



**Best in Service
Best in Safety**

WEL Networks

2018 Asset Management Plan

0800 800 935 | wel.co.nz



OUR **PURPOSE**

**Enabling our
communities to thrive**

OUR **VISION**

**Creating an innovative
energy future**



FOREWORD

29 March 2018

Dear Stakeholders,

Thank you for taking the time to review the WEL Networks Limited Asset Management Plan (AMP) 2018. In essence the AMP is a snapshot of our intended capital expenditure on our network over the next ten years. It outlines the investment rationale and performance measurement of our assets and enables our community to thrive through the provision of a strong, safe, efficient and reliable supply for our customers.

The AMP reflects our vision to create an innovative energy future. This vision is clearly demonstrated through projects focused on safety, continuous improvement and understanding new technologies and how they can benefit our network and our customers.

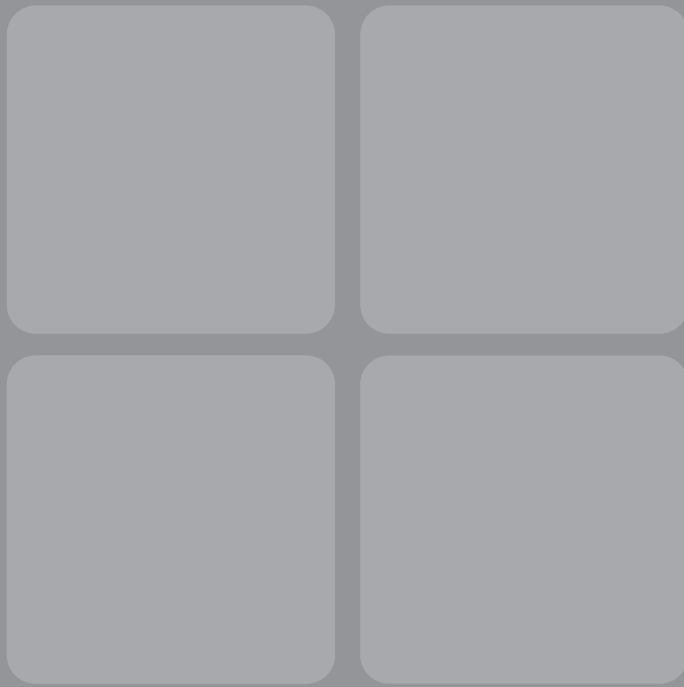
Your feedback is essential for our business to progress and I'd invite you to comment on the initiatives outlined either by emailing me (garth.dibley@wel.co.nz) or phoning **0800 800 935**.



Garth Dibley

Chief Executive





EXECUTIVE SUMMARY



EXECUTIVE SUMMARY

The Asset Management Plan (AMP) describes the nature and characteristics of our assets and investment requirements; it also provides an overview of our asset management planning, systems, procedures and practices.

The Asset Management Plan provides a clear description of the objectives, measures, and targets we aim to achieve on behalf of our stakeholders.

It describes the investments we intend to make over the next 10 years and how these activities will be managed to deliver and meet the requirements of our current and future customers.

PURPOSE

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

- providing readers with an appreciation of the nature and characteristics of the assets we own and operate
- recording the investment requirements we foresee over the AMP period so we can continue in accordance with our vision of “Creating an innovative energy future”
- providing an overview of how stakeholder interests are incorporated into our asset management planning, systems, procedures and practices
- demonstrating the interaction between the plans, our corporate vision and our asset management objectives
- conveying 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

- describing the relationship of the AMP with our strategic plans and its importance as a key planning document.

Where there is technical information in this AMP we aim 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 2018 to 31 March 2027 (AMP period). As with any long-term plan, the integrity and accuracy of the details tend to be more accurate in the earlier years as it is easier to predict the near-term state of our assets and required actions, plans and expenditure.

Approval Date

This plan was reviewed and approved by the WEL Networks Limited Board of Directors on 21 December 2017.

Scope of the AMP

This AMP covers the WEL Networks 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 community, our customers, the Commerce Commission and the Electricity Authority, our staff and contractors, and other interested parties.

OVERVIEW OF WEL NETWORKS (WEL)

WEL Networks (WEL) is owned by the WEL Energy Trust (Trust). WEL supplies electricity to the northern Waikato and small networks in Cambridge and Auckland. Hamilton is the main electrical load centre where customers enjoy a high level of reliability. Outside of Hamilton the network area is predominantly rural. WEL's network area is shown in page 18. Our network is supplied by three Grid Exit Points (GXP) owned by Transpower and two large embedded generators at Te Rapa and Te Uku. Our 33kV

subtransmission network connects the GXPs with zone substations which in turn supply our 11kV distribution network. This network feeds our low voltage network supplying the majority of our customers. Our network is more than 5,300km in length and consists of more than 200,000 individual asset components. Within the network we maintain and operate 25 zone substations and 17 switching stations (11kV) to enable a reliable supply of electricity to our customers.

The total electricity delivered in 2017 was 1,219GWh with a coincident peak demand of 273MW. We have nine broad groups of stakeholders - our customers, retailers, community, environment management, regulators, Transpower, service providers, staff, and our Board of

Directors. We have identified our customers' expectations through surveys and direct interaction to ensure we continually focus on what is important to our customers. Our stakeholder requirements are discussed in detail in Section 3.1, which drive our expenditure plans.

KEY THEMES AND INITIATIVES

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

Safety

WEL desires to be the 'Best in Safety'. To put us on the right path, we have developed a health and safety strategic road map and an annual health, safety and wellness plan. Further, we have undertaken safety initiatives to improve awareness of and our response to potential harm to the public. These are: 'Stop-for safety' exercise, Incident Causation Analysis Method, concentrated pillar inspection exercise and Health and Safety meetings with WEL contractors and WEL senior management are held bi-monthly to discuss any safety issues that arise and to share industry safety information

Our primary measure for safety performance is Total Recordable Injury Frequency Rate (TRIFR). This measures all injuries within a given period relative to the total number of hours worked and we have set our annual target to ≤ 3.5 throughout the AMP period. Details of our safety objectives, initiatives and measures are discussed in section 5.2.

Continuous Improvement

WEL Networks operates on a Continuous Improvement framework and have invested in improvements as outlined in the following sections:

- **Works management improvement**

WEL Networks has engaged a specialist asset management consultancy to support Maintenance Strategy, Asset Planning, Works Programming and Operations Scheduling to achieve a more robust delivery work flow with improved and more stable planning horizons. The same organisation is also completing a strategic level review of WEL Networks data management framework.

A work management roadmap was developed and has allowed WEL to balance resources and investment by shifting key responsibilities within teams to meet the demands for work in the different job categories on a risk-prioritised basis.

For Contract Management – WEL Networks has established a preferred contractor relationship and through a collaborative approach by both companies, efficiency gains will benefit our customers. We maintain Terms of Trade for all contractors to ensure all parties have a clear understanding of responsibilities for work engagement.

Works management improvement is further described in Chapter 4.

- **Maintenance and renewal**

Condition Base Risk Management (CBRM) models have been implemented across the key asset fleets and the results are used for the renewal strategy. Failure mode, effects and criticality analysis (FMECA) are now integrated in our maintenance strategy. Standard Maintenance Procedures for plant maintenance and corrective works were developed to improve our delivery of maintenance works.

- **Customer Initiated Work process**

A project is underway with a focus on lifting customer service within the Customer Initiated Works team. A consultant organisation was engaged to complete an initial review which included customer involvement through interviews and a series of workshops. A roadmap has been provided for WEL Networks to work through.

- **Establishing centre of excellence for smart data analytics**

Approximately 70% of WEL Networks ICPs (Installation Control Point) have a WEL-owned smart meter installed. With the data from smart meters, WEL has developed data analytics that are used for real time operation and planning activities. Benefits are, but not limited to, proactive low voltage correction, improved fault detection and management, improved network flexibility, reduction in fault call outs, revenue assurance and reduction in capital expenditure. WEL as a Metering Equipment Provider, shares these benefits and expertise with other EDB's with similar systems. Chapter 7 describes these benefits in detail.

- **Customer experience**

WEL seeks to continually improve rural reliability. To achieve this we have an annual allotment for replacement of 16mm² copper conductor, installation of isolation devices to minimise affected customers during an outage and provide network interconnections as back feed during outages. Our customer experience is further enhanced with the use of smart meter data as described above providing us with real time operational benefits including fault detection and network flexibility (minimising customer affected by faults).

- **Emerging technology**

WEL is undertaking investigation and testing of solar generation (PV) and battery storage to have a robust understanding of the capabilities, impacts and influence to the network. These investigations and tests will help us in our future network investment decisions to further our services to our stakeholders. Chapter 7 provides information on our plans and initiatives.

EXPENDITURE FORECAST

Our forecast expenditure for the 10 year AMP plan is shown below in nominal price terms.

Capital Expenditure on Assets

The capital expenditure is up by \$15M across the 10 year planning period compared to last year.

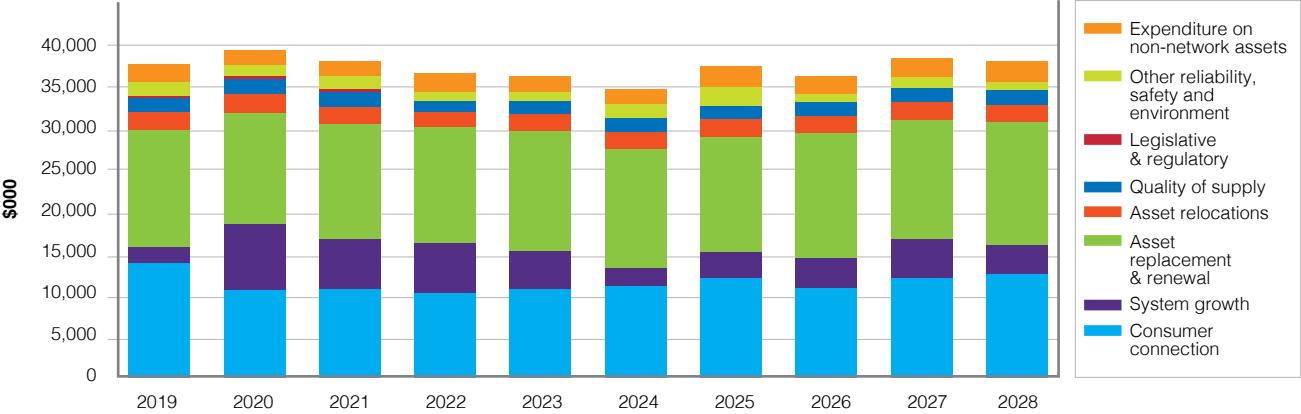
In the previous year, we raised our customer connection budget by \$12M. This year we have increased the 10 year budget by an additional \$21M. Of this increase, \$12M is expected across the three years from FY19-21. This is driven by strong regional growth in all areas.

The strong customer growth has affected our network development expenditure in two ways. Some network development is triggered and replaced by customer projects. Other network development projects have been delayed to allow customer projects to be programmed. The overall effect is a reduction in Network Development of \$8M across the 10 year period.

Asset renewal is up by a total of \$2M across the 10 year period. The majority of this expenditure is driven by safety and environmental initiatives in the following three areas:

1. **Pole replacements:** improved inspection techniques have identified further at-risk poles.
2. **Pillar replacements:** following the 2017 inspection of all pillars.
3. **Distribution transformers:** a short term boost in expenditure is required to replace transformers where we unsuccessfully attempted to extend their operational life beyond the design life.

CAPITAL EXPENDITURE ON ASSETS
In Nominal Price



Operational Expenditure

The operational expenditure gradually ramps up across the 10 year planning period. The total budget has been increased by \$4M. There are two areas where increases have been significant:

1. Budgeted maintenance of distribution lines, including additional corona inspection and additional requirements for voltage regulators.
2. Overhead costs for fault responses.

OPERATIONAL EXPENDITURE ON ASSETS
In Nominal Price

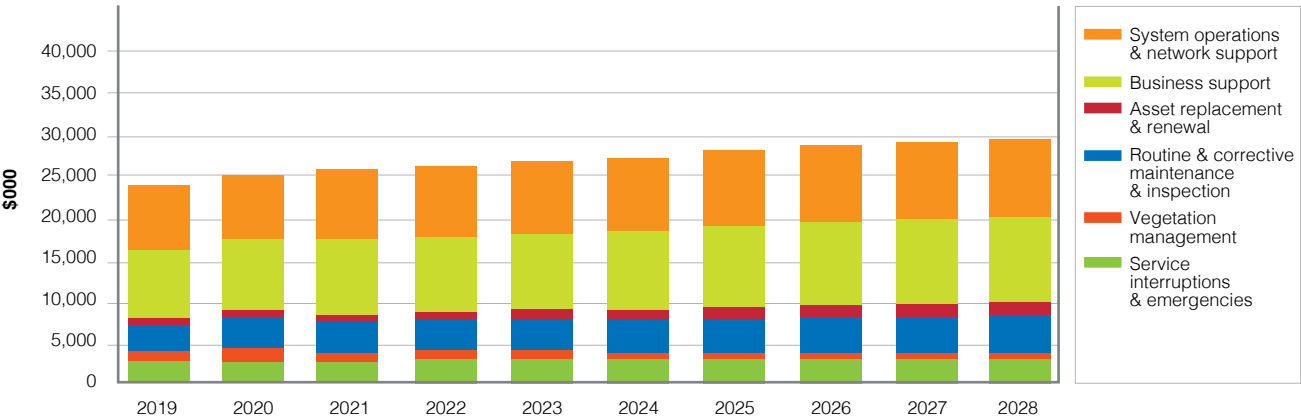


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BACKGROUND



1 BACKGROUND

This chapter introduces WEL Networks Limited (WEL) and our customers. It provides an overview of our distribution network that serves our customers

1.1 WEL OVERVIEW

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

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

1.1.1. OWNERSHIP AND GOVERNANCE

WEL Energy Trust

WEL Networks is fully community-owned, with the WEL Energy Trust as our sole shareholder. The Trustees are elected by WEL's customers, with elections held every three years. The Trust is responsible for appointing WEL's Board of Directors. The Trust monitors the performance of WEL and is consulted on strategic initiatives including asset management measures and targets. As the Trust is

community owned the income it generates benefits the community that WEL serves.

Hamilton City Council, Waikato and Waipa District Councils, and ultimately their respective communities, are our capital beneficiaries.

For more information about the Trust go to welenergytrust.co.nz

1.1.2. CORPORATE OBJECTIVES AND VALUES

Our corporate purpose, vision and values align with the Trust's purpose statement outlined below. This ensures there is a clear line of sight between the aspirations of the Trust and how we operate as a business.

Our purpose expresses why we exist as a business while our vision describes our future state while our values describe the mind-set required of our people to ensure our success in this aspiration.

WEL Energy Trust's 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.

As our communities grow WEL Networks continues to play an essential role in the region's long-term economic and social development. We do this by identifying and investing in new technologies that benefit our people, modernise our network and future proof our communities.

Our purpose expresses why we exist as a business while our vision describes our future state. Our values describe the mindset required of our people to ensure our success in this aspiration.

Our Purpose

“Enabling our communities to thrive”

Our Vision

“Creating an innovative energy future”

Our Values

A	AGILITY	We explore opportunities, we listen to ideas and we adapt to changing situations with an open mind.
B	BUILD THE BUSINESS	We ensure our day to day activity is sound while exploring ways to improve the way we work. We ask “is there a better way to do this?” and we investigate options.
C	CARE FOR OUR PEOPLE, CUSTOMERS AND ASSETS	We work as a team across the business to do things the right way. We treat others with respect, listening to their needs so we can deliver a safe and reliable service to our communities.
D	DO THE RIGHT THING	We make decisions with integrity and we earn the respect of our communities by being accountable for our actions.
E	EVERY DAY – HOME SAFE	The safety of our staff, our colleagues and our communities is our highest priority. We lead by example, challenging unsafe actions to ensure everyone goes home safe, every day.

As a business we take pride in these values and demonstrate them in every interaction with our customers and the community.

Informing our Asset Management Objectives

Our purpose, vision and values drive the 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 Condition Base Risk Management (CBRM) and Failure Modes Effects and Criticality Analysis (FMECA). These techniques allow for a quantifiable trade-off between capital and operational expenditure, risk, and reliability considerations.
- We leverage our Smart Meter 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 as outlined.

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.

Asset Performance: Our asset performance objective is to optimise the price-quality trade-off based on our stakeholders' needs. We will support this by more clearly understanding our customer needs, developing our asset management capability, asset strategies, network configuration, and supporting business processes.

Our asset management performance objectives are set out in more detail within Chapter 5.

1.1.3. CORPORATE AND ORGANISATION STRUCTURE

This section describes the governance arrangements, organisation structure and key responsibilities of our Executive Management, Asset Management, Operational teams and supporting functions. 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.

These are the key Board level governance activities relating to asset management:

- Approval of strategic plans.

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

The Board receives regular reports and information on the 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 five divisions plus a wholly owned subsidiary for delivery for the majority of the works plan. The divisions are: Finance, Asset Management, People

and Performance, Commercial and Technology. Figure 1.1.1 illustrates our organisational structure.

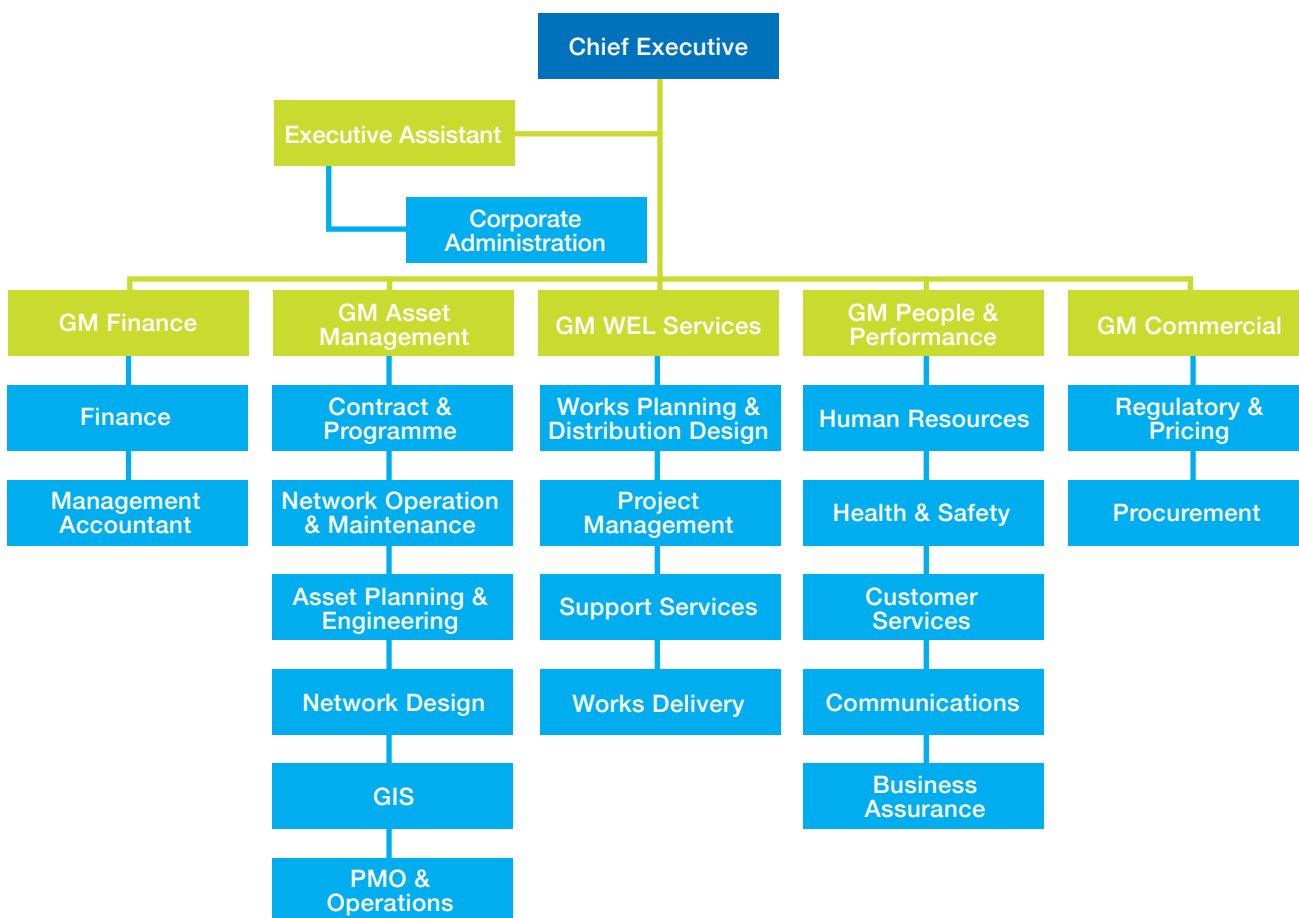


Figure 1.1.1 Organisation Structure

Executive Management Team

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

Asset Management Team

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

Teams	Key Responsibilities
Asset Planning and Engineering	<ul style="list-style-type: none"> 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 and Network Operate and Restore	<ul style="list-style-type: none"> 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 24/7 monitoring and operation of the network Control and permitting of access to the network Asset data management
Network Design	<ul style="list-style-type: none"> Design services for internal and external customers Review and approval of design works provided by external contractors
Contract & Programme Management	<ul style="list-style-type: none"> Works programme management, works plan & spend profile development Management of outsourced work through contract management Front-end management of customer initiated works
Principal Advisor	<ul style="list-style-type: none"> Monitoring asset performance outcomes Maintenance of project optimisation tools SLA and KPI management Strategy and business planning Portfolio Management

Table 1.1.2 Asset Management Team Responsibilities

Commercial Team – sets pricing and provides a commercial perspective on capital investment and the contributions required for third party developments.

People and Performance Team – provides health and safety advice on new equipment, operation and maintenance of equipment. Provide recruitment and workforce planning guidance and support.

Finance Team – provides financial modelling support and advice and management of funding to allow for the asset management plan initiatives.

WEL Services

In 2015 WEL Networks undertook a review of our delivery model as outlined in the WEL Networks Strategic Plan (developed February 2015). The aim was to ensure the right commercial decisions are made with regards to insourcing and outsourcing of maintenance and capital works. The project followed a robust methodology and included learnings from other organisations as well as thorough financial and non-financial analysis and evaluation.

The models evaluated were: status quo; partial outsourcing; full outsourcing; an alliance and a subsidiary. The results of our investigation demonstrated that the best long term cost/benefit value for WEL would result from a 'combination' model, in which:

- a wholly owned subsidiary delivers maintenance, first response, second response and asset renewal works
- there is outsourcing of selected capital works, such as customer initiated works and major capital project work to one or more external service providers.

This model was endorsed by the WEL Networks Board and work undertaken in the remainder of the 2015-16 financial year prepared the organisation for the wholly owned subsidiary model.

The WEL Networks subsidiary was in place for the beginning of the 2016-17 financial year and is now recognised as WEL Services.

WEL Services is a fully owned subsidiary of WEL Networks.

The WEL Services team has overall responsibility for the operational delivery of the Works Plan assigned to them and is divided into four primary sub-teams.

The key responsibilities are set out below.

Teams	Key Responsibilities
Planning & Scheduling	<ul style="list-style-type: none"> ▪ Receipt of incoming work, complete detailed design where required ▪ Plan and schedule all work to efficiently manage resources
Dispatch & Delivery	<ul style="list-style-type: none"> ▪ Assignment and handover of work to resources ▪ Delivery of maintenance, customer work, faults and capital projects
Project Management	<ul style="list-style-type: none"> ▪ Provide project management services to support planning and scheduling on complex projects
Administration	<ul style="list-style-type: none"> ▪ Reconciliation of work order costs, SAP processing and reporting

1.1.4. CAPABILITY

We have commenced an in-depth review of the competencies required by our staff and by our contractors to build and maintain the electricity network.

Currently we are establishing the requirements framework around both technical and behavioural competences. Following the completion of the framework we will

undertake a gap analysis which will lead to a training and development programme for each craft and each individual.

Consideration will also be given to developing the framework in accordance with other electricity industry frameworks to provide the greatest level of alignment and standardisation possible.

1.2. WEL NETWORKS' DISTRIBUTION AREA

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

Network Overview

Our network stretches from Hamilton 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 Figure 1.2.1 and 1.2.2 below.



