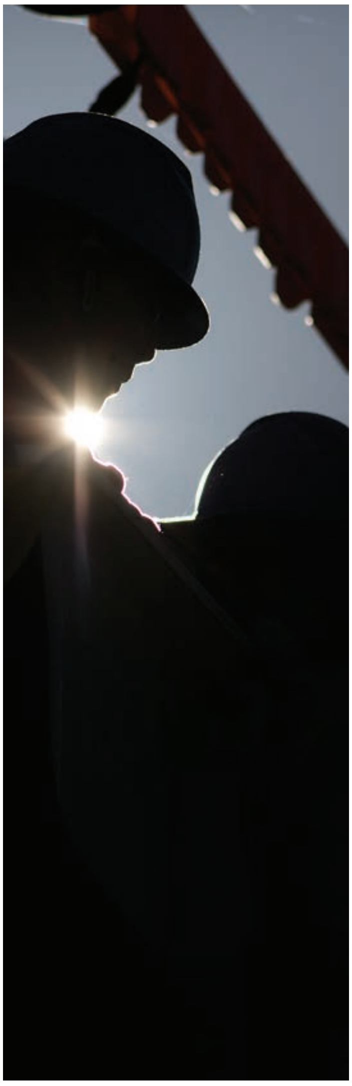
WEL Networks

ASSET MANAGEMENT PLAN

2015



2015 | WEL ASSET MANAGEMENT PLAN

FOREWORD

24 March 2015

Dear Stakeholders

The WEL Networks Limited ten-year Asset Management Plan 2015 (AMP) presents the investment rationale and performance measurement for our assets for the coming ten years. It is aimed at ensuring we continue to provide a strong, safe, efficient, and reliable supply for our customers, and reflects our desire to be *Best in Service, Best in Safety.*

As a result of revising our asset management strategies this AMP has an entirely new structure and significant changes in content. These changes are aimed at improving the experience for our stakeholders - making the document easier to read, and a more valuable resource.

The AMP focuses on a number of key initiatives that will improve our planning, business performance, and investment decisions. While achieving these initiatives we will not compromise on our efforts to ensure the safety of our staff, contractors, and the general public. This is always our foremost priority, and directs everything we do.

A number of significant themes and initiatives centre on providing the level and quality of supply our customers expect, increasing our core capabilities in key areas, and improving on our established performance objectives. We believe our service to urban customers meets expectations, and will ensure that this is maintained in the coming years. On the other hand, we need to improve our service reliability in rural areas. A number of new initiatives have been put in place to achieve this.

I trust you will find our AMP to be an informative and valuable resource. I welcome any comments on this plan or other aspects of our performance. Please forward your comments to me (garth.dibley@wel.co.nz) or Paul Blue, General Manager Asset Management (paul.blue@wel.co.nz).

Garth Dibley

Garth Dibley

CHIEF EXECUTIVE

TABLE OF CONTENTS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NETWORKS
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PLAN SUMMARY

INTRODUCTION

This AMP represents a significant evolution from our previous AMPs. We are confident the changes improve the AMP, making it easier to read and understand.

Our aim is to ensure the AMP is a valuable resource for all our stakeholders. It describes the nature and characteristics of our assets and investment requirements, providing an overview of our asset management planning, systems, procedures, and practices. It demonstrates the interaction with our corporate vision, our asset management objectives and the relationship with our other corporate documents such as the strategic plan and business plan.

Where there is technical information in this AMP we have sought to explain it in a way that provides meaning and value to all our stakeholders.

This AMP covers the period from 1 April 2015 to 31 March 2025.

KEY INITIATIVES

Throughout this AMP we describe and explain our key themes and initiatives for the AMP period. They are:

- Safety is our highest priority. Our Vision places safety first and foremost, making it the top priority in everything we do. We strive to ensure safe environments for our staff, contractors, and the public;
- Our customers are our primary focus. We have identified that our network performance comfortably exceeds our urban customers' expectations. In contrast, our rural customers expect to experience significantly less interruption minutes than they currently do. As a result, a key focus of this AMP is on a renewal of the rural network, targeting high risk and aged assets to reduce customer outages. In addition to our focus on the performance of the rural network, our network development includes:
  - Projects to maintain network safety;
  - Providing additional capacity in localised areas of forecast growth; and
  - addressing network security issues.
- Our core capabilities are in asset management, health and safety, operational control, reliability management and service restoration. We have plans to further lift our capability in these areas and in work delivery, business acumen, and corporate information systems. This will drive further efficiencies across our business; and
- We strive for continuous improvement and have established performance objectives and measures in four key asset management areas: safety, customer experience, cost efficiency and asset performance.

OVERVIEW OF WEL NETWORKS LTD (WEL)

WEL is owned by the WEL Energy Trust (Trust). The Trust's purpose ***"Growing investment for our community"*** requires being diligent shareholders and sharing profits with our community through annual discounts and community grants.

Our business vision is to ***"Provide high quality, reliable utility services valued by our customers whilst protecting and enabling our community."*** By keeping our vision at the forefront of our activities, we focus on enhancing customer service and protecting the community we serve. We play a pivotal role by providing services that are essential to the economic, social and environmental wellbeing of the community.

NETWORK OVERVIEW

WEL supplies electricity to the Northern Waikato and small networks in Cambridge and Auckland. Hamilton City is the main electrical load centre, where customers enjoy a high level of reliability. Outside of Hamilton City the network area is predominately rural. Our network areas are shown in Figures S1 and S2 below.

WEL NETWORKS AREA

Figure S1 – Map of WEL Networks area

Figure S2 – Map of WEL external networks

Our network is supplied by four Grid Exit Points (GXPs) owned by Transpower and two large embedded generators at Te Rapa and Te Uku. Our 33 kV subtransmission network connects the GXPs with zone substations which in turn supply our distribution network. This network feeds our low voltage network that supplies the majority of our customers.

ELECTRICITY DELIVERED AND DEMAND

The total electricity delivered during 2015 is forecast to be 1,203 GWh with a coincident peak demand of 244MW. Delivered electricity has continued to increase while peak demand has generally remained flat since 2011. Peak demand has been forecast to grow modestly during the AMP period, driven primarily by continued residential subdivision activity in the north and new residential subdivision activity in the east of Hamilton along with residential, commercial and industrial connection growth in the Tasman substation area (between The Base and Rotokauri).

Our network development plan proposes additional network capacity and security projects to meet the growth in forecast peak demand in localised areas of the network and to address existing constraints. An overview of our network development plan is described further below and in detail within Chapter 7.

OUR STAKEHOLDERS

As a community owned company we consider our stakeholder requirements to have utmost importance. Accordingly we have considerable focus on identifying and meeting stakeholder expectations. We have eight broad groups of stakeholders. These are customers, community, regulators, Transpower (including their role as System Operator (SO)), electricity retailers, service providers, staff, and our Board of Directors. Customers are our primary focus and we have identified their expectations through surveys and direct interaction. Our stakeholder requirements, discussed in detail in Section 4.1, drive our expenditure plans.

ASSET OVERVIEW

Our network is more than 6,400 km in length and comprised of more than 200,000 individual asset components. Within our network there are 26 zone substations and 17 switching stations (11kV) we maintain and operate to enable a reliable supply of electricity to our customers. Table S1 below provides a summary of the assets we operate.

ASSET TYPE	UNIT	QUANTITY
Lines	km	3512
Cables	km	2987
Poles	No.	39555
Crossarms	No.	70100
Transformers	No.	5680
Ring Main Units	No.	724
Smart Meters	No.	56286
Load Control Relays	No.	53664

Table S1 – Summary of Assets

In general, our assets are in good condition. We have targeted our renewal and maintenance programmes based on our assessment of asset health and condition. An overview of these programmes is described further below and in detail within Chapter 8.

APPROACH TO ASSET MANAGEMENT AND GOVERNANCE

Our approach to asset management is evolving. We have identified that we need to continuously improve and build additional capability. Good asset management is central to achieving our vision, strategic and business plans and the performance outcomes set out in Chapter 6.

We have established an asset management framework that links the Trust's purpose, our vision, strategy and business plans to our Asset Management Policy, which in turn determines key strategies contained within our network development, non-network investment and renewal and maintenance plans. Our strategies are recorded in this AMP and together form our work plan and incorporate the lifecycle activities required to meet the performance sought by stakeholders. Each component of our asset management framework is further described below.

ASSET MANAGEMENT POLICY

The Asset Management Policy informs our corporate governance arrangements. Its primary objective is to deliver a safe and reliable network over the long-term that meets customers' quality and price expectations. The development of the policy to further align it to ISO55000 has been identified as an improvement initiative for 2016.

ASSET MANAGEMENT STRATEGY

Asset management strategy links our policy objectives to the network development projects and asset renewal and maintenance plans described in Chapters 7 and 8. The strategy adopted supports three distinct components. These are:

- **Network Development:** In line with customer expectations our strategic objective for network development is to maintain our urban reliability level while improving the performance of the rural network. This involves consideration of network security over the planning period against the established security criteria. We will need to maintain capacity required to supply localised areas of growth within the urban network. To achieve these cost-effectively, we will seek projects with high cost benefit ratios such as network automation, and non-network alternatives such as demand management. The initiatives and projects that result from this strategic approach are discussed further in Chapter 7;
- **Non-network Development:** We invest in non-network assets to increase operational flexibility and to improve the information that supports our asset management decision making. We are now utilising the information and flexibility this provides to improve services to customers and to ensure efficient investment decisions are made. The initiatives and projects that result from this are discussed further in Chapter 7; and
- **Maintenance and Renewals:** Our strategic approach to maintenance and asset renewal is to maintain a consistent and sustainable level of risk over the long-term. The principal methodology employed for this is Condition Based Reliability Management (CBRM) . This strategic approach and the resultant renewal and maintenance expenditure over the AMP period is discussed further in Chapter 8.

Central to our asset strategies is our whole of life approach. We seek to optimise investment decisions by taking into account the full life-cycle costs of our assets.

WORKS PLANNING

Works planning is integral to meeting the needs of our stakeholders. The focus of works planning is to efficiently deliver both planned and unplanned works. It also includes operational services required to meet customer requirements. It involves three key steps:

- Integration and optimisation of network development, renewal, and maintenance works;
- Works and resource scheduling and programme management; and
- Management of delivery through field services.

The governance arrangements for works planning are discussed further in Chapter 5.

We understand that the integration and optimisation of our planning process and works delivery is key to achieving our safety, efficiency and least cost objectives. We have identified a number of improvement opportunities in the integration and optimisation of works delivery. One significant change in 2015 was the reorganisation of our First Response team for faults.

The works delivery plan and our operations scheduling is expected to improve in accuracy over the next 12 months as we build on our initial improvement initiatives. We are currently instigating a project to further integrate and extract benefits from our SAP system and, in particular, by the enhanced utilisation of its powerful scheduling module.

RISK MANAGEMENT FRAMEWORK

Risk management is a fundamental asset management discipline. It requires robust processes to be in place for assessing and managing asset-related risk. We have in place an effective and efficient risk framework for identifying and managing business and network risks.

EXPENDITURE APPROVALS

Investment planning is fundamental to many of our asset management activities. Our planning capability is central to efficiently delivering on customer price and quality expectations.

Our development process has the same fundamental stages for all investments, from needs identification through to delivery. These stages are managed under an overarching governance, prioritisation and approvals framework as illustrated below.

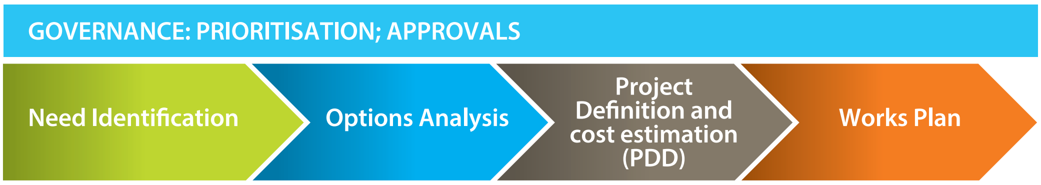


Figure S3 – Investment Planning Framework

Our Board of Directors has established a delegated financial authority structure for the business. Prior to approval, expenditure plans are subject to an internal challenge process. The expenditure approval limits have been established commensurate with our organisational structure, meaning higher limits are set corresponding to a person's position within the organisation.

ASSEST MANAGEMENT IMPROVEMENT

The Asset Management Maturity Assessment Tool (AMMAT) gauges our performance against the selected components of the PAS 55:2008 (replaced by the ISO55000 standard) Asset Management framework. The self-assessment informs us and stakeholders about the level of competency we believe we have reached at the time of assessment. We derive benefit from our internal discussions and views around the level of asset management capability and competency appropriate for our stakeholders, and the identification of improvement opportunities.

2015 AMMAT ASSESSMENT

Overall we believe our performance and maturity in asset management is good. We strive for continual improvement and we believe our revised AMP is a significant step in the right direction.

The results shown below indicate lower scores than our last assessment. We believe the results signal a maturing of our understanding of the ISO55000 standards and therefore is consistent with the Commerce Commission's intended purpose for this assessment. It does not reflect a deterioration of our asset management capability.

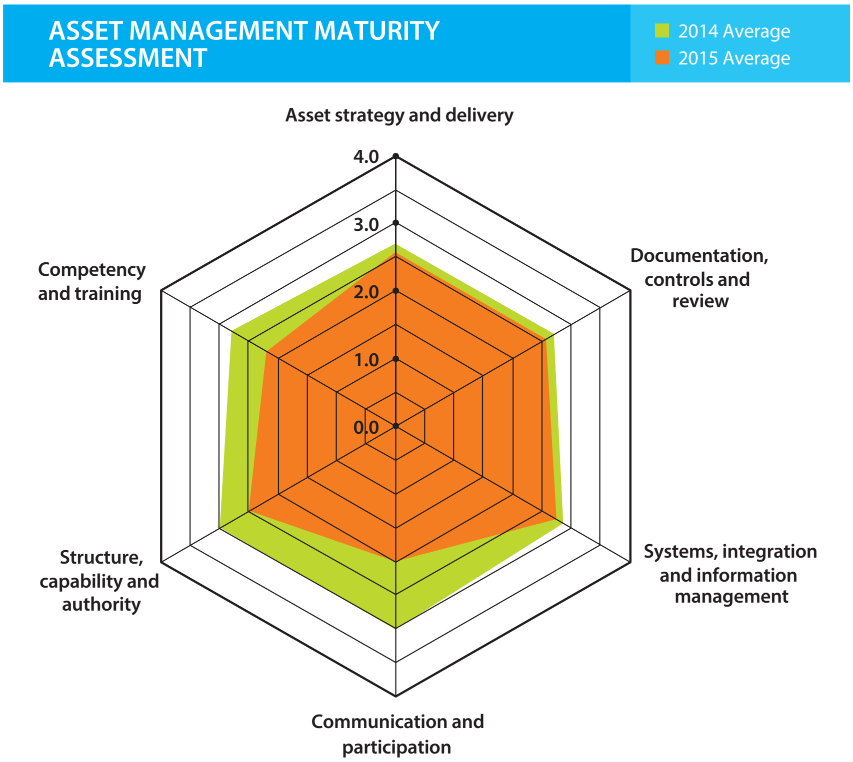


Figure S4 – AMMAT Assessment

The conclusion drawn from the result is that we are maturing as asset managers and are now more realistic about our asset management performance. This analysis has informed two key areas for improvement:

- Improving the communication of our plans by finding new ways to communicate our AMP within our business and with stakeholders; and
- Improving our level of asset management capability to further lift our performance.

ASSET MANAGEMENT OBJECTIVES

Our asset management objectives cover four key areas. The objectives are:

- **Safety:** Safety is our highest priority. Our objective is to provide a safe environment for our staff, contractors, and the public;
- **Customer Experience:** Our customer objective is to deliver the quality of supply (reliability) sought by our customers and provide them with a service they value;
- **Cost Efficiency:** Our objective is to make the right investment choice at the right time, and to deliver our works programme for the lowest total ownership cost possible while achieving our quality and safety targets; and
- **Asset Performance:** Our asset performance objective is to optimise the price-quality trade-off based on our stakeholders needs. We will support this by further developing our asset management capability, asset strategies, network configuration, and supporting business processes.

Furthermore our purpose, vision and values drive our strategic priorities defined within our Strategic Plan. They also provide context for our business and asset management practices. The asset management strategies defined in our Strategic Plan are:

- Our asset management investment decisions reflect safety as our top priority and are optimised based on a quantifiable trade-off between capital and operational expenditure, risk and reliability;

- Preventive and corrective maintenance decisions are made using quantitative analytical techniques such as Reliability Centred Maintenance (RCM) or Failure Modes and Effects Analysis (FMEA). These techniques allow for a quantifiable trade-off between capital and operational expenditure, risk, reliability and safety considerations;
- We fully leverage our Smart Box data to inform the way we plan, build, maintain and operate our network. This includes voltage exception analysis, fault identification and remediation, peak capacity planning and optimised load control;
- How, when and who we use to deliver our AMP are key inputs in our investment decisions; and
- We have an effective operational business metering team and are recognised externally as a leading player in the smart metering business environment.

ASSET MANAGEMENT PERFORMANCE

We have established performance objectives, measures and targets in four areas covered by our asset management objectives. In each performance area we have established measures and targets for the AMP period which flow directly from our Strategic Plan. Our performance objectives and measures are:

- **Safety:** Safety is our highest priority. Our safety performance objectives cover aspects of our culture and leadership, how we operate, equipment purchased and requirements for continuous improvement and improved communications. We will measure our safety performance. Our key measures and targets include our Total Recordable Injury Frequency Rate (TRIFR), staff behaviours and public safety incidents;
- **Customer Experience:** Our customer experience objectives cover both reliability (quality of supply) and the quality of service we deliver through our interactions with customers e.g. the time taken to resolve a complaint. In addition to these measures we are committed to restoring supply as soon as possible following an interruption. Accordingly we undertake to restore power to our urban customers within three hours of an outage and within six hours of an outage to our rural customers. If we do not meet this, our residential and small commercial customers will receive $40 and our large commercial customers will receive $150 from us.[1]
- **Cost Efficiency:** Cost efficiency is driven by making the right investment choices at the right time, and delivering our works programme for the lowest total ownership cost possible while achieving our quality and safety targets. We measure operating cost per customer and capital expenditure performance as our key cost efficiency measures; and
- **Asset Performance:** The performance of our assets directly determines the quality and cost of providing services to our customers. This, in turn, is a direct consequence of the asset management decisions we make on a daily basis. Reflecting these linkages, our asset performance objective is to optimise the price-quality trade-off based on our stakeholders' needs. We measure our GXP load factor and transformer utilisation as key initiators of our asset performance.

DEVELOPMENT INVESTMENTS

With our customers investing more in electricity efficiency initiatives over the AMP period, we anticipate the total electricity delivered to grow at a slower rate than in the past. However, we also expect to see small increases in peak demand in some localised areas of the network, driven by growth in residential subdivisions and the commercial/industrial sectors. Accordingly, we expect a slow increase in peak demand over the AMP period, as set out below.

[1] *The 'WEL promise' does not apply to faults beyond our control such as storms, lightning, vehicle accidents, or third party damage.*

GXP	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Hamilton 11kV	36.2	29.4	28.5	28.8	29.0	29.3	29.5	29.8	30.0	30.3
Hamilton 33kV	133.0	137.1	139.3	140.6	141.6	142.4	143.4	144.3	145.3	146.3
Huntly 33kV	25.3	25.4	25.4	25.5	25.6	25.7	25.8	25.9	26.0	26.1
Te Kowhai 33kV	83.9	89.3	90.2	91.1	92.0	92.5	93.0	93.5	94.0	94.5
System Peak	247.6	251.0	253.3	255.5	257.6	259.0	260.6	262.2	263.8	265.5

Table S2 – GXP Demand Forecast

The network development initiatives that result from our peak demand forecast are summarised below.

GXP DEVELOPMENT PLAN

Our peak demand forecast implies a need to augment the supply capacity at the Hamilton GXP because the capacity is forecast to be exceeded during 2016. However, one of the two transformers at Hamilton is smaller than the other and due to be upgraded by Transpower. When this occurs this will increase capacity at the GXP. Until that time the demand will be managed through load management and switching.

URBAN DEVELOPMENT PLAN

Our Urban Development Plan addresses the needs arising from localised growth in Hamilton City. Growth is expected from residential subdivision development activities in the north and southeast of Hamilton and residential, commercial and industrial connections in the Tasman area (between The Base and Rotokauri). Expenditure has also been included for investment required specifically to meet the needs of individual customer works. The Urban Development Plan also provides for improving and updating our control and automation equipment and specific safety related investments and works.

RURAL DEVELOPMENT PLAN

Our Rural Development Plan addresses the need to improve voltage performance and security on our rural network. The expenditure is targeted at improving the supply to our Glasglow, Kimihia, Raglan and Te Uku substations through improving our subtransmission network and developing the rural zone substations at Weavers and Gordonton and the completion of the new Hoeka zone substation. We have also included a number of distribution network improvements aimed at improving security, voltage levels and reducing interruptions due to avoidable circuit tripping. Improvement to the reliability of the rural network will primarily come from our maintenance and renewal of the assets.

NON-NETWORK INVESTMENT

Our non-network investments during the AMP period cover our planning expenditure on computer equipment including the periodic renewals of software and hardware used to support our asset management functions. It also includes plant, equipment and motor vehicle renewals.

The GXP, Urban, Rural and Non-network investment expenditure is summarised on the following page.

10 YEAR DEVELOPMENT EXPENDITURE

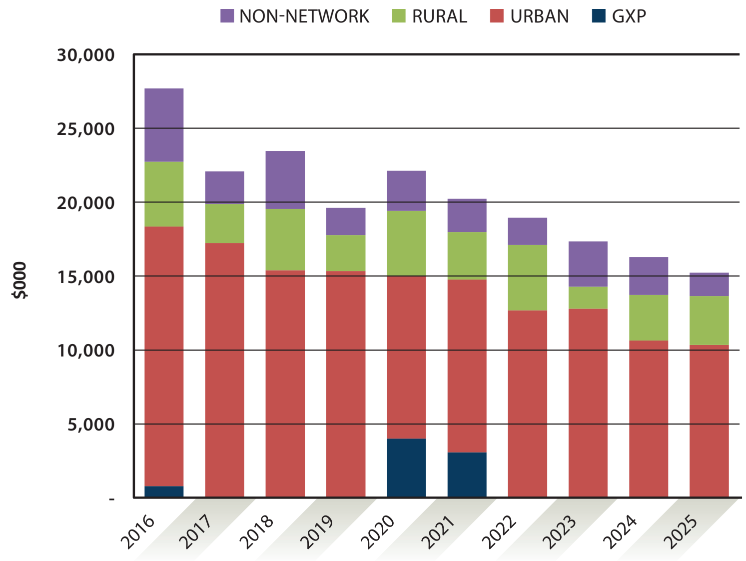


Figure S5 –Development Expenditure

RENEWAL AND MAINTENANCE

Delivering our performance objectives requires the right balance between expenditure on maintenance and investment in renewals. In striking this balance, we have considered the whole of life cost of our assets, and required interventions during their lifecycle.

MAINTENANCE

Our maintenance activity is first and foremost safety focused. After which, it is structured to minimise the whole of life costs of our assets while managing their performance over time. This is achieved by selecting maintenance techniques and processes that:

- Ensure safety risks are identified and mitigated;
- Optimise the costs of maintenance together with renewal expenditure;
- Meet any regulatory requirements; and
- Where possible improve network availability.

VEGETATION MANAGEMENT

We manage vegetation in and around our assets that have the potential to interfere with the safe and reliable supply of electricity to our customers. We have increased our inspection rates and created a growth model to predict when future work will be required based on vegetation type.

Vegetation expenditure is based on our vegetation growth model. Based on current cutting rates our model predicts expenditure will reduce towards the end of the AMP period.

SERVICE INTERRUPTION AND EMERGENCY MANAGEMENT

Service Interruption and Emergency Management relates to faults work required to be undertaken. We have forecast a decrease in our faults expenditure due to efficiency gains from the introduction of the new faults team, proactive repairs on defects due to enhanced diagnostic testing and reduction in line breaks due to the conductor asset renewal programme.

Our forecast expenditure on maintenance, vegetation and faults activities is shown on the following page.

10 YEAR MAINTENANCE, VEGETATION AND FAULTS EXPENDITURE

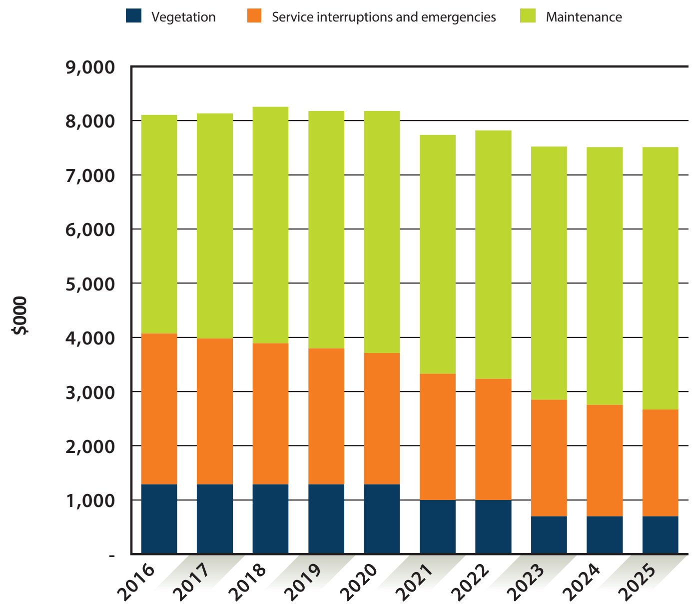


Figure S6 – Maintenance, Vegetation and Faults Expenditure

RENEWALS

We have forecast renewal expenditure to vary over the AMP period, primarily due to the variable expenditure on zone substation renewal. Step changes are also evident on our planned transformer and distribution and LV line expenditure from 2019. This reflects our risk based approach to asset renewals known as CBRM. This approach prioritises the renewal of assets that present the highest risk to safety, network performance, and the environment. The methodology is used by numerous electricity distribution companies internationally to deliver effective risk related asset management.

Further details on the CBRM process is provided in Appendix B.

Our forecast expenditure on renewals is shown below.

10 YEAR RENEWAL EXPENDITURE

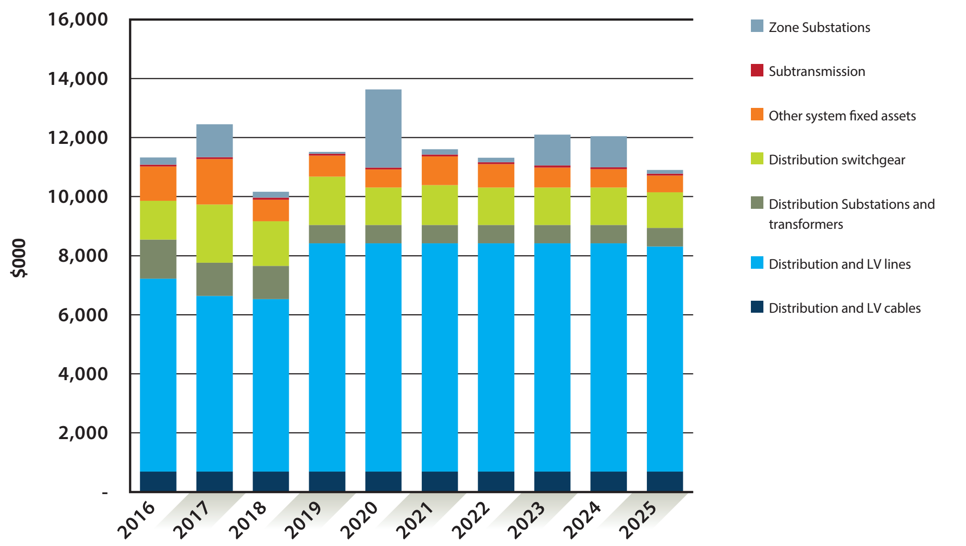


Figure S7 – Renewal Expenditure

OVERALL SUMMARY

We consider this AMP provides a clear description of our objectives, measures, and targets that we aim to achieve on behalf of our stakeholders. It sets out the investments we need to make over the next 10 years to deliver services to our customers at the quality they expect.

Te Uku substation at dawn. Photo by Nic Reardon.

1 INTRODUCTION

1 INTRODUCTION

This 2015 Asset Management Plan (AMP) represents a significant evolution from our pervious AMPs. In producing this AMP we have adopted a new process and governance arrangement from that used previously. We have also received independent expert advice and input.

Accordingly, this AMP contains new content and follows a new structure. We are confident the changes improve the AMP and make it easier to read and understand. Our aim is to ensure the AMP is a valuable resource for all our stakeholders.

This chapter introduces our AMP, and is structured as follows:

- **Purpose (1.1):** explains the purpose of the AMP, the period covered, the date it was approved by our Board of Directors, its scope, and the intended audience;
- **Key Themes and Initiatives (1.2):** summarises our key themes and initiatives included for this AMP; and
- **Document Structure (1.3):** provides a summary of the AMP and its structure.

1.1 PURPOSE

The purpose of this AMP is to communicate with our stakeholders. It:

- Provides readers with an appreciation of the nature and characteristics of the assets we own and operate;
- Records the investment requirements we foresee over the AMP period so we can continue in accordance with our Vision to "provide high quality, reliable, utility services valued by our customers whilst protecting and enabling our community;"
- Provides an overview of how stakeholder interests are incorporated into our asset management planning, systems, procedures and practices;
- Demonstrates the interaction between the plans and our corporate vision, and our asset management objectives;
- Conveys our asset management and planning processes, which have been set in place to meet our asset management objectives of safety, high quality customer experience, cost efficiency and asset performance; and
- Describes the relationship of the AMP with our strategic plan and its importance as a key planning document and an output from our annual business planning process.

Where there is technical information in this AMP we have sought to explain it in a way that provides meaning and value to all our stakeholders.

PERIOD COVERED BY THE AMP

This plan covers a ten year period from 1 April 2015 to 31 March 2025 (AMP period). With any long-term plan, the details tend to prove more accurate in the earlier years as it is easier to predict the state of our assets.

APPROVAL DATE

This plan was reviewed and approved by the WEL Networks Limited Board of Directors on 24 March 2015.

SCOPE OF THE AMP

This AMP covers the assets used in the delivery of electricity distribution services to the customers connected to our network.

INTENDED AUDIENCE

The intended audience for this AMP includes our customers; the Commerce Commission and Electricity Authority (our key regulators); our staff and contractors; and other interested parties.

1.2 KEY THEMES AND INITIATIVES

Throughout this AMP we describe and explain our key themes and initiatives for the AMP period. They are introduced and summarised below:

- Safety is our highest priority. Our Vision places safety first and foremost, making it the top priority in everything we do. We strive to ensure safe environments for our staff, contractors, and members of the public;
- Our customers are our primary focus. We have identified that our network performance comfortably exceeds our urban customers' expectations. In contrast our rural customers expect to experience significantly less interruption minutes than they currently do. As a result, a key focus of this AMP is on a renewal of the rural network, targeted at improving reliability performance. In addition to our focus on the performance of the rural network our network development projects include:
  - projects to maintain network safety;
  - providing additional capacity in localised areas of forecast growth; and
  - addressing network security issues.
- Our core capabilities are in asset management, health and safety, operational control, reliability management and service restoration. We have plans to further lift our capability in these areas, and in work delivery, business acumen, and corporate information systems. This will drive further efficiencies across our business; and
- We strive for continuous improvement and have established performance objectives and measures in four key asset management areas: safety, customer experience, cost efficiency, and asset performance. Our performance objectives, initiatives, measures and targets are set out in Chapter 6.

1.3 DOCUMENT STRUCTURE

The document is structured as illustrated in Figure 1.3 below.

INTRODUCTION (THIS CHAPTER)

BACKGROUND INFORMATION ON WEL NETWORKS

2 **CHAPTER 2 – BACKGROUND** Introduces WEL Networks, our customers and network.	3 **CHAPTER 3 – ASSET OVERVIEW** Describes the assets we own and operate along with their current condition.

OUR APPROACH TO ASSET MANAGEMENT AND PERFORMANCE OBJECTIVES

4 **CHAPTER 4 – APPROACH TO ASSET MANAGEMENT** Sets out the approach we take to asset management.	5 **CHAPTER 5 – ASSET MANAGEMENT GOVERNANCE** Describes the processes we use to manage our assets and network.
6 **CHAPTER 6 – ASSET MANAGEMENT PERFORMANCE** Describes both the performance we are seeking to achieve and the performance levels delivered over the last two years.	

OUR 10 YEAR PLAN

7 **CHAPTER 7 – NETWORK DEVELOPMENT AND NON-NETWORK INVESTMENTS** Sets out our plans for developing the network over the next 10 years, along with our non-network expenditure.	8 **CHAPTER 8 – RENEWALS AND MAINTENANCE** Sets out the requirements for replacement and maintenance expenditure over the next 10 years.
9 **CHAPTER 9 – SUMMARY OF EXPENDITURE FORECASTS** Summarises our projected expenditure over the next 10 years.	

APPENDICES

Provides supporting information and the detailed regulatory schedules

Figure 1.3 AMP Structure

2 BACKGROUND

2. BACKGROUND

This chapter introduces WEL Networks Limited (WEL) and our customers. It provides an overview of our distribution network (network) that serves our customers. The chapter is structured as follows:

- **Overview of WEL (2.1):** background information on WEL, including our governance arrangements, purpose, vision, values, and stakeholders;
- **Our Customers (2.2):** describes our customers and the quality of supply they require from our network; and
- **Our Network (2.3):** provides an overview of the network assets used to distribute electricity.

2.1 OVERVIEW OF WEL

WEL and its direct predecessors have supplied electricity to the Northern Waikato for nearly 100 years. The Northern Waikato region includes the major population centre of Hamilton City, and the regional centres of Raglan, Gordonton, Horotiu, Ngaruawahia, Huntly, Te Kauwhata and Maramarua.

The following sections describe WEL's ownership and governance structure in more detail, along with our company purpose, vision and values.

2.1.1 OWNERSHIP AND GOVERNANCE

WEL is locally owned. The company has one shareholder, the Trust. The beneficiaries of the Trust are the local councils; Hamilton City Council, Waikato District Council and the Waipa District Council. As the Trust is community owned the income it generates benefits the community WEL serves. The Trustees of the Trust are elected by WEL's customers, with elections held every three years. The next election is scheduled for June 2017. The Trust is responsible for appointing WEL's Board of Directors.

WEL is run for the benefit of customers and the community. The Trust monitors the performance of WEL and is consulted on our strategic initiatives including asset management measures and targets. More information about the Trust and its activities can be found at www.welenergytrust.co.nz.

2.1.2 CORPORATE OBJECTIVES

Our corporate purpose, vision, values and objectives are detailed below.

OUR PURPOSE:

"Growing investment for our community"

The Trust's purpose is to grow investment for our community by being diligent shareholders and by utilising our profits effectively in our community through an annual discount on individual electricity accounts and through a programme of community grants.

Our business vision and values are driven directly from the Trust's purpose statement. This ensures that there is a clear line of sight between the aspirations of the Trust and how we operate as a business.

OUR VISION:

"Provide high quality, reliable utility services valued by our customers whilst protecting and enabling our community"

The overriding principle of our vision is to continually develop a high quality electricity network which provides cost effective and reliable services to our customers. By keeping our vision at the forefront of our activities, we focus on enhancing our customer's experience and protecting the community we serve.

We play a pivotal role by providing services that are essential to the economic, social and environmental wellbeing of the community we serve.

Our vision is supported by our fundamental values.

OUR VALUES:

Our values are designed for our staff to easily remember and emulate in their everyday interaction with our customers and the community. They are in the form of A, B, C, D and E:

A	Agility	Being quick and responsive to change and opportunities. Having the flexibility to respond when the situation demands it.
B	Build the Business	Grow our business' influence and competitiveness. Making sure that our business is always as efficient and effective as it can be. Continuously improving what we do.
C	Care for our people, customers and assets	Working well with people in our business, respecting and providing service to our community, caring about the assets we own and operate.
D	Do the right thing	Earn respect for our actions. Making decisions that might not always be easy, but are the right thing to do.
E	Every day home safe	Everyone, focusing every day, on their own safety, their colleagues' safety, and the public's safety.

As a business we take pride in these values and demonstrate them in everything we do.

INFORMING OUR ASSET MANAGEMENT OBJECTIVES

Our purpose, vision and values drive our strategic priorities defined within our Strategic Plan. They also provide context for our business and asset management practices. The asset management strategies defined in our strategic plan are:

- Our asset management investment decisions reflect safety as our top priority and are optimised based on a quantifiable trade-off between capital and operational expenditure, risk and reliability;
- Preventive and corrective maintenance decisions are made using quantitative analytical techniques such as Reliability Centred Maintenance (RCM) or Failure Modes and Effects Analysis (FMEA). These techniques allow for a quantifiable trade-off between capital and operational expenditure, risk, and reliability considerations;
- We fully leverage our Smart Box data to inform the way we plan, build, maintain and operate our network. This includes voltage exception analysis, fault identification and remediation, peak capacity planning and optimised load control;
- How, when and who we use to deliver our AMP are key inputs in our investment decisions; and
- We have an effective operational business metering team and are recognised externally as a leading player in the smart metering business environment.

The strategic plan in turn provides the performance requirements, targets and initiatives for each of our asset management objectives. Our asset management objectives cover four key areas; safety, customer experience, cost efficiency and asset performance. The objectives are:

- **Safety:** Safety is our highest priority. Our objective is to provide a safe environment for our staff, contractors, and members of the public;
- **Customer Experience:** Our customer objective is to deliver the quality of supply (reliability) sought by our customers and provide them with high quality services;
- **Cost Efficiency:** Our objective is to make the right investment choice at the right time, and to deliver our works programme safely for the lowest total ownership cost possible while achieving our performance targets; and

- **Asset Performance:** Our asset performance objective is to optimise the price-quality trade-off based on our stakeholders' needs. We will support this by further understanding our customer needs, developing our asset management capability, asset strategies, network configuration, and supporting business processes.
- Our performance objectives are set out in more detail within Chapter 6.

2.1.3 STAKEHOLDERS

As a community owned company we consider our stakeholder requirements to have utmost importance. Accordingly, we have considerable focus on identifying and meeting stakeholder expectations. We have eight broad groups of stakeholders:

- Customers;
- Community;
- Regulators;
- Transpower (including their role as System Operator (SO);
- Electricity retailers;
- Service providers;
- Staff; and
- Board of Directors.

Each group is described below.

CUSTOMERS

Our customers are our primary focus. We have differentiated them into six groups; domestic, non-domestic, small scale distributed generation, streetlight, unmetered and large. In addition we have domestic and non-domestic customers in Cambridge and Auckland on our external networks. These groups can be further characterised as either being located within the Central Business District (CBD), urban and rural areas of our network. We also have a number of generation customers who inject electricity into our network.

We identify our customer needs through surveys, feedback and direct interaction. While there is diversity in the level of service sought by the different groups, all customers are concerned with four key service areas; public safety, quality of supply, price of the service they receive, and the level of customer service we provide. Their interests are accommodated within our asset management practices through delivering acceptable asset management, technical and performance standards.

Our customers are further discussed in Section 2.2.

RETAILERS

There are approximately fifteen retailers who sell electricity and ancillary services to our customers. In addition, retailers in most situations are responsible for collecting revenue on our behalf and maintaining direct contractual relationship with customers.

We maintain frequent communications with retailers through our operational, billing and payment interactions and regular consultation. We understand retailers' requirements of us as an electricity distributor. These requirements include: the delivery of effective business to business services; use of transparent, simple and appropriate network tariff structures and prices; and fair contractual arrangements. Retailers are viewed as customers in their own right and representatives of our customers.

COMMUNITY

We have a responsibility to the wider community in which we operate. Our owner is a community trust and as such the wider community needs are an important focus for us. We have developed our understanding of the community's needs through a number of channels including the Trust. These needs include safety and the impact that our assets have on the environment. These needs are paramount to us and are accommodated for in our asset management practices. Our objectives and approach for public safety and environmental issues are described in Chapter 6.

REGULATORS

As an electricity distribution business our operations are subject to regulations established under various Acts including the Commerce Act and the Electricity Industry Act. The regulations are primarily administered by the Commerce Commission and the Electricity Authority. The Commerce Commission is our economic regulator. It manages regulations around price-quality requirements, and disclosure of important information (Information Disclosure) that applies to WEL. The Electricity Authority is responsible for establishing and regulating an efficient electricity market and other related aspects of an electricity distribution business, such as pricing structure and commercial agreements with retailers that also apply to WEL.

TRANSPOWER

We receive our electricity supply via Transpower, the New Zealand transmission company. Transpower also holds the role of SO responsible for, amongst other things, maintaining the integrity of the electricity system including the coordination of electricity generation. Transpower and WEL consult extensively with each other regarding our respective AMP plans, commercial relationship and other industry issues. We have established systems and protocols with the SO for immediate communications for operational matters should the circumstances require it.

SERVICE PROVIDERS

Our service providers are essential to our ability to supply electricity distribution services to our customers. Accordingly we are focused on ensuring they perform and deliver the services required of them in an effective and efficient manner. They in turn require our interactions with them to be predictable, transparent and commercially sound.

STAFF

Our staff are the driving force behind our business. Our staff value job satisfaction, a safe and enjoyable working environment and to be fairly remunerated for the work they perform. We strive to be a good employer and have incorporated health and safety policies and initiatives, performance reviews, and forward work planning so that staff can maintain a work/life balance.

BOARD OF DIRECTORS

The Board of Directors are the shareholder's representatives in setting direction for the business. As such they are concerned, amongst other things, with:

- Providing a safe environment for staff, service providers and the public;
- Enterprise value and the long-term sustainability of the business;
- Ensuring a good reputation with the community;
- Customer engagement;
- The long-term management of our assets;
- Managing business risk;
- Seeking opportunities for growth;
- Efficient operation; and
- Developing organisational capability.

Their interests are identified and incorporated into asset management practices through our governance processes.

2.1.4 CORPORATE AND ORGANISATION STRUCTURE

The next sections describe the governance arrangements, organisation structure and key responsibilities of our Executive Management, Asset Management and Operational teams. The aim of the governance and organisation structure is to ensure the necessary accountabilities are in place for good asset management.

BOARD OF DIRECTORS AND GOVERNANCE ARRANGEMENTS

The Trust appoints the Board of Directors, who govern the company and appoint the Chief Executive.

The key Board level asset management related governance activities are:

- Approval of strategic plans;
- Approval of the annual business plan and budgets;
- Approval of the AMP and corresponding work plan;
- Individual project approval (for projects greater than $2M); and
- Monitoring performance against the strategies, objectives and targets in relation to the above governance activities.

The Board receives regular reports and information on operational revenue and expenditure of the company, capital expenditure and progress against established timeframes, risk management and compliance, performance, and any customer complaints.

ORGANISATION STRUCTURE

WEL is structured into four divisions: Corporate and Strategy, Asset Management, Operations, and People and Performance. Figure 2.1.4 below illustrates our organisational structure.

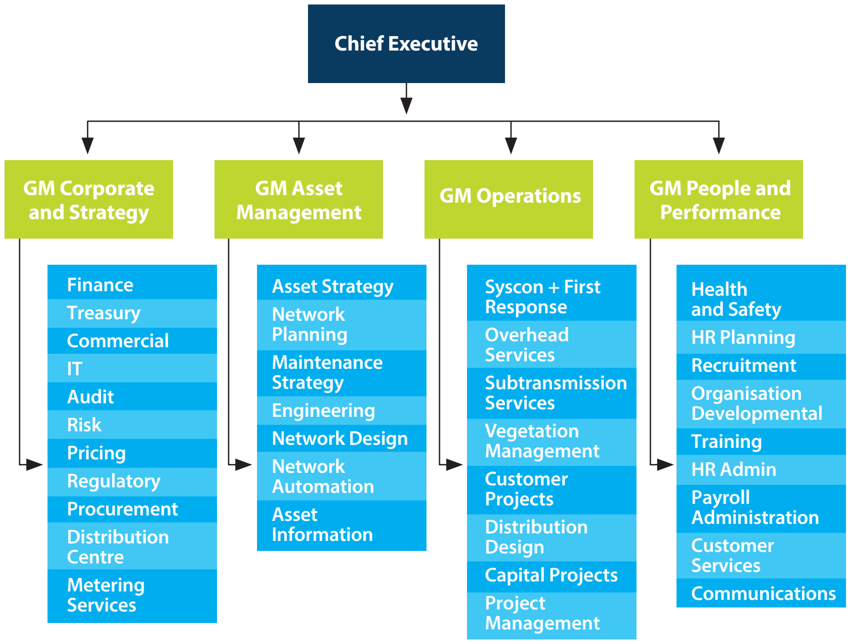


Figure 2.1.4: Organisation Structure

EXECUTIVE MANAGEMENT TEAM

Our Chief Executive and executive management team are responsible for developing our strategy and the leadership of our organisation. The executive team is headed by our Chief Executive, Garth Dibley.

ASSET MANAGEMENT TEAM

Our Asset Management team has overall responsibility for management of the network assets. This includes ensuring that the assets are developed, renewed, maintained, operated and used on a long-term sustainable basis to meet the needs of all stakeholders. The key responsibilities are set out in the following table.

TEAMS	KEY RESPONSIBILITIES
Asset Planning and Engineering	• Investment planning to meet the needs of stakeholders • SCADA/Network Management System (NMS), network automation, Smart Grid and communications • Manage Land Access, Consenting and Resource Management Act requirements
Maintenance Strategy	• Renewals and Maintenance strategy • Development of maintenance standards, policies and procedures • Optimisation of lifecycle costs of network assets • Management of the renewal and maintenance programme
Network Design	• Design services for internal and external customers • Review and approval of design works provided by external contractors
Performance and Asset Investment	• Optimisation of Work Plan • Works Plan programme management • Monitoring asset performance outcomes • Ensuring business management systems are in place including processes, systems and information

Table 2.1.4.1 Asset Management Team Responsibilities

OPERATIONS TEAM

The Operations team has overall responsibility for the operational delivery of the Works Plan. Within the Operations division there are four main teams. The key responsibilities are set out in Table 2.1.4.2 below.

TEAMS	KEY RESPONSIBILITIES
Field Services	• Delivery of the renewal and maintenance programme • Delivery of capital projects
Capital Project Management	• Project Management of large projects • Project Management of external contractors
Network Operate and Restore	• 24/7 monitoring and operation of the network • Control, switching and permitting of access to the network • Effective and efficient fault response and restoration services
Customer Projects	• Delivery of customer driven projects

Table 2.1.4.2 Operations Team Responsibilities

OTHER TEAMS

The Asset Management and Operations teams are supported by the Corporate and Strategy and People and Performance teams. Each team provides essential services in the areas outlined in our organisation structure in Figure 2.1.4 and contribute to the fulfilment of our overall asset management objectives and performance.

CAPABILITY

We have recently undertaken an assessment of our organisational capability. The assessment confirms our core capability rests in the areas of asset management, health and safety, operational control, and reliability management and service restoration. While all our staff and contractors are competent and have appropriate training programmes in place, we have identified and are in the process of forming plans to further lift our capability and competency these areas, and in works delivery, business acumen, and corporate information systems. We will establish a capability development programme to ensure we meet the challenges of the future including the implementation of this AMP.

2.1.5 OUR OPERATING ENVIRONMENT

The environment we operate in is an important factor in delivering our services. There are a range of factors that determine the operational environment. These include:

- Topography;
- Climate;
- Land access;
- Vegetation; and
- Regulations.

The sections below discuss each environmental factor.

TOPOGRAPHY

The topography of our region varies greatly from the gently undulating landscapes of the central Waikato, South Auckland and Hauraki Plains to the steep slopes of the western hill country towards Raglan. The soil of our region is largely free-draining and cultivated. However, there are also areas of peaty loam and peat soils along with wetlands in the Waikato lowlands and large tracts of native forest in the western hill country which add complexity to the design, construction and operation of our network.

CLIMATE

The northern Waikato region enjoys a moderate climate with prevailing winds from the west. On occasions unpredictable extreme weather conditions negatively impact the performance and reliability of our assets. Weather related events cause the highest incidence of interruptions to our customers, particularly in rural areas. This is due to the presence of overhead lines and outdoor assets which are subject to interference from windblown debris and failure during weather events.

LAND ACCESS

Our ability to gain access to our existing assets or land for new assets is critical to our continuing operations. We have been granted special rights under the Electricity Act for assets built prior to 1992 to remain where they are currently located. We are also entitled to access Road Reserves under the relevant council's conditions.

We acquire easements for the location of new assets on private property in order to formalise the respective party's legal rights. Obtaining the rights is usually straightforward when a private land owner will directly benefit from providing access e.g. a new connection. However obtaining access for new assets to transit private land is often challenging and can take time.

As such our planning systems ensure work commences on obtaining the necessary land access rights as soon as practical in the planning process. A conservative approach is taken to the amount of land access required as changes in access requirements can cause additional expense and delay in the delivery of new assets.

VEGETATION

Vegetation located close to our assets has the potential to interfere with the safe and reliable supply of electricity to our customers. We manage all vegetation in accordance with the requirements of The Electricity (Hazards from Trees) Regulations 2003. We do this by patrolling, monitoring and recording sites where vegetation could interfere with the safe and reliable supply to our customers. We trim or remove vegetation accordingly.

REGULATION

We operate in a regulated environment. As we are community owned and our size is below the threshold contained within Part 4 of The Commerce Act 1986, we are exempt from direct price and quality control by the Commerce Commission. We remain subject to all other regulatory controls including significant Information Disclosure requirements.

2.2 OUR CUSTOMERS

WEL supplies electricity to a mix of customers across our CBD, urban and rural environments. Our customers range from low-use domestic though to very large users e.g. Waikato Hospital. Effective engagement with customers requires a targeted approach. Our largest customers are regularly consulted on a range of issues important to them through our key account and customer works teams. Regular surveys are undertaken across all other customer groups, with the latest customer survey undertaken in February 2014.

2.2.1 CUSTOMER PROFILES

There are over 85,000 connections across WEL's traditional network area with an additional 1,800 within our networks located in Auckland and Cambridge. The breakdown of load by customer group is set out in Table 2.2.1 below.

<table>
<tr><th>CUSTOMER GROUP</th><th>NUMBER OF ACTIVE ICPS</th><th>ELECTRICITY DELIVERED (GWH)</th><th>DEMAND (MW)</th></tr>
<tr><td>Domestic</td><td>71,752</td><td>497 (42%)</td><td rowspan="4">165 (65%)</td></tr>
<tr><td>Non-Domestic</td><td>12,025</td><td>201 (17%)</td></tr>
<tr><td>Small Scale Distributed Generators</td><td>247</td><td>0.4 (0 %)</td></tr>
<tr><td>Streetlights and Unmetered</td><td>273</td><td>9 (1%)</td></tr>
<tr><td>Large</td><td>709</td><td>480 (40%)</td><td>91 (36%)</td></tr>
<tr><td>Embedded Networks</td><td>1,819</td><td>14</td><td>n/a</td></tr>
<tr><td>TOTAL</td><td>86,825</td><td>1,201</td><td>255</td></tr>
</table>

Table 2.2.1 Electricity Delivered and Demand by Customer Group

2.2.2 MAJOR CUSTOMERS

- We remain in regular contact with all our major customers to ensure their needs are considered in our asset planning and service delivery. In some instances the specific needs of these customers influence the design and operation of our network. For example additional security levels are required in the connection of some customers, while others require fast response times to fault events to ensure that essential operations can continue. Our ten largest major customers are:

- Hamilton City Council;
- Waikato District Health Board;
- Solid Energy;
- AFFCO;
- Pack Group (Alto Packaging);
- The University of Waikato;
- Fonterra / Canpac International ;
- Spark;
- Westfield; and
- Proform Plastics.

	ELECTRICITY DELIVERED (GWH)	PEAK TIME DEMAND (MW)
Top 10 Customers	159	23
Percentage of WEL Traditional Network	13.4%	8.9%

Table 2.2.2 Major Customers Electricity Delivered and Peak Time Demand

Our two largest customers, Hamilton City Council and Waikato Hospital are, like us, suppliers of essential services. Accordingly they warrant special consideration and priority of attention in the event of loss of supply.

2.2.3 ELECTRICITY DELIVERED AND DEMAND

The total electricity delivered during 2015 is forecast to be 1,203 GWh with a coincident peak demand of 244MW. As illustrated in Figure 2.2.3, electricity delivered has continued to increase while peak demand has generally been flat since 2011.

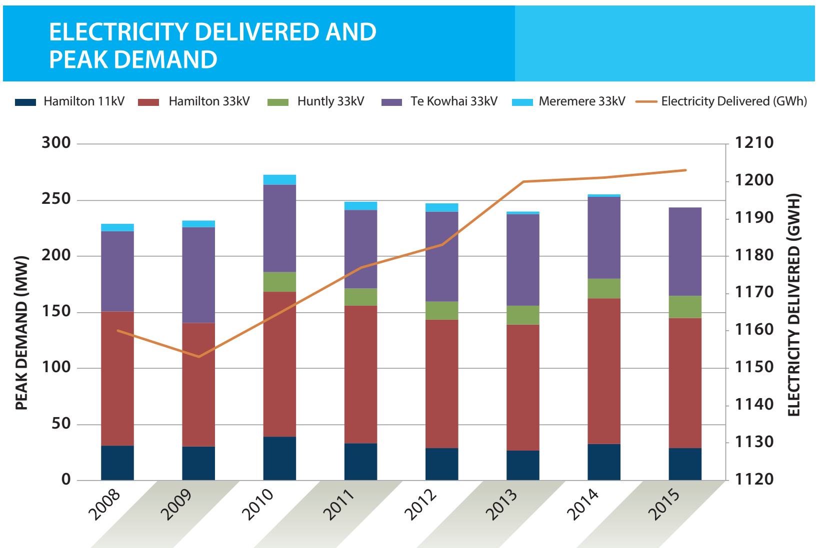


Figure 2.2.3 Electricity Delivered and Peak Demand

The majority of customers across our network have two distinct load profiles throughout the day. For urban customers load is generally high in the morning with a trough during the day and then increasing again in the late afternoon, early evening as residential customers prepare the evening meal. The peak load occurs during winter. The rural profile follows a similar pattern with the addition that dairy farms peak in summer during milking times of early morning and mid-afternoon.

CHANGING ELECTRICITY DELIVERED, PEAK DEMAND AND GENERATION

We have observed a number of changes in the quantities of electricity delivered and in peak demand patterns. Examples include:

- A declining amount of electricity delivered on average to our domestic customers. The average delivered quantity has fallen to 6,700 kWh p.a. from over 8,000 kWh p.a. or 16% in recent years. New domestic customers connecting to our network tend to be double glazed with electricity efficient lighting and appliances and on an average only take delivery of 5,200 kWh of electricity p.a.;
- Delivery of electricity to our large customers on average has also declined by approximately 1% p.a. since 2013, while their peak demand has declined by 2% on average. Our large customers pricing includes a strong peak time demand price component and it is evident many of our large customers are actively managing their demand during these times;
- Small scale distributed generation conversions are increasing. More than 100 new small scale distributed generators connected to our network in the past year. This increase is expected to continue as the cost of photovoltaic (PV) installation becomes more affordable. Each conversion typically results in a reduction of 3,000 kWh p.a. of delivered electricity;
- Our local councils have started to utilise LED technology for street lighting. LED technology could see electricity used in street lighting drop by up to 80%; and
- The use of electric vehicles has commenced. We anticipate the use of electric vehicles will increase during the AMP period.

The impact of these changes on our plans is discussed further in the demand forecasting section in Chapter 7.

2.3 OUR NETWORK

This section describes our network and provides an overview of our assets grouped according to their function.

2.3.1 NETWORK OVERVIEW

Our region stretches from Hamilton City in the southeast, to Raglan in the west to Maramarua in the north. We also own and operate small embedded networks in Cambridge and Auckland. Our coverage area is illustrated in Figures 2.3.1.1 and 2.3.1.2 below.

Figure 2.3.1.1
Map of WEL Networks area

Figure 2.3.1.2
Map of WEL external networks

The network we utilise to supply the area consists of four main components:

- Grid Exit Points (GXPs) which connect our network to the National Grid;
- Subtransmission circuits and zone substations that transport the bulk supply across the region (33kV);
- Distribution assets (11kV) that move power from the zone substations to areas of local supply; and
- Low voltage network that then connects directly to houses and businesses.

Figure 2.3.1.3 below provides a high level depiction of the GXPs and Subtransmission network.

