’);
- 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 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 being implemented. No. 8 fencing wire has been used historically for emergency conductor repair. Although this practice has ceased, it is now causing problems due to corrosion. Fencing wire is being replaced as it is found; however there are no records of its use and thus it is difficult to locate and identify.

6.3.2 Planned Inspection & Maintenance Practices for Overhead Conductors

Ground-based visual inspection of sub-transmission conductors is performed annually, and distribution and low voltage conductors are inspected on a five-year cycle. Thermal imaging of sub-transmission lines is conducted annually and six-yearly for distribution conductors. Helicopter-based inspection of sub-transmission 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.

6.3.3 Vegetation Strategy

Vegetation management has always been a part of the work that TEN has been directly involved with. 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 TEN's vegetation management strategy.

Initial tree trimming/removal costs are borne by TEN; however as the tree owners are identified and the compulsory first cut and trim on the tree is complete, the ongoing maintenance is passed to the tree owner. TEN's preference is to remove trees where practical and economic to do so, to minimise ongoing maintenance cost and risks. TEN 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.

6.3.3.1 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 entire life of the tree and for any new tree that should grow into the power lines; historically, this has not been done. Top Energy now stores this information in its 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.

6.3.3.2 Far North District Council (FNDC) Relationship

The FNDC has a significant numbers of trees that affect TEN's power lines. Top Energy has an informal relationship with the FNDC that allows TEN 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 TEN's 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 by TEN. TEN is still in negotiation with the FNDC to progress this initiative.

6.3.3.3 Targeted Cutting Strategy

The three year vegetation management programme that commenced in FYE2010 was completed in FYE2012. Vegetation management in FYE2014 is budgeted at $2.72 million, but expenditure is expected to reduce to a sustainable level of $1.72 million (real) by FYE2017.

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.

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

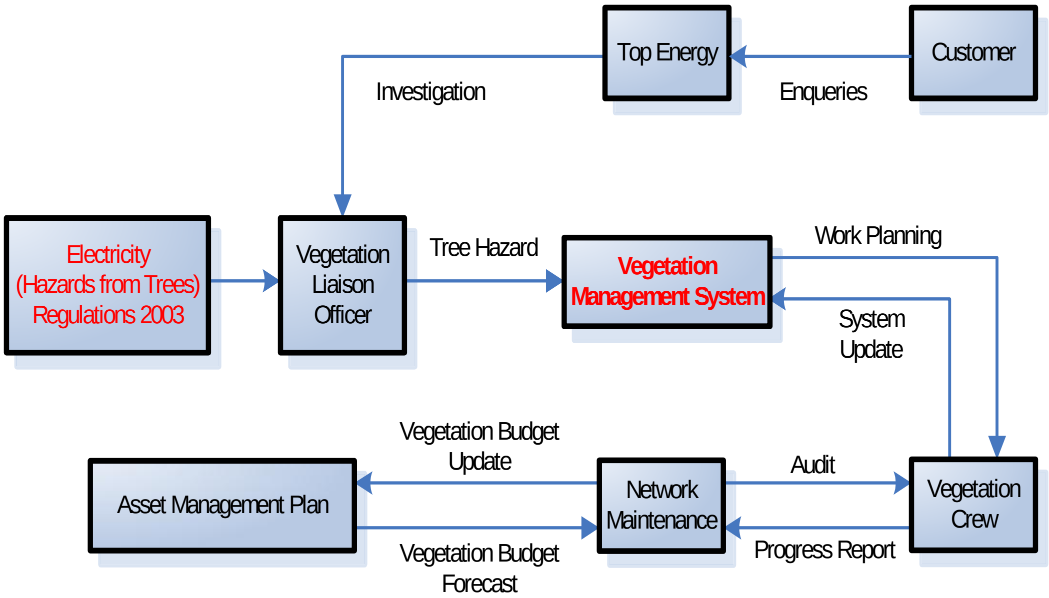

Figure 6.1: Information Flow – Vegetation Management

6.4 Poles and Structures

6.4.1 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 degrade steadily over a long period of time and this degradation is not always immediately apparent. Degradation 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 TEN's wooden poles are hardwood, treated pine and a few Larchwood. Top Energy has stopped the installation of wooden poles in favour of pre-stressed concrete. Older wooden poles are therefore being phased out over a twenty year period, starting with the wooden poles on the 33kV sub-transmission 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 the Top Energy supply area, can affect concrete poles.

Concrete poles can fail suddenly when loading on the pole is altered. 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 falling trees or constant chipping/cracking from intermittent contact with heavy mowers, farm equipment, low speed vehicles, etc.

Early concrete poles were manufactured internally by TEN. The oldest of these are now approximately 60 years old are beginning to spall, exposing the reinforcing. Some poles have stay wires to assist with their loading and these stay wires are connected to ground anchors. Stays and anchors may deteriorate and this, if not identified and remedied through regular inspection and maintenance, could result in 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 the 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, so pole failure poses a real safety risk.

6.4.2 Planned 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 sub-transmission 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 sub-transmission 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, TEN uses traditional methods of condition assessment for wooden poles on the sub-transmission 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 combination of periodic ground-based and aerial inspection is considered sufficient at present and specific pole top inspections are not normally carried out unless other work is being undertaken on the pole.

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

6.4.3 Asset Renewal Programme

TEN replaces poles that are no longer considered fit for service.

TEN's 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.

Wooden poles are being phased-out over a 20 year period.

6.5 Underground & Submarine Cables

6.5.1 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. TEN offers a cable location service to encourage people to reduce this risk. It also has 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 customers. 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 cable 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. 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 for TEN.

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 will be four-core aluminium cables utilising a completely sealed system. Existing installations will be changed over to the sealed system as prone areas are identified and as age and condition dictate.

6.5.2 Planned Inspection & Maintenance Practices for Underground & Submarine Cables

As these assets are buried, it is not possible to carry out a general 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 PD 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 basic approach to ensuring long life for cables is to ensure they are carefully 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, TEN carries 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.

6.5.3 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.

TEN's 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.

6.6 Distribution and SWER Transformers

6.6.1 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.

TEN is in the process of reducing the number of transformer failures resulting from lightning events by fitting lightning arrestors to all new pole-mounted transformers. It is also planning a retroactive programme of fitting surge arrestors on transformers in the Kawakawa and Kaitaia areas during the planning period.

The majority of TEN's customers live either on farmland or in coastal locations. Farmland tends to have a low density population, whereas coastal areas tend to have a higher, though 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 a transformer and the impact that a new or larger transformer could have on the network.

Transformers are constructed using 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.

6.6.2 Planned Inspection and Maintenance Practices for Distribution and SWER Transformers

Distribution transformers are inspected three-yearly. In addition to the normal 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 minimal maintenance requirements. Older units with signs of significant degradation or damage are replaced and the old unit is refurbished if viable or scrapped.

6.6.3 Asset Renewal Programme

TEN has a large quantity of transformers at the end of their service life; these are often located in remote areas. As the failure rate of these units is relatively low, the most effective practice is to replace on 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.

6.7 Auto-Reclosers

6.7.1 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. Personal risk of injury is very low.

6.7.2 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.

6.7.3 Asset Renewal Programme

A significant proportion of auto-reclosers are relatively new; these are SF_6 and vacuum units. There are few oil-filled auto-reclosers left in operation. These oil-filled units are being phased out, with the last few being replaced with resin-encased vacuum units.

6.8 Regulators

6.8.1 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 (specifically around the lid, bushing and control box) allows water and contamination to enter and is also a problem.

6.8.2 Planned Inspection and Maintenance Practices for Regulators

Regulators are inspected at two-yearly intervals or at 50,000 operations, whichever occurs earlier. 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.

6.8.3 Asset Renewal Programme

As all voltage regulators are less than ten years old, there is no renewal programme required.

6.9 Ring Main Units (RMU)

6.9.1 Failure Modes and Risks Associated with Ring Main Units

The main causes of failure of RMUs within the Top Energy geographical area is third-party vehicle accidents. This is followed by corrosion, due to harsh coastal conditions.

6.9.2 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 five years, with a partial discharge test of the cable terminations on an annual basis. Routine inspection includes an annual hazard inspection and visual condition assessment.

6.9.3 Asset Renewal Programme

A significant proportion of RMUs are relatively new. There is no programme for asset renewal, although older units will be replaced as required.

6.10 Sectionalisers

6.10.1 Failure Modes and Risks Associated with Sectionalisers

The main causes of failure of sectionalisers are lightning and sudden mechanical failure.

6.10.2 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 in their operation.

6.10.3 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.

6.11 Air Break Switches

The average age of air break switches on the sub-transmission system is 28 years and 24 years on the distribution system. Many units are older and a large number 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 eliminates 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.

6.12 Capacitors

6.12.1 Failure Modes and Risks Associated with Capacitors

The main causes of failure of capacitors are lightning and sudden mechanical failure.

6.12.2 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.

6.12.3 Asset Renewal Programme

There are currently no renewal programmes in place for these assets, but individual replacement will be as a result of specific condition inspection.

6.13 Zone Substation Transformers

6.13.1 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 becomes even higher with the mobile transformer, which uses biodegradable vegetable oil to minimise environmental risk from accidental spills 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.

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 the TEN area, and the transformers and auxiliaries have been appropriately secured.

Lightning arresters are provided to address the issue of lightning strike. These may not necessarily protect the substation against a direct lightning strike. However, based on a risk analysis, the substantial costs of upgrading to provide such protection is considered prohibitive.

6.13.2 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 is 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.

TEN undertakes its own interpretation of oil test data and has built a spreadsheet programme to assist in 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 TEN’s 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 (%DW) 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 by means of 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 action.

The overall condition of TEN’s 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 Kaikohe, Kawakawa and Waipapa substations during the AMP planning period.

Zone substation tap-changers have their oil changed two-yearly. Parts are replaced or refurbished based on inspected conditions and manufacturer's recommendation per cyclometer reading (i.e. number of operations). Maintenance costs are being tracked, so that the option of adopting new technology by replacing existing oil-filled tap changers with vacuum type tap changers may be considered on a business case basis.

6.13.3 Asset Renewal Programme

There are currently no formal asset renewal programmes in place for zone substation transformers. As noted in Section 5.10, the transformer at Taipa Substation is to be relocated to the Omanaia Substation to replace the three old single phase transformers in FYE2019.

6.14 Circuit Breakers

6.14.1 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 TEN circuit breaker classes.

6.14.2 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.

The following maintenance strategy has been adopted by TEN:

- 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 with/without electronic control are serviced two-yearly. This is done more frequently if the number of operations since last service is > 15;
- 33kV vacuum interrupter/oil insulated are service four-yearly;
- 33kV vacuum interrupter/air insulated are service 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.

6.14.3 Asset Renewal Programme

Circuit breakers that are considered to be beyond economic repair are programmed for replacement within a defined period. Circuit breakers are also replaced routinely as part of larger scale zone substation refurbishment programmes. During the planning period, replacement of outdoor circuit breakers with indoor switchboards are proposed at Moerewa and Waipapa substations, and 11kV switchboard replacements are proposed at Kaikohe and Kaitaia.

6.15 Zone Substation Structures

6.15.1 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.

6.15.2 Planned Inspection and Maintenance Practices for Zone Substation Structures

TEN's 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, they are individually checked for correct operation every two years and maintained if necessary.

6.15.3 Asset Renewal Programme

Pukenui substation has recently undergone refurbishment, with the bus reconfigured to allow the mobile substation to be connected and obsolete switchgear replaced. Modern protection systems have been installed.

Moerewa and Waipapa substations have been identified as needing attention and the outdoor switchyards will be replaced with indoor switchboards at both sites during the planning period.

6.16 Zone Substation DC Systems

6.16.1 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.

6.16.2 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.

6.16.3 Asset Renewal Programme

Due to the limited population, there are currently no 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.

6.17 Zone Substation Protection

6.17.1 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.

6.17.2 Planned Inspection and Maintenance Practices for Zone Substation Protection

Until an upgrade to numerical relays is commissioned, the present maintenance regime for all relays will continue as follows:

- functional tests, minor visual inspection of settings and condition will occur two-yearly;

- calibration tests will occur four-yearly; and
- more frequent testing than the above two-yearly functional and four-yearly calibration test regime will be considered for very old relays, where there is evidence of drift or degradation.

The adoption of modern, microprocessor-based numerical relays will provide the opportunity to increase the interval of calibration testing beyond four years.

TEN will continue to 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.

6.17.3 Asset Renewal Programme

A major capital expenditure programme covering the entire TEN network is planned to address the current issues surrounding ageing and ineffective protection systems. The detailed renewal and replacement programme will be managed on a risk assessed basis.

6.18 Zone Substation Grounds and Buildings

6.18.1 Failure Modes and Risks Associated with Zone Substation Grounds and Buildings

The Omanaia Substation has been identified as being 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.

6.18.2 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.

6.18.3 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 for this asset class.

6.19 Customer Service Pillars

6.19.1 Failure Modes and Risks Associated with Customer 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.

6.19.2 Planned Inspection and Maintenance Practices for Customer Service Pillars

All customer 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 incidental contact.

Service pillar fuse bases are a constant source of failure commonly due to loose connection into the fuse base. This can result from poor installation, vehicular vibration or any form of impact. TEN has recently 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 eliminate the on-going issue of failure from poor connections. Being sealed, these units also provide waterproofing and protection against incidental contact.

6.19.3 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.

6.20 Earth installations

6.20.1 Failure Modes and Risks Associated with Earth Installations

Failure of an earth installation can result from a variety of reasons, including: vandalism, foreign interference, environmental 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. Either one of these scenarios can lead to injury or damage to persons or property.

6.20.2 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, TEN has 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 those areas with the highest frequency of people (i.e. shopping areas, schools).

6.20.3 Asset Renewal Programme

Earth systems for distribution equipment have historically been very simplistic and reviews of earthing practices have shown some inadequacy. TEN's earthing standards have been therefore revised and aligned with best industry practice. This, in conjunction with regular inspections, has revealed that significant investment is necessary to improve system reliability and safety. Earth systems 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 million (real) has been included in the asset replacement CAPEX forecast for the renewal of transformer earths.

6.21 SCADA and Communications

6.21.1 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.

6.21.2 Planned Inspection and Maintenance Practices for SCADA and Communications

Recent installations of new Foxboro & Schweitzer Engineering remote terminals and associated Ethernet communications equipment, combined with the decommissioning and removal of legacy remote terminal units and radio systems, has prompted a review of the maintenance strategy. The installation of this new equipment with its onboard 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 this media. These systems will be developed in conjunction with external specialist consultants.

6.21.3 Asset Renewal Programme

There are currently no formal renewal programmes in place for the SCADA system, although a need to replace a limited number of zone substation RTU cabinets has been identified and provided for in the asset replacement CAPEX forecast.

6.22 Load Control Plant

6.22.1 Failure Modes and Risks Associated with Load Control Plant

Failure of load control plant can result in Top Energy incurring additional transmission charges and could also result in the overload of highly loaded sections of the TEN 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.

6.22.2 Planned Inspection and Maintenance Practices for Load Control Plant

The maintenance regime for this plant involves their daily functional use. 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 an annual 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.

6.22.3 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.

6.23 Breakdown of Network Maintenance OPEX Forecast

Sections 6.23.1 to Section 6.23.3 below provide a breakdown of Top Energy's forecast network maintenance OPEX in accordance with the standard asset management categories currently used by Top Energy. Table 6.3 shows how these categories have been aggregated into the Commerce Commission's standard maintenance OPEX forecast categories presented in Schedule 11b of Appendix A.

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<tr><th>Disaggregated expenditure
Sections 6.23.1 – 6.23.3</th><th>Summary
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<tr><td>Routine and corrective maintenance – transmission; other categories</td><td>Other maintenance - transmission</td></tr>
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Table 6.3: Mapping of Top Energy's Asset Forecast

In mapping Top Energy's OPEX expenditure categories into the Commerce Commission's standard categories two issues have emerged as discussed below. These issues will be addressed during FYE2014 and corrected in the 2014 AMP.

- Both Top Energy and the Commission use the term "routine and corrective maintenance" in their OPEX category descriptions. However Top Energy uses the term more broadly than the Commission. This is a nomenclature issue that has the potential to cause confusion.
- Top Energy categorises routine maintenance that does not form part of its asset inspection programme as "other maintenance". Examples include invasive tap changer and circuit breaker maintenance that is undertaken on a regular basis. As a result this maintenance OPEX would be included in the Commission's "asset replacement and renewal" category rather than the more correct "routine and preventive maintenance and inspection".