Figure 1.2.1

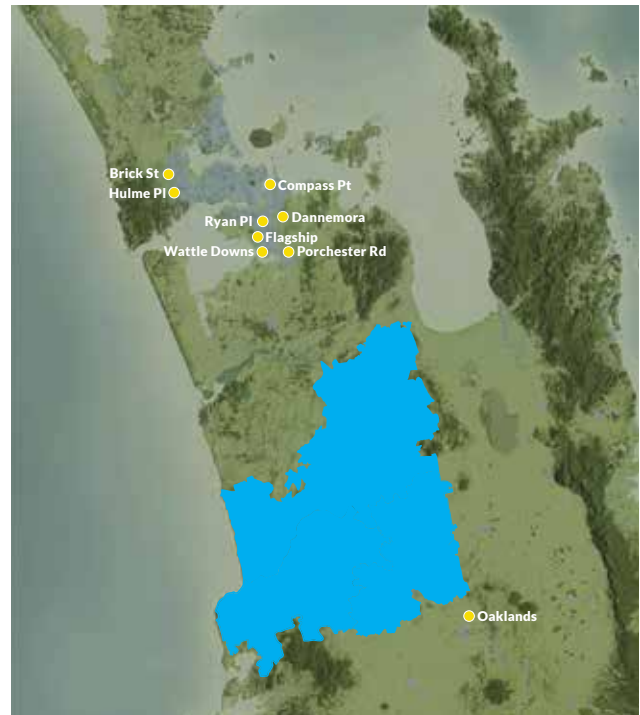


Figure 1.2.2

The network assets that are used to provide electricity to the WEL distribution area consist of four main components:

(1) Grid Exit Point (GXP)

We take supply from three GXPs (owned by Transpower) located at Hamilton, Te Kowhai and Huntly as described below.

GXP	General Description
Hamilton	Hamilton GXP supplies electricity at both 33kV and 11kV. Hamilton GXP supplies part of Hamilton and the eastern part of our distribution area. Our 33kV subtransmission network from Hamilton has a degree of interconnection with Te Kowhai providing an additional level of backup and security for Hamilton
Te Kowhai	Commissioned in 2005 Te Kowhai GXP supplies electricity at 33kV. Te Kowhai GXP supplies the remaining part of Hamilton and the western part of our network. As mentioned above, the 33kV subtransmission network from Te Kowhai has a degree of interconnection with Hamilton GXP
Huntly	Huntly GXP supplies electricity at 33kV to our northern distribution area. In 2017, we have discontinued the use of Bombay GXP via Meremere as an alternative supply to the northern network.

OVERVIEW

LEGEND

- Grid Exit Point (GXP)
- Zone Substation
- 33kV Subtransmission
- WEL Networks Boundary



Figure 1.2.3: WEL Network Boundary, 33kV subtransmission, GXP and zone substation

(2) 33kV Subtransmission and Zone Substations

Our 33kV subtransmission network transports electricity from Transpower's GXP's to our zone substations that in turn supply the 11kV distribution network. The subtransmission network is 440km in length and consists of an interconnected mesh around Hamilton, with double and single radial circuits. Zone substations that are supplied with single radial circuits have 11kV distribution circuits 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 25 zone substations on the network including Hoeka substation which was commissioned in October 2016. All zone substations have two transformers (N-1) except Whatawhata, Glasgow, Finlayson, Raglan, Hampton Downs and Hoeka. These are smaller rural zone substations that supply smaller loads with a single transformer (N security).

The level of security available at each zone substation is in accordance with WEL network security criteria discussed further in Chapter 6.

(3) 11kV 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 approximately 2,620km of 11kV cables and overhead lines, generally known as feeders.

The Hamilton 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 CBD and its urban customers.

In other areas the 11kV distribution network is primarily 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 district plan requirements.

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

Industrial and commercial distribution substations typically consist of enclosed, ground mounted transformers with integrated high voltage switchgear integral to or adjacent to the unit. They are 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 substations consist of enclosed ground mounted transformers with integrated high voltage switchgear integral to or adjacent to the unit, and customers are typically supplied from these units via fuses and underground low voltage (LV) cables.

Residential pole 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 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.

(4) Low Voltage Network

We manage approximately 2,300km 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.

1.2.1. 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
- Regulation

The sections below discuss each environmental factor.

Topography

The topography of our region varies greatly from the gently undulating landscapes of Central Waikato, South Auckland and the 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, peat soils with wetlands in the Waikato lowlands and large tracts of native forest in the western hill country. This adds 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 secure land for new assets is fundamental to our continuing operations. As a Network Operator WEL has special rights under the Electricity Act 1992 for assets built prior to 1992. These special rights give equipment established prior to 1992 existing use rights and the ability for WEL to access and maintain the equipment. WEL is

also permitted to access designated road reserves for installation, maintenance and repair of electrical equipment under the Electricity Act.

We acquire easements for the installation of new assets on private property in order to formalise both the landowner's and WEL's legal rights. Obtaining an easement is usually straightforward when a private land owner will directly benefit from the easement e.g. a new connection. However, obtaining an easement for new assets to transit private land where the landowner gains no benefit is often challenging and time consuming.

As such, our planning systems ensure work commences on obtaining the necessary easement as soon as practical in the planning process. A conservative approach is taken to the amount of land required for an easement in order to reduce expense and any 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 or advise customers of their obligations if at-risk lines cross private property.

Regulation

We operate in a highly 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.

1.2.2. ELECTRICITY DELIVERED AND DEMAND

As illustrated in Figure 1.2.2.1, the total electricity delivered at the end of financial year 2017 is 1,219 GWh with a coincident peak demand of 273MW.

ELECTRICITY DELIVERED AND SYSTEM DEMAND

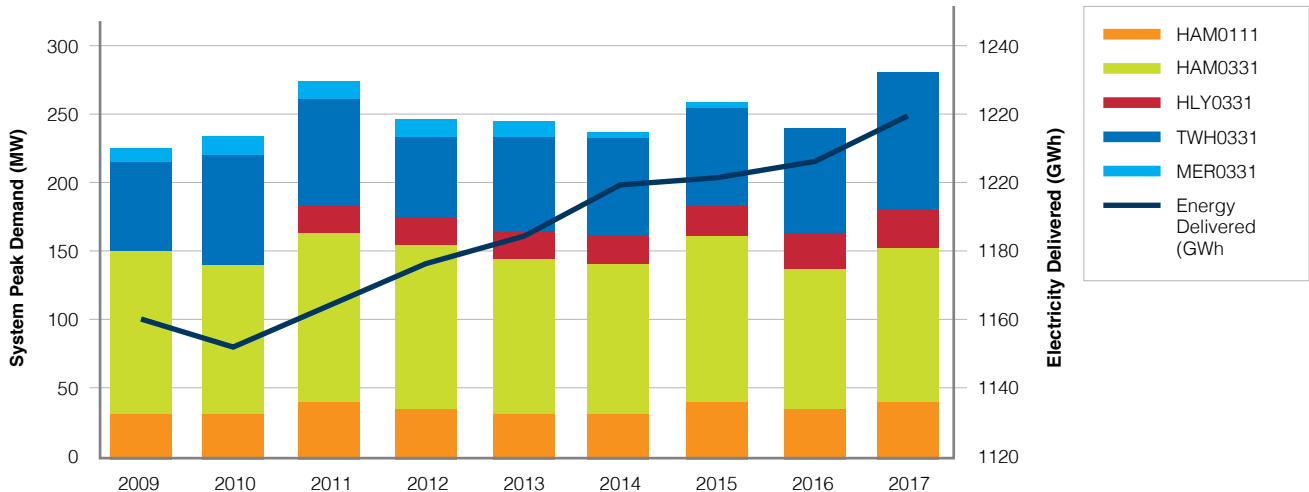


Figure 1.2.2.1 Electricity Delivered and Peak Demand

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 and early evening. Peak load occurs during winter. The rural profile follows a similar pattern with the addition that dairy farms peak in summer during milking times in early morning and mid-afternoon.

1.2.3. 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 nine broad groups of stakeholders:

- Our Customers
- Community
- Regulators
- Transpower
- Retailers
- Service providers
- Staff
- Board of Directors
- WEL Energy Trust (as described in section 1.1.1)

Each group is described on the next pages.

Our Customers

We place a strong emphasis on delivering quality service to our customers. We have differentiated them into six groups; domestic, general, small scale distributed generation, streetlights and unmetered, large and commercial customers. In addition we have residential, general, streetlights and large 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 or rural areas of our network. We also have a number of generation customers who inject electricity into our network.

We identify our customers' 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.

See Section 1.3 for further detail.

Retailers

There are 24 retailers brands 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 the direct contractual relationship with customers.

We maintain frequent communication 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 price structures; and fair contractual arrangements. Retailers are viewed as customers in their own right in addition to their role as 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 our assets have on the environment. These needs are paramount to us and are accommodated in our asset management practices. Our objectives and approach to 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 public 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, interactions with the System Operator and commercial agreements with retailers that also apply to WEL.

Transpower

We receive our electricity supply via transmission lines owned and operated by Transpower, the New Zealand transmission company. Transpower also holds the role of System Operator (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 asset management plans, commercial relationship and other industry issues. We have established systems and protocols with the SO for immediate communications regarding operational matters should 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 a safe, 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. They 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, safety and wellness policies and initiatives, performance reviews and forward work planning so 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
- developing organisational capability.

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

1.3. OUR CUSTOMERS

WEL supplies electricity to a mix of customers across our CBD, urban and rural environments. Our customers range from low-use domestic through to very large users such as the Waikato District Health Board. 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.

Customer Profiles

There are over 88,000 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 for the 2017 year is set out in the table below.

Customer Group	Number of Active ICPs	Electricity Delivered (GWh)	Demand (MW)
Domestic	74,183	488 (40%)	163 (60%)
General	12,162	215 (18%)	
Small Scale Distributed Generation	639	7 (1 %)	
Streetlights and Unmetered	277	9 (1%)	
Large Commercial ¹	775	486 (40%)	110 (40%)
Embedded Networks	1,869	14	n/a
Total	89,905	1,219	273

Table 1.3.1 Electricity Delivered and Demand by Customer Group

¹Large Commercial all have a fuse capacity of 110 kVA or greater, are Time of Use metered and have a connection voltage of 400V, 11kV, or 33kV

1.3.1. MAJOR CUSTOMERS

We remain in regular contact with all of 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 may be required in the connection of some customers, while others require fast response times to fault events to ensure that essential operations can continue.

Our nine largest major customers are:

- Fonterra/Canpac International
- The Embedded Network Company
- AFFCO
- Foodstuffs
- University of Waikato
- Pact Group Holdings
- Progressive Enterprises
- Hamilton City Council
- Waikato District Health Board

	Electricity Delivered (GWh)	Peak Time Demand (MW)
Top 10 Customers	174	25
Percentage of WEL Traditional Network	14.4%	9.3%

Table 1.3.2 Major Customers Electricity Delivered and Peak Time Demand

Our two largest customers Hamilton City Council and Waikato District Health Board are, like us, suppliers of essential services. Accordingly they warrant special

consideration and priority attention in the event of loss of supply under provisions of the Civil Defence and Emergency Management Act 2002.



2

ASSET OVERVIEW



2 ASSET OVERVIEW

This chapter describes the population, age profile, and condition of our assets. This chapter should be read in conjunction with Chapter 8 as this discusses the maintenance and renewal methodology and expenditure.

WEL is continuing to improve asset condition data collection and processing. For the last three years, we have been capturing the asset condition data using measurement points through the mobility solution that are directly linked in the Computerised Maintenance Management System (CMMS) (a function in SAP). This methodology minimises inaccuracies, discrepancies and eases processing of condition data. Traditionally, condition data were captured in hard copies then saved as pdf files

against the asset record in CMMS. Data sets presented in this document reflect higher accuracies due to the following improvement implemented as part of the data management continuous improvement programme:

- Use of SAP configured measurement points in capturing asset condition through the mobility solution
- SAP master data validation, verification and re-structuring in SAP for ease in generating disclosure and asset management reports

2.1. ASSET POPULATION SUMMARY

A summary of the population and condition of our assets is shown in Table 2.1.1 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 is 'due for replacement'.

Section	Asset Category	Unit	Quantity	WEL Condition Score					
				0	1	2	3	4	5
2.2	Subtransmission								
2.2.1	Poles	No.	2,702	0	0	0	14	163	2,525
2.2.2	Crossarm	No.	2,850	0	0	0	155	478	2,217
2.2.3	Subtransmission Lines	km	191	0	0	0	0	105	86
2.2.4	Subtransmission Cables	km	249	0	0	0	3	28	218
2.2.5	Subtransmission CBs	No.	124	0	0	0	2	2	120
2.3	Zone Substations								
2.3.1	Power Transformer	No.	46	0	0	0	0	11	35
2.3.2	Switchboards	No.	55	0	0	0	6	4	45
2.3.3	Substation Buildings	No.	30	0	0	0	4	21	5
2.4	Distribution and LV Lines								
2.4.1	Poles	No.	36,713	0	0	34	342	2,861	33,476
2.4.2	Crossarms	No.	71,113	0	0	482	7,569	16,359	46,703
2.4.3	Distribution and LV Conductors	km	3,275	0	0	454	132	600	2,089

¹For 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.

Section	Asset Category	Unit	Quantity	WEL Condition Score					
				0	1	2	3	4	5
2.5	Distribution and LV Cables								
2.5.1	Distribution Cables	km	680	0	0	71	60	197	352
2.5.2	LV Cables	km	2,246	0	0	0	533	860	853
2.6	Distribution Substations and Transformers								
2.6.1	Distribution Switching Stations	No.	17	0	0	0	1	9	7
2.6.2	Distribution Transformers	No.	5,899	10	3	28	328	671	4,859
2.7	Distribution Switchgear								
2.7.1	Ring Main Units	No.	1,002	0	0	0	28	141	833
2.7.2	Distribution Circuit Breakers	No.	448	0	0	7	45	30	366
2.7.3	Distribution Air Break Switches	No.	930	0	2	4	7	17	900
2.7.4	Distribution Sectionalisers & Reclosers	No.	133	0	0	0	0	0	133
2.8	Other Network Assets								
2.8.1	LV Pillars	No.	25,771	0	0	139	764	22	24,846
2.8.2	Protection Relays	No.	655	0	2	16	106	12	519
2.8.3	Network Management System Remote Terminal Units (RTU)	No.	389	0	0	0	26	0	363
2.8.4	Load Control Equipment	No.	6	0	0	0	0	6	0
2.8.5	Meters	No.	58,027	0	0	0	0	0	58,027

Table 2.1.1 Asset Population and Condition Summary

2.1.1. 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 it is near the end of its life with a high probability of failure. This is illustrated in Figure 2.1.2.

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

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 2.1.2 CBRM Health Indices

2.2. SUBTRANSMISSION

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

The subtransmission network operates at 33kV and is 440km in length, of which 191km is overhead and 249km 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
- Subtransmission circuit breakers

2.2.1. SUBTRANSMISSION POLES

Population

We have 2,702 subtransmission poles. Figure 2.2.1.1 shows the distribution by construction material. The majority are concrete poles, with a small number of softwood, hardwood and steel poles remaining.

SUBTRANSMISSION POLES BY TYPE

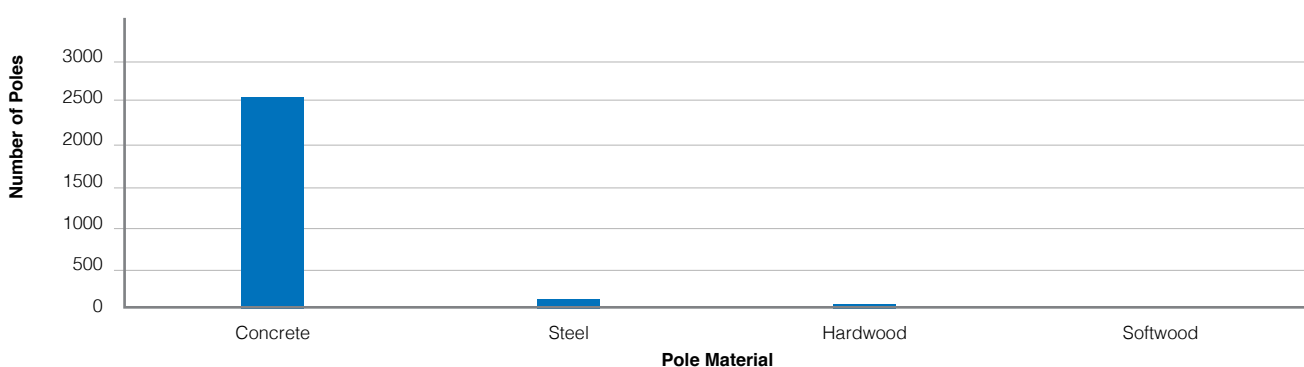


Figure 2.2.1.1 Subtransmission Pole Types

Age Profile

Subtransmission poles share the same age profile as subtransmission lines, shown in Figure 2.2.3.2, as they are installed at the same time. The exception to this is wooden and steel poles that have a shorter life

expectancy and therefore require earlier replacement. New poles installed are concrete due to the increased life expectancy, unless site considerations dictate otherwise.

Asset	Life expectancy (Years)
Concrete poles	70
Wooden poles (both softwood and hardwood)	45
Steel Poles	45

Table 2.2.1.1 Life Expectancy of Subtransmission Poles

Condition

The condition profile of the subtransmission poles is shown in Figure 2.2.1.2 below. Field inspections indicate that in general the condition of subtransmission poles is good.

CONDITION OF SUBTRANSMISSION POLES

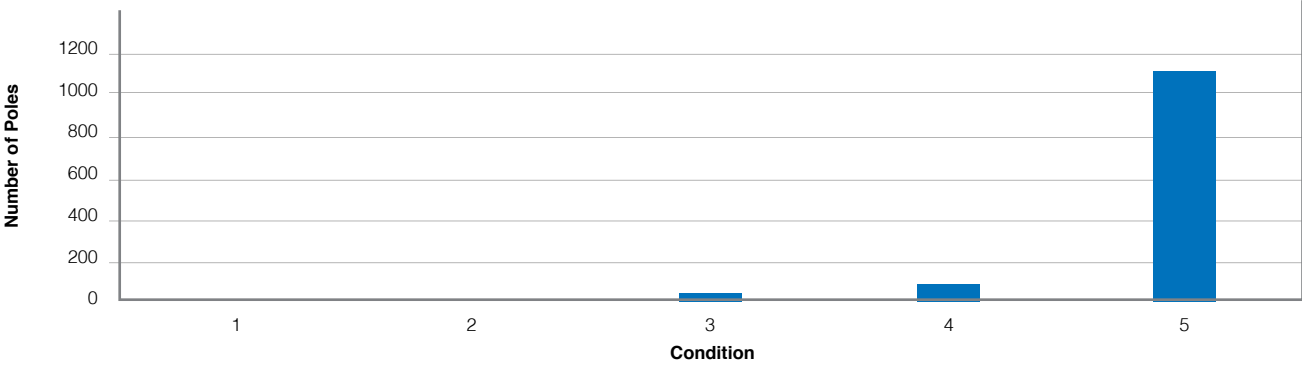


Figure 2.2.1.2 Condition of Subtransmission Poles

2.2.2. SUBTRANSMISSION CROSSARMS

Population

We have 2,850 subtransmission crossarms with the vast majority being hardwood. It is our current practice to install galvanised steel crossarms on the network due to their increased life expectancy and lower resultant whole of life cost.

SUBTRANSMISSION CROSSARMS BY TYPE

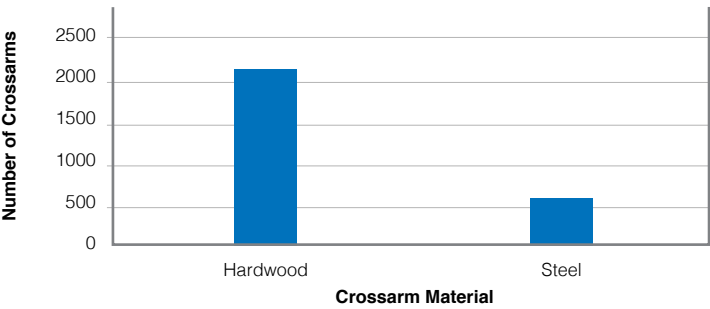


Figure 2.2.2.1 Subtransmission Crossarm Types

Age Profile

The age profile of the subtransmission crossarms is shown in Figure 2.2.2.2.

CONDITION OF SUBTRANSMISSION CROSSARM

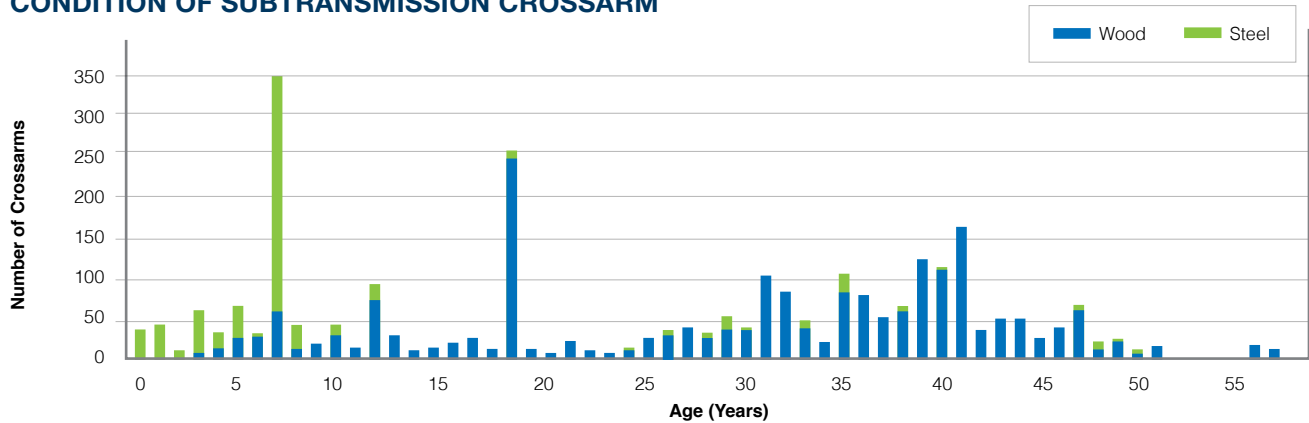


Figure 2.2.2.2 Age Profile of Subtransmission Crossarm

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 2.2.2.1 Life Expectancy of Subtransmission Crossarms

Condition

The condition profile of the subtransmission crossarms is shown in Figure 2.2.2.3. Field inspections indicate that in general the condition of subtransmission crossarms is good.

CONDITION OF SUBTRANSMISSION CROSSARMS

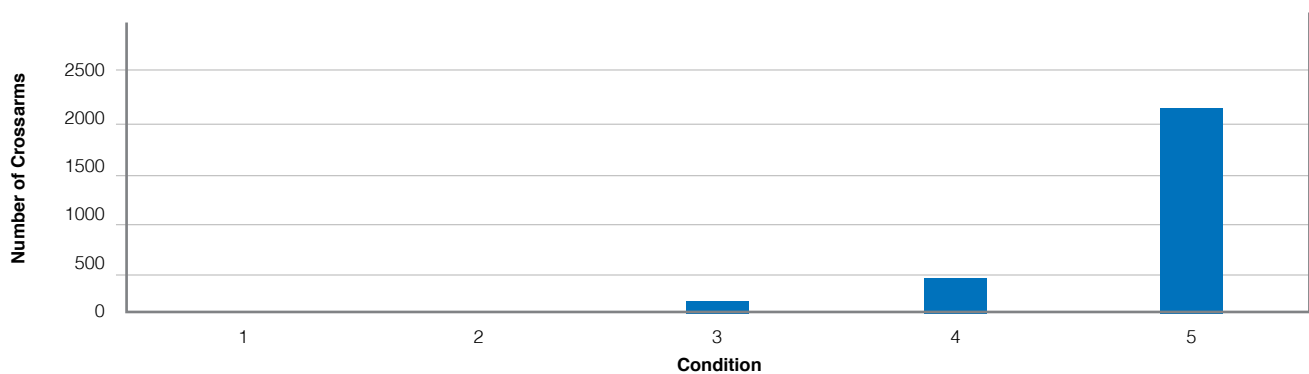


Figure 2.2.2.3 Condition of Subtransmission Crossarms

2.2.3. SUBTRANSMISSION LINES

Subtransmission lines connect GXP's to the zone substations at 33kV, and are overhead conductors.

Population

We have 146km of subtransmission lines in rural areas, 37km within the Hamilton urban area and 8km in Huntly. Subtransmission lines consist of conductors (wire). Four types of conductors are used on our network.

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.