NETWORK OVERVIEW

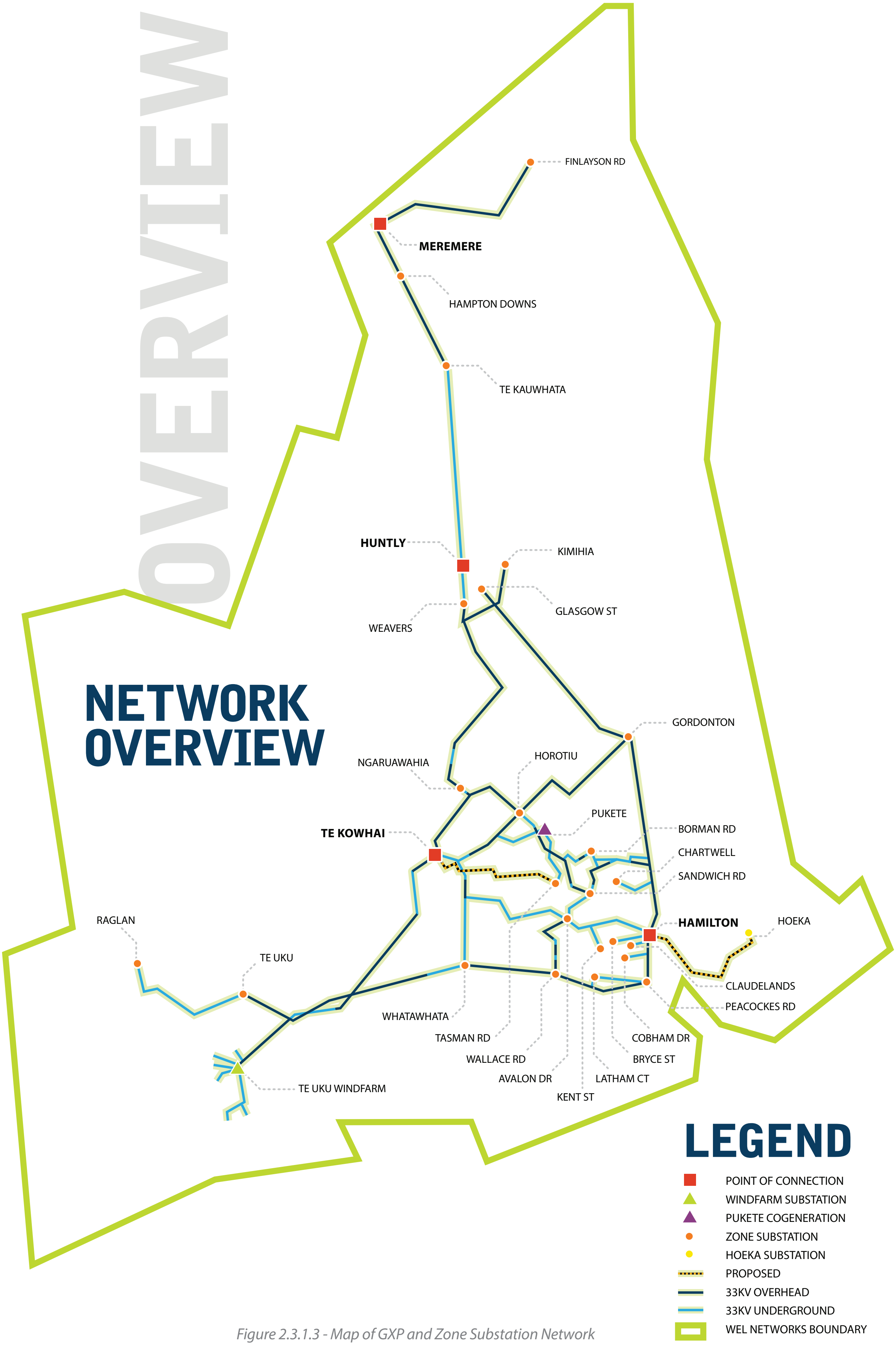


Figure 2.3.1.3 - Map of GXP and Zone Substation Network

The following sections describe each network component in more detail.

GXPS

We take supply from three GXPs (owned by Transpower) located at Hamilton, Te Kowhai and Huntly. A general description of assets at each GXP is provided in Table 2.3.1.1 below:

GXP	GENERAL DESCRIPTION
Hamilton	Hamilton GXP supplies electricity at both 33kV and 11kV. Our 33kV subtransmission network from Hamilton provides a degree of interconnectivity with Te Kowhai providing an additional level of backup and security for Hamilton City. We own some protection and ancillary equipment located at the Hamilton GXP consisting primarily of check meters, auxiliary power supplies, load control plants, SCADA and communications equipment.
Te Kowhai	Commissioned in 2005 Te Kowhai GXP supplies electricity at 33kV. The 33kV subtransmission network from Te Kowhai has a degree of interconnection capability with Hamilton GXP. We own protection and ancillary equipment located within the Te Kowhai GXP. This includes check meters, auxiliary power supplies, load control plant, SCADA and communications equipment.
Huntly	Huntly GXP supplies electricity at 33kV. The Huntly GXP can also be supplied from the neighbouring Bombay GXP via Meremere and a 33kV subtransmission circuit should this be required. We own all the 33kV equipment on site including the 33kV switchgear, protection equipment and ancillary equipment.

Table 2.3.1.1 GXP General Description

Hamilton GXP has the largest supply capacity and is the principle supply point for Hamilton City Over the last five years the anytime peak demand across all our GXPs has declined from 298 MW in 2010 to 274.2 MW in 2015.

SUBTRANSMISSION AND ZONE SUBSTATIONS

Our 33kV subtransmission network transports electricity from Transpower's GXPs to our zone substations that in turn supply the 11kV distribution network. The subtransmission network is 433km in length and consists of a 33kV interconnected mesh around Hamilton City and double radial 33kV circuits supplying all but our Raglan and Finlayson zone substations. For Raglan and Finlayson the zone substations are supplied from single radial 33kV subtransmission circuits with our 11kV distribution network providing partial backup.

The level of security provided in the majority of the subtransmission network is known as N-1. This means that the network can withstand the loss of one component and continue to supply electricity to customers.

There are 26 zone substations on the network. All zone substations have two or more transformers (N-1) except Whatawhata, Finlayson, Raglan and Hampton Downs, which are smaller rural zone substations that supply smaller loads with a single transformer (N security).

The level of security supplied available at each zone substation is in accordance with our network security criteria discussed further in Chapter 7.

DISTRIBUTION

Our distribution system takes supply from zone substations and the Hamilton GXP at 11kV. The distribution system is comprised of 11kV overhead lines on poles and crossarms, underground cables, distribution transformers and switching stations and consists of 2603km of 11kV cables and overhead lines, generally known as feeders.

The Hamilton City CBD 11kV distribution network consists of 11kV underground trunk feeders interconnecting within the CBD network. The interconnection of the 11kV feeders provides an additional level of security, over and above that provided in the subtransmission network. The CBD distribution system has provided a high level of reliability to the CDB and its urban customers.

In other areas the 11kV distribution network is mostly overhead lines except where they traverse the newer residential areas. All recent and new subdivisions, whether they are rural or urban, are reticulated with underground cables in accordance with modern district plan requirements.

There are four main types of distribution substations on the network, industrial and commercial, residential berm, residential pole mounted, and rural substations. Each has different characteristics.

Industrial and commercial distribution substations typically consist of enclosed, ground mounted transformers with integrated high voltage switchgear enclosed or adjacent to the unit. They are either site specific or only distribute electricity to a small number of customers. Low voltage distribution to these customers is protected using either fuses or circuit breakers (CBs) located within the unit.

Residential berm type substations consist of enclosed ground mounted transformers with integrated high voltage switchgear enclosed or adjacent to the unit and customers are typically supplied from these units via fuses and underground LV cables.

Residential pole type substations consist of pole mounted transformers with high voltage fuses above the unit. Customers are supplied from these units via fuses to LV overhead lines or underground cables.

Rural pole type substations consist of pole mounted transformers with high voltage fuses adjacent to the unit. Customers are supplied via fuses and LV overhead lines.

A number of our large customers own distribution networks within their sites. WEL only maintains and operates these where it is contracted to do so.

LOW VOLTAGE NETWORK

We manage 3463 km of low voltage (LV) lines and cables. Approximately 90% of rural and 40% of the urban low voltage network is overhead lines. All new residential subdivisions, whether they are rural or urban, are reticulated with underground cables.

LV assets include overhead lines, poles, insulators, cables, supply pillars, fuses and other ancillary equipment.

2.3.2 ASSET CLASSES

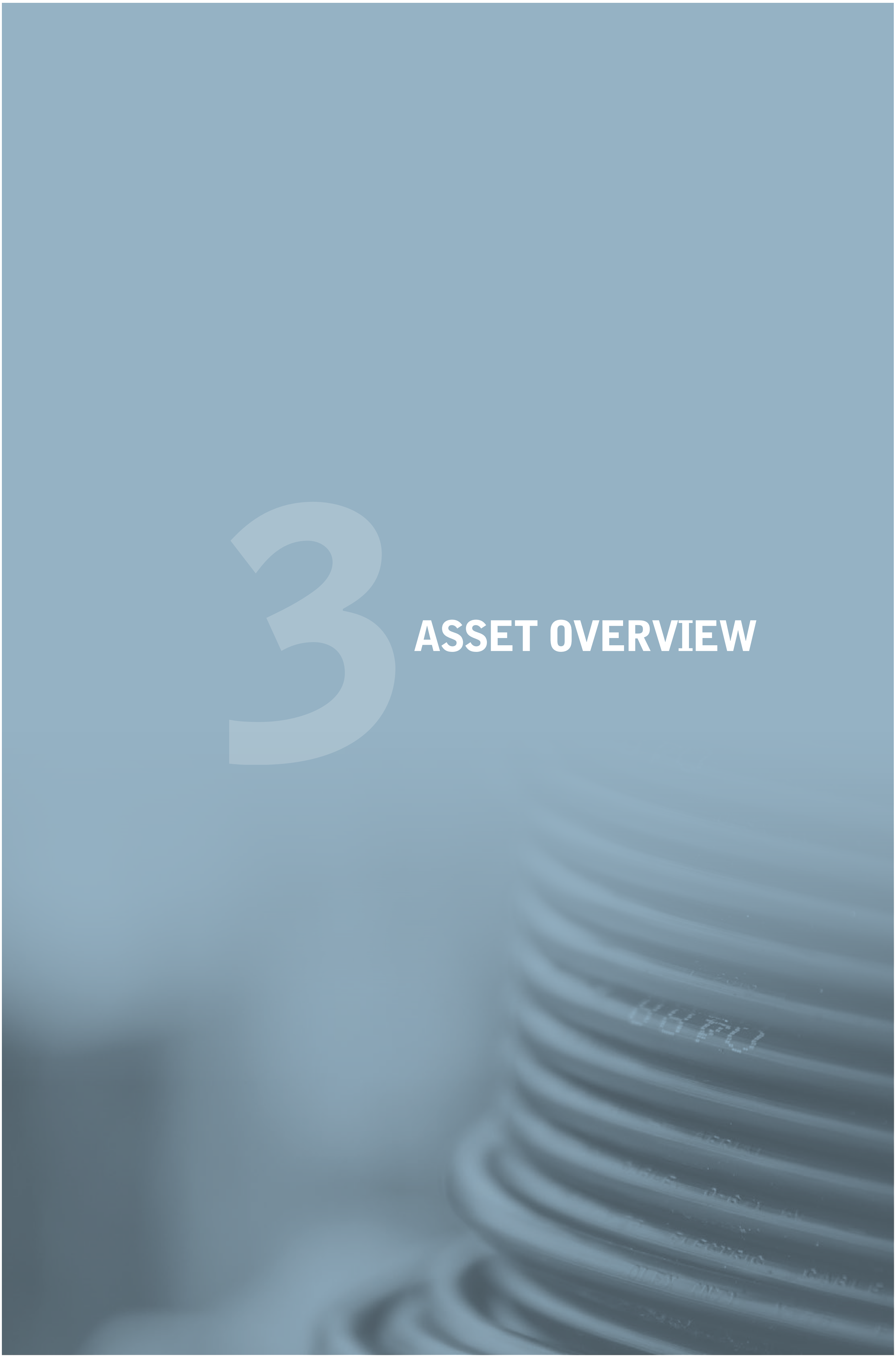
We group our assets into asset classes. We have utilised these asset classes throughout the AMP. These asset classes are defined below and align with those required for Information Disclosure purposes. More detail on each asset class is included in Chapter 3.

The asset classes utilised throughout this AMP are:

- **Subtransmission:** the lines, cables and switchgear associated with the 33kV subtransmission system;
- **Zone Substations:** includes switching stations and the transformers, switchgear and buildings located within zone substations;
- **Distribution and LV Lines:** covers the 11kV and LV conductors, poles and other equipment associated with our overhead lines;

- **Distribution and LV cables:** includes the 11kV and LV underground cables;
- **Distribution substations and transformers:** covers the small substations and transformers that convert electricity from 11kV to LV;
- **Distribution switchgear:** includes switches and reclosers that are utilised on the distribution system to change the configuration of the network during maintenance or fault situations;
- **Other system fixed assets:** covers the important ancillary equipment used on the network to control and monitor the network; and
- **Other assets:** covers all the other ancillary assets we utilise in providing services to our customers.

3 ASSET OVERVIEW



3. ASSET OVERVIEW

This chapter describes the population, age profile, and condition of our assets. The chapter is structured as follows:

- **Asset Population (3.1):** quantifies the population and condition of our assets;
- **Subtransmission (3.2):** describes our subtransmission assets;
- **Zone Substations (3.3):** describes our zone substation assets;
- **Distribution and LV lines (3.4):** describes our distribution and LV line assets;
- **Distribution and LV cables (3.5):** describes our distribution and LV cable assets;
- **Distribution substations and transformers (3.6):** describes our distribution substation and transformer assets;
- **Distribution switchgear (3.7):** describes our distribution switchgear assets;
- **Other system fixed assets (3.8):** describes our other system fixed assets;
- **Other assets (3.9):** describes our other assets; and
- **Assets owned by WEL at GXPs (3.10):** lists the assets we own that are installed at Transpower's GXPs.

3.1 ASSET POPULATION SUMMARY

A summary of the population and condition of our assets is shown in Table 3.1.1 below.
The condition is presented in the scale we use for grading our assets. Condition 5 represents an asset in 'as new' condition and an asset is at condition 0 when it's 'due for replacement'.[1]

SECTION	ASSET CATEGORY	UNIT	QUANTITY	WEL CONDITION SCORE					
				0	1	2	3	4	5
3.2	**Subtransmission**								
3.2.1	Poles	No.	2874	0	0	0	23	1919	932
3.2.2	Crossarms	No.	3040	0	0	0	24	2030	986
3.2.3	Subtransmission Lines[2]	km	195	0	0	0	107	2	86
3.2.4	Subtransmission Cables[3]	km	238	0	0	2	3	53	180
3.2.5	Subtransmission Circuit Breakers	No.	117	0	0	0	0	70	47
3.3	**Zone Substations**								
3.3.1	Power Transformers	No.	43	0	0	0	0	3	40
3.3.2	Switchboards	No.	60	0	0	0	0	29	31

[1] *For regulatory reporting purposes these condition profiles are translated into the Commerce Commission's C1 to C4 condition scale in the schedules attached to this AMP. The translation from our 0 to 5 condition scale to the Commerce Commission's prescribed C1 to C4 scales is: WEL Condition 0 and 1 is translated to C1, 2 and 3 become C2, 4 is C3 and 5 is C4.*

[2] *Condition score based on age.*

[3] *Condition score based on age.*

SECTION	ASSET CATEGORY	UNIT	QUANTITY	WEL CONDITION SCORE					
				0	1	2	3	4	5
3.3.3	Substation Buildings	No.	45	0	0	1	14	24	6
3.4	**Distribution and LV Lines**								
3.4.1	Poles	No.	36681	0	466	910	2893	14536	17876
3.4.2	Crossarms	No.	70100	0	343	772	36217	13691	19077
3.4.3	Distribution and LV conductors	km	3317	0	0	654	166	550	1947
3.5	**Distribution and LV Cables**								
3.5.1	Distribution Cables	km	649	0	0	68	58	188	335
3.5.2	LV Cables	km	2100	0	0	5	497	802	796
3.6	**Distribution Substations and Transformers**								
3.6.1	Distribution Switching Stations	No.	17	0	0	0	9	8	0
3.6.2	Distribution Transformers	No.	5637	0	0	19	734	2847	2037
3.7	Distribution Switchgear								
3.7.1	Ring Main Units	No.	724	0	0	17	81	463	163
3.7.2	Distribution Circuit Breakers	No.	430	0	0	3	0	222	205
3.7.3	Distribution Air Break Switches	No.	1030	2	0	2	8	608	410
3.7.4	Distribution Sectionalisers	No.	46	0	0	0	0	39	7
3.8	**Other System Fixed Assets**								
3.8.1	LV Pillars	No.	22000	0	0	21	17	9264	12698
3.8.2	Protection Relays	No.	852	0	32	13	162	27	618
3.8.3	Network Management System	No.	976	0	0	0	64	0	912
3.8.4	Load Control Equipment	No.	10	0	0	0	0	7	3
3.8.5	Meters	No.	56286	0	0	0	0	0	56286

Table 3.1.1 Asset Population and Condition Summary

3.1.1 ASSET HEALTH INDEX (AHI)

Our asset renewal strategy discussed in Chapter 8 utilises the CBRM methodology. In implementing the CBRM approach we have established an AHI for some of the asset categories.

AHIs combine age, condition, environment and risk to generate a more comprehensive measure of asset health than a condition score. A probability of failure (PoF) is derived from the AHI and combined with consequential losses in order to establish a risk level. An AHI of 0 means the asset is in 'as new' condition with a very low PoF, whereas an AHI of 10 means that it is near the end of its life with a high probability of failure. This is illustrated in Figure 3.1.1 below.

CONDITION	HEALTH INDEX	REMNANT LIFE	PROBABILITY OF FAILURE
Bad	10	At EOL (<5 years)	High
Poor		5-10 years	Medium
Fair		10-20 years	Low
Good	0	>20 years	Very low

Figure 3.1.1 CBRM Health Indices

Where an AHI exists for an asset category it has been shown along with the population, age profile and condition information in the following sections.

3.2 SUBTRANSMISSION

The subtransmission system transports bulk electricity across the region. It connects Transpower's GXPs to our zone substations. It also provides a level of interconnection between zone substations.

The subtransmission network operates at 33kV and is 433 km in length, of which 195 km is overhead and 238 km is underground. The majority of the overhead lines are in the rural areas while the underground network is split between the urban and rural areas.

The following asset categories are included within the subtransmission category:

- Subtransmission poles;
- Subtransmission crossarms;
- Subtransmission lines;
- Subtransmission cables; and
- Subtransmission circuit breakers.

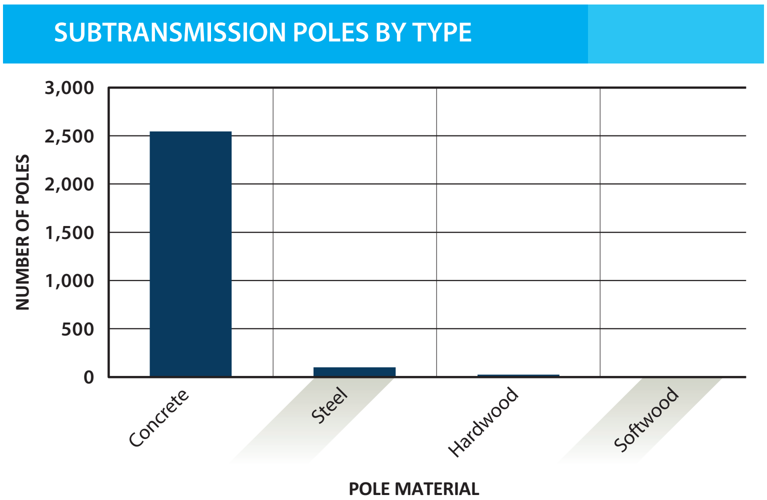
Each asset category is described in the following Sections.

3.2.1 SUBTRANSMISSION POLES

POPULATION

We have 2874 subtransmission poles. Figure 3.2.1.1 shows the distribution by construction material. The majority are concrete poles, with a small number of softwood, hardwood and steel poles remaining.

Figure 3.2.1.1 Subtransmission Pole Types



AGE PROFILE

The age profile of subtransmission poles share the same age profile as subtransmission lines, shown in Figure 3.2.3.2, as they are installed at the same time. The exception to this is wooden poles that have a shorter life expectancy and therefore require earlier replacement. New poles installed are concrete due to the increased life expectancy.

ASSET	LIFE EXPECTANCY (YEARS)
Concrete poles	70
Wooden poles (both softwood and hardwood)	45

Table 3.2.1.1 Life Expectancy of Subtransmission Poles

CONDITION

The condition profile of the subtransmission poles is shown in Figure 3.2.1.2 below. Field inspections indicate that in general the condition of subtransmission poles is good.

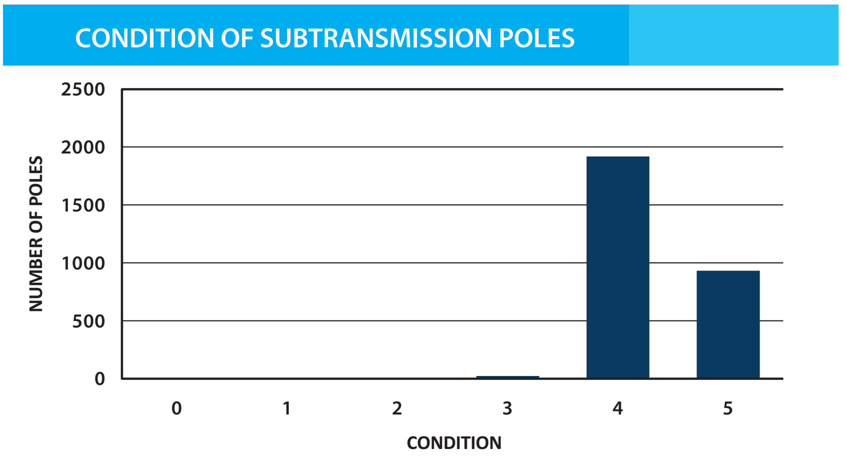


Figure 3.2.1.2 Condition of Subtransmission Poles

3.2.2. SUBTRANSMISSION CROSSARMS

POPULATION

We have 3040 subtransmission crossarms with the vast majority being hardwood. Due to hardwood crossarms having a comparatively short life we have recently changed to installing galvanised steel crossarms on the network.

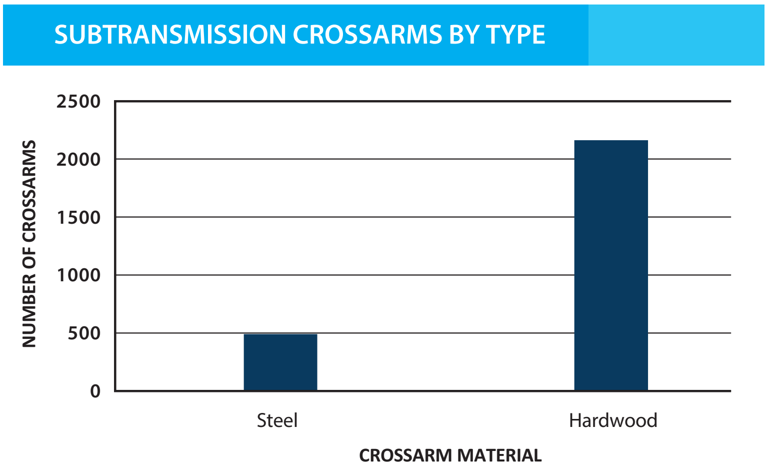


Figure 3.2.2.1 Subtransmission Crossarm Types

AGE PROFILE

The age profile of subtransmission crossarms share the same age profile as subtransmission lines, shown in Figure 3.2.3.2, as they are installed at the same time. The exception to this is hardwood crossarms that have a shorter life expectancy and therefore require earlier replacement. Wooden crossarms have half the life expectancy of the line, so must be replaced at least once during a line's lifetime.

ASSET	LIFE EXPECTANCY (YEARS)
Steel crossarms	60
Hardwood crossarms	35

Table 3.2.2.1 Life Expectancy of Subtransmission Crossarms

CONDITION

The condition profile of the subtransmission crossarms is shown in Figure 3.2.2.2 below. Field inspections indicate that in general the condition of subtransmission crossarms is good.

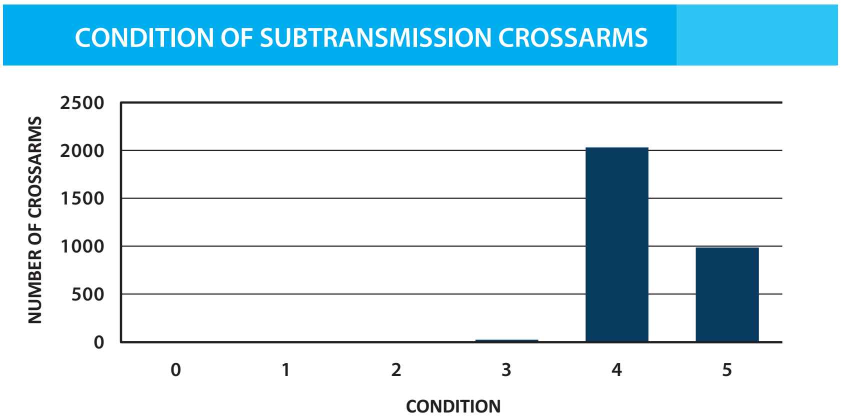


Figure 3.2.2.2 Condition of Subtransmission Crossarms

3.2.3. SUBTRANSMISSION LINES

Subtransmission lines connect GXPs to the zone substations at 33kV.

POPULATION

We have 164 km of subtransmission lines in rural areas, 25 km within the Hamilton urban area and 6 km in Huntly.

Subtransmission lines consist of conductors (wire). Four types of conductors are used on our network:

- Copper;
- Aluminium conductor steel reinforced (ACSR);
- All aluminium (AAC); and
- All aluminium alloy (AAAC).

Copper was the original conductor installed on the network. Since the 1980s the relatively high cost of copper precluded its use and the installation of various aluminium conductors commenced. ACSR was the first aluminium conductor utilised, but more recently AAC and AAAC have been adopted as network standards.

Figure 3.2.3.1 below shows the quantity of subtransmission conductor by type.

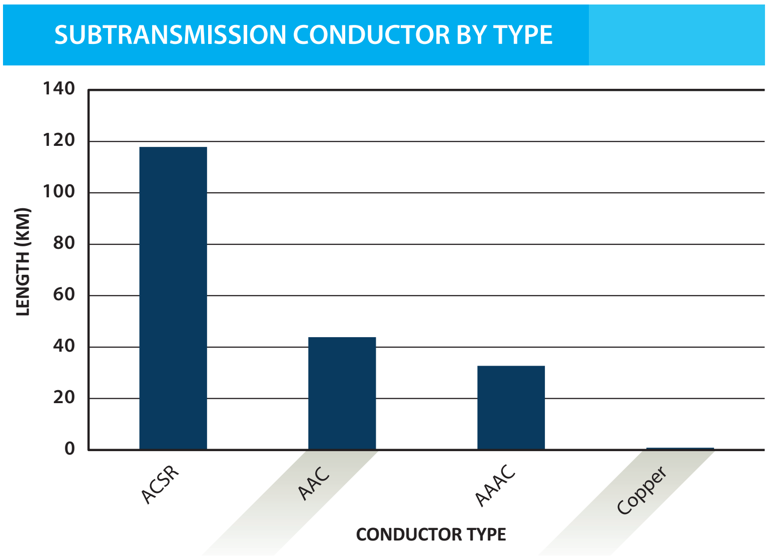


Figure 3.2.3.1 Subtransmission Poles and Crossarm by type

AGE PROFILE

Figure 3.2.3.2 below shows the age profile of our subtransmission lines. The life expectancy of conductors is 58 years. The graph shows the length of line installed in each year. There have been periods of major investment in our subtransmission lines. The spike at year four (2010) corresponds to the construction of a subtransmission line to the Te Uku Wind Farm. In year 16 (1998), the link between Horotiu and Weavers substations was constructed. A number of areas of the subtransmission network were strengthened in year 37 (1977).

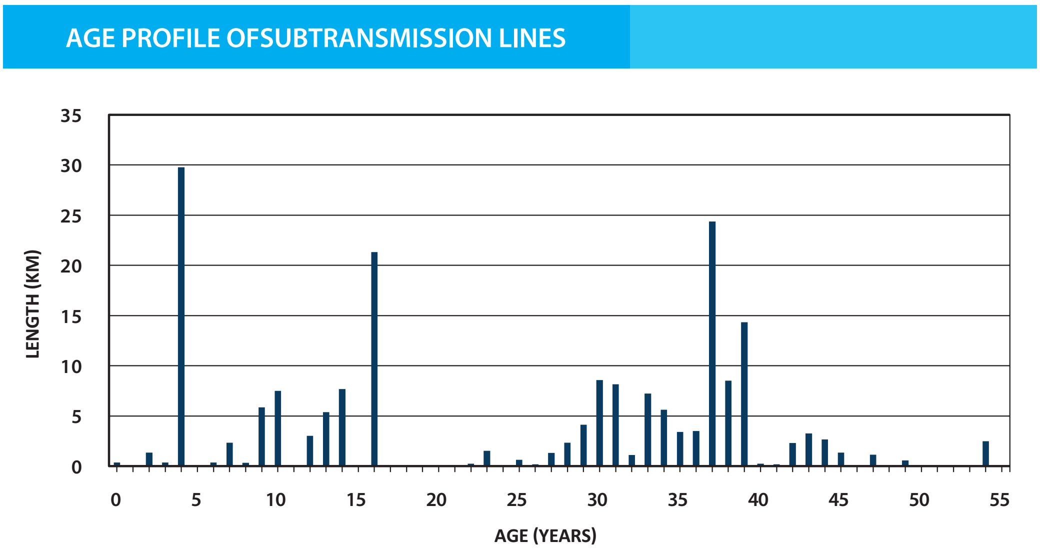


Figure 3.2.3.2 Age Profile of Subtransmission Lines

AGE PROFILE

The condition profile of the subtransmission lines is shown in Figure 3.2.3.3 below. Field inspections indicate that in general the condition of subtransmission lines is good.

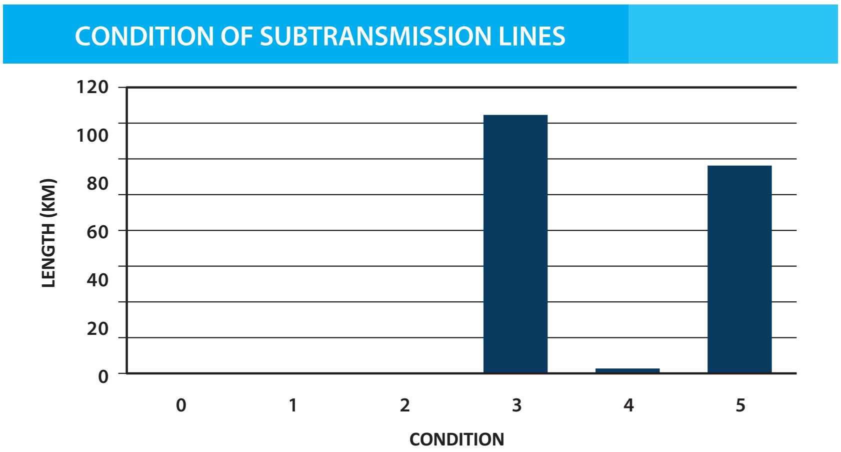


Figure 3.2.3.3 Condition of Subtransmission Lines

3.2.4 SUBTRANSMISSION CABLES

Subtransmission cables connect GXPs to the zone substations at 33kV. We have 238 km of subtransmission cables, with 95 km in Hamilton.

POPULATION

Figure 3.2.4.1 shows the geographical location of our subtransmission cables. There are two types of subtransmission cables in use. Cross-linked polyethene (XLPE) aluminium cables comprise 88% of cables in use. The remainder are various types of paper insulated, lead covered (PILC) copper cables. The move from copper PILC cables to aluminium XLPE insulated cables began in the mid-1970s. We have standardised on the use of XLPE insulated single core aluminium conductor cables with copper wire screens.

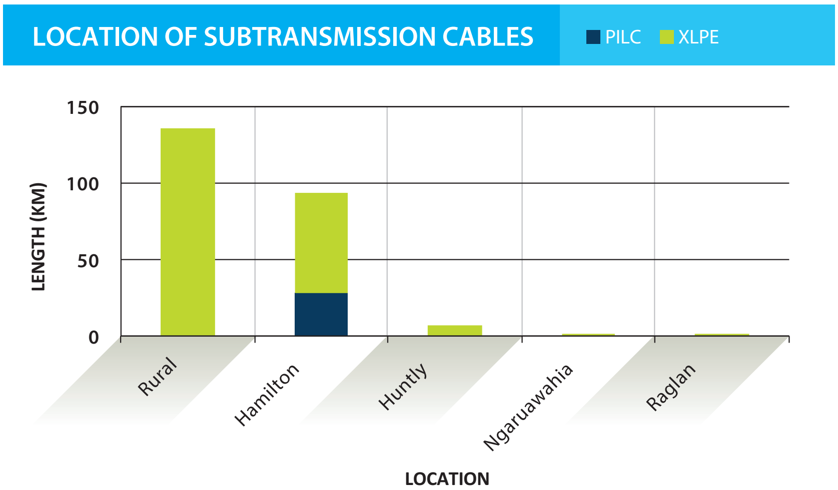


Figure 3.2.4.1 Location of Subtransmission Cables

We do not have any gas or oil filled subtransmission cables in our network.

AGE PROFILE

Figure 3.2.4.2 shows the age profile for subtransmission cables. The age of PILC cables range from 32 to 44 years and XLPE cables range from new to 44 years old. The weighted average age of the XLPE cables is 8 years and the weighted average age of the PILC is 36 years old.

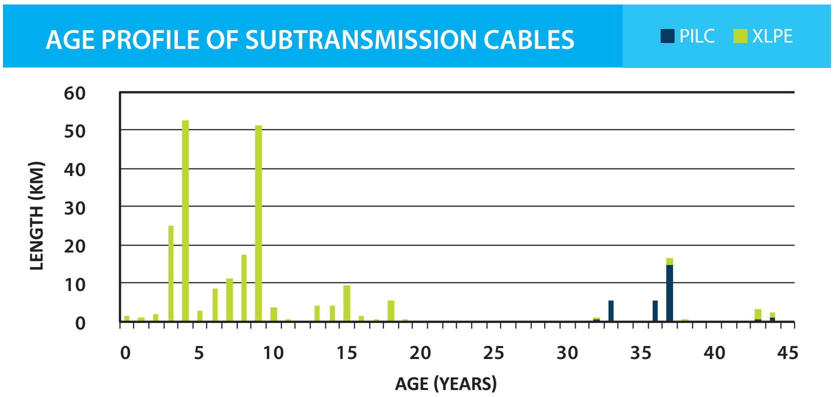


Figure 3.2.4.2 Age Profile of Subtransmission Cables

The life expectancy of the cables is shown in Table 3.2.4.1 below.

CABLE TYPE	LIFE EXPECTANCY (YEARS)
PILC Cables	70
XLPE Cables	45

Table 3.2.4.1 Life Expectancy of Subtransmission Cables

CONDITION

The condition of our subtransmission cables is considered to be generally good. The only issues experienced to date are joint failures in a number of cables. These failures have been attributed to faulty workmanship during installation. A programme of partial discharge tests has been initiated to determine the extent of these problems.

3.2.5 SUBTRANSMISSION CBS

The majority of subtransmission CBs are located within substations on incoming circuits. Their main function is to protect the power transformers at each substation. A CB is also a switching device that can be operated either manually or automatically. When operated automatically it interrupts the flow of electricity if the current exceeds a predetermined level.

POPULATION

We own 117 33kV CBs. Three types of CB are in use on our network; oil, gas insulated (SF_6), and vacuum breakers. Typically the older oil circuit breakers were installed in outdoor switchyards, while the newer types (gas insulated and vacuum) are more often installed indoors. Over recent years, the older outdoor switchgear has been upgraded to indoor switchgear. Consequently only 10 % of the fleet remain outdoors. Figure 3.2.5.1 shows the distribution by type.

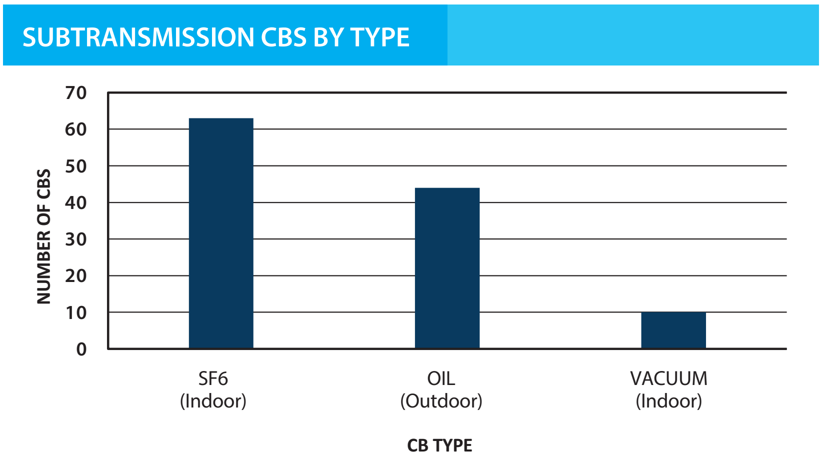


Figure 3.2.5.1 Subtransmission CBs by Type

AGE PROFILE

Figure 3.2.5.2 shows the age profile of the CBs installed on the network. Most 33kV CBs installed over the last 10 years were indoor SF_6 type.

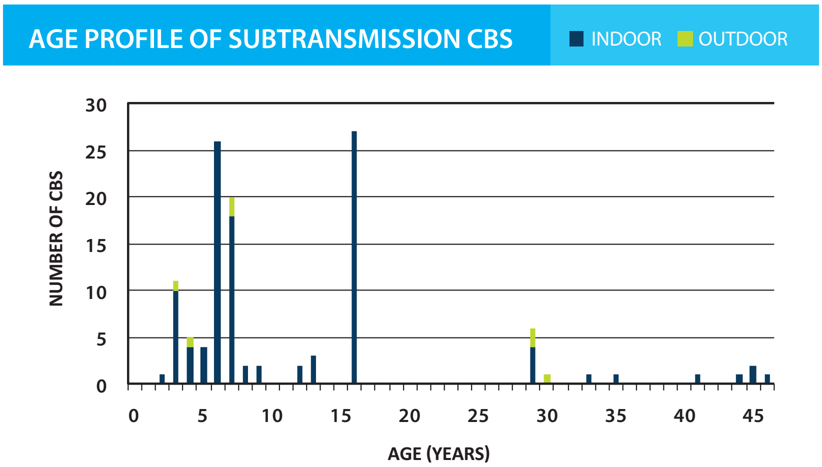


Figure 3.2.5.2 Age Profile of Subtransmission CBs

The expected lives are shown in Table 3.2.5.1 below.

ASSET	LIFE EXPECTANCY (YEARS)
Outdoor Breakers	45
Indoor Breakers	60

Table 3.2.5.1 Life Expectancy of Subtransmission CBs

CONDITION

All 33kV CBs are regularly maintained in accordance with recognised maintenance practices and are in good condition. The condition profile of the subtransmission CBs is shown in Figure 3.2.5.3 below.

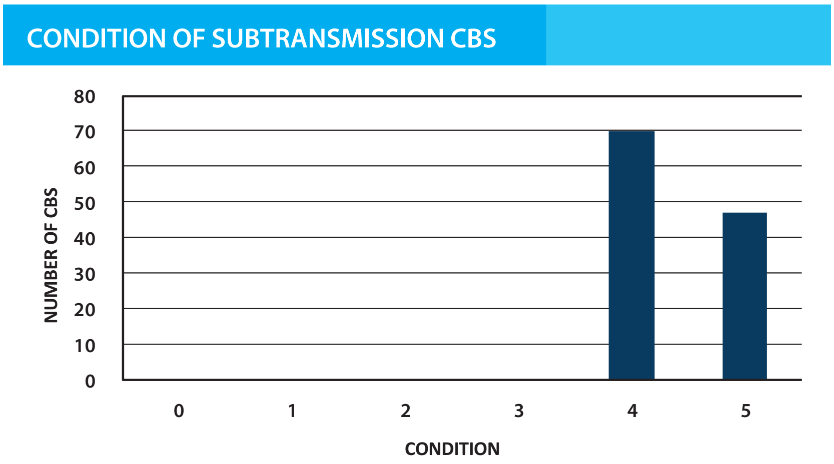


Figure 3.2.5.3 Condition of Subtransmission CBs

3.3 ZONE SUBSTATIONS

Zone substations transform power from the subtransmission 33kV to the 11kV distribution voltage. Switching stations (a form of zone substation) provide the capability to switch between interconnected 33kV circuits and provide security of supply during fault conditions or planned maintenance.

We own 26 zone substations with construction dates ranging from the 1950s to 2012. Six of the 26 zone substations have outdoor switchyards which include 33kV CBs, outdoor instrument transformers, switches, insulators and busbars. Twenty of the zone substations have N-1 security and six have N security, in accordance with the WEL security standard, which is discussed in further detail in Chapter 7.

Substations include buildings, outdoor structures, foundations, fences, oil interception equipment and auxiliary equipment such as low voltage AC and DC power supplies. The major plant items located at substations include power transformers and the associated switchgear.

Within the zone substation asset class there are three asset categories:

- Power transformers;
- Indoor switchboards; and
- Substation buildings.

3.3.1 POWER TRANSFORMERS

Power transformers reduce the voltage from the subtransmission voltage (33kV) to distribution voltage (11kV).

POPULATION

We own 43 power transformers with installation dates ranging from 1960 to 2012. There are two 10MVA and two 15MVA spare power transformers strategically located in our zone substations that are readily available when needed.

Figure 3.3.1.1 shows the size distribution of our power transformers. The majority are rated at 15/23 MVA with forced air-cooling.

DISTRIBUTION OF POWER TRANSFORMER RATINGS

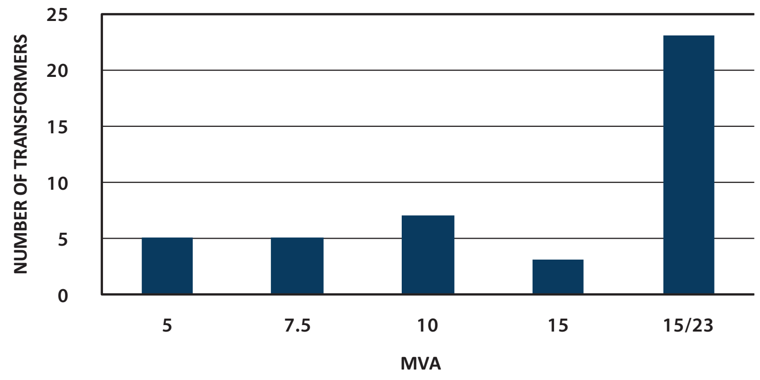


Figure 3.3.1.1 Distribution of Power Transformer by Ratings

AGE PROFILE

The age profile of our power transformers is shown in Figure 3.3.1.2 below.

AGE PROFILE OF POWER TRANSFOMERS

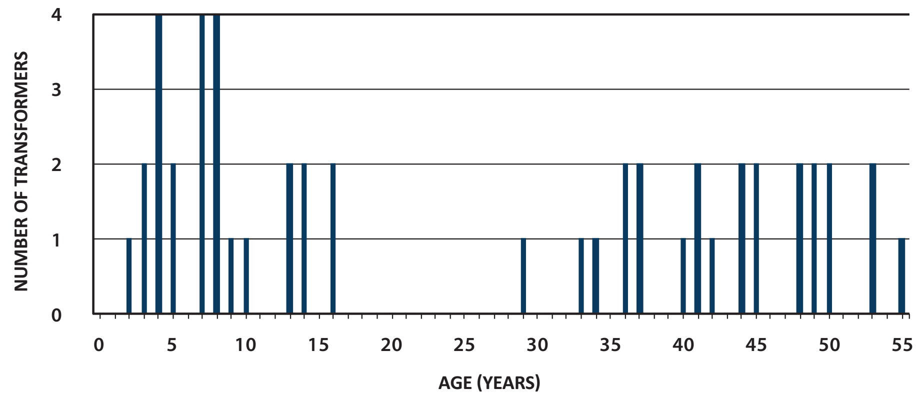


Figure 3.3.1.2 Age Profile of Power Transformers

The average age of the power transformer fleet is currently 24 years old. The life expectancy of power transformers is 60 years. All transformers undergo a mid-life refurbishment to achieve this lifespan. Transformers often are upgraded, not because of old age, but because the load has exceeded their capacity. In such situations, we rotate the transformers from one substation to another smaller one.

CONDITION

The internal condition of the transformers is monitored by utilising annual Dissolved Gas Analysis (DGA) and periodic furans analysis to give an indication of remaining life. Test results are then correlated with the results from other diagnostic testing such as Sweep Frequency Response Analysis (SFRA) and Dissipation Factor tests. The overall results of the testing shows that our power transformers are in a good condition. This is illustrated in Figure 3.3.1.3 below.

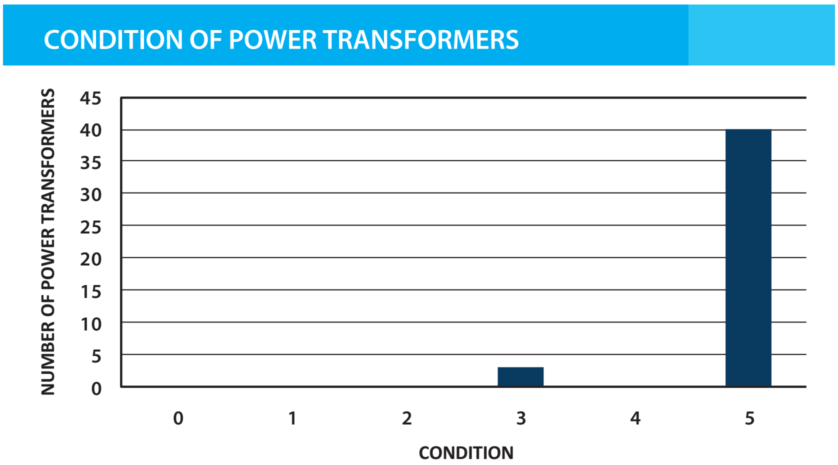


Figure 3.3.1.3 Condition of Power Transformers

3.3.2 SWITCHBOARDS

Switchboards contain switchgear that provide control and protection for the network. There are two main types of switchgear; Air Insulated Switchgear (AIS) and Gas Insulated Switchgear (GIS). GIS is located indoors and installed in our newly constructed substations. Rural zone substations with outdoor switchyards are progressively being converted to indoor.

POPULATION

We own 60 switchboards, with 51 being AIS and nine GIS. Generally, the type of switchboards is a reflection of the age of the substations.

AGE PROFILE

The age profile of the indoor switchboards is shown in Figure 3.3.2.1. The average age of switchboards is 17 years. The life expectancy of switchboards is 60 years.

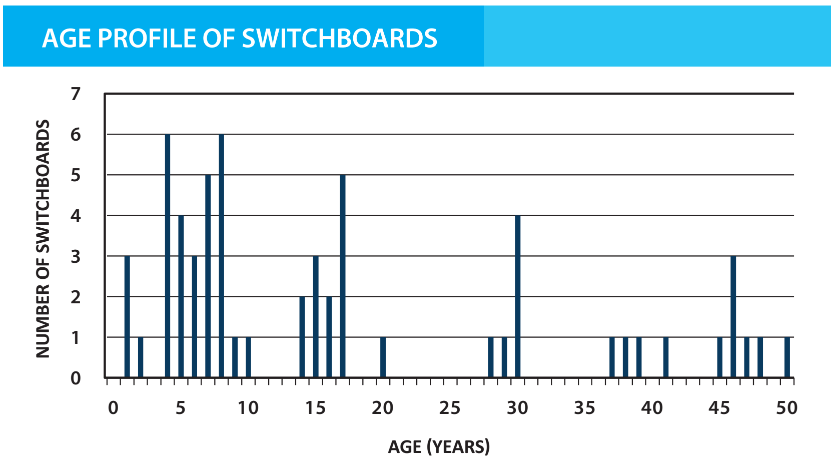


Figure 3.3.2.1 Age Profile of Switchboards

CONDITION

The condition of the majority of our switchboards is good. Partial discharge appears to be a problem for some of the older ones.

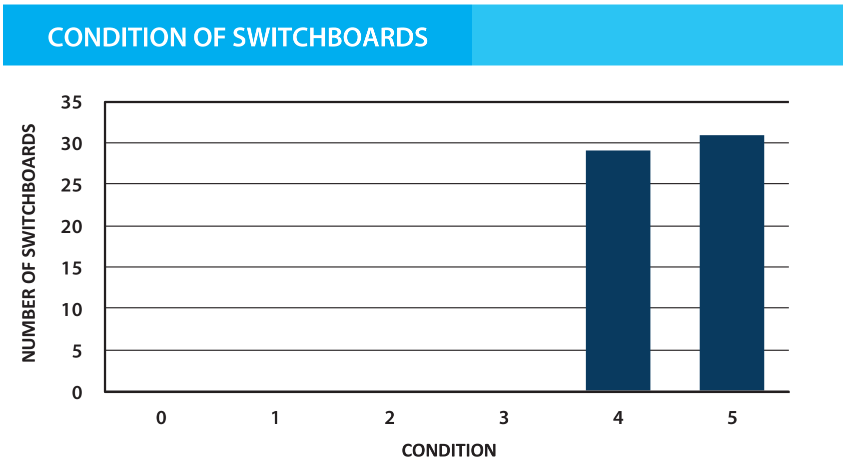


Figure 3.3.2.2 Condition of Switchboards

3.3.3 SUBSTATION BUILDINGS

Substation buildings provide protection against environmental factors and prevent unauthorised entry reducing safety risk to members of the public.

POPULATION

Each of the 45 substations were built to meet specific site and regulatory requirements at the time of construction. As the construction of our substations occurred over several decades they have differing designs.

AGE PROFILE

Figure 3.3.3.1 shows the age profile for substation buildings.

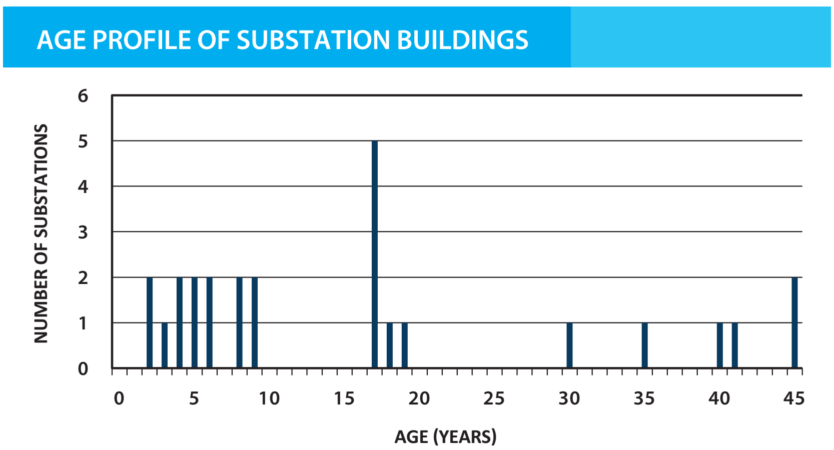


Figure 3.3.3.1 Age Profile of Substation Buildings

When a substation is substantially refurbished the buildings are usually reinforced or completely rebuilt.

CONDITION

The seismic rating and the general condition of the substation buildings have been assessed.

We commenced a programme of specialised seismic assessment in 2007. The results of the seismic assessment to date are shown in Figure 3.3.3.2 below. Six buildings have been rated below standard and work is scheduled to bring them up to standard.

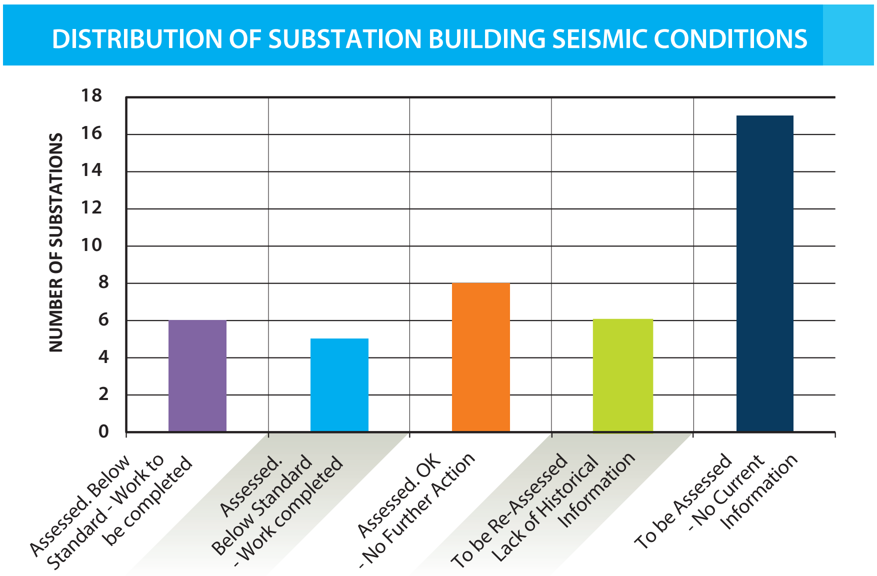


Figure 3.3.3.2 Distribution of Substation Building Seismic Conditions

Our substation buildings were also assessed by registered quantity surveyors as part of a financial valuation process in 2013. The assessment found that the majority of them are in good condition, as illustrated in Figure 3.3.3.3 below.

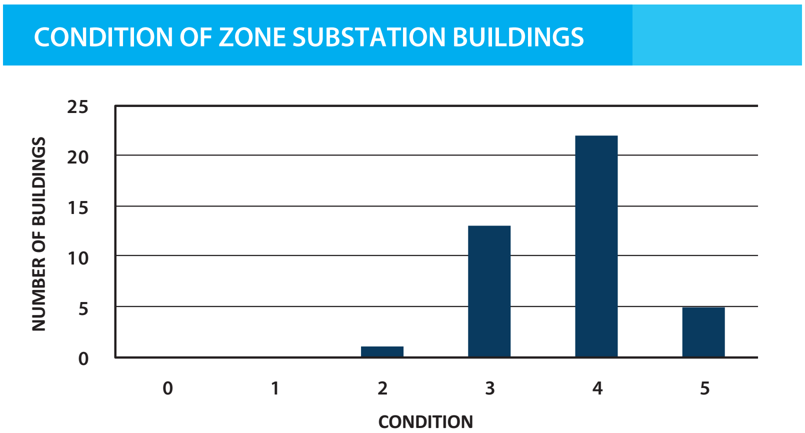


Figure 3.3.3.3 Condition of Zone Substation Buildings

3.4 DISTRIBUTION AND LV LINES

The distribution network conveys electricity from zone substations to the LV network. The LV network supplies the majority of our customers. The network includes overhead lines and underground cables. The total length is 6,000 km, of which 55% is overhead line.

This section describes the following asset categories which are included within Distribution and LV Lines:

- Poles;
- Crossarms; and
- Distribution and LV conductors.

3.4.1 POLES

Poles support the overhead lines. They play a key role in isolating conductors and preventing contact with people and property.

POPULATION

We own approximately 36,600 poles. Figure 3.4.1.1 shows the distribution by construction material. The majority are concrete poles, with a small number of softwood, hardwood and steel poles remaining.

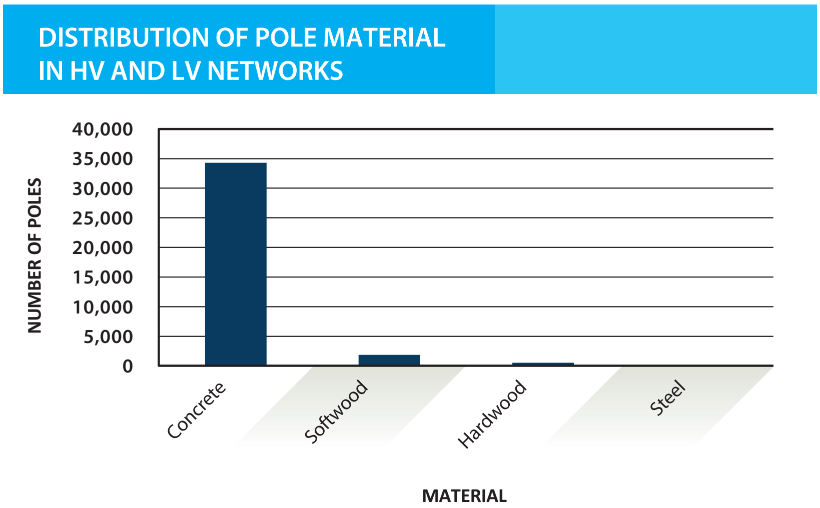


Figure 3.4.1.1 Distribution of Pole Material in HV and LV Networks

AGE PROFILE

Figure 3.4.1.2 shows the age profiles of our poles. The average age of our concrete poles is 30 years, while the average age of our wooden poles is 32 years.

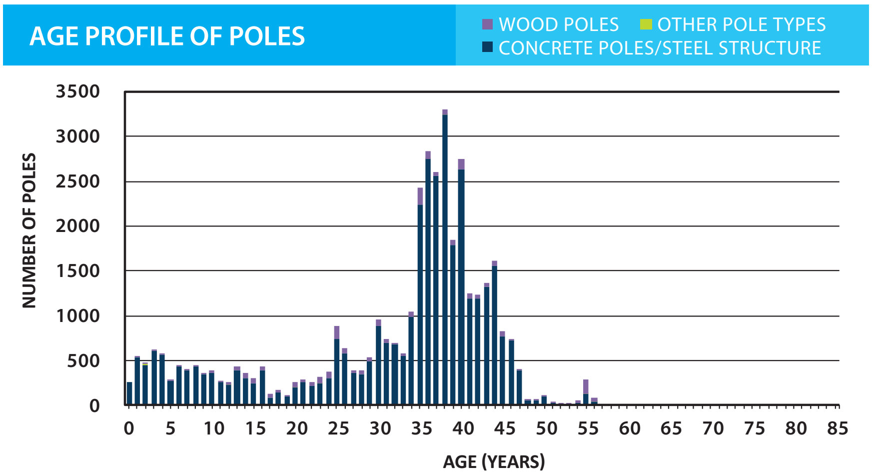


Figure 3.4.1.2 Age Profile of Poles

The life expectancy of concrete poles is 70 years and 45 years for wooden poles as illustrated in Table 3.4.1.1. The population of wooden poles is older and closer to end of life than the concrete ones.