6.23.1 Service Interruptions and Emergencies

($000, real)	FYE									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Lines and poles	790	775	775	646	646	659	672	685	699	713
Cables and pillars	290	275	275	229	229	234	238	243	248	253
Transformers	78	80	80	67	67	68	70	71	72	74
Buildings and grounds	6	5	5	4	4	4	4	4	4	4
Switchgear and protection	24	50	50	42	42	43	44	45	45	46
Secondary systems	12	15	15	13	13	13	14	14	14	14
	1,200	**1,200**	**1,200**	**1,000**	**1,000**	**1,020**	**1,040**	**1,061**	**1,082**	**1,104**

Table 6.4: Service Interruptions and Emergency Maintenance OPEX by Category

6.23.2 Routine and Corrective Maintenance – Distribution

($000, real)	FYE									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Inspection	1,000	1,000	1,020	1,040	1,061	1,082	1,104	1,126	1,149	1,172
Vegetation	2,000	1,500	1,500	1,000	1,000	1,020	1,040	1,061	1,082	1,104
Lines and poles	625	625	546	555	564	576	587	599	611	623
Cables and pillars	250	250	219	222	226	230	235	240	245	250
Transformers	94	94	82	83	85	86	88	90	92	94
Buildings and grounds	9	9	8	8	8	9	8	8	9	9
Switchgear and protection	188	188	164	167	169	173	176	179	183	187
Secondary systems	84	84	74	75	76	78	79	81	82	84
Safety and Compliance	100	100	102	104	106	108	110	113	115	117
Total	**4,350**	**3,850**	**3,715**	**3,255**	**3,296**	**3,362**	**3,429**	**3,497**	**3,567**	**3,639**

Table 6.5: Breakdown of Routine and Corrective Maintenance – Distribution

6.23.3 Routine and Corrective Maintenance – Transmission

($000, real)	FYE									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Inspection	235	235	235	235	235	240	244	249	254	259
Vegetation	72	72	72	72	72	73	75	76	78	79
Lines and poles	250	250	250	250	250	255	260	265	271	276
Cables and pillars										
Transformers	24	24	24	24	24	24	25	25	26	26
Buildings and grounds	6	6	6	6	6	6	6	6	6	7
Switchgear and protection	24	24	24	24	24	24	25	25	26	26
Secondary systems	30	30	30	30	30	31	31	32	32	33
Safety and Compliance	6	6	6	6	6	6	6	6	6	7
Total	**647**	**647**	**647**	**647**	**647**	**660**	**673**	**687**	**700**	**714**

Table 6.6: Breakdown of Routine and Corrective Maintenance – Transmission

6.23.4 Summary of Maintenance OPEX Forecast

($000, real)	FYE									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Service Interruptions and Emergencies	1,200	1,200	1,200	1,000	1,000	1,020	1,040	1,061	1,082	1,104
Inspection	1,341	1,341	1,363	1,385	1,408	1,437	1,465	1,495	1,524	1,555
Vegetation	2,072	1,572	1,572	1,072	1,072	1,093	1,115	1,137	1,160	1,183
Other maintenance – distribution	1,250	1,250	1,093	1,110	1,129	1,151	1,174	1,198	1,222	1,246
Other maintenance - transmission	334	334	334	334	334	341	347	354	362	369
Total	**6,197**	**5,697**	**5,562**	**4,902**	**4,943**	**5,042**	**5,142**	**5,245**	**5,350**	**5,457**

Table 6.7: Breakdown of Total Maintenance OPEX Forecast

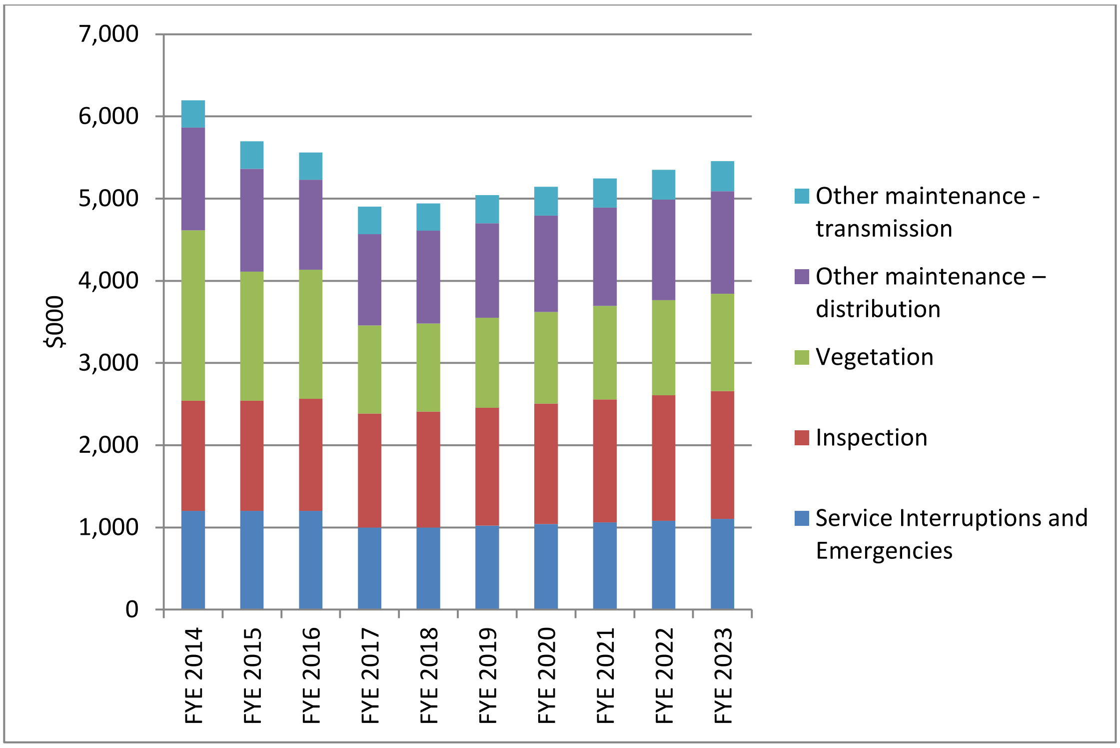


Figure 6.2: Breakdown of Total Maintenance OPEX Forecast

6.24 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. Another example would be the planned refurbishment of the Kaikohe-Kaitaia 110kV line, where detailed planning and design is expected to commence in FYE2017 and implementation is forecast to be undertaken over a five-year period, commencing in FYE2018. 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 5.15 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 6.6.

6.25 Non-network CAPEX

As noted in Section 3.4.16, TEN's non-network assets covered by this AMP are limited to TEN's computer hardware and software, motor vehicles assigned to TEN 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 TEN staff levels and replacement of assets as required. The CAPEX forecast in Appendix A, Schedule 11a, includes a provision of $400,000 in FYE2014, and $250,000 per annum thereafter, for non-network assets.

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

6.26 Non-network OPEX

This AMP discusses in some detail:

- the existing and planned service levels provided by TEN's network assets;
- the development and maintenance strategies planned by TEN 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 Kaikohe;
- the cost of planning and implementing the asset management strategies described in this AMP. This includes the cost of staffing TEN's asset management team, as shown in Figure 2.2; and
- the cost of the business support functions required for TEN to function effectively. These include governance, commercial, human resource, regulatory, finance and other support services, which are provided by Top Energy's corporate team based in Kerikeri and are shared with Top Energy's other operating divisions. The costs of providing these services are allocated to TEN consistent with the Commerce Commission's regulatory requirements.

Table 6.9 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									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Transmission and sub-transmission lines	200	200	174	173	179	193	187	203	194	198
Transmission and zone substations	200	200	174	173	179	193	187	203	194	198
Distribution lines	1,173	1,173	1,017	1,016	1,046	1,132	1,096	1,191	1,136	1,159
Distribution cables	200	200	174	173	179	193	187	203	194	198
Distribution substations and transformers	887	887	769	768	791	856	828	900	859	876
Distribution switchgear	200	200	174	173	179	193	187	203	194	198
Total	**2,860**	**2,862**	**2,480**	**2,477**	**2,550**	**2,762**	**2,672**	**2,904**	**2,770**	**2,826**

Table 6.8: Breakdown of Maintenance CAPEX Forecast

($000, real)	FYE									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
System operations and network support	3,284	3,350	3,417	3,485	3,555	3,626	3,626	3,626	3,626	3,626
Business support	4,548	4,599	4,651	4,704	4,759	4,814	4,814	4,814	4,814	4,814
Total	**7,832**	**7,949**	**8,068**	**8,189**	**8,313**	**8,439**	**8,439**	**8,439**	**8,439**	**8,439**

Table 6.9: Non-network OPEX Forecast

Section 7 Risk Management

7 Risk Management

7.1 Risk Management Policy

Governance of Top Energy 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 Top Energy. 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 Top Energy'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.

Top Energy's 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. Top Energy's 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. Where changes within TEN are being considered, reference is made to the Institute of Asset Management's specification PAS55.

In order to ensure that risk management is recognised and treated as a core competency, Top Energy 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, Top Energy's risk management framework provides for:

- the identification of Top Energy's 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 Top Energy'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.

TEN's risk management process focuses on the assessment of credible network risks, which from 1 April 2012 includes the transmission assets acquired from Transpower. These risks include asset failure due to the normal asset ageing processes, overloading, material deterioration, human error, poor workmanship, lightning, fire, earthquake and flood. All EDBs, including Top Energy, have experienced these risks.

7.1.1 Corporate Risk Management Committee

Risk management is an on-going cyclical process that is managed by Top Energy's 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 Network Risk Management Committee

TEN has its own specialised network risk committee consisting of the following personnel:

- General Manager Network;
- Network Maintenance Manager;
- Network Operations Manager;
- Network Planning Manager;
- Network Project Delivery Manager; and the
- Network Standards 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.

TEN's 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 TEN's 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	Network General Manager	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

TEN employs 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.

TEN's 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.

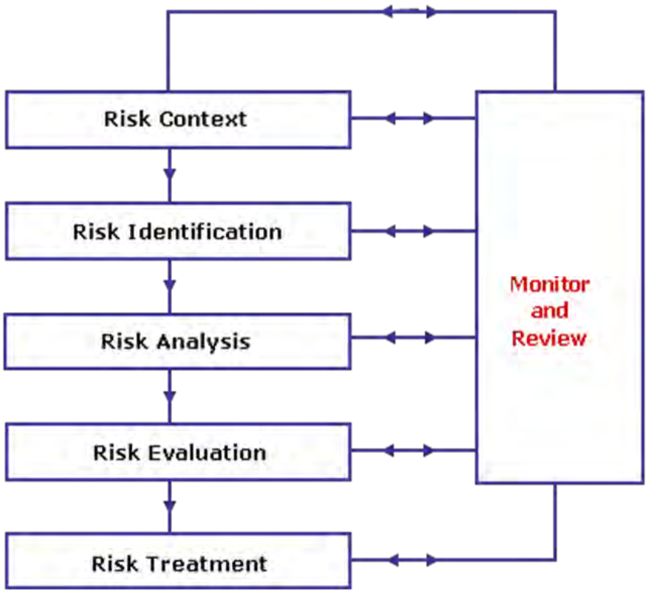


Figure 7.1 TEN's risk management process

The risk process adopted for TEN 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. TEN's 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 customer 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

GENERAL MANAGEMENT	CONSEQUENCE ARISING FROM POOR MANAGEMENT PRACTICES
Technology	High reliance on specific technologies Impact relating to the failure of technology Impact of significant technological changes

Table 7.2: Risk process main elements

- **Risk identification:** Identifying all elements relevant to the risk context. After establishing this, the next step is to identify potential risks. A culture of risk awareness at all levels is encouraged within TEN, to recognise, assess and manage risk before possible adverse impact on public, personnel and company. There are also formal processes based around focus groups that actively identify new and review known risks.

  Identified risks are considered by the TEN Risk Committee; 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 Top Energy's 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.

  Top Energy'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.

- **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 Top Energy's risk analysis, plus 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, GFN units 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	Sub-transmission & 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 sub-transmission 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	Sub-transmission & 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	Sub-transmission	Capital projects over-running budgets	Major	Possible	Extreme	Moderate	Tight project management, regular monitoring and review	
20	Asset Management	Network	Sub-transmission & Distribution	Major storm event	Moderate	Almost certain	Extreme	Moderate	Emergency preparedness plans. Weather tracked. Efficient first response resources	Upgrade sub-transmission network as per AMP
22	Asset Management	Network	Sub-transmission - 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 sub-transmission network as per AMP
22	Asset Management	Network	Sub-transmission - 33kV Lines	33kV Zone substation failure.	Moderate	Almost certain	Extreme	Moderate	Regular maintenance. Dual bank configurations and mobile substation.	Upgrade sub-transmission 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 TEN recognises, are described in the following sections.

7.2.1 Update on TEN's Current Risk Profile

- TEN's exposure to transmission risk has changed following the April 2012 acquisition of Transpower's 110kV assets. TEN is now positioned to improve asset management and operational performance in this area. Conversely, ownership of these assets has increased TEN's physical exposure to risk. These new risks are identified within this section, along with their impact on levels of service and life cycle asset management (Sections 4 and 6).
- Load growth has flattened over the last 12 months and is expected to result in a modest reduction in load related risk.
- The network development plan is progressing well and a positive impact is expected in FYE2014. This will mitigate some of the risks associated with high network loading in the Kerikeri area.

7.2.2 Ongoing Risks

7.2.2.1 Health and Safety Policy

The safety of Top Energy's employees, contractors and the general public is of utmost importance in the operation, maintenance and expansion of the network. TEN operates 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.

TEN has committed to a reduction in both the frequency and severity of injuries to staff, contractors and the general public. The results of initiatives implemented under this system demonstrate the commitment by staff to effectively manage health and safety. As at December 31 2012, Top Energy's Lost Time Injury Frequency Rate (LTIFR) was 9.08, which equates to 3 lost time injuries in the year.

This trend is shown in Table 7.4 and Figure 7.2.

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012
LTIFR	42	24	19	7	19	17	18	5.8	9.1

Table 7.4: Lost Time Injury Frequency Rate (LTIFR)

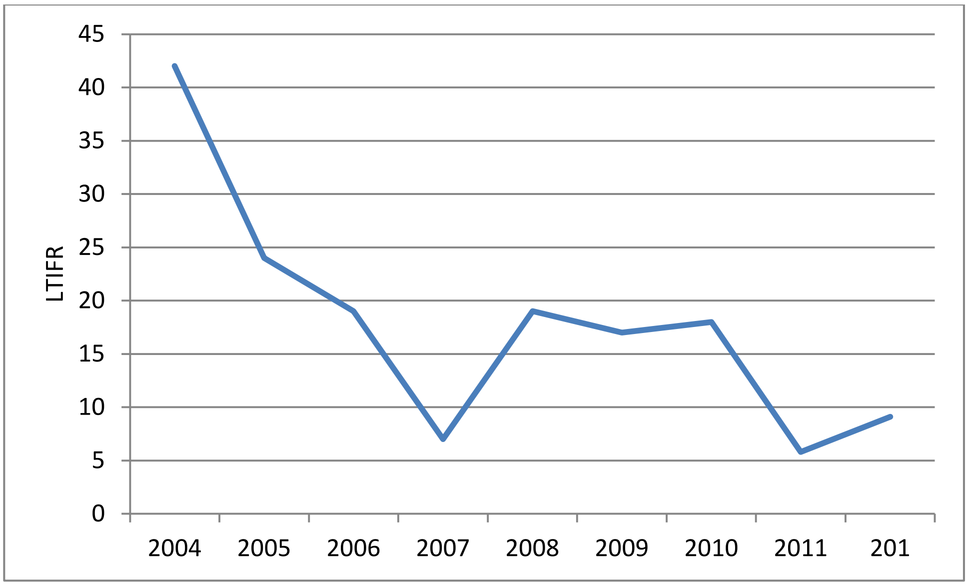


Figure 7.2: LTIFR Trends

A philosophy of continuous improvement prevails within TEN's 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.

A high standard is being maintained in the time frames 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.

TEN recently gained accreditation as an Electrical Workers' Registration Board (EWRB) safety refresher provider and continues to make a significant investment in the training and development of its employees as they undergo both regulatory and NZQA Unit Standard based training towards appropriate National Certificates for their various roles.

Top Energy offers training to upskill existing employees in the following work practices: hotstick 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 TEN's ability to maintain the network efficiently.