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

SUBTRANSMISSION CONDUCTOR BY TYPE

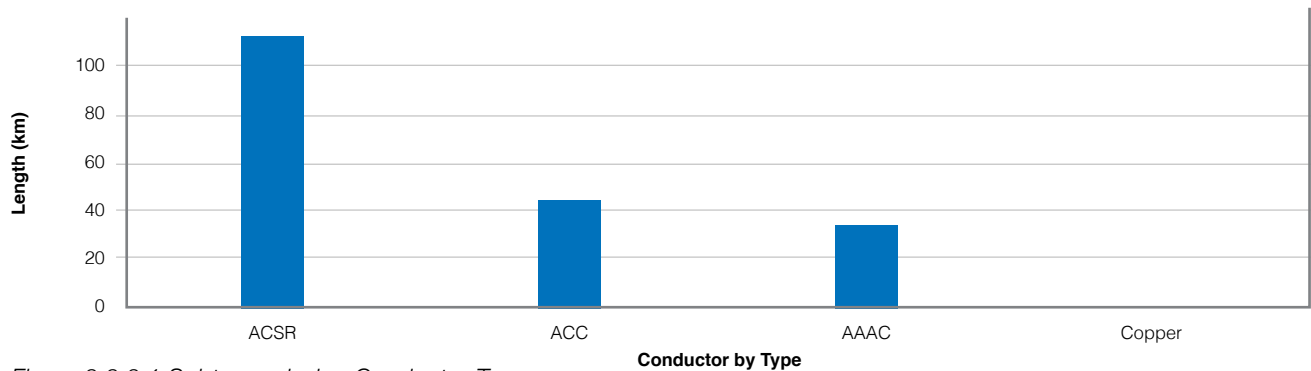


Figure 2.2.3.1 Subtransmission Conductor Types

Age Profile

Figure 2.2.3.2 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 seven (2010) corresponds to the construction of a subtransmission line to the

Te Uku Wind Farm. In year 19 (1998), the link between Horotiu and Weavers substations was constructed. A number of areas of the subtransmission network were strengthened in year 40 (1977). The oldest conductors are 57 years old and located at Horotiu and Dey Street.

AGE PROFILE OF SUBTRANSMISSION CONDUCTOR

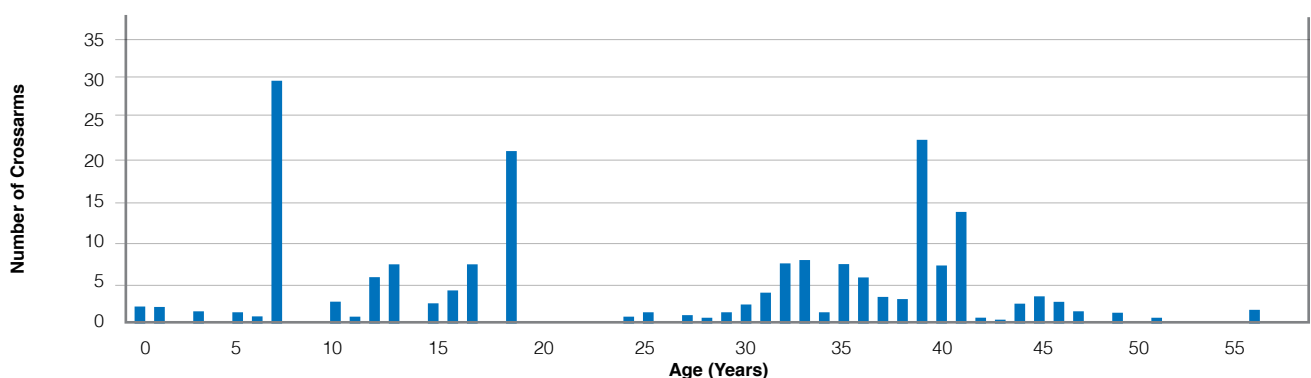


Figure 2.2.3.2 Age Profile of Subtransmission Lines

Condition

The condition profile of the subtransmission lines is shown in Figure 2.2.3.3. Field inspections indicate that in general, the condition of subtransmission lines is good.

CONDITION OF SUBTRANSMISSION LINES

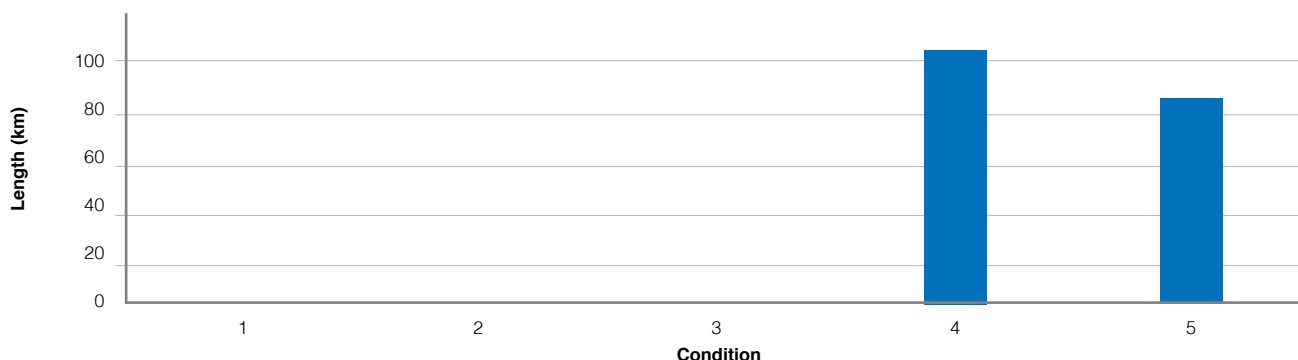


Figure 2.2.3.3 Condition of Subtransmission Lines

2.2.4. SUBTRANSMISSION CABLES

Subtransmission cables connect GXP's to the zone substations at 33kV and are placed underground.

Population

We have 249km of subtransmission cables, with 111km in Hamilton. Figure 2.2.4.1 shows the geographical location of our subtransmission cables. There are two types of subtransmission cables in use. Cross-linked polyethylene (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.

LOCATION OF SUBTRANSMISSION CABLES

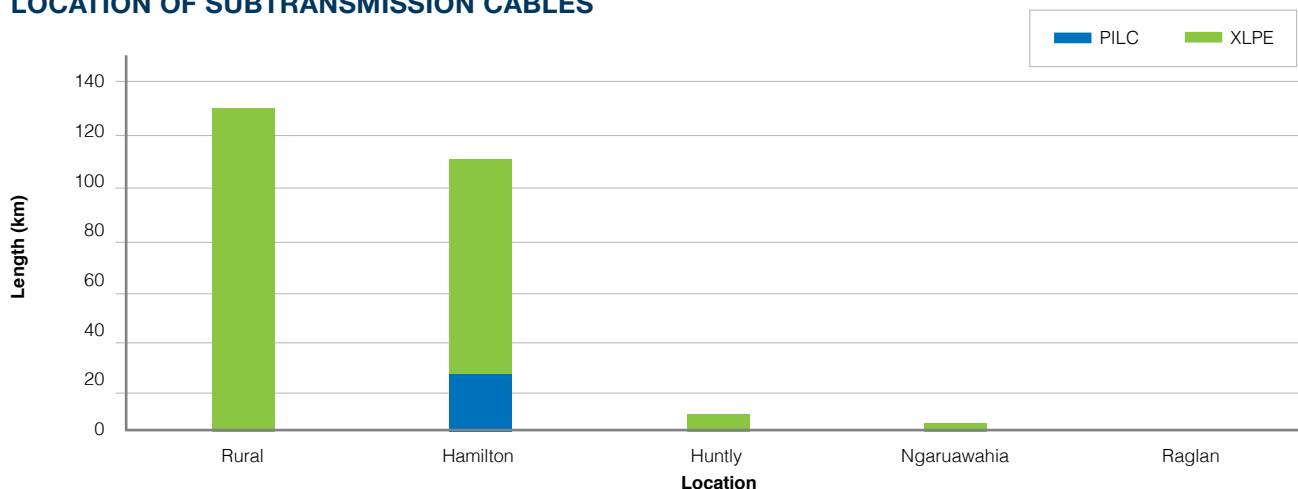


Figure 2.2.4.1 Location of Subtransmission Cables

WEL does not have any gas or oil filled subtransmission cables in the network.

Age Profile

Figure 2.2.4.2 shows the age profile for subtransmission cables. The age of PILC cables ranges from 33 to 45 years and XLPE cables range in age from new to 45 years old. The weighted average age of the XLPE cables is nine years and the weighted average age of the PILC

is 38 years old. The peak in year seven was due to the installation of the cables connecting Avalon, Te Kowhai and Whatawhata. The peak in year 12 was due to the cables installed as part of the Te Uku windfarm project.

AGE PROFILE OF SUBTRANSMISSION CABLES

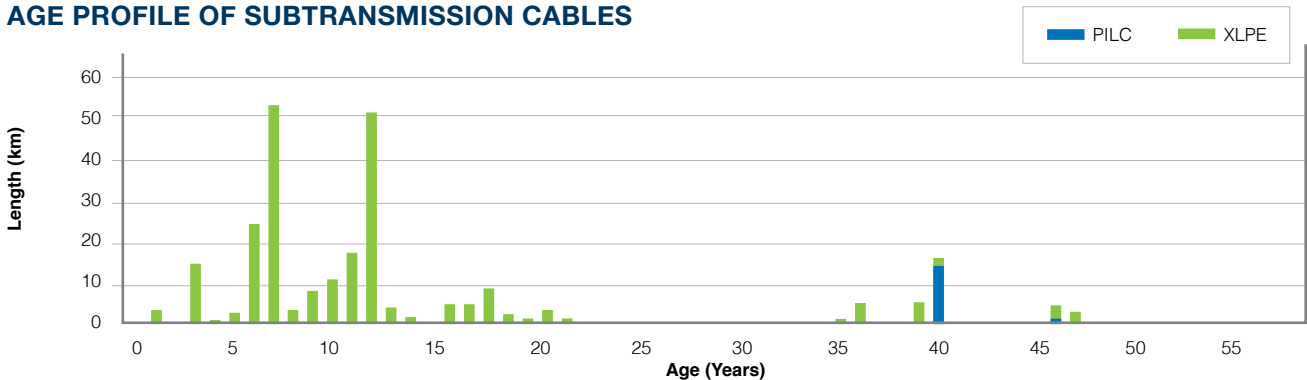


Figure 2.2.4.2 Age Profile of Subtransmission Cables

The life expectancy of the cables is shown in Table 2.2.4.1 below. The oldest PILC cables on our network are 46 years old and are located at Bryce St, Brooklyn Rd and Te Aroha St. The oldest XLPE cables on our network are now

47 years old. These are part of the circuits from Hamilton 33kV GXP that supplies individual zone substations Peacockes, Chartwell and Bryce street and their reliability to date is good.

Cable type	Life expectancy (Years)
PILC Cables	70
XLPE Cables	45

Table 2.2.4.1 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 limited number of cables. These failures have been attributed to poor workmanship on that

section of the cable network during installation. A programme of partial discharge tests has been initiated to determine the extent of these problems.

2.2.5. SUBTRANSMISSION CIRCUIT BREAKERS (CBs)

The majority of subtransmission CBs are located within substations on incoming circuits. Their main function is to protect transformers, interconnections and circuits between substations.

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 124 33kV CBs. Three types of CB are in use on our network; oil, gas insulated (SF6), 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 6 % of the fleet remains outdoors. Figure 2.2.5.1 shows the distribution by type.

SUBTRANSMISSION BREAKER TYPES

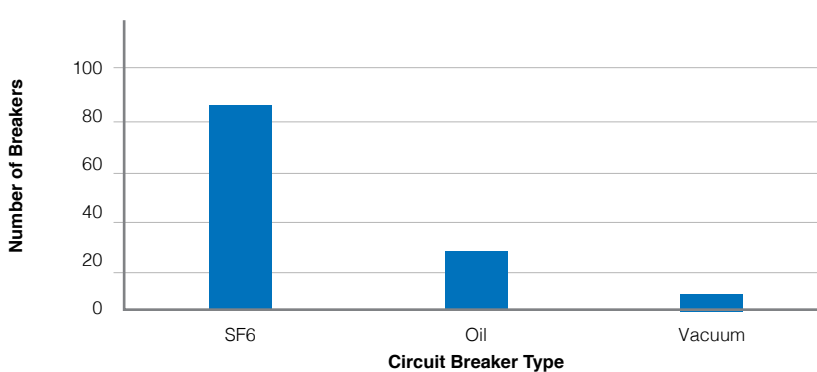


Figure 2.2.5.1 Subtransmission CBs by Type

Age Profile

Figure 2.2.5.2 shows the age profile of the CBs installed on the network. Most 33kV CBs installed over the last 10 years were indoor SF6 type.

AGE PROFILE OF SUBTRANSMISSION CBs

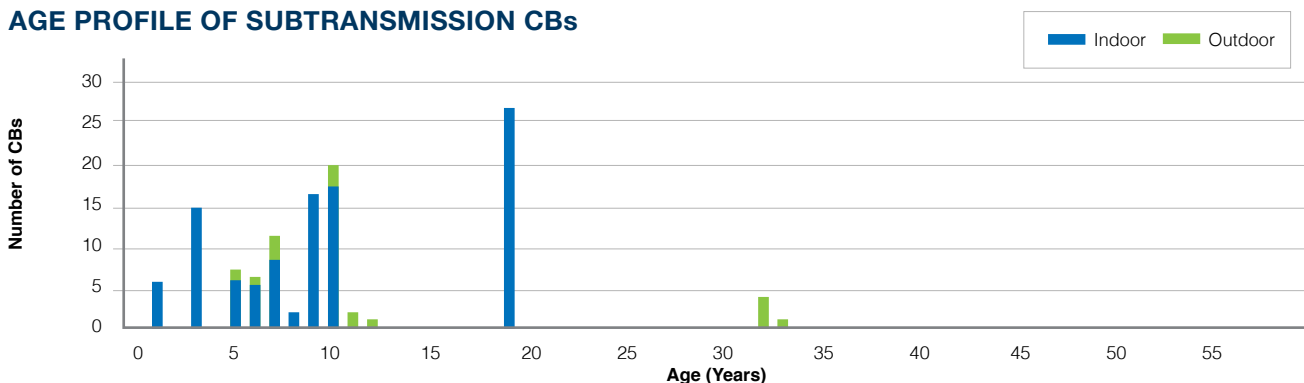


Figure 2.2.5.2 Age Profile of Subtransmission CBs

The expected lives are shown in Table 2.2.5.1

Asset	Life expectancy (Years)
Outdoor Breakers	45
Indoor Breakers	60

Table 2.2.5.1 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 2.2.5.3.

CONDITION OF SUBTRANSMISSION CBs

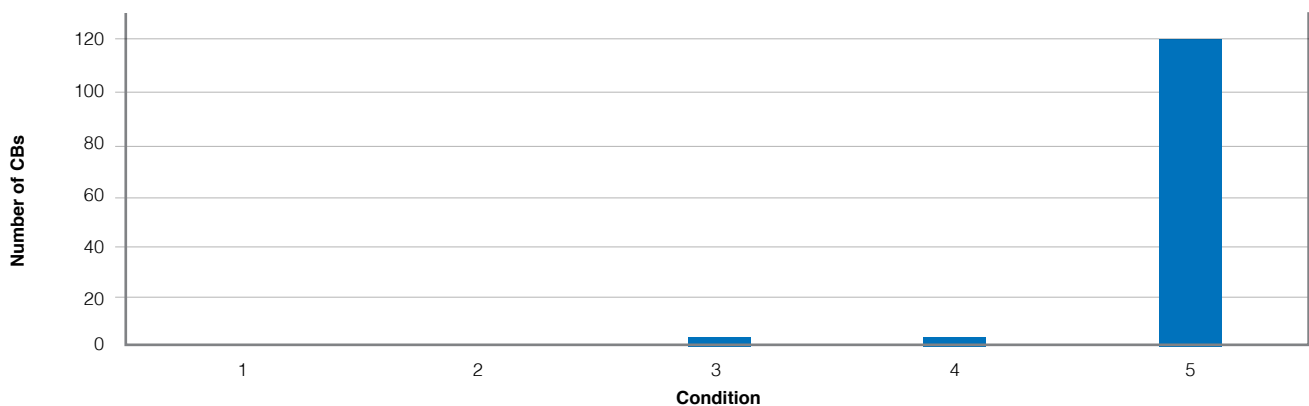


Figure 2.2.5.3 Condition of Subtransmission CBs

2.3. ZONE SUBSTATIONS

Zone substations transform power from the 33kV subtransmission to the 11kV distribution voltage. Switching stations provide the capability to switch load between different zone substation circuits, thereby providing security of supply during fault conditions or planned maintenance.

We operate 25 zone substations sites with construction dates ranging from the 1950s to 2016. Six of the 25 zone substations have outdoor switchyards which include 33kV CBs, outdoor instrument transformers, switches, insulators and busbars. In accordance with WEL security standard, 17 zone substations are N-1 security and 8 are N security. This is further discussed in Chapter 6.

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
- Substation buildings

2.3.1. POWER TRANSFORMERS

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

Population

We own 51 power transformers including spares with installation dates ranging from 1960 to 2015. There are 46

“in-service” transformers, two 10MVA, two 15MVA and one 23MVA spare power transformers strategically located in our zone substations that are readily available when needed.

Figure 2.3.1.1 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

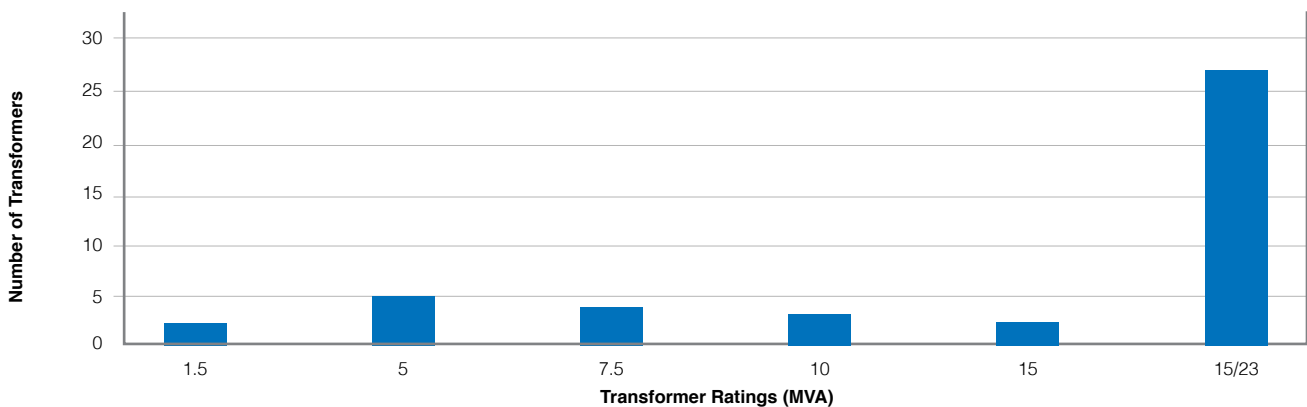


Figure 2.3.1.1 Distribution of Power Transformer by Ratings

Age Profile

The age profile of our power transformers is shown in Figure 2.3.1.2.

AGE PROFILE OF POWER TRANSFORMER

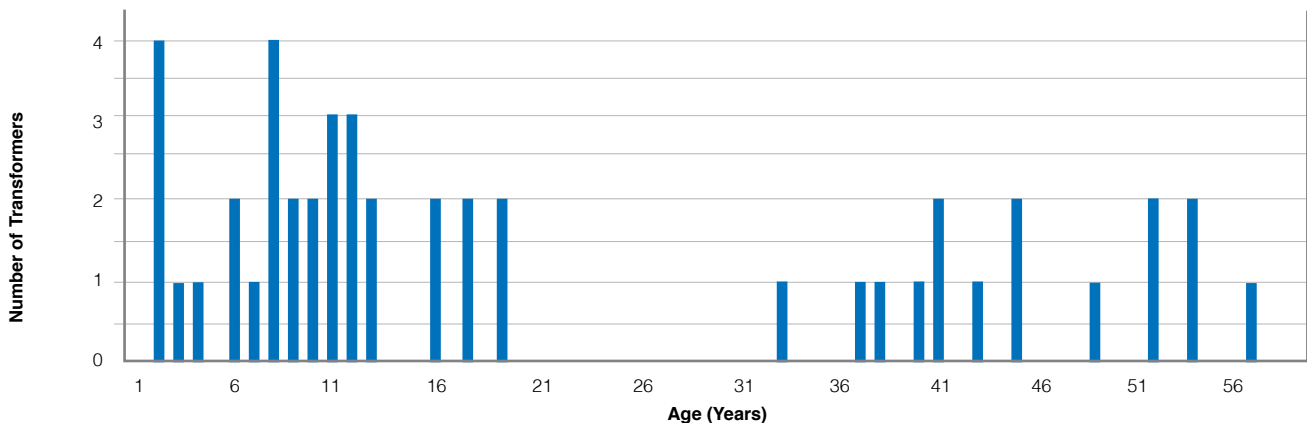


Figure 2.3.1.2 Age Profile of Power Transformers

The average age of the power transformer fleet is currently 17 years old. The life expectancy of power transformers is 60 years. Some transformers undergo a mid-life refurbishment to achieve this lifespan. Transformers are

often 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 2.3.1.3.

CONDITION OF POWER TRANSFORMERS

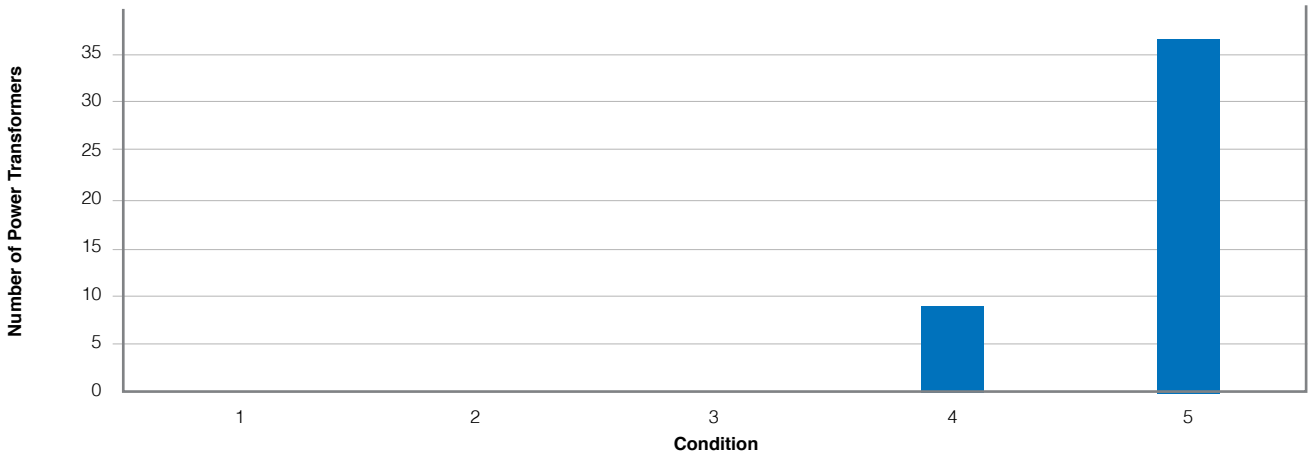


Figure 2.3.1.3 Condition of Power Transformers

2.3.2. SWITCHBOARDS

Switchboards contain switchgear that provides 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 55 33kV and 11kV switchboards, with 44 being AIS and 11 GIS within our subtransmission network. 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 2.3.2.1. The average age of switchboards is 20 years. The life expectancy of switchboards is 60 years.