ASSET	LIFE EXPECTANCY (YEARS)
Wooden Poles	45
Concrete Poles	70

Table 3.4.1.1 Life Expectancy of HV and LV Poles

CONDITION

The distribution of pole conditions is shown in Figure 3.4.1.3 below.

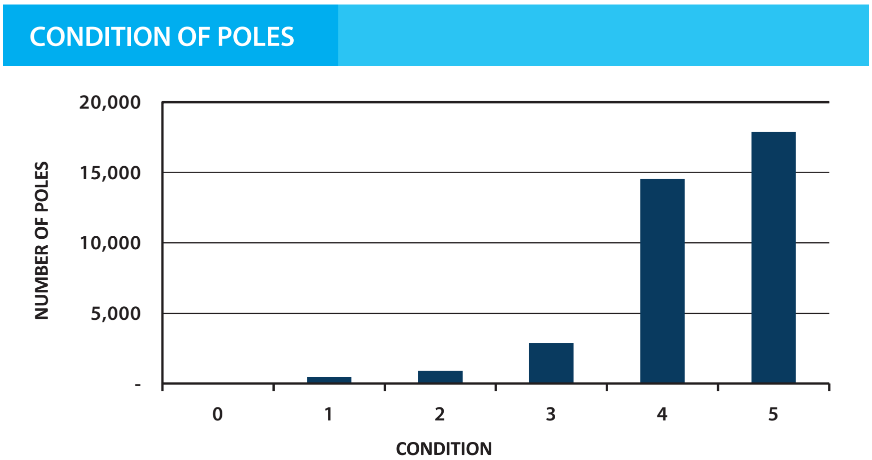


Figure 3.4.1.3 Condition of Poles

The majority of concrete poles are in good condition as the average age is young compared to their life expectancy.

There are approximately 530 hardwood poles on our network that range in condition from good to poor. Wooden poles have a shorter service life than newer concrete poles. As such, it is expected that most wooden poles will need to be replaced in the 10 year AMP period covered by this AMP. In recent years all hardwood poles have been tested for hidden rot at ground level and all poles that were identified as dangerous have been replaced with concrete ones.

Figure 3.4.1.4 shows the AHI profile of our poles.

POLES HEALTH INDEX PROFILE

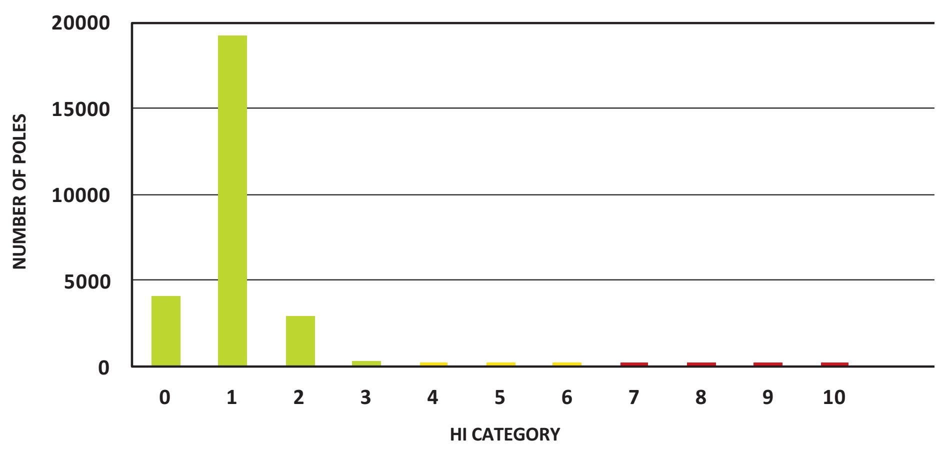


Figure 3.4.1.4 Poles Health Index Profile

3.4.2 CROSSARMS

Crossarms are found at the top of our poles. They support and insulate the conductors and separate each of the three phase conductors. Until recently all of our crossarms were constructed from hardwood, however all new crossarms installed are now steel. As the majority of the crossarms are wooden, which have half the life expectancy of the concrete poles, they are generally replaced half way through the life of the pole.

POPULATION

There are 70,100 crossarms in operation on our network. The majority of crossarms are wooden as shown in Figure 3.4.2.1 below.

DISTRIBUTION OF CROSSARM MATERIAL

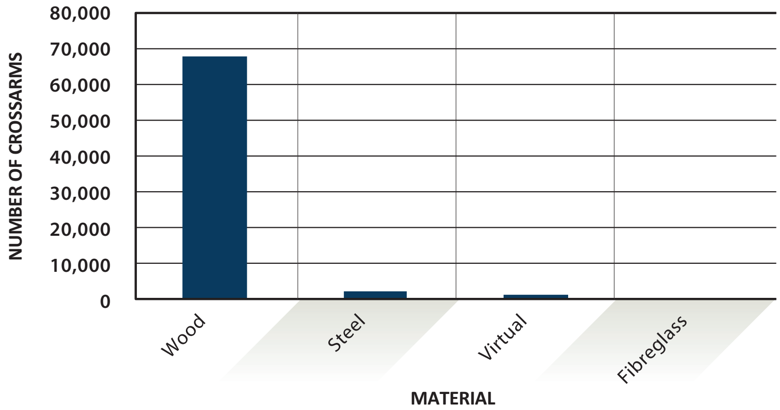


Figure 3.4.2.1 Distribution of Crossarm Material

AGE PROFILE

Figure 3.4.2.2 shows the age profile of wooden and metal crossarms. The average age of the fleet is 32 years.

AGE PROFILE OF CROSSARMS

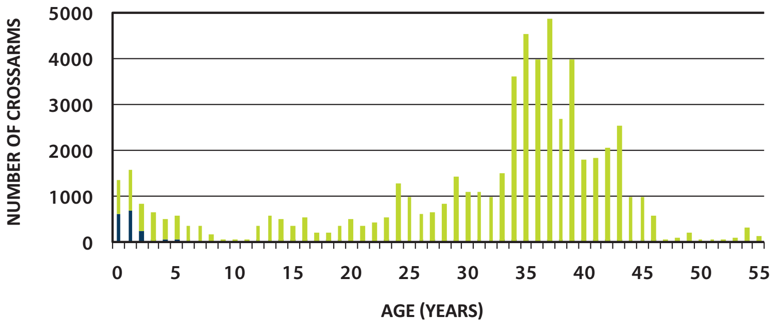


Figure 3.4.2.2 Age Profile of Crossarms

As shown in Table 3.4.2.1 the life expectancy of wooden crossarms is 35 years and metal crossarms is 60 years. Therefore, many of the wooden crossarms already exceed their expected lives. Consequently there is a high failure rate, especially of the insulators. Chapter 8 details the maintenance strategies designed to address these issues.

ASSET	LIFE EXPECTANCY (YEARS)
Wooden Crossarms	35
Metal Crossarms	60

Table 3.4.2.1 Life Expectancy of Crossarms

CONDITION

The condition distribution of our crossarms is shown in Figure 3.4.2.3 below.

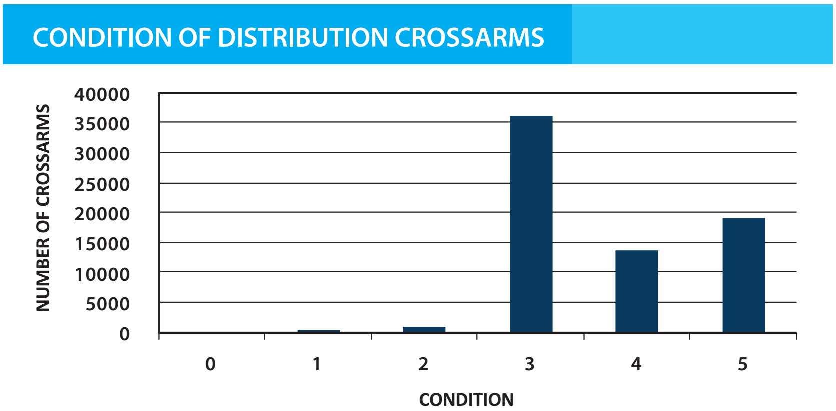


Figure 3.4.2.3 Condition of Distribution Crossarms

The AHI profile for our crossarms is shown in Figure 3.4.2.4. The graph indicates that a significant number are approaching the stage where they will need to be replaced. The Asset Health Index and what factors are used to assess an asset are explained in section 3.1.

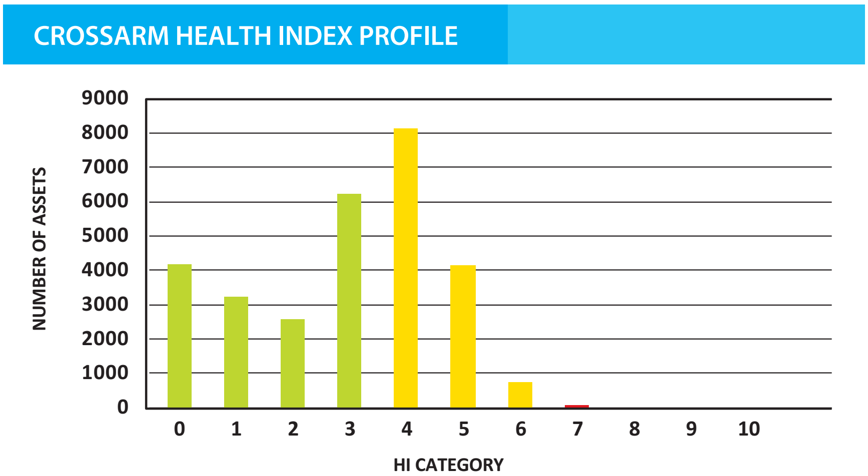


Figure 3.4.2.4 Crossarm Health Index Profile

3.4.3 DISTRIBUTION AND LV CONDUCTORS

Distribution and LV lines transport electricity from zone substations to our customers on the LV network.

POPULATION

We own 3,317 km of overhead distribution and LV lines, of which 1,954 km is 11kV distribution lines and 1,363 km is LV.

Figure 3.4.3.1 shows the distribution of overhead conductor types.

DISTRIBUTION AND LV CONDUCTOR TYPES

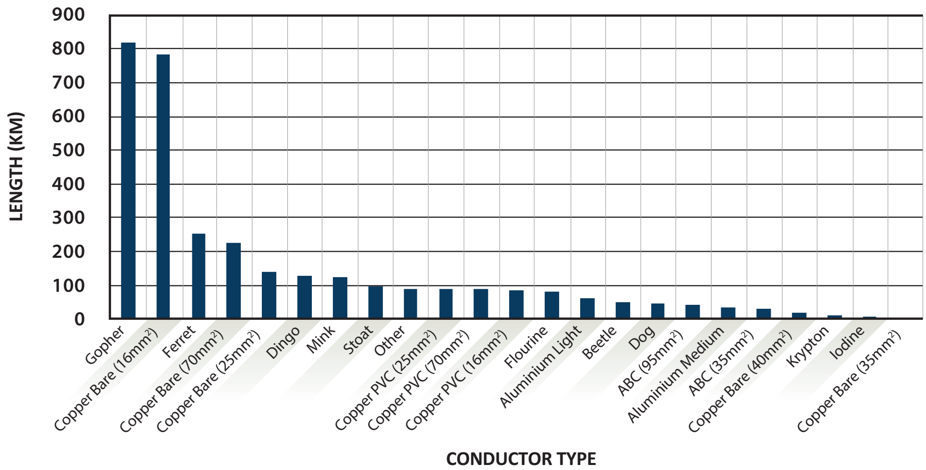


Figure 3.4.3.1 Distribution and LV Conductor Types

Figure 3.4.3.2 shows the location of the distribution and LV lines is primarily in the rural areas. Urban areas are typically reticulated with underground cables.

LOCATION OF DISTRIBUTION AND LV LINES

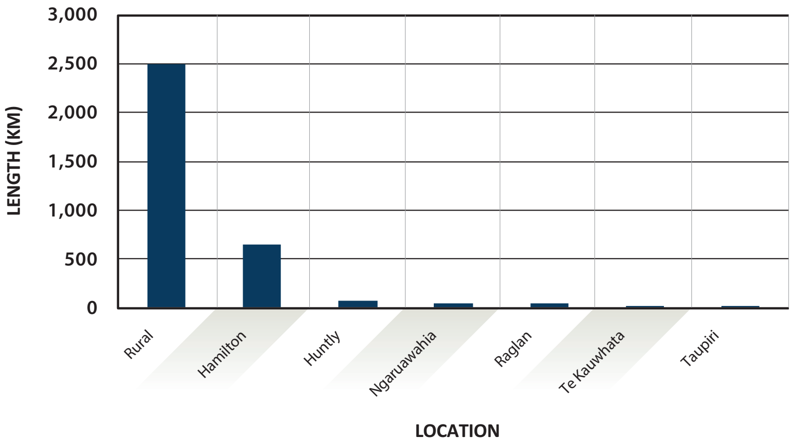


Figure 3.4.3.2 Location of Distribution of LV Lines

AGE PROFILE

Figure 3.4.3.3 shows the age profile of all types of the distribution and LV conductors. The average age of our overhead conductors is 32 years.

AGE PROFILE OF DISTRIBUTION AND LV CONDUCTORS

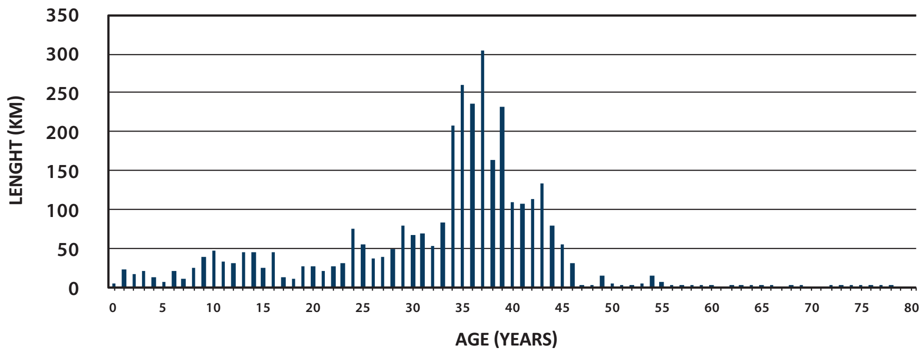


Figure 3.4.3.3 Age Profile of HV and LV Conductor

The spike in installing of new conductors corresponds to the rapid expansion of the network during the 1970s. The life expectancy of all conductor types is 58 years.

CONDITION

The condition distribution of overhead line conductors is shown in Figure 3.4.3.4 below.

CONDITION OF DISTRIBUTION AND LV CONDUCTORS

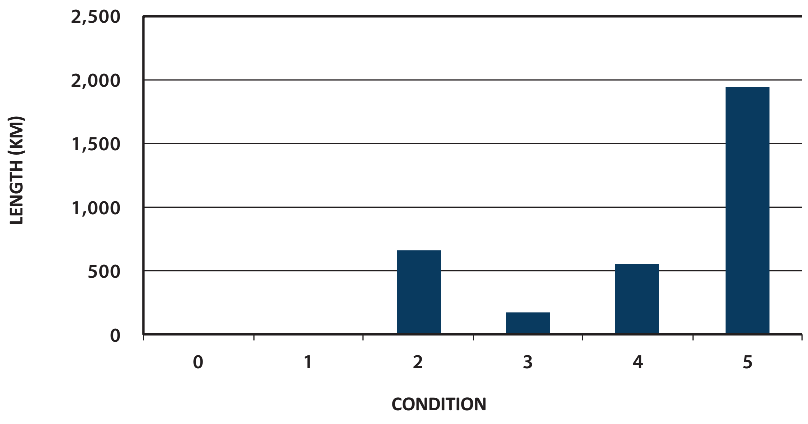


Figure 3.4.3.4 Condition of Distribution and LV Conductor

The condition is further supported by the AHI shown in Figure 3.4.3.5.

DISTRIBUTION CONDUCTOR HEALTH INDEX PROFILE

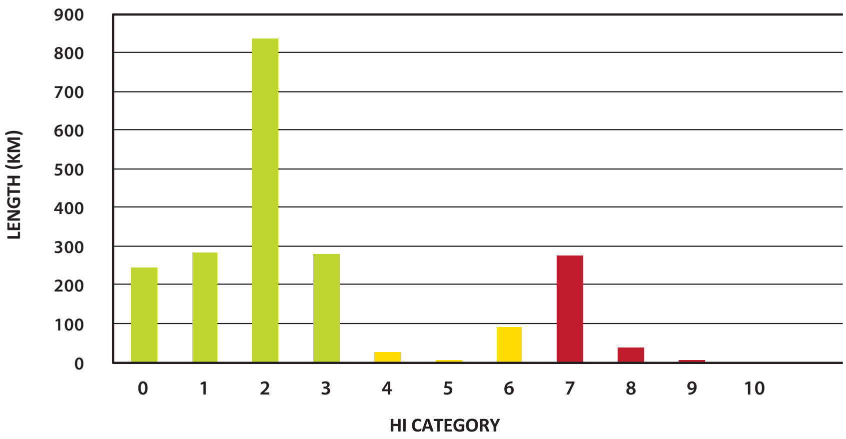


Figure 3.4.3.5 Distribution Conductor Health Index Profile

The majority of the conductors with an AHI of greater than 7 or greater are the 16 mm^2 copper type. This issue and remedial actions are discussed further in Chapter 8.

3.5 DISTRIBUTION AND LV CABLES

The distribution network conveys electricity from the zone substations to our customers via the LV network. The network is a mixture of overhead lines and underground cables. The total length is 6,000 km, 45% of which is underground cables. This section describes our:

- Distribution cables; and
- LV Cables.

3.5.1 DISTRIBUTION CABLES

Distribution cables form part of the 11 kV distribution network.

POPULATION

We own 649 km of 11kV underground cables. All of the 11kV cable installed prior to 1976 was PILC. Between 1976 and 1990 XLPE cable was installed in the Hamilton CBD area with predominantly PILC installed in other areas. Since 1990 most cable installations have been XLPE. Most of the 11 kV underground network is now aluminium conductor (71%), the remainder is copper.

AGE PROFILE

Figure 3.5.1 shows the age profile of the distribution cable. The average age of PILC cable is 38 years and the average age of XLPE cable is 14 years.

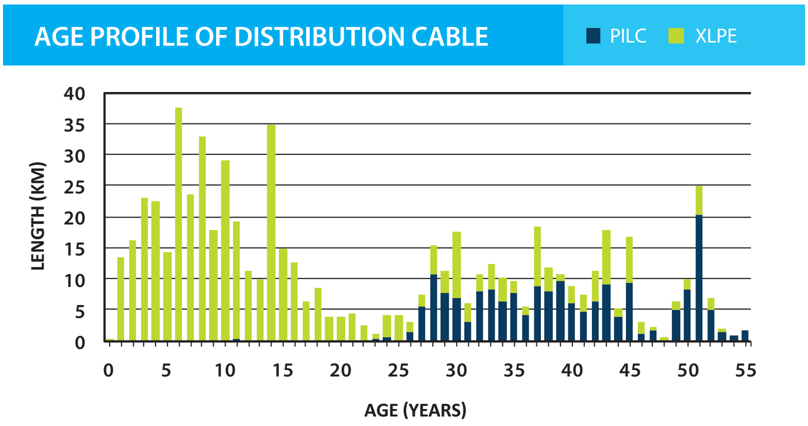


Figure 3.5.1 Age Profile of Distribution Cable

The life expectancy of cables is shown in Table 3.5.1 below.

ASSET	LIFE EXPECTANCY (YEARS)
XLPE Cables	45
PILC Cables	70

Table 3.5.1 Life Expectancy of Distribution Cables

While some of the XLPE cables may be reaching the end of their expected life experience has shown that XLPE cables can usually be safely operated for much longer than 45 years.

CONDITION

The condition of underground cable is hard to assess. The main indication of underground cable health is the number of faults that occur on it. A key determining factor of cable health is the quality of its installation. The cables are generally in good condition. The 11 kV ring around the CBD was built around 1945 and still supplies customers very reliably.

3.5.2 LV CABLES

The LV cables convey electricity from distribution transformers to customers at a domestic voltage level.

POPULATION

We have 2,100 km of installed LV underground cable, of which 7 km is PILC and the rest is XLPE. Figure 3.5.2.1 shows that the majority of LV XLPE cable is in the Hamilton area. Figure 3.5.2.2 shows virtually all the LV PILC cable is in Hamilton, with a small amount in Huntly.

DISTRIBUTION OF LV XLPE TYPE CABLE

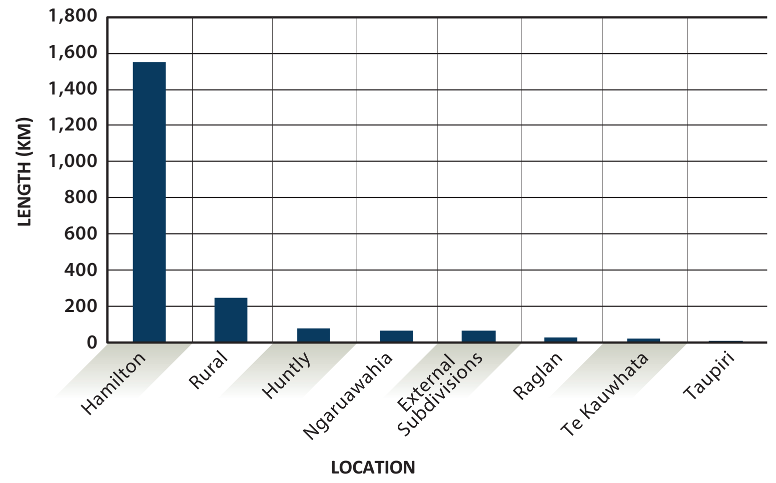


Figure 3.5.2.1 Location of LV XLPE Type Cable

This situation is similar for PILC Cable as shown in Figure 3.5.2.2.

DISTRIBUTION OF LV PILC TYPE CABLE

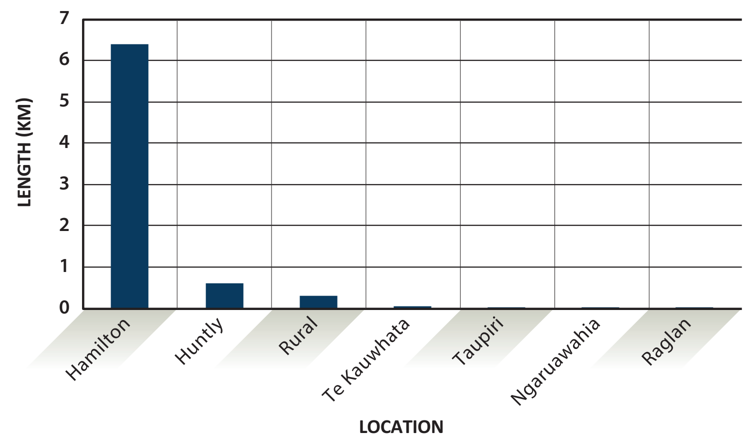


Figure 3.5.2.2 Location of LV PILC Type Cable

AGE PROFILE

Figure 3.5.2.3 below shows the age profile of the underground LV cables in the network. The average age of PILC cable is 52 years, because small amounts have been installed over the years, and the average age of XLPE cable is 21 years.

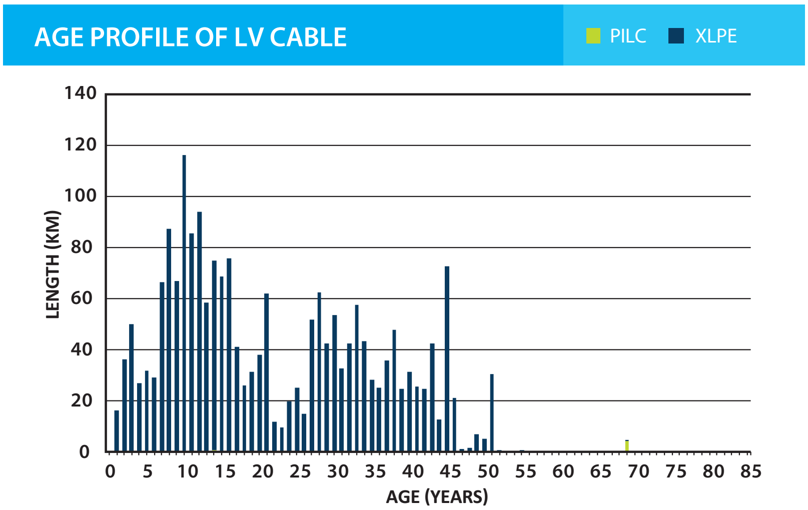


Figure 3.5.2.3 Age Profile of LV Cable

PILC cables have a life expectancy of 70 years and XLPE cables have a life expectancy of 45 years as shown in Table 3.5.2.1 below. Some of the cables are reaching the end of their life expectancy. However, operational experience shows that XLPE can be safely operated for much longer than 45 years.

ASSET	LIFE EXPECTANCY (YEARS)
XLPE Cables	45
PILC Cables	70

Table 3.5.2.1 Life Expectancy of LV Cable

CONDITION

The condition of underground LV cables is difficult to access. However to date the number of failures experienced has been small. The majority of faults have been caused by damage from external factors such as the works associated with the installation of ultra-fast fibre around Hamilton.

3.6 DISTRIBUTION SUBSTATIONS AND TRANSFORMERS

There are two asset categories within the distribution substations and transformers asset class:

- Distribution switching stations; and
- Distribution transformers.

3.6.1 DISTRIBUTION SWITCHING STATIONS

Distribution switching stations provide the capability to switch between interconnected 11kV circuits providing security of supply during fault conditions or planned maintenance.

POPULATION

WEL owns 17 11kV switching stations that were installed between 1967 and 2009. Simsey Place is operated by WEL, but not owned by WEL.

AGE PROFILE

The age profile of switching stations is shown in Figure 3.6.1.1 below.

AGE PROFILE OF SWITCHING STATIONS

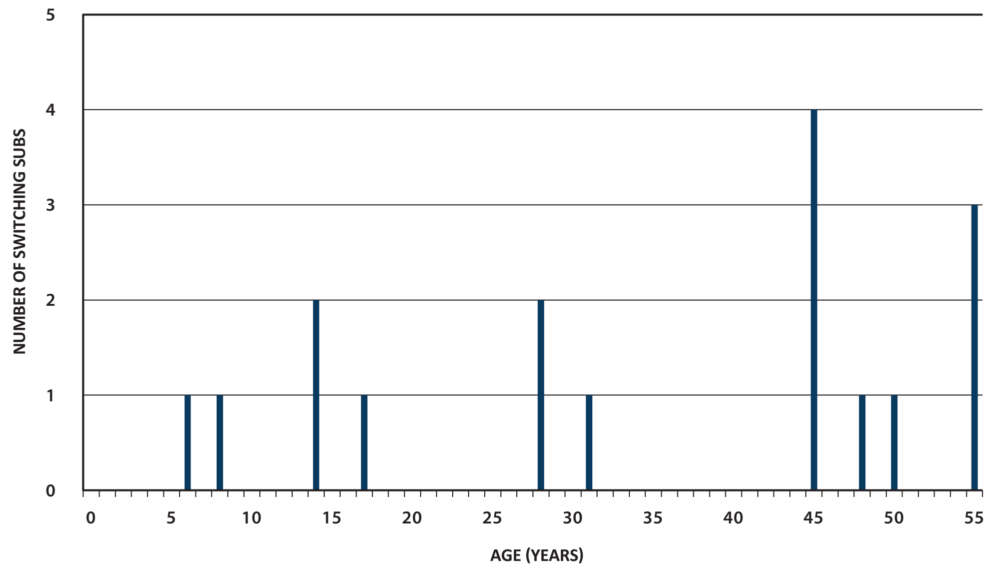


Figure 3.6.1.1 Age Profile of Switching Substations

CONDITION

The condition profile of switching stations is shown below in Figure 3.6.1.2.

CONDITION OF SWITCHING STATIONS

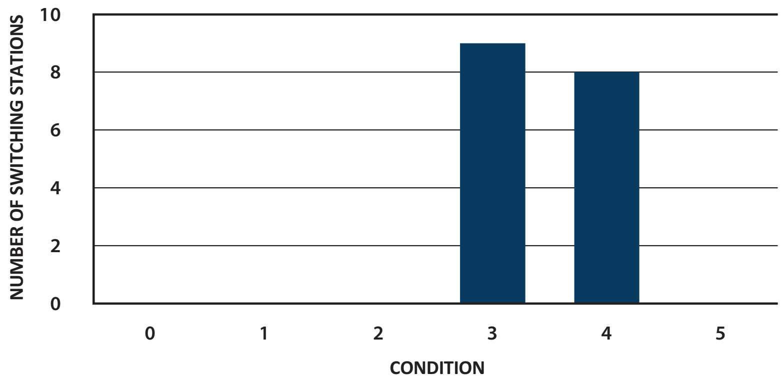


Figure 3.6.1.2 Condition of Switching Substations

3.6.2 DISTRIBUTION TRANSFORMERS

Distribution transformers step down electricity supply from the 11kV distribution voltage to LV. Transformers allow adjustments so the supply voltage remains within statutory limits.

Distribution transformers are either mounted on poles or the ground. Following the Christchurch earthquakes industry practice has changed so that larger transformers are always ground mounted.

POPULATION

We own 3,865 pole mounted transformers and 1,772 ground mounted transformers.

Due to economies of scale we purchase transformers in a limited number of predefined sizes. The standard pole mounted transformer sizes we utilise are 1, 30, 50 and 100 kVA. Standard ground mounted transformer sizes are 100, 200, 300, 500, 750 and 1,000 kVA.

The population of transformers in each size is shown in Figure 3.6.2.1.

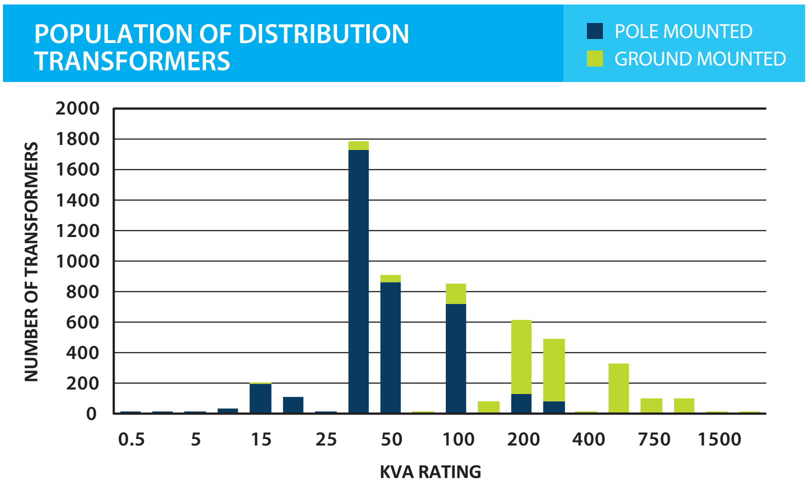


Figure 3.6.2.1 Population of Distribution Transformers

AGE PROFILE

Figure 3.6.2.2 below shows the age profile of our distribution transformers. The average age is 20 years old. The significant investment made over the last 20 years was driven by an active replacement programme of older transformers in poor condition (often pole mounted) and the growth in load necessitating capacity upgrades. Consequently the overall population of distribution transformers is young compared to other asset fleets. There are a small number of transformers that have exceeded their life expectancy, but they are still operating effectively.

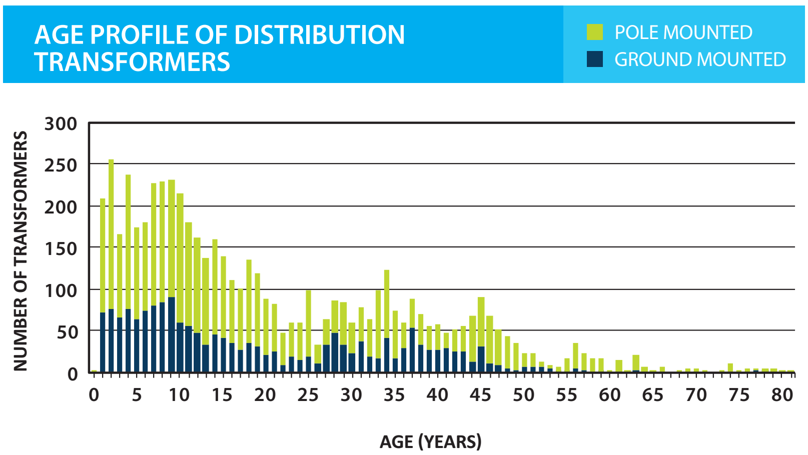


Figure 3.6.2.2 Age Profile of Distribution Transformers

CONDITION

Figure 3.6.2.3 below shows the condition profile of our distribution transformers.

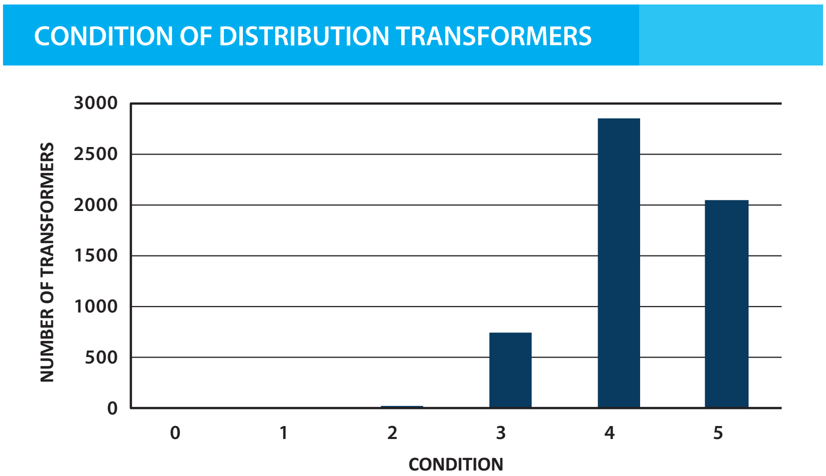


Figure 3.6.2.3 Condition of Distribution Transformers

The AHI for distribution transformers is shown in Figure 3.6.2.4 below. The Asset Health Index and what factors are used to assess an asset are explained in section 3.1.

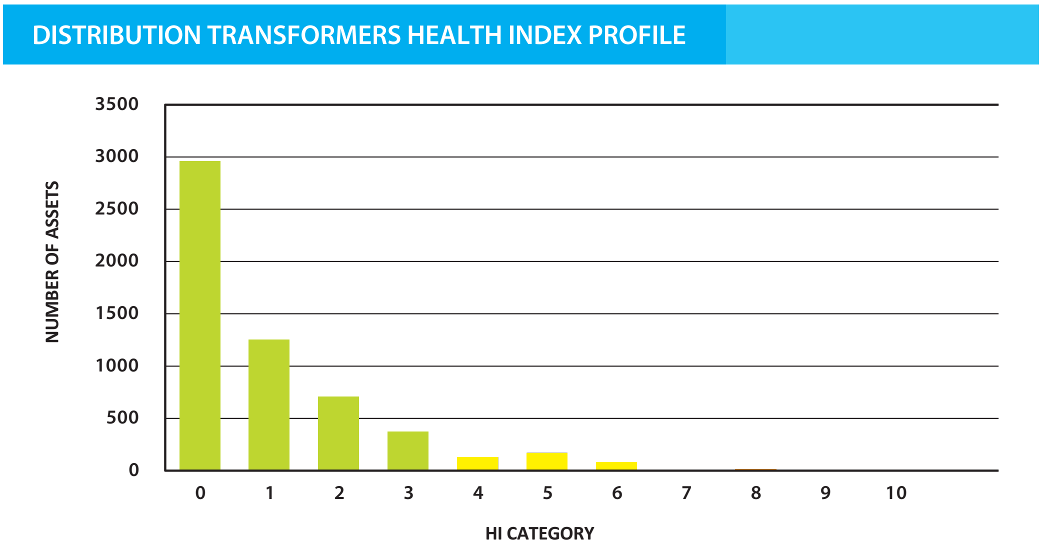


Figure 3.6.2.4 Distribution Transformers Health Index Profile

The condition profile and the health indices show that the fleet is in good health. The transformers with a very poor health index of '8-9', correspond to those that have exceeded their life expectancy.

3.7 DISTRIBUTION SWITCHGEAR

Four switch types exist within our network. These are:

- Ring Main Units (RMUs);
- Air Break Switches (includes the modern SF_6 and Vacuum types);
- Circuit Breakers; and
- Reclosers and Sectionalisers.

Each switch type is discussed in the following sections.

3.7.1 RMUS

RMUs, are ground mounted switches that connect to 11kV cables. There are 710 RMUs in operation on the network ranging from new to approximately 60 years old. Older RMUs are typically oil insulated with all new installations being SF_6 gas-insulated switchgear.

POPULATION

The ring mains are a mixture of oil filled and gas filled types, as shown in Figure 3.7.1.1 below.

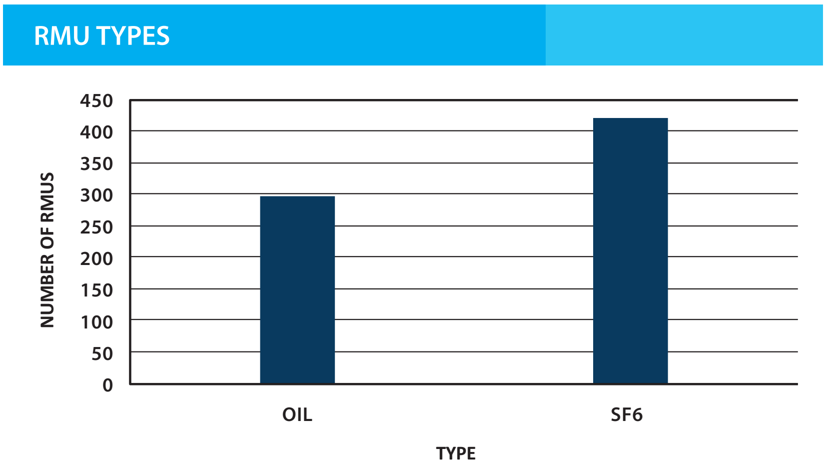


Figure 3.7.1.1 RMU Types

AGE PROFILE

The age profile of RMUs is shown in Figure 3.7.1.2 below. The average age is 18 years.

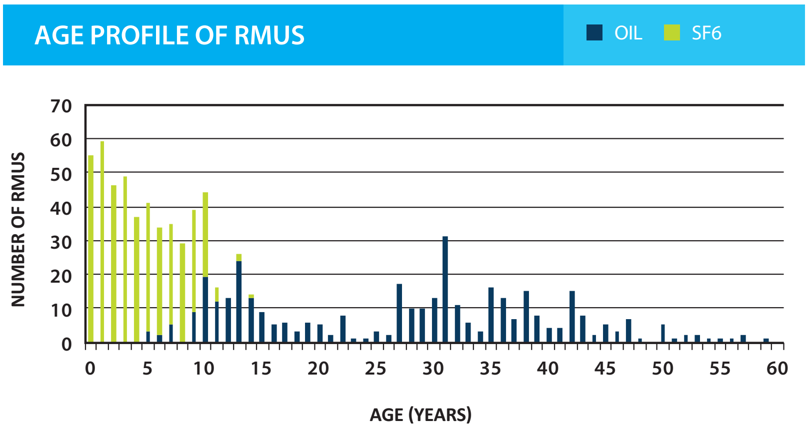


Figure 3.7.1.2 Age Profile of RMUs

The life expectancy of RMUs is detailed in Table 3.7.1.1 below.

ASSET	LIFE EXPECTANCY (YEARS)
Oil Filled RMU	40
Gas Filled RMU	55

Table 3.7.1.1 Life Expectancy of RMUs

CONDITION

The distribution of RMU conditions is shown in Figure 3.7.1.3 below.

CONDITION OF RMUS

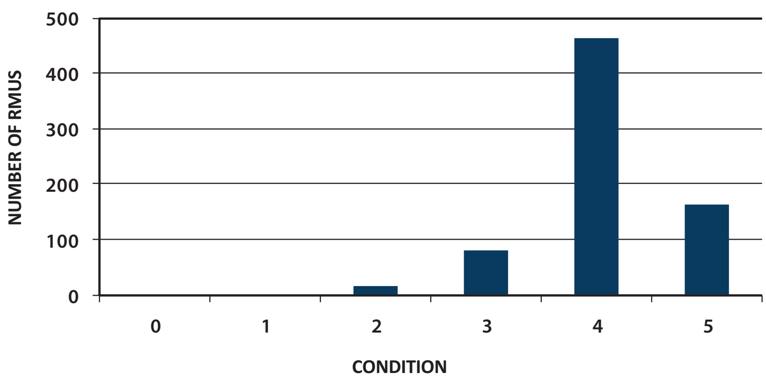


Figure 3.7.1.3 Condition of RMUs

A few oil filled RMUs, failed from an incorrect set up of the internal contacts. Consequently a rigorous inspection programme was instigated. Where appropriate the RMUs were replaced. As a result of this programme the overall condition and health profile for RMUs is good. The AHI profile for RMUs is shown in Figure 3.7.1.4 below. The Asset Health Index and what factors are used to assess an asset are explained in section 3.1.

RMU HEALTH INDEX PROFILE

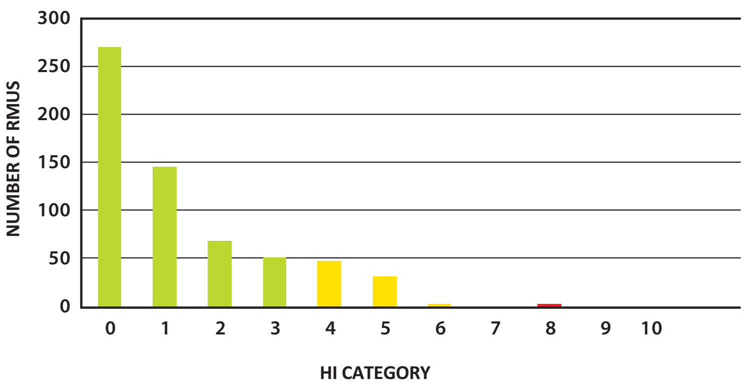


Figure 3.7.1.4 RMU Health Index Profile

3.7.2 DISTRIBUTION CIRCUIT BREAKERS (CBS)

Distribution CBs are used to control and protect the distribution network. The CB is a switching device that can be either operated manually or automatically. When operating automatically they interrupt the flow of electricity if the current exceeds predetermined limits.

POPULATION

The 430 CBs on our network range in age from new to over 45 years. The CBs deployed consist of a mix of technologies. These include oil filled, SF_6 and vacuum as shown in Figure 3.7.2.1 below. The oil-filled CBs are the oldest followed by SF_6 and vacuum types.

DISTRIBUTION CB TYPES

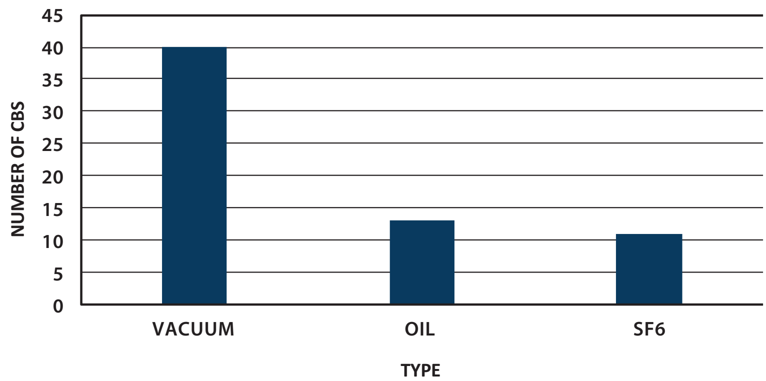


Figure 3.7.2.1 Distribution CB Types

AGE PROFILE

The age profile is shown below in Figure 3.7.2.2. The average age of the fleet is 20 years.

AGE PROFILE OF DISTRIBUTION CBS

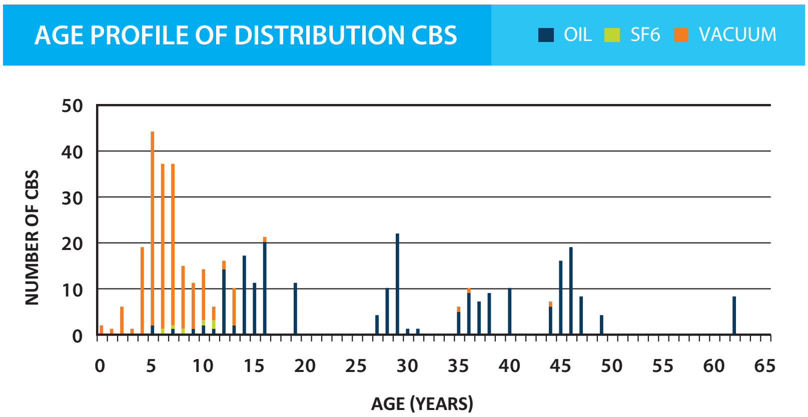


Figure 3.7.2.2 Age Profile of Distribution CBs

The life expectancy of CBs by type is shown in Table 3.7.2.1 below.

ASSET	LIFE EXPECTANCY (YEARS)
Oil	45
SF_6	55
Vacuum	55

Table 3.7.2.1 Life Expectancy of Distribution CBs

CONDITION

The condition of CBs is summarised in Figure 3.7.2.3 below. This is a reflective sample of the fleet.

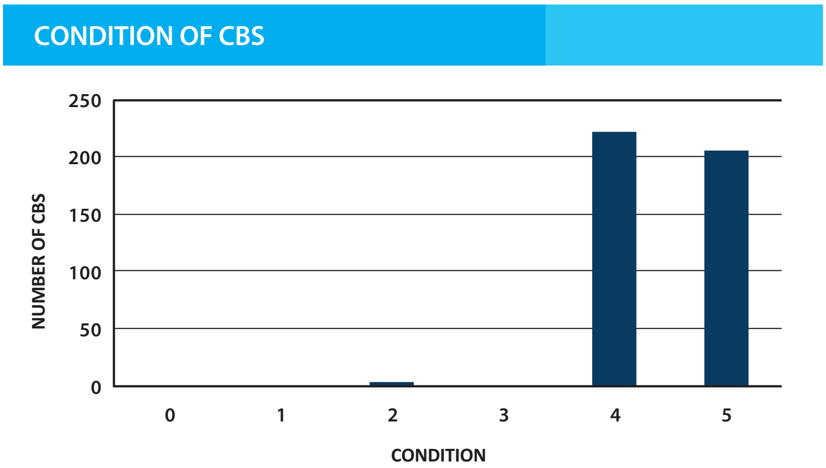


Figure 3.7.2.3 Condition of CBs

Routine condition monitoring indicates there are no significant maintenance problems. Since the operational count is well below operational limits, life expectancy is likely to exceed the standard life for each class within the fleet. Vacuum and SF_6 CBs are now used for all new installations, as they have low maintenance requirements.

3.7.3 DISTRIBUTION AIR BREAK SWITCHES (ABSS)

ABSs are installed on the network and used for isolation and switching. ABSs are categorised as load break or non-load break. Operators are able to open a load break switch when current is flowing through it. A non-load break switch is designed to only open when no current is flowing. The majority of our switches are non-load break switches.

POPULATION

We own 1,030 ABSs. Approximately one third can be operated remotely from the control room. This has the dual advantage of reducing SAIDI and improving safety. The location of our ABSs is shown in Figure 3.7.3.1 below. A large proportion are in the rural areas. Remote control in rural areas provides greater benefit than in urban areas.

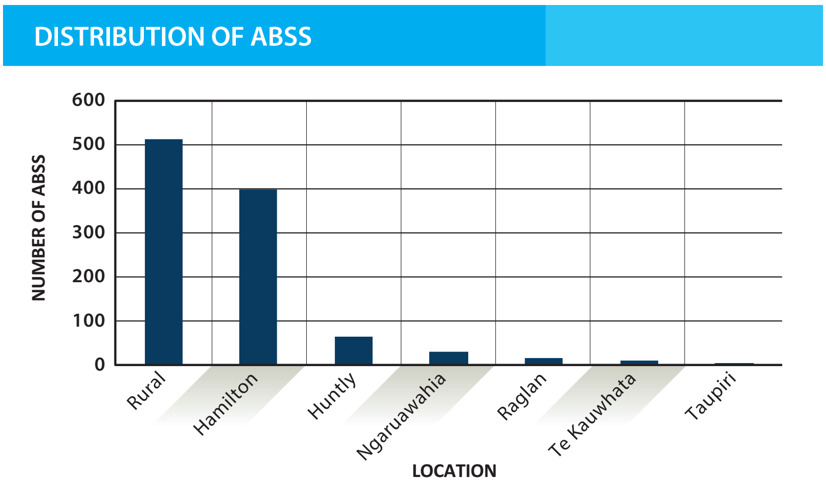


Figure 3.7.3.1 Distribution of ABSs

AGE PROFILE

The age profile of ABSs is shown in Figure 3.7.3.2 below. The average age is 22 years.

AGE PROFILE OF ABSS

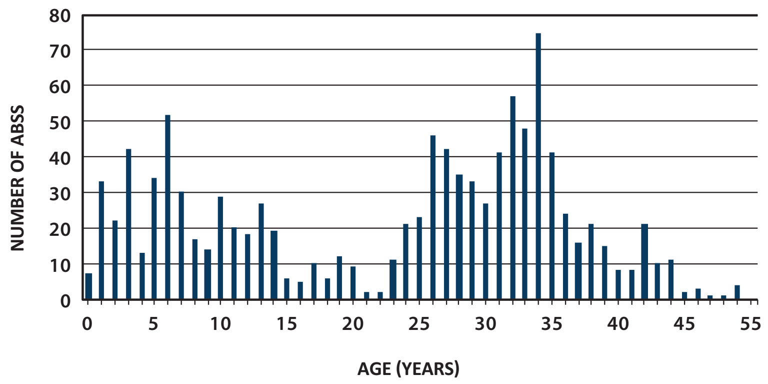


Figure 3.7.3.2 Age Profile of ABs

The life expectancy of ABSs is 35 years. The replacement programme for our ABSs is discussed further in Chapter 8.

CONDITION

The condition of ABSs is generally good, as reflected in Figure 3.7.3.3 below. The AHI profile of ABSs is shown in Figure 3.7.3.4 and indicates a substantial number of the population has a medium AHI value, which signifies an increasing rate of asset degradation over the AMP period. The renewal strategy to address this is discussed in Chapter 8.

CONDITION OF ABSS

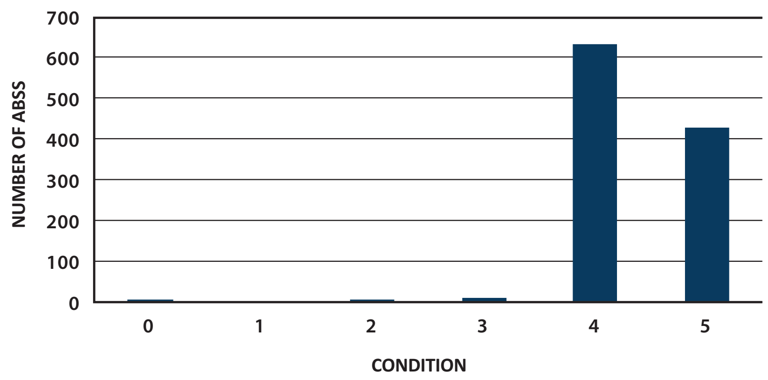


Figure 3.7.3.3 Condition Profile of ABs

ABS HEALTH INDEX PROFILE

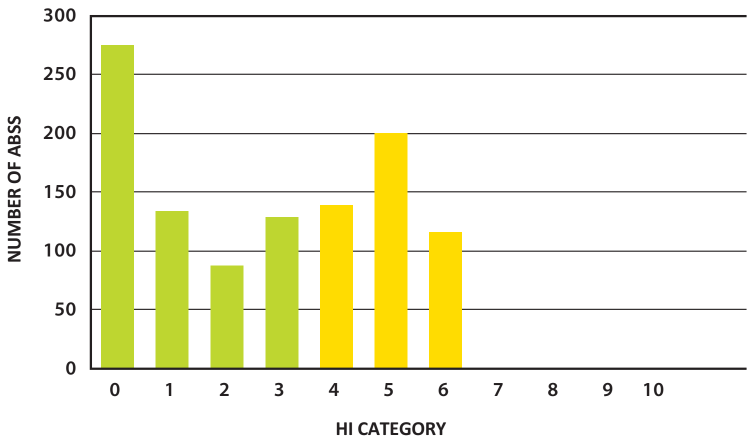


Figure 3.7.3.4 ABS Health Index Profile

The condition of the ABS fleet is good, but the health index shows about a third of the fleet is in only fair condition. The reason for the difference lies in the nature of the condition assessment and the extra factors included in the assessment of the health index. The condition assessment is based on a visual inspection, so could not detect weaknesses such as impending insulator failure. The health index accounts for the relatively old age of the fleet and environmental factors such as proximity to waterways and the sea. The age in particular has a strong influence on the above health index profile.

3.7.4 DISTRIBUTION SECTIONALISERS

Sectionalisers automatically isolate faults within the network but only when no current is flowing. They are used to automatically isolate the end of long overhead line feeders following a fault. It allows operators to locate a fault more accurately and quickly, as well as minimising the number of customers affected by any one fault.

POPULATION

We own 46 sectionalisers. There are a mix of the Dropout Sectionalisers and the Enclosed Unit Sectionalisers on our network as shown in Figure 3.7.4.1 below.

DISTRIBUTION OF SECTIONALISER TYPES

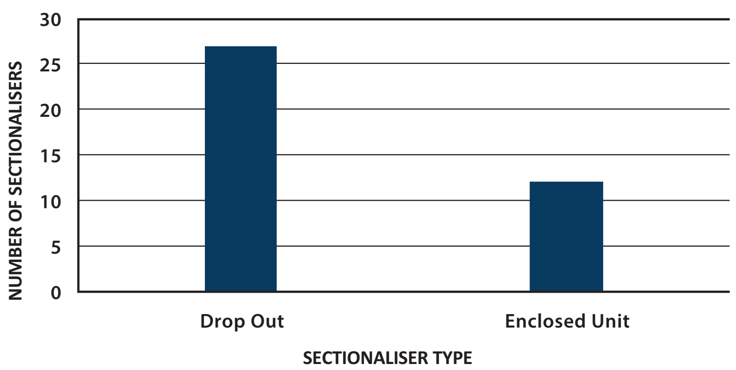


Figure 3.7.4.1 Distribution of Sectionaliser Types

AGE PROFILE

Figure 3.7.4.2 shows age profile of the sectionalisers. A large number of units were installed in 2004 and 2005 which was part of a reliability improvement programme.

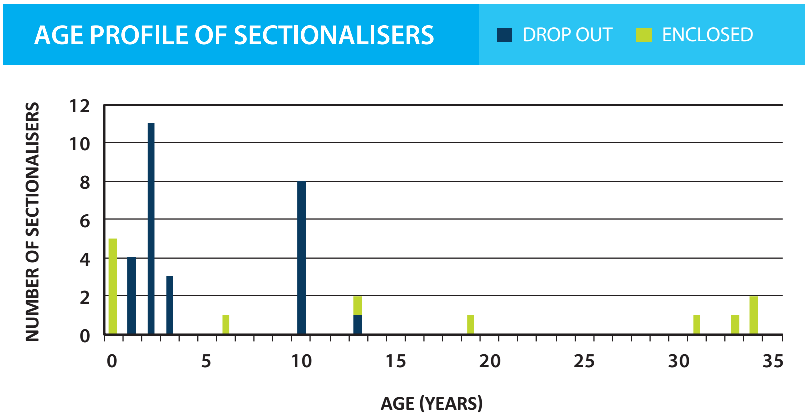


Figure 3.7.4.2 Age Profile of Sectionalisers

The life expectancy of sectionalisers is 40 years. The average age of the fleet is 8 years.

CONDITION

Routine testing of old sectionalisers is detrimental to their reliability. Therefore testing is only done when there is an indication that an incorrect operation has occurred. The condition profile is shown in Figure 3.7.4.3 below.

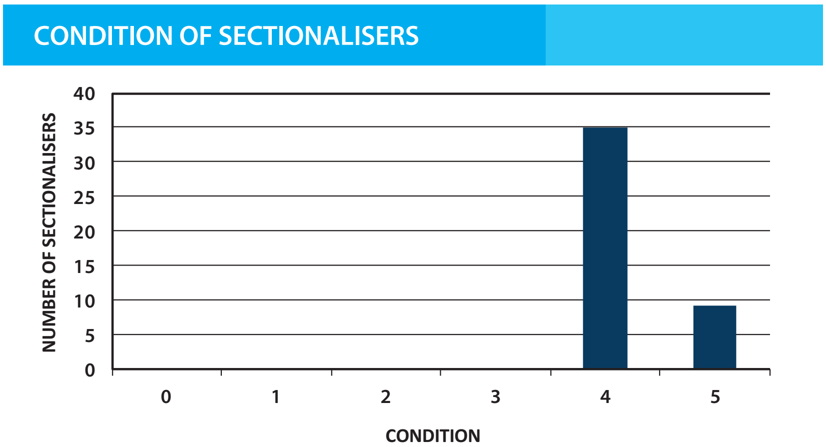


Figure 3.7.4.3 Condition of Sectionalisers

Figure 3.7.4.4 below, shows the AHI of the sectionalisers and reclosers together. The Asset Health Index and what factors are used to assess an asset are explained in section 3.1.