TEN considers itself an industry leader in the development of its 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, Top Energy will launch a company-wide "values programme" in early 2013 and the current AHC system is being updated to integrate the EWRB's competency based refresher classes. TEN maintains a proactive role in staff competency, monitoring industry safety issues and implementing training and guidance where required. For example, training in 2012 included:

- Four wheel drive training
- Truck loader cranes
- Manual handling
- First aid/CPR
- Hazard ID and controls
- Electrical testing
- Installing pillars
- Live oil testing

Top Energy's current health and safety system was recognised by the wider industry in 2010 when the company was awarded with the Accident Compensation Corporation's (ACC's) tertiary level accreditation for workplace safety management practices at its first attempt. Further recognition was gained when it won the Electricity Engineers' Association's Public Safety Award in 2010 and its Workplace Safety Award in 2011. Top Energy currently holds "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 recent acquisition of transmission assets by Top Energy transfers much of this risk from Transpower to Top Energy. TEN will 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 engineering assessment of 110kV line assets. This was completed in December 2012, and the new assets have been incorporated into TEN's programmed asset inspection cycle;
- contracting the maintenance of 110kV 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; and
- a commitment to facilitate regular site visits and engagement with owners of property over which TEN's 110kV assets are situated.

The backlog of distribution defects identified during the asset inspection programme and requiring remediation has been increasing. If this trend continues, achievement of the reliability targets set out in Section 4 of this AMP could be at risk. This is mitigated through an increased maintenance budget from FYE2014 and will continue to be monitored, reported and reviewed.

Ongoing expenditure on vegetation management is budgeted to be reduced in accordance with what TEN considers a sustainable level. However, insufficient expenditure could adversely impact future reliability. The situation will be monitored closely to ensure that vegetation management remains in-step with actual outage data and risk profiles.

Of increasing concern is the medium-term ability for the network to meet the growing demand. The risk register shows a growing number of network areas that are approaching capacity constraints. The consequence of each one is of varying significance, but together they form a business risk that is being addressed through the network development plan described in Section 5. In the short-term, the risk of being unable to meet growing demand is being mitigated through a recent slowing in the rate of demand increase. However, TEN considers this may be temporary and that growth in demand could accelerate as the economy improves.

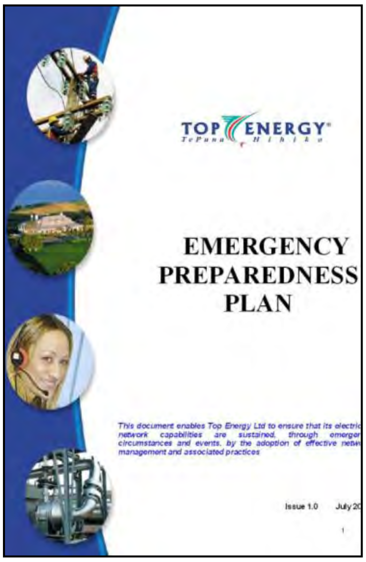
7.2.2.3 Network Critical Spares

TEN maintains an inventory of critical spares for where there could be that require long delivery times in the event of network equipment failure.

TEN's electrical network is mainly of overhead construction. In most cases, the equipment is of modular design and can be relatively easily replaced using TEN's inventory of equipment held to maintain and expand the electrical network. However, TEN maintains a regularly reviewed level of specialised spares and has joined a cooperative group of other EDBs to provide mutual risk mitigation in this area.

For the recently acquired 110kV 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



Top Energy has well-established disaster readiness and emergency preparedness plans. Top Energy's formal Emergency Preparedness Plan ensures that its electricity 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 Top Energy has the capability and resources to meet its obligations to its community, 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, customers 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:

- Top Energy's own electricity network management facilities and capabilities for its network, Transpower's supply to Top Energy and the coordination of responses and communications; and
- Top Energy's major customers 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.

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 stormwater, 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 on-going research and technology transfer aimed at protecting and preserving the lifelines of the region.

As part of the Lifelines Group coordination activities, TEN 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 TEN meets its commitment to stakeholders to operate its 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

TEN maintains a load shedding system to meet its regulatory requirements designed to ensure, at all times, that an automatic under-frequency load shedding system is installed for each grid exit point to which its local network is connected. 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.

TEN also maintains an up to date process for the manual disconnection of demand for points of connection in accordance with its regulatory requirements.

A feeder shedding schedule is maintained which specifies the shedding priority (manual and automatic) by under-frequency zone and substation for the TEN 11kV network and the Transpower points 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

TEN has standardized switching instructions that are managed and updated on a regular basis by its central control room staff. These switching instructions outline the methods for re-arranging the electrical network to supply consumers during network contingencies (equipment outages).

TEN has recently 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 TEN's risk scenarios involve customer non-supply through equipment failure in zone substations, particularly in substations where there is only one transformer. In FYE2003, TEN 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 is also used to facilitate maintenance on zone substations and therefore reduce planned consumer outages.

Section 8 Evaluation of Performance

8 Evaluation of Performance

8.1 Introduction

This section presents a review of TEN's performance against the set financial and performance targets for FYE2012. Discussion is centred on the various factors that influenced progress 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.

8.2 Review of Performance against Targets

8.2.1 Network Reliability Performance

Consistent with the requirements of the information disclosure regime, network reliability performance is measured by SAIDI and SAIFI. These measures are also used for internal monitoring purposes and target service levels are included in Section 4. Overall, TEN's SAIDI performance maintained the improvements seen from FYE2009 to FYE2010, although the company's tough SAIDI target was not met within the year. As a result of TEN attributable causes, there were a total of:

- 394 unplanned 11kV and 33kV faults; and
- 167 planned outages.

The adverse weather conditions caused a significant increase in the average number of interruptions experienced by each consumer, which is reflected in the high measured SAIFI. Notwithstanding this, the number of minutes that the average consumer was without electricity (measured by SAIDI) was marginally lower than in FYE2011. This is because the average length of each interruption was significantly shorter; it reduced from 89.2 minutes in FYE2011 to 68.4 minutes in FYE2012. This is a reflection of the success of TEN's initiatives to reduce outage durations, and in particular the installation of remote-controlled switches in the field. These devices allow switching to be done remotely from the control room and to not require operators to travel to site to perform a switching operation. Hence, after a fault occurs, they speed up the process of determining its location and allow faster restoration of supply to consumers that are not directly affected. The management focus on reliability since 2009 has also improved the efficiency of TEN's management of faults.

RELIABILITY MEASURE[1]	FYE 2011 TARGET	FYE 2011 ACTUAL	FYE 2012 TARGET	FYE 2012 ACTUAL	FYE 2013 Target	YTD 2013[2] Actual
SAIDI (including transmission, but excluding Transpower)	375	440	375	435.0	402	219.4
SAIFI (including transmission, but excluding Transpower)	4.9	4.93	4.5	6.4	5.0	3.15
Number of customers without power for 24 hours – all causes	<25	226	<25	56	<25	18
Number of customers without power for more than 3hrs – all causes	<7,000	19,789	<7,000	15,629	<7,000	12,351

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

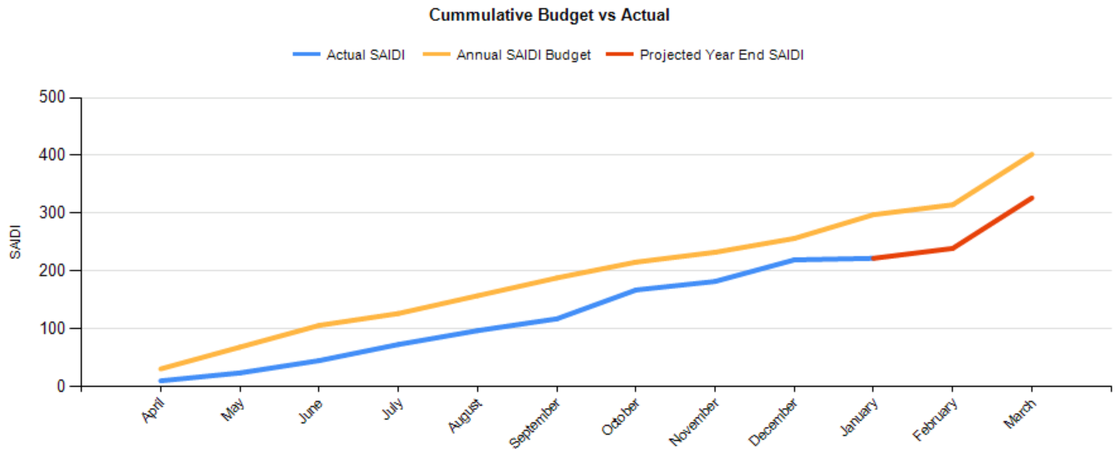
Note 2: From 1 April to 31 December 2012.

Table 8.1: Network reliability performance

As indicated in Table 8.1, the performance to date in FYE2013 is significantly better that in the previous two years and, in the absence of any significant unforeseen events in the last quarter, TEN expects its FYE2013 reliability targets to be met by a significant margin. This is allowing for a planned outage of the 110kV Kaikohe-Kaitaia circuit scheduled for 17 March 2013, which will have a SAIDI impact of 56 minutes and a SAIFI impact of about 0.4, as discussed in Section 4.2.1. The one exception where the target will not be met is the number of customers without power for more than three hours, which will increase by approximately

10,000 as a result of the 110kV shutdown. TEN is reviewing its internal target for this measure, which needs to be adjusted to account for the impact of the annual planned 110kV shutdown through to FYE2016. It is also reassessing whether the internal target of 7,000, as a result of distribution network related faults, is realistic at this time.

This improved reliability for FYE2013 is illustrated in Figure 8.1, which compares TEN's actual SAIDI with its expected performance at the time of setting the FYE2013 target. The graph, which shows the actual position at the end of the first week of January, shows that TEN has generally bettered its expected monthly performance for the year.



TOTAL	SAIDI
Annual SAIDI Budget	402
Projected Year End SAIDI	326.56

YTD SAIDI
222.10

Figure 8.1: Actual and expected SAIDI performance, FYE2013

The most significant causes of TEN's unplanned interruptions in FYE2012 were adverse weather, defective equipment, third-party incidents and tree contacts. Generally, faults (other than lightning) that occur under storm conditions are treated as adverse weather faults, whereas faults that occur under more benign weather conditions are attributed to other causes. Adverse environment faults are due to situations such as flooding, which may or may not be a consequence of storm conditions. Faults classified as unknown are generally unplanned faults causing a supply interruption in benign weather conditions, where supply can be restored from the control room without the need for field intervention or where supply is restored after a line patrol cannot find a fault cause. A more detailed breakdown of these outage statistics is shown in Tables 8.2 and 8.3.

TOP ENERGY CAUSE OF INTERRUPTION	SAIDI	% OF TOTAL
Adverse Weather	125.2	28.6%
Defective Equipment	104.2	23.8%
Foreign Interference	57.7	13.2%
Tree Contacts	57.4	13.1%
Unknown	48.4	11.7%
Lightning	19.4	4.4%
Planned	15.3	3.5%
Human Element	4.3	1.0%
Adverse Environment	3.1	0.7%
Total	435.0	100.0%

Table 8.2: Network reliability performance FYE2012

FAULT CLASS	FAULT TYPE	FAULT COUNT	SAIDI	SAIFI	CAIDI
Transpower Faults	Loss of Bulk Supply (Unplanned)	0	0	0	0
	Subtotal:	0	0	0	0
Top Energy Faults	Adverse Environment	4	3.1	0.03	103.23
	Adverse Weather	78	125.2	1.01	123.54
	Equipment Failure	113	104.2	1.78	58.55
	Foreign Interference	36	57.7	0.66	87.92
	Human Element	3	4.3	0.06	75.26
	Lightning	26	19.4	0.52	37.28
	Vegetation	61	57.4	0.8	71.62
	Unknown or Other	73	48.4	1.46	35.04
	Subtotal:	**394**	**419.7**	**6.32**	**592.44**
Top Energy Planned Outages	Planned Capital Extension	28	3.7	0.01	262.93
	Planned - Planned External Work	31	3.4	0.01	240.57
	Planned - Planned Fault Prevention	33	2.9	0.03	90.34
	Planned General	11	0.9	0.002	466.5
	Planned Maintenance	51	3.7	0.02	173.67
	Planned - Planned New Connection	0	0	0	0.00
	Planned Vegetation Control	13	0.9	0.002	452
	Subtotal:	**167**	**15.3**	**0.09**	**1686.01**
	Total:	**561**	**435.0**	**6.4**	**2291.69**

Table 8.3: Network reliability statistics

Figures 8.2-8.4 below show the contribution of the various interruption causes to the total number of interruptions, as well as network SAIDI and SAIFI for FYE2012.