AGE PROFILE OF SWITCHBOARDS

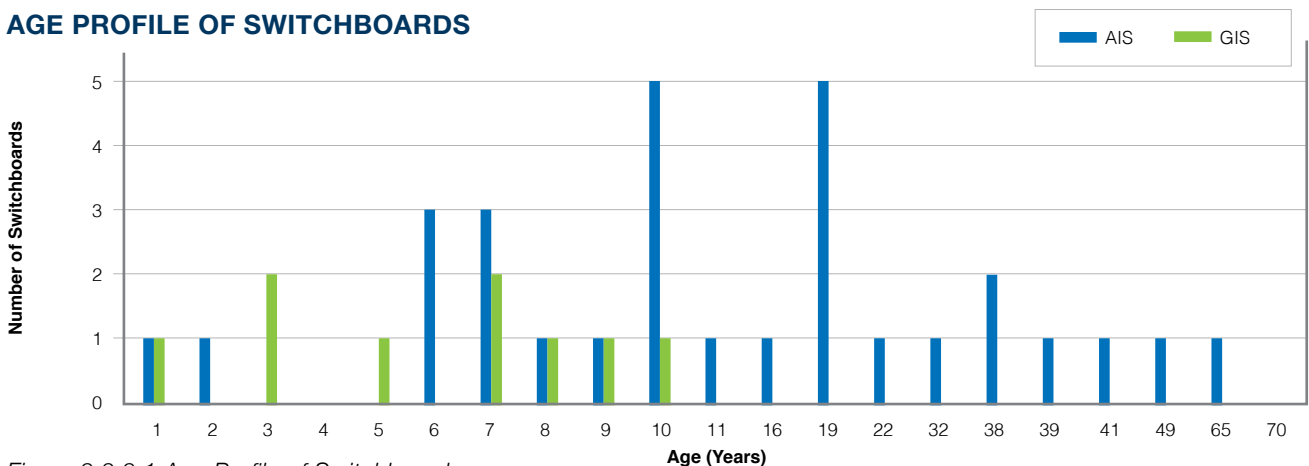


Figure 2.3.2.1 Age Profile of Switchboards

Condition

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

CONDITION OF SWITCHBOARD

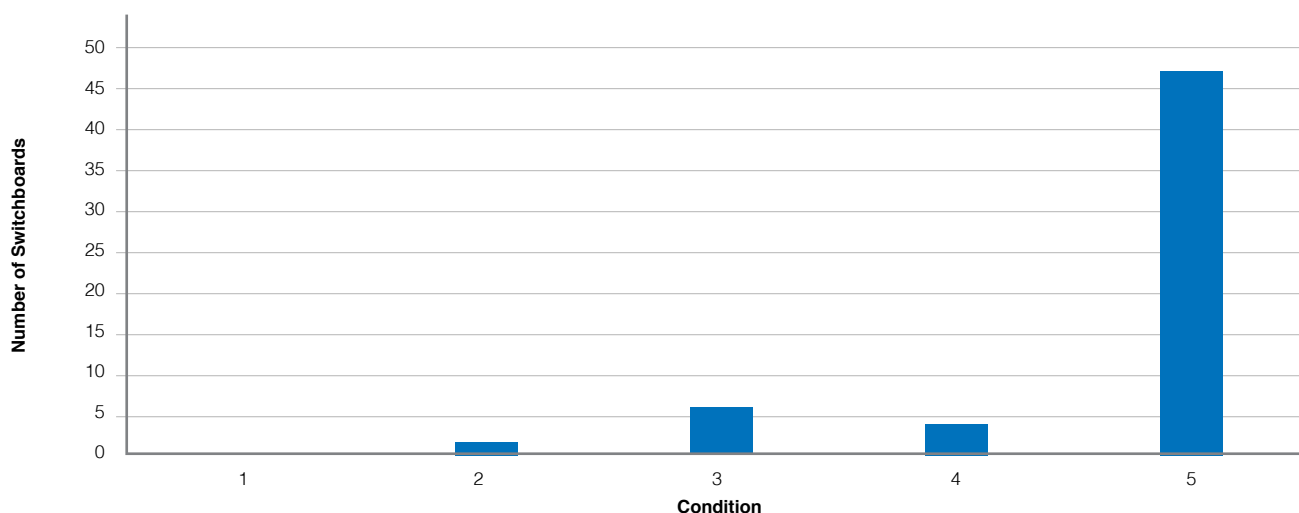


Figure 2.3.2.2 Condition of Switchboards

2.3.3. SUBSTATION BUILDINGS

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

Population

In total there are 30 zone substation buildings across the 25 zone substation sites that WEL operates. These 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

The average life of the substation buildings is 12 years. Figure 2.3.3.1 shows the age profile for substation buildings.

AGE PROFILE OF ZONE SUBSTATION BUILDINGS

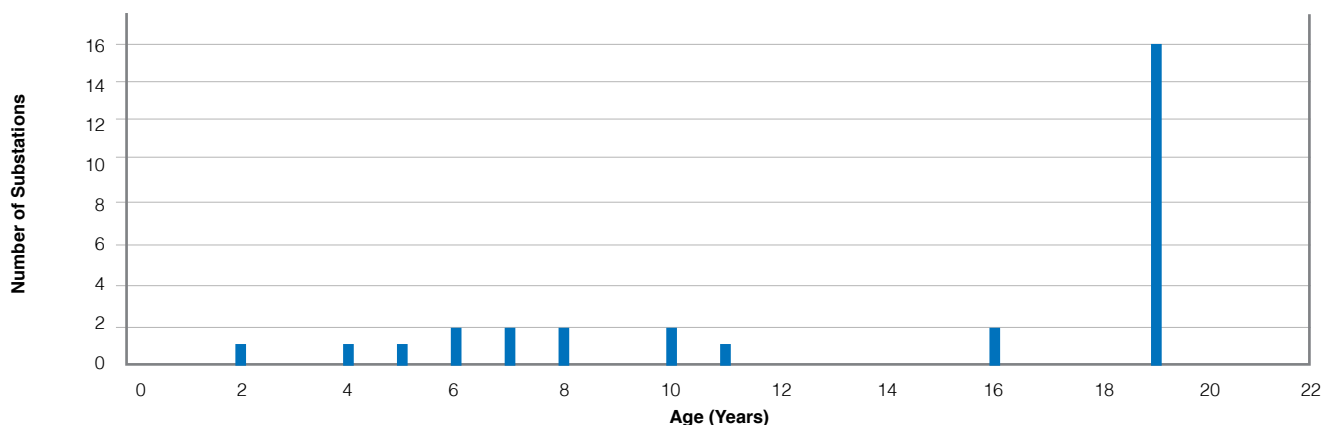


Figure 2.3.3.1 Age Profile of Substation Buildings

Condition

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

CONDITION OF ZONE SUBSTATION BUILDINGS

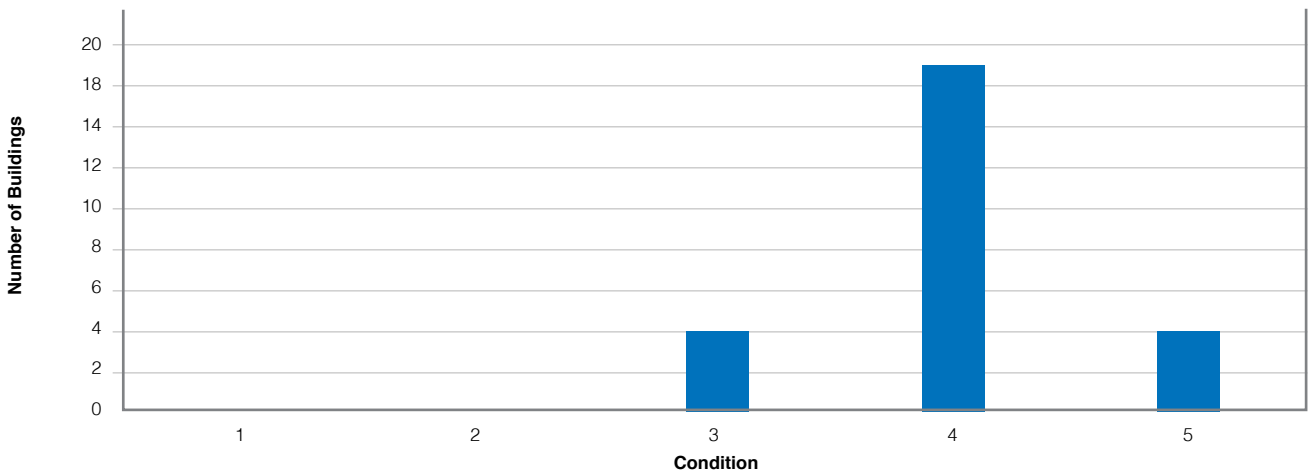


Figure 2.3.3.2 Condition of Zone Substation Buildings

All new WEL Zone Substation buildings will be designed and built to IL4 standard. Seismic strengthening of existing zone substation buildings where practical and as per recommendation in the assessment undertaken, shall be to IL4 and a minimum of 75% of New Building Standard (NBS). Where it is not practical to strengthen a building to the required level then a cost-risk assessment will be carried out to determine the most practical level.

WEL commenced a programme of specialised seismic assessment in 2007. The remaining eight buildings were assessed in 2017. Five were recommended to have seismic upgrades and planned as follows: (2019) Claudelands substation, (2020) substations Horotiu and Weavers (11kV room) and (2021) Ruakura ripple plant and Kent substation.

The overall results of the seismic assessment to date are shown in Figure 2.3.3.3.

SEISMIC CONDITION OF SUBSTATION BUILDINGS

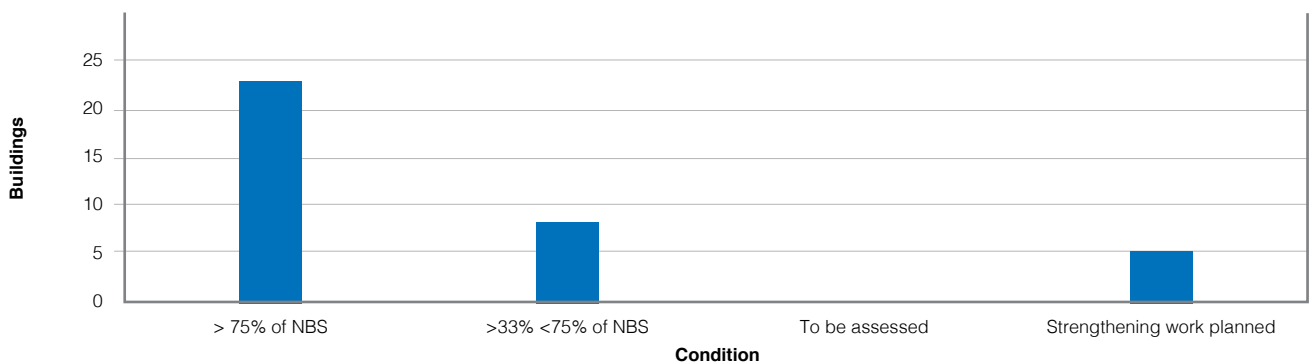


Figure 2.3.3.3 Distribution of Substation Building Seismic Conditions

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 approximately 6,200km, 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

2.3.4. 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 36,700 poles. Figure 2.4.1.1 shows the distribution by construction material. The majority are concrete poles, with a small number of softwood, hardwood and steel poles remaining.

DISTRIBUTION OF POLE MATERIAL IN HV AND LV NETWORKS

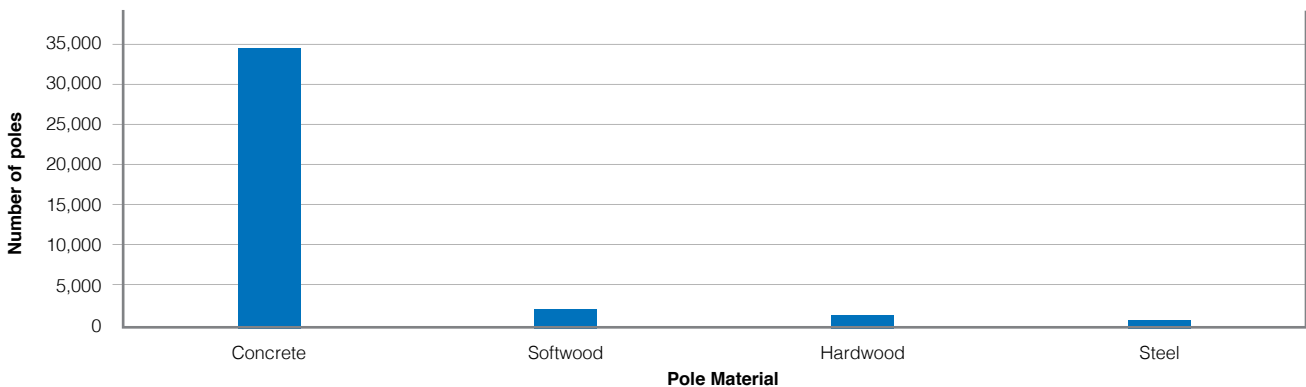


Figure 2.4.1.1 Distribution of Pole Material in HV and LV Networks

Age Profile

Figure 2.4.1.2 shows the age profiles of our poles. Both concrete poles and wooden poles have an average age of 31 years.

AGE PROFILE OF POLES

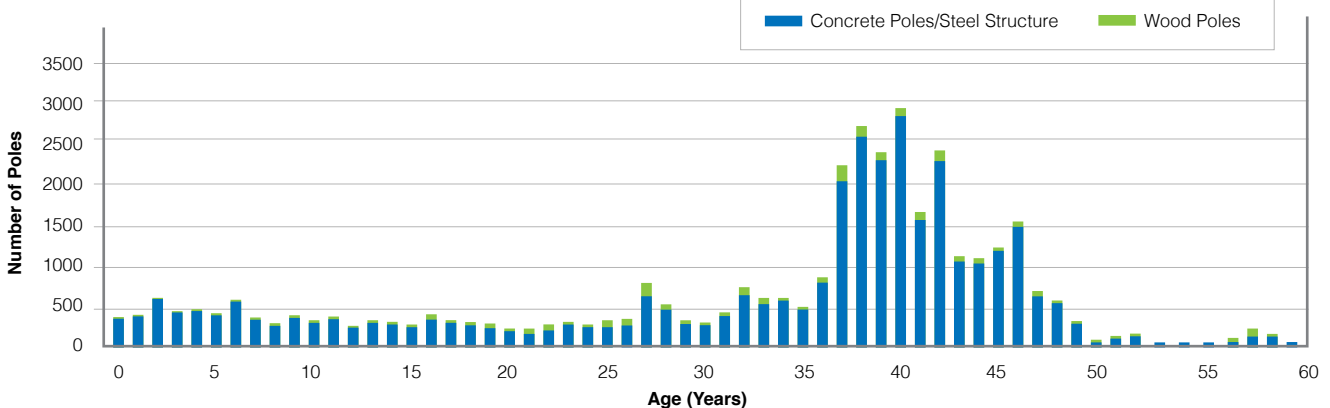


Figure 2.4.1.2 Age Profile of Poles

The life expectancy of concrete poles is 70 years and wooden poles 45 years as illustrated in Table 2.4.1.1. 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 2.4.1.1 Life Expectancy of HV and LV Poles

Condition

The distribution of pole condition is shown in Figure 2.4.1.3.

CONDITION OF POLES

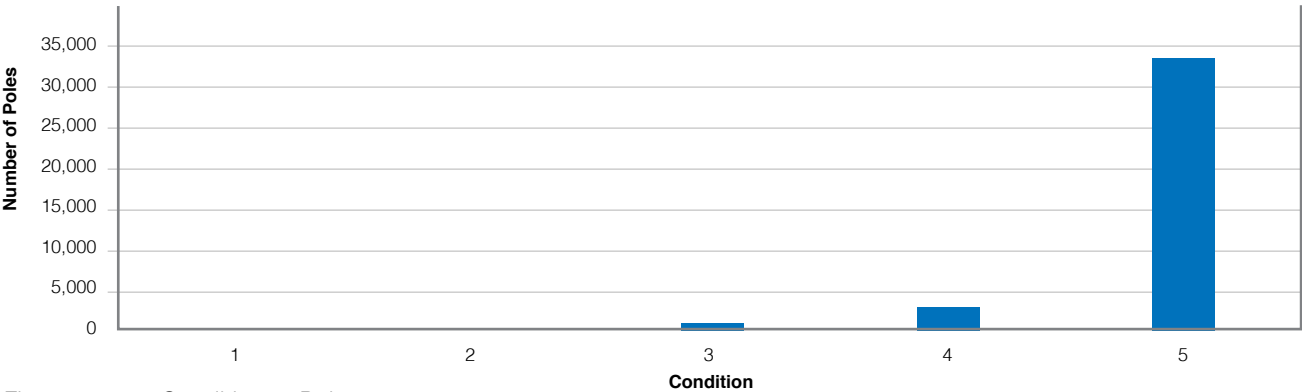


Figure 2.4.1.3 Condition of Poles

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

There are approximately 387 hardwood poles remaining on our network that range in condition from good to poor. WEL stopped installing hardwood poles on the network approximately 15 years ago and as such, it

is expected that most wooden (hardwood) poles will need to be replaced in the AMP period. All hardwood poles have been tested and monitored for hidden rot at ground level and poles that were identified as needing replacement have been replaced with concrete ones.

Figure 2.4.1.4 shows the AHL profile of our poles.

POLES HEALTH INDEX PROFILE

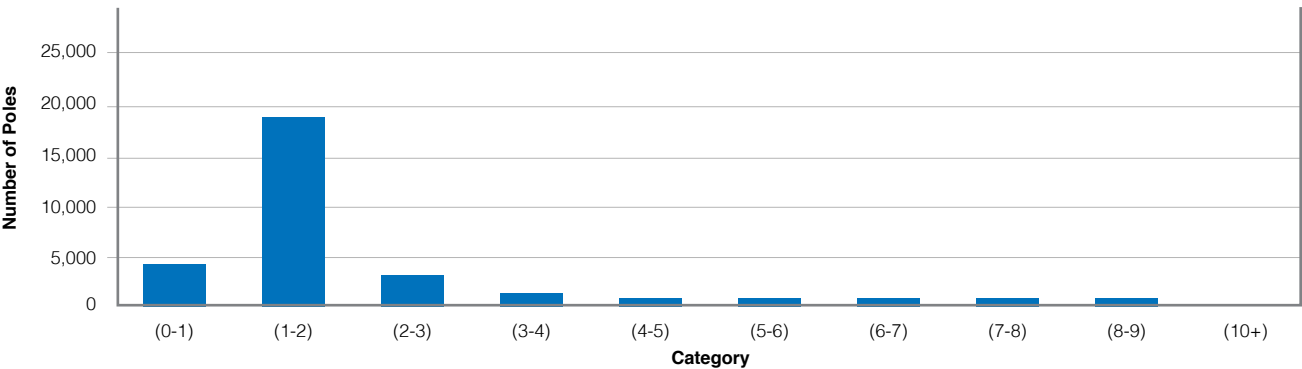


Figure 2.4.1.4 Poles Health Index Profile

2.3.5. 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 we have changed our design standard for new crossarms on HV circuits to steel. We are currently investigating the use of fibreglass composite crossarms and expect to be installing these next year, due to these crossarms having similar life expectancy to steel but significantly less weight. WEL has also installed virtual crossarms which are a type of insulator that attaches the line directly to the pole.

As the majority of the existing 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 71,113 crossarms installed on our network. The majority of crossarms are wooden as shown in Figure 2.4.2.1.

DISTRIBUTION OF CROSSARM MATERIAL

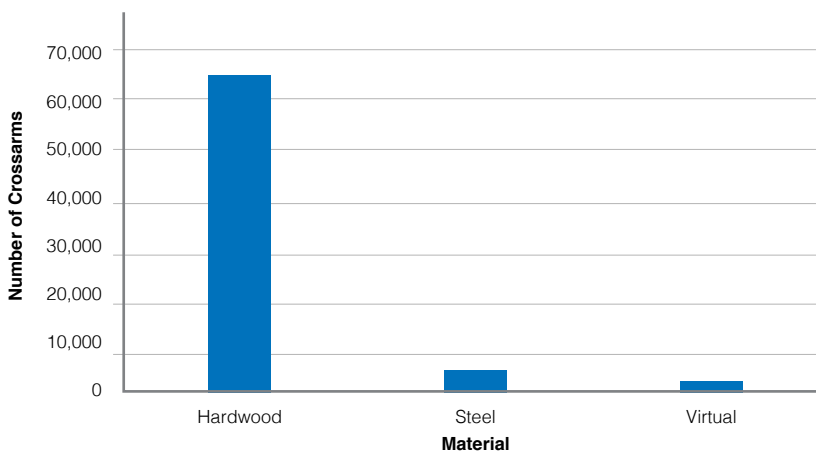


Figure 2.4.2.1 Distribution of Crossarm Material

Age Profile

Figure 2.4.2.2 shows the age profile of wooden and metal crossarms. The average age of the fleet is 30 years.

AGE PROFILE OF CROSSARMS

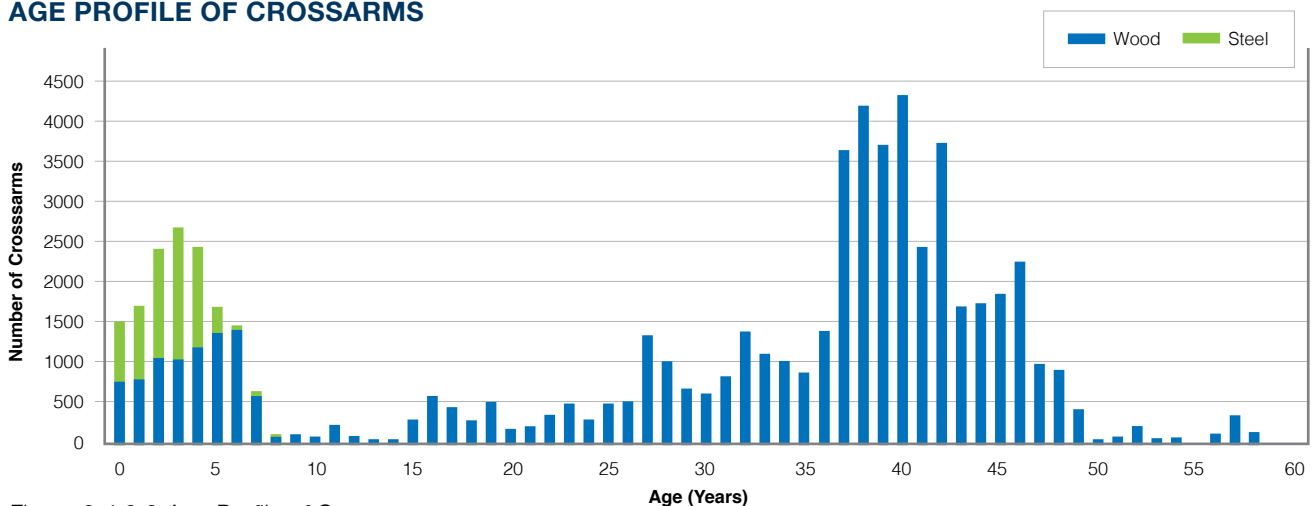


Figure 2.4.2.2 Age Profile of Crossarms

As shown in Table 2.4.2.1 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 2.4.2.1 Life Expectancy of Crossarms

Condition

The condition distribution of our crossarms is shown in Figure 2.4.2.3.

CONDITION RATING OF CROSSARMS

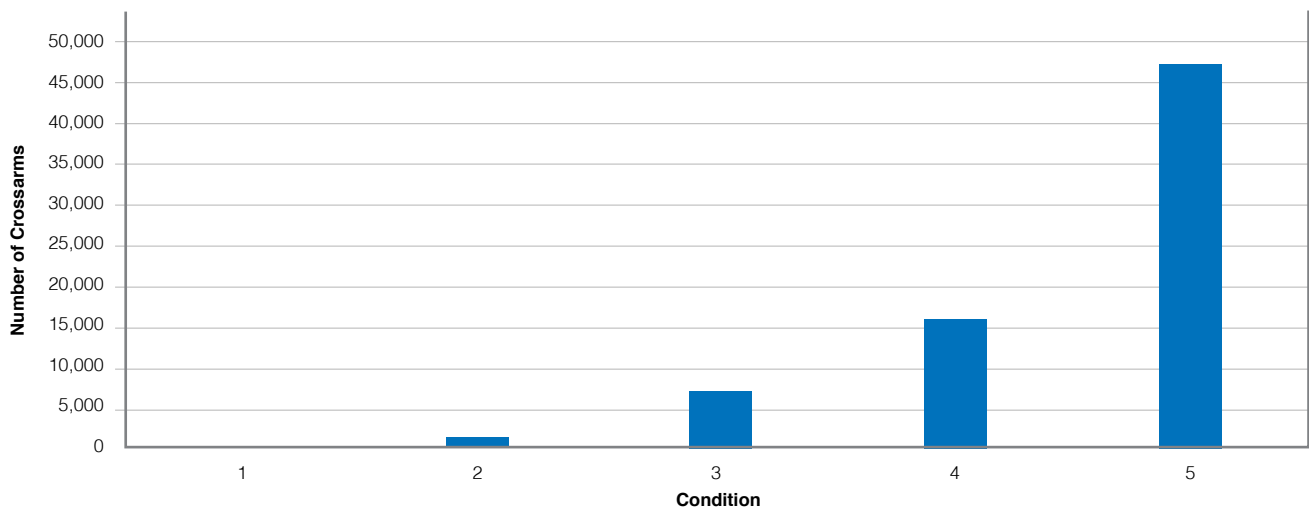


Figure 2.4.2.3 Condition of Distribution Crossarms

The AHI profile for our crossarms is shown in Figure 2.4.2.4. The graph indicates that a significant number are approaching the stage where they will need to be

replaced. The AHI and the factors used to assess an asset are explained in section 2.1.