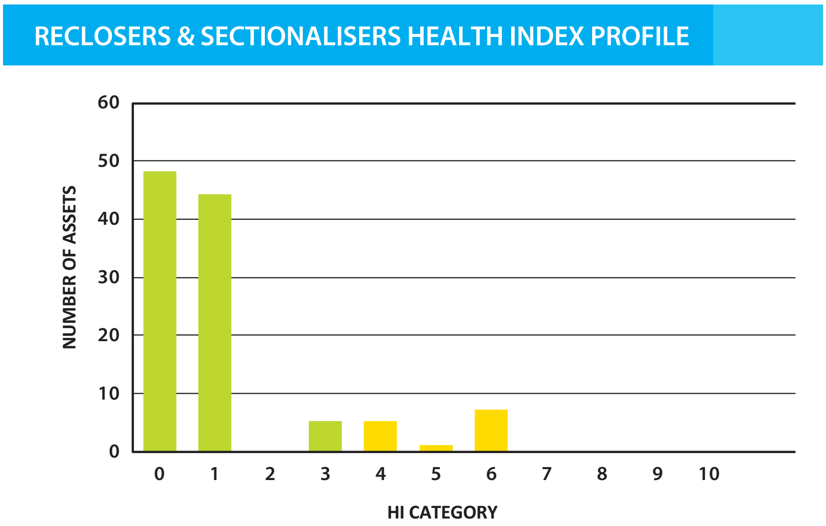


Figure 3.7.4.4 Reclosers & Sectionalisers Health Index Profile

Since a large majority of the fleet is comparatively young the fleet is in good condition overall.

3.8 OTHER SYSTEM FIXED ASSETS

This section covers the electrical protection, load control equipment and other system fixed assets and is structured by asset class:

- LV Pillars
- Protection Relays;
- NMS;
- Load Control Equipment; and
- Meters

3.8.1 LV PILLARS

The LV pillars provide termination points for LV cables, as well as fusing and isolation points.

POPULATION

There are two types of LV pillars: distribution pillars and service pillars. Distribution pillars are the connection points for larger LV supplies, and allow for easy back feeding. They are usually located close to town centres. Service pillars are the point of connection between the main LV feeder and a service main to the customer. There are 22,000 LV pillars on the network.

AGE PROFILE

The age profile of LV pillars is shown in Figure 3.8.1.1 in following page.

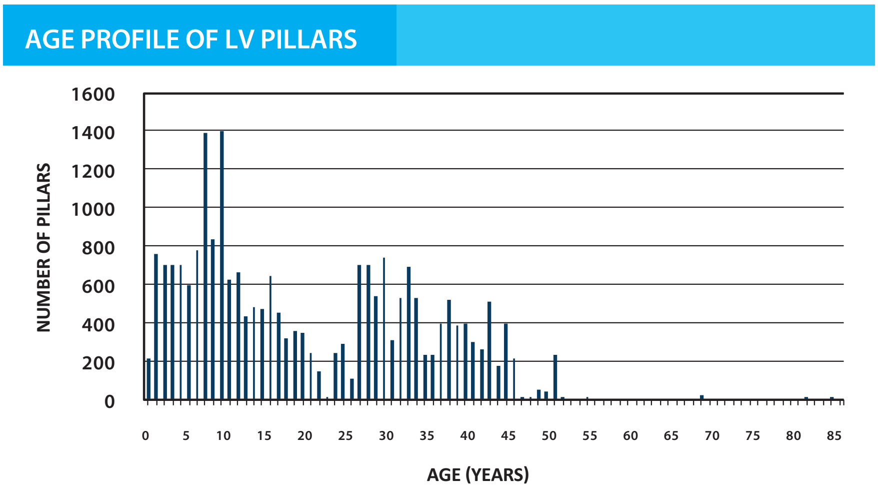


Figure 3.8.1.1 Age Profile of LV Pillars

CONDITION

The condition of LV pillars is shown in Figure 3.8.1.2 below. They are in good condition, but if the lid is open they can be a public health risk, so are patrolled regularly.

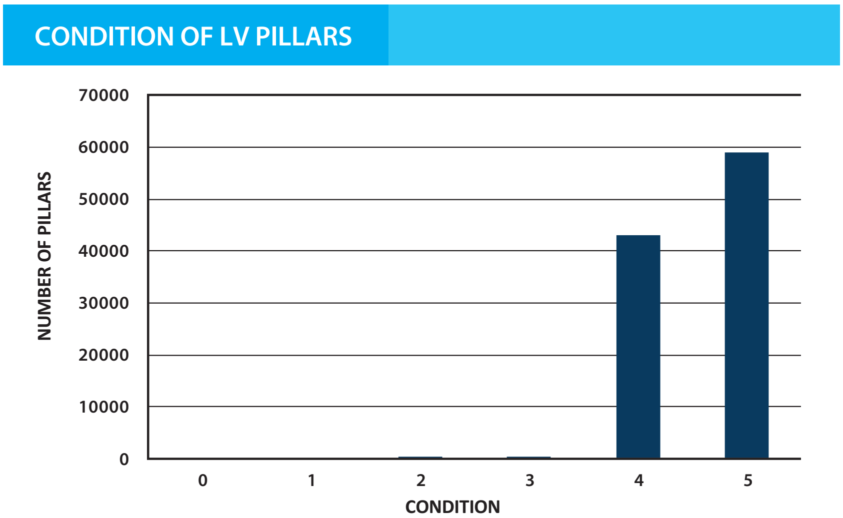


Figure 3.8.1.2 Condition of LV Pillars

3.8.2 PROTECTION RELAYS

Electrical protection is the primary safety system within the electricity network. Protection relays are required to act quickly and trip a CB within a few thousandths of a second.

POPULATION

We own 852 relays in total, with a mixture of electromechanical and numeric protection relays, with electromechanical representing the older relays. The distribution is shown in Figure 3.8.2.1 below.

DISTRIBUTION OF PROTECTION EQUIPMENT

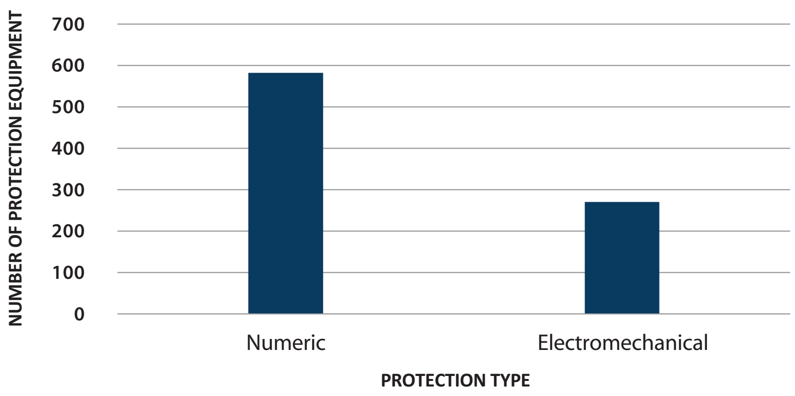


Figure 3.8.2.1 Distribution of Protection Equipment

AGE PROFILE

Figure 3.8.2.2 below shows the age profile of the protection equipment.

AGE PROFILE OF PROTECTION EQUIPMENT

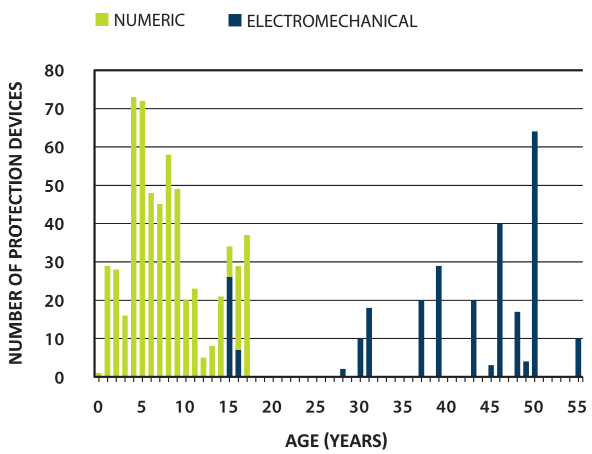


Figure 3.8.2.2 Age Profile of Protection Equipment

The average age of the protection relays on our network is 18 years. The life expectancy for all types of protection relays is 30 years.

CONDITION

The condition of the newer relays is good, but the older relays need replacing. This is discussed further in Chapter 8. The distribution of their conditions is shown in Figure 3.8.2.3 below.

CONDITION OF PROTECTION EQUIPMENT

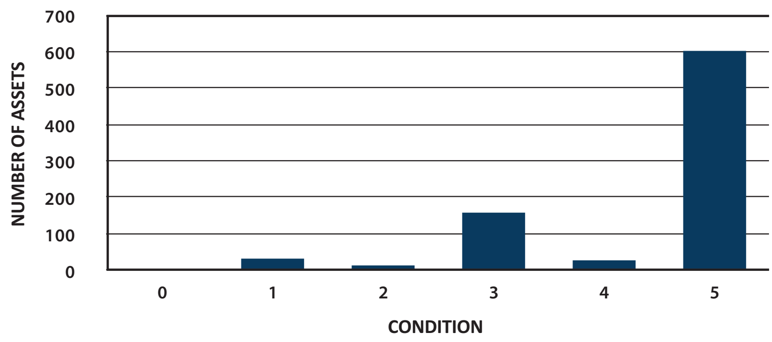


Figure 3.8.2.3 Condition of Protection Equipment

In managing numerical relays the configuration data is critical to the correct operation of the relays in the field. In order to ensure the integrity of this data WEL uses a protection database.

3.8.3 NETWORK MANAGEMENT SYSTEM (NMS)

The NMS enables the fast and efficient control of the electricity network for the operator. It consists of the PowerOn Fusion General Electric software package and data storage systems integrated with our SCADA network. The Supervisory Control And Data Acquisition (SCADA) network includes remote terminal units (RTUs) that communicate back to the control room equipment in real time. The key business benefit of the system is to enhance the safe, reliable and efficient management of the network, as well as provide effective customer service.

The NMS consists of the following subsystems:

- Distribution Management System (DMS)
- Outage Management System (OMS)
- Trouble Call Taker.

The DMS is the core of the NMS. It collects the real time information and disseminates it to users and other subsystems. A key element of the DMS is the connectivity model that allows operators to easily see the effects of actual and planned switching. It also controls all switching management steps (preparation, validation and execution) so can enforce built in safely logic throughout all stages. This is a particularly powerful aspect of the system, especially from a safety perspective.

The OMS is an application designed to aid in the management, prioritisation and administration of outages on the network and individual customers. The OMS automatically associates customer call taker calls and clusters of calls to the one incident and to the respective devices supplying them. To do this OMS relies on the Installation Control Point (ICP) to transformer relationship and the connectivity of the DMS. 'Last gasp' data from the Smart Boxes has been integrated with the OMS to improve fault location.

The Trouble Call Taker records customer calls and provides vital information to dispatch. The information derived from the calls is integrated with the OMS to predict the location of faults or likely future faults. It can also be used for post event analysis. It is available to the internal WEL dispatch team as well as the external after-hours call centre staff.

Access to NMS functionality is controlled in a secure authorisation hierarchy. System Management, System Administration, Operator, Call Taker, Dispatcher, Engineering, Report Access or View Only provide different levels of system access. Access can be via a full client installed on a workstation or through a web browser.

POPULATION

We own 280 RTUs. The older fleet are progressively being upgraded or replaced to provide improved functionality and communications capability. Figure 3.8.3.1 shows the location of our RTU's.

DISTRIBUTION OF RTUS

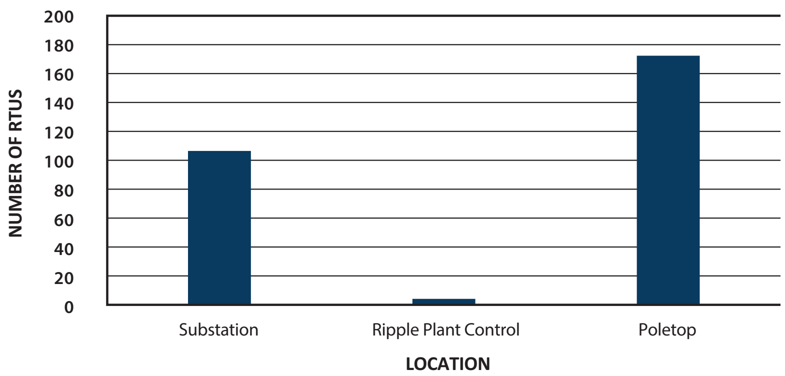


Figure 3.8.3.1 Location of Remote Terminal Units

AGE PROFILE

The lifecycle of the NMS software is approximately fifteen years. The NMS software is four years old.

The life expectancy of the supporting infrastructure, especially the RTUs is fifteen years. The average age is 8.5 years. The age profile of NMS related equipment (RTUs) is shown in Figure 3.8.3.2.

AGE PROFILE OF NMS AND RELATED EQUIPMENT

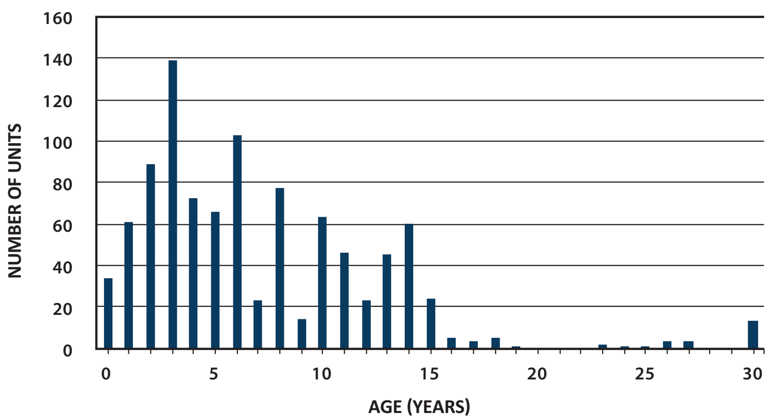


Figure 3.8.3.2 Age Profile of NMS Infrastructure

CONDITION

The condition of the control room NMS equipment is good. The software will be upgraded to a new release in the coming year. The entire communication network is being converted to an IP network.

3.8.4 LOAD CONTROL EQUIPMENT

Load control is an important part of managing peak loads on the network. It is initiated from the NMS which provides control signals to the ripple injection plants which in turn signal the ripple relays located at each customers site. Load control equipment consists of the ripple injection plants and ripple relays.

The load management system within the NMS provides centralised intelligence to monitor network peak demand, forecasting expected demand, and managing control of interruptible load within service levels to ensure demand does not exceed targets. Regional Coincident Peak Demand (RCPD) functionality is used to coordinate load control to manage the total regional demand. Other controls provided by the load management system include street lighting and meter tariff rate control.

POPULATION

We own three 33 kV static ripple injection sets, two 11 kV static sets and five 11 kV rotary sets. The static sets operate at 283Hz and the rotary sets operate at 500 Hz.

Due to signal attenuation the sets must be distributed throughout the network. The 33 kV injection plants are located at the Hamilton GXP, Te Kowhai GXP and Weavers substation for the Northern area. The 11 kV static sets are located at Pukete and Hamilton 11 kV zone substations. The 11 kV injection plants are located at the Weavers; Te Kauwhata; Glasgow; Hampton Downs; and Finlayson Road zone substations.

Nearly ten years ago new ripple relays were installed at customer premises across the central region of the network. However, the northern region was left with the old relays. Part of the justification for installing Smart Boxes in the northern region was the opportunity to replace the old ripple relays with new ones fitted to the Smart Boxes. This project is currently in progress.

AGE PROFILE

The life expectancy of load control plant is 20 years. The average age of the rotary plant is 44 years and the average age of the static plant is 12 years. The age profile of our load control equipment is shown in Figure 3.8.4

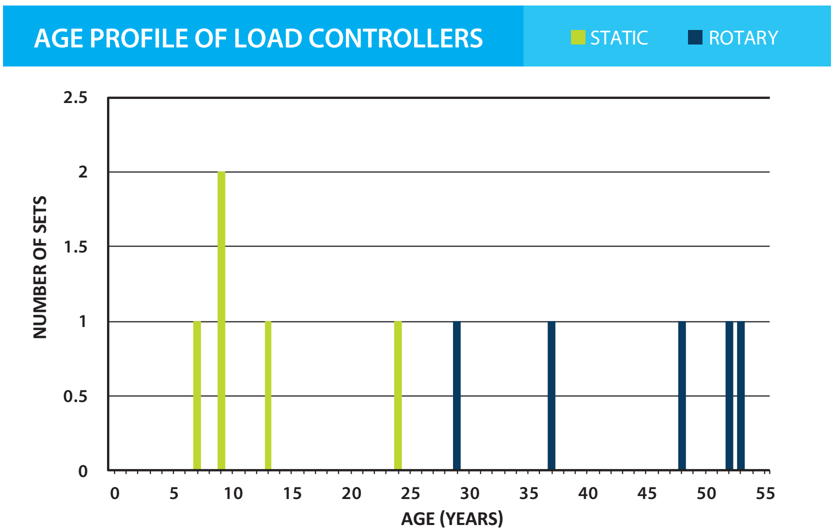


Figure 3.8.4 Age Profile of Load Controllers

CONDITION

The old rotary load control plant is well past its life expectancy and will be retired once all the 500 Hz load control relays are replaced in the northern region. The static plant is within its life expectancy.

We are managing the old load control plant so that it continues to operate until the Smart Box relays replace the old 500 Hz ones in the northern region.

3.8.5 METERS

WEL has a range of meters from 33 kV meters down to LV smart meters. For details about the systems that support Smart Boxes refer to section 3.9.4.

POPULATION

The subtransmission and distribution meters are used for revenue protection, operation and network protection. These meters have limited time stamping ability, so it is difficult for the planners to ascertain coincident peaks and hence network growth. WEL has currently 56,000 LV smart meters installed. The vast majority of these meters are installed as check meters in series with revenue meters, except approximately 500 which are currently used as revenue meters. WEL has also installed a small number of data loggers at locations of special interest, which can be relocated as required for investigative work.

AGE PROFILE

The average age of the subtransmission and distribution meters is 10 years. The low voltage smart meters are installed as compliant meters under the Electricity Industry Participation Code 2010 (Code), requiring strict auditing of procedures and a controlled maintenance and inspection management over their total lifespan of 15 years. The number of Smart Boxes installed over recent years is shown in Figure 3.8.5 below.

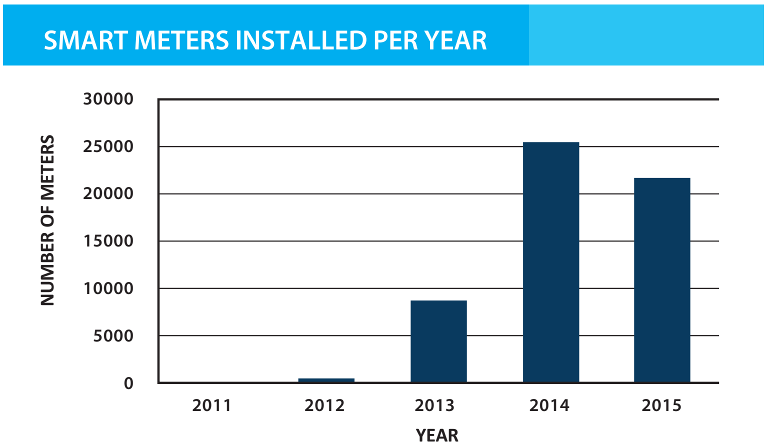


Figure 3.8.5 Smart Meters Installed per Year

CONDITION

The condition of all these assets is good; all low voltage meters are maintained under the Code and the subtransmission meters are housed indoors.

3.9 OTHER ASSETS

This section describes the asset classes that are not directly part of the normal operation of the network.

3.9.1 BACKUP GENERATORS

We have three emergency generators, one in the new Disaster Recovery Centre (DRC), one for the corporate office and depot and one at the old DRC. The new 100 kVA generator is only a year old and in excellent condition (condition 5). The depot 100 kVA generator is six years old and in very good condition (condition 4). The 65 kVA emergency generator at the old DRC is in average condition (condition 3) and is due for decommissioning at the end of 2015. Portable generators are hired as necessary.

3.9.2 EMERGENCY CRITICAL SPARES

We hold the following critical spares reserved for emergency conditions:

- 4 km overhead 33 kV line;
- Substation battery bank;
- Protection relays;
- Substation communications equipment;
- Four zone transformers, two 10 MVA and two 15 MVA transformers;
- One 33 kV circuit breaker;
- 33 kV and 11 kV sectionalisers and reclosers; and
- 33 kV and 11 kV air break switches.

Ring mains are always in stock so not included in the critical spares list explicitly. The zone transformers will be distributed geographically across the network and on opposite sides of the Waikato River should bridges be destroyed in some disaster

3.9.3 HEAD OFFICE AND DEPOT BUILDINGS

We own our Head Office building and the depot for our field staff. These buildings are six and seven years old respectively. Our Head Office has a four star efficiency rating. Both buildings are in very good condition.

3.9.4 COMPUTER HARDWARE, SOFTWARE AND DATA

The core software packages within WEL are an Enterprise Resource Planning system (ERP system), a Geographic Information System (GeoIS) and the NMS. Smaller and more focused systems include the vegetation management system and the Smart Box head end. WEL continuously monitors and improves the data quality within these systems through an information framework.

GEOGRAPHIC INFORMATION SYSTEM (GEOIS)

The assets managed by WEL are distributed over a large geographical area, so at the most basic level WEL needs to know the geographical location of each asset. The GeoIS contains this spatial information as well as asset specifications. The GeoIS also contains data describing the electrical attributes of assets, connectivity, landbase data (which includes property boundaries and owner details), topological maps and aerial photography. Some of this data is integrated with other systems. The GeoIS is the primary tool for assisting field staff to locate assets.

The GeoIS aims to leverage existing data and present it in a way that decision makers can easily comprehend. One of the strategic focuses for the GeoIS is to increase the degree to which it leverages existing company data for the benefit of decision makers at all levels.

The purchase of aerial photography provides cost savings across the company and also is a means of improving data quality. Other recent data enhancement initiatives include the criticality project, addition of easements, implementation of distributed generation, street light controllers and aerial bundled cable, recording of vertical heights as well as communication features. The criticality project leverages the GeoIS data to optimise asset replacement decisions. The addition of easements is particularly important for managing the associated legal risks and responsibilities. The upgrade from a relational model to a full spatial has enabled improved efficiencies is compliance reporting.

Future enhancements include electronic capture of field data and utilisation of the linear referencing functionality to provide advanced reporting and greater system integration.

ENTERPRISE RESOURCE PLANNING (ERP) SYSTEM

SAP, an ERP system, supports finance, asset management, maintenance, capital works and procurement. In addition a third party scheduling package was purchased for works delivery.

The system is based on work orders, which capture all costs associated with a particular piece of work. Information derived from this data provides a measure of productivity and efficiency of the field staff, which in turn aids cost control. At the close of capital jobs the costs are added to the Financial Asset Register, so WEL always knows the value of its asset base.

The plant maintenance module in SAP supports the management of all maintenance and capital work undertaken on the network through the work orders application, as well as the inventory management and purchasing applications. The maintenance module enables engineers to create planned maintenance work schedules and capture important information when faults occur.

Continuous improvements in the functionality include:

- Improved reporting through the application of Business Intelligence
- Implementation and enhancement of mobility

NMS

The NMS is described in section 3.8.3 and the associated load control equipment is discussed in section 3.8.4.

VEGETATION MANAGEMENT DATABASE

TThis application was commissioned by WEL in order to better manage the tracking of vegetation removal. It has a graphical interface which is derived from a landbase and GeoIS extract. All vegetation is recorded in the system and registered against a span or sub-span of line. Information includes the priority, owner, species, previous work, previous notifications and other notes as required. Job cards are created from the system and direct field work. Periodic field patrols are done to update information into the system. The interface allows tree issues to be visually observed in a spatial mapping environment. The system is a key element in allowing WEL to comply with the vegetation regulations.

SMART METER

The Silver Spring Network head end hosts a suite of applications that support the Smart Box implementation. The head end itself is hosted in the United States and operates as Software as a Service. The application is accessed in the WEL office via a web interface. Data traffic from devices and other application traffic flows from the WEL office to the head end via an Internet VPN.

ADVANCED METER MANAGEMENT

This is the main application and is used for managing devices (meters, relays, access points) and for setting up schedules, reports and exports. The number of devices in various life cycle states can be monitored along with events and alarms from devices. On demand interrogation and control of devices in the field can be performed. Smart Box meter readings and events are obtained at scheduled intervals.

INFORMATION FRAMEWORK

We recognise that the information derived is only as good as the source data it depends upon. Therefore we are progressively developing our systems and processes to aid the capture and retention of good quality data. As part of this framework, we have established a set of data quality metrics which are reported each month. These empower continuous data quality improvement through process improvements, training, communication and data cleansing projects. WEL has implemented an auditable data correction process for key data points. A data collection programme verifying ABS attributes is nearing completion. This is operationally important for safety reasons and also for maintenance. Suspected connectivity errors within the low voltage network and streetlights are being progressively corrected. The Smart Boxes have created the issue of "big data" for WEL, which it is starting to address.

3.9.5 OTHER OPERATIONAL ASSETS

We have a number of miscellaneous assets including test equipment; and vehicles.

The test equipment is replaced as needed.

Approximately half of WEL's vehicle fleet is leased. Financial analysis undertaken by WEL revealed that there was a significant financial and operational advantage if WEL owned its own vehicles. As vehicle leases expire WEL is purchasing replacements.

3.10 ASSETS OWNED BY WEL AT GXPS

The WEL owned assets located at GXPs are covered in the above sections. However, for clarity they are summarised below. They generally include switchgear, metering and load control equipment.

HAMILTON GXP

Hamilton GXP has the following assets:

- Communications equipment;
- Ripple Plant (load control equipment);
- Metering equipment;
- RTUs; and
- Protection relays.

TE KOWHAI GXP

Te Kowhai GXP has the following assets:

- Communications equipment;
- Ripple Plant (load control equipment);
- Metering equipment;
- RTUs; and
- Protection relays.

HUNTLY GXP

Huntly GXP has the following assets:

- Communications equipment;
- Metering equipment;
- RTUs;
- Protection relays; and
- 33kV Switchgear.

4 APPROACH TO ASSET MANAGEMENT

4 APPROACH TO ASSET MANAGEMENT

This chapter describes our approach to asset management. Asset management is the core of what we do and as such our approach is fundamental to achieving the service level outcomes sought by our customers and stakeholders. Within this context this chapter covers the following:

- **Stakeholder Requirements (4.1):** the performance requirements expected from each of our stakeholders. These form the basis for the level of investment and expenditure required to meet these expectations;
- **Asset Management Framework (4.2):** describes the strategic approach and framework we utilise in managing and developing our assets over the AMP period;
- **Asset Life Cycle (4.3):** explains our long-term whole of life approach to asset management;
- **Risk Management Framework (4.4):** describes our risk management approach, specifically in relation to network assets; and
- **Asset Management Performance Assessment (4.5):** describes our asset management performance and improvement initiatives. This section discusses our assessment using the Asset Management Maturity Assessment Tool (AMMAT) prescribed by the Commence Commission.

4.1 STAKEHOLDER REQUIREMENTS

Chapter 2 identified our stakeholders. In this section we describe our understanding of our stakeholders and our environmental management requirements. The remainder of this section is structured to describe the requirements of:

- Our customers;
- Retailers;
- Community;
- Environment management;
- Regulators;
- Transpower (including in their role as SO);
- Service providers;
- Staff; and
- Board of Directors.

Their requirements and expectations are described below. Stakeholder requirements are incorporated into our asset management practices through the metrics we use to measure our performance and in our network design and security standards. The metrics used to measure our performance against these requirements is described in Chapter 6 and our design and security standards are discussed in Chapter 7.

CUSTOMER REQUIREMENTS

Our customers were last surveyed in February 2014. The survey provided customers' views on the trade-off between price and quality. Table 4.1 below compares our actual performance to our customers' expectations of average power outages per customer, measured in minutes (SAIDI).

CUSTOMER GROUP	ACTUAL PERFORMANCE 2014 (MINUTES)	CUSTOMER EXPECTATIONS FEBRUARY 2014 (MINUTES)
Urban	48	122
Rural	269	145
All Customers	91	126

Table 4.1 Customer Outage Expectations

From this survey we have concluded that our urban customers' reliability performance is being comfortably exceeded, while rural customers expect significantly less interruption minutes. The survey results are a clear indicator to us that improvement is expected from our rural customers.

Our large customers communicate directly with us about out their expectations and requirements. Our commercial and customer project teams are set up to interact with them on a day-to-day basis.

COMMUNITY

Public safety and community prosperity (economic and social) are primary concerns for our community. Our assets form part of the landscape in which our communities live and work. Accordingly public safety is a key concern and consideration in our asset management planning, equipment design and network operations. These requirements are reflected in our safety objectives and performance measures. WEL contributes to the community's prosperity on many levels but primarily through the safe and efficient delivery of our services.

ENVIRONMENTAL MANAGEMENT

Our environmental and sustainability policy aims to reduce our impact on the environment. We have identified that in order to reduce our environmental impact we must ensure all staff and contractors are aware of their responsibilities and are actively engaged and committed to improving our environmental performance.

As part of giving effect to the policy we have developed an Environmental Guideline as a basis for managing our activities in the field. Our field staff are trained in how to identify potential environmental impacts and discuss any environmental considerations prior to commencing work, applying and monitoring erosion and sediment controls as required.

TRANSPOWER (INCLUDING IN THEIR ROLE AS SO)

Transpower is one of our largest suppliers of services and we are each co-dependant on each other for the effective delivery of electricity to meet our customer expectations. Transpower requires that we keep them informed of our plans and events with the potential to affect them.

In their role as SO they require that we maintain instantaneous communications and are able to respond to their instructions. They, in turn, must take into account our requirements.

We maintain communications through our regular planning discussions and through our Network Operation Control Centre. All Code requirements are met by our established procedures and practices, and monitored through our risk and compliance framework.

REGULATOR'S REQUIREMENTS

We are subject to regulation under various Acts including the Commerce Act administered by the Commerce Commission and the Electricity Industry Act administered by the Electricity Authority. Our compliance with regulation is a key requirement of theirs and is a key focus for us. The publication of an AMP is an example of regulatory requirements we meet. In general, our regulators require our compliance, constructive input and collaboration to assist them in fulfilling their duties.

SERVICE PROVIDERS

We rely on service provides to carry out a number of functions. These include providing critical components of equipment and services. The requirements of service providers vary depending on the nature of the services they are required to deliver. However to be effective they require appropriate payment for services and good working relationships. Accordingly we put significant effort into ensuring sustainable working relationships are fostered with all service providers.

STAFF

Our staff are critical to our business. They enable us to deliver on customer and stakeholder expectations. As such, staff safety and wellbeing are our primary concern.

BOARD OF DIRECTORS

The Board of Directors is responsible for the delivery of outcomes sought by our stakeholders including the Trust. Their requirements are therefore related to the purpose of "growing the investment for our community."

4.1.1 BALANCING STAKEHOLDER REQUIREMENTS

With a wide range of stakeholders, striking the appropriate balance between their requirements is necessary where the outcomes sought are mutually exclusive. In a majority of cases our stakeholder requirements align and can therefore be met without conflicting outcomes. However, when they don't align we always prioritise safety requirements ahead of all other needs, followed by other legal and regulatory requirements. Any remaining unserved stakeholder requirements are prioritised on a case by case basis depending on the particular circumstances.

4.2 ASSET MANAGEMENT FRAMEWORK

Effective asset management is critical to achieving our objectives. We have developed an asset management framework that links our corporate objectives and day-to-day activities. It comprises the following:

- **Asset Management Policy:** aligns our asset management approach with our corporate objectives (Vision, Mission, Values and Strategic Plan). Our asset management objectives reflect these objectives by focusing on risk management and the skills and competencies of our workforce;
- **Asset Management Strategy:** translates the Asset Management Policy into drivers and high level objectives. The strategies employed currently sit within our network development, renewal and maintenance and non-network development plans;
- **AMP:** (this document) reflects our asset lifecycle model, aligns our high level objectives to relevant processes and activities, and details our 10 year investment plans; and
- **Work Plans:** apply our strategies to individual assets and set out intervention plans. Our work plans consider each element of the asset lifecycle.

Together these components align with the performance objectives established for the urban and rural network.

The asset management framework is depicted in the following page.

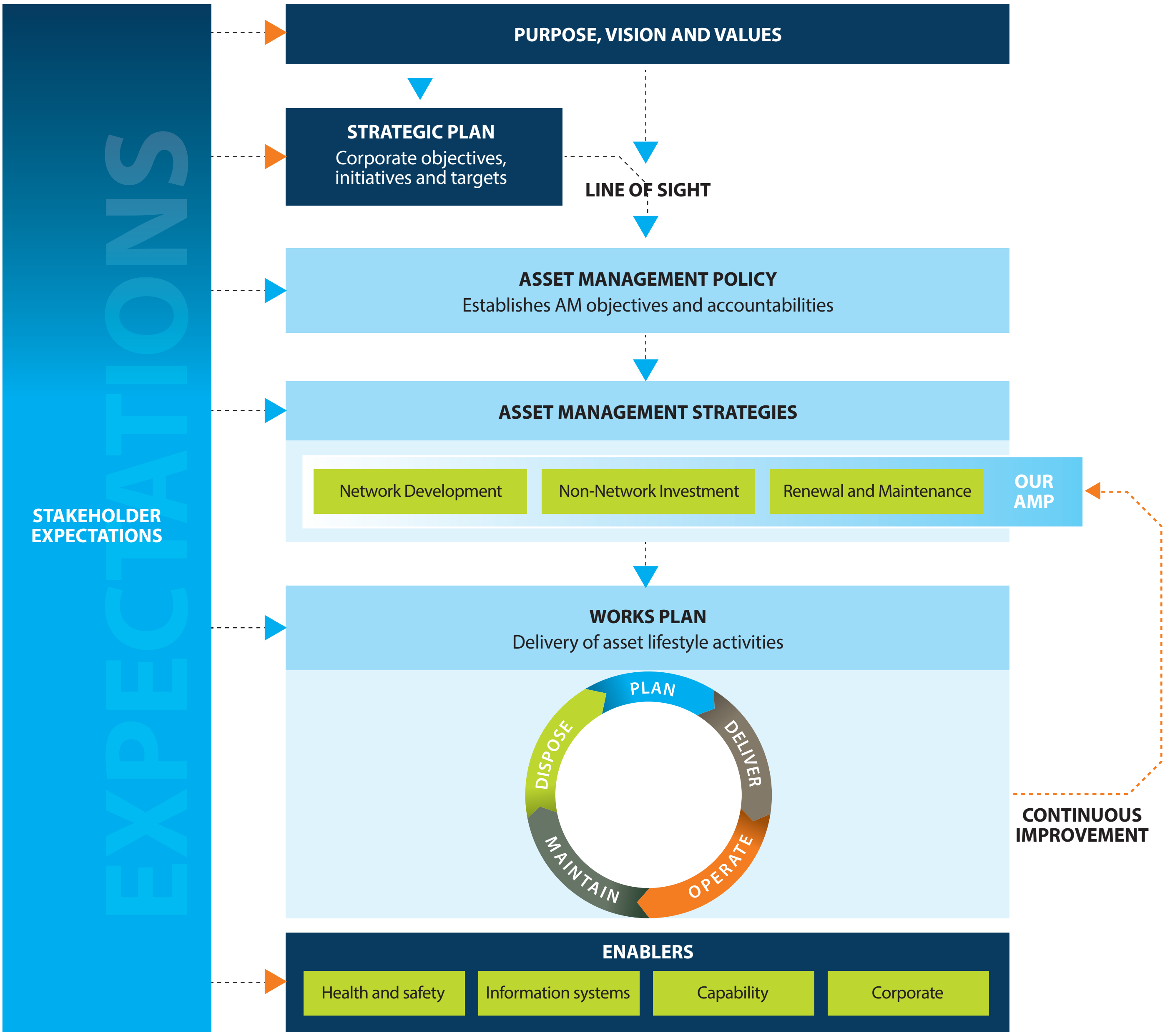


Figure 4.2 Asset management framework

4.2.1 ASSET MANAGEMENT POLICY

The Asset Management Policy is established within the corporate governance arrangements. The General Manager, Asset Management has overall responsibility for asset management with the primary objective of delivering a safe and reliable network over the long-term that meets the customers quality and price expectations. The development of our Asset Management Policy document to further align it to ISO 55000 content requirements has been identified as an improvement initiative for 2015.

4.2.2 ASSET MANAGEMENT STRATEGY

Asset Management Strategy links our policy objectives to the network development projects and asset renewal and maintenance plans we have described in Chapters 7 and 8. The strategy adopted considers three distinct components, network development; non-network investments and maintenance and renewals.

NETWORK DEVELOPMENT

In line with customer expectations our strategic objective for network development is to maintain our urban reliability level while improving the performance of the rural network. This involves consideration of network security over the AMP period against the established security criteria. We will need to maintain capacity required to supply localised areas of growth within the urban network. To achieve these cost-effectively, we will seek projects with high cost benefit ratios such as network automation, and non-network alternatives such as demand management. The initiatives and projects that result from this strategic approach are discussed further in Chapter 7.

NON-NETWORK INVESTMENTS

We invest in non-network assets to increase operational flexibility and to improve the information that supports our asset management decision making. We are now utilising the information and flexibility this provides to improve services to customers and to ensure efficient investment decisions are made.

MAINTENANCE AND RENEWALS

Our strategic approach to maintenance and asset renewal is to maintain a consistent and sustainable level of risk over the long-term. The principal methodology employed for this is CBRM. This strategic approach and the resultant renewal and maintenance expenditure over the AMP period is discussed further in Chapter 8.

4.2.3 WORKS PLAN

The integration of outcomes across the three strategy components is implemented through our works planning process. Work planning is integral to meeting the needs of our stakeholders. The focus of works planning is safety and efficiently delivering both planned and unplanned works. It also includes operational services required to meet customer requirements. It involves three key steps:

- Integration and optimisation of network development, renewal, and maintenance works;
- Works and resource scheduling and programme management; and
- Management of delivery through field services.

The governance arrangements for works planning are discussed further in Chapter 5, and the associated performance metrics and targets are described in Chapter 6.

ASSET LIFECYCLE

Management of our assets is based on taking a whole of life approach to asset management. This involves considering five aspects of the asset lifecycle, as depicted in Figure 4.2.3 on the right.

The approach to each of the five asset lifecycle components is strongly linked to the overall strategic approach described in 4.2.3 above.

Figure 4.2.3 The asset life cycle

These are:

- **Plan** – identifying specific network requirements that will deliver on stakeholder expectations for service and price, investigating options and authorisation of expenditures. Our planning processes are discussed in Chapter 5, and our expenditure plans are discussed in Chapters 7 and 8;
- **Deliver** – implementation of the planning process through works delivery. This is discussed in Chapter 5;
- **Operate** – operate the network and assets in such a way as to deliver the service levels sought by customers. Network operations and field delivery is discussed in Chapter 5;
- **Maintain** – efficiently maintain the equipment and network through defect identification and planned maintenance activities. The treatment of each asset class is identified in strategic asset management decisions. Our approach to maintenance is set out in Chapter 8; and
- **Dispose** – efficient, safe and environmentally appropriate disposal of assets. Any specific requirements for disposal of an asset are discussed in Chapter 8.

4.3 RISK MANAGEMENT FRAMEWORK

This section describes our approach to risk management. Risk management is a fundemental asset management discipline that supports the management of our assets. It requires that robust processes are in place for assessing and managing asset-related risk. It is key to fulfilling our ultimate aim of keeping people safe.

4.3.1 RISK MANAGEMENT POLICY

Our Risk Management Policy identifies risk management as a key requirement when managing day-to-day operations and longer-term network planning. It ensures that risk management is an integral part of our management and operating processes. It seeks to improve decision-making, so that the business can maximise improvement opportunities while managing risk.

We have developed and maintain a 'risk aware' culture, where staff are empowered and enabled to identify relevant risks. We have in place processes to evaluate, prioritise and mitigate these identified risks. Other than in safety related decisions, we seek to balance the costs of mitigation with the residual risk.

RISK ACCOUNTABILITIES

Ultimate responsibility for risk management resides with the Board of Directors. The Board of Directors have delegated management of this responsibility to the Audit and Risk sub-committee. The sub-committee meets every six months to review risk and audit and assurance activity. The full Board is updated on a monthly basis by the Chief Executive as part of the regular management reporting functions.

We have established an internal Risk and Audit Management Committee (RAMC) comprising a cross business representation of managers including the Chief Executive, all General Managers, the Risk and Audit Manager, the Risk and Quality Auditor, and senior operational, corporate and health and safety managers.

The RAMC provides management oversight of our risk management and audit processes. This includes reviewing all new risks entered in the risk database to validate the data, determine the classification of the risks, and approving the treatments. This committee meets on a quarterly basis. Specific actions are then delegated to the relevant managers.

Each staff member is responsible for ensuring they understand the risk management process and how it applies to them. This includes being actively engaged in the identification of new risks and ensuring these are appropriately escalated.

4.3.2 RISK MANAGEMENT FRAMEWORK

Our Risk Management Framework is aligned to the ISO 31000 standard. It consists of five process steps for systematically managing risk, as illustrated in Figure 4.3.2 below.

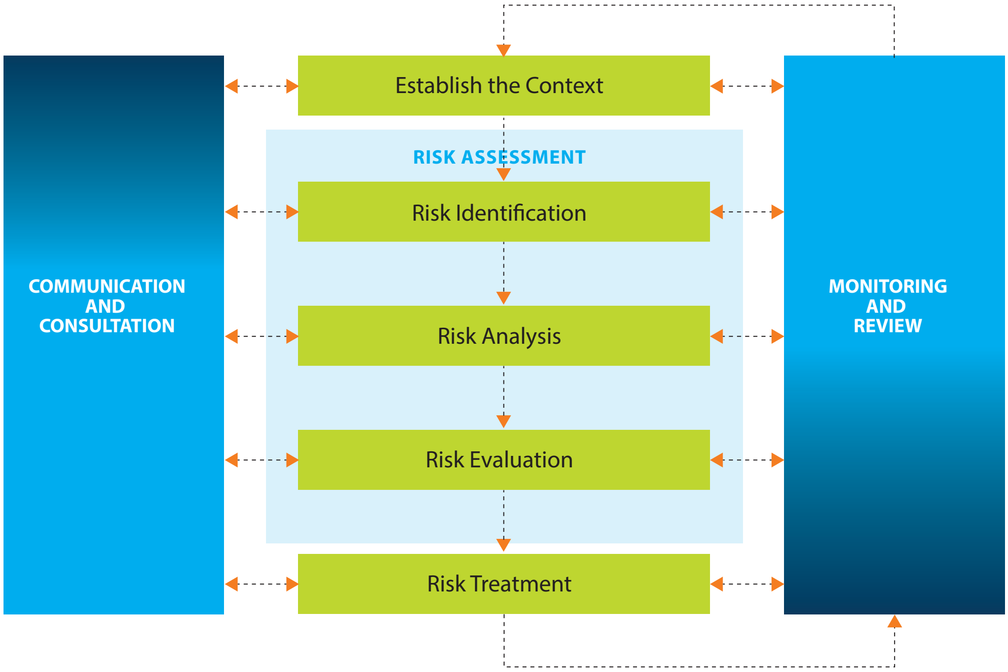


Figure 4.3.2 Risk Management Framework

The following describes our approach to each process step in the framework.

ESTABLISH THE CONTEXT

The risk context is established from many factors including; accessibility by the public, location e.g. rural or urban, asset age and condition, inspection programmes and data quality.

RISK IDENTIFICATION

Our asset management risks are identified via the hazard identification process, regular risk meetings, audit results or event analysis. Any new risk will then be assessed and ratified by the RAMC.

Managers from our Asset Management team meet on a monthly basis to review a selection of risks. This provides a formal mechanism for risk assessment, risk monitoring and the identification of new or emerging risks.

RISK ANALYSIS

When a potential new risk is raised a process of analysis is completed to understand the nature and extent of the risk. This includes discussion with relevant staff.

RISK EVALUATION

Each risk is evaluated against established criteria to determine the degree of acceptability. The criteria are discussed in Section 4.3.3 below.

RISK TREATMENTS

Options to mitigate risks are identified. The costs (both initial and on-going) of the proposed treatment options are estimated. The treated risk is then evaluated against the 'inherent' risk. The 'gap' indicates the effectiveness of the treatment option.

Once agreed treatment actions are included in business plans and budgets where necessary, priorities are set and timeframes for actions are agreed with the risk owner and relevant managers.

MONITORING AND REVIEW

An active programme of risk monitoring and review is in place. Our internal audit programme also assesses key risks and the effectiveness of controls. The results of these audits are reported to the RAMC with improvement opportunities discussed and additional actions approved. The internal audit programme utilises both our internal auditors and independent third party auditors to conduct a range of internal audits to verify performance.

RISK MANAGEMENT DATABASE

To support our risk management framework, we use the Quantate Risk Management application. This software-based process supports ISO 31000. It helps to ensure we have a structured approach to the risk management processes, and has assisted with the efficient administration of risk management reporting.

4.3.3 RISK CLASSIFICATION

Figure 4.3.3 below illustrates our risk management classifications. Risk classification bands (indicated by different colours) have been set to reflect our tolerance for risk. These settings were determined by establishing the potential impact and degree of acceptability.

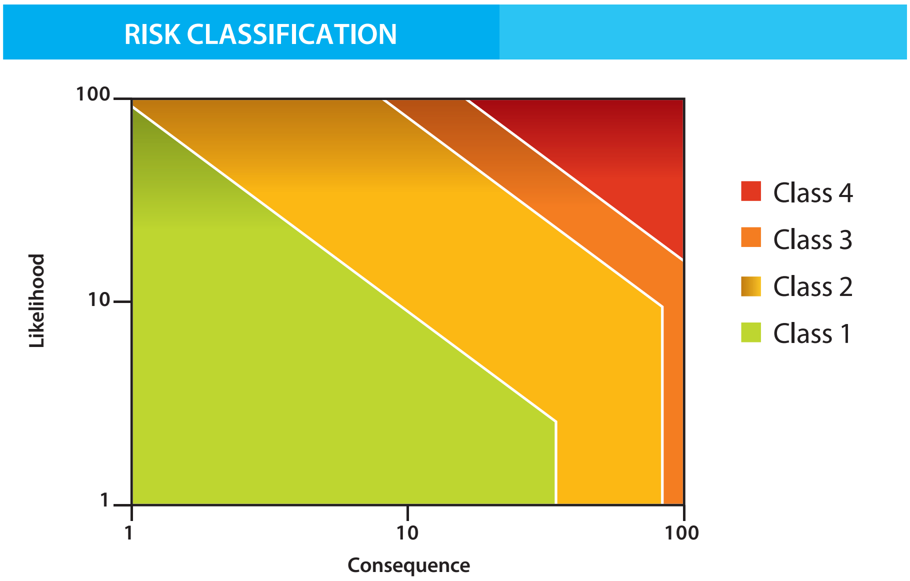


Figure 4.3.3 Risk Classification

There are two aspects to the classification of risk: likelihood and consequence.

Likelihood (y axis) is determined from:

- **Historical data** - from our company and other similar companies
- **Empirical data** - externally sourced data e.g. equipment manufacturer information
- Consequences (x axis) are considered and rolled up into three broad categories of:
- **Health and safety** - the risk of a health and safety impact e.g. is there a risk of single or multiple fatalities, serious harm or minor injury.

- **Financial impact** - includes the service, environment and reliability factors estimated as cost impacts from $0 to > $100,000,000.
- **Reputation** - this looks at the impacts on various groups of internal and external stakeholders including our customer and community is categorised in five bands from 1 (very serious impact) to 5 (very minor impact).

Each combination of consequence and likelihood has been given a value according to the potential impact on the business.

The classification of risks, shown by the colour bands in Figure 4.3.3 above, and description are:

- **Class 4 (Extreme)** risks are considered intolerable. Risk reduction actions must be applied to reduce the level or consequences of the risk.
- **Class 3 (High)** risks are unacceptable without further controls unless the cost of such controls outweighs the benefits.
- **Class 2 (Medium)** risks are tolerable but undesirable. Higher consequences (those further over to the right hand side of the chart) are less desirable. Low cost mitigation may be justified unless the cost of such controls outweighs the benefits.
- **Class 1 (Low)** risks are acceptable.

4.3.4 IDENTIFIED TOP 10 RISKS

We have identified the following asset risks as being the top 10 inherent.

RISK	INHERENT CLASSIFICATION	RESIDUAL CLASSIFICATION	KEY MITIGATIONS
Asset class failure prior to scheduled replacement e.g. 16mm copper conductor failure	Extreme	Extreme	Asset Management Condition-based Assessment
Major storm or natural disaster	Extreme	High	Contingency Planning Network Design
Staff or contractors injured while working on the network	Extreme	Medium	Training Processes
Harm to member of the public through equipment failure	Extreme	Medium	Asset Management Maintenance
Harm to member of the public through deliberate contact with the network	Extreme	Medium	Asset Security Maintenance
Harm to staff or member of the public through defective work	Extreme	Medium	Training Processes and Standards
Harm to staff or member of the public through theft of earthing	Extreme	Medium	Maintenance Work with NZ Police
Harm through failure of safety equipment	Extreme	Medium	Test and Inspection Purchasing Standards
Harm to staff and equipment damage through ring main failure	Extreme	Medium	Equipment Training Purchasing Standards
Harm and or reliability impact from critical network systems e.g. NMS not being accurate	Extreme	Medium	Commissioning Process As-built Process

Table 4.3.4 Top 10 Inherent Risks

4.3.5 MANAGING ASSET-RELATED SAFETY RISK

Safety management is a critical component of the overall risk management framework and, due to the inherent nature of our electricity network, many network risks have a significant safety consequence weighting. Minimising both the likelihood of safety events occurring, and the ability to minimise the consequences when events do occur are therefore of paramount importance to us.

Our Public Safety Management System reflects our approach to managing asset based safety risk. The key principle in managing asset and infrastructure risk is to reduce the residual risk to being as low as reasonably practical.

ASSET FAILURE RISK MANAGEMENT

Safety risk due to asset failure is a key concern for WEL. The Asset Management team is responsible for managing risk associated with our assets and the Operations team is responsible for managing any operational or delivery risks.

WEL has employed the technique of exposure rate analysis to assess the likelihood (frequency) of asset failure and related impacts. Risk assessments have been conducted for the various classes of network asset. This approach is inherently built into our CBRM asset management tool, discussed further in Chapter 8.

4.3.6 RESILIENCE AND HIGH IMPACT LOW PROBABILITY EVENTS

Even though natural disasters and emergency situations are unlikely, they would have a significant impact on our assets and operations. Reflecting this, our planning in this area is extensive and includes the following aspects. While the network is not designed to withstand significant natural events, we actively identify areas and sections of the network that may be subject to HILP events and have response plans in place.

LIFELINE UTILITY

As a critical infrastructure provider in New Zealand, WEL is a Lifelines Utility and has a significant Civil Defence Emergency Management (CDEM) role to play. Section 60 of the CDEM Act 2002 requires WEL to:

- Function at the fullest possible extent during and after an emergency;
- Have plant for such functioning;
- Participate in CDEM planning at national and regional levels; and
- Provide technical advice on CDEM issues where required.

We are a participating member of Waikato Engineering Lifelines Group (WELG) which has overall goals to:

- Assist members to meet their obligations under the CDEM Act;
- Coordinate and work to progress the completion of projects which benefit lifeline organisations in their region;
- Strive to ensure that member organisations get value for money through their participation; and
- Endeavour to meet ever increasing customer expectations that Lifeline Utilities will deliver secure services.

Lifeline utilities are responsible for strengthening relationships within and across sectors, and individually committing to actions that ensure continuity of operation and delivery of service. Through our membership in WELG, we have access to regional and national studies carried out on natural, technological and biological hazards. From these we have identified the top hazards and developed a comprehensive vulnerability assessment which identifies the risks in terms of importance, vulnerability, resilience, and impact of each major asset on the network.

MAJOR EVENT PROCEDURES

A major event procedure has been established and is applied when events e.g. weather, flood or earthquake have a major impact on our ability to supply electricity, or when a Civil Defence Emergency is declared. It is designed to prepare resource levels beyond those normally available or on call.
The procedure requires the following actions to be taken:

- Prepare for impending weather that has been forecast. Teams are required to make preparations and resources are put on notice;
- Manage increased or increasing numbers of faults due to weather conditions. Resources are increased accordingly;
- Liaise with Civil Defence in the event of a Civil Defence Emergency being declared; and
- Respond to Civil Defence requirements to prioritise the restoration of supply to critical sites.

We also have a communications process for major events which covers external communications during an event.

CONTINGENCY PLANNING

We have developed contingency plans for loss of significant assets or groups of assets.
Further development of specific plans for zone substations and critical 33kV circuits is ongoing.
Our contingency plans include switching processes to ensure essential services, as much as is practicable, are able to continue to receive power supply in the event of a major outage. We have also entered into arrangements to gain priority access to emergency generation should the need arise.

EMERGENCY EXERCISES

We undertake annual emergency response exercises. These alternate between desktop and full scale emergency scenario simulations. Typically these have involved full scale alarms being initiated without prior warning. A range of scenarios have been staged including major rolling storms, significant failure of the communications network (affecting SCADA) and failure of a Transpower point of supply.
Most recently we simulated a significant earthquake event, putting into practice some of the learning's from the Canterbury earthquakes.

Following every exercise we discuss any potential improvements to be made and record lessons learnt.

DISASTER RECOVERY SITE

We operate our control centre under normal circumstances from our Maui Street premises.
When this is not available for any reason, our Disaster Recovery site provides a full back-up of the Network Management, SCADA and major corporate systems. The Disaster Recovery site allows full monitoring and control of the network to continue.

4.4 ASSESSMENT OF ASSET MANAGEMENT PERFORMANCE

In this section we describe the assessment tool we and all other electricity distributors are required to use to assess our respective asset management capability.

4.4.1 AMMAT

AMMAT is a prescribed set of questions identified by the Commerce Commission for the self-assessment of electricity distributors' asset management performance and maturity. The Commerce Commission developed the tool to help all electricity distribution businesses and stakeholders to assess and understand their performance and to encourage continuous improvement.

The tool uses a selection of 31 questions, which are grouped into six key areas. The questions relate to the key components of the internationally recognised ISO 55000 framework for asset management.

In addition the Electricity Engineer's Association has developed guidelines to assist in the assessments process. We made this resource available to all key personal invited to participate in the 2015 assessment.

4.4.2 THE PURPOSE OF AMMAT

The purpose of the assessment is to gauge our performance against the selected components of the ISO 55000 framework. The self-assessment informs us and stakeholders about the level of competency we believe we have reached at the time of assessment. While we have no immediate aspirations to seek ISO 55000 certification, we do agree at this stage that there is benefit to be obtained from performing the assessment. The benefit comes from our internal discussions and views around the level of asset management capability and competency appropriate for our stakeholders, and the identification of improvement opportunities.

4.4.3 IMPROVEMENTS IMPLEMENTED SINCE 2014

Since our last survey in 2014 we have implemented a number of improvement initiatives including:

- CBRM tools have been implemented across a number of fleets and the results are starting to be used to inform our planning and decision making;
- Safety Improvements
  - Safety by design concepts have been formally incorporated into our design processes;
  - Improvements have been made to the identification of safety hazards, their documentation and handover to external contractors;
  - Contract Management - we have revised our tender documents under NZS3915:2005 to improve their consistency and to better manage commercial risks; and
- Resource Management - we have employed a dedicated Works Programme Manager and have improved the visibility of resource scheduling in our works plan. More work in this key area has been identified for 2016.

4.4.4 2015 AMMAT ASSESSMENT

Our 2015 assessment is summarised below. We have undertaken detailed analysis of the responses to gain a deeper understanding of our latest performance assessment.

Overall we believe our performance and maturity in asset management is good. We aspire to be better and we believe our revised AMP is a significant step in the right direction.

The results shown below indicate lower scores than our last assessment undertaken in 2014. We believe there are a number of explanations for this as our asset management performance has not deteriorated. Rather, we believe the results are consistent with the Commerce Commission's intended purpose and signal a maturing of our understanding of the PAS55 standards. Another reason the two assessments are not comparable is that in 2015 a wider selection of managers were surveyed within our business. We did this to increase awareness and to gain a broader perspective.