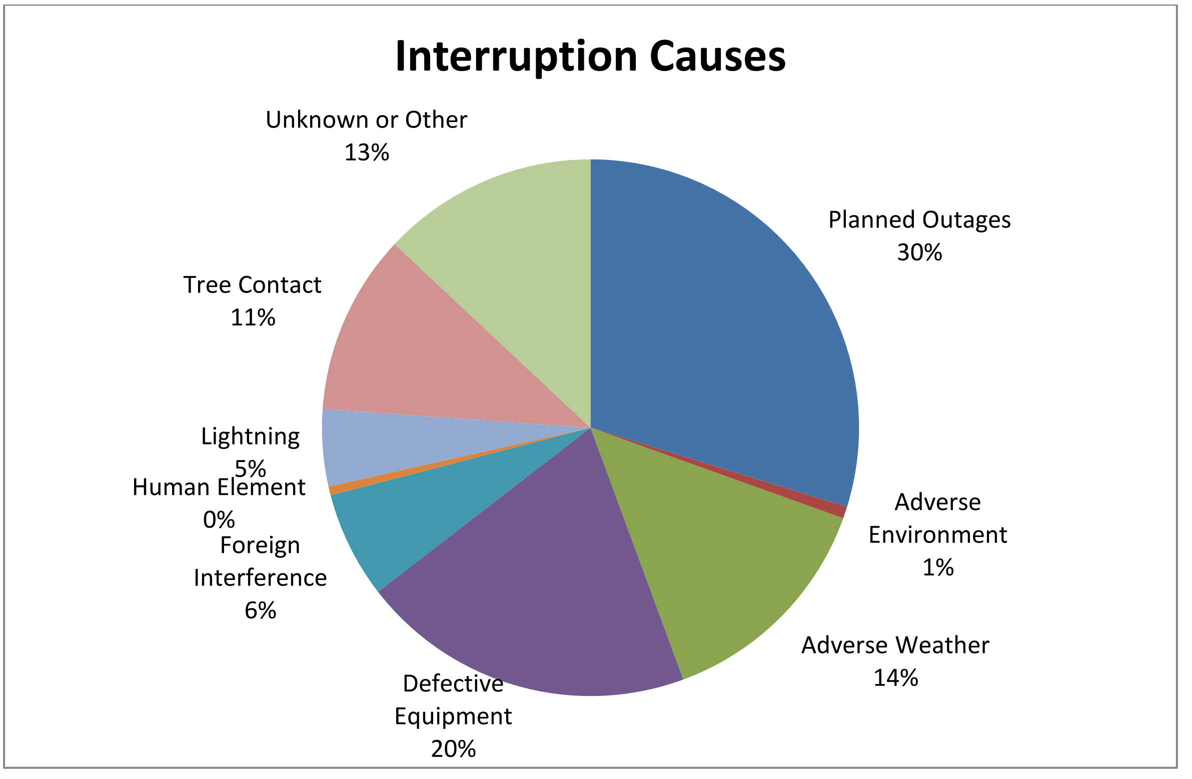


Figure 8.2: Contribution of Interruption Causes to Total Number of Interruptions

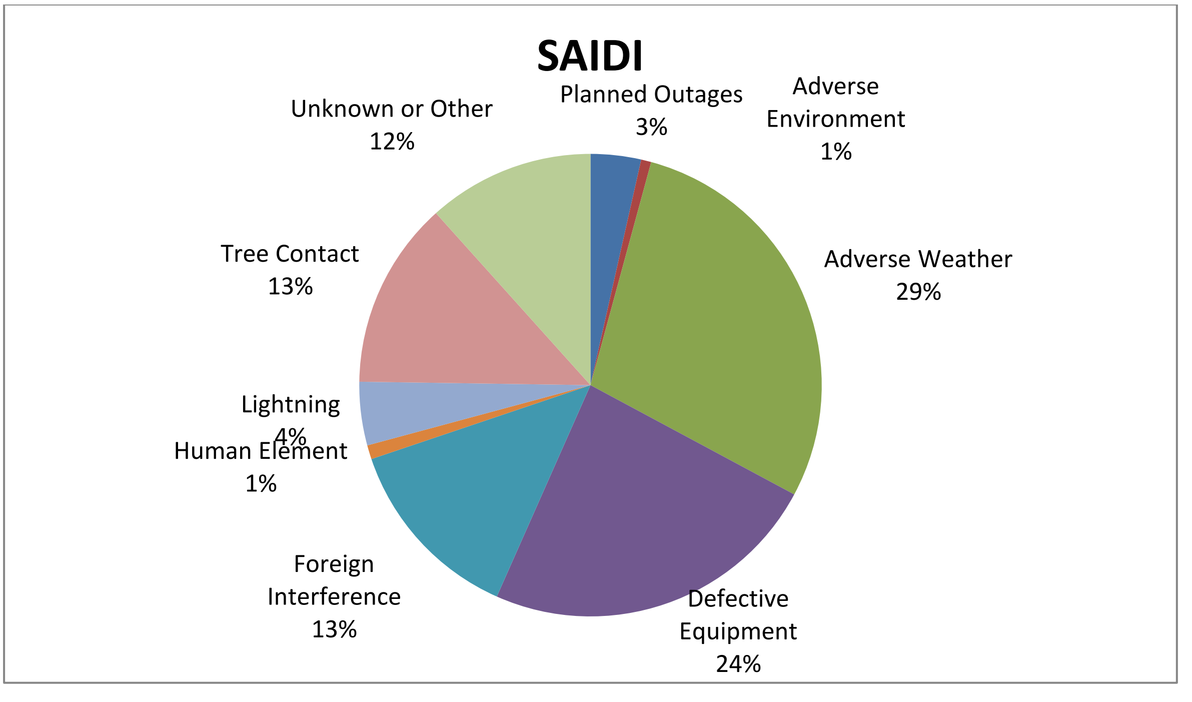


Figure 8.3: Contribution of Interruption Causes to Network SAIDI

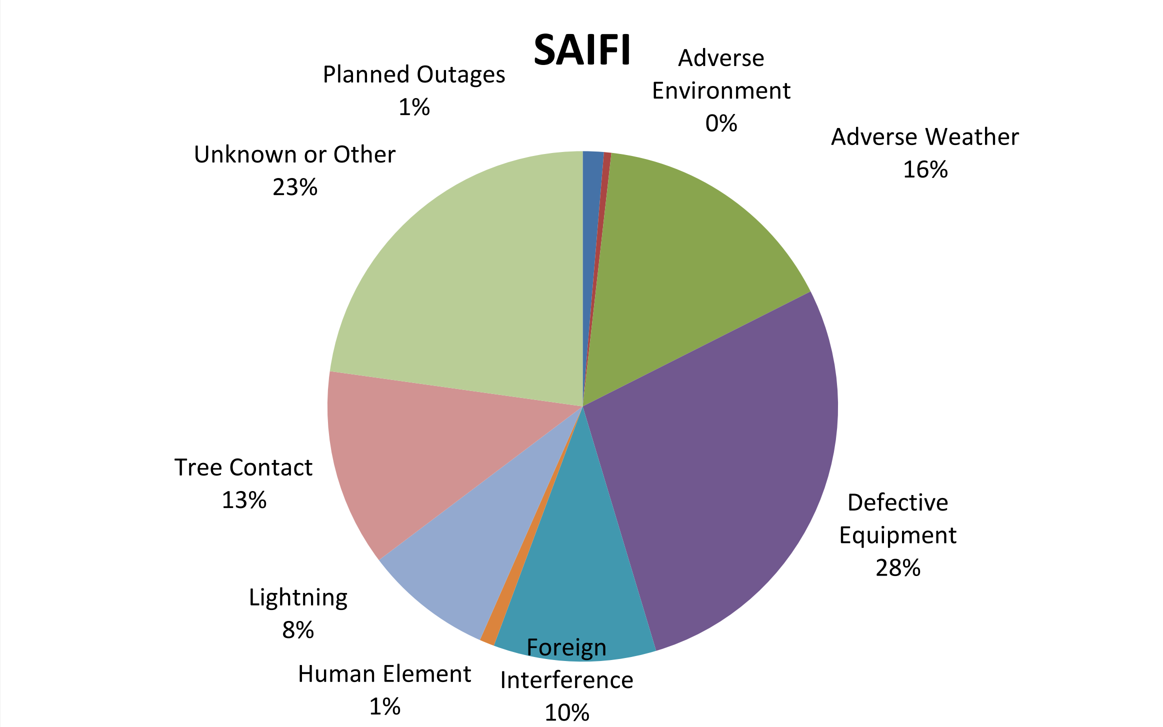


Figure 8.4: Contribution of Interruption Cause to Network SAIFI

SAIDI due to storm-related faults almost doubled in FYE2012 to 125.2 from 63.2 in FYE2011. Outside of this, defective equipment, foreign interference (faults caused by the actions of an external party) and tree contacts had the most significant impact on network performance during FYE2012. The increase in SAIFI from 4.9 in FYE2011 to 6.4 in FYE2012 is also indicative of increased storm activity, as storm-related outages tend to be widespread and affect large numbers of customers.

During FYE2012, the SAIDI contribution caused by faults on the 11kV network increased by 117.53 minutes, with the worst performing feeder of FYE2012 causing double the SAIDI of the worst performing feeder of FYE2011. This has been due to the significant level of storm activity that was experienced in April, May, June 2011 and March 2012. SAIDI for these four months totalled 250.96 minutes, which was 67% of the target for the full year. There has also been a small increase in the SAIDI impact of 11kV vegetation faults; however, these have generally been as a result of landslides and falls from outside of the vegetation control zone.

The increase in 11kV SAIDI has been offset by a reduction in 33kV SAIDI. The sub-transmission network was less affected by the storm related weather and showed an improvement of 118.25 SAIDI minutes between FYE2011 and FYE2012. This is discussed in Section 8.2.1.1.

TEN did not breach its reliability thresholds under the Commerce Commission’s price quality path during FYE2012, despite the significant storm activity that was experienced. This is not cause for satisfaction, as the Commission’s reliability thresholds were derived from an analysis of the historic network reliability experienced over the FYE2005-2009 period and therefore incorporate the very poor reliability reported in FYE2009 and FYE2010. The Commerce Commission thresholds are therefore set at a level significantly worse than the reliability the network is now routinely delivering and do not represent a level of reliability that TEN management now considers acceptable, even under adverse weather conditions.

A comparison of the FYE2012 supply reliability with the Commerce Commission’s regulatory thresholds is shown in the Table 8.4 below.

FYE 2012	SAIDI (MINUTES)	SAIFI
2010-15 Regulatory Quality Threshold	573.6	7.6
Actual reliability	435.0	6.4
Below 2010-2015 Regulatory Quality Threshold by:	**24%**	**16%**

Table 8.4: Comparison of FYE2012 supply reliability with regulatory threshold

While final figures are not available, in FYE2013, as noted above, the reliability of supply has shown a significant improvement over FYE2012 and it is expected that the ambitious targets set in the 2012 AMP (which are lower than the Commission's threshold levels) will be met.

8.2.1.1 Reliability by Voltage

Sub-transmission network

TEN is focusing its reliability improvement efforts on the sub-transmission system since, while it is operated in a radial configuration, sub-transmission network outages impact large numbers of consumers. As indicated above, 33kV network reliability significantly improved in FYE2012 compared to FYE2011 with a reduction in 33kV SAIDI of 118.25 minutes (75%). Whilst an increase in overall outage events as a result of storms and lightning was observed, outages resulting from defective equipment were reduced by 60%. This improvement is shown in Table 8.5.

CLASS	TYPICAL CAUSE	COUNT		SAIDI	
		FYE 2012	FYE 2011	FYE 2012	FYE 2011
Adverse Weather	Storm	2	1	13.4	7.0
Defective Equipment	Insulator Damage	4	10	4.9	84.6
Foreign Interference	Car vs. Pole	3	5	5.4	53.5
Human Element	Switching Interruption (Operational Failure)	0	2	0	3.4
Lightning	Lightning	4	0	9.5	0
Tree Contact	Tree Contact	1	0	1.1	0
Unknown	Unknown	2	2	4.9	9.0
	TOTAL:	**16**	**20**	**39.3**	**157.52**

Table 8.5: Top Energy 33kV Sub-transmission Fault Statistics FYE2012

Figure 8.5 and Table 8.6 rank TEN's 33kV feeders by their SAIDI performance respectively for FYE2012 and compare this performance with the corresponding performance in FYE2011.

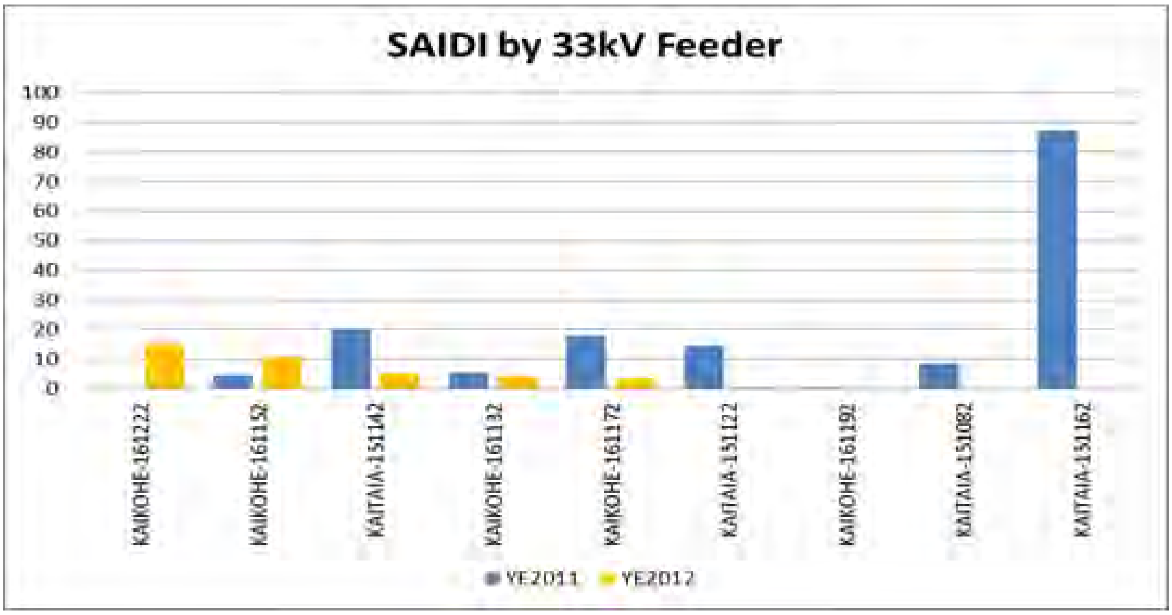


Figure 8.5: **SAIDI performance by 33kV feeder FYE2011 and FYE2012**

Feeder	FYE 2012		FYE 2011	
	SAIDI	% of Total	SAIDI	% of Total
Kaitaia 151162	0	0%	86.8	54.7%
Kaitaia 151142	5.3	13.4%	19.9	12.6%
Kaikohe 161172	3.5	9.0%	17.9	11.3%
Kaikohe 161222	15.0	38.2%	14.4	9.1%
Kaitaia 151082	0	0%	8.6	5.4%
Kaikohe 161132	4.4	11.2%	5.6	3.5%
Kaikohe 161152	10.9	27.6%	4.7	3.0%
Kaikohe 161192	0	0%	0.6	0.4%
Kaitaia 151122	0.3	0.6%	0	0%
Total:	**39.27**	**100%**	**158.622**	**100%**

Table 8.6: **Top Energy Network Worst Performing 33kV Feeders by SAIDI FYE2011 and FYE2012**

South Hokianga (Kaikohe-161222) was the worst performing 33kV feeder for FYE2012, where the SAIDI of 15 minutes was the result of two storm-related outages. The most improved 33kV feeder was Taipa 33 kV (Kaitaia-151162), which decreased from 87 SAIDI minutes in FYE2011 to zero in FYE2012. Generators have been installed at Taipa to limit the SAIDI impact of 33kV planned and unplanned outages, since there is only one incoming circuit to supply a load of almost 5MW.

Distribution Network

As also noted above, overall 11kV feeder performance deteriorated in FYE2012, primarily as a result of the increase in storm activity. Adverse weather outages and the resultant SAIDI was double that experienced in

FYE2011, with associated increases in both lightning and unknown faults. Nevertheless, even with the storm-related categories of adverse weather and lightning removed, the reliability of the network under normal weather conditions also deteriorated. The number of 11kV faults unrelated to storms (non-storm) increased from 369 in FYE2011 to 443 in FYE2012, an increase of 20% and non-storm 11kV SAIDI increased 24% from 221.0 minutes in FYE2011 to 273.6 minutes in FYE2012. Defective equipment on the 11kV network remains the predominant single cause of distribution network unreliability. This performance is summarised in Table 8.7.

CLASS	CAUSE	COUNT		SAIDI	
		FYE 2012	FYE 2011	FYE 2012	FYE 2011
Adverse Weather	Storm	80	42	114.87	56.24
Defective Equipment	Insulator Damage (Non Human Interference)	109	110	99.3	92.3
Foreign Interference	Car versus Pole	33	35	52.35	41.56
Human Element	Switching Interruption (Operational Failure)	3	2	4.3	1.84
Lightning	Lightning	22	8	9.9	3.6
Tree Contact	Tree Contact	60	55	56.26	45.7
Unknown	Unknown	71	36	46.05	18.91
Planned	Planned	167	131	15.42	20.77
	TOTAL:	**545**	**419**	**398.5**	**280.9**

Table 8.7: Top Energy 11kV Feeder Fault Statistics FYE2011 and FYE2012

The reliability of individual 11kV feeders is shown in Figure 8.6 and Table 8.8.

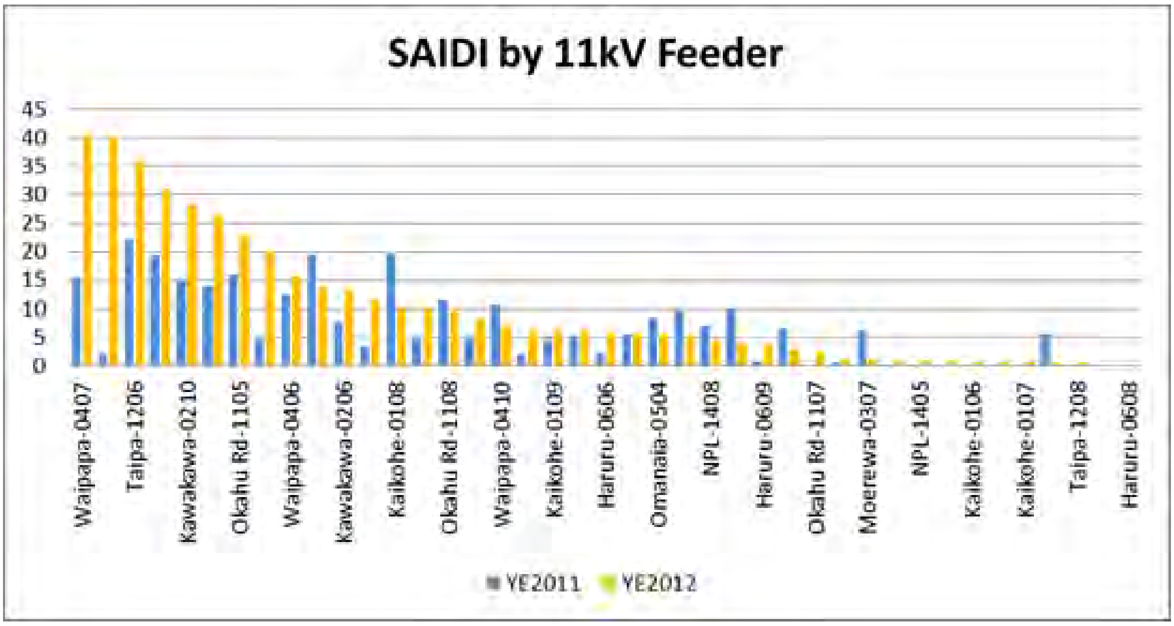


Figure 8.6: SAIDI performance by 11kV feeder FYE2011 and FYE2012

Feeder	FYE 2012		FYE 2011	
	SAIDI	% of Total	SAIDI	% of Total
Waipapa-0407	40.6	10.2%	16.0	5.7%
Taipa-1206	35.9	9.0%	22.1	7.9%
Taipa-1207	33.3	8.4%	2.0	0.7%
Omanaia-0506	31.0	7.8%	19.0	6.8%
Kaikohe-0111	26.5	6.6%	14.0	5.0%

Feeder	FYE 2012		FYE 2011	
	SAIDI	% of Total	SAIDI	% of Total
Okahu Rd-1105	22.5	5.6%	16.9	6.0%
Kawakawa-0210	20.1	5.0%	14.9	5.3%
Waipapa-0405	18.5	4.7%	4.6	1.7%
Waipapa-0406	15.7	3.9%	12.6	4.5%
Kaikohe-0105	14.7	3.7%	19.4	6.9%
Kawakawa-0206	13.3	3.4%	8.5	3.0%
Pukenui-1305	11.7	2.9%	9.9	3.5%
Kaikohe-0108	11.3	2.8%	19.6	7.0%
Waipapa-0408	10.1	2.5%	4.6	1.6%
Okahu Rd-1108	9.9	2.5%	11.4	4.1%
NPL-1406	8.2	2.1%	4.6	1.6%
Waipapa-0410	8.0	2.0%	10.6	3.8%
Okahu Rd-1110	7.2	1.8%	1.9	0.7%
Kaikohe-0109	6.8	1.7%	4.2	1.5%
Okahu Rd-1109	6.3	1.6%	5.1	1.8%
Haruru-0607	6.1	1.5%	9.6	3.4%
Pukenui-1306	6.0	1.5%	4.3	1.5%
Waipapa-0409	5.8	1.5%	5.5	2.0%
Omanaia-0504	5.6	1.4%	8.4	3.0%
NPL-1408	5.4	1.4%	7.0	2.5%
Haruru-0609	4.7	1.2%	1.6	0.6%
Kaikohe-0110	3.5	0.9%	6.5	2.3%
Okahu Rd-1107	2.6	0.7%	1.1	0.4%
Haruru-0606	2.6	0.7%	2.2	0.8%
Moerewa-0305	1.2	0.3%	0.7	0.2%
Moerewa-0307	1.1	0.3%	6.1	2.2%
Kawakawa-0208	0.7	0.2%	6.2	2.2%
Kaikohe-0107	0.6	0.2%	-	-
Taipa-1208	0.4	0.1%	-	-
Okahu Rd-1106	0.4	0.1%	-	-
Moerewa-0308	0.1	0.0%	-	-
Haruru-0608	0.0	0.0%	0.0	0.0%
Total:	**398.45**	**100%**	**280.92**	**100%**

Table 8.8: Top Energy Network Worst Performing 11kV Feeders by SAIDI FYE2011 and FYE2012

Whangaroa feeder (Waipapa -0407) was the worst performing 11kV feeder for FYE2012, with SAIDI increasing from 16.0 minutes to 40.6 minutes in FYE2012. This was as a result of the significant increase in storm weather activity within the rural parts of the region that this feeder serves. The FYE2011 worst performing feeder, Oruru (Taipa 1206), has seen an increase in SAIDI by 13.8 minutes. This is primarily as a result of a number of third-party incidents that occurred on this line during the year.