CROSSARM HEALTH INDEX PROFILE

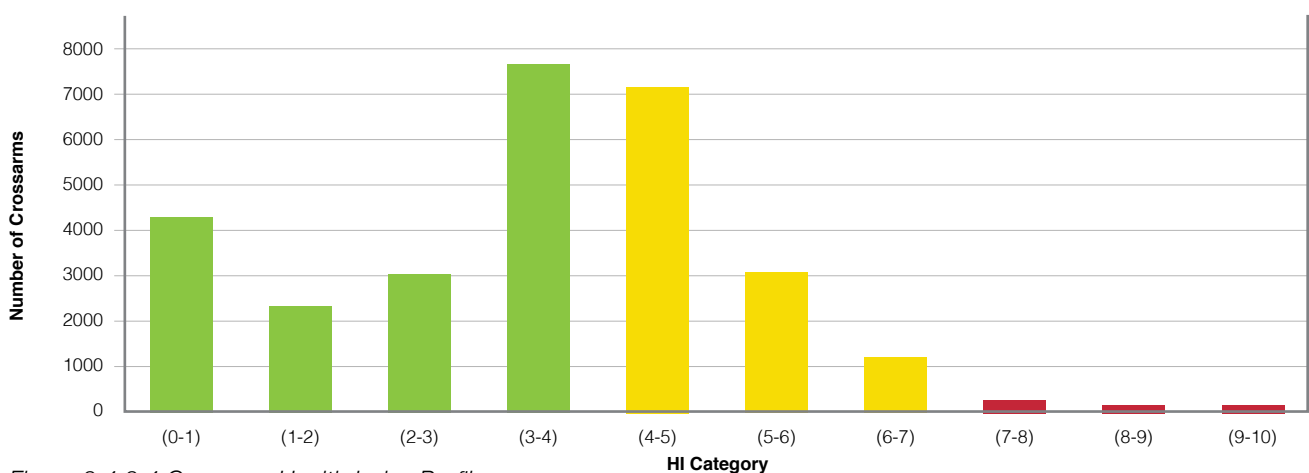


Figure 2.4.2.4 Crossarm Health Index Profile

2.3.6. DISTRIBUTION AND LV CONDUCTORS

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

Population

We own 3,275km of overhead distribution and LV lines, of which 1,938km is 11kV distribution lines and 1,337km is LV. Figure 2.4.3.1 shows the distribution of overhead conductor types.

DISTRIBUTION AND LV CONDUCTOR TYPES

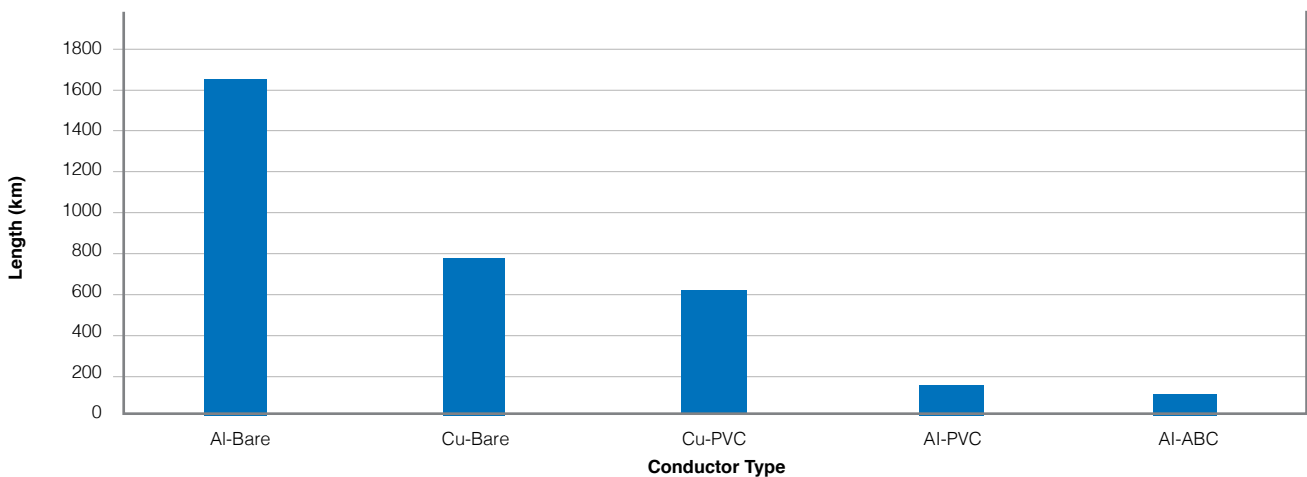


Figure 2.4.3.1 Distribution and LV Conductor Types

Figure 2.4.3.2 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 LINES

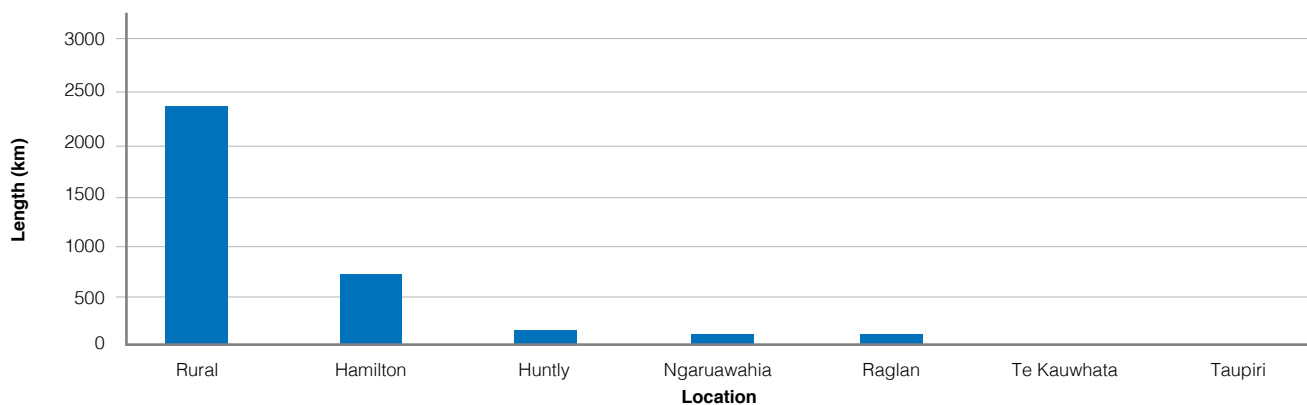


Figure 2.4.3.2 Location of Distribution of LV Lines

Age Profile

Figure 2.4.3.3 shows the age profile of all types of the distribution and LV conductors. The average age of our overhead conductors is 33 years.

AGE PROFILE OF DISTRIBUTION AND LV CONDUCTORS

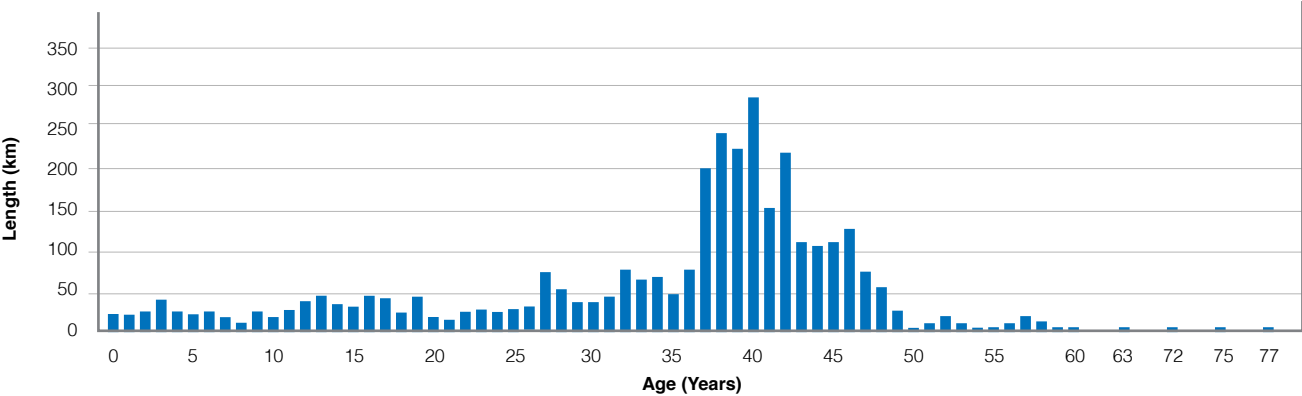


Figure 2.4.3.3 Age Profile of HV and LV Conductor

The spike in installing new conductors corresponds to the rapid expansion of the network during the 1970s. The life expectancy of conductors is 55 to 60 years depending on conductor type.

Condition

The condition distribution of overhead line conductors is shown in Figure 2.4.3.4.

CONDITION OF DISTRIBUTION CONDUCTORS

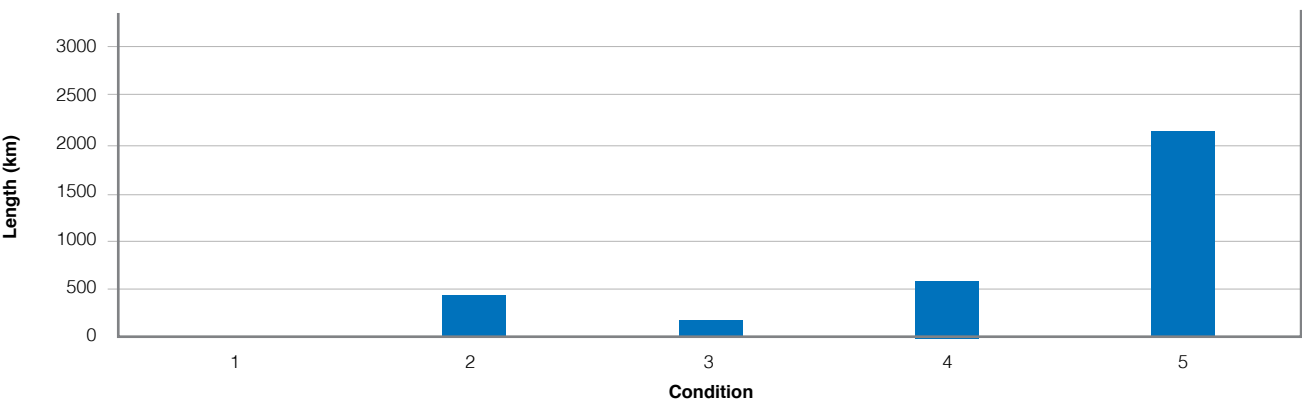


Figure 2.4.3.4 Condition of Distribution and LV Conductor

The condition is further supported by the AHI shown in Figure 2.4.3.5. Approximately 400km of distribution overhead line conductors are becoming poor in condition. These are predominantly 16mm² copper conductors which

are being analysed for replacement through the CBRM model. The majority of the conductors with an AHI of 7 or greater are the 16 mm² copper type. This issue and remedial actions are discussed further in Chapter 8.

DISTRIBUTION CONDUCTOR HEALTH INDEX PROFILE

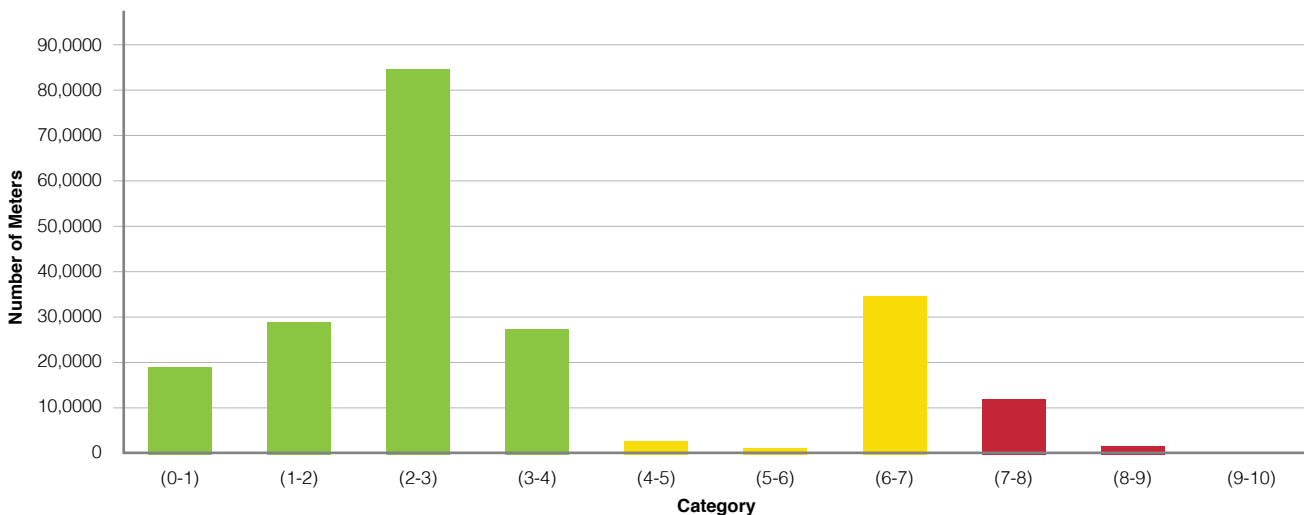


Figure 2.4.3.5 Distribution Conductor Health Index Profile

2.4. 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 approximately 6,200km, 47% of which is underground cables. This section describes our Distribution cables and LV cables.

2.4.1. DISTRIBUTION CABLES

Distribution cables form part of the 11kV distribution network.

Population

We own 680km 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 11kV underground network is now aluminium conductor (71%), the remainder is copper.

Age Profile

Figure 2.5.1 shows the age profile of the distribution cable. The average age of PILC cable is 39 years and the average age of XLPE cable is 15 years.

AGE PROFILE OF DISTRIBUTION CABLE

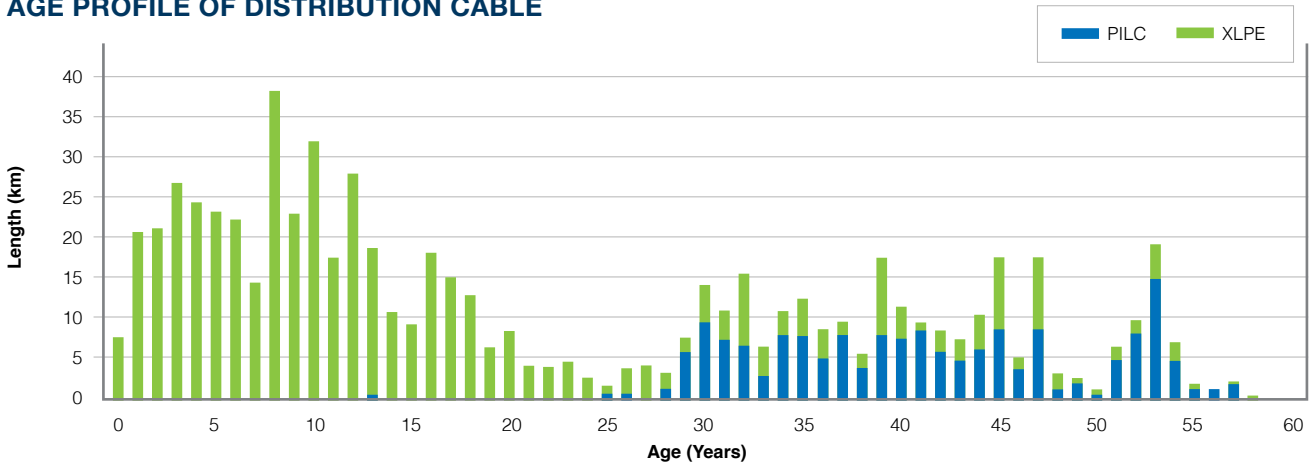


Figure 2.5.1 Age Profile of Distribution Cable

The life expectancy of cables is shown in Table 2.5.1 below.

Asset	Life expectancy (Years)
XLPE Cables	45
PILC Cables	70

Table 2.5.1 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 11kV ring around the CBD was built around 1945 and still supplies customers very reliably, this is not shown in figure 2.5.1 as the records regarding the installation dates are not reliable.

2.4.2. LV CABLES

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

Population

We have 2,246km of installed LV underground cable, of which 7km is PILC and the rest is XLPE. Figure 2.5.2.1 shows that the majority of LV XLPE cable is in the

Hamilton area. Figure 2.5.2.2 shows virtually all the LV PILC cable is in Hamilton, with a small amount in Huntly.

DISTRIBUTION OF LV XLPE TYPE CABLE

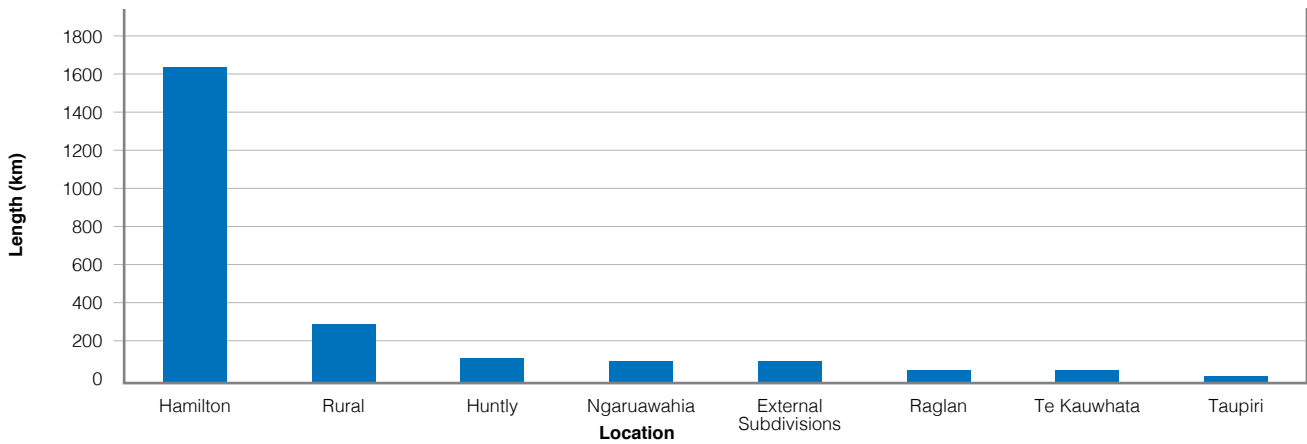


Figure 2.5.2.1 Location of LV XLPE Type Cable

This situation is similar for PILC Cable as shown in Figure 2.5.2.2.

DISTRIBUTION OF LV PILC TYPE CABLE

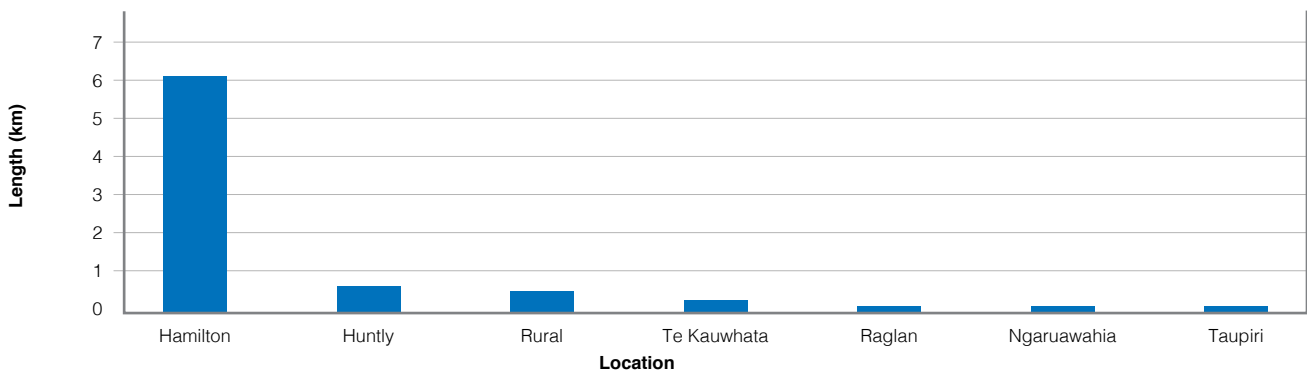


Figure 2.5.2.2 Location of LV PILC Type Cable

Age Profile

Figure 2.5.2.3 shows the age profile of the underground LV cables in the network. The average age of PILC cable is 68 years, because small amounts have been installed over the years, and the average age of XLPE cable is 21 years.

AGE PROFILE OF LV CABLE

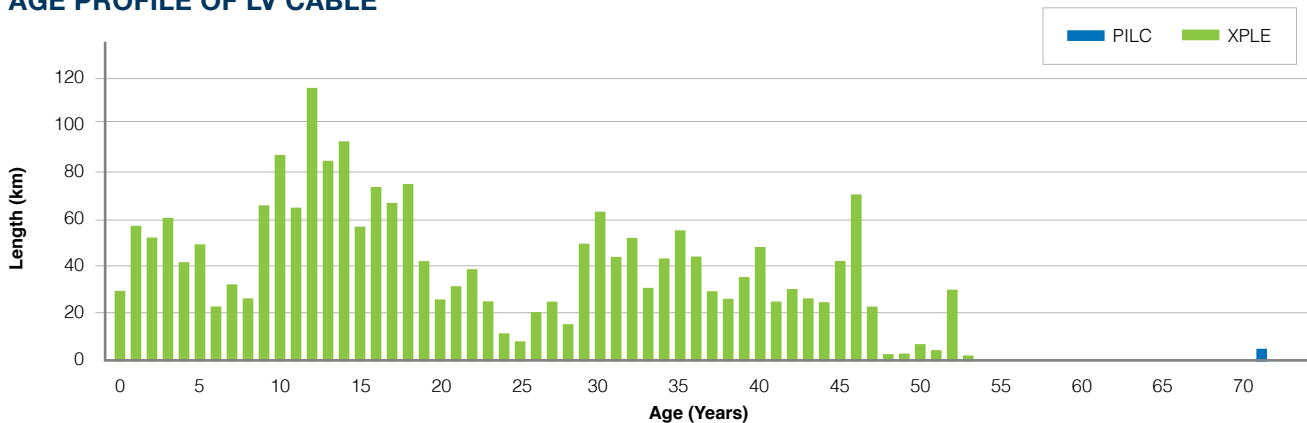


Figure 2.5.2.3 Age Profile of LV Cable

PILC cables have a life expectancy of 70 years and XLPE cables have a design life expectancy of 45 years as shown in Table 2.5.2.1. 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 2.5.2.1 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.

2.5. DISTRIBUTION SUBSTATIONS AND TRANSFORMERS

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

- Distribution switching stations; and
- Distribution transformers.

2.5.1. 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 operates 17 11kV switching stations that were installed between 1967 and 2012.

Age profile

The age profile of switching stations is shown in Figure 2.6.1.1.

AGE PROFILE OF SWITCHING STATIONS

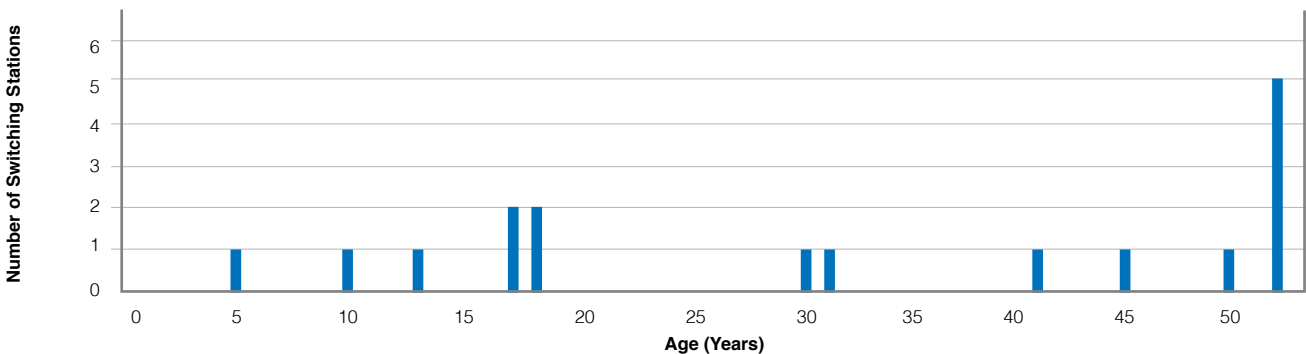


Figure 2.6.1.1 Age Profile of Switching Substations

Condition

The condition profile of switching stations is shown in Figure 2.6.1.2.