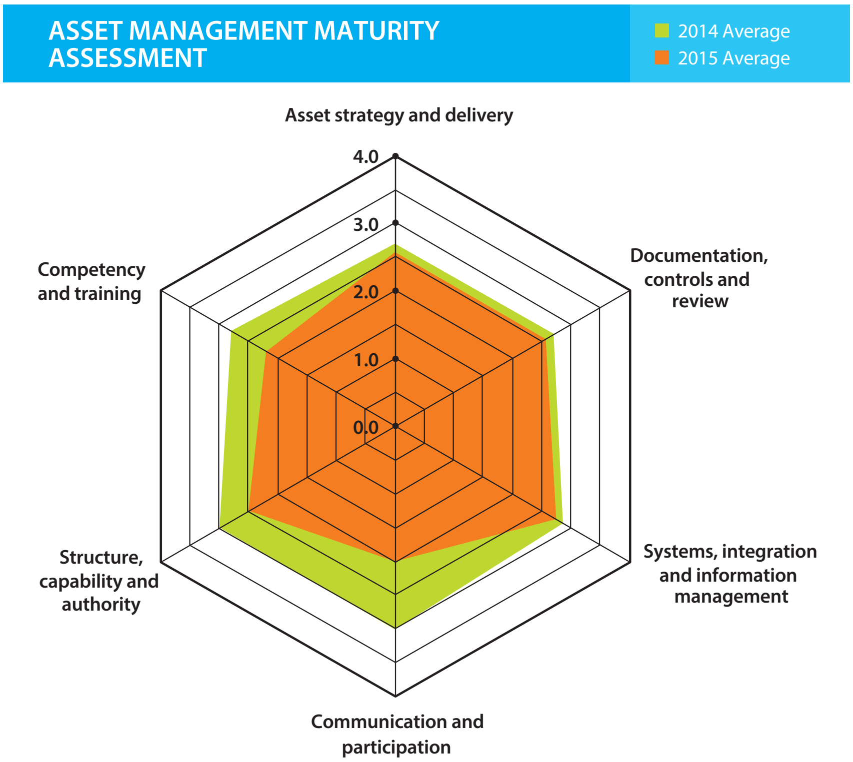


Figure 4.4.4 2015 AMP AMMAT Summary Results

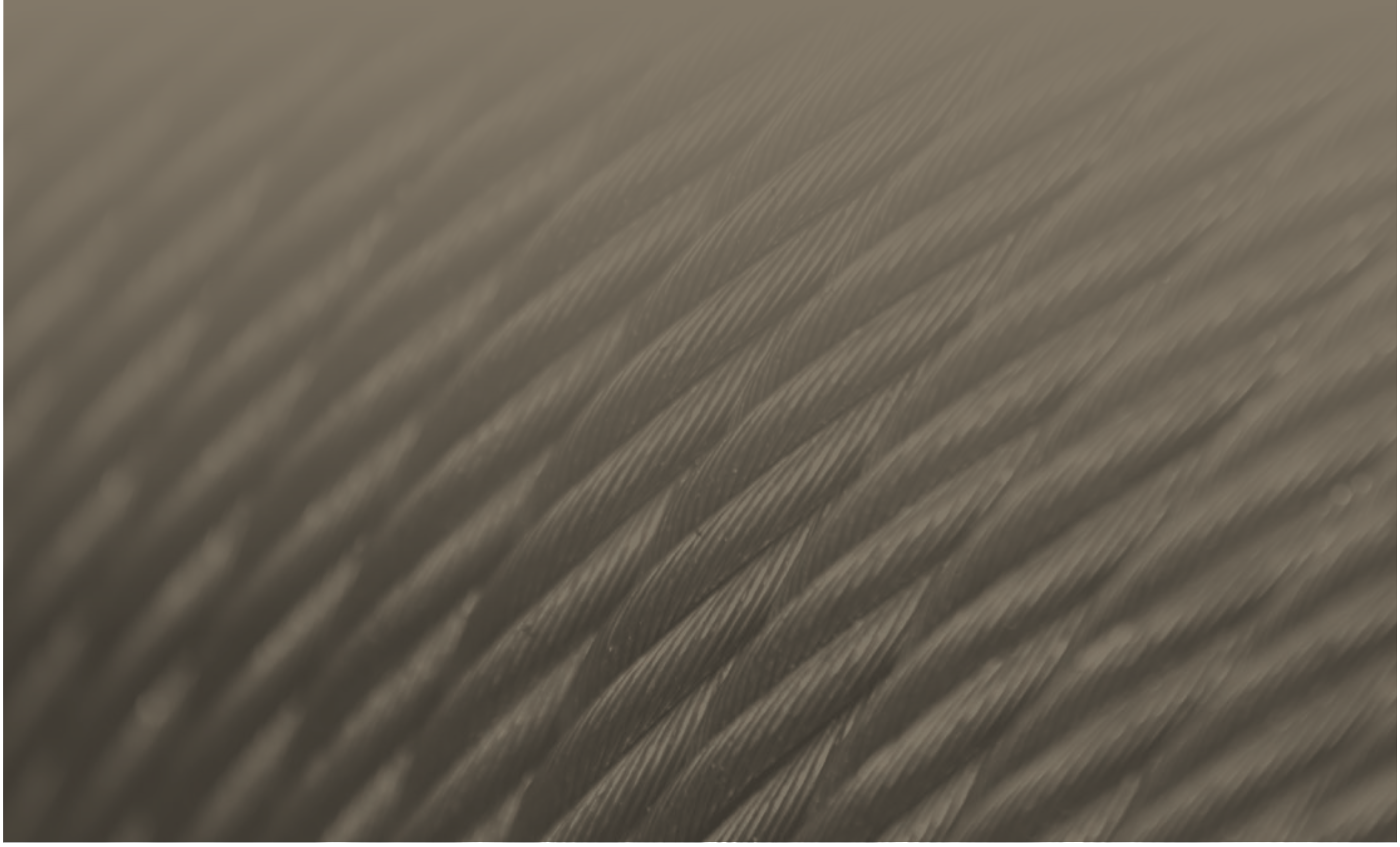
The conclusion drawn from the result is that we are maturing as asset managers and are now more realistic about our asset management performance. We are now setting higher standards for ourselves as we strive for continuous improvement. This applies to the four areas covered by our asset management objectives of safety, customer experience, cost efficiency and asset performance.

4.4.5 2015 IMPROVEMENT AREAS AND INITIATIVES

Of particular note is that are that the two lowest areas of assessment in 2015 are Communication and Participation, and Competency and Training. Both areas also recorded the biggest shift from the previous survey. Following our internal review and after weighing up the changes from the previous survey we have concluded that the results are entirely consistent and should be interpreted as meaning:

- We need to improve the communication of our plans (note the survey was completed pre-completion of the revised AMP). At the time of the survey many respondents were either heavily involved in the revision of the AMP or at least aware of it. We also tak e the result to mean that we need to find new ways to communicate our AMP within our business and with stakeholders; and
- We have identified some areas where a higher level of capability is required to further lift our performance. The results align with the finding from our strategic planning and therefore support our plans to improve our level of capability in targeted areas.

5 ASSET MANAGEMENT GOVERNANCE



5 ASSET MANAGEMENT GOVERNANCE

This chapter sets out WEL's asset management governance framework, in which established processes support investment planning decisions with clear accountability and expenditure approvals. The later sections of the chapter describe our approach to works delivery. The chapter is structured as follows:

- **Investment Planning (5.1):** explains our methodology applied to investment planning including an explanation of our four staged approach to investment decisions and implementation. The four stages are: need identification, options analysis, project definition and cost estimation, and establishment of a works plan. All stages are undertaken under overarching governance, prioritisation and approval controls;
- **Expenditure Approvals (5.2):** provides a description of our governance arrangements including the delegated financial authority framework, and our challenge and prioritisation processes. This section concludes by summarising the decision support tools underpinning our expenditure approval process; and
- **Works Plan (5.3):** describes how we integrate and optimise our works delivery, the associated delivery model, and how the resources for this are determined. It also describes our approach to materials management and works management.

5.1 INVESTMENT PLANNING

Investment planning is fundamental to many of our activities. Our planning capability is also central to efficiently delivering on customer price and quality expectations.

Our development process has the same fundamental stages for all investments, from needs identification through to delivery. These stages are managed under an overarching governance, prioritisation and approvals framework as illustrated below. These stages are:

- Need identification;
- Options analysis;
- Project definition and cost estimation (Project Definition Document (PDD)); and
- Works Plan.

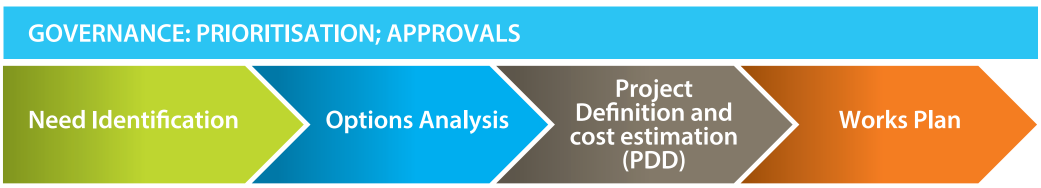


Figure 5.1 Investment Planning Model

The first three planning related stages are described below. The processes employed for investment approvals and works delivery are described in sections 5.2 and 5.3. Details of the proposed projects and associated expenditure can be found in Chapters 7 and 8.

5.1.1 NEED IDENTIFICATION

Investments are made in response to a number of needs. During the coming AMP period our network expenditure will be primarily driven by:

- Safety;
- Reliability performance;
- Asset condition and health;
- Growth and security;
- Customer requests;
- Technology change; and
- Legal, regulatory and environmental requirements.

In many instances an investment, or a series of investments, will meet more than one of the above drivers. As such it is imperative to have a very clear definition of the need being met in order to ensure that the most prudent solutions are being proposed.

The investment drivers are discussed below.

SAFETY

Investment to address safety concerns and safety related asset issues is a high priority for us. The majority of safety related risks can be addressed in the design and selection of equipment on the network. In addition, there will be specific safety drivers within our expenditure on reliability, asset condition and health, and growth and security. There are instances where specific safety related investments emerge from risk review meetings and are assessed on their individual merits.

RELIABILITY PERFORMANCE

As assets age and or demand grows, the reliability performance of sections of the network can degrade. In addition, previously unidentified reliability issues become apparent. In these instances investment to maintain reliability performance is required. Typically this will result in additional network automation, further sectionalising of circuits, or the addition of new feeders. These issues are identified as part of our network planning process. It is the responsibility of the Network Planning team to propose and manage these performance issues.

ASSET CONDITION AND HEALTH

Expenditure on asset maintenance and renewals is primarily driven by the need to maintain asset condition and health. We have a comprehensive and continuous programme to identify asset condition and health, which informs maintenance requirements. Field inspections are carried out by line crews and a dedicated team of inspectors. The renewal and maintenance requirements are then fed into the renewal planning and maintenance process.

The overall responsibility for asset health and condition related investment sits with the Maintenance Strategy team. A more detailed explanation of our asset condition and health assessments and how we manage identified issues is set out in Chapter 8.

GROWTH AND SECURITY

As peak demand grows new capacity from additional investment is generally required to reconfigure the network. The process starts with an assessment of expected future demand on the network and identifying where current network capacity is insufficient to meet expected demand and security requirements. The required level of security at each level in the network has been established as part of our network design security criteria. Assessing the need for growth and security investment is the responsibility of the Asset Planning and Engineering team.

CUSTOMER REQUESTS

Individual customers often seek new connections or an upgrade to their existing connection. Network changes are also frequently requested due to road layout changes e.g. widening or safety improvements, or new roads being built e.g. the Waikato Expressway. Customers have the choice of initiating contact with us through a number of channels. They can initiate the change request with their retailer, call WEL's contact centre, and customers familiar with the connections process can make direct contact through their relationship manager or our Customer Projects team.

Regardless of the channel used, our Customer Projects team will process the request in a timely manner and keep the customer informed of the status of the request. The Customer Project team is part of the wider operations team and will assess the works required, advise any costs to be paid by the customer and initiate the works required to fulfil the customer request. Any capital contribution required from the customer is calculated in accordance with our Capital Contribution Policy. The main purpose of the Capital Contribution Policy is to further ensure the best option selected is financially viable. A copy of can be found on our website www.wel.co.nz.

TECHNOLOGY CHANGE

Technology obsolescence and technology change can also drive the need for investment expenditure. This is particularly true where critical operational equipment is required for continued electricity supply. This includes network management software and communications, network monitoring, and corporate support technologies. Responsibility for proposing technology investment lies with individual business units. For example, the Information Technology (IT) team is accountable for all corporate systems, hardware and software investments, while the Asset Planning and Engineering team is accountable for SCADA and network automation investments.

LEGAL, REGULATORY AND ENVIRONMENTAL

Our formal compliance policy requires that we endeavour to comply with all relevant legal, regulatory, and environmental obligations. Where we find we are non-compliant we will take all reasonable steps to work towards compliance. It is therefore a key consideration in our needs identification that we are either maintaining compliance or are taking all reasonable steps to achieve compliance through the AMP period.

5.1.2 OPTIONS ANALYSIS

Following need identification, potential solutions are identified and considered. The number and type of options (or solutions) varies depending on the type, value and complexity of the investment. Our options analysis is also tailored based on whether the capital expenditure is related to renewals or network development.

Renewals analysis is informed by our CBRM framework and processes as detailed in Appendix B. Accordingly renewals are based on targeting high risk assets. This process is described further in Chapter 8.

For all other investment needs, maintenance and development options are explicitly considered.

Typical options considered include; maintenance, network reconfiguration, network automation, capacity upgrades, additional assets, and non-network investments such as demand management.

ASSESSMENT PROCESS

Our options analysis process involves considering all technically feasible options then ranking these to select the best in terms of safety, whole of life cost and reliability outcomes. In assessing options we take into account metrics such as the affected customers' value of lost load (VoLL), SAIDI and other reliability improvements. In some instances where different development timeframes are available, such as staging the construction over several years, we use economic analysis to account for expenditure timing differences and identify the best option. This analysis includes Net Present Value (NPV) assessment. The outcome sought is the least cost option that meets the identified need.

DECISION SUPPORT TOOLS

We use a number of decision support tools in our assessment process. These include, as appropriate:

- Safety considerations and operating processes;
- Technical Analysis;
- Risk Analysis;
- Economic Analysis (Cost Benefit, NPV, VoLL/Cost Ratios);
- Capital Expenditure / Operational Expenditure trade-offs; and
- CBRM.

These tools help us assess and choose the best option for the maintenance and development of our distribution network and associated systems.

5.1.3 PROJECT DEFINITION AND COST ESTIMATION

The PDD for each capital project is written and approved to provide a high level project scope, cost and resource estimations. Following expenditure approval of the PDD and associated budgets, resource planning for detailed design and project construction is used to produce a high level project delivery timeline.

5.2 EXPENDITURE APPROVALS

Expenditure approval is governed by the delegated financial authority structure within WEL. Prior to approval, expenditure plans are subject to an internal challenge process. This section describes the approval model, the challenge process, and the accountabilities at each level in the organisation.

5.2.1 GOVERNANCE APPROACH

Our Board has established a delegated financial authority structure for the business. The structure amongst other criteria sets the expenditure approval level of the Chief Executive, the General Management Team and senior managers.

DELEGATED FINANCIAL AUTHORITY

The expenditure approval limits have been established commensurate with our organisational structure, meaning higher limits are set corresponding to a person's position within the organisation.

The expenditure limits are further differentiated between budgeted and unforeseen expenditure. Unforeseen expenditure limits are set significantly lower than budgeted expenditure given that budgeted expenditure has already undergone preliminary approval process incorporated in our strategic, business planning and asset management planning processes. The Chief Executive's budgeted expenditure limit has been set at $2 million excluding regular payments above this amount e.g. Transpower's monthly charges.

CHALLENGE PROCESSES

We have established formal challenge processes during 2015. This AMP was subjected to these and reflects a collaborative effort across our business. All participants in the process were encouraged to challenge any aspect of the AMP in a constructive manner.

This year a formal steering group comprising of the Chief Executive, selected general managers and a selection of senior managers were convened to review key strategies and projects in our draft AMP. As a result of this and the general challenge process, significant refinements were made to the AMP.

PRIORITISATION

In addition to general governance, delegated financial authorities, and challenge processes there is also an overarching requirement to prioritise our planning resources. For example, we cannot simultaneously complete options analysis on all projects. As such, projects are prioritised based on the following criteria:

- Projects which impact on health and safety;
- Legal, regulatory and environmental compliance; and
- Growth and security and customer driven projects.

DECISION SUPPORT TOOLS

For expenditure approvals the key decision support tools are:

- Delegated financial authority limits;
- Our strategic, business and AMP strategies;
- Economic analysis e.g. results of the options analysis stage; and
- PDD documents.

5.3 WORKS PLAN

This section describes the process utilised in delivery of planned projects, and responding to unplanned events. The focus of works delivery is driving efficiencies and ensuring timely outcomes.

5.3.1 INTEGRATION AND OPTIMISATION

WEL is a maturing business focused on continuous improvement. We understand that the integration and optimisation of our planning process and work delivery is key to achieving our safety, efficiency and least cost objectives. We have identified a number of potential enhancements to our current practices.

The role of the Works Programme Manager was recently established to further enhance the integration and optimisation process. The primary role of the Works Programme Manager is to develop and manage the works delivery plan. The plan accounts for resource requirements, expenditure, and high level delivery timelines for planned projects.

The Works Delivery Plan is utilised by the operations team to establish a delivery schedule (by month) to achieve planned delivery in a financial year.

We have identified a number of improvement opportunities in the integration and optimisation of works delivery. One significant change during 2015 was the reorganisation of our First Response team for faults. This is expected to reduce the impact that attending a fault can have on scheduled works.

The works delivery plan and operations scheduling are expected to improve in accuracy over the next 12 months as we build on our initial improvement initiatives. We are currently instigating a project to further integrate and extract benefits from our enterprise system (SAP) and, in particular, by the enhanced utilisation of its powerful scheduling module.

5.3.2 DELIVERY MODEL

This section describes our works delivery model. The aim of the works delivery model is to manage the safe and efficient delivery of maintenance, renewals, and development works. The delivery process involves the following stages:

- **Resource and expenditure forecasting:** The Works Delivery Plan is a high level plan based on PDD information for growth and security, renewal and scheduled maintenance activities. For customer driven and reactive maintenance work, historical resource utilisation and expenditure are used for forecasting;
- **Detailed Design:** We utilise standard designs and construction techniques as documented in our design and construction manual to drive quality, standardisation and cost efficiency. Asset categories where standardised designs have been developed include subtransmission lines, zone substation equipment and switchgear. All designs incorporate safety by design concepts assisting assets to be safely accessed and maintained. Opportunities to develop standardised designs is typically identified as part of the asset renewal process and development of maintenance strategies. Specialist independent design support is sought to help manage work flows and cover capability gaps;
- **Scheduling Plan:** A detailed monthly schedule for the delivery of all work types, monitoring delivery against the plan to improve coordination of resources;
- **Construction Handover:** applies to internal resources and external service providers. Capital Projects have a handover meeting between design and the project manager to effectively manage any safety, delivery risks or complexity; and
- **Project Closeout**: all capital projects and, any other project with a budget that exceeds a defined financial threshold, require a close out report to be completed, circulated and a meeting held to capture and discuss lessons learned.

RESOURCING

The Works Delivery Plan establishes our resourcing requirements. To ensure full utilisation and cost efficiency of our internal staff we do not plan to deliver our full works programme using only internal staff. Instead we selectively outsource works at peak times and contract specialist resource as required. Projects for outsourcing are identified as early as possible to enable the timely procurement of external support. The process of engaging and managing contractor performance is described in the Section 5.3.4 Works Management below.

5.3.3 MATERIALS PROCUREMENT

This section describes our materials procurement activities. The objective of the materials procurement process is to efficiently acquire the materials specified by the asset management and delivery functions at an optimal cost given the specification, quantity and quality required.

The stages of the procurement process are:

- Requirements Identification;
- Supplier Pre-qualification;
- Tender or Request for Proposal (RFP);
- Approval;
- Purchase order raised or Preferred Supplier Agreement established; and
- Evaluate and monitor quality.

The processes and business rules for procurement activities have been recorded in our process management systems. This has proven to be a highly effective means of procuring items e.g. inventory, equipment and vehicles because the procurement model for these items is centralised. The centralised model works well because the business processes are adhered to, the benefits and results are measurable, responsibilities are clearly defined and are supported by senior management.

TENDERING

We tender all major equipment requirements, generally over the value of $100,000. The tender process encompasses assessing business requirements, establishing timeframes, selecting suitable suppliers, detailing specification, tender preparation and evaluation, and finally developing a formal written recommendation.

For purchases or categories up to $499,000, a written recommendation approval is sought from the WEL Tenders Committee. Approvals for values over $500,000 are approved by the Board.

PREFERRED SUPPLIERS

Through the process of category management and the use of RFP, we have established a number of preferred suppliers. The benefits of a preferred supplier arrangement are consistency and certainty of supply, optimal and stable pricing structures which reflect current market conditions, quality assurance, and volume rebate options.

MONITORING COST PERFORMANCE

We use various techniques for monitoring suppliers to ensure required specifications, quality and cost requirements are being achieved. These include market analysis and product cost benchmarking, monitoring raw material and foreign exchange trends, and new technology evaluation.

5.3.4 WORKS MANAGEMENT

Our works management function is split across a number of teams as the requirements of each type of work varies. For example, the management of large works by third party contractors involves additional complexities associated with the contracted works, scheduling, and performance monitoring of delivery. It is therefore assigned to our specialist project management team.

The works management handover paths are shown in Table 5.3.4 below.

WORK SOURCE	DETAIL	HANDOVER PATH
Maintenance	Proactive maintenance inclusive of asset replacements	Typically handover is to the Scheduling team - complex asset replacements may go direct to Capital Projects for delivery management
Faults	Reactive & time limited maintenance	Handover to the Faults Supervisor for delivery management in consultation with Scheduling
Customer Driven	Small & large customer works	Handover to Scheduling or Capital Projects dependant on project complexity
Capital Projects	Complex long term planned projects	Handover to the Capital Projects Manager for delivery by internal or external resource

Table 5.3.4 Work management handover paths

Revised contract templates have been developed for the engagement of contracted service and now incorporate:

- Design services templates using Conditions of Contract for Consultancy Services as a base document due to its relatively good uptake in New Zealand; and
- Invitation for Tender template based on the New Zealand Standard Conditions of contract for building and civil engineering construction (NZS3915).

6 ASSET MANAGEMENT PERFORMANCE

6 ASSET MANAGEMENT PERFORMANCE

This chapter describes our performance objectives, initiatives, measures and targets for the AMP period. The chapter is structured as follows:

- **Overview of Performance Objectives (6.1):** provides an overview of our performance objectives, initiatives and measures;
- **Safety (6.2):** describes our safety objectives, initiatives, and measures for the AMP period;
- **Customer Experience (6.3):** describes our customer experience objectives, initiatives, and measures for the AMP period;
- **Cost Efficiency (6.4):** describes our cost efficiency objectives, initiatives, and measures for the AMP period;
- **Asset Performance (6.5):** describes our asset performance objectives, initiatives, and measures for the AMP period; and
- **Performance Evaluation (6.6):** describes our historical performance.

6.1 OVERVIEW OF PERFORMANCE OBJECTIVES

We have established performance objectives in four key areas: safety, customer experience, cost efficiency and asset performance. The objectives reflect outcomes sought by our stakeholders as described in Chapter 4. They are also directly linked to our business plan, strategic plan and ultimately support our corporate Vision.

The areas of focus for our objectives can be summarised as follows:

- **Safety:** Safety is our highest priority. Our Vision places safety first and foremost, making it the top priority in everything we do. We strive to ensure safe environments for our staff, contractors, and members of the public;
- **Customer Experience:** Our customer experience objectives cover both reliability (quality of supply) and the quality of service we deliver through our interactions with customers e.g. the time taken to resolve a complaint;
- **Cost Efficiency:** Cost efficiency is driven by making the right investment choices at the right time, and delivering our works programme for the lowest total ownership cost possible while achieving our quality and safety targets; and
- **Asset Performance:** The performance of our assets directly determines the quality and cost of services provided to our customers. This, in turn, is a direct consequence of the asset management decisions we make on a daily basis. We will improve our asset performance by further developing our asset management capability and decisions.

The objectives, initiatives, measures and targets for each performance area are described in more detail below.

6.2 SAFETY

Our Vision states that WEL aspires to being 'Best in Safety.' This underlines our commitment to ensuring the health and safety of our staff and the communities we operate in. To help achieve this we have developed a five year Health and Safety Strategy to 2020. The key deliverables of the strategy are summarised below.

6.2.1 SAFETY OBJECTIVES

Our safety objectives are comprehensive. They specify safety outcomes and inform aspects of our culture and leadership. They cover how we operate including the equipment we purchase. To achieve them will require continuous improvement and improved communications. The objectives can be summarised as:

- No business outcome is more important than safety;
- We have a committed and sustainable leadership that supports a culture of openness where people speak up and actively participate;
- Our people are engaged and take personal responsibility;
- We always design and plan our work in a manner that puts safety first;
- Our people are competent to identify hazards and control risks;
- We accept that errors can occur and always learn from them to prevent reoccurrences; and
- Our systems and tools support our continuous improvement.

6.2.2 SAFETY INITIATIVES

To support these objectives, we are undertaking the following six initiatives over the next two years:

- Developing strong and sustainable leadership in health and safety;
- Ensuring competence to identify hazards and manage associated risks;
- Actively engaging staff in health and safety across the business;
- Ensuring everyone understands our Health and Safety Strategy, objectives and accountabilities;
- Raising the standard of continuous improvement in our health and safety performance; and
- Communicating our performance and any health and safety issues.

Together we consider that these initiatives will contribute significantly to achieving our Vision and safety objectives.

PUBLIC SAFETY

We have a strong commitment to protecting the public from harm. During this AMP period we will continue to make improvements to eliminate or control asset-related safety risks to members of our community. The public safety initiatives that are in progress or are planned include:

- The commissioning of a Ground Fault Neutraliser in the Weavers zone substation area. This will reduce the risks of electric shock or damage to property caused by live high voltage lines coming into contact with persons or property. It will do so by reducing the resulting earth current to a safe level;
- Routine earth testing of all our substations fencing and earth grids has commenced. This practice will help identify any site where corrective actions may be necessary to ensure our fencing assets don't pose an electrocution risk to people or animals;
- Due to potential theft of copper earth conductor, a new design standard has been introduced using an equivalent current capacity steel wire conductor that has a lower resale value. The initiative is aimed at discouraging theft to reduce the associated safety risk of electrocution or damage to property as a result of unknown missing earth cables on our equipment; and
- Our Public Safety Management System (certified to NZS 7901), has identified our highest risk to the public is electrocution or shocks from damaged service pillars. To help control this our inspection programme for pillars has been modified from a five to a three year cycle. Additionally, a safety warning label and contact telephone number has been placed on every pillar.

6.2.3 SAFETY MEASURES AND TARGETS

Our safety performance measures are:

- **Total Recordable Injury Frequency Rate (TRIFR).** We will commence reporting TRIFR as our primary measure of safety performance. TRIFR is more comprehensive than Lost-Time Injury Frequency Rates (LTIFR) previously used as our key measure. TRIFR measures all injuries within a given period relative to the total number of hours worked in the same period. In order to standardise the measure it is reported against a base period of 200,000 work hours;
- **Staff Behaviours.** We have three key measures for staff behaviour related improvements. These are:
  - **A Safety Improvement Implementation Rate.** This is the number of safety improvements implemented, divided by the number suggestions made by staff;
  - **Safety Improvement Indicators.** This measures the occurrence of a specific set of safety behaviours that staff witness; and
  - **Safety Improvement Behaviours.** This measures the occurrence of a specific set of safety supporting behaviours by staff themselves.

Data for the safety improvement measures will be informed by a staff safety culture survey. This measures the behaviours of staff in relation to health and safety.

- **Public Safety Incidents**. This measures the reported incidents involving the public.

The targets for our safety measures over the AMP period are based on our judgement of what is achievable. They have been set at levels that if achieved would reflect very high levels of safety performance amongst electricity distribution businesses. The target performance is set out in Table 6.2.3 below.

MEASURE		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TRIFR		≤3	≤2	≤2	≤1	≤1	≤1	≤1	≤1	≤1	≤1
Staff Behaviours	Implementation Rate	20%	20%	25%	25%	30%	30%	30%	30%	30%	30%
	Indicators	≥80%	≥85%	≥85%	≥85%	≥85%	≥85%	≥85%	≥85%	≥85%	≥85%
	Improvement Behaviours	≥90%	≥95%	≥95%	≥95%	≥95%	≥95%	≥95%	≥95%	≥95%	≥95%
Public Safety Incidents		0	0	0	0	0	0	0	0	0	0

Table 6.2.3 Safety Targets 2016-2025

6.3 CUSTOMER EXPERIENCE

Our Vision states that WEL aspires to being 'Best in Service.' This epitomises our objective to provide excellent customer service. We also believe that relationships in our community, with businesses, councils, and community groups are vital to our future success. Accordingly, customer experience is a high priority performance area that is key to our ongoing business.

6.3.1 CUSTOMER EXPERIENCE OBJECTIVES

Customer experience is a measure of how customers feel about the service and the value they receive. For WEL, customer experience includes the level of reliability each customer receives, how we interact with them, the value derived from the package of services we provide, and the information we supply on what is happening on our network.

Our objectives for providing 'Best in Service' customer experience are:

- Delivery of electricity at the service level sought by our customers;
- Customers know who we are, and can contact us across multiple mediums;
- Customer feedback is easy to give, and customers know we will act on it;
- Customers value the services we offer and can rely on us to meet their needs; and
- WEL is considered to be a 'partner of choice' within the community and within the industry.

6.3.2 CUSTOMER EXPERIENCE INITIATIVES

Our customer experience initiatives have been categorised into two keys aspects: network performance; and customer service.

NETWORK PERFORMANCE INITIATIVES

The following network reliability initiatives will be pursued during the AMP period:

- Renewal of the rural network, targeted at improving its reliability performance. This is described further in Chapter 8;
- Investment in urban network capacity and security. The investment will address localised areas of forecast growth. This is described further in Chapter 7;
- Better utilisation of our smart metering data. We will further leverage data from our Smart Boxes in support of our investment decision making processes; and
- Monitoring Technology. We will actively monitor and assess new technology to maximise the opportunities available from emerging technologies like PV and EV.

CUSTOMER SERVICE INITIATIVES

Our customer service initiatives include:

- Continuous improvement in our internal processes, so that customer interactions and broader relationship management are centrally supported and co-ordinated;
- Measure and benchmark delivery times for services and set key targets for improvement;
- Ensure that customer needs are fully integrated into our asset management decision making processes. This includes proactive stakeholder engagement in the development of the AMP;
- Develop and implement a customer relationship improvement plan. Ensure that key stakeholders, and their business needs are central to this plan;
- Reinforce our Vision and Values with our staff, particularly the 'Best in Service' objective by providing additional training; and
- Establish a 'customer effort score' or other survey output.

6.3.3 CUSTOMER EXPERIENCE MEASURES AND TARGETS

Similar to our initiatives above, our customer experience measures have been categorised into: network performance; and customer service.

NETWORK PERFORMANCE MEASURES

Our network performance measures include those prescribed by the Commerce Commission. The measures are:

- **SAIDI (weighted)** – System Average Interruption Duration Index (weighted). SAIDI (un-weighted) is the most frequently used reliability indicator. It signifies the average interruption duration for an average customer, over the course of a year. It is measured in units of time, usually minutes. For example, a SAIDI of 60 minutes indicates that the average consumer on the network experienced 60 minutes without power. Our SAIDI targets have been differentiated between urban and rural customers to allow us to focus on rural network performance. In addition, the targets shown below reflect the Commerce Commission's revised approach to weight (adjust) SAIDI outcomes by 50% for planned outages. This means only half of the duration of planned outages are included in the measure. The targets below incorporate 50% of planned outages;
- **SAIFI (weighted)** – System Average Interruption Frequency Index (weighted). SAIFI measures the number of times an average customer will have a power interruption per year. For example a SAIFI of two indicates that the average customer on the network has two interruptions in a year. As with SAIDI, our SAIFI targets have been differentiated between urban and rural to allow us to focus on rural network performance and weighted for planning outages; and
- **Repeated Interruptions** – Is a measure of the number of actual interruptions experienced by each customer. Our targets measure the percentage of urban customers that experience two or less outages in each year and the percentage of rural customers that experience four or less outages per year. For example 90% means 90% of our customers in the relevant segment didn't exceed the targeted number of interruptions.

Our targets for network performance are based on our historical performance adjusted for the planned improvements in our rural network, primarily from our renewal and maintenance programmes. Table 6.3.3.1 sets out the targets for each measure over the AMP period.

MEASURE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban SIADI (weighted)	42	42	42	42	42	42	42	42	42	42
Rural SAIDI (weighted)	236	226	225	223	221	221	221	221	221	221
Total SAIDI (weighted)	81	79	78	78	77	77	77	77	77	77
Urban SAIFI (weighted)	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Rural SAIFI (weighted)	4.72	4.74	4.70	4.67	4.63	4.63	4.63	4.63	4.63	4.63
Total SAIFI (weighted)	1.41	1.41	1.40	1.39	1.39	1.39	1.39	1.39	1.39	1.39
Urban Repeat Interruptions *(target is 2 or less)*	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Rural Repeat Interruptions *(target is 4 or less)*	73%	75%	77%	79%	80%	80%	80%	80%	80%	80%

Table 6.3.3.1 Network Customer Experience Performance Targets 2016 - 2025

In addition to these measures we are committed to restoring supply as soon as possible following an interruption. Accordingly we undertake to restore power to our urban customers within three hours of an outage and within six hours of an outage to our rural customers. If we do not meet this, our residential and small commercial customers will receive $40 and our large commercial customers will receive $150. The 'WEL Promise' does not apply to faults beyond our control such as storms, lightning, vehicle accidents, or third party damage.

The maximum times for restoration are detailed below in Table 6.3.3.2 and, apply for the duration of the AMP period.

	URBAN	RURAL
Maximum time to restore power	3 hours	6 hours

Table 6.3.3.2 Restoration Promise

CUSTOMER SERVICE MEASURES

Our customer service performance measures are:

- **Customer Satisfaction** – we regularly survey a sample of customers to gauge their performance expectations, the price they're prepared to pay, and their satisfaction with our service. During the AMP period we are targeting an improvement in customer satisfaction from 85% to 90%;
- **New Connection Quote Time** – measures the average number of working days it takes us to provide a quote for upgrades and new connections to our network. During the AMP period we are targeting an improvement in our quoting times from 15 to 10 working days; and
- **Complaint Response Time** – the average number of work days to provide a resolution to any complaint we receive. During the AMP period we will seek to maintain our resolution period of ten working days.

Our targets are based on our historical performance adjusted for steady improvement over the AMP period. Table 6.3.3.3 shows the targets for each measure over the AMP period.

MEASURE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Customer Satisfaction	85%	85%	86%	86%	87%	87%	88%	88%	89%	90%
New Connection Quote Time (workdays)	15	14	13	12	11	10	10	10	10	10
Complaint Response Time (workdays)	<10	<10	<10	<10	<10	<10	<10	<10	<10	<10

Table 6.3.3.3 Other Customer Experience Performance Targets 2016 – 2025

6.4 COST EFFICIENCY

Our overarching cost efficiency objective is to implement our works plan, without compromise to safety, at the least feasible cost to customers. Our cost efficiency objectives are primarily concerned with the efficiency of our works delivery function. Section 6.5 below addresses our asset management capability.

6.4.1 COST EFFICIENCY OBJECTIVES

Our objectives for cost efficiency are:

- Works delivery is safe, of high quality, and on time;
- Essential core skills and knowledge are developed and retained;
- The systems we use enable and support efficient delivery;
- Value for money is achieved through appropriate commercial tension in the delivery model;
- We continuously measure and monitor our delivery performance (safety, quality, time, and cost) and always seek ways to improve; and
- We understand that errors can occur and always learn to prevent reoccurrences.

Collectively our objectives reflect the cost position we wish to achieve and provide the right incentives for capability development and the safe delivery of projects and maintenance services.

6.4.2 COST EFFICIENCY INITIATIVES

To achieve our cost efficiency objectives there are a number of initiatives we will put in place over the next two years. They include initiatives to:

- Undertake a review to optimise our works delivery model, and then implement the outcomes using a change management programme;
- Review our works delivery management policies and procedures and ensure they are aligned;
- Align systems functionality with our works delivery model;
- Reset performance indicators and targets for key delivery activities; and
- Enhance our continuous improvement approaches and performance reporting.

6.4.3 COST EFFICIENCY MEASURES AND TARGETS

The measures we have established for cost efficiency are:

- **Cost Per Customer** – operating costs that are allocated, in accordance with Information Disclosure requirements, to electricity distribution service excluding costs treated as an asset under Generally Accepted Accounting Principles, depreciation, tax subvention payments, revaluation, interest expenses, and pass-through and recoverable costs divided by the number of connections; and
- **Capital Expenditure Performance** – project delivery performance for capital works (excluding customer initiated) will be measured by comparing the delivered cost of projects with the budget (which has been appropriately challenged). The performance is subject to the following conditions being met:
  - Full scope of the project delivered;
  - Safety performance is maintained;
  - Design and construction standards are met;
  - Timeframes are met; and
  - As built information and drawings are captured accurately and timely.

The targets are based on achieving the expenditure levels forecast. Table 6.4.3 shows the targets for each measure over the AMP period.

MEASURE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cost per customer ($)	226	221	215	209	203	203	203	203	203	203
Capital Expenditure performance %	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%

Table 6.4.3 Cost Efficiency Performance Targets 2016 - 2025

6.5 ASSET PERFORMANCE

Asset performance is a direct consequence of our asset management decisions and processes. Accordingly, our asset performance objectives focus on further developing our asset management capability.

6.5.1 ASSET PERFORMANCE OBJECTIVES

Our asset performance objectives are to ensure that:

- Our asset management investment decisions are optimised and are based on appropriate trade-offs between capital and operational expenditure, risk, and reliability;
- Preventive and corrective maintenance decisions are made using quantitative analytical techniques such as FMEA. These techniques support quantifiable trade-offs between operational expenditure, asset condition, and reliability;
- We fully leverage our Smart Box data to inform the way we plan, build, maintain and operate our network. This includes voltage exception analysis, fault identification and remediation, peak capacity planning and optimised load control;
- How, when and who we use to deliver our works plan are key inputs in our investment decisions; and
- We have an effective operational metering team and are recognised externally as a leading player in the smart metering environment enabling new revenue streams for the benefit of our community.

6.5.2 ASSET PERFORMANCE INITIATIVES

The initiatives we are undertaking in the next two years to achieve our asset performance objectives include:

- We will review our asset management planning and decision making processes to ensure that the right capabilities, processes, and decision support tools are identified and then implemented;
- We will review our maintenance approach and develop a five-year maintenance roadmap that defines how we will enhance our maintenance practices;
- We will assess and explore opportunities to use Smart Box data to improve the way we manage our assets and operate our network; and
- We will monitor and systematically assess opportunities to integrate emerging technologies e.g. PV to improve the performance of existing and future network assets.

6.5.3 ASSET PERFORMANCE MEASURES AND TARGETS

In the short term our asset performance measures focus on network utilisation as our capability measures are being developed. These initial asset performance measures are:

- **Load Factors at GXPs –** measures the efficiency of assets we contract from Transpower at GXPs. Low values indicate the provision of excess capacity and cost while higher values can also cause concern due to not having sufficient capacity available; and
- **Total Transformer Capacity Utilisation** – maximum coincident demand divided by total transformer capacity.

The basis of the targets is maintaining our historical performance. Table 6.5.3 shows the targets for each measure over the AMP period.

MEASURE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Factor at GXPs	>60%	>60%	>60%	>60%	>60%	>60%	>60%	>60%	>60%	>60%
Total Transformer Utilisation	>35%	>35%	>35%	>35%	>35%	>35%	>35%	>35%	>35%	>35%

Table 6.5.3 Asset Performance Targets 2016 - 2025

6.6 PERFORMANCE EVALUATION

This section describes our historical performance for the measures we have established under each performance area. However, reflecting our recent improvement initiatives, many of the measures are new and have no relevant historical information.

Our performance information is recorded within our information systems. For faults the time, location, duration and fault category is recorded. Other performance information is captured and reported regularly in monthly management and Board reporting processes.

For those measures with historical data, this section provides context and scale for the targets going forward. The section is structured by performance area:

- Safety;
- Customer experience;
- Cost efficiency; and
- Asset performance.

6.6.1 SAFETY

The table below shows our safety performance against the targets we set for 2014 and 2015. Note that the measures established in this AMP differ from those used last year. TRIFR and the safety improvement measures are new and as such no historical data is available.

SAFETY MEASURE	2014			FORECAST AT JANUARY 2015		
	TARGET	ACTUAL	VARIANCE %	TARGET	FORECAST	VARIANCE %
Number of near miss and improvement suggestions	192	205	7%	240	280	16%
Site Observations by Supervisors and Managers	352	335	(5%)	500	520	4%
Injury related lost days	36	48	(33%)	36	34	5%
Public Safety Incidents	0	2	(200%)	0	3	(300%)

Table 6.6.1 Safety Performance 2014 and 2015

Our safety performance is forecast to improve during 2015, relative to 2014. We remain concerned by the level of public safety incidents involving our network. Our safety objectives and initiatives have been established to continuously improve our performance.

6.6.2 CUSTOMER EXPERIENCE

Traditionally our measures of customer experience have focused primarily on network performance. Accordingly, the majority of the historical performance data we have is associated with the length and frequency of interruptions to customer's power supply. Our 10 year historical performance is shown on a weighted basis, reflecting the Commerce Commission's revised measurement approach. The presentation on a weighted basis makes the historical performance directly comparable to the targets shown in Section 6.3.3 as only 50% of outages that were planned are included in the SAIDI and SAIFI outcomes.

ANNUAL PERFORMANCE	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SAIDI (weighted)	87	69	97	79	83	70	74	65	68	80
SAIFI (weighted)	1.65	1.53	1.84	1.40	1.63	1.12	1.19	1.00	1.36	1.27

Table 6.6.2.1 Network Customer Experience Historical Performance 2005 and 2014

Our network performance over the last two years is presented below in greater detail and also on a weighted basis where indicated.

NETWORK PERFORMANCE

CUSTOMER EXPERIENCE MEASURES	2014			FORECAST AT JANUARY 2015		
	TARGET	ACTUAL	VARIANCE %	TARGET	FORECAST	VARIANCE %
Urban SAiDI (weighted)	38	41	(8%)	41	41	0%
Rural SAIDI (weighted)	163	241	(48%)	216	392	(35%)
Total SAIDI (weighted)	**62**	**80**	**(29%)**	**76**	**91**	**(20%)**
Urban SAIFI (weighted)	n/a	0.59	n/a	n/a	0.58	n/a
Rural SAIFI (weighted)	n/a	4.03	n/a	n/a	4.74	n/a
Total SAIFI (weighted)	**1.23**	**1.27**	**(3%)**	**1.29**	**1.40**	**(9%)**
Urban Repeat Interruptions (target is 2 or less)	90	91	1%	90%	90%	0%
Rural Repeat Interruptions (target is 4 or less)	80%	74%	(8%)	80%	74%	(8%)

Table 6.6.2.2 Network Customer Experience Performance 2014 and 2015

With the exception of urban repeat outages, for the year ended March 2014 we did not meet our network performance targets. The primary reasons for this are:

- A decision to stop live line work on the 16mm copper conductor resulted in an additional 2 SAIDI minutes;
- A storm in late September 2013 caused 11 SAIDI minutes;
- Additional outages to accommodate a higher level of customer connections during the year resulted in 2 SAIDI minutes; and
- A higher than normal incidence of cable damage by third party excavations or directional drilling caused 3 SAIDI minutes.

We do not expect to achieve our targets for 2015. The primary reason for this was a severe storm in mid June 2014 that caused 16.4 SAIDI minutes, offset by 1.4 less planned SAIDI minutes.

WORST PERFORMING FEEDERS

We monitor the performance of individual lines and cables supplying customers. Reporting on our worst performing feeders helps identify and develop appropriate action plans to improve the poor service received by affected customers and to address broader issues with these feeders.

Our 10 worst performing feeders during the period 2011 to 2014 along with the most recent 10 months performance is shown in Table 6.6.2.3 over.

RANK	FEEDER	AREA SUPPLIED	2011-2014 (AVERAGE)	2015 (YTD)
1	NGACB2	Ngaruawahia South	2.76	0.13
2	WEACB6	Rotowaro	2.42	2.43
3	TEUCB1	SH23 Te Uku	2.28	0.05
4	SILCB1	Matangi	1.91	2.26
5	FINCB3	Miranda	1.88	0.26
6	WALCB6	Ngahinapouri	1.87	1.10
7	WEACB2	Huntly West	1.69	0.76
8	SILCB4	Matangi	1.61	5.30
9	FINCB2	Kopuku	1.61	1.11
10	GORCB1	Taupiri, Orini	1.59	4.07

Table 6.6.2.3 Top 10 Worst Performing Feeders

Of note is that 60% of the feeders show improvement. In some instances, events beyond our normal control affect performance. An explanation of the performance for each feeder is summarised below together with ongoing initiatives to improve service.

FEEDER	STRATEGY
NGACB2	The current year's performance shows significant improvement with historical outages being predominantly caused by lightning strikes.
WEACB6	Performance has been affected by failing insulators and 16mm copper conductor. Improvement strategy is to prioritise this feeder within our renewal programme, add additional automation and a Ground Fault Neutraliser (GFN).
TEUCB1	The performance of this feeder has been impacted by failed insulation and 16mm copper conductor. Proactive crossarm replacements and selected re-conductoring projects have been undertaken in recent years which have significantly improved the performance for 2015.
SILCB1 / SILCB4	The performance of both feeders has predominantly been impacted by line clashes and, insulator and 16mm copper conductor failures. These are being addressed by our renewals programme and shortening of feeders is planned. The current year's poor performance on SILCB4 feeder is predominately driven by a number of high impact "car vs pole" events.
FINCB3 / FINCB2	These two feeders have been impacted by vegetation falling onto the lines, failed insulators and 16mm copper conductor. Re-conductoring projects have been undertaken in the current financial year which will improve the performance of these feeders in future.
WALCB6	Performance has been impacted by a number of bird strikes, broken lines and "car vs pole" events. A number of sections have been addressed by our re-conductoring projects and this has contributed to the improved performance.
GORCB1	Performance has been impacted by sectionaliser failures which are now being progressively replaced. The large drop in performance in the current year is due to the storm in June 2014.

Table 6.6.2.4 Worst Performing Feeder Strategies

CUSTOMER SERVICE

The single customer service related measure we have historical data is for customer satisfaction. The results of our performance against our target is shown in the Table 6.6.2.5 below.

CUSTOMER EXPERIENCE	2014			FORECAST AT JANUARY 2015		
	TARGET	ACTUAL	VARIANCE %	TARGET	FORECAST	VARIANCE %
Customer Satisfaction	85%	84%	(1%)	85%	n/a	n/a

Table 6.6.2.5 Network Customer Experience Performance 2014 and 2015

6.6.3 COST EFFICIENCY

Our performance measures for cost performance efficiency are shown in Table 6.6.3 below.

COST EFFICIENCY	2014			FORECAST AT JANUARY 2015		
	TARGET	ACTUAL	VARIANCE %	TARGET	FORECAST	VARIANCE %
Cost per Customer ($)	253	235	7%	226	200	12%
Capital Work Delivery ($M)	42.9	31.6	(26%)	32.8	33.5	(2%)

Table 6.6.3 Cost Efficiency Performance 2014 and 2015

We met our cost per customer cost efficiency targets in 2014. We are on track to meet it again in 2015. We did not complete our capital delivery programme in 2014 but are on track to having a smaller variance in 2015.

6.6.4 ASSET PERFORMANCE

Our asset performance for 2014 and forecast for 2015 is shown below.

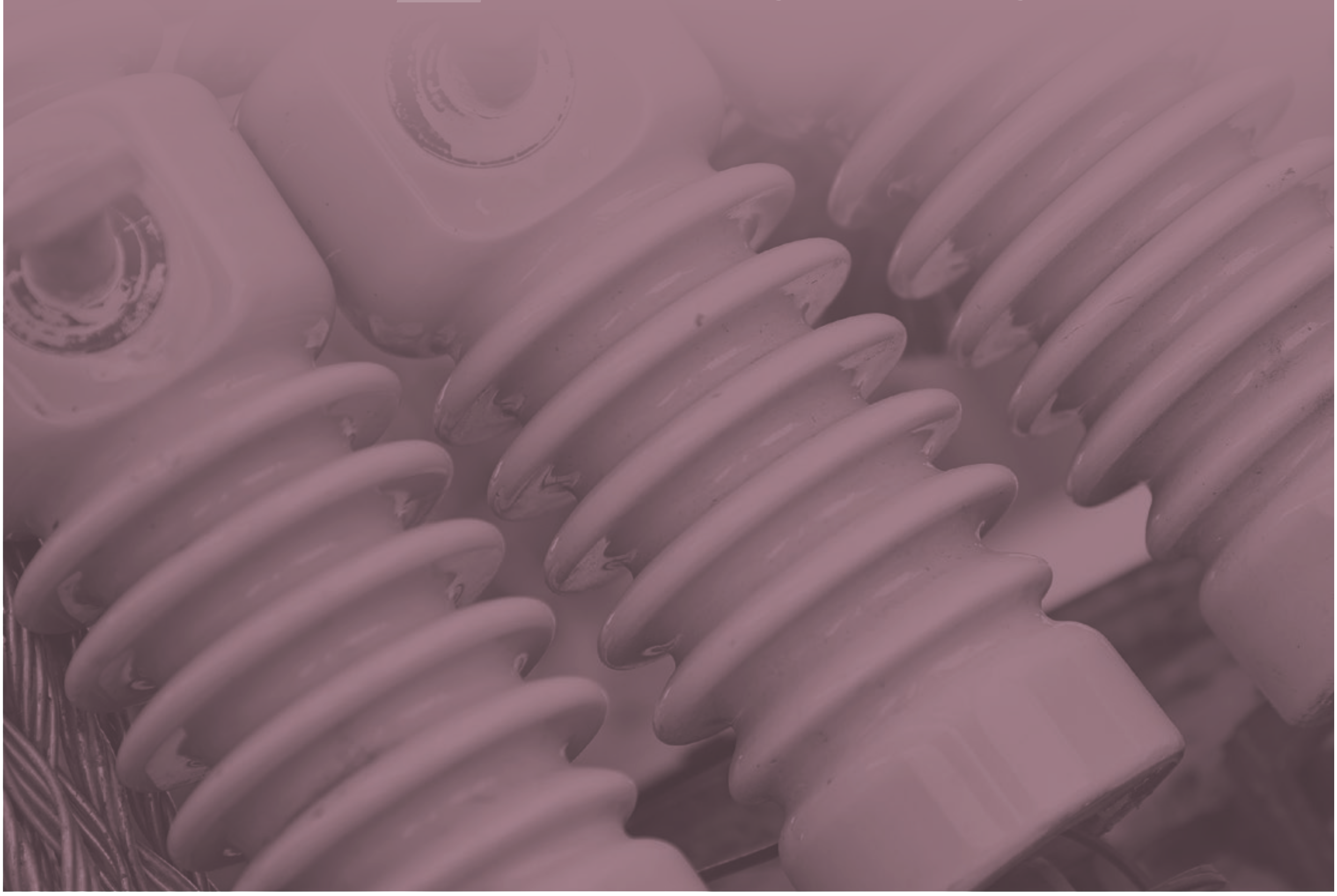
ASSET PERFORMANCE MEASURES	2014			FORECAST AT JANUARY 2015		
	TARGET	ACTUAL	VARIANCE %	TARGET	FORECAST	VARIANCE %
GXP Load Factor (%)	60%	50%	(17%)	60%	59%	(2%)
Transformer Utilisation (%)	34%	34%	0%	34%	28%	(18%)

Table 6.6.4 Asset Performance 2014 and 2015

Our load factor performance has remained below target in both years, without any additional capacity being added at GXPs. Our transformer utilisation has dropped in 2015 primarily due to lower peak demand and increased transformer capacity in growing areas of our network.

In regard to delivery of asset management projects, we have completed all our asset management projects recorded in our 2014 AMP within the expenditure profile presented.

7 NETWORK DEVELOPMENT AND NOT-NETWORK INVESTMENTS



7 NETWORK DEVELOPMENT AND NON-NETWORK INVESTMENTS

This chapter sets out our approach to network and non-network development and describes the plans we have in place for the AMP period. The chapter is structured as follows:

- **Overview of approach (7.1):** explains the core elements of our approach to network planning. This covers planning assumptions, security criteria, definition of the equipment ratings we use, changing delivery requirements, and the potential for small scale distributed generation and emerging technologies to impact the AMP;
- **Demand forecast (7.2):** describes how we forecast electricity demand for the AMP period. This is a fundamental input that influences the expected timing for growth and security related investment across the network;
- **Overview of our network development plans (7.3):** provides a summary of GXP development requirements and outlines our urban and rural development plans;
- **GXP Investment (7.4):** describes our proposed investment at Transpower's GXPs;
- **The Urban Network Plan (7.5):** presents the needs analysis, options, development projects, and expected timing for the required growth and security related investment in the urban network;
- **The Rural Network Plan (7.6):** presents the needs analysis, options, development projects, and expected timing for the required growth and security related investment in the rural network;
- **Summary Network Development Expenditure (7.7):** presents the summary of the total forecasted network spend; and
- **Non-Network Investments (7.8):** describes our non-network related projects and expenditure.

7.1 OVERVIEW OF APPROACH

Our approach to network planning and non-network development is aligned with our vision to:

"Provide high quality, reliable utility services valued by our customers whilst protecting and enabling our community"

Accordingly, our plans have been reviewed and aligned with the requirements of our customers and the overall performance objectives described in Chapter 6. This approach leads to targeted investment based on needs in each area of the network.

The two fundamental performance needs addressed by our network development investments are:

- Capacity constraints forecasted to arise due to peak demand growth in specific areas within the network; and
- Security issues arising from reduced back-up capacity due to growth in peak demand.

The projects identified in this chapter are our view of what is appropriate. It is our expectation that as the operating environment changes the investments forecast for the mid to latter part of the AMP period may need to be refined.

OUR APPROACH

Chapter 5 describes our process and approach to all investment projects, including network development and non-network investment. In summary, our approach consists of two stages:

- **Need identification:** an investment need or primary driver for an investment is identified. The needs considered typically fall under seven categories: safety, reliability performance, asset condition and health, growth and security, customer requests, technology change, or legal, regulatory and environmental requirements. Network development projects can fall under all the need categories with the exception of asset condition and health, which is covered by renewals and maintenance discussed in Chapter 8; and
- **Options analysis:** Following need identification, potential options that meet the need identified are formulated and considered. The number of options will vary depending on the type and complexity of need(s) and option may include non-network and demand management solutions where they are practical.

The investment option selected is the one that ensures safety, and best meets identified need(s) for the lowest whole of life cost. There are occasions where a specific externality will result in a decision to adopt an alternative investment path e.g. regulation. All investments are subject to the governance framework and processes described in Chapter 5.

7.1.1 KEY PLANNING ASSUMPTIONS AND INPUTS

The key assumptions informing our network development planning are:

- Future peak demand growth as forecast in Section 7.2 below;
- The large embedded generation plants operated at Te Uku and Te Rapa will not be available to meet demand following a major power outage; and
- The network is well designed and can be operated to prevent overloads.

There are many inputs utilised in the planning process, the key inputs are:

- The reliability performance sought by our customers and stakeholders as detailed in Chapter 2 and the corresponding performance objectives discussed in Chapter 6;
- Specific individual customer and stakeholder requirements;
- The inputs required to forecast electricity consumption and demand, as set out in Section 7.2 below;
- Voltage requirements and other regulated limits; and
- Equipment ratings based on the manufacturer nameplate ratings as detailed in Section 7.1.3.

7.1.2 SECURITY CRITERIA

Security criteria sets the minimum required level of network redundancy. The degree of redundancy determines the ability of the network to maintain supply following the failure of an asset. Our security criteria are specified to achieve our performance objectives (Chapter 6) and the reliability performance sought by our customers and stakeholders (Chapter 2).

The security used by us is set out Table 7.1.2 below.

RANGE OF POST CONTINGENT DEMAND (PCD) MVA	CUSTOMER IMPACT	SECURITY LEVEL	TIME TO RESTORE AFTER 1ST INTERRUPTION	TIME TO RESTORE AFTER 2ND INTERRUPTION
10 to 25 MVA CBD zone and switching substations	>2000	N-1	Maintai n 100% of PCD*	Majority restored within two hours, 100% in repair time
10 to 25 MVA Small GXP or large urban zone substations	>5000	N-1	Maintain 100% of PCD	Within three hours Restore 90%, repair time 100%
5 to 10 MVA Medium urban zone substations	>2000	N	Within 15 minutes restore 75%, within three hours 90%, repair time 100%	Within three hours restore 90%, repair time 100%
2.5 to 5 MVA Rural zone subs and urban interconnected feeders	>1000	N	Within one hour restore 75%, within three hours 90%, repair time 100%	Restore 100% in repair time
1 to 2.5 MVA Urban & rural interconnected feeders	>300	N	Within one hour restore 50%, within three hours 75%, repair time 100%	Restore 100% in repair time
Under 1 MVA Rural feeder, urban spur, distribution transformers	<300	N	Restore 100% in repair time	Restore 100% in repair time

Table 7.1.2 WEL's Planning Security Criteria

* *Post Contingent Demand (PCD) is the peak demand after demand reduction through contracted load control services.*

7.1.3 EQUIPMENT RATINGS

All equipment, with the exception of power transformers[1], is factored into our planning at the capacity rating stated on their nameplate.

7.1.4 INFLUENCE OF DISTRIBUTED GENERATION, EMERGING TECHNOLOGY AND DEMAND MANAGEMENT INITIATIVES

There are two large embedded generators in WEL's network located at Te Rapa (50MW cogeneration) and Te Uku (64MW wind) and one small generation unit at Hamilton City Council's Waste Water Plant (1MW cogeneration).

The amount of small-scale distributed generation within our network is small, however the amount is expected to increase as the cost becomes more affordable during the AMP period. Our policy for connecting distributed generation is to comply with the regulated terms and to facilitate connections as efficiently as possible. Most distributed is expected in the form of PV installations that generate electricity during sunlight hours, and as such, it is unlikely to materially reduce peak demand during winter evenings. Figure 7.1.4 below shows the recent growth in PV installations.