The top 10 worst performing feeders are identified each year based on the feeder SAIDI performance, but with feeder SAIFI performance also taken into consideration; these feeders are targeted for reliability improvement focused maintenance work. In this process, SAIDI performance has a higher priority than SAIFI for the selection. Nevertheless, 7 of the 10 worst feeders chosen in terms of SAIDI ranking are also in the worst 10 feeders in terms of SAIFI ranking, so SAIDI and SAIFI performance is fairly consistent. The top 10 worst performing feeders in FYE2012 are shown in Table 8.9.

FEEDER NAME	SAIDI	% OF TOTAL SAIDI	SAIFI	% OF TOTAL SAIFI
Whangaroa (Waipapa 0407)	40.6	10.2%	0.44	7.0%
Oruru (Taipa 1206)	35.9	9.0%	0.41	6.4%
Tokerau (Taipa 1207)	33.3	8.4%	0.39	6.2%
Opononi (Omanaia 0506)	31.0	7.8%	0.33	5.1%
Horeke (Kaikohe 0111)	27.4	6.6%	0.29	4.5%
South Rd (Okahu Rd 1105)	22.5	5.6%	0.28	4.4%
Russell (Kawakawa 0210)	20.1	5.0%	0.24	3.8%
Totara North (Waipapa 0405)	18.5	4.7%	0.22	3.5%
Riverview (Waipapa 0406)	15.7	3.9%	0.18	2.9%
South Hokianga 33kV	15.0	3.5%	0.10	1.5%

Table 8.9: Top ten worst ranking feeders FYE2012

These feeders are all subject to the expectation of significant improvement over the planning period as a result of the capital investment identified within this AMP. In particular:

- Russell will be substantially improved by the proposed installation of back-up generation and the new Paihia-Russell submarine cable;
- Whangaroa feeder will benefit from the installation of the new Kaeo substation and the improvements to the 33kV network;
- The South Road, Rangiahua, Oruru, Russell and Purerua feeders have been heavily targeted by the specific reliability projects and have had reclosers and sectionalisers installed to reduce the impact of faults since FYE2009;
- Te Kao, Opononi, Herekino and Oxford St feeders will all benefit from 11kV upgrades and the 33kV security of supply work planned; and
- TEN will continue with its extensive lines surveys and increased vegetation cutting programme on the above feeders.

8.2.1.2 Industry comparison

TEN has undertaken a benchmarking analysis of system reliability and performance indicators from within a justified peer group of rural and extensive rural New Zealand EDBs. The following criteria have been applied using the data from ELBs' FYE2011 Information Disclosures. This is the most recent comparative data available:

- larger than 15,000 customer base (i.e. eliminates small networks);

- less than 10 customers per km (i.e. eliminates urban/rural and dense urban networks); and
- underground cable contributes less than 10% of the total system length (high voltage and extra high voltage only, excluding low voltage circuits).

ELBs chosen for the peer group are the following:

- Alpine Energy
- Eastland Network
- Electricity Ashburton
- Horizon Energy Distribution
- MainPower New Zealand
- Marlborough Lines
- Northpower
- The Lines Company
- The Power Company

Figures 8.7 and 8.8 compare TEN's supply reliability in FYE2012 with others in its selected peer group. It shows that TEN continues to be the worst performing distribution network in the group. While TEN's SAIDI was marginally better than that of Eastland Network, TEN's SAIFI was 40% higher. The network development and maintenance initiatives discussed in Sections 5 and 6 of this AMP are designed to deliver a level of reliability close to, or below, the peer group average.

This is unlikely to be achievable with an annual planned shutdown of the single 110kV transmission circuit between Kaikohe and Kaitaia. However, after the second circuit is commissioned in FYE2017, this annual shutdown will not cause a supply outage and SAIDI will therefore be reduced by a capped 56 minutes. As indicated in Figure 8.1, TEN is projecting a year end SAIDI of 327 minutes in FYE2013. If this is reduced by 56 minutes when an annual shutdown of the northern part of the area is no longer required, the projected SAIDI would reduce to 271 minutes. This is much closer to the current peer group average of 247 minutes shown in Figure 8.7. The distribution system initiatives discussed in Sections 5 and 6 are expected to close the remaining gap.

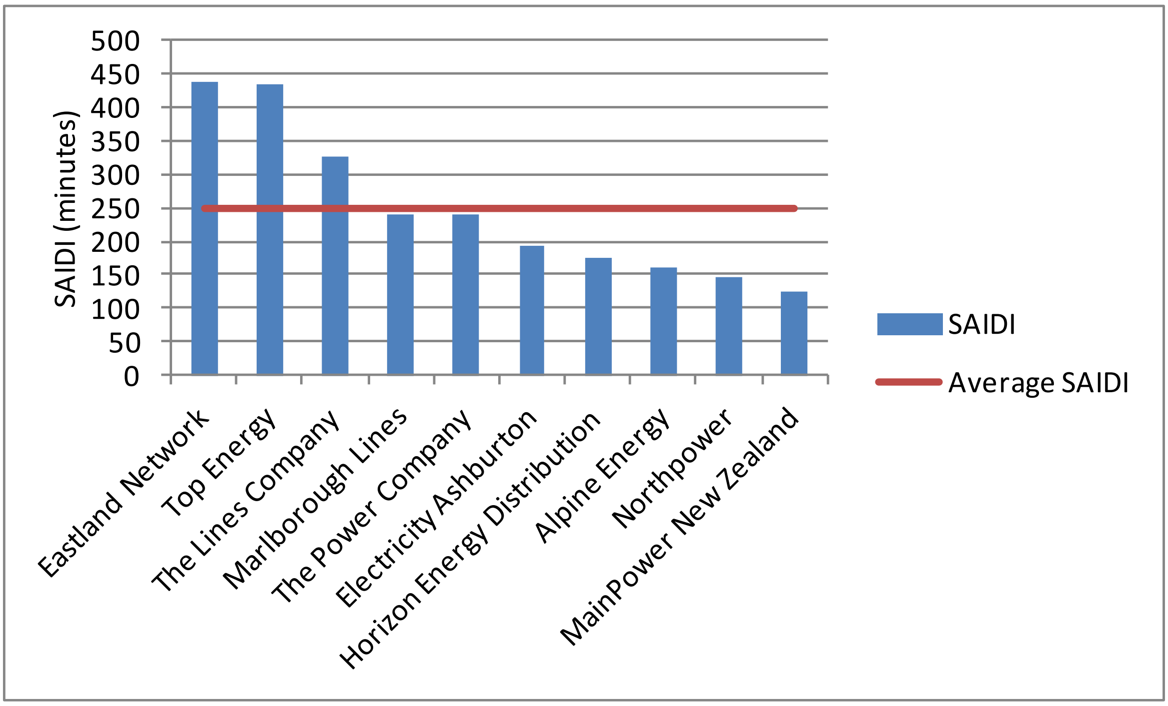


Figure 8.7: Comparative SAIDI Performance (FYE2012)

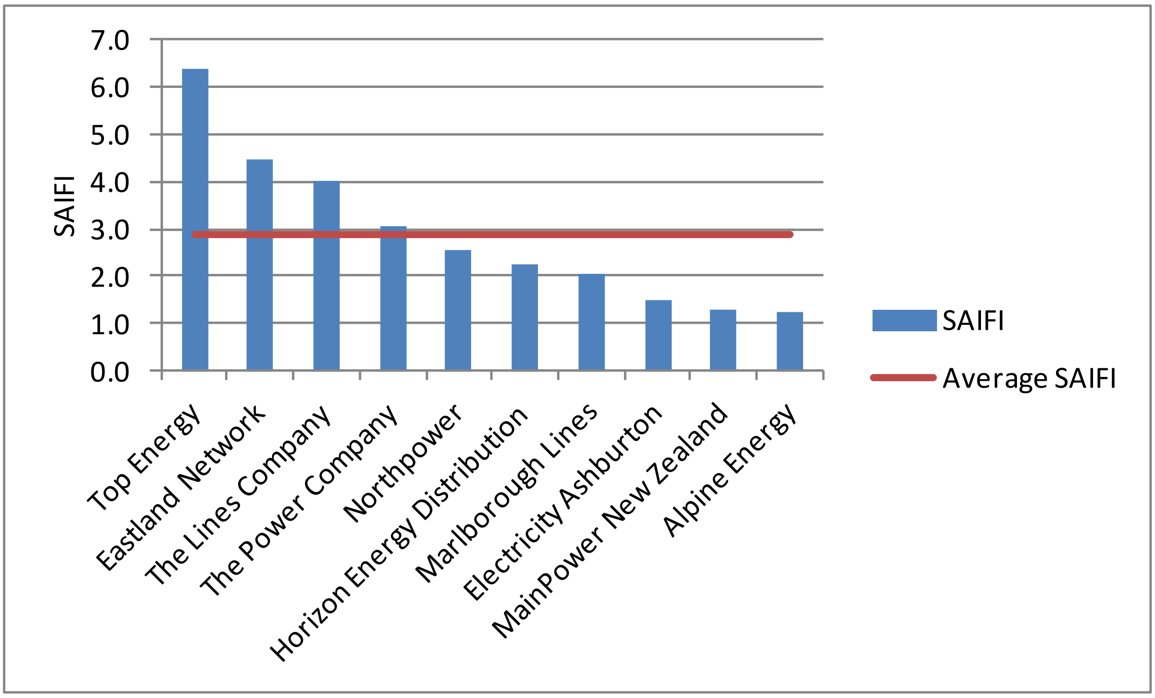


Figure 8.8: Comparative SAIFI Performance (FYE2012)

8.2.2 Asset Performance and Efficiency

Table 8.9 compares TEN's achieved asset performance and efficiency measures in FYE2012 with the target levels set out in the 2011 AMP.

PERFORMANCE MEASURE	FYE 2012 TARGET	ACTUAL PERFORMANCE	VARIANCE
Loss Ratio	8%	8.5%	+0.5%
Operational Expenditure Ratio	4.75%	4.84%	+0.09%

Table 8.10: Comparison of actual asset performance and efficiency with target levels for FYE2012

As indicated by the table, neither target was met in FYE2012; notwithstanding the fact that, for both measures, TEN's performance ranks amongst the worst of any EDB in the country. While TEN expects this performance to improve in the medium-term, it has not identified any "silver bullet" that would deliver a sustained short-term improvement in performance against either measure.

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 the TEN network has the lowest reliability and the highest loss ratio of any EDB in the country. Implementation of the network development plan described in Section 5 of this AMP should bring about an improvement in the loss ratio and TEN remains confident that its longer-term target of reducing the loss ratio to 6.5% by FYE2022 is achievable.

Maintenance expenditure represents 46% of total OPEX and is a significant cause of the high operational expenditure ratio. The ongoing programmes to improve reliability, such as the vegetation management initiative, are not without cost and this is reflected in the relatively poor performance. Over time, the operational expenditure ratio should reduce, as reliability targets are achieved and maintenance expenditure is reduced to more sustainable levels; this is indicated in the maintenance OPEX profile shown in Figure 6.2. Furthermore, the addition of new assets as a result of the network development plan will also drive down the operational expenditure ratio due to the increase in asset replacement cost.

8.2.3 Financial and Physical Performance

A comparison of TEN's actual expenditure in FYE2012 for both network CAPEX and network maintenance with the budgeted expenditures, as presented in the 2011 AMP is provided in Table 8.11. Variances between actual and budgeted expenditures are discussed in detail in Sections 8.2.3.1 and 8.2.3.2 below.

EXPENDITURE CATEGORY	AMP BUDGET FYE 2012	ACTUAL SPEND FYE 2012	VARIANCE	
Capital expenditure ($000)				
Customer connection	1,000	1,571	571	57.1%
System growth	6,686	6,904	218	3.3%
Asset replacement and renewal	4,085	3,101	(984)	(24%)
Reliability, safety and environment	5,393	7,948	2,555	47.4%
Asset relocations	175	-		-
Subtotal – Capital expenditure	**17,339**	**19,524**	**2,185**	**12.6%**
Maintenance expenditure ($000)				
Routine and preventive	4,100	3,779	(321)	(7.8%)
Refurbishment and renewal	1,078	1,312	234	21.7%
Fault and emergency	900	1,737	837	93.0%
Subtotal – Maintenance expenditure	**6,078**	**6,828**	**750**	**12.3%**
TOTAL DIRECT NETWORK EXPENDITURE	**23,417**	**26,352**	**2,935**	**12.5%**

Table 8.11: Comparison of actual and budget network CAPEX and network maintenance OPEX for FYE2012

8.2.3.1 Network Capital Expenditure

The actual FYE2012 CAPEX shown in Table 8.11 is taken from TEN's 2012 information disclosure, which indicates over-expenditure of $2.19 million or 12.6%. However, the actual customer connection CAPEX spend of $1.57 million was fully recovered from capital contributions and was therefore not provided for in the AMP budget, which provided only for expenditure funded by TEN. Budgeted expenditure on customer connections has, in reality, been absorbed into the system growth and the reliability, safety and environment cost categories. This has identified a discrepancy between TEN's network budgeting (undertaken internally within TEN) and its financial reporting (undertaken by Top Energy's corporate finance division). This will be addressed in FYE2014.

If the customer connection CAPEX is backed out, the actual FYE2014 CAPEX reduces to under $18.0 million and is only 3.5% higher than the budgeted $17.3 million. This total CAPEX overrun was due to the 47% cost overrun in the reliability, safety and environment cost category, which can in turn be attributed to two projects:

- the costs of the first stage of the Kaikohe-Wiroa 110kV double circuit line were higher than forecast, primarily because the costs were under-estimated. The costs of all 110kV lines in the network development plan in this AMP have been updated and the forecasts incorporate more realistic cost estimates; and
- the second line to the Ngawha geothermal plant encountered unforeseen design and construction issues relating to both the line and its associated protection systems. While these have now been addressed, additional costs were incurred as a result of these problems.

When the customer connection adjustment is allowed for, the system growth CAPEX was lower than expected due to the flattening of demand growth below historic levels. TEN was also forced to defer some asset replacement and renewal CAPEX in order to manage the budget overrun.

Table 8.12 below indicates progress made in implementing projects identified in the 2011 AMP as being undertaken in FYE2012.