CONDITION OF SWITCHING STATIONS

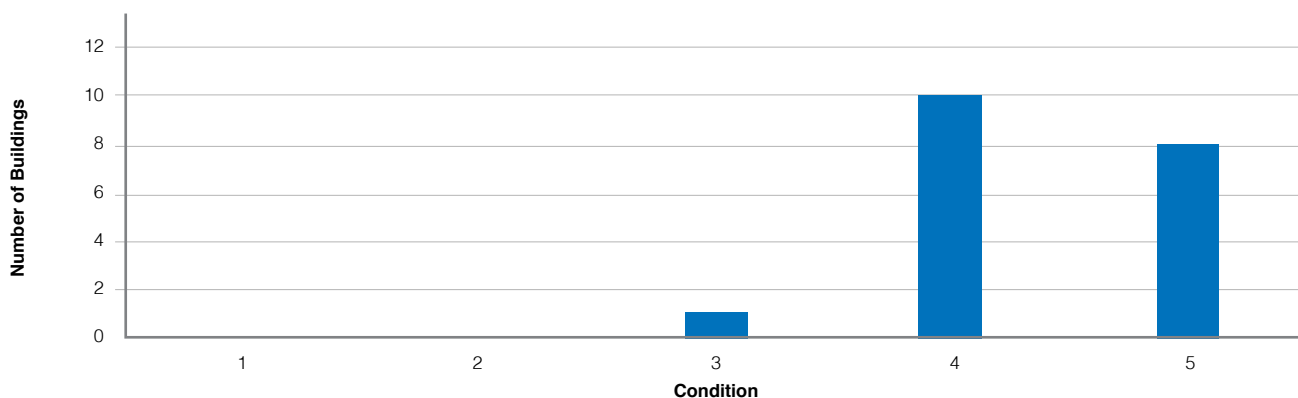


Figure 2.6.1.2 Condition of Switching Stations

The seismic ratings of most of the buildings have also been assessed. WEL commenced a programme of specialised seismic assessment in 2007. The results of the seismic assessment to date are shown in Figure 2.6.1.3. The three remaining switching stations were assessed in 2017 and two were assessed to have seismic

upgrades. These upgrades are planned for this financial year (2019) namely for Alexandra and Barton switching stations. The remaining switching station Garden Place, will be subject to investigation next financial year whether to proceed with numerous upgrades (including seismic) or move the station to another location.

SEISMIC CONDITION OF SWITCHING STATION BUILDINGS

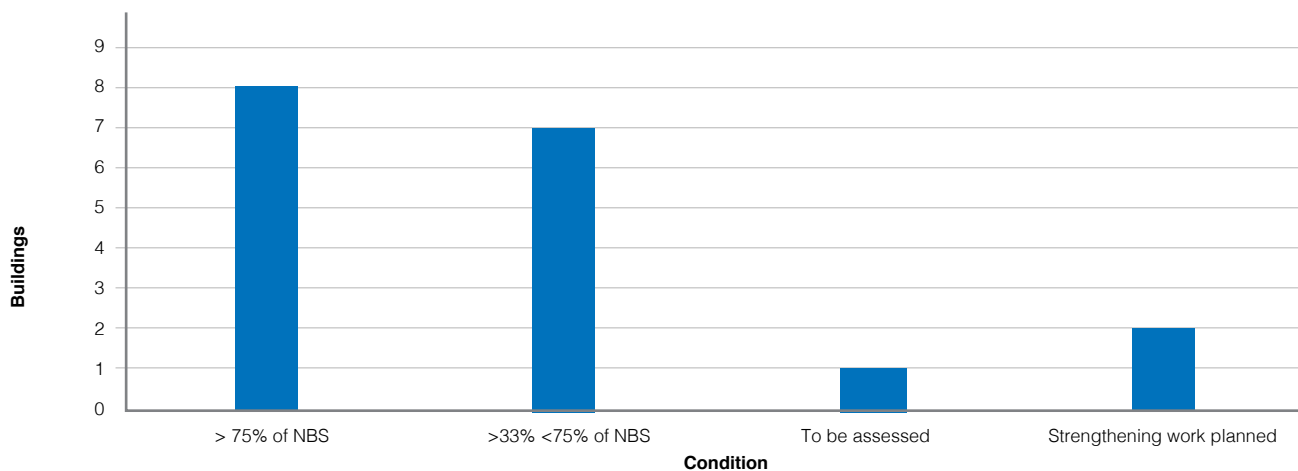


Figure 2.6.1.3 Seismic Condition of Switching Substations

All new WEL switching station buildings will be designed and built to IL4 standard. Seismic strengthening of existing Switching station buildings, where practical, shall be to IL3 and a minimum of 75% of NBS. Where it is not practical

to strengthen a building to the required level then a cost-risk analysis will be carried out to determine the most practical level.

2.5.2. 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 3,969 pole mounted transformers and 1,930 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

100kVA. Standard ground mounted transformer sizes are 100, 200, 300, 500, 750 and 1,000kVA.

The population of transformers in each size is shown in Figure 2.6.2.1.

POPULATION OF DISTRIBUTION TRANSFORMERS

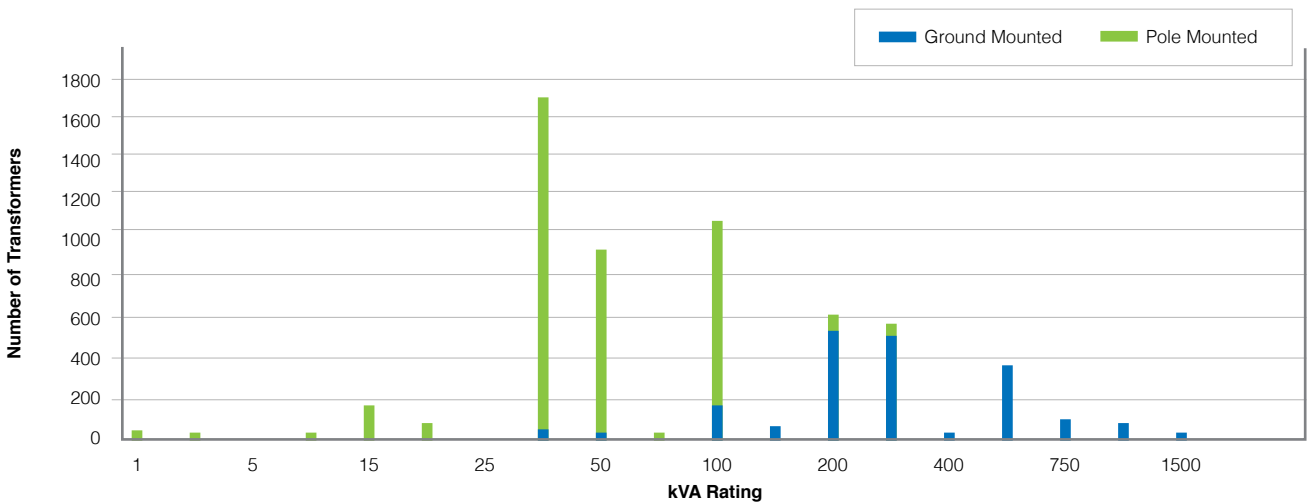


Figure 2.6.2.1 Population of Distribution Transformers

Age Profile

Figure 2.6.2.2 shows the age profile of our distribution transformers. The average age is 19 years. 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.

AGE PROFILE OF DISTRIBUTION TRANSFORMERS

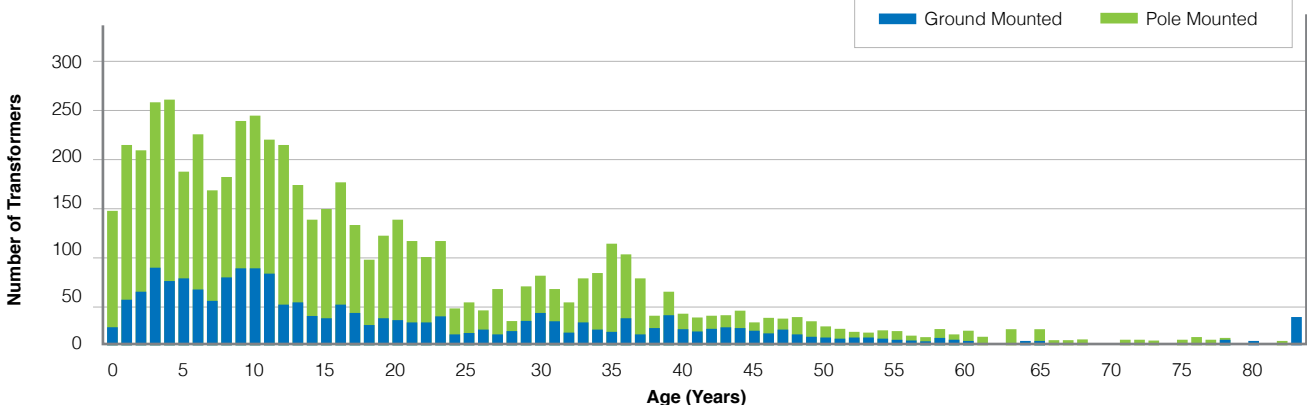


Figure 2.6.2.2 Age Profile of Distribution Transformers

Condition

Figure 2.6.2.3 shows the condition profile of our distribution transformers. We have a total of 13 distribution transformers in poor condition however, these will be replaced in financial year 2019.

CONDITION OF DISTRIBUTION TRANSFORMERS

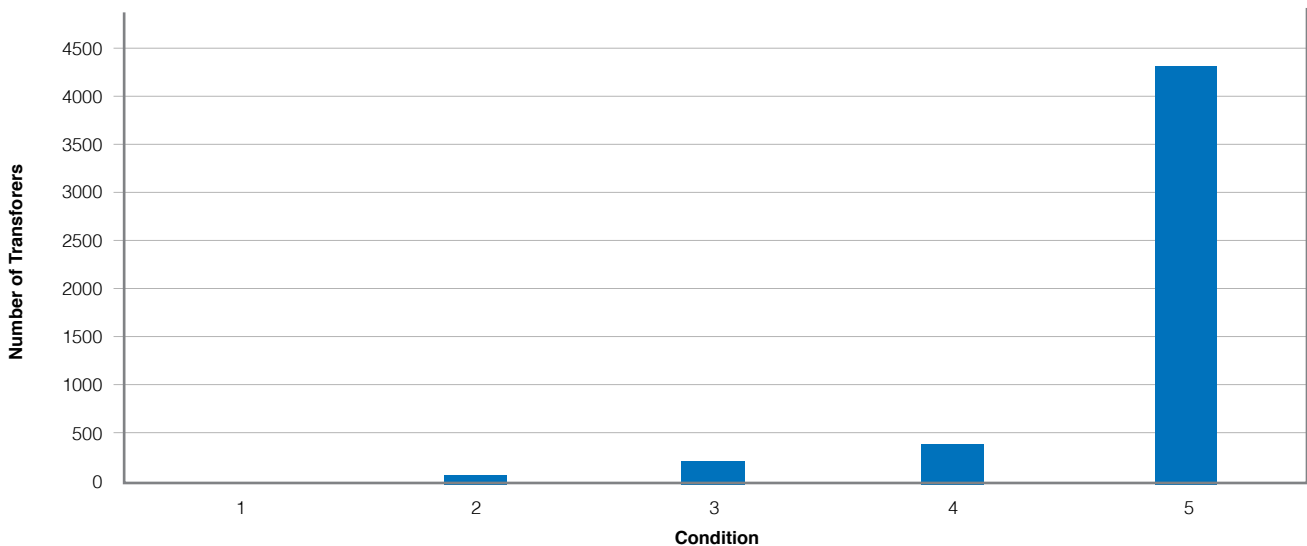


Figure 2.6.2.3 Condition of Distribution Transformers

The AHI for distribution transformers is shown in Figure 2.6.2.4. The AHI and the factors used to assess an asset are explained in section 2.1.

DISTRIBUTION TRANSFORMERS HEALTH INDEX PROFILE

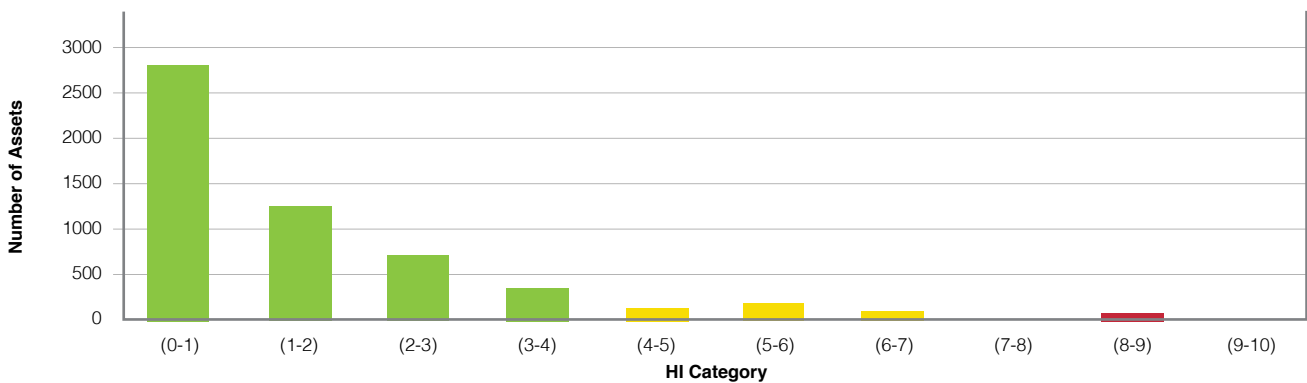


Figure 2.6.2.4 Distribution Transformers Health Index Profile

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.

2.6. DISTRIBUTION SWITCHGEAR

Four switch types exist within our network. These are:

- Ring Main Units (RMUs);
- Circuit Breakers;
- Air Break Switches (includes the modern SF6 and Vacuum types); and
- Reclosers and Sectionalisers.

Each switch type is discussed in the following sections.

2.6.1. RING MAIN UNITS (RMU)

RMUs are ground mounted switchgear that connects to 11kV cables. There are 1,002 RMUs in operation on the network ranging from new to approximately 60 years old. Older RMUs are typically oil insulated with all new RMUs being SF6 gas-insulated switchgear.

Population

The RMUs are a mixture of oil filled and gas filled types, as shown in Figure 2.7.1.1.

TYPE OF RMUs

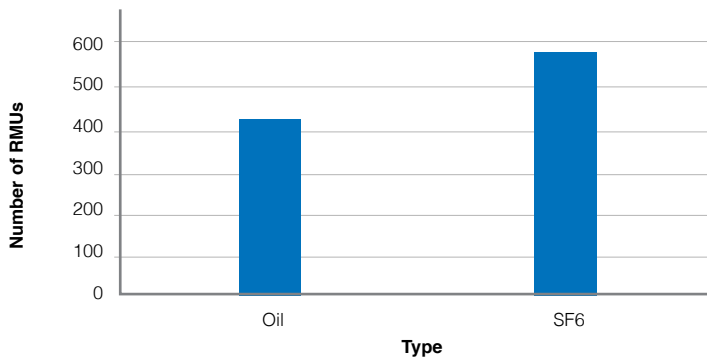


Figure 2.7.1.1 RMU Types

Age Profile

The age profile of RMUs is shown in Figure 2.7.1.2. The average age is 15 years.

AGE PROFILE OF RMUs

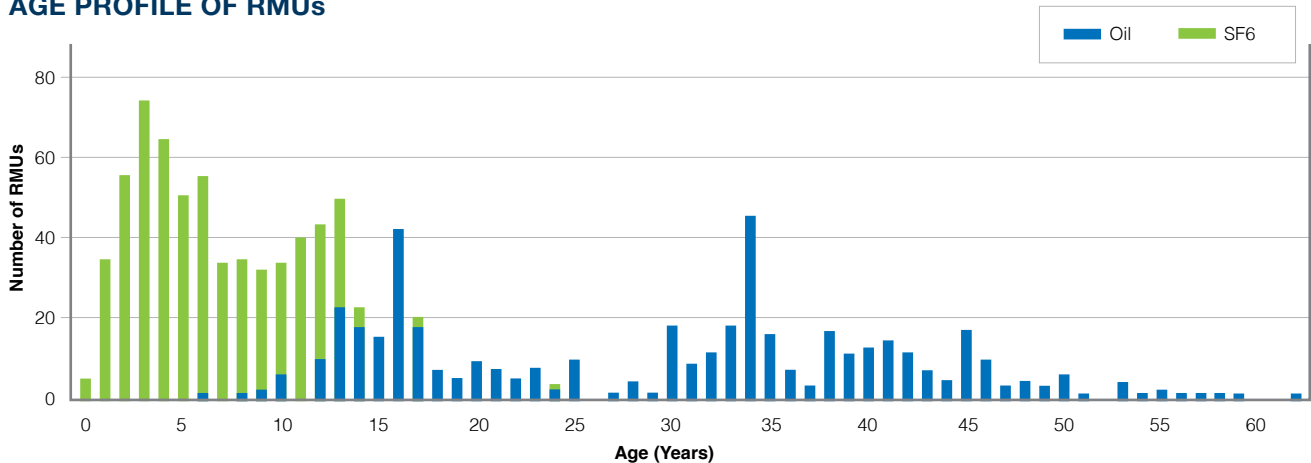


Figure 2.7.1.2 Age Profile of RMUs

The life expectancy of RMUs is detailed in Table 2.7.1.1.

Asset	Life expectancy (Years)
Oil Filled RMU	40
Gas Filled RMU	55

Table 2.7.1.1 Life Expectancy of RMUs

Condition

The distribution of RMU conditions is shown in Figure 2.7.1.3.

CONDITION OF RMUs

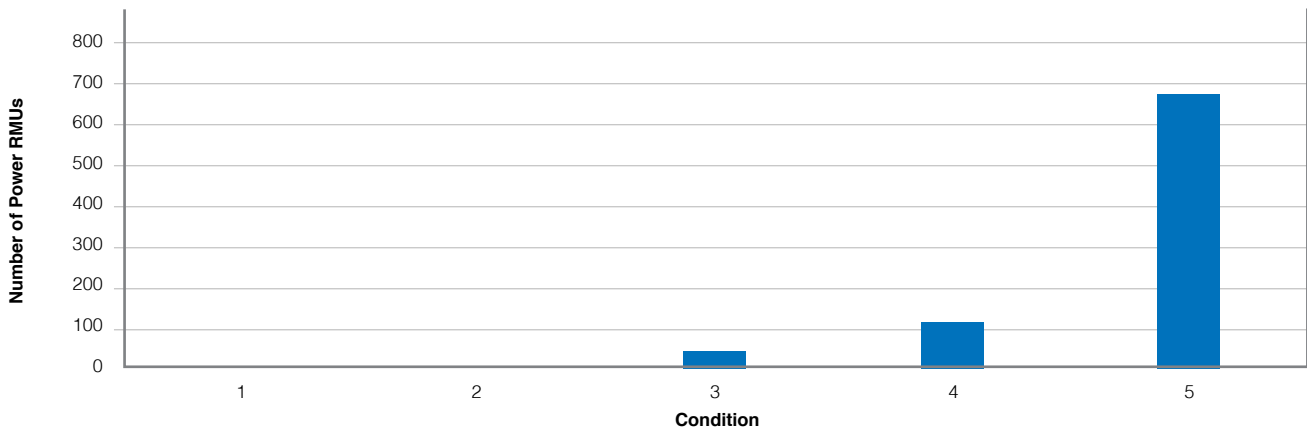


Figure 2.7.1.3 Condition of RMUs

A few oil filled RMUs failed from misalignment 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 2.7.1.4. The AHI and the factors used to assess an asset are explained in section 2.1.

RMU HEALTH INDEX PROFILE

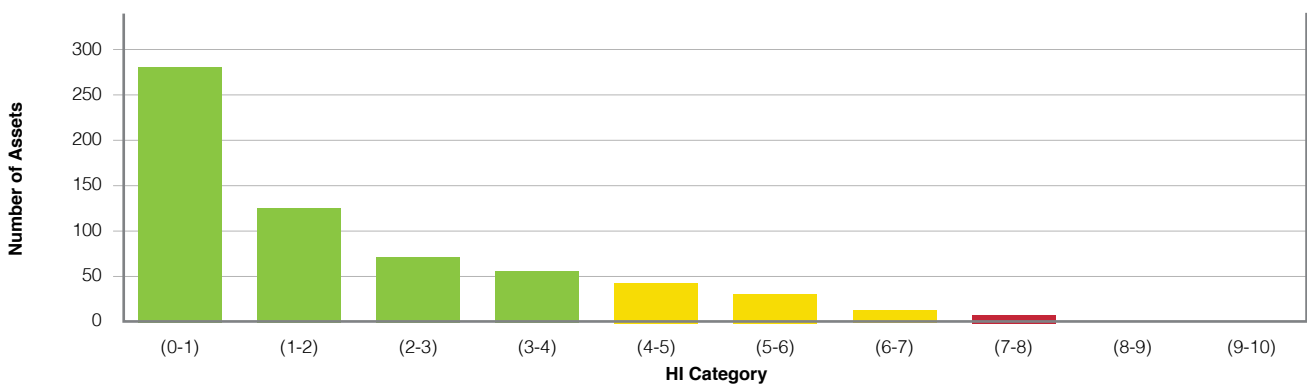


Figure 2.7.1.4 RMU Health Index Profile

2.6.2. 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. Automated CBs can be remotely controlled and monitored via SCADA.

Population

We have 448 CBs on our network which range in age from new to over 45 years old. The CBs deployed are a mix of technologies which include oil filled, SF6 and vacuum as shown in Figure 2.7.2.1.

The oil-filled CBs are the oldest followed by SF6 and vacuum types.

DISTRIBUTION CB TYPES

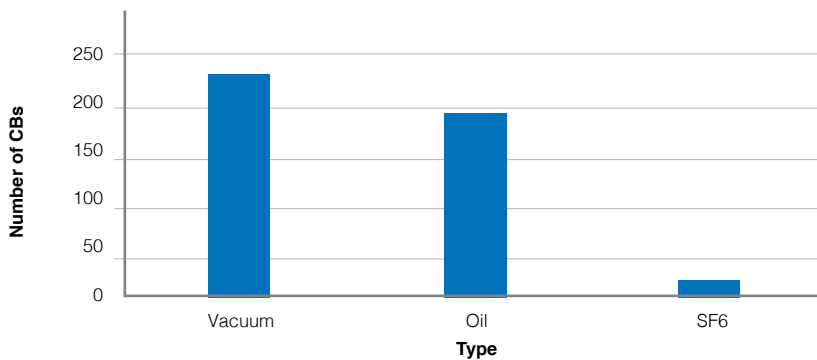


Figure 2.7.2.1 Distribution CB Types

Age Profile

The age profile is shown in Figure 2.7.2.2. The average age of the fleet is 13 years. The replacement of the oldest CBs will be completed in financial year 2019.

AGE PROFILE OF DISTRIBUTION CBs

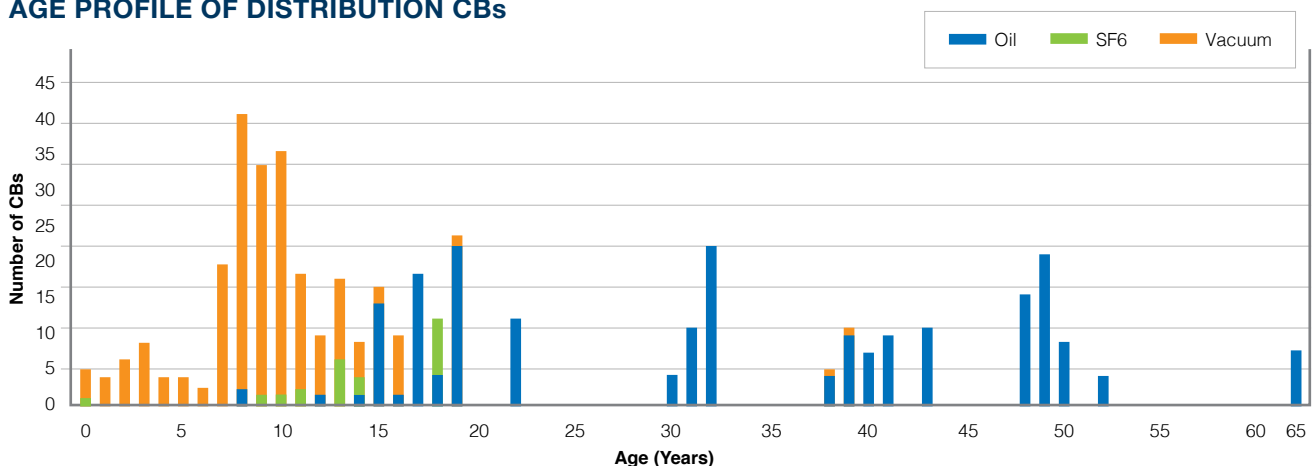


Figure 2.7.2.2 Age Profile of Distribution CBs

The life expectancy of CBs by type is shown in Table 2.7.2.1.

Asset	Life expectancy (Years)
Oil	45
SF ₆	55
Vacuum	55

Table 2.7.2.1 Life Expectancy of Distribution CBs

Condition

The condition of CBs is summarised in Figure 2.7.2.3.