[1] *The transformer emergency capacity rating is used for planning purposes. All new power transformers are designed with an emergency overload rating of 130%. Older power transformers without an emergency overload rating stated on the nameplate are assumed to have an emergency overload of 120%.*

CUMULATIVE CAPACITY OF PV CONNECTIONS

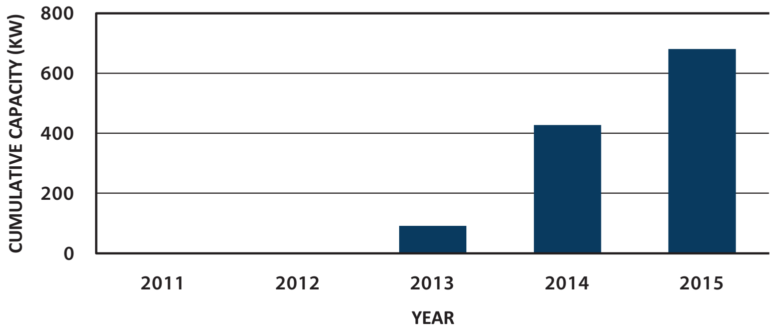


Figure 7.1.4 Installed PV Connection Capacity

While the growth in PV installations does not have a material influence on the network design and investment at this time it may drive the need for further network investment during the AMP period.

EMERGING TECHNOLOGY

In addition to PV, EV and residential and commercial battery storage systems are the main examples of emerging technologies with the potential to impact the design and operation of our network. Like PV generation, EVs do not at this time influence our network planning or investment. However, there is significant potential for this to change during the AMP period.

Through our participation in two industry forums, the GreenGrid[2] and NZ Transform[3] we expect to gain a better understanding of the potential impacts of emerging technology on our network.

DEMAND INITIATIVES

We assume that the current level of load control will continue for the AMP period. Accordingly, a base level of demand based initiatives are accounted for in our planning. Similar to the impact of PV and EV we would expect that the impact of demand initiatives will likely increase over the AMP period, however this is difficult to quantify at this time.

7.2 PEAK DEMAND FORECAST

Our network is currently delivering just over 1,200 GWhs of electricity per year with coincident peak demand of 244MW. This peak demand is the principle driver of our network development investment. Our forecast of peak demand is a fundamental input and determines the expected timing for growth related investment across the network during the AMP period.

Forecasting future peak demand is inherently challenging and somewhat subjective. For example, we are currently observing reducing average amounts of electricity being delivered to our domestic customers, flat peak demand across the network, and increasing amounts of PV being installed on our network.

Our approach to developing demand forecasts is discussed in this section, including our assumptions and the level of uncertainty involved.

[2] *Ministry of Business, Innovation and Employment funded forum assessing the impact of distributed generation.*
[3] *Electricity Networks Association (ENA) initiative to assess the impact of emerging technologies on NZ distribution networks.*

7.2.1 FORECASTING METHODOLOGY

Our forecasting methodology involves a number of components. Each component is assessed and combined to produce our best estimate of peak demands during the AMP period. Historically our peaks occur during winter months.

ESTABLISHING BASE DEMAND

The most recent peaks for 2015 were measured at zone substations, GXPs and in total across our network. The peaks between zone substations and their respective GXP are generally not coincident, meaning they generally don't occur at the same time, due to diversification in customer use. Similarly, there is diversity in peak demand between GXPs and the total network peak demand. One-off events not likely to repeat are eliminated from these actual peaks. This establishes a baseline demand level for our forecasts.

DRIVERS OF PEAK DEMAND

The second component of the methodology assesses the drivers of peak demand growth during the forecast AMP period. The drivers are set out below:

- **Hamilton City Residential -** residential growth is expected in the Borman area, in the northeast and new subdivisions planned for Ruakura in the southeast of Hamilton City. We have estimated 9MVA of peak demand growth for the Borman area. Due to uncertainty of timing and intensity, we have assumed 2 MVA of peak demand for Ruakura during the AMP period;
- **Waikato District Residential & Agricultural –** growth in these areas is expected to be modest and we have assumed a continuation of the historical trend observed adjusted for the step change as a result of the Te Kauwhata Structural Plan change;
- **Industrial and Commercial –** our growth forecast is based on applications received and our discussions with developers. A diversity factor is assigned to the new demand and an uptake rate is estimated using the best information available. We have forecast 20MVA demand increase in the Tasman area (between The Base and Rotokauri) and 2MVA for the adjacent Horotiu area;
- **Distributed Generation –** no adjustment has been made for small scale distributed generation due to its limited ability to impact peak demand. This assumption will be reviewed in future forecasts as our understanding of PV and other emerging technologies improves and these technologies become more prevalent;
- **Load Control -** is assumed at current levels throughout the planning period;
- **Temperature impacts -** temperature can impact peak demand. Colder winters can increase demand by as much as 10% compared to average winters. This variation is allowed for in our contingency planning;
- **Residential Time of Use Tariffs (enabled by smart meters) -** are unlikely to impact peak demand in the immediate future. However, Time of Use (TOU) tariffs may become a feature of future retail tariffs offerings so we have assumed a 1% reduction in peak demand from 2020 onwards; and
- **EVs –** growth in EV usage has the potential to significantly increase the amount of electricity our network delivers. The impact on peak demand will depend on how and when customers charge their EVs. No allowance for the impact of EVs is included in the forecast, however we are monitoring developments and will review our assumptions as necessary.

FORECASTING UNCERTAINTY

All forecasts involve a degree of uncertainty particularly over longer periods. As a result our demand forecast is expected to be less accurate in the later years of the AMP period. The uncertainty will be greater where there are changing circumstances or the potential for new activities.

Our development plans and corresponding investments may be amended in subsequent revisions of our AMP reflecting the emerging needs of our customers and stakeholders and changing circumstances on our network.

7.2.2 DEMAND FORECAST 2016 TO 2025

We expect to see small increases in localised peak demand caused by connection growth in residential subdivisions and the commercial/industrial sectors.

We expect peak demand to modestly increase over the AMP period. Table 7.2.2 shows the individual GXP forecast and the demand forecast for the AMP period.

GXP	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Hamilton 11kV	36.2	29.4	28.5	28.8	29.0	29.3	29.5	29.8	30.0	30.3
Hamilton 33kV	133.0	137.1	139.3	140.6	141.6	142.4	143.4	144.3	145.3	146.3
Huntly 33kV	25.3	25.4	25.4	25.5	25.6	25.7	25.8	25.9	26.0	26.1
Te Kowhai 33kV	83.9	89.3	90.2	91.1	92.0	92.5	93.0	93.5	94.0	94.5
System Peak	**247.6**	**251.0**	**253.3**	**255.5**	**257.6**	**259.0**	**260.6**	**262.2**	**263.8**	**265.5**

Table 7.2.2 GXP demand forecast to 2025

7.2.3 ZONE SUBSTATION DEMANDS

Table 7.2.3 shows the expected peak demand at each of our zone substations. The zone substations where growth is expected to exceed the firm capacity are highlighted. In the table firm capacity means the 4 hour emergency thermal chain rating.

ZONE SUBSTATION	SECURITY	FIRM (N-1) CAPACITY[4] (MVA)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avalon Dr	N-1	23.8	19.9	20.2	20.4	20.6	20.6	20.5	20.4	20.2	20.0	19.9
Borman	N-1	20.6	13.7	14.8	16.0	17.2	18.1	18.6	19.1	19.6	20.1	20.5
Bryce St	N-1	22.9	15.2	15.5	15.5	15.6	15.5	15.3	15.2	15.1	15.0	14.8
Chartwell	N-1	25.9	17.5	17.7	17. 9	18.0	18.0	17.9	17.9	17.9	17.9	17.9
Claudelands	N-1	22.9	20.4	20.6	20.6	20.7	20.5	20.4	20.2	20.0	19.9	19.7
Cobham	N-1	25.9	12.0	12.1	12.1	12.1	12.0	11.9	11.8	11.7	11.6	11.5
Finlayson Rd	N	7.5	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Glasgow St	N	10	7.7	7.7	7.8	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Gordonton	N*	10	7.2	7.3	7.3	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Hampton Downs	N	9.1	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

ZONE SUBSTATION	SECURITY	FIRM (N-1) CAPACITY[4] (MVA)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Horotiu	N-1	18	9.5	9.8	10.0	10.3	10.4	10.6	10.7	10.9	11.0	11.2
Kent St	N-1	22.9	16.1	16.1	16.2	16.2	16.0	15.9	15.7	15.6	15.4	15.3
Kimihia	N	10	3.8	3.8	3.8	3.8	3.8	3.7	3.7	3.7	3.6	3.6
Latham Court	N-1	22.9	19.3	19.6	19.6	19.6	19.5	19.3	19.1	18.9	18.7	18.6
Hoeka Rd	N	23	-	7.4	7.6	7.9	8.0	8.2	8.3	8.5	8.7	8.8
Ngaruawhia	N-1	7.5	4.9	5.0	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Peacockes Rd**	N-1	10 / 28	14.4	14.7	15.2	15.7	15.7	15.7	15.7	15.7	15.6	15.6
Pukete – Anchor	N-1	30	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Pukete – 11kV	N-1	12.6	7.8	8.0	8.0	8.0	8.0	7.9	7.8	7.7	7.7	7.6
Raglan	N	11.4	5.2	5.3	5.4	5.5	5.6	5.6	5.7	5.7	5.8	5.8
HAM11	N-1	40	36.3	29.3	29.4	29.7	29.6	29.6	29.5	29.5	29.3	29.2
Sandwich Rd	N-1	28.2	20.2	20.3	20.3	20.3	20.2	20.0	19.8	19.7	19.5	19.3
Tasman	N-1	25.9	20.0	22.3	24.4	26.5	28.3	29.6	31.9	34.1	36.3	38.5
Te Kauwhata	N-1	10	4.0	4.1	4.2	4.3	4.4	4.5	4.5	4.6	4.7	4.8
Te Uku	N-1	5	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2
Wallace Rd	N*	15.2	13.6	13.7	13.7	13.7	13.6	13.5	13.4	13.3	13.2	13.1
Weavers	N*	15	8.3	8.4	8.5	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Whatawhata	N	22.9	3.0	3.0	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4

Table 7.2.3 Zone Substation demand forecast to 2025

* *Substations run at N Security, however these substations have an N-1 capacity of: Gordonton 5MVA, Wallace Rd 7.5 MVA and Weavers 7.5 MVA.*
** *Peacockes road substation is currently under upgrade, once completed the firm capacity rating will be 28MVA.*

[4] *Based on emergency thermal chain rating*

7.3 OVERVIEW OF NETWORK DEVELOPMENT PLANS

Our network development plan is comprised of three component plans:

- GXP investment;
- Urban development; and
- Rural development.

These reflect the performance requirements described in Chapter 6 and align with our stakeholder expectations discussed in Chapter 4. The sections below discuss each plan component.

7.4 GXP INVESTMENT

Table 7.4.1 below shows the firm capacity at each GXP and the forecast peak demand in 2016 and 2025.

GXP	INSTALLED CAPACITY[5] (MVA)	FIRM (N-1) CAPACITY[6] (MVA)	PEAK DEMAND FORECAST (MVA)	
			2016	2025
Hamilton 11kV	80.0	40.0	36.2	30.3
Hamilton 33kV	220.0	132.0[7]	133.0	146.3
Huntly	120.0	82.0	25.3	26.1
Te Kowhai	200.0	136.0	83.9	94.5

Table 7.4.1 GXP Capacity and Demand Forecast

Our peak demand forecast shows a need to augment the supply capacity at the Hamilton GXP. To address the capacity issue at the Hamilton 33kV GXP the following measures will be investigated and implemented:

- Improved load management. Initial investigations indicate that reductions in the peak demand can be achieved by improving the restitution of our load control;
- Shifting the Gordonton load from the Hamilton GXP to the Huntly GXP (coincident peak demand of approximately 3MVA); and
- One of the two transformers at Hamilton (T5) is smaller than the other and due to be upgraded. Transpower's life cycle replacement of T5, will add additional firm capacity of 9MVA. The replacement is scheduled for 2024.

PLANNED INVESTMENT

There is only one GXP related investment need over the AMP period. This is the purchase of Transpower-owned switchgear at Hamilton (11kV, 33kV) and Te Kowhai. The options and proposed expenditure are described below in Table 7.4.2.

PROJECT / PROGRAMME	INVESTMENT NEED / OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Hamilton 11 GXP Switchgear	**Investment:** Transpower charges for the 11kV board are significantly higher than the operational costs if this board was under the operational cost of WEL. Ownership would also provide greater control of this equipment **Options Considered:** Retain status quo i.e. Transpower ownership and on charging of this equipment, or purchase the equipment	800	2016

[5] *Based on continuous rating*
[6] *Based on emergency thermal chain rating*
[7] *Hamilton 33kV firm capacity is based on HAMT5 (HAMT4 is rated at 141MVA)*

PROJECT / PROGRAMME	INVESTMENT NEED / OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Hamilton 33 GXP Switchgear	**Investment:** Transpower charges for the 33kV board are higher than the operational costs if this board was under the operational cost of WEL. Ownership would also provide greater control of this equipment **Options Considered:** Retain status quo i.e. Transpower ownership and on charging of this equipment, or purchase the equipment	4,012	2020
Te Kowhai 33 GXP Switchgear	**Investment:** Transpower charges for the 33kV board are higher than the operational costs if this board was under the operational cost of WEL. Ownership would also provide greater control of the availability of this equipment **Options Considered:** Retain status quo i.e. Transpower ownership and on charging of this equipment, or purchase the equipment	3,085	2021

Table 7.4.2 GXP investment 2016 to 2025

Table 7.4.3 below summarises the expected GXP related investment over the AMP period.

GXP INVESTMENT ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GXP Investment	800	-	-	-	4,012	3,085	-	-	-	-

Table 7.4.3 GXP forecast investment profile

7.5 URBAN DEVELOPMENT PLAN

Our Urban Development Plan addresses the need for additional capacity and security in localised areas of growth within Hamilton City. It also reflects additional needs including:

- Improvement in network control and automation;
- Identified safety related network investments; and
- Investments specifically requested by individual customers.

This section describes the identified development needs, the options considered, and the resulting investment required over the AMP period. It is structured as follows:

- Subtransmission;
- Zone Substation;
- Distribution;
- LV;
- Other system fixed Assets; and
- Customer driven works.

7.5.1 SUB-TRANSMISSION

One subtransmission investment need has been identified over the AMP period. Residential, commercial and industrial growth expected within the Tasman area (between The Base and Rotokauri) will require additional subtransmission capacity by 2020. Options to address this included:

- Increasing the subtransmission capacity to the Tasman substation;
- Developing a new zone substation; and
- Offloading to neighbouring zone substations.

The preferred option is the installation of additional capacity to the Tasman substation (TAS). This option includes increasing the capacity at TAS as discussed in Section 7.5.2 below. The installation of a new cable is expected to take two years and therefore the work is scheduled to start in 2017.

The subtransmission project for the period are summarised in Table 7.5.1.1 below.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Te Kowhai (TWH) GXP –TAS 33kV link	**Investment Need:** Increased demand growth at TAS substation due to increased industrial commercial development. **Options Considered:** Upgrade the capacity to Tasman, develop a new zone substation, or off load to existing substations.	6,339	2017 to 2018

Table 7.5.1.1 Urban subtransmission development projects 2016 to 2025

Table 7.5.1.2 summarises the expected subtransmission investment over the AMP period.

SUBTRANSMISSION ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Subtransmission	-	2,000	4,339	-	-	-	-	-	-	-

Table 7.5.1.2 Urban subtransmission development projects forecast expenditure profile

7.5.2 ZONE SUBSTATIONS

Four categories of urban zone substation investment needs have been identified during the AMP period. These are:

- Additional capacity for localised demand growth in the Tasman area. As discussed in Section 7.5.1 above, forecast growth in the Tasman area requires additional capacity to be installed by 2020.
- Safety related investments. A number of projects are planned to improve the safety of the equipment and operation of that equipment. They also ensure that access to potential hazardous areas is controlled. The planned safety projects include:
    - **Caro switching station:** the old Garden Place switching station has very limited space, the equipment is old and the substation is damp. Together these characteristics make substation safety complex to manage. Therefore, to improve the safety for our employees a new switching station is planned and the old station will be decommissioned;
    - **Substation Site Security Access Project:** we are planning to upgrade the access control in all zone substations with an improved card reader system; and

- **Arc Flash protection upgrade:** arc flash protection detects the flash of light produced by an electrical arc and then automatically trips the effected equipment. This greatly reduces the energy released during such events and reduces the risk and severity of injury for the equipment operator.

- The upgrade of Latham 33kV switchgear to improve network security. The current legacy switchgear at the Latham 33kV zone substation does not interface with our proposed protection upgrade (as discussed in Section 7.5.5). Therefore, an upgrade of the switchgear is scheduled to be undertaken in co-ordination with the protection upgrade during 2016 and 2017.

- Completion in 2016 of the following multi-year projects that were commenced in 2015:
  - Wallace Rd transformer upgrade ($289k); and
  - Peacockes transformer and 11kV switchboard upgrade ($1.84m).

The following table summarises the zone substation projects, options considered, projected investment and timing.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Tasman 3rd Transformer	**Investment Need:** Demand growth of Rotokauri structure development **Options Considered:** New Zone substation, or increase capacity, or transfer demand	3,853	2019
Install Caro Switching Station and de commissioning of Garden Place Switching Station	**Investment Need:** Safety Issue, complex management **Options Considered:** Upgrade existing GAR Switching Station, Establish new 11kV switching station	1,690	2016 to 2017
Substation Site Security Access Project	**Investment Need:** Improve security of the substation sites **Options Considered:** Improve security or do nothing	312	2016 to 2019
Arc Flash Implementation	**Investment Need:** Improved operator safety **Options Considered:** Provide full-cover flash protection PPE, or Install arc flash protection.	1,400	2016 to 2017
Latham 33kV GIS outdoor to indoor conversion	**Investment Need:** Security upgrade of switchgear **Options Considered:** Upgrade of switchgear to be compatible with protection or do nothing	1,674	2016 to 2017
Wallace Rd Transformer Upgrade	**Investment Need:** Completion of a project to address noise from the Wallace transformers and comply with the requirements of the district plan O**ptions Considered:** Continue and complete	289	2016
Peacockes Transformers and 11kV Switchboard	**Investment Need:** Completion of a project to address load growth in the Peacockes area **Options Considered:** Replace with new transformers and 11kV switchboard, Replace with used transformer with higher rating and new 11kV switchboard. Or Construct Airport Zone Substation to off-load Peacockes, then replace Peacockes transformers and 11kV switchboard.	1,840	2016

Table 7.5.2.1 Urban zone substation development projects for 2016 to 2025

Table 7.5.2.2 summarises the zone substation investment required over the AMP period.

ZONE SUBSTATIONS ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Zone substations	4,984	2,084	122	3,868	-	-	-	-	-	-

Table 7.5.2.2 Urban zone substation projects forecast spend profile

7.5.3 DISTRIBUTION

Four categories of urban distribution network investment needs have been identified over the AMP period. These are:

- **Improved network security**. These projects address distribution feeders that don't meet our security criteria based on the number of customers supplied. It also includes the upgrade of LV circuits which have become underrated due to demand growth. The security projects include:
  - Enhancement of Borman feeders by extending BORCB5 to offload BORCB4;
  - Installation of new Cobham to Alexandra 11kV feeder for CBD load enhancement and security improvement;
  - Enhancement of the Chartwell to Hamilton11kV interconnection capacity;
  - Enhancement of Chartwell feeders by extending CHACB15 to offload CHACB13;
  - Upgrade of CBD Distribution Ring Feeders;
  - Elimination of critical daisy-chained distribution transformers;
  - Hamilton 11kV interconnection upgrade;
  - Transfer of customers between Peacockes feeders (PEACB3 to PEACB6)
  - Upgrade Avalon feeder AVACB4; and
  - 11kV cables zone interconnection upgrades.
- **Load monitoring of distribution transformers**. Demand monitoring of distribution transformers will improve modelling of network voltages. This project includes the installation of additional 11 LV transformer demand monitoring devices;
- **Demand growth capacity projects**. These projects include:
  - Installation of new 11 kV cables to replace a section of Sandwich feeder SANCB6 due to capacity constraint;
  - Upgrade four distribution transformers due to overloading and voltage issues; and
  - Distribution network reinforcement of feeders that have identified loading issues.
- **Embedded generation.** Network issues resulting from the installation of small scale embedded generation.

The following table summarises the distribution level projects, options considered, projected expenditure and timing.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Extend BORCB5 to offload BORCB4 stage 1	**Investment Need:** BORCB4 has exceeded number of customers standard and was growing progressively. **Options Considered:** Extend BORCB5 to transfer other customers from BORCB4 to BORCB5, do nothing	125	2016
Install new COB ALE trunk for CBD load enhancement and security improvement	**Investment Need:** Rural Switching Station is the highest loaded Station in the CBD with load reaching 7.3 MVA **Options Considered:** Transfer demand to other Switching Station Install COB ALE trunk to strengthen ALE Switching Station and transfer demand, do nothing	241	2016 to 2017
Install new 11 kV cables to replace weak section of SANCB6	**Investment Need:** Existing 16 mm^2 Copper line supplying 649 customers including a hospital has a risk of overloading and no supply under contingency **Options Considered:** Install new 11 kV cables to replace 16mm^2 section, Replace 16mm^2 section with conductors	998	2016
Upgrade Distribution Transformers	**Investment Need:** 4 transformers identified with overloading issues **Options Considered:** Install new transformer to offload, Upgrade transformer, Offload to existing transformer	600	2016
CHA-HAM11kV interconnection	**Investment Need:** HAM 11 kV north feeders have no interconnection with other 11 kV feeder to supply HAM 11 kV under contingencies **Options Considered:** Install new CHA 11 kV feeders to supply HAM 11 kV feeders under contingencies, Interconnect with existing 11 kV feeders	1,131	2017
Extend CHACB15 to offload CHACB13	**Investment Need:** CHACB13 has exceeded customer number standard (1200) which resulted to high SAIDI impact **Options Considered:** Transfer customers to CHACB15 by installing new 11 kV cables, Transfer customers to BOR feeders	193	2016
Upgrade CBD Distribution Ring Feeders	**Investment Need:** Feeder weak sections limits feeder capacity and ability to supply under contingency **Options Considered:** Replace weak sections to increase feeder capacity. Install new feeder.	512	2023
Daisy-chained Distribution Transformers Upgrade	**Investment Need:** Non-standard design for distribution transformers which results in high SAIDI, maintenance and operation costs **Options Considered:** Install new Ring Main Units to provide individual fuse for transformers, Do nothing	340	2017

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Installation of LV transformer demand monitoring device	**Investment Need:** Lack of monitoring devices. Old devices have faulted **Options Considered:** Upgrade to new monitoring devices, Repair of faulted old devices, Do nothing	110	2016 to 2017
Hamilton 11kV interconnection upgrade	**Investment Need:** Limited ability to transfer demand during planned and unplanned outages **Options Considered:** Install new cable link to provide interconnection, Do nothing	1,543	2020 to 2021
Reduce customers on PEACB3 by transferring to PEACB6	**Investment Need:** PEA CB3 exceeds network standard on number of connected customers **Options Considered:** Transfer some customers to PEACB6, Do nothing	522	2022
Upgrade AVACB4	**Investment Need:** AVACB4 have exceeded customer number standard (1,200) which resulted to high SAIDI impact **Options Considered:** Transfer some customers to AVACB1, upgrade feeder to increase capacity and install automated switch, Do nothing	536	2023
Distribution Network Reinforce - Ongoing	**Investment Need:** Feeder identified with loading and/or security issue **Options Considered:** Upgrade feeder, Install new 11 kV cables, Install automated switch	4,534	2017 to 2025
11kV cables zone interconnections upgrades	**Investment Need:** Feeder demands exceeds network capacity standard which affects ability to supply other feeder under contingency **Options Considered:** Upgrade feeder weak sections, Install new feeder, Change feeder open points	4,114	2017 to 2025
Network Work Upgrade due to Distributed Generation applications	**Investment Need:** Capacity and security issues due to distributed generation connections to the network **Options Considered:** Upgrade network to rectify pre-existing issues	500	2015 to 2025

Table 7.5.3.1 Urban distribution level network projects for 2016 to 2025

Table 7.5.3.2 summarises the distribution investment required over the AMP period.

DISTRIBUTION ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Distribution	1,977	2,862	1,050	1,050	1,521	1,721	1,486	2,098	1,184	1,050

Table 7.5.3.2 Urban distribution level network projects forecast spend profile

7.5.4 LV DEVELOPMENT

Two LV investment drivers have been identified over the AMP period. These are:

- **LV Circuit upgrades.** Ongoing investigations will determine areas of the network that require upgrading. This programme is included to address these LV circuits; and
- **LV transformer upgrades.** Ongoing investigations will determine areas of the network that require transformer upgrading. This programme is included to address these transformers.

The following table summarises the LV programmes, options considered, projected expenditure and timing.

PROJECT / PROGRAMME	INVESTMENT DRIVERS /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
LV Circuits Upgrade	**Investment Drivers:** LV security and reliability issues	12,369	2017 to 2025
	Options Considered: Upgrade LV network where required, Transfer demand		
LV Feeder and Transformer Overloading Issues	**Investment Drivers:** Demand exceeds feeder and transformer capacity	3,800	2017 to 2025
	Options Considered: upgrade transformer and reconfigure the feeder, do nothing		

Table 7.5.4.1 Urban low voltage projects for 2016 to 2025

Table 7.5.4.2 summarises the expected low voltage investment required over the AMP period.

LOW VOLTAGE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Low Voltage	-	769	1,900	1,900	1,900	1,900	1,900	1,900	2,000	2,000

Table 7.5.4.2 Urban low voltage projects forecast expenditure profile

7.5.5 OTHER SYSTEM FIXED ASSETS

Seven investment needs have been identified for other system fixed assets during the AMP period. These are:

- **Smart Box investments.** Continuation of Smart Boxes installation at customer's meter boards. These provide information on the network and assist in the network management;
- **Consenting for projects**. Ongoing subdivision development within the northwest and northeast areas of Hamilton requires that land access for utility services is secured. Therefore, we have allowed for consenting costs within these areas for future subtransmission supply routes;
- **Automatic Under Frequency Load Shedding (AUFLS) scheme changes.** AUFLS is used by the SO to shed load to prevent total failure of the power system. The way in which AUFLS will be set is changing and changes will be required to comply with the new national requirements. Provision covers the cost of new assets required to meet the SO requirements;
- **Access and Monitoring - Video IP Camera.** With improved communication circuits to many of our Zone substations cameras can be installed, which can be used to remotely determine what is happening at a Zone substation prior to fault staff entering;
- **Protection upgrade.** Replacement of old and less reliable distance protection is planned for 2016. The improved system will provide a simpler protection system, improving safety and will result in less false tripping and a corresponding improvement in network performance;

- **Installation of the Avalon Ripple Plant.** This will allow N-1 security on both Hamilton and Te Kowhai load control equipment; and
- **Fibre routes.** This is a communications enhancement project to allow for the protection upgrade and improved operational flexibility.

The following table summarises the projects, options considered, projected expenditure and timing.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Smart Boxes	**Investment Need:** Smart meters provide the opportunity to provide information on the network that can identify power quality issues **Options Considered:** Continue with Smart Box roll out, do nothing	4,051	2016 to 2025
Consenting costs for projects	**Investment Need:** Secure access within development areas to support future supply options **Options Considered:** Process resource consent, do nothing	454	2016 to 2025
AUFLS scheme changes	**Investment Need:** Compliance to new AUFLS regime **Options Considered:** Comply with regulatory requirement, do nothing	150	2017
Access & Monitoring - Video IP Camera	**Investment Need:** Provide visibility on Substation's building and yard **Options Considered:** Install Video IP Camera, Install standard video camera, do nothing	75	2016
33kV Protection Upgrade distance to differential	**Investment Need:** Existing distance protection does not provide proper tripping discrimination on some types of faults in a meshed network causing security issues **Options Considered:** Do nothing, Review settings to reduce permissive over-reach, Install differential protection on circuits, Install open points in the 33kV mesh	948	2016 to 2017
Install Avalon Ripple Plant Project	**Investment Need:** Provide backup to existing Hamilton and Te Kowhai ripple plant **Options Considered:** Provide backup, Rely on maintenance contract from Auckland where repair time includes travel time	514	2019
Fibre Routes	**Investment Need:** Install new fibre to provide redundancy and replace existing pilot wires **Options Considered:** Install new fibre, Install radio, remain on pilot wire	2,284	2016 To 2022

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Opportunistic fibre installations	**Investment Need:** Opportunity to install fibre cable or duct when there is Council or third party road and footpath works	1,430	2016 To 2025
	Options Considered: Install fibre cable or duct when there is Council or third party road and footpath works		

Table 7.5.5.1 Urban other system fixed assets projects for 2016 to 2025

Table 7.5.5.2 summarises the expected other system fixed asset investment required over the AMP period.

OTHER SYSTEM FIXED ASSETS ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Other system Fixed Assets	2,617	1,504	682	1,423	810	776	515	507	557	517

Table 7.5.5.2 Urban other system fixed assets projects forecast expenditure profile

7.5.6 CUSTOMER DRIVEN WORKS

Three customer driven needs have been identified during the AMP period. These are:

- **New connections and upgrades.** Investment required to connect new customers and upgrades for customers that have a step change in demand. A provision based on the historical levels has been made to account for these works;
- **Relocations.** This is predominantly relocations of our assets associated with the continuing development of the Waikato expressway (Huntly and Hamilton sections); and
- **Undergrounding.** In some circumstances and upon request we convert overhead lines to underground cables. We fund up to 50% of the total project cost, up to a total project cost of $1 million.

The following table summarises the projects, options considered, projected expenditure and timing.

PROJECT / PROGRAMME	INVESTMENT NEED	ESTIMATED COST ($000)	TIMING
New Connections and upgrade`s	**Investment Need:** Network existing capacity is compromised with the additional demand	84,246	2015 to 2025
Relocations	**Investment Need:** relocation of assets to support the expressway development	11,955	2015 to 2025
Undergrounding	**Investment Need:** undergrounding of overhead lines	9,250	2015 to 2025

Table 7.5.6.1 Urban customer driven works projects for 2016 to 2025

Table 7.5.6.2 summarises expected customer driven works investment over the AMP period.

CUSTOMER DRIVEN WORKS ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Customer Driven Works	9,869	10,658	9,949	9,743	8,684	9,184	10,684	10,184	8,799	8,684

Table 7.5.6.2 Urban customer driven works forecast expenditure profile

7.5.7 SUMMARY OF 10 YEAR EXPENDITURE PLAN

Table 7.5.7 below summarises the expected urban area growth and security expenditure required over the AMP period.

URBAN EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Subtransmission	-	2,000	4,339	-	-	-	-	-	-	-
Substation	4,984	2,084	122	3,868	-	-	-	-	-	-
Distribution	1,977	2,862	1,050	1,050	1,521	1,721	1,486	2,098	1,184	1,050
LV	-	769	1,900	1,900	1,900	1,900	1,900	1,900	2,000	2,000
Other system Fixed assets	2,617	1,504	682	1,423	810	776	515	507	557	517
Customer Driven Works	9,869	10,658	9,949	9,743	8,684	9,184	10,684	10,184	8,799	8,684
Urban Total	19,447	19,877	18,042	17,984	12,915	13,581	14,585	14,689	12,540	12,251

Table 7.5.7 Urban development expenditure forecast expenditure profile

7.6 RURAL DEVELOPMENT PLAN

Our Rural Development Plan addresses the need to improve voltage performance and security on our rural network. There are no growth related rural investments required within the AMP period.

The reliability performance of the rural network is predominantly addressed by our asset renewal programme, as discussed in Chapter 8. There are a number of projects planned to address rural network security which will also contribute to improved reliability performance.

This section is structured by network level:

- Subtransmission;
- Zone Substation; and
- Distribution.

7.6.1 SUBTRANSMISSION

Three subtransmission investment needs have been identified over the AMP period. These are security upgrades of supply to:

- The Glasgow substation;
- The Kimihia substation; and
- The Raglan and Te Uku areas.

The following table summarises the projects, options considered, projected expenditure and timing.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Huntly to Glasgow 33kV cable	**Investment Need:** Presently at N security level and constraints adjacent substation during outages **Options Considered**: Install 33kV cables, transfer demand, new substation	1,263	2025
Huntly to Kimihia 33kV cable	**Investment Need:** Presently at N security level and constrains adjacent substation during outages **Options Considered**: Install 33kV cables, transfer demand, new substation	1,411	2025
Te Uku and Raglan security upgrade	**Investment Need:** Te Uku and Raglan substations are supplied by a single 33kV supply **Options Considered**: Presently re-assessing the options to minimise the impact of an outage on the single 33kV supply	3,700	2020 to 2023

Table 7.6.1.1 Rural subtransmission development projects for 2016 to 2025

Table 7.6.1.2 summarises the rural subtransmission investment required over the AMP period.

SUBTRANSMISSION ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Subtransmission	-	-	-	-	100	1,500	2,000	103	-	2,674

Table 7.6.1.2 Rural subtransmission projects forecast expenditure profile

7.6.2 ZONE SUBSTATIONS

Three investment needs have been identified for rural zone substations over the AMP period. These are:

- **Improved network security and reliability:** These projects include:
  - Weavers Transformer Upgrade; and
  - Gordonton Substation upgrade.
- **Safety and security:** Programme is primarily concerned with the seismic strengthening of substations and switching stations. The aim of the project is to bring zone substations up to the requirements for importance level 4 buildings;
- **Completion of the Hoeka Rd Zone Substation:** This commenced in 2015 and is expected to be completed in 2016. The second stage of the Hoeka Rd substation is scheduled for late in the AMP period.

The following table summarises the projects, options considered, projected expenditure and timing.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Weavers Transformer Upgrade	**Investment Need:** Demand exceeds N-1 limit	2,109	2017 to 2018
	Options Considered: Upgrade Transformers, or transfer demand		
Hoeka Rd Zone Substation	**Investment Need:** Increase capacity to cater for future demands.	2,877	2016 to 2024
	Options Considered: New zone substation to cater for demands on the far south east, do nothing		
Seismic strengthening of substations and switching stations	**Investment Need:** Safety and compliance	685	2016 To 2019
	Options Considered: Strengthen buildings to comply		
Gordonton Substation upgrade	**Investment Need:** Asset replacement and existing configuration is only one circuit breaker for two transformers	3,487	2019 To 2021
	Options Considered: Upgrade substation to present standards, transfer demand, do nothing		

Table 7.6.2.1 Rural Zone substation growth and security projects 2016 to 2025

Table 7.6.2.2 summarises the rural zone substation investment required over the AMP period.

ZONE SUBSTATION ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Zone Substation	1,567	644	1,665	800	2,690	97	-	-	1,695	-

Table 7.6.2.2 Rural Zone substation projects forecast expenditure profile

7.6.3 DISTRIBUTION

Four distribution investment needs have been identified during the AMP period. These are:

- **Improved network security:** These projects include:
  - Network Automation. By automating selected devices significant improvements in fault restoration times can be achieved;
  - Security projects. Network investigations will continue to identify opportunities to improve reliability by adding additional feeders and feeder interconnections to the network;
  - Provide a contingency supply to the Whatawhata feeder WHACB6 by providing an inter-tie to Wallace feeder WALCB6 ;
  - Provide a contingency supply and upgrade the line on Horotiu Rd / Onion Rd. This will also provide better support of the demand growth in the area; and
  - To provide better contingency supplies to the airport the distribution network in the area will be enhanced.

- **Voltage Levels:** There are a number of areas within the rural network that experience low voltages during peak demand times. A number of projects are planned to rectify these issues and improve the voltage within the rural network. These projects include:
  - Where Smart Boxes or network modelling has indicated an issue with voltage this is investigated and solutions determined;
  - Due to the installation of the Hoeka substation the distribution network needs enhancement to gain the full benefit from the substation; and
  - Where a customer complaint is determined by power quality issues network investment is often required;
- **Ground Fault Neutralisers or line renewal:** To reduce interruptions to customers in rural locations due to earth faults caused by contact with trees or other such events; and
- **Spacer Installation:** To reduce the tripping of circuits due to line clashing, spacers will be installed or line configurations changed in key locations.

The following table summarises the rural distribution projects, projected investment and timing.

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Network Automation	Investment Need: Minimise impact of SAIDI minutes Options Considered: Provide automation, do nothing	564	2016
Reliability projects	Investment Need: Minimise SAIDI impact Options Considered: Addition of new equipment, line reconfiguration, do nothing	1,021	2018 to 2022
WHA CB6 - WAL CB6 Feeder	Investment Need: No contingency supply to WHACB6 and downstream of X104 Options Considered: Extend WHACB6 to interconnect with WALCB6	214	2016
Voltage upgrade projects due to monitoring	Investment Need: ICP's identified by Smart boxes with power quality issues Options Considered: Install new transformer and/or LV circuits, upgrade existing transformer and/or LV circuits	4,900	2016 to 2025
Power Quality - Works required to correct customer complaints	Investment Need: Power quality issues identified within the network through customer complaints Options Considered: Install new distribution transformer and/or LV circuits to transfer customers, upgrade existing distribution transformer and/or LV circuits	1,300	2016 to 2025
Horotiu Rd / Onion Rd 11kV Upgrade (Stg 1)	Investment Need: No contingency supply to X161A **Options Considered:** Install new 11 kV cable to interconnect with HORCB5, do nothing	155	2016
Distribution network Enhancement in HOE area	**Investment Need:** With the installation of the new Hoeka substation enhancement to the distribution network is required **Options Considered:** Undertake reconfiguration, undertake reconfiguration and automate the interties	907	2016

PROJECT / PROGRAMME	INVESTMENT NEED /OPTIONS CONSIDERED	ESTIMATED COST ($000)	TIMING
Distribution Network Enhancement in Airport Area	**Investment Need:** The is limited ability to provide supply to the airport should there be a fault on that feeder **Options Considered:** Undertake reconfiguration, do nothing	174	2016
GFN or line renewal	**Investment Need:** Loss of supply during single phase to earth faults **Options Considered:** Major upgrade of all 11kV feeders in worst performing area of network, install GFN at substations of worst performing area	7,785	2017 to 2024
Mitigation of line clashing near zone substations	**Investment Need:** Identified line clashing near zone substations, fault level increase due to new zone substation **Options Considered:** Replace cross arms, Install line spacers	880	2017 To 2025

Table 7.6.3.1 Rural distribution projects for 2016 to 2025

Table 7.6.3.2 summarises the rural distribution investment required over the AMP period.

DISTRIBUTION EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Distribution	2,814	1,995	2,480	1,630	1,580	1,601	2,410	1,380	1,380	630

Table 7.6.3.2 Rural distribution projects forecast expenditure profile

7.6.4 EXPENDITURE SUMMARY

Table 7.6.4 below summarises the rural area growth and security expenditure required over the AMP period.

RURAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Subtransmission	-	-	-	-	100	1,500	2,000	103	-	2,674
Substation	1,567	644	1,665	800	2,690	97	-	-	1,695	-
Distribution	2,814	1,995	2,480	1,630	1,580	1,601	2,410	1,380	1,380	630
Rural Total	4,381	2,639	4,145	2,430	4,370	3,198	4,410	1,483	3,075	3,304

Table 7.6.4 Rural development forecast profile

7.7 SUMMARY NETWORK CAPITAL INVESTMENT

The 10 year Network Capital Investment forecast is forecast to decline over the AMP period.

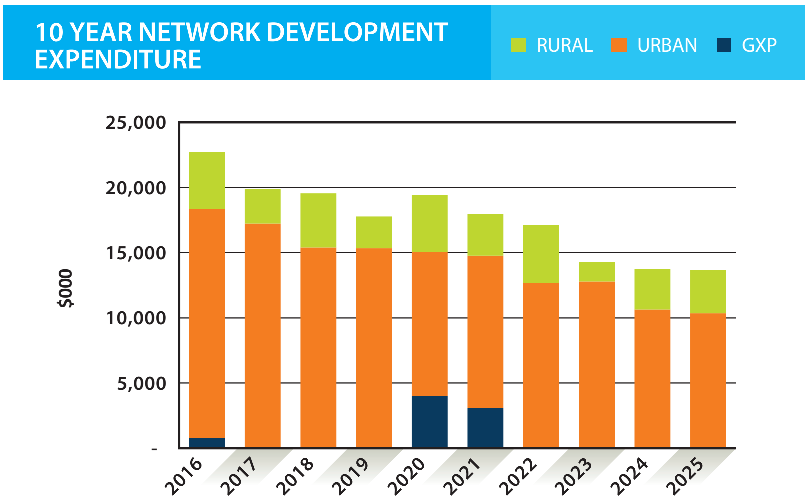


Table 7.7 Network development forecast profile

7.8 NON-NETWORK INVESTMENTS

This section describes our non-network related projects. These projects focus on enabling a higher level of efficiency across the company and enabling the delivery of services to our customers. Our policy for the development, renewal and maintenance of our non-network assets is to ensure that they remain fit for purpose at the lowest overall lifecycle cost. The non-network expenditure falls into two categories:

- Non-network capital expenditure; and
- Non-network operational expenditure

Each of these are addressed below.

7.8.1 NON-NETWORK CAPITAL EXPENDITURE

The non-network capital expenditure addressed in this section covers:

- **Computer Software Capital Expenditure.** This covers the periodic upgrades of existing software applications and the development of new business tools. Examples include:
  - Major version upgrades for our industry standard software applications including SAP, Intergraph GeoIS, Microsoft Office, desktop and server platforms, our document management system (Content Manager) and the NMS;
  - Implementation of the mobility project, which provides direct in-field to SAP connectivity, resulting in significant productivity gains;
  - A revenue billing project will provide increased revenue assurance, by identifying exceptions and anomalies between retail and wholesale billing; and
  - Mobile GeoIS platform will provide a range of services to our staff, partners and customers, by allowing access to key asset information such as service plans, fault details, and outages in real time.

- **Computer Hardware Capital Expenditure**. This covers the physical computing infrastructure including servers, storage, switches, firewalls and desktops. Our server systems have an expected lifespan of 3-4 years and will need to be updated in 2018. Desktop, laptop, and tablet computing devices are also on a three year replacement cycle. We will also continue to monitor and review the use of "on-premises" infrastructure, versus moving hosting into the 'cloud'. It is highly likely that relatively non-critical systems (e.g. Office, PABX, Exchange, and even SAP) could migrate into the cloud over the timeframe of this plan, with transfer of costs into operating expenditure.
- **Plant and Equipment**. A replacement of existing testing equipment is forecast for 2016 to facilitate putting in place a new testing regime by the Asset Management team.
- **Motor Vehicles.** The forecast reflects the programme to replace leased vehicles with owned. The replacement schedule of leased vehicles will conclude in 2018. In addition, several rebuilds of trucks are due to be completed in 2018. A high number of owned vehicles will be replaced due to age and anticipated kilometres in 2020. The forecast reflects the advantage of owning our vehicles as the asset can be retained for longer periods than leasing legislation allows and that is demonstrated in the lower forecast for 2019 to 2025.

7.8.2 NON-NETWORK OPERATIONAL EXPENDITURE

The non-network operational expenditure addressed in this section covers:

- **Systems operations and network support.** This covers areas of the business functions including:
  - Assets Management which includes Asset Information and Strategy, Network Planning, Maintenance Strategy, Network Design, Development and Automation and Engineering.
  - Operations which includes System Control, Field Services, Customer Projects, Distribution Design, Capital Projects.
  - Customer Support and Procurement
- **Business support.** This covers areas of the business functions including:
  - Corporate and Strategy which includes Finance, Commercial, Information Services, Audit , Risk, Regulatory and Metering Services.
  - People and Performance which includes Health and Safety, Organisational Development and Human Resources.

The spend profile over the AMP period remains flat due to stable level of activities.

7.8.3 SUMMARY OF NON-NETWORK EXPENDITURE

The table below summarises the expected non-network expenditure required over the AMP period.

NON-NETWORK CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Computer Hardware	450	300	700	400	300	700	400	300	700	400
Computer Software	1,790	900	1,950	1,080	1,510	890	970	2,100	1,530	910
Plant and Equipment	724	249	229	229	229	229	267	267	267	267
Motor Vehicles	1,964	846	1,118	188	735	526	257	447	169	37
Total	4,928	2,295	3,997	1,897	2,774	2,345	1,894	3,114	2,666	1,614

Table 7.7.3.1 Non-Network Capital Expenditure

NON-NETWORK OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL
System operations and network support	3,856	3,805	3,962	3,782	3,731	3,661	3,737	3,752	3,752	3,752	37,790
Business support	7,958	8,108	8,108	8,158	8,108	8,108	8,158	8,108	8,108	8,158	81,080
Total	11,814	11,913	12,070	11,940	11,839	11,769	11,895	11,860	11,860	11,910	118,870

Table 7.7.3.2 Non-Network Operational Expenditure

8 RENEWALS AND MAINTENANCE

8 RENEWALS AND MAINTENANCE

This chapter describes our renewal and maintenance approach for the AMP period. It details our planned renewals and maintenance work and how we have forecast the associated expenditure.

The chapter is structured as follows:

- **Overview of Maintenance and Renewals (8.1):** provides an overview of our approach to renewals and maintenance and how it fits within our asset management framework;
- **Maintenance (8.2):** describes how we ensure that we undertake an appropriate level of maintenance on our assets;
- **Renewals (8.3):** describes our approach to determining an appropriate level of renewal expenditure on our assets;
- **Asset Life Cycle Management (8.4):** describes the maintenance and renewals challenges we face and how we will address these during the AMP period; and
- **Expenditure Summary (8.5):** summarises our renewal and maintenance expenditure during the AMP period.

8.1 OVERVIEW OF MAINTENANCE AND RENEWALS

Delivering our performance objectives, as described in Chapter 6, requires the right balance between expenditure on maintenance and investment in renewals. In striking this balance, we have considered the whole of life cost of our assets, and required interventions during their lifecycle.

As established by our asset management framework, described in Chapter 4, we have utilised the RCM philosophy and taken a risk based approach to renewals with the implementation of CBRM. The resulting maintenance works and renewal plans are described below.

8.2 MAINTENANCE

Our maintenance activity is first and foremost safety focused. After which, it is structured to minimise the whole of life costs of our assets while managing their performance over time. This is achieved by selecting maintenance techniques and processes that:

- Ensure safety risks are identified and mitigated;
- Optimise the costs of maintenance together with renewal expenditure;
- Meet any regulatory requirements; and
- Where possible improve network availability.

These techniques are described for each asset category in Section 8.4 below.

8.2.1 ASSUMPTIONS AND INPUTS

A number of assumptions and inputs inform the level of maintenance undertaken on our assets. The key assumptions and inputs are described below.

INDUSTRY STANDARDS AND ANALYSIS TOOLS

Maintenance tasks are determined by the use of industry maintenance standards, support tools, and analysis.

ASSET INSPECTIONS

We regularly inspect our assets and the surrounding vegetation. The frequency at which an asset is inspected or monitored is determined by potential risk, manufacturer's recommendations, and legislative requirements. During an asset inspection, the condition is assessed and recorded along with any defects found.

CONDITION ASSESSMENT

Asset condition influences the extent of servicing required, the necessary repairs required, and provides vital data to inform our asset renewal decisions. Our condition assessment is based on a 0 to 5 rating system, as set out in Table 8.2.1.1 below.

CONDITION SCORE	REMAINING LIFE DESCRIPTION	DEFINITION
5	Early Life	As newly installed or equivalent
4	Mid Life	Normal ageing and use
3	Near End of Life	Likely to meet replacement criteria at the next inspection
2	End of Life	Meets replacement criteria. Schedule for replacement within 12 months
1	Unserviceable	Unserviceable but not hazardous. Replace within 14 days
0	Hazard	Immediate action is required to eliminate hazard

Table 8.2.1.1 Asset Condition Assessment Ratings

DEFECT NOTIFICATIONS

Defects are identified during inspections. If an asset has a defect, the asset inspector will assess the severity of the defect and assign a defect rating as specified in Table 8.2.1.2 below.

DEFECT RATING	DEFECT CLASSIFICATION	DEFECT DESCRIPTION
1	Red Defect	Condition that requires immediate follow up. Undertake permanent repairs or renewal within 2 days
2	Amber Defect	Condition not otherwise classified as a Red Defect that requires permanent repair or renewal within 2 weeks
3		Condition not otherwise classified as an Amber 2 Defect that requires permanent repair or renewal within 3 months
4		Condition not otherwise classified as an Amber 3 Defect that requires permanent repair or renewal within 12 months
5	Green Defect	Serviceable for another 2 years or next scheduled inspection e.g. paint defects
6		Serviceable for another 5 years and does not affect the overall operation of the asset

Table 8.2.1.2 Defect Classifications

8.2.2 MANAGEMENT OF SF_6

SF_6 is a gas used in modern switchgear. We have initiated a review of equipment that could be used as an alternative to SF_6 filled switchgear. In the meantime we are required by law to disclose the quantity we have installed in our network. We record and monitor the volumes of SF_6 gas installed, disposed and emitted into the environment. As at November 2014 the volume of SF_6 utilised by our switchgear was 1.2 tonnes.

8.2.3 VEGETATION MANAGEMENT

Vegetation management is the process of managing vegetation in and around our assets that have the potential to interfere with the safe and reliable supply of electricity to our customers. We have increased our inspection rates and maintain a vegetation growth model to predict when future work will be required for different vegetation types.

Vegetation expenditure is based on our vegetation growth model. Based on current cutting rates our model predicts expenditure will reduce towards the end of the AMP period as shown in Table 8.2.3.1.

VEGETATION MANAGEMENT ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Operational Expenditure										
Vegetation Management	1,290	1,290	1,290	1,290	1,290	1,000	1,000	700	700	700
Total	1,290	1,290	1,290	1,290	1,290	1,000	1,000	700	700	700

Table 8.2.3.1 Vegetation Management Expenditure

8.2.4 SERVICE INTERRUPTION AND EMERGENCY MANAGEMENT

Service interruption and emergency management relates to required faults work.

The decrease in the projected faults costs as shown in Table 8.2.4 is mainly due to the efficiency gains with the introduction of the new Faults team, proactive repairs on defects due to the enhanced diagnostic testing we have introduced, and reduction in line breaks due to the conductor renewal programme.

SERVICE INTERRUPTION AND EMERGENCY MANAGEMENT ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Operational Expenditure										
Service Interruption and Emergency Management	2,785	2,694	2,603	2,513	2,422	2,331	2,240	2,149	2,058	1,967
Total	**2,785**	**2,694**	**2,603**	**2,513**	**2,422**	**2,331**	**2,240**	**2,149**	**2,058**	**1,967**

Table 8.2.4 Service Interruption and Emergency Expenditure

8.2.5 MAINTENANCE FORECASTING

Our maintenance activities and associated expenditure have been forecast by asset category. The basis of the forecast are estimates of asset quantity, maintenance type (preventive, predictive and corrective), and relevant unit costs. Unit costs are based on historical maintenance task costs adjusted for known changes e.g. increases in labour costs.

The maintenance forecast for each asset category is shown at the end of each section below.

8.2.6 INNOVATIONS AND IMPROVEMENTS IN MAINTENANCE PRACTICES

Innovation and continuous improvements are necessary to meet our cost efficiency objectives. The maintenance related improvements and innovations we have recently implemented include:

- Development of mobility solutions to record asset information in the field and transfer it directly into our office systems;
- Improved inspection strategies that enhance risk identification, asset condition and population data;
- Implementation of 'accelerated' inspection programmes for overhead line assets and LV pillars;
- Improvement of asset data quality and accuracy through the field verification programme;
- Specification of strategic spare requirements for emergency preparedness; and
- Development of a modular substation used for equipment testing, spares and training of technical staff.

The application of these innovations and improvements is discussed in Section 8.4 below.

8.3 RENEWALS

We have used CBRM to develop a risk based approach to planning our asset renewals. This approach prioritises the renewal of assets that present the highest risk to safety, network performance, and the environment. The methodology is used by numerous electricity distribution companies internationally to deliver effective risk related asset management.

CBRM is a process that combines asset information, engineering knowledge and practical experience to estimate future condition, and performance of network assets. Specific risks for each asset category are identified and quantified. We have developed CBRM models for most of our key assets and will complete the modelling during 2016.

Further details on the CBRM process is described in Appendix B.

REPLACEMENT CAPITAL EXPENDITURE (REPEX) REVIEW

An independent review of our proposed renewal expenditure has been undertaken using a Repex modelling approach.[1] The review provided assurance that our proposed expenditure (developed using CBRM) is appropriate.

8.3.1 INVESTMENT SCENARIOS

To determine the optimal level of renewal expenditure across our key asset categories we considered four alternative investment scenarios. Figure 8.3.1 below shows indicative 10-year risk profiles for each scenario. The scenarios are:

- **Scenario 1** – Do nothing models a hypothetical base case to understand the effects of not undertaking renewals. By year ten the risk is expected to be increase rapidly;

[1] *The Repex model benchmarks expenditure forecasts against other Electricity Distribution Businesses.*

- **Scenario 2** – Model of expenditure previously planned in our 2014 AMP;
- **Scenario 3** – Is a slight risk improvement over our 2014 plan. However this outcome can be achieved with less renewal expenditure through the further optimisation and prioritisation of critical assets; and
- **Scenario 4** – is included for completeness and the relative risk profile of the hypothetical maximum renewal expenditure. It seeks to illustrate that even with maximum expenditure not all risk can be removed.

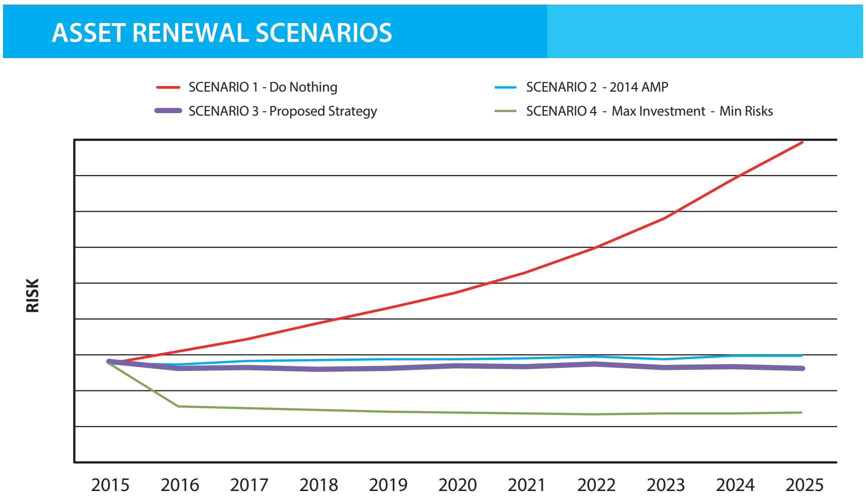


Figure 8.3.1 Asset Renewal – Scenario Risk Profiles

Our renewal programme is based on scenario 3 as it maintains a stable level of risk over the AMP period as our renewal expenditure will be optimised by prioritising highest risk assets.

8.3.2 ASSUMPTIONS AND INPUTS

There are a range of assumptions and inputs necessary for establishing our renewal plan and CBRM models. These are described below.

ASSET HEALTH AND CONDITION INFORMATION

The accuracy of asset age and condition is critical to determining when an asset is due for renewal. For planning purposes we have assumed our data is generally reflective of our asset fleet and that it is sufficiently robust to support the modelling undertaken.

ASSET MONITORING

Diagnostic measurement techniques such as ultrasonic surveys on overhead lines, PD acoustic surveys on switchgear, and SFRA on zone transformers provide better asset condition information than simple visual inspections. These techniques help eliminate failures proactively through early intervention programmes and can be used to defer premature asset renewal.

DESIGN LIFE ASSUMPTIONS

The expected design lives of assets are based on manufacturers' guidance and our own practical experience managing the assets.

8.4 ASSET LIFE CYCLE MANAGEMENT

This section describes how we manage our assets over their full lifecycle. For each asset category we have:

- Identified the routine and corrective maintenance tasks;
- Described the inspection policy and programme employed;
- Identified any systemic problems and described our approach to addressing these problems;
- Identified the replacement programme and drivers;
- Described the innovations we have made to defer asset replacements; and
- Listed the projects underway or planned.

The remainder of this section is structured by the following asset categories with details of included assets and expenditure summaries.

- Subtransmission Lines (8.4.1 to 8.4.4)
- Zone Substations (8.4.5 to 8.4.8)
- Distribution and LV Lines (8.4.9 to 8.4.12)
- Distribution and LV Cables (8.4.13 to 8.4.15)
- Distribution Substations and Transformers (8.4.16 to 8.4.17)
- Distribution Switchgear (8.4.18 to 8.4.19)
- Other System Fixed Assets (8.4.20 to 8.4.25)

8.4.1 SUBTRANSMISSION LINES

RISKS AND ISSUES

The principal risks and issues associated with subtransmission lines are:

- Cars colliding with poles can result in outages and public safety risk from falling poles or uncontrolled live conductors;
- Insulator failures or tree debris blown onto the lines during high wind or storm events;
- External influences such as possums or birds causing flashovers; and
- Insulator type issues on our urban meshed network.

MAINTENANCE UNDERTAKEN

Inspections on subtransmission lines include:

- Detailed inspections every six months for critical feeders not meshed with other lines;
- Detailed inspections every five years for all other lines; and
- Visual inspections on an annual basis.

During detailed inspections tests are carried out on all earth banks. Recently ultrasonic surveys using a multi-functional PD instrument have also been undertaken. Thermo graphic surveys or thermal imaging is carried out on selected critical subtransmission feeders. Other diagnostic measurement techniques such as Corona surveys are currently being evaluated.

Maintenance tasks are undertaken to correct any defects identified.

ASSET RENEWAL PROGRAMME

No renewal of these assets is planned during the AMP period as they are well within their life expectancy and have an acceptable risk profile, based on their condition.