Project ID	Description	Actual Performance
Transmission and Sub-transmission Line Projects		
-	Second 33kV line to Ngawha geothermal power plant	Construction completed and due for commissioning in Feb/March 2013
8010	New 110kV Kaikohe-Wiroa line. Stage 1	Completed to Hariru Rd and livened at 33kV
8013	New 110kV Kaikohe-Wiroa line. Stage 2	Delayed by finalisation of route negotiations. Commenced November 2012
-	Waipapa No 1 line refurbishment	Completed
Transmission and Sub-transmission Substation Projects		
-	Wiroa - land purchase and consent	Completed FYE2013
-	Okahu Rd - ground fault neutraliser installation	Installed and operating; full commissioning pending
6070	Pukenui - new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
6069	Taipa - new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
7109	Taipa - new transformer protection panels	Project cancelled as a consequence of decision to build new 110kV substation
7017	NPL - line protection for new 33kV Pukenui tap-off feeder	Completed FYE2013
6071	NPL – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
-	Kaikohe - ground fault neutraliser installation	Project cancelled
6062	Kaikohe – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
-	Kawakawa – ground fault neutraliser installation	Installed and operating; full commissioning pending
6063	Kawakawa – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
-	Moerewa – ground fault neutraliser installation	Project cancelled
6064	Moerewa – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
-	Haruru – ground fault neutraliser installation	Project cancelled
6067	Haruru – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
-	Waipapa – New feeder circuit breaker for Waipapa business centre	Deferred until feeder route secured

Project ID	Description	Actual Performance
6014	Waipapa – four 750kVAr switched capacitor banks	Cancelled due to the construction of Kerikeri substation
-	Waipapa – 33kV busbar and protection upgrade	Cancelled pending Waipapa outdoor-indoor conversion now scheduled for FYE2018
6065	Waipapa – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
7106	Waipapa – lower transformers to ground and bunding	Deferred – now scheduled for FYE2018
7032	Omanaia – Feeder protection upgrade	To be completed in FYE2014
6066	Omanaia – new security cameras	Deferred pending review of the implications of adopting a cloud communications approach
6072	Omanaia – substation tap-in before boosters for alternative 11kV feed from Taheke feeder (Kaikohe substation)	Completed
7033	Omanaia – transformer protection upgrade	Completed
Distribution Network Projects		
6126	Convert Te Hapua SWER line to 3 wire	Completed
7099	Upgrade all $50mm^2$ copper conductor exiting Kawakawa substation to bee conductor	Two feeders completed. Remaining feeders to be completed in FYE2015
7105	Install new feeder to existing 33kV line. Take load off Russell feeder. Move some load off Opua feeder	Partially complete. Final stage to be completed in FYE2014
9001	Install cable for new feeder to Waipapa business centre	Deferred until feeder route can be secured
8037	Install new voltage regulators on Purerua feeder	Deferred until load growth warrants it
8039	Install new voltage regulators on Riverview feeder	Cancelled due to construction of Kerikeri substation

Table 8.12: Progress on implementing projects identified in the 2011 AMP for installation in FYE2012

The above table indicates a reasonable attainment of major project targets. With improved data streams becoming available to the asset management team, it is not surprising that a number of projects have been reprioritised and new projects have been identified. TEN plans to continue to reduce the risk of disruptions and to directly improve the alignment between budget and expenditure in the future.

8.2.3.2 Network Maintenance Expenditure

As shown in Table 8.11, maintenance expenditure was $2.94 million or 12.5% over budget. This was caused by an overrun of $840,000 in the cost of responding to unplanned faults and other emergency maintenance, which in turn was a result of the adverse weather conditions experienced in FYE2012. TEN has no control over the weather. The high level of non-weather related equipment failures was also a contributing factor. This is a result of the existing network condition and will take time to address. These factors were also responsible for the budget overrun in refurbishment and renewal maintenance.

TEN found it necessary to reduce expenditure on routine and preventive maintenance in order to manage the overall expenditure overrun.

8.3 Asset Management Improvement Programme

TEN's asset management strategy is one of seeking continuous improvement across the range of knowledge building and decision-making that it is involved with. TEN proposes to build on its present knowledge base to refine the options that it will pursue to address the multiple and, sometimes conflicting, solutions available to provide the desired level of service.

TEN has committed to aligning its asset management processes to the UK Publicly Available Specification PAS 55. To this end, in early 2012 TEN commissioned Asset Management Consulting Limited (AMCL) to perform a gap analysis review of its current level of asset management maturity against the PAS55 requirements.

AMCL concluded that TEN is undergoing significant organisational change in order to deliver an ambitious network development plan. Senior management commitment to best practice asset management is clear and the organisation is being re-configured and expanded based on this commitment. However, the asset management system is not sufficiently defined or demonstrably effective, although many key elements are in place. The AMP provides an excellent anchor for the development of an effective asset management strategy. TEN's main challenge is to develop and embed the asset management system and its associated processes through a programme of organisational and cultural change, which must include not only TEN but also TECS.

The gap analysis assessment concluded that TEN is compliant with four of the 24 clauses of PAS 55, partially compliant for 16 out of 24 clauses, and four clauses have been assessed as non-compliant. However, AMCL also concluded that there were no significant issues which could not be resolved prior to a certification audit (programmed for FYE2015) considering that the process of change is already well underway.

8.3.1 Asset Management Maturity

AMCL undertook its gap analysis using its asset management excellence model (AMEM), which assesses asset management capability and maturity, and benchmarks it against world best practice. The AMEM tests the existence, completeness, effectiveness and integration of asset management activities and is applicable to any organization operating in an asset intensive, highly regulated environment.

Organisations are scored against each of the 23 AMEM activities using a range of assessment criteria. The scores are presented using the maturity scale shown in Figure 8.9, which in turn is based on the scale described in the International Infrastructure Management Manual[3]. AMEM results are used to identify and prioritise improvements based on where an organization sits relative to world best practice. The AMEM is fully mapped to the requirements of PAS 55 and covers everything that the PAS 55 assessment methodology tool does, but in greater detail. This means that assessments using the AMEM are entirely consistent with those undertaken using the PAS 55 assessment tool, which has been used by the Commerce Commission in developing its Asset Management Maturity Assessment Tool (AMMAT). Subsequently, the results of the detailed independent AMCL AMEM review have been presented as evidence in completing the AMMAT for disclosure purposes. TEN's AMMAT assessment is presented in Schedule 13 of Appendix A of this AMP.

[3] The International Infrastructure Management Manual (IIMM) is published in the UK by the Institute for Asset Management. See www.theiam.org.

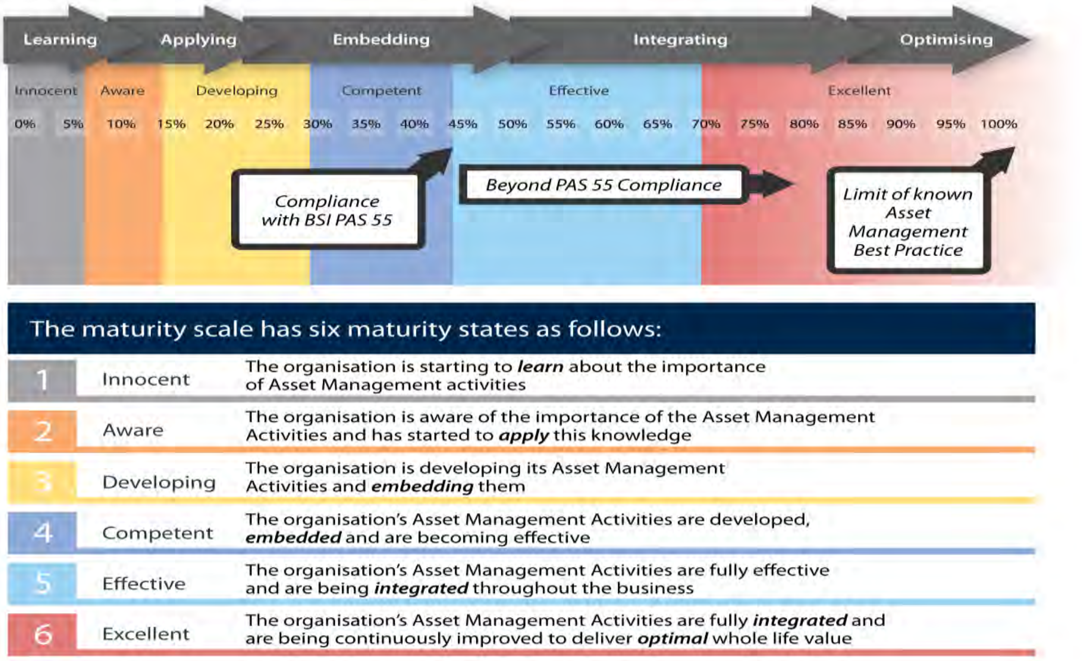


Figure 8.9: The AMEM asset management maturity scale

8.3.2 Gap Analysis Maturity Findings

Figure 8.10 below shows TEN's current asset management maturity, as assessed by AMCL, against each of the requirements of PAS 55. The "competent" band, which ranges between 30%-45% on the scale, signifies an organisation whose asset management processes are largely developed, being embedded and becoming effective. The top of this "competent" maturity band, 45% on the scale, represents the level where an organisation is compliant with PAS 55. TEN has matured to within the "competent" band for all requirements of the PAS 55 asset management framework. To achieve PAS 55 compliance, TEN needs to complete the development, integration and embedding of asset management practice to a level where it transitions into the competent band for all elements of the PAS 55 framework.

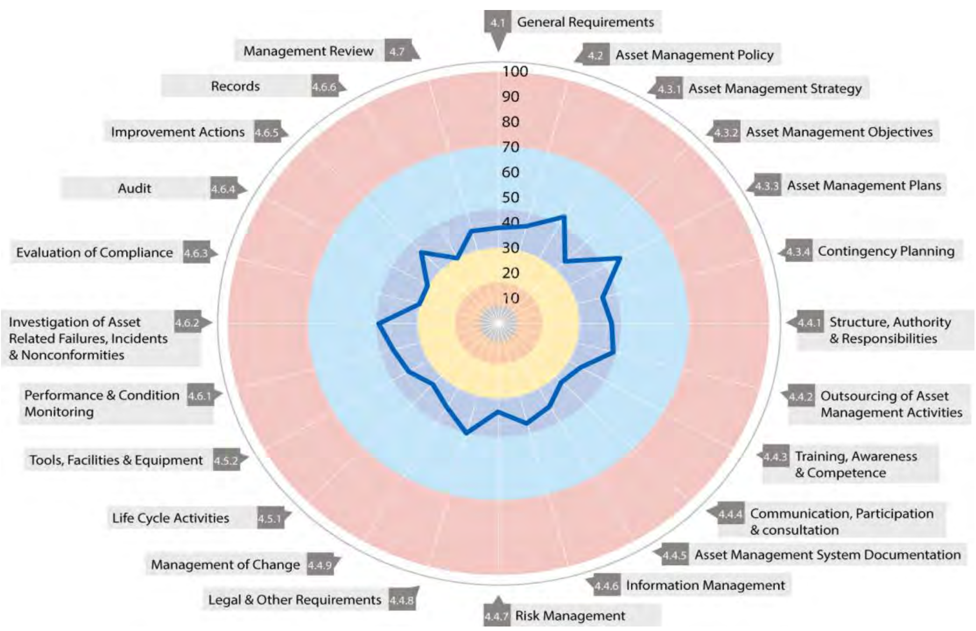


Figure 8.10: Top Energy's maturity scores by PAS 55 requirements

8.3.3 Future Actions

The numbers of associated improvement actions for each clause identified by AMCL are shown in Table 8.13 below. The majority of these actions are of a procedural development nature; however the key 15 strategic improvement actions together with timeframes for implementation are detailed in Table 8.14.

PAS55 Clause	Number of Activities
4.1- General Requirements	2
4.2- Asset Management Policy	4
4.3 - Asset Management Strategy, Objectives & Plans	11
4.4 - Asset Management Enablers & Controls	27
4.5 - Implementation of Asset Management Plans	5
4.6 - Performance Assessment & Improvement	18
4.7 - Management Review	1
TOTAL	**68**

Table 8.13: Number of improvement actions identified by AMCL

PAS 55 Clause / Summary of Findings	AMCL Maturity Assessment	Key Actions Required	Target End
4.3.2 AM Objectives Asset management objectives exist but are not clearly defined	35%	Derive no more than 10 top-level asset management objectives to support the asset management strategy.	April 2014
4.3.4 Contingency Planning Current contingency plans (Emergency Preparedness Plan) are not formally rehearsed with stakeholders.	40%	Define, implement, review and rehearse Emergency Preparedness Plan processes which include all relevant stakeholders as required.	Sept 2014
4.4.1 Structure, Authority and Responsibilities Not enough clarity with respect to roles and responsibilities within TEN and TECS.	41%	Complete the current reorganisation of TECS, concentrating on embedding the roles, organisation and interfaces of TECS in delivering the AMP and the interfaces between the two parts of Top Energy.	June 2014
4.4.2 Outsourcing of Asset Management Activities Sourcing strategy needs to properly embed.	44%	Continue the implementation and embedding of the sourcing strategy and ensure compliance with existing processes and procedures can be demonstrated.	June 2014
4.4.3 Training, Awareness and Competence Effective management of competence and the forward forecasting of resources.	35%	Define an asset management competence framework which defines the levels of competences for each role in TEN required to run the asset management system. Develop a future asset management resources forecast to meet the requirements of the asset management system and sourcing strategy.	June 2014
4.4.4 Communication, Participation and Consultation Communication, Participation and Consultation between the middle and lower levels of TEN and TECS is not as effective as it should be.	32%	Develop and implement an asset management communication, consultation and participation plan delivered through all existing TEN channels (briefings, intranet, newsletter, email etc.) which supports the current re-organisation. Integrate with proposed PAS55 manual.	June 2014
4.4.5 Asset Management System Documentation The population of the new TEN document hierarchy is not complete.	39%	Define, risk assess, and develop the required documentation to fill the policy, procedure and work instruction levels of TEN document hierarchy according to asset management system need.	June2014

PAS 55 Clause / Summary of Findings	AMCL Maturity Assessment	Key Actions Required	Target End
4.4.6 Information Management Field maintenance and inspection work management systems is not as effective as it should be.	41%	Complete the implementation of the defect database and associated processes and procedures. Set targets for the accuracy and currency of defect data, and monitor these until they are achieved. Complete the implementation of a work management system for maintenance and inspection activities (SAP). Ensure the full engagement of TECS in this process.	June 2014
4.4.7 Risk Management Differing Risk Management Policies.	35%	Define a single risk management policy that integrates the three existing risk frameworks (PSMS, workplace safety, and asset risk). Develop procedures which integrate risk management into lifecycle asset management and delivery processes.	June 2014
4.4.9 Management of Change No overall change management process clearly defined.	39%	Develop an overall procedure for the management of change which incorporates risk assessment of changes to the assets and changes to the asset management system as appropriate.	June 2014
4.5.1 Lifecycle Activities Work management control problems related to field delivery of maintenance, inspection and defect management activities.	35%	Ensure that TEN is able to demonstrate that the implementation of the AMP is fully aligned to the asset management policy, strategy and objectives and that activity on the ground within TECS is under full management control. (Linked to 4.4.1 and 4.4.3)	March 2015
4.5.2 Tools, Facilities and Equipment Equipment calibration is fully outsourced not well documented.	39%	Determine what vehicles, plant, tools and test equipment should be included and develop an overall equipment register (possibly in conjunction with TEX Onsite) which is managed centrally within TECS. Consider roles of Smart-Track and SAP in supporting this process.	June 2014
4.6.4 Audit There is no central audit capability or regime focused on the AM System.	30%	Develop and implement an internal compliance auditing process for asset management and an audit plan focused on the newly defined asset management system and PAS55.	June 2014
4.6.6 Records Quality of records relating to maintenance, inspection and defect management.	30%	Ensure records held within TEN and TECS relating to field maintenance, inspection and defect management are current, accurate and timely.	March 2015

PAS 55 Clause / Summary of Findings	AMCL Maturity Assessment	Key Actions Required	Target End
4.7 Management Review There is no overall management review system focused on the asset management system.	38%	Develop and implement an overall management review process, aligned with the asset management system, which includes (but is not limited to) business performance information, information from audits, corrective and preventive actions, and other sources of management information.	June 2014

Table 8.14: Summary of Key Findings and Required Actions by PAS55 Clause

EVALUATION OF PERFORMANCE

Whilst a more rounded and mature asset management culture has been established within the company, there is still significant work to undertake to achieve full PAS 55 compliance. TEN has embarked on formal certification in order to demonstrate continual improvement and comparability against international best-practice as part of its annual disclosures.

TEN believes that it is the only New Zealand lines company proactively seeking full PAS 55 certification at this time.

Certification to PAS 55 should give our stakeholders the confidence that the asset management processes within TEN are of an international best-practice standard and are continually being monitored and improved.

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

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), sub-transmission (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.
Sub-transmission	Circuits carrying electricity at 33kV (in TEN's case) from the transmission substations at Kaikohe and Kaitaia to TEN's zone substations.