CONDITION OF CBs

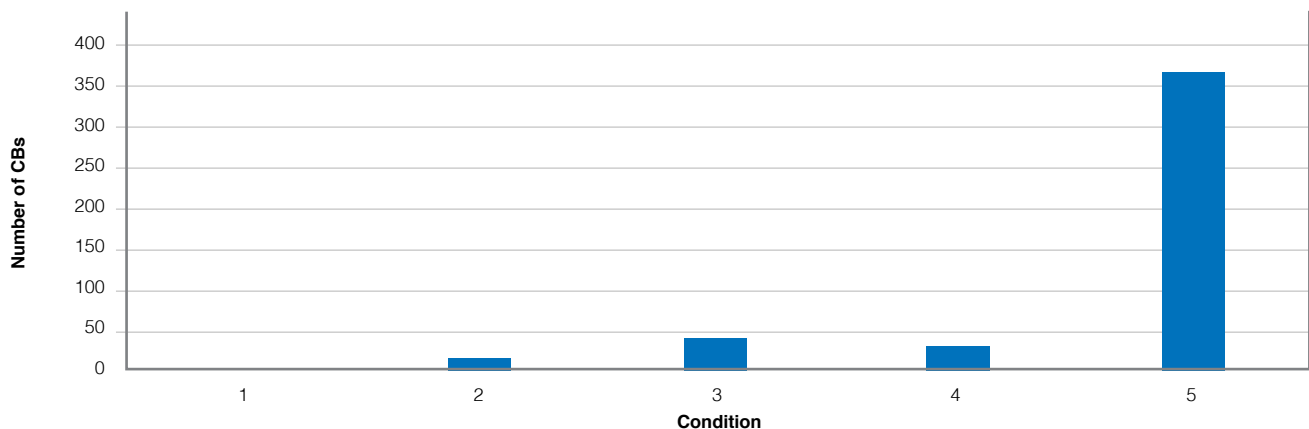


Figure 2.7.2.3 Condition of CBs

Routine condition monitoring indicates there are no significant maintenance problems. Overall the condition of the circuit breakers is good and the rate of operation is well below the annual rate that equates to end of life at 60

years. Therefore, the life expectancy is likely to exceed the standard life of each type of CB. Vacuum and SF6 CBs are now used for all new installations, as they have low maintenance requirements.

2.6.3. DISTRIBUTION AIR BREAK SWITCHES (ABS)

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.

Population

We own 930 ABSs where approximately 77 can be operated remotely from our centralised control room. This has the dual advantage of reducing SAIDI and improving safety. The location of our ABSs is shown in Figure 2.7.3.1 below. Large proportions are in the rural areas as remote control capability in rural areas provides greater benefit than in urban areas.

DISTRIBUTION OF ABS

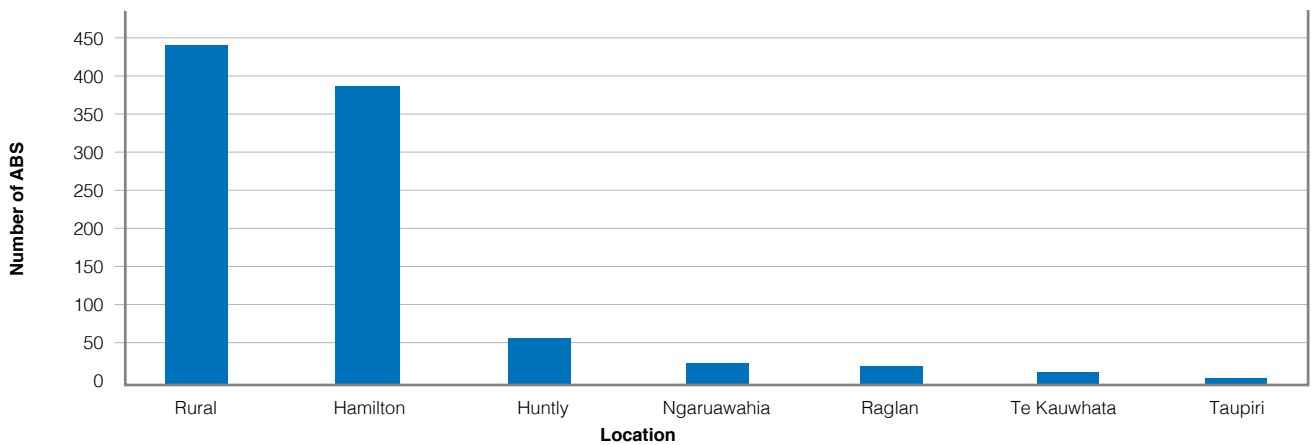


Figure 2.7.3.1 Distribution of ABSs

Age Profile

The age profile of ABSs is shown in Figure 2.7.3.2. The average age is 22 years.

AGE PROFILE OF ABS

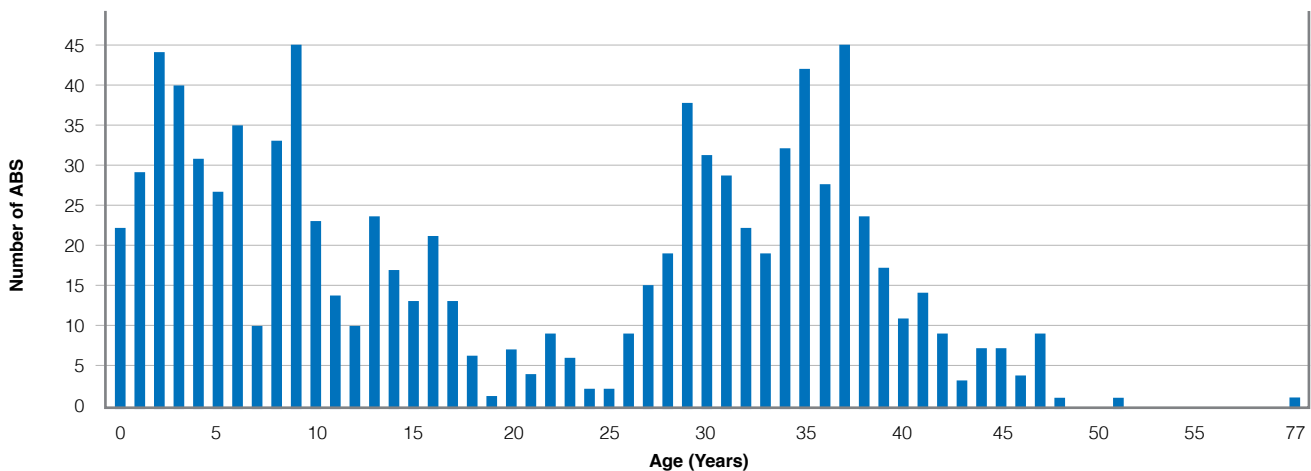


Figure 2.7.3.2 Age Profile of ABSs

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 2.7.3.3. The AHI profile of ABSs is shown

in Figure 2.7.3.4 and indicates a substantial number of ABSs have 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 ABS

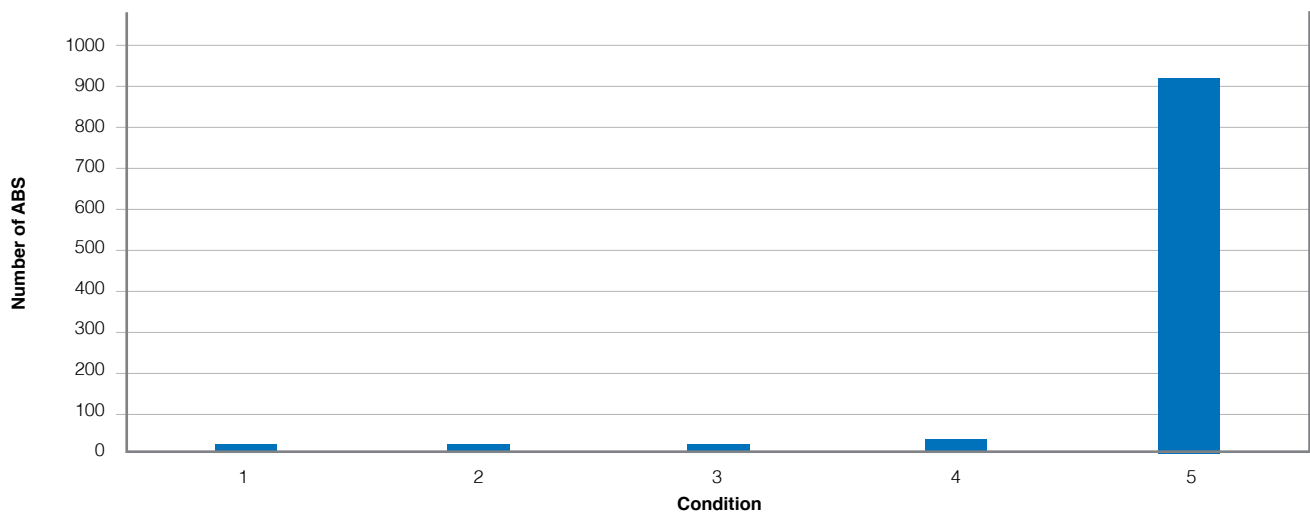


Figure 2.7.3.3 Condition Profile of ABS

ABS HEALTH INDEX PROFILE

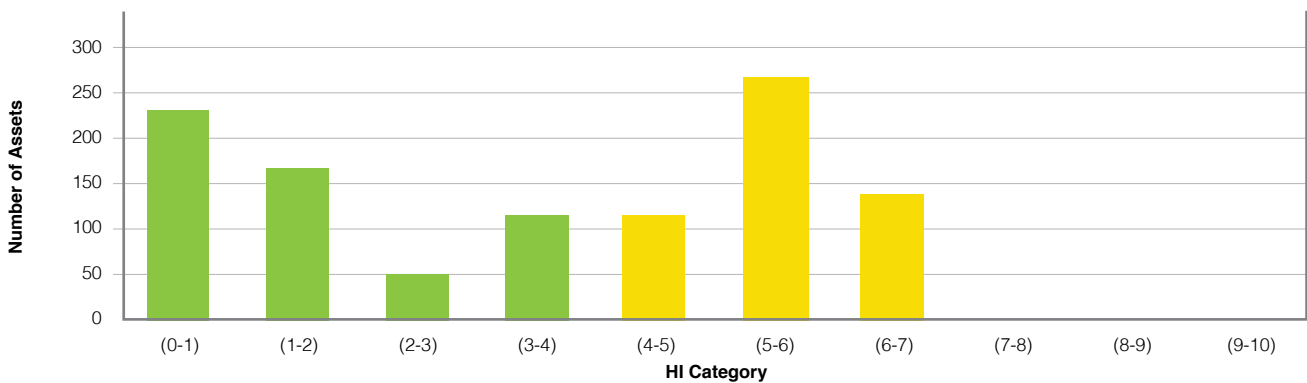


Figure 2.7.3.4 ABS Health Index Profile

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

the information provided does not include weaknesses such as impending insulator failure. The AHL 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 AHL.

2.6.4. DISTRIBUTION RECLOSERS AND SECTIONALISERS

Sectionalisers are self-contained, circuit-opening devices used in conjunction with reclosers to automatically isolate faulted sections of the network. Sectionalisers also allow operators to locate a fault more accurately and quickly, as well as minimising the number of customers affected by any one fault.

A recloser, is a circuit breaker equipped with a mechanism that can automatically close the breaker after it has been

opened due to a fault. Reclosers are used to detect and interrupt momentary faults and have the ability to automatically restore power to the line subject to the fault.

Population

We own 64 sectionalisers and 69 reclosers. There are a mix of the enclosed sectionalisers and reclosers on our network as shown in Figure 2.7.4.1.

RECLOSERS AND SECTIONALISERS BY TYPE

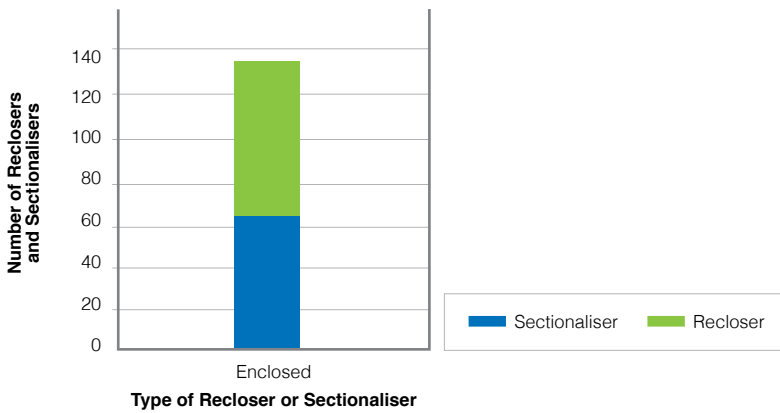


Figure 2.7.4.1 Distribution of Recloser & Sectionalisher Types

Age Profile

Figure 2.7.4.2 shows age profile of the reclosers and sectionalisers. The dropout sectionalisers, which were installed in 2004 and 2005 as part of reliability improvement programme, have been all replaced as they have become operationally problematic.

AGE PROFILE OF RECLOSERS AND SECTIONALISERS

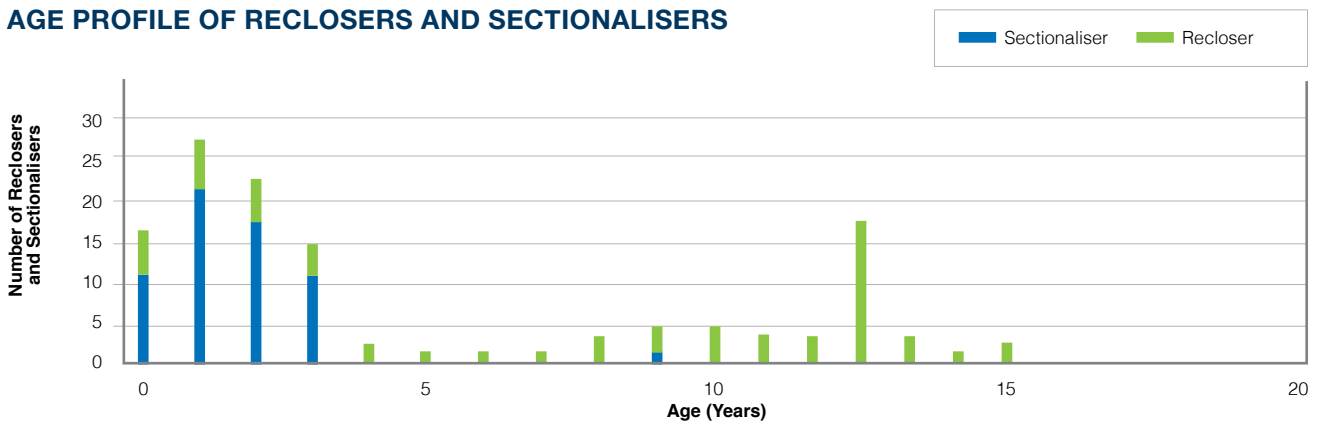


Figure 2.7.4.2 Age Profile of Reclosers & Sectionalisers

The life expectancy of sectionalisers and reclosers is 40 years. The average age of the fleet is five years.

Condition

All reclosers are generally in good condition. Ancillary devices such as COMMs protection and battery systems are maintained periodically. The condition profile is shown in Figure 3.2.4.3.

CONDITION OF RECLOSERS AND SECTIONALISERS

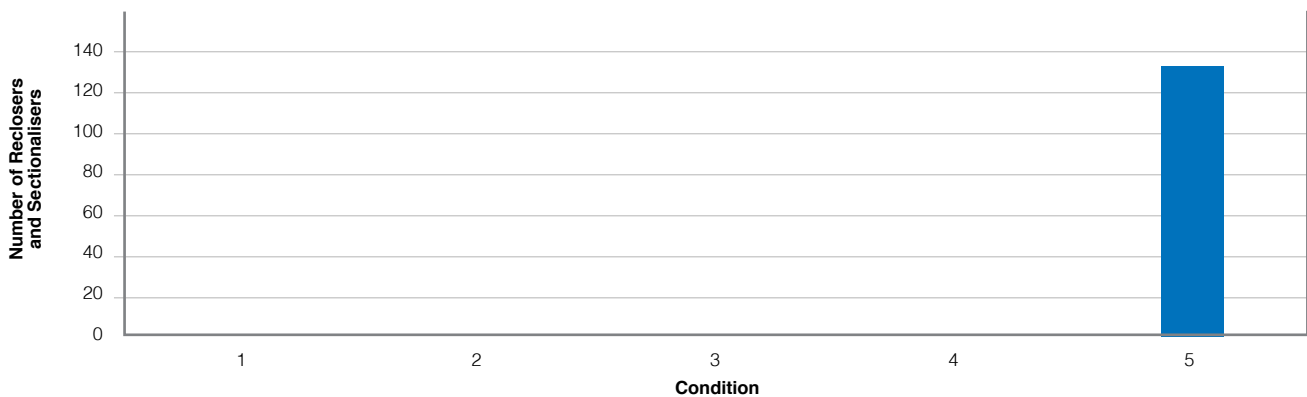


Figure 2.7.4.3 Condition of Reclosers & Sectionalisers

Figure 2.7.4.4 shows the AHI of the sectionalisers and reclosers. The AHI is further explained in section 2.1.

RECLOSERS AND SECTIONALISERS HEALTH INDEX PROFILE

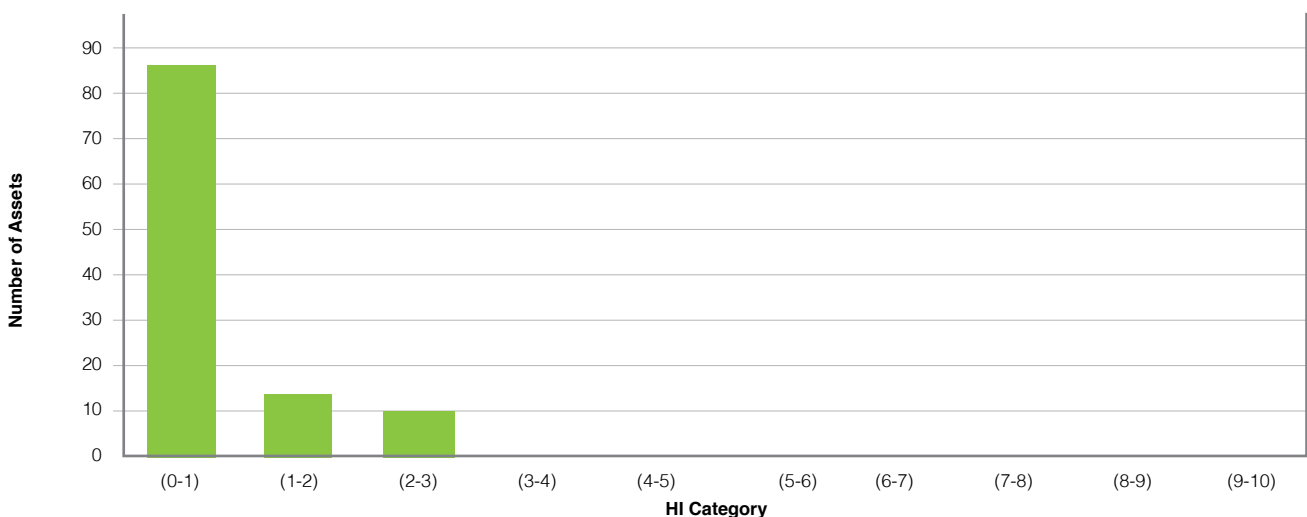


Figure 2.7.4.4 Reclosers & Sectionalisers Health Index Profile

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

2.7. OTHER NETWORK 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

2.7.1. 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 25,771 LV pillars on the network.

Age Profile

The age profile of LV pillars is shown in Figure 2.8.1.1.

AGE PROFILE OF LV PILLARS

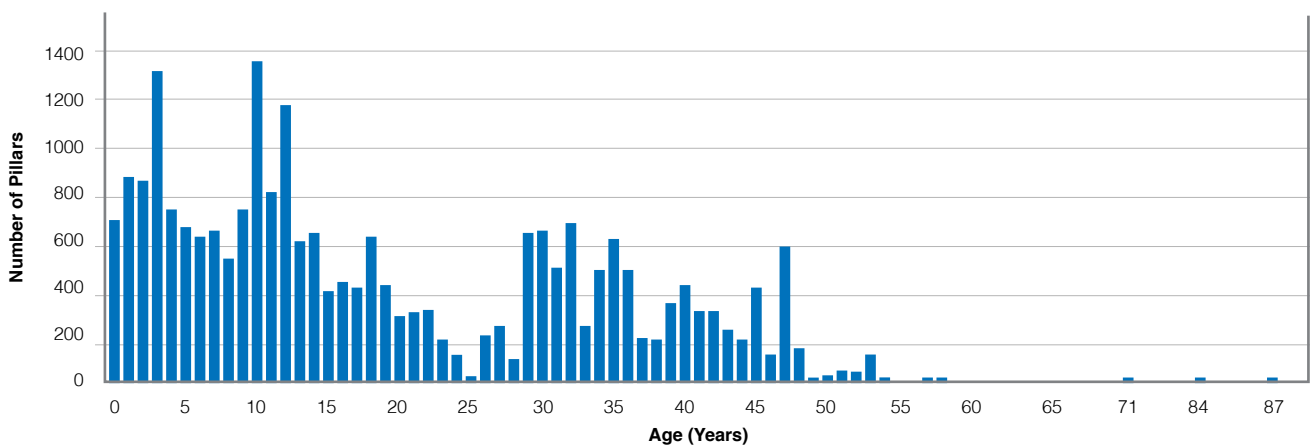


Figure 2.8.1.1 Age Profile of LV Pillars

Condition

The condition of LV pillars is shown in Figure 2.8.1.2. They are in good condition, but if the lid is open they can be a public health risk, so are patrolled regularly.

CONDITION OF LV PILLARS

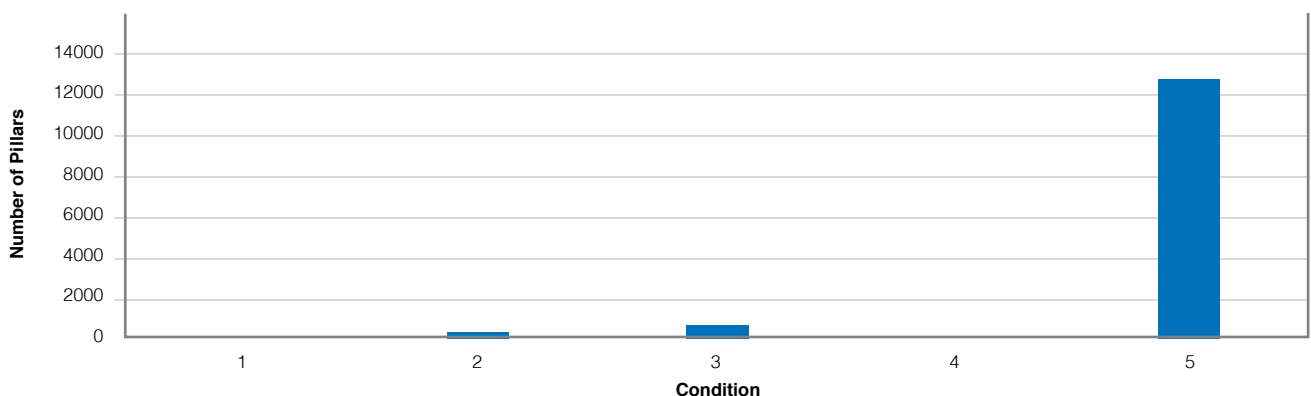


Figure 2.8.1.2 Condition of LV Pillars

2.7.2. 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 655 relays in total, with a mixture of electromechanical and numeric protection relays, with electromechanical representing the older relays. The distribution of relays is shown in Figure 2.8.2.1 below.

TYPE OF PROTECTION EQUIPMENT

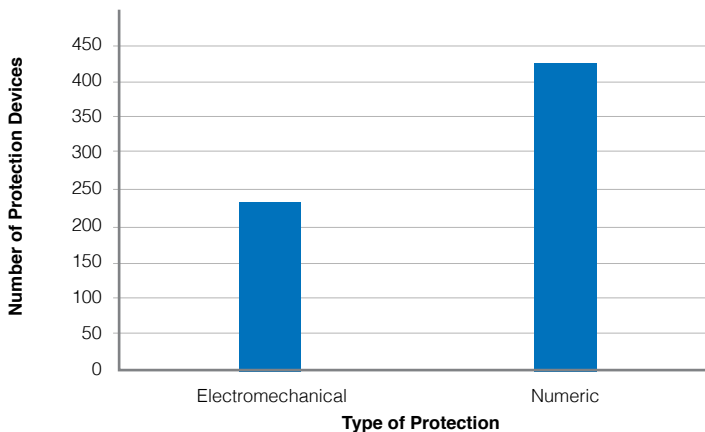


Figure 2.8.2.1 Type of Protection Equipment

Age Profile

Figure 2.8.2.2 illustrates the age profile of the protection equipment.