8.4.2 SUBTRANSMISSION CABLES

RISKS AND ISSUES

The principal risks and issues associated with subtransmission cables arise from:

- Mechanical damage due to third party excavations or directional drilling; and
- Cable joint failures.

MAINTENANCE UNDERTAKEN

Subtransmission cable maintenance is based on results from partial discharge testing as visual inspections are not possible for underground assets. Testing is carried out:

- Annually for selected critical circuits; and
- More frequently where critical levels of discharges are identified.

Analysis has been undertaken to determine suspected cable joints which may have similar failure modes. These feeders have been prioritised for on-line partial discharge testing and further monitoring. Joints identified as defective following testing are replaced.

ASSET RENEWAL PROGRAM

No renewal of subtransmission cables is planned during the AMP period.

8.4.3 SUBTRANSMISSION CIRCUIT BREAKERS (CBS)

RISKS AND ISSUES

- There have been no significant issues identified with our subtransmission CBs.

MAINTENANCE UNDERTAKEN

CBs are inspected and tested every three years. Tests undertaken include PD tests, and dynamic tests such as the 'first-trip' test using a CB profile analyser.

The level of servicing is increased where multiple trips have occurred. Major servicing is also undertaken every six years. Servicing includes changing the insulating oil in oil filled CBs, testing for turbulator erosion, trip-timing tests, trip circuit integrity checks, close circuit integrity checks, SCADA alarm and control checks, and testing of all functional parts (both electrical and mechanical) to ensure they meet the manufacturer's minimum requirements and recommended industry minimum acceptance criteria.

ASSET RENEWAL PROGRAMME

CBs scheduled for renewal due to the age and condition include those at; Alexandra St (2017), Massey St (2018), Claudelands (2020), Civic Car Park and Findlay (2022), and Barton St (2024). Renewing CBs involves considerable resource and outages on the network. Therefore where possible other co-located asset renewals are co-ordinated at the same time. This includes protection, battery and SCADA systems.

A CBRM model has been implemented to assist in renewal prioritisation and forecasting the required level of investment for subtransmission CBs.

8.4.4 SUMMARY OF SUBTRANSMISSION RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.4 summarises the Subtransmission expenditure for the AMP period.

SUBTRANSMISSION EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
33kV Circuit Breaker	-	-	-	-	-	-	-	-	-	-
33 kV Overhead Lines	-	-	-	-	-	-	-	-	-	-
33kV Subtransmission cable	66	66	66	66	66	66	66	66	66	66
Capital Expenditure Total	66	66	66	66	66	66	66	66	66	66
Operational Expenditure										
33kV Circuit Breaker	33	34	36	36	37	36	38	38	39	40
33 kV Overhead Lines	-	-	-	-	-	-	-	-	-	-
33kV Subtransmission cable	24	25	26	26	27	26	28	28	29	29
Operational Expenditure Total	57	59	62	62	64	63	65	67	68	69

Table 8.4.4 Subtransmission Expenditure

8.4.5 ZONE SUBSTATION POWER TRANSFORMERS

RISKS AND ISSUES

The principal risks and issues associated with power transformers are:

- Debris, on external or exposed bushings increase flashover risk;
- Poor insulation or degradation of the paper windings resulting in operational failure of the transformer. The condition of the insulation drives the degradation rate for the transformer;
- Unbunded transformers may result in uncontained oil spills and result in soil contamination or other environmental damage. Systematic upgrading of transformer bunding has been included in this AMP and focuses on rural zone transformers where oil leakage may potentially have a higher impact on the environment;
- Noise emission levels from some older transformers do not meet current regulatory standards. While these transformers are exempt, because the standards did not apply at the time of their installation, they will be progressively replaced with transformers that meet the new standards. Priority will be given to those causing public concern; and
- Vibration from external factors such as trains. Vibration can cause mal-operation of the mercury switches with the Buchholz type relays causing tripping of the incomer CBs. The mercury switches are being progressively replaced with magnetic reed.

MAINTENANCE UNDERTAKEN

Inspections are undertaken every two months. Testing and maintenance is specific to the subcomponent of the power transformer. This includes:

- Annual dissolved gas analysis and oil tests, these occur more frequently if evidence suggests there may be an issue that needs to be monitored more regularly;
- Minor maintenance e.g. cleaning, oil checks and visual inspection is carried out every three years;
- Major maintenance including acoustic partial discharge and dissipation factor analysis is undertaken with minor maintenance and servicing at six yearly intervals; and
- Tap changer maintenance is undertaken every two years.

Zone transformers also undergo mid-life refurbishment. This work involves removing (de-tanking) the core, an internal inspection, dry out, testing and repairs as required. The remaining life is assessed at this time, and we expect well maintained transformers with mid-life refurbishment will have a life exceeding 60 years.

Table 8.4.5 below summarises transformer maintenance plans and their corresponding frequencies.

FREQUENCY	MAINTENANCE	OIL-OLTC[2]	VACUUM-OLTC
2 Months	Inspection	X	X
Yearly	Annual DGA	X	X
3 Yearly	Transformer Minor	X	X
6 Yearly	Transformer Major	X	X
2 Yearly	OLTC Servicing	X	
4 Yearly			X

Table 8.4.5 Summary of Power Transformer Maintenance

ASSET RENEWAL PROGRAMME

No zone transformers will exceed their nominal lives within the AMP period. Transformer CBRM models are scheduled to be developed during 2016.

8.4.6 ZONE SUBSTATION SWITCHBOARDS

We have AIS and GIS switchboards on our network.

RISKS AND ISSUES

The principal risks and issues for zone substation switchboards are:

- Fault flashover causing injury to staff and equipment damage;
- Surface discharges on voltage transformer compartments and vacuum bottles on older AIS switchboards. The cause is believed to be high humidity within the substations during winter. Expenditure to install suitable air-conditioning units in substations has been included during the AMP period;
- Mechanical misalignment of movable parts and damaged interlocks on AIS switchboards;
- A lack of spare parts for older equipment. A recent failure required the acquisition of a replacement CB from overseas;

[2] *In-Load Tap Changer*

- Incompatible designs on newer switchboards. Although similar types of switchboards are used, legacy CB units can be incompatible causing a lack of compatible spares. Design has subsequently been standardised; and
- Operational handling and testing of SF_6 gas in GIS switchboards. Staff have been trained and testing equipment purchased to reduce our reliance on external service providers for this critical task.

MAINTENANCE UNDERTAKEN

Visual inspections on switchboards are undertaken every two months.

Annual partial discharge and surveys are conducted on indoor switchboards. The following items are checked as part of the survey:

- CT/VT chambers;
- Cable terminations in the switchgear;
- Cable end boxes and cable sealing ends; and
- Outdoor switchyard connections e.g. insulators, busbars.

Major maintenance is carried out on AIS equipment every nine years, and every 12 years on GIS equipment. Main tasks include:

- Bus maintenance for AIS e.g. general cleaning;
- Insulation resistance tests on the main busbar and connected VTs;
- Contact resistance tests on the main busbar; and
- Gas pressure checks and HV withstand tests on GIS.

ASSET RENEWAL PROGRAMME

Renewal of indoor switchboards is generally undertaken in conjunction with CB replacements.

A CBRM model has been implemented to assist in replacement prioritisation and forecasting the required level of investment in switchboards.

8.4.7 ZONE SUBSTATION BUILDINGS

The zone substation buildings category also includes subtransmission switching stations, indoor and outdoor transformer bays, and earthing systems.

RISKS AND ISSUES

The principal risks and issues associated with zone substation buildings include:

- Physical and environmental risks such as fires and oil spills. Substations with outdoor switchyards have higher physical and environmental risk than indoor switchrooms;
- Vandalism and graffiti;
- Theft of copper earth wire is a significant safety and cost issue;
- Humidity and high temperatures causing damage to electronic devices and switchboards;
- Water causing damage to control cables at our older sites. Our newer sites are installed with sump pumps which remove water accumulated in trenches and basements; and
- Records of earth test results and earthing design are lacking on some of our older sites and therefore difficult to confirm the integrity of the earthing system on those sites. A programme to assess these sites has been implemented.

MAINTENANCE UNDERTAKEN

Grass cutting, pest control and general cleaning of substation buildings is conducted monthly.

Substation buildings are inspected every two months. Tasks include inspection of soil erosion surrounding the building, visual cracks, paintwork, building condition, and transformer bunding. Site specific safety risks and defects are recorded in the hazard identification and defect notification systems.

Electrical compliance checks, testing and inspection of LV installations are carried out annually.

Every three years earthing systems are tested.

ASSET RENEWAL PROGRAMME

No zone substations are scheduled for renewal in the AMP period. The renewal programme for zone substations equipment continuation of the security system upgrade project to deter copper conductor theft. Zone substations located in rural areas with outdoor switchyards have been prioritised.

8.4.8 SUMMARY OF ZONE SUBSTATION RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.8 summarises Zone Substation expenditure for the AMP period.

ZONE SUBSTATION EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
11kV Switching Station/ Zone Sub	137	442	197	57	327	177	152	122	122	122
Alexandra Street Station Replacement	100	670	-	-	-	-	-	-	-	-
Glasgow 33kV GIS	-	-	-	-	1,658	-	-	-	-	-
Glasgow second transformer	-	-	-	-	656	-	-	-	-	-
Gordonton Zone transformer Replacement	-	-	-	-	-	-	-	926	926	-
Te Kauwhata replace transformers	-	-	-	-	-	-	-	-	-	-
Zone Substation Transformer	-	-	-	-	-	-	-	-	-	-
Capital Expenditure Total	237	1,112	197	57	2,641	177	152	1,048	1,048	122
Operational Expenditure										
11kV Switching Station/ Zone Sub	462	476	500	502	512	505	525	536	545	555
Zone Substation Transformer	208	214	224	225	230	227	236	241	245	249
Operational Expenditure Total	670	690	725	727	742	732	761	777	790	805

Table 8.4.8 Zone Substation Expenditure

8.4.9 DISTRIBUTION AND LV POLES

RISKS AND ISSUES

The principal risks and issues associated with poles are:

- Falling poles pose a staff and public safety risk or can cause damage to property. The risk of failure is greatest with the remaining hardwood poles; and
- Third party damage to poles e.g. car vs pole.
- The most common failure modes for distribution and LV poles are:
- Rotten bases and splitting on the heads for wooden poles; and
- Spalding of concrete in concrete poles.

MAINTENANCE UNDERTAKEN

Inspections are undertaken every three years. Gamma ray imaging is used to determine the condition of the base of wooden poles. This measures wood density and remaining pole strength. Poles are classified and assigned a renewal date based on results from the imaging.

Maintenance of poles includes the repair of possum guards.

ASSET RENEWAL PROGRAMME

Informed by a CBRM model, between 70 and 80 poles are planned to be replaced annually over the next 10 years.

8.4.10 DISTRIBUTION AND LV CROSSARMS

RISKS AND ISSUES

The principal risks and issues associated with crossarms is insulator failure due to pin corrosion or wood rot around the insulator pin hole. Insulator failure can cause wooden crossarms to burn or break causing the conductor to fall to the ground resulting in a public safety hazard and poor network performance.

MAINTENANCE UNDERTAKEN

Visual inspections of crossarms are undertaken every three years coinciding with pole and conductor inspections. As faulty insulators are difficult to detect by visual inspection, new ultrasonic diagnostic testing is being introduced as part of the inspection process. This technology has proved reliable in detecting early signs of insulator cracking or high levels of partial discharge.

ASSET RENEWAL PROGRAMME

Informed by a CBRM model, approximately 1,200 cross arms per year will be replaced in the first two years of the plan, increasing to 1,800 per year.

8.4.11 DISTRIBUTION AND LV CONDUCTORS

RISKS AND ISSUES

The principal risks and issues associated with conductors are:

- Public safety and property damage from live lines falling to the ground;
- Our 16mm^2 copper conductor fleet is failing earlier because of damaged strands from conductors clashing as a result of high wind, bird contact or tree debris predominately in rural areas. This has contributed to poor network performance; and

- Due to higher safety risks associated with 16mm^2 copper conductors prone to breaking while being handled we have ceased 'live line' renewal work. This will result in a greater number of planned outages to renew this conductor during the AMP period than included in our previous plans.

MAINTENANCE UNDERTAKEN

Inspections for distribution and LV conductors are undertaken as follows:

- Thermal imaging and ultrasonic testing is completed annually on critical sections of distribution conductors;
- Visual inspection only are conducted on the remaining distribution and all LV conductors;
- More detailed inspections and condition data capture is conducted every three years; and
- Thermal imaging is also used after major faults to check conductor and joint integrity. Corona discharge inspection is used to check feeders with incidences of insulator failure.

It is not practical to proactively service Distribution and LV conductors but failures are reactively repaired.

ASSET RENEWAL PROGRAMME

The CBRM-based programme for the AMP period includes targeted renewal of the Weavers, Silverdale, Wallace and Finlayson, Whatawhata, Raglan, Te Uku and Te Kauwhata feeders.

8.4.12 SUMMARY OF DISTRIBUTION AND LV LINE RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.12 summarises Distribution and LV Lines expenditure for the AMP period.

DISTRIBUTION AND LV LINES EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
Crossarms and Insulators	1,505	2,398	2,398	3,208	3,208	3,208	3,208	3,208	3,208	3,103
Distribution Lines	3,253	2,603	2,603	3,683	3,683	3,683	3,683	3,683	3,683	3,683
LV Lines	241	241	241	241	241	241	241	241	241	241
Medium mixed Projects	829	-	-	-	-	-	-	-	-	-
Poles	708	708	601	601	601	601	601	601	601	601
Capital Expenditure Total	6,536	5,950	5,843	7,733	7,733	7,733	7,733	7,733	7,733	7,628
Operational Expenditure										
Crossarms and Insulators	46	47	49	50	51	50	52	53	54	55
Distribution Lines	566	582	612	613	626	618	642	656	666	679
LV Lines	403	415	436	437	446	440	458	467	475	484

DISTRIBUTION AND LV LINES EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Poles	192	198	208	208	212	210	218	222	226	230
Operational Expenditure Total	1,206	1,241	1,304	1,308	1,335	1,318	1,370	1,398	1,421	1,448

Table 8.4.12 Distribution and LV Line Expenditure

8.4.13 DISTRIBUTION CABLES

RISKS AND ISSUES

The principal risks and issues associated with distribution cables are damage caused by excavations or directional drilling. Network outages can be extensive while cable jointing repair work is undertaken.

MAINTENANCE UNDERTAKEN

No routine maintenance is undertaken on distribution cables. However, a number of critical trunk feeder circuits have been identified for PD testing.

When failures have occurred samples of cable sections are retrieved to assess the internal condition of the cable.

ASSET RENEWAL PROGRAMME

No renewal is planned during the AMP period. A CBRM model is scheduled to be completed during 2016.

8.4.14 LV CABLES

RISKS AND ISSUES

The principal risks and issues for LV cables is cable failure caused by third party excavations or directional drilling and water ingress causing breach joints to fail.

MAINTENANCE UNDERTAKEN

Due to their inaccessibility there is no routine maintenance performed on LV cables.

ASSET RENEWAL PROGRAMME

There is no renewal programme for LV cables. Where cables are replaced they are done so as part of other projects such as upgrades or further LV reticulation development.

Distribution and LV cable CBRM models are scheduled for completion during 2016.

8.4.15 SUMMARY OF DISTRIBUTION AND LV CABLES RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.15 summarises Distribution and LV cables expenditure for the AMP period.

DISTRIBUTION AND LV CABLES EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
Distribution Cables	285	285	285	285	285	285	285	285	285	285
LV Cables	402	402	402	402	402	402	402	402	402	402
Capital Expenditure Total	687	687	687	687	687	687	687	687	687	687
Operational Expenditure										
Distribution Cables	-	-	-	-	-	-	-	-	-	-
LV Cables	178	183	192	193	197	194	202	206	209	213
Operational Expenditure Total	178	183	192	193	197	194	202	206	209	213

Table 8.4.15 Distribution and LV Cables Expenditure

8.4.16 DISTRIBUTION SUBSTATIONS AND TRANSFORMERS

RISKS AND ISSUES

The principal risks and issues associated with distribution substations and transformers are:

- Insulator cracks;
- Poor conductor connections; and
- External factors such as lightning strikes, birds, possums, and vegetation.

We have not identified any systemic problems with any particular manufacturer or model of transformer.

Copper theft from our distribution substations and transformers is a serious public safety issue and is costly to identify and replace. We undertake regular earth resistance tests to identify missing earth wires. We have implemented a security system upgrade across all our substation sites. Our rural sites with outdoor switchyards have been prioritised for this work.

MAINTENANCE UNDERTAKEN

Our pole mounted transformers are inspected every three years. Our pad mounted transformers are inspected every three years, coinciding with RMU inspections. Maintenance and testing includes:

- Testing of earth banks;
- Security checks;
- External panel deterioration or damage;
- Vegetation control;

- Cleaning of HV and LV cubicles; and
- Thermal imaging of connections and busbars.

For larger ground based CBD and industrial distribution transformers the maintenance programme includes:

- Reading of maximum demand indicators at six monthly intervals, timed to occur at peak load times;
- Annual inspection;
- Thermal imaging inspections of all links, bus bars and connections;
- Maintenance checks on tank and cubicles;
- Cleaning equipment and building internal areas; and
- Oil tests conducted on a condition basis for transformers 750kVA and above.

Transformers may be refurbished after being replaced by larger transformers due to growth and prior to being redeployed back into the network. An economic model has been developed to determine if a transformer should be scrapped or refurbished.

Data loggers are fitted to all new ground mounted transformers 300kVA and over. Loggers record three phase voltage, transformer temperature, three phase transformer currents and one phase of the outgoing circuit current. This data enables more accurate evaluation of transformer loading over time. It is envisaged that data loggers will be replaced by smart meters in the future. A project to retrofit existing transformers has been implemented with the corresponding expenditure included in our forecasts.

ASSET RENEWAL PROGRAMME

Renewal of distribution transformers only occurs on failure. A programme of works has been included to renew these as they occur.

A CBRM model has been implemented to assist in renewal prioritisation and level of investment for distribution substations and transformers.

8.4.17 SUMMARY OF DISTRIBUTION SUBSTATIONS AND TRANSFORMERS RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.17 summarises Distribution Substation and Transformer expenditure for the AMP period.

DISTRIBUTION SUBSTATIONS AND TRANSFORMERS EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
Distribution Transformers (11kV/400V)	1,324	1,124	1,124	624	624	624	624	624	624	624
Capital Expenditure Total	1,324	1,124	1,124	624	624	624	624	624	624	624
Operational Expenditure										
Distribution Transformers (11kV/400V)	662	681	715	717	732	723	751	767	779	794
Operational Expenditure Total	662	681	715	717	732	723	751	767	779	794

Table 8.4.17 Distribution Substations and Transformers Expenditure

8.4.18 DISTRIBUTION SWITCHGEAR

RISKS AND ISSUES

Distribution switchgear includes RMUs, ABSs, CBs, reclosers, sectionalisers, and distribution overhead line fuse units. The principal risks and issues associated with distribution switchgear are:

- **RMUs:** The possibility of SF_6 gas leakage from GIS units. High levels of partial discharges and mechanical interlock failures have been observed on the older oil-filled RMUs;
- **ABS:** Older, manually operated ABSs are a safety risk to the operator during switching. The most common failure for ABS is the main contacts being stuck in either an opened or closed position;
- **CBs:** There have been no major issues with our distribution CBs;
- **Reclosers and Sectionalisers:** Problems have been experienced with electronic drop out sectionalisers that have been installed over recent years. These units have not operated reliably, increasing fault restoration times; and
- **Distribution Overhead Line Fuses:** Failure due to the deterioration of the fuse element normally occurs from age and weather conditions.

MAINTENANCE UNDERTAKEN

Maintenance and testing is undertaken on switchgear as follows.

RMUs

RMUs are inspected and tested every three years. Inspection and testing consists of visual inspections, earth testing, vegetation control, oil level, SF_6 gas pressure, and through-fault indicator checks. During inspections checks are also made on the operating handles, earth conductor, tank condition, pitch box leaks, panel steelwork, labels, and warning signs. This work is undertaken in association with distribution transformer inspections. RMUs with busbar extension units also include partial discharge testing and visual inspection of busbar boxes. Oil type RMUs are also subject to major maintenance every 12 years.

ABSs

Inspections are undertaken every three years and include visual inspections of insulators, arc horns/chutes, contacts and handles. Earth testing is undertaken at the same time.

CBs

CBs are inspected and tested every three years. Tests undertaken include PD tests, and dynamic tests such as the 'first-trip' test using a CB profile analyser. Tests are also undertaken during servicing. The level of servicing is increased where multiple trips have occurred.

Major servicing is undertaken every six years. Servicing includes changing the insulating oil in oil filled circuit breakers, testing for turbulator erosion, trip-timing tests, trip circuit integrity checks, close circuit integrity checks, SCADA alarm and control checks, and testing of all functional parts (both electrical and mechanical) to ensure they meet the manufacturer's minimum requirements and recommended industry minimum acceptance criteria.

Reclosers, Sectionalisers and HV Overhead Line Fuses

Inspection and maintenance is undertaken every five years. This includes visual inspection, reporting on condition of insulators, handles, earth conductor rating and steelwork, operational verification of line recloser, SCADA and communications signalling, earth test, thermal vision, ultrasound tests and reporting of results. For older oil filled type models, removal of the recloser from service is required for workshop-based maintenance and testing.

ASSET RENEWAL PROGRAMME

The renewal programme for distribution switchgear is as follows:

- **RMUs:** Targeted renewal of oil filled RMUs with SF_6 is included within the AMP period;
- **ABSs:** approximately 25 units each year, prioritised by risk, are planned to be renewed. In addition, a programme has been implemented to replace manually operated ABSs with SF_6 gas-insulated switches over the AMP period. Vacuum switch units will also be considered due to environmental risk posed by possible SF_6 leaks. Many ABSs associated with 2 pole transformer structures are being removed completely and in other situations cable end switches are being replaced with solid isolating links;
- **CBs**: The CBs that exceed their life expectancy in the AMP period will be renewed. These are Alexandra St (2017), Massey St (2018), Claudelands (2020), Civic Car Park and Findlay (2022) and Barton St (2024). Replacing CBs involves considerable resource and outages on the network. Therefore where possible other asset renewals are co-ordinated at the same time. This includes protection upgrades, battery and SCADA systems;
- **Reclosers and Sectionalisers:** A small number of older oil-filled hydraulic reclosers will be systematically renewed based on our CBRM assessment. They will be replaced with new electronic controlled units over the AMP period. In addition, a number of sectionalisers installed during recent years have not worked as expected, increasing the risk to the network. These will be proactively replaced over the AMP period; and
- **HV Overhead Line Fuses:** Renewal of these assets is primarily driven by the need to renew other larger components, primarily crossarms.

8.4.19 SUMMARY OF DISTRIBUTION SWITCHGEAR RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.19 summarises Distribution Switchgear expenditure for the AMP period.

DISTRIBUTION SWITCHGEAR EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
11kV Air Break Switch	499	499	499	499	499	499	499	499	499	499
11kV Circuit Breaker	-	710	250	370	-	80	-	-	-	-
11kV Reclosers and Sectionalisers	332	332	332	332	332	332	332	332	332	332
11kV Ring Main Unit	485	432	432	432	432	432	432	432	432	380
Capital Expenditure Total	1,316	1,973	1,513	1,633	1,263	1,343	1,263	1,263	1,263	1,211
Operational Expenditure										
11kV Air Break Switch	11	11	11	11	12	11	12	12	12	13
11kV Circuit Breaker	118	122	128	128	131	129	134	137	139	142
11kV Reclosers and Sectionalisers	24	25	26	26	27	26	27	28	28	29
11kV Ring Main Unit	205	211	221	222	227	224	233	237	241	246
Operational Expenditure Total	357	368	387	388	396	391	406	414	421	429

Table 8.4.19 Distribution Switchgear Expenditure

8.4.20 SERVICE AND DISTRIBUTION PILLARS

RISKS AND ISSUES

The principal risks and issues for Service and Distribution Pillars are:

- Damaged LV pillars may pose a risk to public safety; and
- Fibreglass type pillars are fragile and prone to damage.

LV pillars are part of the LV underground network and have been identified as having the highest public safety risk among our asset classes. This is due to the higher accessibility to the public. Safety risks include the probability of electrocution following damage to the unit and live parts being exposed to public contact. Minor issues involve vegetation build up around the pillar, obsolete types of pillars and location installed e.g. inside a private property.

MAINTENANCE UNDERTAKEN

LV pillars are inspected every three years. Inspections determine the physical condition, accessibility, vegetation, and location. Maintenance on LV pillars includes lid repairs or renewal.

ASSET RENEWAL PROGRAMME

LV Pillars will be renewed based on their type, age and condition with priority given to fibreglass type pillars.

Service and Distribution Pillar CBRM models are scheduled for completion during 2016.

8.4.21 PROTECTION RELAYS

RISKS AND ISSUES

The principal risks and issues associated with protection relays are:

- A lack of spares;
- The significant cost of maintenance;
- A lack of more complex protection functionality in older electromechanical relays; and
- The inability to test electromechanical relays.

MAINTENANCE UNDERTAKEN

Inspections are undertaken every three years. Tests undertaken during inspections are dependent on the type of relay:

- For line differential relays using copper pilots three yearly tests include primary injection testing, pilot resistance checks, and insulation checks;
- Arc flash schemes, that require access to the light sensors in the switchgear, are done at nine yearly intervals to coincide with bus maintenance; and
- For all other relay's maintenance is undertaken on a three year interval to coincide with circuit breaker CB maintenance.

Modular Substation

We have set up a modular substation to expand our in-house knowledge and skills in protection and communications technology. This includes real-time simulation using similar equipment and devices found in our substations and integration with our NMS. The installed devices can be used as spares in an emergency.

ASSET RENEWAL PROGRAMME

Our renewal programme for protection relays over the AMP period includes:

- Replacement of electromechanical relays with modern numerical relays. This work will typically be undertaken in conjunction with other upgrade work at the zone substation or switching station. Priority will be on the CBD area where a substantial number of electromechanical relays operate on critical zone substation feeders; and
- Replacement of Solkor pilot wire protection on 11kV trunk feeders with numerical line differential relays. Fibre and patch panels will be installed on these sites to cater for new differential communication requirements.

In consideration of the complex nature of the works, an integrated renewal programme has been developed that will ensure timely and integration of protection, SCADA/communications, and switchgear renewals. This is reflected in the proposed 10-year spend profile.

A CBRM model for relays is scheduled to be developed during 2016.

8.4.22 SCADA AND COMMUNICATION DEVICES

RISKS AND ISSUES

The principal risks and issues associated with our SCADA and communication devices are primarily related to weak signals. Weak signals can be caused by incorrect positioning of antenna, vegetation interference, failed RTUs and batteries, the degradation of pilot communication cables, and the incompatibility of certain components.

MAINTENANCE UNDERTAKEN

SCADA and communications devices are inspected every four months. The tests and maintenance conducted on all remote station equipment include:

- Visual inspections, dusting, cleaning and minor repairs;
- Operational checks and measurements;
- Testing, calibration checks, and adjustments;
- Meter reading and downloading of data;
- Checking and reporting status indications and software error logs; and
- Maintenance of databases related to the location, maintenance history and status of equipment, and completing test sheets and reports.

Additional comprehensive SCADA 'point-to-point' indication testing is also undertaken in conjunction with CB and protection testing to minimise outage windows.

Protection interface integrity is tested through insulation resistance testing on pilot cables and 'loop-back' checks on fibre cables.

ASSET RENEWAL PROGRAMME

The Conitel Protocol RTUs are scheduled for replacement, with DNP-IP RTUs over the next five years.

CBRM models are being developed for our SCADA and communications systems, scheduled for completion during 2016.

8.4.23 LOAD CONTROL EQUIPMENT

RISKS AND ISSUES

The principal risks and issues associated with our load control injection equipment are: long lead-times on replacement parts; and compatibility issues with the SFU-G type ripple control converter.

MAINTENANCE UNDERTAKEN

The load control injection equipment is inspected twice a year. Inspections involve plant testing, visual checks and, signal strength tests. Additionally each year the static plants undergo a condition assessment and maintenance by the supplier.

ASSET RENEWAL PROGRAMME

Renewal of the SFU-G type control converters has been incorporated into the plan. The load control injection plant will not be renewed as this technology has been superseded by smart metering technology.

8.4.24 BATTERY AND CHARGER SYSTEMS

RISKS AND ISSUES

The principal risks and issues associated with our battery and charger systems are loss of control of primary equipment when battery or charger systems fail, and environmental factors such as high humidity and high temperature that can reduce life expectancy.

MAINTENANCE UNDERTAKEN

Due to their criticality, battery and charging systems are inspected bi-monthly. Tests carried out during these inspections include impedance tests, alarm tests, float voltage, and condition.

Additionally, discharge tests are carried out every two years on all zone substation and switching station battery banks to ensure that battery performance is up to standard.

Other than testing, no other maintenance is undertaken on batteries and charger systems. Faulty systems are renewed.

ASSET RENEWAL PROGRAMME

Distribution equipment batteries are renewed when they fail discharge and impedance tests.

During the AMP period we will renew old or poor condition battery bank and power supplies.
Where appropriate, some units will be replaced with dual battery banks and power supplies with higher capacities to provide greater reliability. A standardised design is now utilised for these systems.

CBRM models are being developed for battery and charger systems and are expected to be completed during 2016. It is expected that the outcomes of the risks analysis, will enable further mitigation of risks in this asset category.

8.4.25 SUMMARY OF OTHER SYSTEM FIXED ASSET RENEWAL AND MAINTENANCE EXPENDITURE

Table 8.4.25 summarises Other System Fixed Assets expenditure for the AMP period.

OTHER SYSTEM FIXED ASSETS EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure										
Protection Relays	162	712	152	172	132	282	232	82	82	82
SCADA & Comms	445	273	113	73	13	223	93	133	73	13
Service and Distribution Pillars	550	550	467	467	467	467	467	467	467	467
Capital Expenditure Total	1,157	1,535	732	712	612	972	792	682	622	562
Operational Expenditure										
Other	555	571	600	602	615	607	630	644	654	667
Protection Relays	96	99	104	104	106	105	109	111	113	115
SCADA & Comms	100	103	108	108	111	109	114	116	118	120
Service and Distribution Pillars	150	155	163	163	166	164	171	174	177	180
Operational Expenditure Total	901	928	975	977	998	985	1,024	1,045	1,062	1,082

Table 8.4.25 Other System Fixed Asset Expenditure

8.5 OVERALL EXPENDITURE SUMMARY

8.5.1 PROPOSED 10-YEAR MAINTENANCE EXPENDITURE

The 10 year maintenance expenditure forecast is relatively flat in the first few years with a lower level of maintenance expenditure in the later periods as shown in Figure 8.5.1.1. This is due to the expenditure increases being offset by decreases in the first few years, with further decreases in the later period. These variations include:

- Field data verification and accelerated inspections to improve the accuracy of asset condition data will increase maintenance costs in the first few years;
- Increased diagnostic testing will result in a slight increase in preventive maintenance costs across the AMP period;

- Implementation of new technology e.g. diagnostic measurements and mobility solutions will result in more efficient maintenance delivery and result in slightly decreased operational costs across the AMP period;
- Better asset data and condition information that would assist in maintenance prioritisation are expected to reduce maintenance costs and reduce corrective works in the later part of the AMP period; and
- Vegetation expenditure is based on our tree growth model. It predicts that fewer sites will be cut towards the end of the AMP period.

10 YEAR MAINTENANCE, VEGETATION AND FAULTS EXPENDITURE

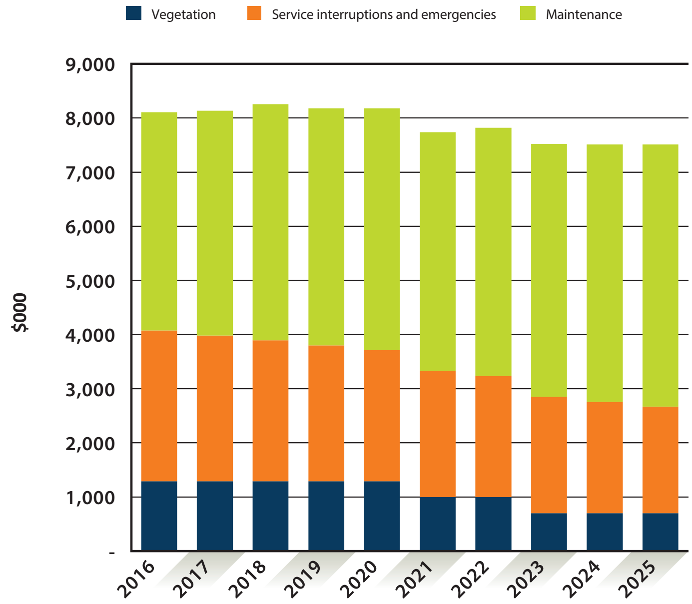


Figure 8.5.1.1 Maintenance, Vegetation and Faults Expenditure Profile

8.5.2 PROPOSED 10-YEAR RENEWAL EXPENDITURE

The 10 year renewal expenditure forecast is predominately driven by the CBRM models for most of the assets categories.

The major variances over the planning period as shown in Figure 8.5.2.1 are due to:

- Zone Substations - an upgrade at the Glasgow substation in 2020;
- Distribution Switchgear – an increase in 2017 for circuit breaker replacements;
- Distribution Substations and Transformers – decreasing spend from 2019 onwards in transformer replacements due to CBRM modelling results; and
- Distribution and LV Lines – an increasing spend mainly due to our 16mm^2 copper conductor replacement programme.

10 YEAR RENEWAL EXPENDITURE

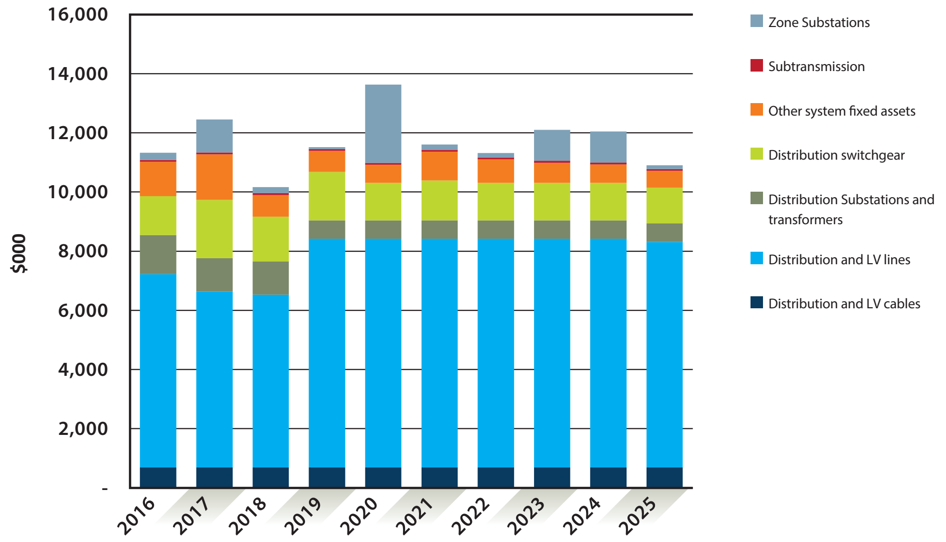


Figure 8.5.2.1 Renewal Expenditure Profile

9 SUMMARY OF EXPENDITURE FORECAST

9 SUMMARY OF EXPENDITURE FORECASTS

This chapter provides a summary of the expenditure forecasts presented and discussed in previous chapters. It provides an overview of our expenditure in a number of categories over the AMP period. The chapter is structured as follows.

- **Introduction (9.1)** describes the financial assumptions used to determine the expenditure forecasts;
- **Capital Expenditure (9.2)** provides an overview of total capital expenditure during the AMP period as described in Chapters 7 and 8; and
- **Operational Expenditure (9.3)** provides an overview of total operational expenditure during the AMP period as described in Chapter 8.

> Unless otherwise stated, figures in this chapter are on a nominal basis (i.e. include an allowance for expected price inflation).

9.1 INTRODUCTION

This section describes the inputs and assumptions used to forecast our capital and operational expenditure.

9.1.1 INTERPRETING THE FORECASTS

The forecasts presented in this chapter are a summary of the expenditure described in previous sections. They are presented here to provide a consolidated view of our expenditure across our business. The expenditure profiles cover the 10 year period of the AMP, 1 April 2015 to 31 March 2025.

As explained previously, the notation adopted in each table refers to financial year-end. For example, the 1 April 2015 to 31 March 2016 financial year is referred to as 2016.

The forecasts are also presented in nominal dollars. This means an allowance has been made for expected price inflation.

9.1.2 FORECAST INPUTS AND ASSUMPTIONS

Our forecasts rely on a number of inputs and assumptions. These include:

- Capital contributions;
- Cost of financing (FDC);
- Inflation; and
- Managing forecast uncertainty.

CAPITAL CONTRIBUTIONS

The customer works expenditure shown are the gross amounts i.e. capital contributions have not been netted out from the forecast.

COST OF FINANCING (FDC)

The cost of financing has been included in accordance with 2.2 (11) of the Electricity Distribution Services Input Methodologies Determination 2012.

INFLATION

The forecasts, unless stated otherwise, are shown in nominal terms. In this case it means we have adjusted our estimates to account for expected cost inflation. There are two main cost components to the delivery of our operations, maintenance, renewal, and capital development expenditures. These are labour and materials. The inflation adjustments used for each are:

- Labour – we have assumed 2% throughout the AMP period; and
- Materials – we have assumed 2.5% throughout the AMP period

Each expenditure category is impacted according to the composition or proportion of labour and materials required to deliver the service or asset. The table below shows the composition and resulting inflation factor used in each case.

	PROPORTION OF LABOUR IN TOTAL COST	PROPORTION OF MATERIALS IN TOTAL COST	WEIGHTED INFLATION ASSUMPTION APPLIED
Operations	100%	0%	2.00%
Maintenance	90%	10%	2.05%
Renewals	50%	50%	2.25%
Capital Development	50%	50%	2.25%

Table 9.1.2 Inflation adjustment for each expenditure category

While the assumed inflation rates provide a general trend for future labour rates and material costs, there is always an inherent level of uncertainty in such aspects. By way of example, market conditions and pricing can change with relative supply and demand pressures.

For the purposes of this AMP, we have assumed the change in labour and material is limited to the assumed inflationary pressures rather than modelling specific trends in network components, or specific trades in the labour market.

9.2 CAPITAL EXPENDITURE

This section provides an overall summary of the forecast capital expenditure by category.

9.2.1 CAPITAL EXPENDITURE SUMMARY

The expenditure is shown in two formats. The first is a breakdown according to the network level and asset classes as described in Chapters 7 and 8 and then secondly according to the regulatory categories specified by the Commerce Commission. Forecast capital expenditure is further broken down into network development, renewals and non-network capital expenditure in sections 9.2.2 to 9.2.4.

Table 9.2.1.1 shows a summary of capital expenditure over the period by development plan and by asset class.

CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GXP	818	-	-	-	4,484	3,527	-	-	-	-
Urban										
Sub transmission	47	2,139	4,687	50	52	53	54	55	56	58
Zone Substations	5,322	3,324	323	4,273	347	183	158	126	129	132
Distribution and LV lines	1,101	614	1,826	1,867	1,909	1,952	2,606	2,682	2,087	2,134
Distribution and LV cables	1,662	2,934	1,533	1,568	2,130	2,406	1,575	2,325	1,916	1,792
Distribution Substations and transformers	869	1,107	662	622	636	650	665	680	818	836
Distribution switchgear	386	885	551	658	375	449	392	401	410	367
Other system fixed assets	3,491	2,714	1,299	2,090	1,432	1,722	1,316	1,241	1,216	1,190
Other Assets	118	83	48	82	22	23	12	12	73	25
Customer	10,091	11,143	10,636	10,650	9,706	10,496	12,485	12,168	10,749	10,848
Urban Total	23,086	24,944	21,565	21,860	16,610	17,935	19,263	19,690	17,454	17,381
Rural										
Sub transmission	21	21	22	22	134	1,737	2,361	147	25	3,366
Zone Substations	1,619	690	1,797	892	5,611	129	19	1,126	3,222	20
Distribution and LV lines	7,193	7,241	7,927	9,352	9,562	9,801	10,967	9,983	10,208	9,369
Distribution and LV cables	258	264	270	276	282	289	295	302	309	316
Distribution Substations and transformers	1,978	1,834	1,769	1,207	1,178	1,205	1,232	1,260	1,288	1,317
Distribution switchgear	1,536	1,178	1,067	1,127	1,037	1,086	1,084	1,108	1,133	1,146
Other system fixed assets	251	381	165	162	135	253	200	167	151	133
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	12,855	11,608	13,016	13,039	17,939	14,500	16,158	14,094	16,335	15,667
Total Network Capital Expenditure	36,760	36,552	34,581	34,899	39,033	35,962	35,421	33,784	33,789	33,048
Non-network Capital Expenditure	5,075	2,316	4,180	2,019	3,044	2,580	2,154	3,661	3,150	1,953
Grand Total	41,834	38,868	38,761	36,918	42,077	38,542	37,575	37,444	36,940	35,001

Table 9.2.1.1 Total Capital Expenditure Forecast

Table 9.2.1.2 shows a summary of capital expenditure over the period according to the Commerce Commission's expenditure categories.

CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Consumer connection	8,152	8,377	7,807	7,758	7,588	7,758	7,933	8,111	8,294	8,480
System Growth	11,754	7,519	10,140	9,703	12,275	10,891	8,564	7,237	6,719	7,734
Asset Replacement and Renewal	11,577	13,013	10,864	12,584	15,230	13,259	13,225	14,461	14,714	13,616
Asset relocations	1,938	2,766	2,828	2,892	2,118	2,166	2,215	2,265	2,316	2,368
Quality of supply	869	889	802	711	671	686	701	717	733	750
Legislative and regulatory	394	261	107	109	-	-	-	-	-	-
Other reliability, safety and environment	2,075	3,727	2,033	1,143	1,151	1,201	2,783	992	1,014	100
Total Network Capital Expenditure	36,760	36,552	34,581	34,899	39,033	35,962	35,421	33,784	33,789	33,048
Non-network Capital Expenditure	5,075	2,316	4,180	2,019	3,044	2,580	2,154	3,661	3,150	1,953
Grand Total	41,834	38,868	38,761	36,918	42,077	38,542	37,575	37,444	36,940	35,001

Table 9.2.1.2 Total Capital Expenditure Forecast

9.2.2 NETWORK DEVELOPMENT CAPITAL EXPENDITURE

This section provides an overview of network development capital expenditure.

As discussed in detail within Chapter 7, localised areas of forecast growth and the need for quality improvements are driving network development expenditure. To illustrate the respective expenditure required for urban and rural development the expenditure has been split. Note that rural reliability is largely addressed through our renewal programme, as discussed in Chapter 8.

Table 9.2.2.1 shows the breakdown of GXP, urban and rural network development capital expenditure by asset class.

NETWORK DEVELOPMENT CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GXP	818	-	-	-	4,484	3,527	-	-	-	-
Urban										
Sub transmission	-	2,091	4,639	-	-	-	-	-	-	-
Zone Substations	5,096	2,179	130	4,229	-	-	-	-	-	-
Distribution and LV lines	128	386	1,604	1,640	1,677	1,714	2,363	2,433	1,833	1,874
Distribution and LV cables	1,218	2,480	1,069	1,093	1,644	1,910	1,068	1,807	1,385	1,249
Distribution Substations and transformers	675	931	481	492	503	514	526	538	672	687
Distribution switchgear	-	-	-	-	-	-	-	-	-	-
Other system fixed assets	2,558	1,490	681	1,473	883	864	590	594	607	621
Other Assets	118	83	48	82	22	23	12	12	73	25
Customer	8,152	8,377	7,807	7,758	7,588	8,330	10,270	9,904	8,433	8,481
Urban Total	17,945	18,015	16,459	16,767	12,317	13,355	14,829	15,287	13,004	12,937
Rural										
Sub transmission	-	-	-	-	112	1,714	2,337	123	-	3,340
Zone Substations	1,602	673	1,780	874	3,007	111	-	-	2,071	-
Distribution and LV lines	1,483	1,249	1,903	1,126	1,151	1,201	2,173	992	1,014	100
Distribution and LV cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations and transformers	818	836	748	656	615	629	643	657	672	687
Distribution switchgear	577	-	-	-	-	-	-	-	-	-
Other system fixed assets	-	-	-	-	-	-	-	-	-	-
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	4,480	2,759	4,431	2,656	4,884	3,655	5,153	1,772	3,757	4,127
Grand Total	23,242	20,774	20,890	19,423	21,685	20,537	19,982	17,059	16,761	17,064

Table 9.2.2.1 Total Network Development Capital Expenditure Forecast

Table 9.2.2.2 shows network development capital expenditure over the period according to the Commerce Commission's expenditure categories. A more detailed breakdown of expenditure within the Commerce Commissions expenditure categories can be found in Tables 9.2.2.3 to 9.2.2.7.

NETWORK DEVELOPMENT CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Consumer connection	8,152	8,377	7,807	7,758	7,588	7,758	7,933	8,111	8,294	8,480
System Growth	11,754	7,519	10,140	9,703	12,275	10,891	8,564	7,237	6,719	7,734
Quality of supply	869	889	802	711	671	686	701	717	733	750
Legislative and regulatory	394	261	107	109	-	-	-	-	-	-
Other reliability, safety and environment	2,075	3,727	2,033	1,143	1,151	1,201	2,783	992	1,014	100
Total	23,244	20,773	20,889	19,423	21,685	20,536	19,981	17,057	16,760	17,064

Table 9.2.2.2 Total Network Development Capital Expenditure Forecast

CONSUMER CONNECTION

Forecast customer connection capital expenditure is summarised in the table below.

CONSUMER CONNECTION CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
New Connections <100 amp	2,683	2,785	2,309	2,361	2,414	2,469	2,524	2,581	2,639	2,698
New Connections >=100 amp	2,103	1,889	1,878	2,249	2,299	2,351	2,404	2,458	2,513	2,570
Subdivisions	3,366	3,441	3,299	3,148	2,874	2,939	3,005	3,072	3,142	3,212
Asset Specific Pricing Customer Driven Jobs	-	261	321	-	-	-	-	-	-	-
Total	8,152	8,377	7,807	7,758	7,588	7,758	7,933	8,111	8,294	8,480

Table 9.2.2.3 Total Customer Connection Expenditure Forecast

SYSTEM GROWTH

Urban and rural system growth capital expenditure by asset class is summarised in the table below.

SYSTEM GROWTH CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GXP	818	-	-	-	4,484	3,527	-	-	-	-
Urban										
Subtransmission	-	2,091	4,638	-	-	-	-	-	-	-
Zone Substations	3,833	56	-	4,212	-	-	-	-	-	-
Distribution and LV lines	128	385	1,604	1,640	1,677	1,714	1,753	2,433	1,833	1,874
Distribution and LV cables	1,218	2,480	1,069	1,093	1,645	1,910	1,068	1,806	1,385	1,249
Distribution Substations and transformers	624	523	428	437	447	457	467	478	611	625
Distribution switchgear	-	-	-	-	-	-	-	-	-	-
Other system fixed assets	2,482	1,333	680	1,474	883	864	590	593	607	620
Other Assets	118	83	48	82	22	23	12	12	73	25
Customer	-	-	-	-	-	571	2,337	1,792	140	-
Urban Total	8,403	6,951	8,467	8,938	4,673	5,540	6,227	7,114	4,648	4,393
Rural										
Subtransmission	-	-	-	-	112	1,714	2,337	123	-	3,341
Zone Substations	1,209	568	1,673	765	3,007	111	-	-	2,071	-
Distribution and LV lines	1,324	-	-	-	-	-	-	-	-	-
Distribution and LV cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations and transformers	-	-	-	-	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-	-	-	-	-
Other system fixed assets	-	-	-	-	-	-	-	-	-	-
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	2,533	568	1,673	765	3,118	1,825	2,337	123	2,071	3,341
Grand Total	11,754	7,519	10,140	9,703	12,275	10,891	8,564	7,237	6,719	7,734

Table 9.2.2.4 Total System Growth Capital Expenditure Forecast

QUALITY OF SUPPLY

Quality of supply capital expenditure by activity is summarised in the table below.

QUALITY OF SUPPLY CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Network Upgrades due to DG applications	51	52	53	55	56	57	58	60	61	62
Power Quality - Works required to correct customer complaints	409	314	214	109	56	57	58	60	61	62
Voltage upgrade projects	409	523	535	547	559	571	584	597	611	625
Total	869	889	802	711	671	686	701	717	733	750

Table 9.2.2.5 Total Quality of Supply Capital Expenditure Forecast

LEGISLATIVE AND REGULATORY

Legislative and regulatory capital expenditure by activity is summarised in the table below.

LEGISLATIVE AND REGULATORY CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Seismic upgrades of substations	394	105	107	109	-	-	-	-	-	-
AUFLS scheme changes	-	157	-	-	-	-	-	-	-	-
Total	394	261	107	109	-	-	-	-	-	-

Table 9.2.2.6 Total Legislative and Regulatory Capital Expenditure Forecast

RELIABILITY, SAFETY AND ENVIRONMENT (RSE)

Urban and rural RSE capital expenditure by asset class is summarised in the table below.

RSE CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban										
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	1,263	2,122	130	17	-	-	-	-	-	-
Distribution and LV lines	-	-	-	-	-	-	610	-	-	-
Distribution and LV cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations and transformers	51	408	53	55	56	57	58	60	61	62
Distribution switchgear	-	-	-	-	-	-	-	-	-	-
Other system fixed assets	77	157	-	-	-	-	-	-	-	-
Other Assets	-	-	-	-	-	-	-	-	-	-
Urban Total	1,391	2,687	183	72	56	57	668	60	61	62
Rural										
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	394	105	107	109	-	-	-	-	-	-
Distribution and LV lines	158	1,249	1,903	1,126	1,151	1,201	2,173	992	1,014	100
Distribution and LV cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations and transformers	818	836	748	656	615	629	643	657	672	687
Distribution switchgear	577	-	-	-	-	-	-	-	-	-
Other system fixed assets	-	-	-	-	-	-	-	-	-	-
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	1,947	2,190	2,758	1,891	1,766	1,830	2,816	1,649	1,686	787
Grand Total	3,338	4,877	2,941	1,963	1,822	1,887	3,485	1,709	1,747	849

Table 9.2.2.7 Total Reliability, Safety and Environment Capital Expenditure Forecast

9.2.3 RENEWAL CAPITAL EXPENDITURE

This section provides an overview of our renewal capital expenditure during the AMP period.

As discussed in detail in Chapter 8 our renewal expenditure has been targeted at high risk components in the network, with a particular focus on those affecting rural performance. To illustrate the respective expenditure required in urban and rural areas our expenditure has been split.

Urban and rural renewal capital expenditure by asset class is summarised in the table below.

RENEWAL CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban										
Subtransmission	47	48	49	50	52	53	54	55	56	58
Zone Substations	225	1,145	193	44	347	183	158	126	129	132
Distribution and LV lines	973	229	223	228	233	238	243	249	254	260
Distribution and LV cables	444	454	464	475	485	496	507	519	530	542
Distribution Substations and transformers	193	177	181	130	133	136	139	142	146	149
Distribution switchgear	386	885	551	658	375	449	392	401	410	367
Other system fixed assets	933	1,224	618	616	550	858	726	648	610	569
Other Assets	-	-	-	-	-	-	-	-	-	-
Customer	1,938	2,766	2,828	2,892	2,118	2,166	2,215	2,265	2,316	2,368
Urban Total	5,140	6,929	5,107	5,093	4,293	4,580	4,435	4,405	4,451	4,445
Rural										
Subtransmission	21	21	22	22	23	23	24	24	25	25
Zone Substations	17	17	17	18	2,604	19	19	1,126	1,151	20
Distribution and LV lines	5,710	5,992	6,024	8,226	8,411	8,600	8,794	8,991	9,194	9,269
Distribution and LV cables	258	264	270	276	282	289	295	302	309	316
Distribution Substations and transformers	1,160	998	1,020	551	564	576	589	603	616	630
Distribution switchgear	959	1,178	1,067	1,127	1,037	1,086	1,084	1,108	1,133	1,146
Other system fixed assets	251	381	165	162	135	253	200	167	151	133
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	8,375	8,850	8,585	10,383	13,055	10,845	11,004	12,322	12,578	11,539
Grand Total	13,516	15,779	13,692	15,476	17,348	15,425	15,440	16,726	17,029	15,984

Table 9.2.3.1 Total Renewal Capital Expenditure Forecast

Table 9.2.3.2 shows renewal capital expenditure over the period according to the Commerce Commission's expenditure categories. A more detailed breakdown of expenditure within the Commerce Commissions expenditure categories can be found in Tables 9.2.3.3 and 9.2.3.4.

RENEWAL CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Asset Replacement and Renewal	11,577	13,013	10,864	12,584	15,230	13,259	13,225	14,461	14,714	13,616
Asset relocations	1,938	2,766	2,828	2,892	2,118	2,166	2,215	2,265	2,316	2,368
Total	15,532	17,796	15,710	17,495	19,368	17,446	17,462	18,749	19,053	18,009

Table 9.2.3.2 Total Renewal Capital Expenditure Forecast

ASSET REPLACEMENT AND RENEWAL (ARR)

The breakdown of urban and rural ARR capital expenditure by asset class is summarised in the table below.

ARR CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban										
Sub transmission	47	48	49	50	52	53	54	55	56	58
Zone Substations	225	1,145	193	44	347	183	158	126	129	132
Distribution and LV lines	973	229	223	228	233	238	243	249	254	260
Distribution and LV cables	444	454	464	475	485	496	507	519	530	542
Distribution Substations and transformers	193	177	181	130	133	136	139	142	146	149
Distribution switchgear	386	885	551	658	375	449	392	401	410	367
Other system fixed assets	933	1,224	618	616	550	858	726	648	610	569
Other Assets	-	-	-	-	-	-	-	-	-	-
Urban Total	3,202	4,163	2,279	2,201	2,174	2,414	2,220	2,140	2,135	2,077
Rural										
Sub transmission	21	21	22	22	23	23	24	24	25	25
Zone Substations	17	17	17	18	2,604	19	19	1,126	1,151	20
Distribution and LV lines	5,710	5,992	6,024	8,226	8,411	8,600	8,794	8,991	9,194	9,269
Distribution and LV cables	258	264	270	276	282	289	295	302	309	316

ARR CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Distribution Substations and transformers	1,160	998	1,020	551	564	576	589	603	616	630
Distribution switchgear	959	1,178	1,067	1,127	1,037	1,086	1,084	1,108	1,133	1,146
Other system fixed assets	251	381	165	162	135	253	200	167	151	133
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total`	8,375	8,850	8,585	10,383	13,055	10,845	11,004	12,322	12,578	11,539
Grand Total	11,577	13,013	10,864	12,584	15,230	13,259	13,225	14,461	14,714	13,616

Table 9.2.3.3 Total Asset Replacement and Renewal Capital Expenditure Forecast

ASSET RELOCATION

Asset relocation capital expenditure by activity is summarised in the table below.

ASSET RELOCATION CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Relocations	47	48	49	1,014	1,001	1,023	1,046	1,070	1,094	1,119
Undergrounding	256	1,046	1,069	1,093	1,118	1,143	1,169	1,195	1,222	1,249
Transit Hamilton Bypass	614	732	855	785	-	-	-	-	-	-
Transit Huntly Bypass	614	523	428	-	-	-	-	-	-	-
Longswamp	409	418	428	-	-	-	-	-	-	-
Total	1,938	2,766	2,828	2,892	2,118	2,166	2,215	2,265	2,316	2,368

Table 9.2.3.4 Total Asset Relocation Capital Expenditure Forecast

9.2.4 NON-NETWORK CAPITAL EXPENDITURE

The breakdown of non-network capital expenditure by asset type is summarised in the table below.

NON-NETWORK CAPITAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Computer Equipment	460	314	748	437	335	800	467	358	855	500
Computer Software	1,830	857	2,031	1,126	1,632	960	1,075	2,449	1,808	1,074
Plant and Equipment	776	260	245	250	256	262	312	319	326	333
Motor Vehicles	2,008	884	1,156	205	821	559	300	534	161	46
Total	5,075	2,316	4,180	2,019	3,044	2,580	2,154	3,661	3,150	1,953

Table 9.2.4 Non-Network Capital Expenditure Forecast

9.3 OPERATIONAL EXPENDITURE

This Section provides an overall summary of the forecast operational expenditure by category.

9.3.1 OPERATIONAL EXPENDITURE SUMMARY

The expenditure is shown in two formats. The first is a breakdown according to the network level and asset classes as described in Chapter 8 and then secondly according to the regulatory categories specified by the Commerce Commission. Forecast operational expenditure is further broken down into network and non-network in sections 9.3.2 and 9.3.3.

Table 9.3.1.1 in following page shows a summary of operational expenditure over the AMP period by development plan and by asset class.

OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban										
Subtransmission	42	45	48	49	51	51	54	56	59	61
Zone Substations	472	497	532	544	568	572	606	632	655	681
Distribution and LV lines	538	564	606	619	645	651	689	719	745	775
Distribution and LV cables	141	148	158	162	168	169	180	187	194	202
Distribution Substations and transformers	321	337	361	370	385	389	411	429	445	463
Distribution switchgear	200	210	225	231	240	242	257	267	277	288
Other system fixed assets	2,795	2,791	2,799	2,780	2,768	2,734	2,732	2,716	2,695	2,675
Other Assets	-	-	-	-	-	-	-	-	-	-
Urban Total	4,510	4,593	4,730	4,755	4,826	4,807	4,930	5,006	5,072	5,146
Rural										
Subtransmission	16	18	18	18	20	20	21	22	23	23
Zone Substations	211	222	238	243	253	255	271	282	293	304
Distribution and LV lines	2,009	2,071	2,152	2,198	2,260	1,968	2,041	1,750	1,801	1,857
Distribution and LV cables	41	43	46	47	49	50	52	54	56	59
Distribution Substations and transformers	354	372	399	408	425	428	454	473	491	510
Distribution switchgear	165	173	186	190	198	200	211	220	228	238
Other system fixed assets	967	981	1,003	1,006	1,017	1,011	1,030	1,042	1,050	1,061
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	3,765	3,879	4,042	4,110	4,222	3,932	4,080	3,844	3,942	4,051
Total Network Operational Expenditure	8,274	8,472	8,772	8,865	9,048	8,739	9,010	8,850	9,014	9,197
Non- Network Operational Expenditure	13,163	13,587	14,030	14,209	14,388	14,603	14,960	15,208	15,520	15,899
Grand Total	21,436	22,058	22,801	23,075	23,436	23,341	23,971	24,057	24,533	25,097

Table 9.3.1.1 Total Operational Expenditure Forecast

Table 9.3.1.2 below shows total operational expenditure by Commerce Commission expenditure category.

OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Service interruptions and emergencies	2,842	2,806	2,767	2,725	2,680	2,633	2,582	2,528	2,471	2,410
Vegetation management	1,316	1,343	1,371	1,399	1,428	1,129	1,153	823	840	857
Routine and corrective maintenance and inspection	2,011	2,112	2,265	2,318	2,414	2,432	2,579	2,687	2,787	2,898
Asset replacement and renewal	2,103	2,209	2,369	2,425	2,526	2,544	2,698	2,811	2,915	3,032
Total Network Operational Expenditure	8,274	8,472	8,772	8,865	9,048	8,739	9,010	8,850	9,014	9,197
Non- Network Operational Expenditure	13,163	13,587	14,030	14,209	14,388	14,603	14,960	15,208	15,520	15,899
Grand Total	21,436	22,058	22,801	23,075	23,436	23,341	23,971	24,057	24,533	25,097

Table 9.3.1.2 Total Operational Expenditure Forecast

9.3.2 NETWORK OPERATIONAL EXPENDITURE

This section provides an overview of network operational expenditure. The breakdown of the network operational expenditure by activity is summarised in the table below. A more detailed breakdown of expenditure within the Commerce Commissions expenditure categories can be found in Tables 9.3.2.2 to 9.3.2.5.

NETWORK OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Service interruptions and emergencies	2,842	2,806	2,767	2,725	2,680	2,633	2,582	2,528	2,471	2,410
Vegetation management	1,316	1,343	1,371	1,399	1,428	1,129	1,153	823	840	857
Routine and corrective maintenance and inspection	2,011	2,112	2,265	2,318	2,414	2,432	2,579	2,687	2,787	2,898
Asset replacement and renewal	2,103	2,209	2,369	2,425	2,526	2,544	2,698	2,811	2,915	3,032
Total	8,273	8,470	8,772	8,866	9,048	8,738	9,011	8,849	9,013	9,198

Table 9.3.2.1 Total Network Operational Expenditure Forecast

SERVICE INTERRUPTION AND EMERGENCY MAINTENANCE (SIE)

The breakdown of SIE maintenance expenditure by voltage level is summarised in the table below.

SIE OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
High Voltage	654	645	636	627	616	606	594	581	568	554
Low Voltage	2,189	2,161	2,130	2,098	2,064	2,027	1,988	1,947	1,902	1,856
Total	2,842	2,806	2,767	2,725	2,680	2,633	2,582	2,528	2,471	2,410

Table 9.3.2.2 Total Service Interruption and Emergency Maintenance Expenditure Forecast

VEGETATION MANAGEMENT

Forecast vegetation management over the AMP period is summarised in the table below.

VEGETATION OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Distribution and LV lines	1,316	1,343	1,371	1,399	1,428	1,129	1,153	823	840	857
Total	1,316	1,343	1,371	1,399	1,428	1,129	1,153	823	840	857

Table 9.3.2.3 Total Vegetation Management Operational Expenditure Forecast

ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTION (RCI)

The breakdown of RCI operational expenditure between urban and rural network and asset class is summarised in the following table.

RCI OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban										
Subtransmission	42	44	47	49	51	51	54	56	58	61
Zone Substations	346	364	390	399	416	419	444	463	480	499
Distribution and LV lines	54	56	60	62	64	65	69	72	74	77
Distribution and LV cables	2	2	2	2	2	2	2	2	2	2
Distribution Substations and transformers	252	265	284	291	303	305	324	337	350	364
Distribution switchgear	172	181	194	199	207	209	221	230	239	249
Other system fixed assets	185	195	209	213	222	224	238	248	257	267
Other Assets	-	-	-	-	-	-	-	-	-	-
Urban Total	1,054	1,107	1,187	1,215	1,265	1,274	1,351	1,408	1,460	1,519
Rural										
Subtransmission	16	17	18	19	20	20	21	22	23	24
Zone Substations	137	144	155	158	165	166	176	183	190	198
Distribution and LV lines	281	295	316	324	337	340	360	375	389	405
Distribution and LV cables	6	6	7	7	7	7	8	8	8	9
Distribution Substations and transformers	245	258	276	283	294	297	315	328	340	354
Distribution switchgear	73	77	83	84	88	89	94	98	102	106
Other system fixed assets	198	208	223	228	238	239	254	265	274	285
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	957	1,005	1,078	1,103	1,149	1,158	1,228	1,279	1,327	1,380
Grand Total	2,011	2,112	2,265	2,318	2,414	2,432	2,579	2,687	2,787	2,898

Table 9.3.2.4 Total Routine and Corrective Maintenance and Inspection Operational Expenditure Forecast

ASSET REPLACEMENT AND RENEWAL (ARR) MAINTENANCE

The breakdown of ARR operational expenditure between urban and rural network and asset class is summarised in the table below.

ARR OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Urban										
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	126	133	142	145	152	153	162	169	175	182
Distribution and LV lines	484	508	545	558	581	585	621	647	671	698
Distribution and LV cables	139	146	156	160	167	168	178	185	192	200
Distribution Substations and transformers	69	72	78	79	83	83	88	92	95	99
Distribution switchgear	27	29	31	32	33	33	35	37	38	40
Other system fixed assets	329	346	371	379	395	398	422	440	456	474
Other Assets	-	-	-	-	-	-	-	-	-	-
Urban Total	1,175	1,234	1,323	1,354	1,410	1,421	1,506	1,570	1,628	1,693
Rural										
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	74	77	83	85	89	89	95	99	102	106
Distribution and LV lines	413	433	465	475	495	499	529	551	572	595
Distribution and LV cables	35	36	39	40	42	42	45	46	48	50
Distribution Substations and transformers	109	114	122	125	130	131	139	145	151	157
Distribution switchgear	92	96	103	106	110	111	118	122	127	132
Other system fixed assets	208	218	234	239	249	251	266	277	288	299
Other Assets	-	-	-	-	-	-	-	-	-	-
Rural Total	929	976	1,046	1,071	1,115	1,124	1,191	1,241	1,287	1,339
Grand Total	2,103	2,209	2,369	2,425	2,526	2,544	2,698	2,811	2,915	3,032

Table 9.3.2.5 Total Asset Replacement and Renewal Operational Expenditure Forecast

9.3.3 NON-NETWORK OPERATIONAL EXPENDITURE

The breakdown of non-network operational expenditure by Commerce Commission expenditure category is summarised in the table below. The spend profile over the 10 years remains relatively flat in real terms with increases mainly driven by underlying inflation.

NON-NETWORK OPERATIONAL EXPENDITURE ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
System operations and network support	5,042	5,144	5,413	5,361	5,414	5,445	5,557	5,671	5,787	5,906
Business support	8,121	8,444	8,617	8,848	8,974	9,158	9,403	9,537	9,733	9,993
Total	13,163	13,587	14,030	14,209	14,388	14,603	14,960	15,208	15,520	15,899

Table 9.3.3 Total Non-Network Operational Expenditure Forecast

APPENDICES

APPENDIX A: GLOSSARY

ABBREVIATION	DESCRIPTION
AHI	Asset Health Index
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air Break Switch
AC	Alternating Current
ACSR	Aluminium Conductor Steel Reinforced
AIS	Air Insulated Switchgear
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
AUFLS	Automatic Under Frequency Load Shedding
CB	Circuit Breaker
CBRM	Condition Based Risk Management
CDEM	Civil Defence Emergency Management
Code	Electricity Industry Participation Code 2010
CoF	Consequences of Failure
DC	Direct Current
DGA	Dissolved Gas Analysis
DMS	Distribution Management System
DRC	Disaster Recovery Centre
EDB	Electricity Distribution Business
ENA	Electricity Networks Association
ERP	Enterprise Resource Planning
EV	Electric Vehicle
FDC	Cost of financing
FMEA	Failure Modes and Effects Analysis
GFN	Ground Fault Neutraliser
GIS	Gas Insulated Switchgear
GeoIS	Geographic Information System

ABBREVIATION	DESCRIPTION
GWh	Gigawatt Hour
GXP	Grid Exit Point
HI	Health Index
HILP	High Impact Low Probability
HV	High Voltage
ICP	Installation Control Point
IT	Information Technology
kV	Kilovolts
kW	Kilowatt
LTIFR	Lost-time Injury Frequency Rates
LV	Low Voltage
MVA	Mega Volt Ampere
MVA	Mega Volt Ampere
MW	Megawatt
N	N system security means that the system is not able to tolerate the failure of any single component in the network. Any failure will result in a loss of supply
N-1	N-1 means that the system must be able to tolerate the failure of any single component in the network without affecting the supply of electricity
NMS	Network Management System
NPV	Net Present Value
OH	Overhead Lines
OLTC	On-Load Tap Changer
OMS	Outage Management System
P1	Priority 1
PCD	Post Contingent Demand
PCR	Post Contingent Rating
PD	Partial Discharge
PDD	Project Definition Document
PILC	Paper insulated, lead covered
PoF	Probability of Failure

ABBREVIATION	DESCRIPTION
PPE	Personal Protective Equipment
PV	Photovoltaic
RAMC	Risk and Audit Management Committee
RCA	Root Cause Analysis
RCM	Reliability Centred Maintenance
RFP	Request for Proposals
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Systems Applications and processes
SCADA	Supervisory Control and Data Acquisition
SF_6	Sulphur Hexafluoride
SFRA	Sweep Frequency Response Analysis
SO	System Operator
TRIFR	Total Recordable Injury Frequency Rate
Trust	WEL Energy Trust
UG	Underground Assets
VoLL	Value of Lost Load
WEL	WEL Networks Ltd
WELG	Waikato Engineering Lifelines Group
XLPE	Cross linked polyethene

APPENDIX B: CBRM

CBRM is a methodology for establishing the optimum level of renewals developed by EA Technology, a UK based energy consultancy. The methodology assists electricity distribution businesses to deliver effective asset related risk management.

CBRM is a structured process that combines asset information, engineering knowledge and practical experience to estimate future condition, performance and risk of network assets.

The CBRM process can be summarised as follows:

1. **Asset condition –** 'Health indices' for individual assets are derived and built for different assets categories. Current health indices are measured on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst.
2. **Link current condition to performance** – Health indices are calibrated against relative probability of failure (PoF). The health index / PoF relationship for an asset class is determined by matching the health index profile with the recent failure rate.
3. **Estimate future condition and performance** – Knowledge of asset degradation is used to 'age' health indices. The ageing rate for an individual asset is dependent on its initial health index and operating conditions. Future failure rates can then be calculated from aged health index profiles and the previously defined health index / PoF relationship.
4. **Evaluate potential interventions in terms of PoF** – the effect of potential renewal, refurbishment or changes to maintenance regimes can then be modelled and the future health index profiles and failure rates modified accordingly.
5. **Define and weigh consequences of failure (CoF)** – a consistent framework is defined and populated in order to evaluate consequences in significant categories such as network safety, performance, financial and environment. The consequence categories are weighted to relate them to a common relative monetary ($) unit.
6. **Build risk model** – For an individual asset, its probability and consequence of failure are combined to quantify risk. The total risk associated with an asset category is then obtained by summing the risk of the individual assets.
7. **Evaluate potential interventions in terms of risk** – the effect of potential renewal, refurbishment or changes to maintenance regimes can be modelled to quantify the potential relative risk reduction associated with different strategies.
8. **Review and refine information and process** – Building and managing a risk-based process on the basis of asset specific information is not a one-off process. The initial application will deliver results based on available information and, crucially, identify opportunities for ongoing improvement that can be used to progressively build an improved asset information framework.

It is important to emphasise that the methodology is flexible enough to address the specific characteristics and operational context for each category of assets. How we approach the key components of the CBRM process is described below.

DEFINE ASSET CONDITION

The first stage in the CBRM process is to derive a numeric representation of the condition of each asset in the form of an AHI. Essentially, the AHI is a means of combining information that relate to its age, environment, risk and duty, as well as specific condition and performance information to give comparable measure of condition for individual assets in terms of proximity to end of life and PoF.
Figure B.1 in the following page illustrates the AHI.

CONDITION	HEALTH INDEX	REMNANT LIFE	PROBABILITY OF FAILURE
Bad	10	At EOL (<5 years)	High
Poor		5-10 years	Medium
Fair		10-20 years	Low
Good	0	>20 years	Very low

Figure B.1 CBRM Health Indices

The AHI represents the extent of degradation as follows:

Low values (in the range 0 to 4) - represent some observable or detectable deterioration at an early stage. This may be considered as normal ageing, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the PoF remains very low and the condition and PoF would not be expected to change significantly for some time.

Medium values (in the range 4 to 7) - represent significant deterioration, with degradation processes starting to move from normal ageing to processes that potentially threaten failure. In this condition, the PoF, although still low, is just starting to rise and the rate of further degradation is increasing.

High values (in the range > 7) - represent serious deterioration; i.e. advanced degradation processes now reaching the point that they actually threaten failure. In this condition the PoF is significantly higher and the rate of further degradation will be relatively rapid.

The detail of the AHI formulation is inevitably different for each asset category, reflecting the different information and the different rates of degradation.

CONDITION RELATED PROBABILITY OF FAILURE (POF)

The second important relationship in CBRM is that between the AHI and the condition related PoF. This relationship is shown schematically (solid line) in Figure B.2.

RELATIONSHIP BETWEEN AHI AND POF

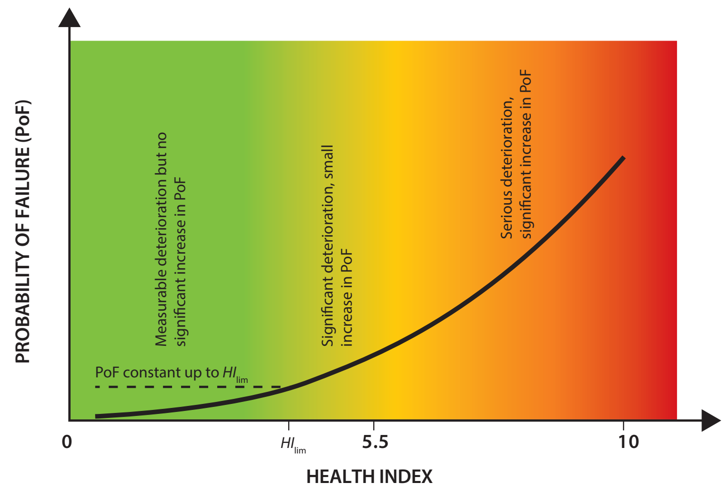


Figure B.2 Relationship between AHI and PoF

The relationship between the AHI and the PoF is non-linear. Under normal conditions, an asset can accommodate significant degradation with very little effect on the risk of failure. Conversely, once the degradation becomes significant or widespread, the risk of failure rapidly increases.

ASSET END OF LIFE

Adopting a consistent scale for the initial definition of condition for all asset types provides a basis for calibrating the AHI values and a basis for defining end of life. In CBRM terminology, end of life can be defined as when the condition related probability of failure becomes unacceptable.

CONSEQUENCES

The risk associated with any asset is a function of the PoF and the CoF. Four categories capture the key (quantifiable) CoF that affect all distribution businesses. These are shown in Figure B.3 together with their units of measurement.

CONSEQUENCE CATEGORY	CONSEQUENCE UNITS
Network performance	- Potential loss of system availability
Safety	- Number of fatalities - Number of major injuries - Number of minor injuries
Financial (e.g. cost of repairs / replacement)	- Money ($)
Environmental impact	- Volume of oil spilled - Volume of SF_6 lost - Number of fires with significant smoke / pollution - Volume of waste created - Scale of disturbance (traffic / noise)

Figure B.3 Consequences Categories and their Units

CRITICALITY

The severity of the consequences associated with an event will vary depending on factors such as the physical location of the asset, the potential load interrupted by the fault, the accessibility of the asset for repair and the cost of replacement. In order to estimate the relative significance of a fault or failure, it is necessary to establish the criticality of an individual asset for each consequence category. This has been achieved for each asset group and consequence category by initially identifying the significant factors that affect the relative criticality, and then defining the factors using a number of levels or bands. Within CBRM criticality factor values are determined based on the relative weighting of the parameter compared to the average.

RISK

Risk can be described as the possibility of misfortune or loss and is generally defined as the combination of:

- the probability / likelihood of an event occurring; and
- the resulting consequences / impacts if the event occurs.

The outcome from CBRM models is a risk analysis for each individual asset category.
Different risk outcomes arise from different renewal scenarios over the AMP period.
The scenarios considered included:

***"Do nothing"* –** this scenario assumes NO investment within the planning period

***"Current"* –** this scenario shows the current year's investment

***"Re-prioritised"* –** this scenario shows optimum investment using CBRM outcomes with the current year's investment

***"Higher spend, No risk increase"* –** this scenario simulates that year-10 (Y10) risks are maintained in the current year's (Y0) level with higher investment requirement

***"Highest spend, Minimum risks"* –** this scenario assume maximum investment to get the risks to the minimum level in year 10

Using the scenarios above, the optimal renewal programme is identified for each individual asset category. The *"Do nothing"* scenario generally demonstrates the level of risks involved per asset category and provides a good indication on the required level of investment priority.

Individual asset risk profiles with their corresponding mitigation programmes are aggregated to determine the overall risk profile for an asset category.

APPENDIX C: INFORMATION DISCLOSURE COMPLIANCE

REFERENCE	REQUIREMENT	REF
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.	Plan Summary
Background and Objectives		
3.2	The AMP must include details of the background and objectives of the EDB's asset management and planning processes.	Throughout the document
Purpose Statement		
3.3	The AMP must include a purpose statement that:	
3.3.1	Makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes.	1.1
3.3.2	States the corporate mission or vision as it relates to asset management.	1.1
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process.	1.1
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management.	1.1
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes and plans.	1.1
AMP 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.	1.1
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	1.1
Stakeholder Interests		
3.6	The AMP must include a description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates:	2.1.3; 4.1
3.6.1	The AMP must include a description of how the interests of stakeholders are identified.	2.1.3; 4.1
3.6.2	The AMP must include a description of what these interests are.	2.1.3; 4.1
3.6.3	The AMP must include a description of how these interests are accommodated in asset management practices.	4.1
3.6.4	The AMP must include a description of how conflicting interests are managed.	4.1.1
Accountabilities and Responsibilities		
3.7	The AMP must include a description of the accountabilities and responsibilities for asset management on at least three levels, including:	2.1.4
3.7.1	Governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors.	2.1.4

REFERENCE	REQUIREMENT	REF
3.7.2	Executive—an indication of how the in-house asset management and planning organisation is structured.	2.1.4
3.7.3	Field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.	5.3.2
Assumptions		
3.8	The AMP must include all significant assumptions.	7.1.1; 8.2.1; 8.3.2; 9.1.2
3.8.1	All significant assumptions must be quantified where possible.	7.1.1; 8.2.1 8.3.2; 9.1.2
3.8.2	All significant assumptions must be clearly identified in a manner that makes their significance understandable to interested persons.	7.1.1; 8.2.1; 8.3.2; 9.1.2
3.8.3	The identification of significant assumptions must include a description of changes proposed where the information is not based on the EDB's existing business.	Throughout the document
3.8.4	The identification of significant assumptions must include a description of the sources of uncertainty and the potential effect of the uncertainty on the prospective information.	Throughout the document
3.8.5	The identification of significant assumptions must include a description of the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	9
Material Difference in Information		
3.9	The AMP must include a description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures.	7.2.1
Asset Management Strategy and Delivery		
3.10	The AMP must include an overview of asset management strategy and delivery.	4.2
Systems and Information Management Data		
3.11	The AMP must include an overview of systems and information management data.	3.9.4
3.12	The AMP must include a statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data.	Throughout the document.
Asset Management Processes		
3.13	The AMP must include a description of the processes used within the EDB for:	
3.13.1	Managing routine asset inspections and network maintenance.	8.4
3.13.2	Planning and implementing network development projects.	7.1
3.13.3	Measuring network performance.	6.6
3.14	The AMP must include an overview of asset management documentation, controls and review processes.	4.3
Communication Processes		
3.15	The AMP must include an overview of communication and participation processes.	4.1
Financial Values		
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	9.1.2

REFERENCE	REQUIREMENT	REF
Disclosure Requirements		
3.17	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Throughout the document
Assets covered		
4	The AMP must provide details of the assets covered, including:	
4.1	A high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including:	2.3
4.1.1	The region(s) covered.	2.3
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities.	2.2.2
4.1.3	A description of the load characteristics for different parts of the network.	2.2.3
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.2.3
Network Configuration		
4.2	The AMP must provide a description of the network configuration, including:	
4.2.1	Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point.	2.2.3; Plan Summary
4.2.2	A description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings.	2.3.1; 7.2
4.2.3	A description of the distribution system, including the extent to which it is underground.	2.3.1
4.2.4	A brief description of the network's distribution substation arrangements.	2.3.1
4.2.5	A description of the low voltage network including the extent to which it is underground.	2.3.1
4.2.6	An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	3.8; 3.9
Sub-networks		
4.3	If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network.	No sub-networks exist that meet disclosure threshold in definitions
Network Asset Information		
4.4	The AMP must describe the network assets by providing the following information for each asset category by-	
4.4.1	Voltage levels.	3
4.4.2	Description and quantity of assets.	3
4.4.3	Age profile.	3

REFERENCE	REQUIREMENT	REF
4.4.4	A discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	3
Network Asset Information by Asset Category		
4.5	The asset categories discussed in subclause 4.4 above should include at least the following asset categories:	
4.5.1	Sub transmission.	3.2
4.5.2	Zone substations.	3.3
4.5.3	Distribution and LV lines.	3.4
4.5.4	Distribution and LV cables.	3.5
4.5.5	Distribution substations and transformers.	3.6
4.5.6	Distribution switchgear.	3.7
4.5.7	Other system fixed assets.	3.8
4.5.8	Other assets.	3.9
4.5.9	Assets owned by the EDB but installed at bulk electricity supply points owned by others;	3.10
4.5.10	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand.	3.9.1
Service Levels		
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	6.2; 6.3; 6.4; 6.5
6	The AMP must include performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next five disclosure years.	6.3.3
7	The AMP must include performance indicators for which targets have been defined in clause 5 above should also include:	6
7.1	Consumer oriented indicators that preferably differentiate between different consumer types.	6.3.3
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.	6.4; 6.5
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 stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	6.6

REFERENCE	REQUIREMENT	REF
9	Targets should be compared to historic values where available to provide context and scale to the reader.	6.6
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	There is no material change.
Network Development Planning		
11	AMPs must provide a detailed description of network development plans, including-	
11.1	A description of the planning criteria and assumptions for network development.	7.1
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described.	7.1
11.3	A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs.	5.3.2
Network Efficient Operation		
11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	
Equipment Capacity		
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network.	7.1.3
Project Prioritisation		
11.7	A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	5.1.1
Demand Forecasts		
11.8	The AMP must provide details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand.	7.2; 7.5; 7.6
11.8.1	The AMP must explain the load forecasting methodology and indicate all the factors used in preparing the load estimates.	7.2.1
11.8.2	The AMP must provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/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.	7.2.2; 7.2.3
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.	7.5; 7.6
11.8.4	The AMP must discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.	7.1.4
Network Development Options		
11.9	The AMP must provide analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including:	7.4 - 7.6
11.9.1	The reasons for choosing a selected option for projects where decisions have been made.	7.1

REFERENCE	REQUIREMENT	REF
11.9.2	The alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described.	7.1.4; 7.4 -7.6
11.9.3	The consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	6.4; 6.5
Network Development Programme		
11.10	A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	7.5; 7.6
11.10.1	A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months.	7.5; 7.6
11.10.2	A summary description of the programmes and projects planned for the following four years (where known).	7.5; 7.6
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period.	7.5; 7.6
Distributed Generation		
11.11	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.	7.1; 7.2
Non-network solutions		
11.12	A description of the EDB's policies on non-network solutions, including-	7.1
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.	7.1
11.12.2	The potential for non-network solutions to address network problems or constraints.	5.1.2
Lifecycle Asset Management Planning (Maintenance and Renewals)		
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.	8.2
Maintenance Programme		
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-	8.4
12.2.1	The approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done.	8.4
12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems.	8.4
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period.	8.4
Renewal Programme		
12.3	Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	9.4

REFERENCE	REQUIREMENT	REF
12.3.1	The processes used to decide when and whether an asset is replaced or 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.	9.4
12.3.2	A description of innovations made that have deferred asset replacement.	Throughout the document
12.3.3	A description of the projects currently underway or planned for the next 12 months.	8.4
12.3.4	A summary of the projects planned for the following four years (where known).	8.4
12.3.5	An overview of other work being considered for the remainder of the AMP planning period.	8.4
12.4	The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	8.4
Non-network Development, Maintenance and Renewal		
13	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	7.8
13.1	A description of non-network assets.	3.9
13.2	Development, maintenance and renewal policies that cover them.	7.8
13.3	A description of material capital expenditure projects (where known) planned for the next five years.	7.8.3
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	7.8
Risk Management		
14	AMPs must provide details of risk policies, assessment, and mitigation, including:	
14.1	Methods, details and conclusions of risk analysis.	4.3.2; 4.3.4
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.	4.3.6
14.3	A description of the policies to mitigate or manage the risks of events identified in subclause 14.2.	4.3.6
14.4	Details of emergency response and contingency plans.	4.3
Evaluation of Performance		
15	AMPs must provide details of performance measurement, evaluation, and improvement, including:	
15.1	A review of progress against plan, both physical and financial.	6.6.4
15.2	An evaluation and comparison of actual service level performance against targeted performance.	6.6
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 against relevant objectives of the EDB's asset management and planning processes.	4.4.4
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.	4.4.5; 6.6
Capability to Deliver		
16	AMPs 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.	Throughout the document
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1.4; 5.2

APPENDIX D: INFORMATION DISCLOSURE SCHEDULES

REPORT ON FORECAST CAPITAL EXPENDITURE

Company Name	WEL Networks Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 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	31 Mar 24	31 Mar 25
9		**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10		Consumer connection	13,611	8,152	8,377	7,807	7,758	7,588	7,758	7,933	8,111	8,294	8,480
11		System growth	18,175	11,754	7,519	10,140	9,703	12,275	10,891	8,564	7,237	6,719	7,734
12		Asset replacement and renewal	11,771	11,577	13,013	10,864	12,584	15,230	13,259	13,225	14,461	14,714	13,616
13		Asset relocations	1,596	1,938	2,766	2,828	2,892	2,118	2,166	2,215	2,265	2,316	2,368
14		Reliability, safety and environment:											
15		Quality of supply	1,493	869	889	802	711	671	686	701	717	733	750
16		Legislative and regulatory	206	394	261	107	109	-	-	-	-	-	-
17		Other reliability, safety and environment	1,576	2,075	3,727	2,033	1,143	1,151	1,201	2,783	992	1,014	100
18		**Total reliability, safety and environment**	3,275	3,338	4,877	2,941	1,963	1,822	1,887	3,485	1,709	1,747	849
19		**Expenditure on network assets**	48,428	36,760	36,552	34,581	34,899	39,033	35,962	35,421	33,784	33,789	33,048
20		Non-network assets	4,100	5,039	2,399	4,273	2,073	3,100	2,680	2,213	3,720	3,257	2,016
21		**Expenditure on assets**	52,528	41,799	38,951	38,854	36,973	42,133	38,642	37,634	37,504	37,046	35,064
22													
23	*plus*	Cost of financing	649	854	558	594	712	795	867	843	965	1,009	895
24	*less*	Value of capital contributions	4,279	3,504	4,046	3,960	4,005	3,544	3,624	3,705	3,789	3,874	3,961
25	*plus*	Value of vested assets	-	-	-	-	-	-		-	-	-	-
26													
27		**Capital expenditure forecast**	48,898	39,149	35,463	35,488	33,680	39,384	35,885	34,772	34,680	34,182	31,998
28													
29		Value of commissioned assets	38,520	30,822	33,151	27,154	31,910	29,339	35,164	26,799	33,983	26,334	31,846
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		for year ended	31 Mar 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	31 Mar 24	31 Mar 25
32			$000 (in constant prices)										
33		Consumer connection	13,611	7,973	8,012	7,303	7,097	6,789	6,789	6,789	6,789	6,789	6,789
34		System growth	18,175	11,495	7,192	9,485	8,876	10,983	9,530	7,329	6,057	5,500	6,191
35		Asset replacement and renewal	11,771	11,322	12,447	10,162	11,512	13,626	11,602	11,317	12,103	12,043	10,900
36		Asset relocations	1,596	1,896	2,646	2,646	2,646	1,895	1,895	1,895	1,895	1,895	1,895
37		Reliability, safety and environment:											
38		Quality of supply	1,493	850	850	750	650	600	600	600	600	600	600
39		Legislative and regulatory	206	385	250	100	100	-	-	-	-	-	-
40		Other reliability, safety and environment	1,576	2,030	3,564	1,902	1,046	1,030	1,051	2,382	830	830	80
41		**Total reliability, safety and environment**	3,275	3,265	4,664	2,752	1,796	1,630	1,651	2,982	1,430	1,430	680
42		**Expenditure on network assets**	48,428	35,951	34,961	32,348	31,927	34,923	31,467	30,312	28,275	27,657	26,455
43		Non-network assets	4,100	4,928	2,295	3,997	1,897	2,774	2,345	1,894	3,114	2,666	1,614
44		**Expenditure on assets**	52,528	40,879	37,256	36,345	33,824	37,697	33,812	32,206	31,388	30,323	28,069

Row		Current Year CY 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20	CY+6 31 Mar 21	CY+7 31 Mar 22	CY+8 31 Mar 23	CY+9 31 Mar 24	CY+10 31 Mar 25
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	6,117	931	347	347	347	347	347	347	347	347	347
48	Overhead to underground conversion	517	250	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
49	Research and development	-	-	-	-	-	-	-	-	-	-	-

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
58	for year ended	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	31 Mar 24	31 Mar 25
59	**Difference between nominal and constant price forecasts**	$000										
60	Consumer connection	-	179	365	504	661	799	970	1,144	1,323	1,505	1,692
61	System growth	-	259	327	655	826	1,292	1,361	1,235	1,180	1,219	1,543
62	Asset replacement and renewal	-	255	566	702	1,072	1,603	1,657	1,907	2,358	2,670	2,716
63	Asset relocations	-	43	120	183	246	223	271	319	369	420	472
64	Reliability, safety and environment:											
65	Quality of supply	-	19	39	52	61	71	86	101	117	133	150
66	Legislative and regulatory	-	9	11	7	9	-	-	-	-	-	-
67	Other reliability, safety and environment	-	46	162	131	97	121	150	401	162	184	20
68	Total reliability, safety and environment	-	73	212	190	167	192	236	503	279	317	169
69	Expenditure on network assets	-	809	1,591	2,233	2,972	4,110	4,494	5,109	5,509	6,132	6,593
70	Non-network assets	-	111	104	276	177	326	335	319	607	591	402
71	Expenditure on assets	-	920	1,695	2,509	3,148	4,436	4,829	5,428	6,115	6,723	6,995

11a(ii): Consumer Connection

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
75	*Consumer types defined by EDB**	$000 (in constant prices)					
76	Residential Customers	9,513	5,573	5,597	4,948	4,740	4,410
77	Business Customers	586	343	358	298	300	321
78	Large Customers - Low Voltage 400V	3,512	2,057	1,807	1,757	2,057	2,057
79	Large Customers - Medium Voltage 11kV	-	-	-	-	-	-
80	Large Customers - High Voltage 33kV	-	-	-	-	-	-
	Asset Specific Customers	-	-	250	300	-	-
	External Network Customers	-	-	-	-	-	-
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	13,611	7,973	8,012	7,303	7,097	6,789
83	*less* Capital contributions funding consumer connection	2,745	1,637	1,637	1,597	1,557	1,497
84	**Consumer connection less capital contributions**	10,866	6,336	6,375	5,706	5,541	5,292

11a(iii): System Growth

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
86	Subtransmission	250	800	2,000	4,339	-	4,112
87	Zone substations	8,484	4,931	598	1,565	4,553	2,690
88	Distribution and LV lines	1,035	1,420	369	1,500	1,500	1,500
89	Distribution and LV cables	649	1,191	2,372	1,000	1,000	1,471
90	Distribution substations and transformers	500	610	500	400	400	400
91	Distribution switchgear	-	-	-	-	-	-
92	Other network assets	7,258	2,542	1,354	682	1,423	810
93	**System growth expenditure**	18,175	11,495	7,192	9,485	8,876	10,983
94	*less* Capital contributions funding system growth	-	-	-	-	-	-
95	**System growth less capital contributions**	18,175	11,495	7,192	9,485	8,876	10,983

for year ended	Current Year CY 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	66	66	66	66	66
Zone substations	940	237	1,112	197	57	2,641
Distribution and LV lines	7,589	6,536	5,950	5,843	7,733	7,733
Distribution and LV cables	120	687	687	687	687	687
Distribution substations and transformers	916	1,324	1,124	1,124	624	624
Distribution switchgear	1,576	1,316	1,973	1,513	1,633	1,263
Other network assets	629	1,157	1,535	732	712	612
Asset replacement and renewal expenditure	11,771	11,322	12,447	10,162	11,512	13,626
less Capital contributions funding asset replacement and renewal	580	580	580	580	580	580
Asset replacement and renewal less capital contributions	11,191	10,742	11,867	9,582	10,932	13,046

11a(v):Asset Relocations

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Relocations	1,079	46	46	46	928	895
Undergrounding	517	250	1,000	1,000	1,000	1,000
Transit Hamilton Bypass	-	600	700	800	718	-
Transit Huntly Bypass	-	600	500	400	-	-
Longswamp	-	400	400	400	-	-
-						
**include additional rows if needed*						
All other asset relocations projects or programmes	-	-	-	-	-	-
Asset relocations expenditure	1,596	1,896	2,646	2,646	2,646	1,895
less Capital contributions funding asset relocations	854	1,094	1,527	1,527	1,527	1,094
Asset relocations less capital contributions	741	801	1,119	1,119	1,119	801

11a(vi):Quality of Supply

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Voltage upgrade projects due to monitoring	847	400	500	500	500	500
Power Quality - Works required to correct customer complaints	550	400	300	200	100	50
Network Work Due To DG applications	96	50	50	50	50	50
-						
**include additional rows if needed*						
All other quality of supply projects or programmes	-	-	-	-	-	-
Quality of supply expenditure	1,493	850	850	750	650	600
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	1,493	850	850	750	650	600

11a(vii): Legislative and Regulatory

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Seismic upgrades of substations	206	385	100	100	100	-
AUFLS scheme changes	-	-	150	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
162	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
163	**11a(viii): Other Reliability, Safety and Environment**						
164	*Project or programme**	$000 (in constant prices)					
165	UFB Fibre roll out - make ready works for the overhead fibre deployment	398	464	503	-	-	-
	Ground fault neutralizer installation for rural substations	350	-	1,035	1,500	750	750
166	Mitigation of line clashing near zone substations	-	160	80	80	80	80
167	Substation Site Security Access Project	132	90	122	16	-	-
168	Network Automation	514	564	-	-	-	-
169	Install Caro Switching Station and de commissioning of Garden Place Switching Station	54	350	1,340	-	-	-
	"Daisy-chained" Distribution Transformers Upgrade (Gap Analysis)	-	-	-	-	-	-
	Arc Flash protection installation	58	800	600	-	-	-
170	**include additional rows if needed*						
171	All other reliability, safety and environment projects or programmes	71	(398)	(115)	306	216	200
172	**Other reliability, safety and environment expenditure**	1,576	2,030	3,564	1,902	1,046	1,030
173	*less* Capital contributions funding other reliability, safety and environment	99	116	126	-	-	-
174	**Other reliability, safety and environment less capital contributions**	1,477	1,913	3,438	1,902	1,046	1,030
175							
176							
177							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181	Computer Equipment	764	450	300	700	400	300
182	Comp Software	1,280	1,790	900	1,950	1,080	1,510
183	Plant and Equipment	465	724	249	229	229	229
184	Motor Vehicles	1,591	1,964	846	1,118	188	735
185	-	-	-	-	-	-	-
186	**include additional rows if needed*						
187	All other routine expenditure projects or programmes	-	-	-	-	-	-
188	**Routine expenditure**	4,100	4,928	2,295	3,997	1,897	2,774
189	**Atypical expenditure**						
190	*Project or programme**						
191	Office and depot purchase and renovations	-	-	-	-	-	-
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**	4,100	4,928	2,295	3,997	1,897	2,774

Company Name	WEL Networks Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 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	31 Mar 24	31 Mar 25
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,558	2,842	2,806	2,767	2,725	2,680	2,633	2,582	2,528	2,471	2,410
11	Vegetation management	1,331	1,316	1,343	1,371	1,399	1,428	1,129	1,153	823	840	857
12	Routine and corrective maintenance and inspection	2,268	2,011	2,112	2,265	2,318	2,414	2,432	2,579	2,687	2,787	2,898
13	Asset replacement and renewal	1,178	2,103	2,209	2,369	2,425	2,526	2,544	2,698	2,811	2,915	3,032
14	**Network Opex**	7,335	8,273	8,470	8,772	8,866	9,048	8,738	9,011	8,849	9,013	9,198
15	System operations and network support	4,179	3,934	3,958	4,204	4,093	4,119	4,123	4,292	4,396	4,484	4,573
16	Business support	7,459	8,117	8,436	8,604	8,831	8,952	9,131	9,371	9,500	9,690	9,945
17	**Non-network opex**	11,637	12,051	12,394	12,809	12,924	13,071	13,254	13,663	13,896	14,173	14,518
18	**Operational expenditure**	18,972	20,324	20,864	21,580	21,790	22,119	21,992	22,675	22,745	23,187	23,716

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
20	for year ended	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	31 Mar 24	31 Mar 25
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,558	2,785	2,694	2,603	2,513	2,422	2,331	2,240	2,149	2,058	1,967
23	Vegetation management	1,331	1,290	1,290	1,290	1,290	1,290	1,000	1,000	700	700	700
24	Routine and corrective maintenance and inspection	2,268	1,970	2,028	2,131	2,137	2,181	2,153	2,238	2,284	2,322	2,366
25	Asset replacement and renewal	1,178	2,061	2,121	2,229	2,236	2,282	2,252	2,341	2,390	2,429	2,475
26	**Network Opex**	7,335	8,107	8,134	8,254	8,175	8,175	7,737	7,818	7,523	7,509	7,509
27	System operations and network support	4,179	3,856	3,805	3,962	3,782	3,731	3,661	3,737	3,752	3,752	3,752
28	Business support	7,459	7,958	8,108	8,108	8,158	8,108	8,108	8,158	8,108	8,108	8,158
29	**Non-network opex**	11,637	11,814	11,913	12,070	11,940	11,839	11,769	11,895	11,860	11,860	11,910
30	**Operational expenditure**	18,972	19,921	20,046	20,323	20,115	20,014	19,505	19,713	19,383	19,368	19,418
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management,											
33	reduction of energy losses	735	802	792	792	792	792	772	772	772	772	772
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	0
35	Research and Development	10	10	10	10	10	10	10	10	10	10	10
36	Insurance	463	463	463	463	463	463	463	463	463	463	463

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
40	for year ended	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	31 Mar 24	31 Mar 25
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	57	112	163	212	259	302	342	379	412	443
43	Vegetation management	-	26	53	81	109	138	129	153	123	140	157
44	Routine and corrective maintenance and inspection	-	40	84	134	181	233	279	342	403	465	532
45	Asset replacement and renewal	-	42	88	140	189	244	292	357	421	487	557
46	**Network Opex**	-	166	337	518	691	873	1,002	1,193	1,326	1,505	1,689
47	System operations and network support	-	77	154	242	312	388	462	556	644	732	822
48	Business support	-	159	328	496	672	844	1,023	1,213	1,392	1,582	1,787
49	**Non-network opex**	-	236	481	739	984	1,232	1,485	1,769	2,036	2,314	2,608
50	**Operational expenditure**	-	402	818	1,257	1,675	2,105	2,487	2,962	3,362	3,818	4,297

REPORT ON ASSET CONDITION

Company Name: WEL Networks Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

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					Asset condition at start of planning period (percentage of units by grade)						
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	1.13%	8.01%	26.27%	54.59%	10.00%	2	2.43%
11	All	Overhead Line	Wood poles	No.	7.58%	37.99%	18.62%	25.82%	10.00%	2	35.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	54.87%	45.13%	-	1	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	0.81%	1.21%	97.98%	-	1	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	0.81%	1.21%	97.98%	-	1	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	2.32%	30.12%	50.98%	11.59%	5.00%	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	49.88%	45.13%	5.00%	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	49.88%	45.13%	5.00%	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	100.00%	-	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-	3	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	N/A	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	-	-	N/A	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	N/A	-
42					Asset condition at start of planning period (percentage of units by grade)						

	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
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1.21%	-	76.92%	16.87%	5.00%	3	4.08%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	19.71%	4.99%	16.59%	58.71%	-	2	6.14%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
48	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	N/A	-
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	10.48%	8.94%	80.59%	-	1	0.25%
50	HV	Distribution Cable	Distribution UG PILC	km	-	10.48%	8.94%	80.59%	-	1	1.04%
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	84.78%	15.22%	-	2	35.44%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	0.66%	-	49.05%	45.29%	5.00%	3	7.44%
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.10%	0.30%	23.94%	59.66%	15.00%	4	2.36%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	N/A	-
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.11%	10.07%	57.56%	20.26%	10.00%	3	6.97%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	0.85%	17.48%	56.67%	25.00%	2	0.64%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.08%	5.36%	36.87%	36.70%	20.00%	3	0.63%
59	HV	Distribution Transformer	Voltage regulators	No.	-	15.83%	19.35%	59.81%	5.00%	3	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	N/A	-
61	LV	LV Line	LV OH Conductor	km	-	19.72%	5.00%	75.28%	-	1	0.06%
62	LV	LV Cable	LV UG Cable	km	-	0.24%	29.67%	70.09%	-	1	0.20%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	9.58%	17.85%	72.58%	-	1	0.08%
64	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	N/A	-
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	1.35%	17.78%	3.04%	67.84%	10.00%	3	31.31%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	5.87%	-	84.13%	10.00%	3	5.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	3	-
68	All	Load Control	Centralised plant	Lot	3.25%	-	63.09%	23.66%	10.00%	3	12.50%
69	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

REPORT ON FORECAST CAPACITY

Company Name: WEL Networks Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

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	Avalon Dr	20	23	N-1	11	87%	23	90%	No constraint within +5 years	-
10	Borman	12	23	N-1	12	52%	23	79%	Subtransmission circuit	Limited by the incoming 33kV OH conductor to 20.6MVA
11	Bryce St	15	23	N-1	15	65%	23	67%	No constraint within +5 years	-
12	Chartwell	18	23	N-1	15	78%	23	78%	No constraint within +5 years	-
13	Claudelands	20	23	N-1	20	87%	23	89%	No constraint within +5 years	-
14	Cobham	12	23	N-1	12	52%	23	52%	No constraint within +5 years	-
15	Finlayson Rd	3	7.5	N	3	40%	7.5	47%	No constraint within +5 years	-
16	Glasgow St	7	10	N	7	70%	10	79%	No constraint within +5 years	-
17	Gordonton	7	10	N	7	70%	10	74%	No constraint within +5 years	2x5MVA transformer. Due to bus arrangement, practically regarded as an N-security site to 10MVA capacity
18	Hampton Downs	1	10	N	1	10%	10	8%	No constraint within +5 years	-
19	Horotiu	9	18	N-1	9	50%	18	58%	No constraint within +5 years	-
20	Kent St	16	23	N-1	16	70%	23	70%	No constraint within +5 years	-
21	Kimihia	4	10	N	2	40%	10	38%	No constraint within +5 years	-
22	Latham Court	18	23	N-1	14	78%	23	85%	No constraint within +5 years	-
23	Hoeka Rd (planned)	0	0	N	-	-	23	40%	No constraint within +5 years	Subject to further review given the Ruakura development
24	Ngaruawahia	5	7.5	N-1	5	67%	10	52%	No constraint within +5 years	One TX suffered internal fault and decided to replace the pair. By 31st Mar, 1x7.5MVA, 1x10MVA, in +5 years, 2x10MVA
25	Peacockes Rd	14	10	N-1	12	140%	23	68%	No constraint within +5 years	Current unit 4-hours emergency rating 15MVA.
26	Pukete - LV winding 1 - Anchor (major customer)	19	30	N-1	-	63%	30	63%	No constraint within +5 years	-
27	Pukete - LV winding 2 - WEL's 11kV	8	15	N-1	8	53%	15	53%	No constraint within +5 years	3-winding tx - share with Contact Energy
28	Raglan	5	23	N	2.5	22%	23	24%	Subtransmission circuit	limited by the incoming 33kV OH conductor. Transfer capacity revised to due voltage regulation issue.
	Ruakura (Replacing TP HAM 11 kV GXP.)	36	40	N-1	17	90%	46	62%	No constraint within +5 years	Phase shift issue at 11kV, also limited 11kV connectivities to adjacent subs
	Sandwich Rd	20	23	N-1	17	87%	23	88%	No constraint within +5 years	-
	Tasman	18	23	N-1	18	78%	46	62%	No constraint within +5 years	3rd TX at TAS in +5yrs
	Te Kauwhata	4	10	N-1	4	40%	10	44%	No constraint within +5 years	TX recently replaced due to age
	Te Uku	1	10	N	1	10%	10	11%	No constraint within +5 years	-
	Wallace Rd	14	23	N-1	14	61%	23	59%	No constraint within +5 years	-
	Weavers	8	7.5	N-1	8	107%	15	57%	No constraint within +5 years	4-hours emergency rating 11.25MVA.
	Whatawhata	3	23	N	3	13%	23	14%	No constraint within +5 years	The capacity utilisation in +5year reduced due to the on-going rationalisation of WHA-WAL PDD

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)	831
33	Distribution transformer capacity (Non-EDB owned)	26
34	**Total distribution transformer capacity**	857
36	**Zone substation transformer capacity**	766

Company Name	**WEL Networks Limited**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
11	*Consumer types defined by EDB**							
12	Residential Customers		1,023	1,091	1,071	1,054	1,059	990
13	Business Customers		166	164	166	169	171	173
14	Large Customers - Low Voltage 400V		11	34	29	28	23	17
15	Large Customers - Medium Voltage 11kV		4	(5)	(5)	(5)	(5)	(5)
16	Large Customers - High Voltage 33kV		-	-	-	-	-	-
17	Asset Specific Customers		-	-	-	-	-	-
18	Unmetered Customers		10	(13)	(9)	(6)	(4)	-
19	External Network Customers		100	(38)	-	-	-	-
20	Connections total		1,204	1,284	1,261	1,246	1,248	1,175
21	**include additional rows if needed*							
22	**Distributed generation**							
23	Number of connections		216	324	454	567	680	816
24	Installed connection capacity of distributed generation (MVA)		118	118	119	119	120	120
25	**12c(ii) System Demand**							
26			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)**	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
28	GXP demand		244	248	251	253	256	258
29	*plus* Distributed generation output at HV and above		3	3	3	3	3	3
30	Maximum coincident system demand		246	250	254	256	258	260
31	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
32	Demand on system for supply to consumers' connection points		246	250	254	256	258	260
33	**Electricity volumes carried (GWh)**							
34	Electricity supplied from GXPs		940	942	945	948	951	952
35	*less* Electricity exports to GXPs		116	117	115	114	113	113
36	*plus* Electricity supplied from distributed generation		426	426	426	426	426	426
37	*less* Net electricity supplied to (from) other EDBs		(14)	(14)	(14)	(14)	(14)	(14)
38	Electricity entering system for supply to ICPs		1,264	1,265	1,271	1,274	1,278	1,279
39	*less* Total energy delivered to ICPs		1,203	1,205	1,210	1,213	1,217	1,218
40	Losses		61	60	61	61	61	61
41								
42	Load factor		59%	58%	57%	57%	57%	56%
43	Loss ratio		4.8%	4.7%	4.8%	4.8%	4.8%	4.8%

REPORT ON FORECAST INTERRUPTIONS AND DURATION

Company Name	WEL Networks Limited
AMP Planning Period	1 April 2015 – 31 March 2025
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	25.2	30.5	32.9	32.9	32.9	32.9
12	Class C (unplanned interruptions on the network)	78.0	65.3	62.1	61.7	61.4	61.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.2	0.3	0.3	0.3	0.3	0.3
15	Class C (unplanned interruptions on the network)	1.3	1.3	1.3	1.3	1.2	1.2

Company Name	**WEL Networks Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

Question No.	Function	Question	Score	Evidence—Summary
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	WEL's Asset Management policy was agreed by the Board and authorised by Chief Executive in 2007 and updated November 2012. It was used to guide the development and delivery of approved AMP. However, the effect is limited.
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?	2	There is a strong linkage with the company strategy, however not all linkages are yet complete. The aim is to address the remaining linkages over the next 12 months.
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	WEL has adopted Condition Based Risk Management as its strategy to manage asset renewals. These asset specific strategies from CBRM are documented, challenged and authorised for implementation.
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?	2	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. However, not all aspects are covered and integrated. These are currently in development.

Question No.	Function	Question	Score	Evidence—Summary
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The plan(s) were communicated to most of those responsible for delivery internally but not to all of employees or contractors. The organisation recognises improvement is needed as is working towards resolution.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. However, responsiblity for delivery management should be improved further.
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)	2	Arrangements have been made for delivery through the use of an inhouse work force. However, there is a lot of room for improvement. This is being addressed through a focus on improvement in works delivery over the next 24 months.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Recently updated plans are in place for disaster recovery and emergency response. This includes civil defence situations. Additional training has been run by civil defence staff.

Question No.	Function	Question	Score	Evidence—Summary
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Responsibilities for asset management are clearly established within the company, with roles assigned within the asset management group.
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	The recently implemented annual planning process provides financial, resource and material estimates for the financial year. This enables for adequate challenge on underlying risks and resource gaps i.e. technicians resource gap.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	This has been communicated at a high level. More detailed communication as part of the asset management process is planned.
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	Controls for outsourced activities are being further developed to close the recognised gaps. Our contracting stragety and contract templates will assist in this area.

Question No.	Function	Question	Score	Evidence—Summary
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	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan. A programme of work has been established to further consider resourse capability over the next 24 months.
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	Competency framework and identification of gaps is in place. Translation of the completency framework into training for internal resources and further alignement with strategic objectives will be carried out over the next 24 months.
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	Competency requirements are identified and assessed for all persons carrying out asset management related activities. The implementation of competency based training is being further extended over the next 24 months.

Question No.	Function	Question	Score	Evidence—Summary
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?	2	Effecitive sharing and two way communication takes place but with a limited group. Little to no sharing with a wider group.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	The organisation has established documentation that describes all the main elements of its asset management system and the interactions between them.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	The organisation has determined what its asset information system should contain in order to support its asset management system. GIS, SAP, NMS, PSS SINCAL, ICP and AIS are in place.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	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.

Question No.	Function	Question	Score	Evidence—Summary
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	The organisation has developed a process to ensure its asset management information system is relevant to its needs.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	We have some good processes for identification of asset condition assessments and risk analysis. However, there are some gaps and the integration with the company risk framework needs to be further developed.
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?	3	The identified needs are directly feed into the capability needs and any actions required are developed as part of the asset management processes.
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?	3	Staff roles have been developed to ensure compliance is achieved and requirements are included in documented procedures.

Question No.	Function	Question	Score	Evidence—Summary
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Effective processes and procedures are in place to manage and control the implementation of asset management plans during activities related to asset creation including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	Effective processes and procedures are in place to manage and control the implementation of asset management plans during activities related to asset creation including design, modification, procurement, construction and commissioning.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	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.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	WEL have defined the appropriate responsibilities and authorities through Root Cause Analysis (RCA) process. Agreed actions were put into AR system for implementation and monitoring.

Question No.	Function	Question	Score	Evidence—Summary
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Clear and active audit process are carried out via the internal audit function. However, these need to be aligned and cover the asset management practices and systems.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Mechanisms (FAR, AR or risk actions) 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, and compliance evaluation.
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	Continuous improvement process is included in asset management activities. However, the embeding and communication of these processes across the business could be improved.
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	We are involved in resarch, conferences or professional organisations. The incorporation of new asset management related technology and practices into existing practices is not sysematically carried out.

APPENDIX E: DIRECTOR CERTIFICATION

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pursuant to clause 2.9.1 of Section 2.9

We, **MARGARET DEVLIN** and **MARK FRANKLIN** being directors of WEL Networks Limited certify that, having made all reasonable enquiry, to the best of our knowledge -

a) the following attached information of WEL Networks Limited prepared for the purposes of clause 2.6.1 and 2.6.5(3) of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination; and

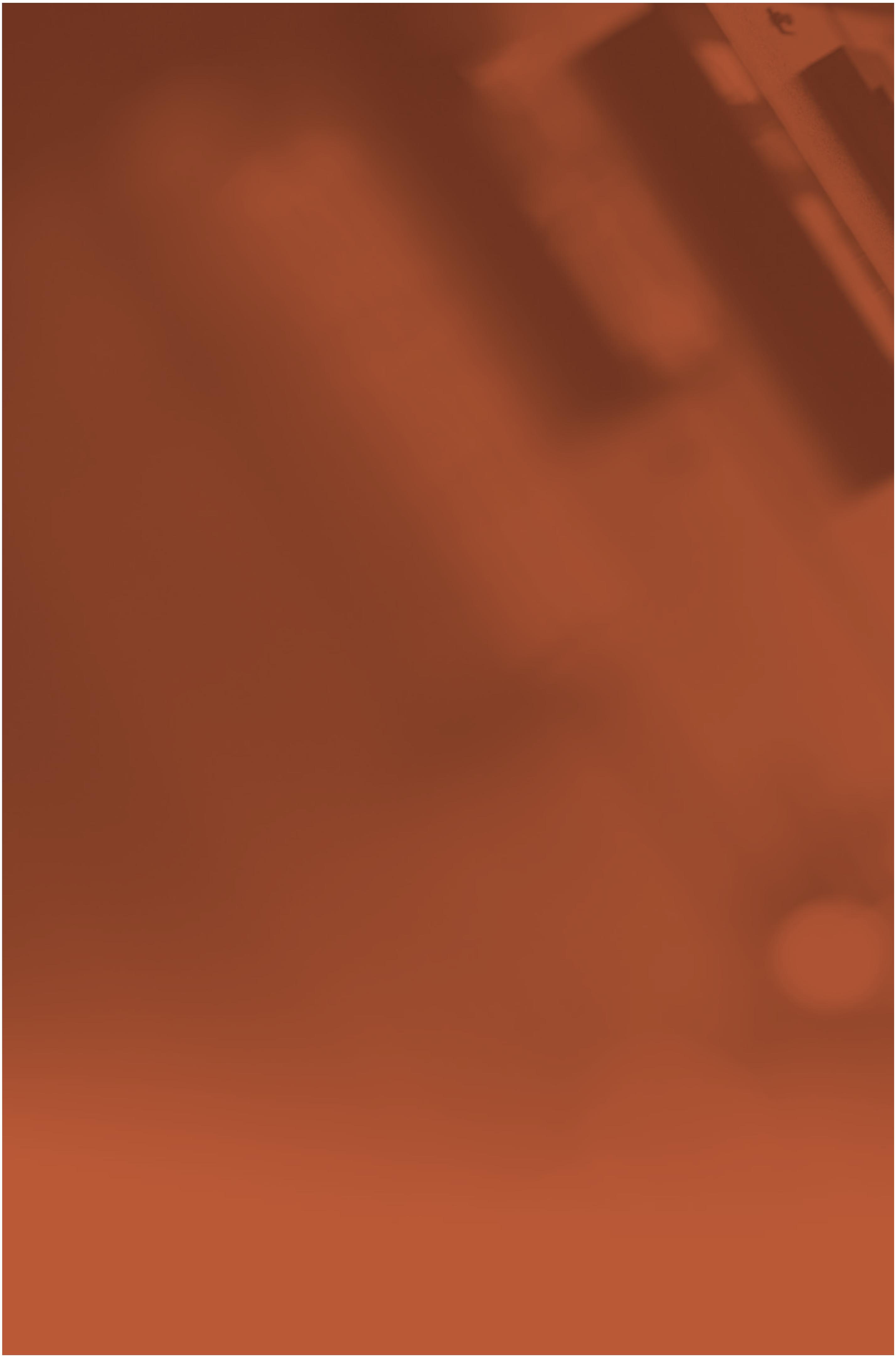
b) the prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

DIRECTOR

DATE 24 March 2015

DIRECTOR

DATE 24 March 2015



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