Zone substation	A TEN 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 used by TEN. 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	TEN sizes its 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. TEN's 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 TEN 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 TEN considers 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 sub-transmission 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 customers' 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 sub-transmission 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, including those that supply TEN. 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 customer 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 customer
CAIDI:	Customer 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 customer 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 Requirements of Attachment A of the Electricity Information Disclosure Determination 2012

Handbook Reference	Requirement	TEN 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	
Iii	- what these interests are;	2.6.3	

Handbook Reference	Requirement	TEN AMP Ref	Comment
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			
3.10	To support the AMMAT disclosure, the AMP must include an overview of asset management strategy and delivery.	2.11	

Handbook Reference	Requirement	TEN AMP Ref	Comment
Asset Management Data			
3.11	To supprt the AMMAT disclosure, the AMP must include an overview of the processes for managing asset management data; and	2.8, 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	TEN 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] sub-transmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the sub-transmission network;	3.1.5, 3.1.6 Table 3.1	
4.2.2	- the extent to which individual zone substations have N-x sub-transmission 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	TEN 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	Sub-transmission	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 TEN network asset and is not part of this AMP.
Service Levels			

Handbook Reference	Requirement	TEN 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 TEN measures these indiators by feeder to assist it 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	TEN 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	TEN 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 TEN has 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	TEN 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	TEN AMP Ref	Comment
13.2	development, maintenance and renewal policies that cover them;	6.25	TEN does not consider its 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	TEN 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;		
16.2	- the organisation structure and the processes for organisation and business capabilities will support the implementation of the AMP plans.		

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 11–13

Company Name	Top Energy Ltd
Disclosure Date	31 March 2013
AMP Planning Period Start Date (first day)	1 April 2013

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 2.0. Prepared 15 November 2012

Table of Contents

Disclosure Template Guidelines for Information Entry

These templates have been prepared for use by EDBs when making disclosures under subclauses 2.6.1(4), 2.6.1(5) and 2.6.5(5) of the Electricity Distribution Information Disclosure Determination 2012. Disclosures made under subclauses 2.6.1(4) and 2.6.1(5) must be made before the start of each disclosure year. Disclosures made under subclauses 2.6.5(5) must be made within 5 months after the start of the disclosure year. With the exception of Schedule 12b(ii) discussed below, the information disclosed under 2.6.5(5) should be identical to that disclosed under 2.6.1(4) and 2.6.1(5).

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the first day of the 10 year planning period should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (planning period start date) is used to calculate disclosure years in the column headings that show above some of the tables. It is also used to calculate the AMP planning period dates in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell. Under no circumstances should the formulas in a calculated cell be overwritten.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to guard against errors in data entry, some data entry cells test entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names or to values between 0% and 100%. Where this occurs, a validation message will appear when data is being entered.

Conditional Formatting Settings on Data Entry Cells

Schedule 12a columns G to K contains conditional formatting. The cells will change colour if the row totals do not add to 100%.

Inserting Additional Rows

The templates for schedules 11a, 12b and 12c may require additional rows to be inserted in tables marked 'include additional rows if Additional rows must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
For schedule 12b the formula for column J will need to be copied into the inserted row(s).

Schedule 12b(ii)

The purpose of schedule 12b(ii) is to disclose transformer capacity as at the end of the current year. Because the information may not be available in time for disclosures made under subclause 2.6.1(4), but available for disclosures made under 2.6.5(5), the Commission intends to consider issuing an exemption from disclosing schedule 12b(ii) under subclause 2.6.1(4). Accordingly, the Excel template has been modified to allow the value "N/A" to be entered into these input cells.

Schedule 12d Report Forecast Interruptions and Duration sub-network disclosures

If the supplier has sub-networks, schedule 12d must be completed for the network and for each sub-network. A copy of the schedule 12d worksheet must be made for each sub-network.

Schedule 13 Report on Asset Management Maturity

The name of the standard applied (eg, 'PAS55') must be entered in cell K4.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7													
8		for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		1,045	1,045	1,072	1,[illegible]99	1,127	1,162	1,186	1,216	1,248	1,286	1,319
11	System growth		11,822	9,420	1,492	5,104	6,599	11,006	7,835	4,517	3,124	5,593	5,962
12	Asset replacement and renewal		3,000	8,195	7,[illegible]54	5,013	6,419	8,506	9,175	12,674	10,917	9,263	7,907
13	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:												
15	Quality of supply		6,597	5,785	11,837	11,333	9,080	1,815	2,[illegible]81	2,364	1,919	478	1,086
16	Legislative and regulatory		-	-	-	-	-	-	-	-		-	-
17	Other reliability, safety and environment		-	100	446	163	113	63	545		-	61	1,306
18	**Total reliability, safety and environment**		6,597	5,885	12,283	11,496	9,193	1,878	3,325	2,364	1,919	539	2,393
19	**Expenditure on network assets**		22,464	24,546	22,701	22,713	23,339	22,552	21,521	20,771	17,208	16,680	17,581
20	Non-network assets		400	400	256	263	270	277	284	291	298	306	314
21	**Expenditure on assets**		22,864	24,946	22,957	22,976	23,609	22,828	21,805	21,062	17,506	16,986	17,895
22													
23	*plus* Cost of financing			209	461	1,279	2,135						
24	*less* Value of capital contributions		800	800	1,000	1,025	1,051	1,077	1,104	1,131	1,160	1,189	1,218
25	*plus* Value of vested assets		500	500	513	525	538	552	566	580	594	609	624
26													
27	**Capital expenditure forecast**		22,564	24,855	22,931	23,755	25,232	22,303	21,267	20,510	16,941	16,407	17,301
28													
29	Value of commissioned assets		19,714	21,496	11,942	12,526	54,974	22,303	21,267	20,510	16,941	16,407	17,301

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
30		for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
32			**$000 (in constant prices)**										
33	Consumer connection		1,045	1,045	1,045	1,045	1,045	1,050	1,045	1,045	1,045	1,050	1,050
34	System growth		11,822	9,420	1,455	4,852	6,117	9,946	7,080	3,8[illegible]0	2,617	4,568	4,748
35	Asset replacement and renewal		3,000	8,195	7,658	4,766	5,950	7,687	8,084	10,[illegible]8	9,144	7,564	6,296
36	Asset relocations		-	-	-	-	-	-					
37	Reliability, safety and environment:												
38	Quality of supply		6,597	5,785	11,541	10,773	8,416	1,640	2,450	2,031	1,607	390	865
39	Legislative and regulatory		-	-	-	-	-	-					
40	Other reliability, safety and environment		-	100	435	155	105	57	480			50	1,040
41	**Total reliability, safety and environment**		6,597	5,885	11,976	10,928	8,521	1,697	2,930	2,031	1,607	440	1,905
42	**Expenditure on network assets**		22,464	24,546	22,133	21,591	21,632	20,380	19,139	17,843	14,413	13,622	13,999
43	Non-network assets		400	400	250	250	250	250	250	250	250	250	250
44	**Expenditure on assets**		22,864	24,946	22,383	21,841	21,882	20,630	19,389	18,093	14,663	13,872	14,249
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses												
48	Overhead to underground conversion												
49	Research and development												

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2013 – 31 March 2023

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

sch ref

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
57												
58	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
59	**Difference between nominal and constant price forecasts**	$000										
60	Consumer connection	-	-	27	54	82	112	141	171	203	236	269
61	System growth	-	-	37	252	483	1,060	755	637	507	1,025	1,215
62	Asset replacement and renewal	-	-	196	248	470	819	1,091	1,786	1,773	1,698	1,611
63	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
64	Reliability, safety and environment:											
65	Quality of supply	-	-	296	560	664	175	331	333	312	88	221
66	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment	-	-	11	8	8	6	65	-	-	11	266
68	**Total reliability, safety and environment**	-	-	307	568	672	181	395	333	312	99	488
69	**Expenditure on network assets**	-	-	568	1,121	1,707	2,172	2,382	2,927	2,795	3,058	3,582
70	Non-network assets	-	-	6	13	20	27	34	41	48	56	64
71	**Expenditure on assets**	-	-	574	1,134	1,727	2,199	2,416	2,968	2,843	3,114	3,646
72												

11a(ii): Consumer Connection

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
74	**11a(ii): Consumer Connection**						
75	*Consumer types defined by EDB**	$000 (in constant prices)					
76	All	1,045	1,045	1,045	1,045	1,045	1,050
77							
78							
79							
80							
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	1,045	1,045	1,045	1,045	1,045	1,050
83	*less* Capital contributions funding consumer connection						
84	**Consumer connection less capital contributions**	1,045	1,045	1,045	1,045	1,045	1,050

11a(iii): System Growth

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
85	**11a(iii): System Growth**						
86	Subtransmission	4,455	4,922	765	1,020	2,215	2,636
87	Zone substations	4,676	3,028	535	3,723	3,2[illegible]7	6,340
88	Distribution and LV lines	2,691	1,460	155	109	615	970
89	Distribution and LV cables		10	-	-	-	-
90	Distribution substations and transformers						
91	Distribution switchgear						
92	Other network assets						
93	**System growth expenditure**	11,822	9,420	1,455	4,852	6,117	9,946
94	*less* Capital contributions funding system growth						
95	**System growth less capital contributions**	11,822	9,420	1,455	4,852	6,117	9,946

Company Name	Top Energy Ltd
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SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
104		for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
105	**11a(iv): Asset Replacement and Renewal**		$000 (in constant prices)					
106		Subtransmission	206	800	506	374	1,701	1,249
107		Zone substations	-	4,035	4,690	2,259	1,723	1,896
108		Distribution and LV lines	2,794	1,673	1,173	1,017	1,015	2,843
109		Distribution and LV cables	-	200	200	174	173	179
110		Distribution substations and transformers	-	1,287	887	769	768	1,117
111		Distribution switchgear	-	200	200	174	569	404
112		Other network assets						
113		**Asset replacement and renewal expenditure**	3,000	8,195	7,658	4,766	5,950	7,687
114	*less*	Capital contributions funding asset replacement and renewal						
115		**Asset replacement and renewal less capital contributions**	3,000	8,195	7,658	4,766	5,950	7,687
116	**11a(v):Asset Relocations**							
117		*Project or programme**						
118								
119								
120								
121								
122								
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes						
125		**Asset relocations expenditure**	-	-	-	-	-	-
126	*less*	Capital contributions funding asset relocations						
127		**Asset relocations less capital contributions**	-	-	-	-	-	-
128								
129	**11a(vi):Quality of Supply**							
130		*Project or programme**						
131		Wiroa-Kaitaia 110kV line	2,850	3,359	10,721	10,688	6,040	
132		Protection and communications	707	1,454	202		808	90
133		Feeder Interconnections			175	85	1,186	899
134		Remote control switches					212	651
135								
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes	3,040	972	443		170	
138		**Quality of supply expenditure**	6,597	5,785	11,541	10,773	8,416	1,640
139	*less*	Capital contributions funding quality of supply						
140		**Quality of supply less capital contributions**	6,597	5,785	11,541	10,773	8,416	1,640
141								
142	**11a(vii): Legislative and Regulatory**							
143		*Project or programme**						
144								
145								
146								
147								
148								
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes						
151		**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory						
153		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Company Name	Top Energy Ltd
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SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
161							
162	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
163	**11a(viii): Other Reliability, Safety and Environn**						
164	*Project or programme**	$000 (in constant prices)					
165	Zone substation security		15	75	155		
166	Transformer bunding			75		105	57
167							
168							
169							
170	**include additional rows if needed*						
171	All other reliability, safety and environment projects or programmes		85	285			
172	**Other reliability, safety and environment expenditure**	-	100	435	155	105	57
173	*less* Capital contributions funding other reliability, safety and environment						
174	**Other reliability, safety and environment less capital contributions**	-	100	435	155	105	57
175							
176							
177							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181							
182							
183							
184							
185							
186	**include additional rows if needed*						
187	All other routine expenditure projects or programmes	400	400	250	250	250	250
188	**Routine expenditure**	400	400	250	250	250	250
189	**Atypical expenditure**						
190	*Project or programme**						
191							
192							
193							
194							
195							
196	**include additional rows if needed*						
197	All other atypical projects or programmes						
198	**Atypical expenditure**	-	-	-	-	-	-
199							
200	**Non-network assets expenditure**	400	400	250	250	250	250

Company Name	Top Energy Ltd
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SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7–8	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	1,425	1,200	1,231	1,262	1,079	1,107	1,158	1,211	1,267	1,325	1,387
11	Vegetation management	2,180	2,072	1,612	1,654	1,157	1,186	1,241	1,298	1,358	1,421	1,486
12	Routine and corrective maintenance and inspection	1,380	1,341	1,375	1,434	1,495	1,558	1,630	1,706	1,784	1,867	1,953
13	Asset replacement and renewal	910	1,584	1,625	1,501	1,558	1,618	1,693	1,771	1,853	1,939	2,028
14	**Network Opex**	5,895	6,197	5,843	5,850	5,289	5,470	5,722	5,986	6,262	6,552	6,854
15	System operations and network support	2,914	3,284	3,436	3,594	3,760	3,934	4,115	4,221	4,329	4,440	4,554
16	Business support	4,564	4,548	4,717	4,893	5,076	5,266	5,463	5,603	5,747	5,894	6,046
17	**Non-network opex**	7,478	7,832	8,153	8,487	8,836	9,199	9,578	9,824	10,076	10,334	10,599
18	**Operational expenditure**	13,373	14,029	13,996	14,337	14,124	14,669	15,301	15,810	16,338	16,886	17,453

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
19–20	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
21		$000 (in constant prices)										
22	Service interruptions and emergencies	1,425	1,200	1,200	1,200	1,000	1,000	1,020	1,040	1,061	1,082	1,104
23	Vegetation management	2,180	2,072	1,572	1,572	1,072	1,072	1,093	1,115	1,138	1,160	1,184
24	Routine and corrective maintenance and inspection	1,380	1,341	1,341	1,363	1,385	1,408	1,437	1,465	1,495	1,524	1,555
25	Asset replacement and renewal	910	1,584	1,584	1,427	1,444	1,463	1,492	1,522	1,552	1,583	1,615
26	**Network Opex**	5,895	6,197	5,697	5,562	4,902	4,943	5,042	5,143	5,245	5,350	5,457
27	System operations and network support	2,914	3,284	3,350	3,417	3,485	3,555	3,626	3,626	3,626	3,626	3,626
28	Business support	4,564	4,548	4,599	4,651	4,704	4,759	4,814	4,814	4,814	4,814	4,814
29	**Non-network opex**	7,478	7,832	7,949	8,068	8,189	8,313	8,439	8,439	8,439	8,439	8,439
30	**Operational expenditure**	13,373	14,029	13,646	13,630	13,091	13,256	13,481	13,582	13,685	13,790	13,897

Subcomponents of operational expenditure (where known)

sch ref												
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											
	Insurance	183	235	238	241	245	248	252	252	252	252	252

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

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
39–40	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	31	62	79	107	138	171	206	243	283
43	Vegetation management	-	-	40	82	85	114	148	183	221	261	303
44	Routine and corrective maintenance and inspection	-	-	34	71	109	150	194	240	290	342	398
45	Asset replacement and renewal	-	-	41	74	114	156	201	250	301	355	413
46	**Network Opex**	-	-	146	289	387	527	680	844	1,017	1,201	1,397
47	System operations and network support	-	-	86	177	275	379	489	595	703	814	928
48	Business support	-	-	118	242	371	507	650	790	933	1,081	1,232
49	**Non-network opex**	-	-	204	419	646	886	1,139	1,385	1,636	1,895	2,160
50	**Operational expenditure**	-	-	350	708	1,033	1,413	1,819	2,228	2,653	3,096	3,556

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2013 – 31 March 2023

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7											
8					Asset condition at start of planning period (percentage of units by grade)						
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	5%	2%	85%	8%	–	2	5%
11	All	Overhead Line	Wood poles	No.	7%	24%	64%	5%	–	2	25%
12	All	Overhead Line	Other pole types	No.	NA	NA	NA	NA	NA	NA	NA
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	89%	–	11%	–	2	–
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	100%	–	–	3	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	100%	–	–	2	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	NA	NA	NA	NA	NA	NA	NA
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	NA	NA	NA	NA	NA	NA	NA
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	NA	NA	NA	NA	NA	NA	NA
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	NA	NA	NA	NA	NA	NA	NA
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	NA	NA	NA	NA	NA	NA	NA
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	NA	NA	NA	NA	NA	NA	NA
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	NA	NA	NA	NA	NA	NA	NA
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	NA	NA	NA	NA	NA	NA	NA
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	16%	68%	16%	–	4	10%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	100%	–	–	4	–
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	NA	NA	NA	NA	NA	NA	NA
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	44%	37%	20%	–	3	20%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	NA	NA	NA	NA	NA	NA	NA
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	37%	53%	10%	–	3	19%
30	HV	Zone substation switchgear	33kV RMU	No.	NA	NA	NA	NA	NA	NA	NA
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	NA	NA	NA	NA	NA	NA	NA
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	40%	–	60%	–	4	20%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	8%	92%	–	–	3	8%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	19%	54%	27%	–	3	19%

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2013 – 31 March 2023**

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

sch ref	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)						
42											
43											
44	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
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	6%	83%	11%	–	4	6%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	5%	91%	4%	–	2	5%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	NA	NA	NA	NA	NA	NA	NA
48	HV	Distribution Line	SWER conductor	km	–	61%	38%	1%	–	2	10%
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	70%	30%	–	2	–
50	HV	Distribution Cable	Distribution UG PILC	km	–	–	99%	1%	–	2	–
51	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	68%	32%	–	2	–
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4%	1%	15%	80%	–	3	5%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	NA	NA	NA	NA	NA	NA	NA
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	29%	53%	18%	–	2	29%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	100%	–	4	–
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2%	5%	55%	38%	–	2	7%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	7%	9%	64%	20%	–	2	5%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	5%	2%	68%	25%	–	2	5%
59	HV	Distribution Transformer	Voltage regulators	No.	–	–	42%	58%	–	2	–
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	100%	2	–
61	LV	LV Line	LV OH Conductor	km	–	2%	95%	3%	–	2	–
62	LV	LV Cable	LV UG Cable	km	–	2%	89%	9%	–	2	–
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	–	3%	89%	8%	–	2	–
64	LV	Connections	OH/UG consumer service connections	No.	–	2%	83%	15%	–	2	–
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	11%	6%	69%	14%	–	3	11%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	3%	19%	78%	–	–	3	23%
67	All	Capacitor Banks	Capacitors including controls	No.	–	9%	86%	5%	–	2	9%
68	All	Load Control	Centralised plant	Lot	–	100%	–	–	–	4	–
69	All	Load Control	Relays	No.	NA	NA	NA	NA	NA	NA	NA
70	All	Civils	Cable Tunnels	km	NA	NA	NA	NA	NA	NA	NA

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2013 – 31 March 2023**

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	12	N-1	1	83%	12	92%	No constraint within +5 years	
10	Kawakawa	6	5	N-1	3	124%	5	112%	Transformer	Load can be transferred to Haruru and Moerewa
11	Moerewa	2	8	N-1	2	24%	8	42%	No constraint within +5 years	
12	Waipapa	18	23	N-1	2	78%	23	59%	No constraint within +5 years	
13	Omanaia	2	-	N-0	0	-	-	-	Transformer	Single transformer. Backed up by mobile substation
14	Haruru	6	23	N-1	0	24%	23	28%	No constraint within +5 years	
15	Mt Pokaka	2	-	N-0	2	-	-	-	Transformer	Single transformer. Backed up by mobile substation
16	Kerikeri	-	-	N-1	6	-	23	32%	No constraint within +5 years	Commissioning FYE 2014
17	Okahu Rd	10	12	N-1	4	86%	12	88%	No constraint within +5 years	
18	Taipa	5	-	N-0	5	-	5	109%	Transformer	Transfer capacity provided by local diesel generation. Network constraint will be fully relieved by installation of second 110kV transformer in FYE 2019
19	Pukenui	2	-	N-0	0	-	-	-	Transformer	Single transformer. Backed up by mobile substation
20	NPL	12	23	N-1	1	52%	23	53%	No constraint within +5 years	
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
32	Distribution transformer capacity (EDB owned)	N/A
33	Distribution transformer capacity (Non-EDB owned)	N/A
34	**Total distribution transformer capacity**	#VALUE!
36	**Zone substation transformer capacity**	230

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9								
10		for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
11	*Consumer types defined by EDB**							
12	Small		31,440	31,782	32,126	32,475	32,827	33,183
13	Medium		185	189	193	197	202	206
14	Large		21	23	25	27	29	31
15	Industrial		3	3	3	3	3	3
16								
17	**Connections total**		31,650	31,997	32,347	32,702	33,061	33,423
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		1	1	1	1	1	1
21	Installed connection capacity of distributed generation (MVA)		26	26	26	26	26	26

12c(ii) System Demand

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
22		**12c(ii) System Demand**							
23									
24		**Maximum coincident system demand (MW)**	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
25		GXP demand		40	40	41	42	42	43
26	*plus*	Distributed generation output at HV and above		25	25	25	25	25	25
27		**Maximum coincident system demand**		65	65	66	67	67	68
28	*less*	Net transfers to (from) other EDBs at HV and above							
29		**Demand on system for supply to consumers' connection points**		65	65	66	67	67	68
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		185	187	189	190	193	192
32	*less*	Electricity exports to GXPs		16	16	16	16	16	16
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**		369	371	373	374	377	376
36	*less*	Total energy delivered to ICPs		335	338	340	343	345	348
37		**Losses**		33	33	32	31	32	28
38									
39		**Load factor**		65%	65%	64%	64%	64%	63%
40		**Loss ratio**		9.0%	9.0%	8.7%	8.4%	8.4%	7.5%

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2013 – 31 March 2023**
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 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		76.0	76.0	76.0	76.0	20.0	20.0
12	Class C (unplanned interruptions on the network)		326.0	264.0	242.0	234.0	226.0	225.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.50	0.50	0.50	0.50	0.10	0.10
15	Class C (unplanned interruptions on the network)		4.50	4.00	3.70	3.60	3.50	3.40

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2013 – 31 March 2023
Asset Management Standard Applied	PAS55

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	It is opinion of AMCL that Top Energy has compliance at risk for Clause 4.2. To rectify this, Top Energy should rectify any line of sight discontinuities between the strategic business direction and the Asset Management Policy. Top Energy should demonstrate that the Asset Management Policy has been authorised by Top Management and ensure it has been communicated to all stakeholders, and prior to a Certification Audit it should be able to demonstrate a review has been completed.		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	It is the opinion of AMCL that Top Energy has current compliance to Clause 4.3.1. Top Energy should ensure that it can demonstrate the content and detailed Processes and Procedures described in the Asset Management Plan can be demonstrated during a Certification Audit.		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	It is the opinion of AMCL that Top Energy has current compliance to Clause 4.3.1. Top Energy should ensure that it can demonstrate the content and detailed Processes and Procedures described in the Asset Management Plan can be demonstrated during a Certification Audit.		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	It isthe opinion of AMCL that Top Energy has current compliance for Clause 4.3.3. Top Energy should ensure that it can demonstrate the content and detailed Processes and Procedures described in the Asset Management Plan can be demonstrated during a Certification Audit. This should ensure its Asset Management Plans cover all of the life cycle stages and the priorities and optimisation between and within each stage are clearly defined.		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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Asset Management Standard Applied	

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	It isthe opinion of AMCL that Top Energy has current compliance for Clause 4.3.3. Top Energy should ensure that it can demonstrate the content and detailed Processes and Procedures described in the Asset Management Plan can be demonstrated during a Certification Audit. This should ensure its Asset Management Plans cover all of the life cycle stages and the priorities and optimisation between and within each stage are clearly defined.		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	It isthe opinion of AMCL that Top Energy has current compliance for Clause 4.3.3. Top Energy should ensure that it can demonstrate the content and detailed Processes and Procedures described in the Asset Management Plan can be demonstrated during a Certification Audit. This should ensure its Asset Management Plans cover all of the life cycle stages and the priorities and optimisation between and within each stage are clearly defined.		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	It isthe opinion of AMCL that Top Energy has current compliance for Clause 4.3.3. Top Energy should ensure that it can demonstrate the content and detailed Processes and Procedures described in the Asset Management Plan can be demonstrated during a Certification Audit. This should ensure its Asset Management Plans cover all of the Life Cycle stages and the priorities and optimisation between and within each stage are clearly defined.		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?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.3.4. To rectify this, Top Energy should ensure compliance with existing Processes and Procedures can be demonstrated during a certification Audit, and that rehearsal of plans which include relevant stakeholders can be clearly demonstrated.		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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Asset Management Standard Applied	

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)?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.1. To rectify this, Top Energy should ensure the completion of its current re-organisation, and should ensure that the roles and responsibilities required to implement its Asset Management System consistently and clearly defined for its staff.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.1. To rectify this, Top Energy should ensure the completion of its current re-organisation, and should ensure that the roles and responsibilities required to implement its Asset Management System consistently and clearly defined for its staff.		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?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.1. To rectify this, Top Energy should ensure the completion of its current re-organisation, and should ensure that the roles and responsibilities required to implement its Asset Management System consistently and clearly defined for its 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	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.2, but this is a borderline case and is almost compliant. To rectify this, Top Energy should ensure compliance with existing Processes and Procedures can be demonstrated during a Certification Audit, and that its Sourcing Strategy has been effectively implemented.		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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Asset Management Standard Applied	

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)?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.3. To rectify this, Top Energy should be able to demonstrate a clear forward view of the development of its staff over time with respect to all roles that have are involved with the delivery of the Asset Management Strategy and Plans. Demonstration of the effectiveness Organisational Development group with respects to this clause would be expected during a Certification Audit.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.3. To rectify this, Top Energy should be able to demonstrate a clear forward view of the development of its staff over time with respect to all roles that have are involved with the delivery of the Asset Management Strategy and Plans. Demonstration of the effectiveness Organisational Development group with respects to this clause would be expected during a Certification Audit.		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?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.3. To rectify this, Top Energy should be able to demonstrate a clear forward view of the development of its staff over time with respect to all roles that have are involved with the delivery of the Asset Management Strategy and Plans. Demonstration of the effectiveness Organisational Development group with respects to this clause would be expected during a Certification Audit.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.4. To rectify this, Top Energy should ensure that all key internal stakeholders (particularly within TECS) are consulted during the continuing development of the Asset Management System and have the opportunity to receive information and provide feedback on Asset Management related issues.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.5. To rectify this, Top Energy should complete the population of its document hierarchy ensuring Processes, Procedures and Work Instructions are developed only if the level of risk to the delivery of the Asset Management Strategy and Plans is high should they not exist.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.6. To rectify this, Top Energy should ensure that the accuracy and completeness of asset information held in its various systems can be demonstrated during a Certification Audit. In particular the accuracy and management of defects and the control of maintenance and inspection activities needs to be improved.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.6. To rectify this, Top Energy should ensure that the accuracy and completeness of asset information held in its various systems can be demonstrated during a Certification Audit. In particular the accuracy and management of defects and the control of maintenance and inspection activities needs to be improved.		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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Asset Management Standard Applied	

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	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.6. To rectify this, Top Energy should ensure that the accuracy and completeness of asset information held in its various systems can be demonstrated during a Certification Audit. In particular the accuracy and management of defects and the control of maintenance and inspection activities needs to be improved.		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	It is the opinion of AMCL that Top Energy has compliance at risk with Clause 4.4.7. To rectify this, Top Energy should ensure its Risk Management Policy is consistent with that published in the 2011 Asset Management Plan and should publish the Risk Management Framework and associated Processes internally. These should be effectively adopted by the organisation, and demonstrably implemented by all Top Energy staff during a Certification Audit.		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	It is the opinion of AMCL that Top Energy has compliance at risk with Clause 4.4.7. To rectify this, Top Energy should ensure its Risk Management Policy is consistent with that published in the 2011 Asset Management Plan and should publish the Risk Management Framework and associated Processes internally. These should be effectively adopted by the organisation, and demonstrably implemented by all Top Energy staff during a Certification Audit.		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	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.4.8, but this is a borderline case and is almost compliant. To rectify this, Top Energy should ensure compliance with existing Processes and Procedures can be demonstrated during a Certification Audit, and be able to demonstrate pro-active update of the compliance database.		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	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?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.5.1 based on the evidence presented during the Gap Analysis Assessment. TEN should establish clear 'line of sight' into the TECS organisation. Implementation of robust work management systems for all maintenance and inspection activities will be essential to demonstrate effective management control during a Certification Audit. Top Energy also needs to effectively implement clear criteria for the inspection and remedial action of Asset defects. Being able to demonstrate that the implementation of Asset Management System was fully aligned with Policy, Strategy and Objectives and that activity on the ground was under full management control is the key to compliance of this clause		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.5.1 based on the evidence presented during the Gap Analysis Assessment. TEN should establish clear 'line of sight' into the TECS organisation. Implementation of robust work management systems for all maintenance and inspection activities will be essential to demonstrate effective management control during a Certification Audit. Top Energy also needs to effectively implement clear criteria for the inspection and remedial action of Asset defects. Being able to demonstrate that the implementation of Asset Management		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	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.6.1. To rectify this, Top Energy should establish a broader proactive and leading set of measures to complement the current reactive and lagging measures driven by SAIDI requirements. These measures should be disaggregated and disseminated down through the organisation (see under Clause 4.7).		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?	2	It is the opinion of AMCL that Top Energy has compliance at risk for Clause 4.6.2. To rectify this, Top Energy should ensure the root cause analysis Process is effectively embedded and ensure recommendations derived from the analyses are systematically tracked (see 4.6.5).		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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	It is the opinion of AMCL that Top Energy is compliance at risk with Clause 4.6.4. To rectify this, Top Energy should develop Auditing capability and an Audit plan which covers all aspects of its Asset Management System. The Auditing process should be clearly linked into the management of improvement actions and management review as described under Clauses 4.6.5 and 4.7.		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	It is the opinion of AMCL that Top Energy is has compliance at risk for Clause 4.7. To rectify this, Top Energy needs to establish an overall management review Process which is focused on the scope of the Asset Management System as defined under Clause 4.1, and should provide a strategic review of all elements of the Asset Management System based on (but not limited to) business performance information, information from Audits, Corrective and Preventive Actions, and other sources of management information.		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?	2	It is the opinion of AMCL that Top Energy is has compliance at risk for Clause 4.7. To rectify this, Top Energy needs to establish an overall management review Process which is focused on the scope of the Asset Management System as defined under Clause 4.1, and should provide a strategic review of all elements of the Asset Management System based on (but not limited to) business performance information, information from Audits, Corrective and Preventive Actions, and other sources of management information.		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?	2	It is the opinion of AMCL that Top Energy is has compliance at risk for Clause 4.7. To rectify this, Top Energy needs to establish an overall management revie[illegible] Process which is focused on the scope of the Asset Management System as defined under Clause 4.1, and should provide a strategic review of all elements of the Asset Management System based on (but not limited to) business performance information, information from Audits, Corrective and Preventive Actions, and other sources of management information.		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
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	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	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	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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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	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	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	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.

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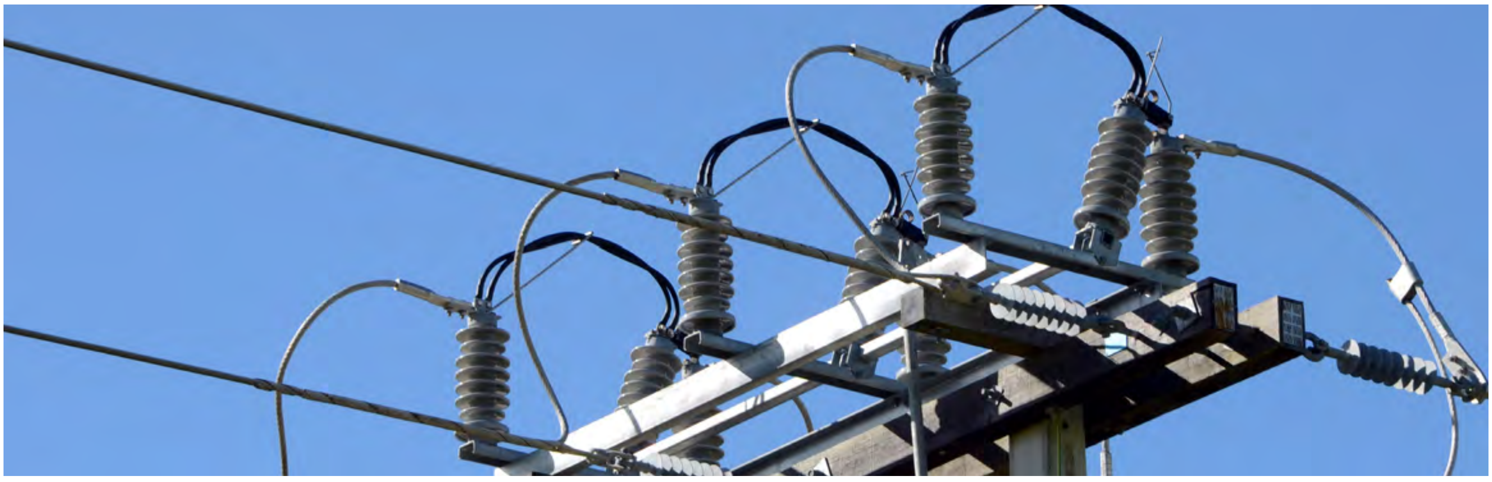

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