AGE PROFILE OF PROTECTION EQUIPMENT

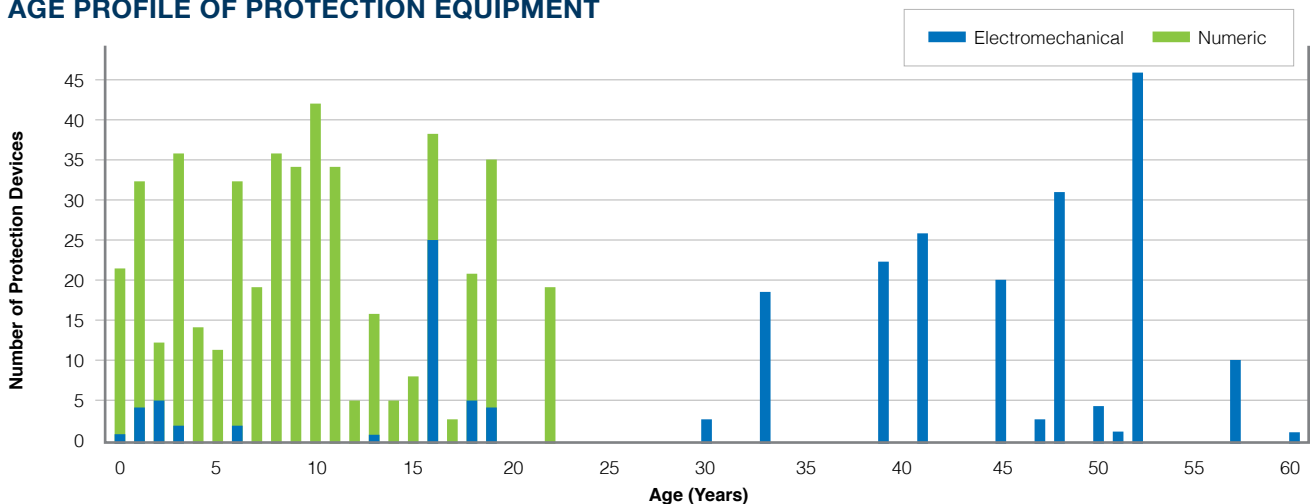


Figure 2.8.2.2 Age Profile of Protection Equipment

The average age of the protection relays on our network is 20 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 condition is shown in Figure 2.8.2.3.

CONDITION OF PROTECTION EQUIPMENT

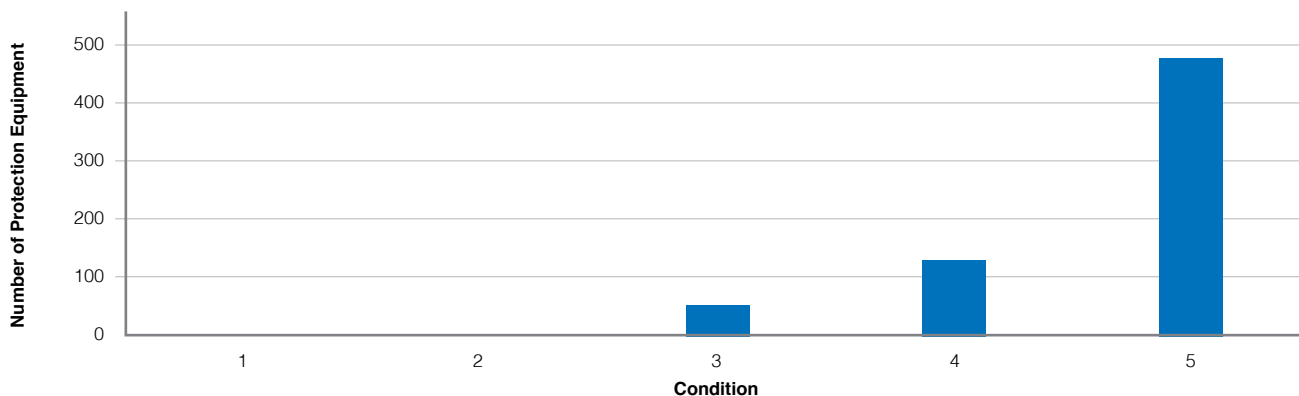


Figure 2.8.2.3 Condition of Protection Equipment

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.

2.7.3. NETWORK MANAGEMENT SYSTEM (NMS)

The NMS enables the fast and efficient control of the electricity network for the operator. It consists of the General Electric PowerOn Fusion software package and data storage systems integrated with our Supervisory Control And Data Acquisition (SCADA) network. The 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. NMS is further discussed in Chapter 7 Non-Network Solutions and Investments.

Population

We own 389 RTUs. The older fleet are progressively being upgraded or replaced to provide improved functionality and communications capability. Figure 2.8.3.1 shows the location of our RTUs.

DISTRIBUTION OF RTUs

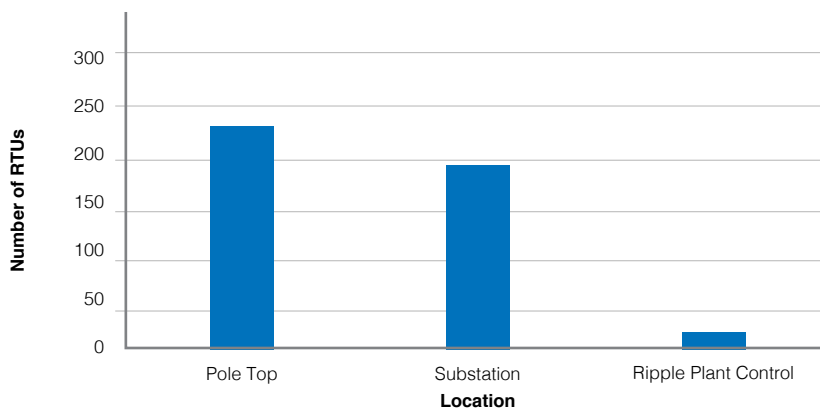


Figure 2.8.3.1 Location of Remote Terminal Units

Age Profile

The lifecycle of the NMS software is approximately 15 years. The NMS software was initially commissioned in December 2010 and the last upgrade was completed in April 2017.

The life expectancy of the supporting infrastructure, including the RTUs, is 15 years. The average age is 8.5 years. The age profile of NMS related equipment (RTUs) is shown in Figure 2.8.3.2.

AGE PROFILE OF RTUs

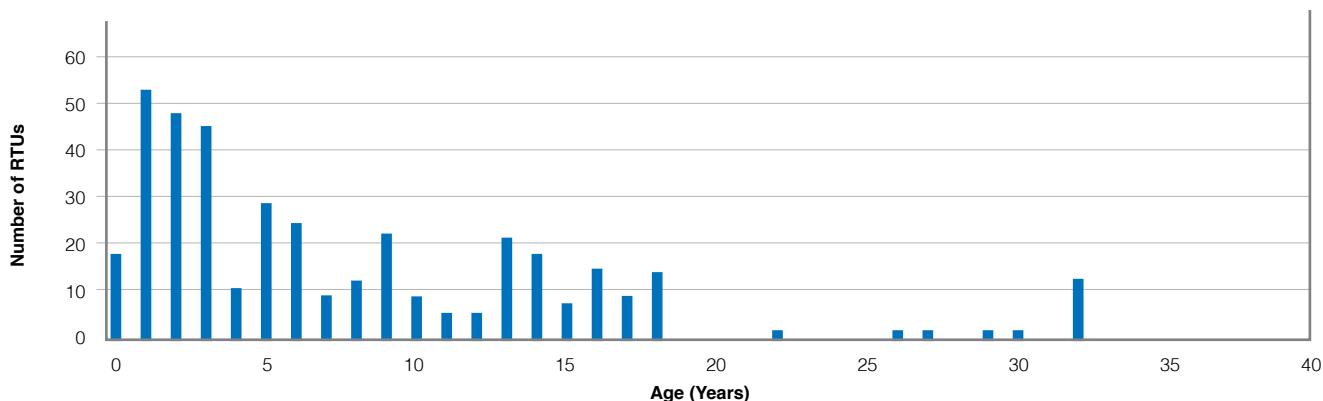


Figure 2.8.3.2 Age Profile of NMS Infrastructure

Condition

The condition of the control room NMS equipment is good with all computer hardware replaced in March 2015. The software upgrade was completed in April 2017.

2.7.4. 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. Furthermore load management functionality is used to manage the total Regional Coincident Peak Demand (RCPD). Other controls provided by the load management system include street lighting and meter tariff rate control.

Population

We own three 33kV static ripple injection sets and two 11kV static sets which operate at 283Hz. WEL has

another five 'out of service' ripple injection sets in the process of removal from sites.

Load Control Equipment is generally located at GXPs and where other signal propagation issues exist. Specifically the 33kV injection plants are located at the Hamilton GXP, Te Kowhai GXP and Weavers substation for the Northern area. The 11kV static sets are located at Pukete and Hamilton 11kV zone substations.

Between 2004 and 2006 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 Meters in the northern region was the opportunity to replace the old ripple relays with new ones fitted to the Smart Meters. This project is now finished; the old ripple plant has been switched off and decommissioned.

Age Profile

The life expectancy of a load control plant is 20 years. The age profile of our load control equipment is shown in Figure 2.8.4.

AGE PROFILE OF LOAD CONTROLLERS

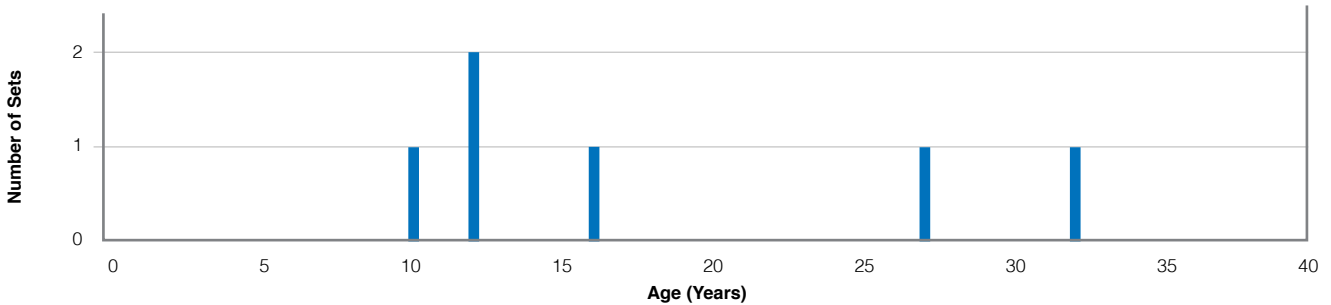


Figure 2.8.4 Age Profile of Load Controllers

Condition

The load control plants are within their life expectancy and are generally in good condition.

2.7.5. METERS

WEL has a range of meters from 33kV meters down to LV smart meters. Further information about the Smart meter system is contained within section 7.

Population

The subtransmission and distribution meters are used for revenue protection, load control, operation, fault management and network protection. WEL has currently 58,027 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. All smart meters can also act as data loggers returning data quality information.

Age Profile

The average age of the subtransmission and distribution meters is 3 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 life span of 15 years. The number of Smart Boxes installed over recent years is shown in Figure 2.8.5.

SMART METER AGE PROFILE

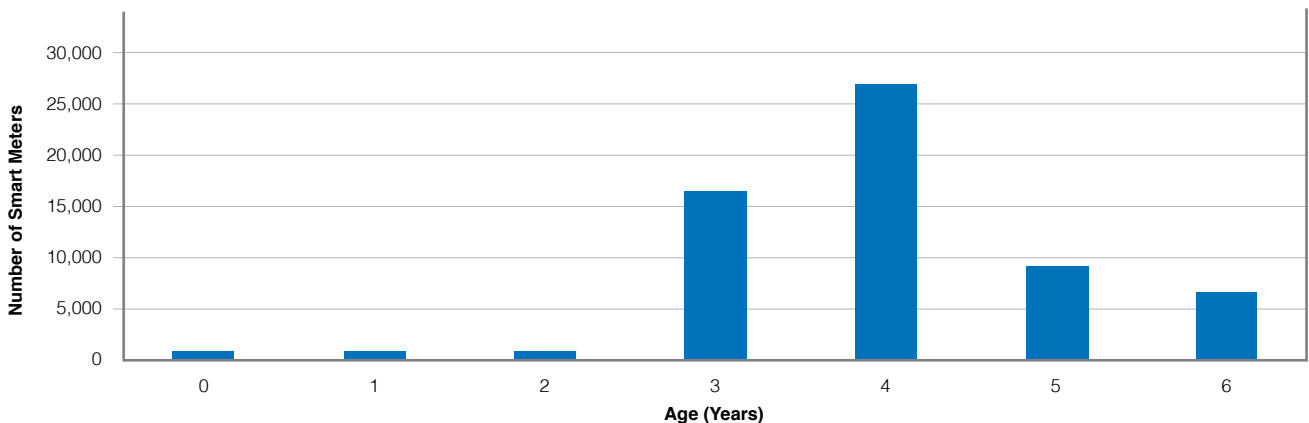


Figure 2.8.5 Smart Meters Installed per Year

Condition

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

2.8. OTHER ASSETS

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

2.8.1. 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 100kVA

generator at the DRC site is only a year old and in excellent condition (condition 5). The depot's 100kVA generator is six years old and in good condition (condition 4).

2.8.2. EMERGENCY CRITICAL SPARES

We hold the following critical spares reserved for emergency conditions:

- 4km of overhead 33kV line;
- Substation battery bank;
- Protection relays;
- Substation communication equipment;
- Five zone transformers, 2x 10MVA, 2x 15MVA and 1x 23MVA transformers;

- One 33kV circuit breaker;
- 33kV and 11kV sectionalisers and reclosers; and
- 33kV and 11kV air break switches.

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

2.8.3. HEAD OFFICE AND DEPOT BUILDINGS

We own our Head Office building and the depot for our field staff. These buildings are 9 and 10 years old respectively. Our Head Office has a four star energy efficiency rating. Both buildings are in very good condition.

2.8.4. COMPUTER HARDWARE, SOFTWARE AND DATA

The core software packages within WEL are Network Management System (NMS), Geographic Information System (GIS), Enterprise Resource Planning (ERP), Network Billing System, Electronic Content

Management and Mobility Systems. These are further discussed in Chapter 7 – Non-Network Solutions and Support Systems.

2.8.5. OTHER OPERATIONAL ASSETS

We have a number of miscellaneous assets including safety equipment, test equipment and vehicles. The safety and test equipment is replaced as needed.

2.9. 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.





APPROACH TO ASSET MANAGEMENT



3

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.

3.1. STAKEHOLDER REQUIREMENTS

Chapter 1 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
- Environmental management
- Regulators
- Transpower
- Service providers
- Staff
- 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 are described in Chapter 5 and our security standards are discussed in Chapter 6.

Our Customers

We conduct a survey every two years to inform us of customers' views about the price and quality of service that we provide. This year's survey is compared to the 2015 survey results to understand and appreciate any changes to our customers' viewpoint. The 2015 survey results indicated that our rural customers were expecting an improvement in performance, through the reduction of both the duration and number of outages. The following are the comparative results.

- 10% decrease of rural customers who had experienced an outage.
- 10% increase of rural customers expressing that the reliability of supply is better than they expected.
- 20% decrease in rural customers who would like to see a further improvement in reliability.

The survey result corresponds to the actual reliability measure data as shown in Table 3.1.1. This improvement is also shown in Chapter 5 on the 10 worst performing feeders.

Reliability Measures (Actual)	2015	2017
Rural SAIDI (weighted)	285	244
Rural SAIFI (weighted)	4.86	3.53

Table 3.1.1 Actual Reliability data

To improve rural reliability, WEL embarked on a two point approach from FY2015 as follows:

- (1) An annual budget was allocated for rural asset replacement projects such as the 16mm² copper overhead line reconductoring project. Using CBRM, we identified and prioritised when and where these asset replacement projects should take place.
- (2) An annual budget was allocated to minimise rural customer numbers affected when a fault occurs. This is by network segmentation using reclosers and sectionalisers and also installing additional switches for backfeed purposes. These devices provide real time information to control room staff to enable fault diagnoses and devices can be remotely operated to reduce restoration time.

Further to the above, we use our smart meter data instantaneous voltage readings to optimise portions of the network that can be back fed during unplanned and planned outages. The above survey result indicates we are on the right path.

Further to the price quality survey results:

- The survey indicates that our customers prefer to have more short outages than fewer long outages.
- The indicated reasonable time to be without power is 45mins to 1-hour except for urban commercial establishments, which require less than 30mins, otherwise the results remain unchanged.
- Similar results apply for acceptable outage frequency, which is two outages per year.

Retailers

WEL has 24 retailer brands operating on our network. Customers on WEL's network engage with retailers for the sale and purchase of electricity. WEL has a good relationship with the retailers and engages and consults with retailers where appropriate.

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 and implementation of a Public Safety Management System (PSMS). 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 Management System as a basis for managing our activities in the field. Our field staff are trained in how to identify potential environmental impacts and how to respond in the case of an environmental incident. Environmental considerations are discussed prior to commencing work.

Regulators' 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. Compliance with regulation is a key requirement of the regulatory bodies and is consequently a key focus for us. The publication of this AMP is an example of a regulatory requirement being met. In general, our regulators require our compliance, constructive input and collaboration to assist them in fulfilling their duties.

Transpower

Transpower is one of our largest suppliers of services and we are co-dependant on each other for the effective delivery of electricity to meet our customer expectations. Transpower requires us to 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. Electricity Industry Participation Code requirements are met through our established procedures and practices, and monitored through our risk and compliance framework.

Service Providers

We rely on service providers 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 is critical to our business. They enable us to deliver on customer and stakeholder expectations. As such, staff safety and wellbeing is critical to our success.

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 "Enabling our communities to thrive."

3.1.1. 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.

3.2. 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, 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 below.

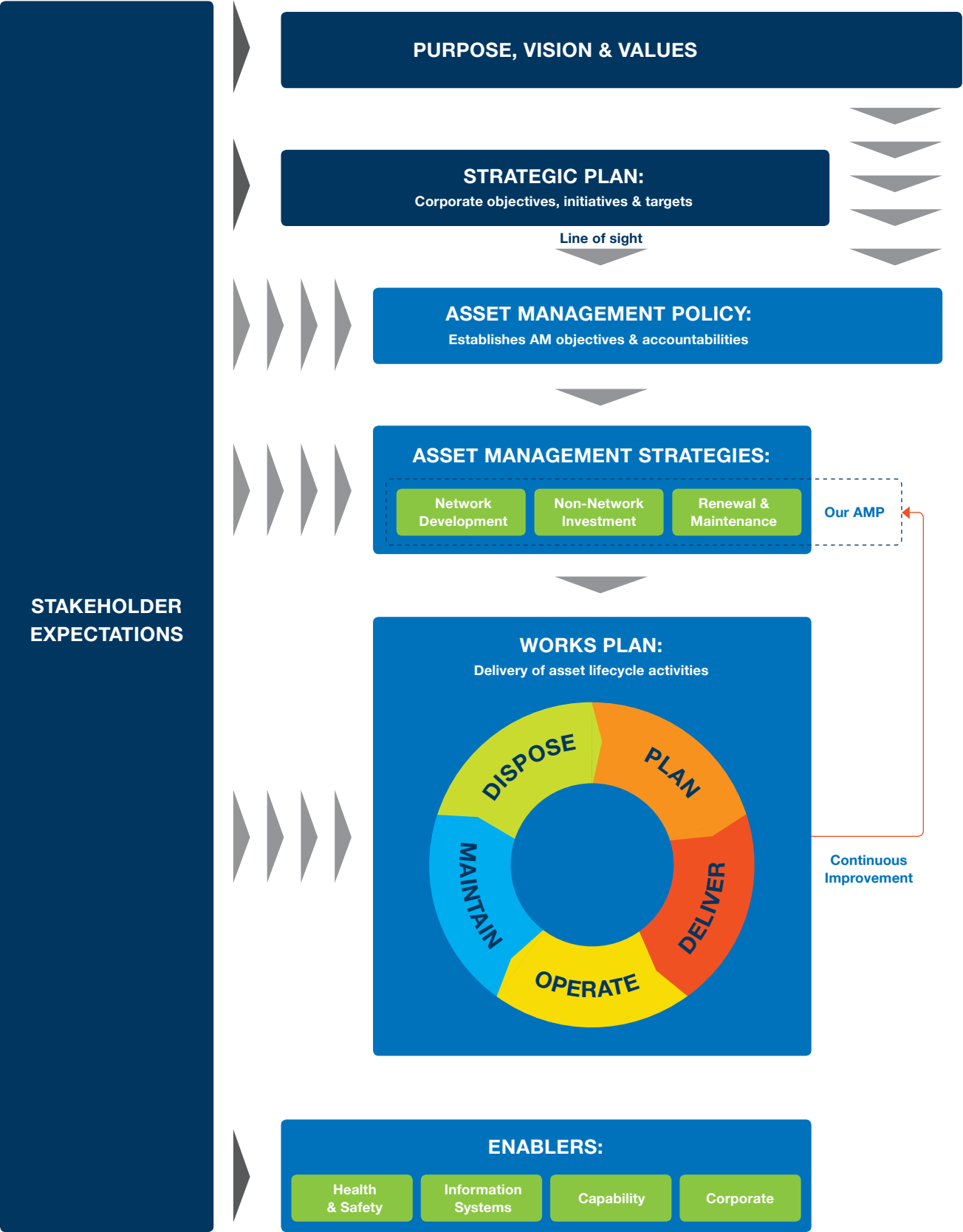


Figure 3.2.1 Asset Management framework

3.2.1. ASSET MANAGEMENT POLICY

The WEL asset management policy is central to the operations and management WEL's distribution network and its business. The key policy principles are:

- Provide an enduring and reliable distribution network, delivered with the aim of achieving best practice levels of resiliency and safety and the efficient long term utilisation of assets, including delivery and capture of quality asset data
- Development of network structure to meet current and future customer performance requirements
- Create an Asset Management Plan outlining the nature and characteristics of our assets and investment requirements and to provide an overview of our asset management planning, systems, procedures, and practices
- Make asset management decisions based on complete, accurate and timely information

The overall objective is that WEL network assets should

be planned, designed, constructed, operated, maintained, renewed, and disposed of in an efficient manner including the following parameters:

- Minimise hazards and risks for people, plant and environment.
- Striving to be "Best in Safety" through embedded safety culture and application of safety in design principles
- Comply with industry, regulatory and statutory requirements
- Optimise the use of and longevity of WEL assets by adopting appropriate methodologies to ensure that optimal benefit continues to be derived from existing assets.
- Support regional economic growth while still maintaining WEL security standards
- Base asset management decisions on the full evaluation of all alternatives taking into account full life cycle costs as well as safety, reliability, environmental, sustainability, social and economic benefits and risks.

3.2.2. ASSET MANAGEMENT STRATEGY

The Asset Management Strategy links our policy objectives to three distinct components:

(1) Network development

We invest to meet the capacity required to supply localised areas of growth in consideration of network security against the established security criteria. To achieve our customers' requirements in a cost effective manner, we will seek projects with high cost benefit ratios.

(2) 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 investigating in new non-network solutions such as solar generation and battery for network support. We have already gained substantial expertise on tools and data analytics using smart meter data. We continue to develop new systems from smart meter data to improve services to our customers as well as providing services to other EDBs.

(3) Maintenance and renewal

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. Outcomes from asset and

network reliability analysis are utilised and overlay onto CBRM to assist in the prioritisation of the renewal plan. This strategic approach and the resultant renewal and maintenance expenditure over the AMP period are discussed further in Chapter 8.

Document control and review

WEL uses promapp for the control and review of its asset management process. Promapp is process management software that allows us to clearly define our process and set review periods. Each process describes the actions that are required and links to all controlled documents. Each process is assigned an owner and it is the owner's responsibility to ensure that a review of the process and supporting documentation is undertaken within the interval set. We also undertake internal and external audits (including certification to ISO9001) of our asset management strategies and policy which ensures their alignment and accuracy.

Works Plan

WEL Networks is currently 12 months into an improvement initiative to enhance our ability to deliver safe, effective and efficient maintenance and capital works

across our network. As part of this ongoing improvement we have set a benchmark of aligning ourselves with selected leading practice asset management guidelines set out in ISO 55000:2014. We recently undertook a maturity assessment of our asset management function utilising the ISO 55000 framework as a benchmark and found several improvement areas to enhance the delivery and forward planning of our work. The improvement program is focused on the enabling functions of managing assets that not only deliver a safe and reliable service but also use key metrics to improve.

The key areas of improvement include:

- SAP functional location reporting
- Work Management
- Performance Reporting
- Maintenance Strategy
- Asset Planning

The integration of outcomes across these improvement components are implemented through our works planning process. Works planning is integral to meeting the needs of our stakeholders. The focus of works planning is to

safely and 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.
- Management of delivery through WEL Services and external contractors.

The governance arrangements for works planning are discussed further in Chapter 4. The associated performance metrics and targets are described in Chapter 5.

The Works Plan is the delivery of approved work extracted from the Asset Management Plan and intended to be completed within the regulatory period. There are three drivers of work: network development to meet both localised and overall load growth, renewal of assets deteriorated to the point they will soon become not fit for purpose, and support of customer works such as new connections.

WORKS PLAN

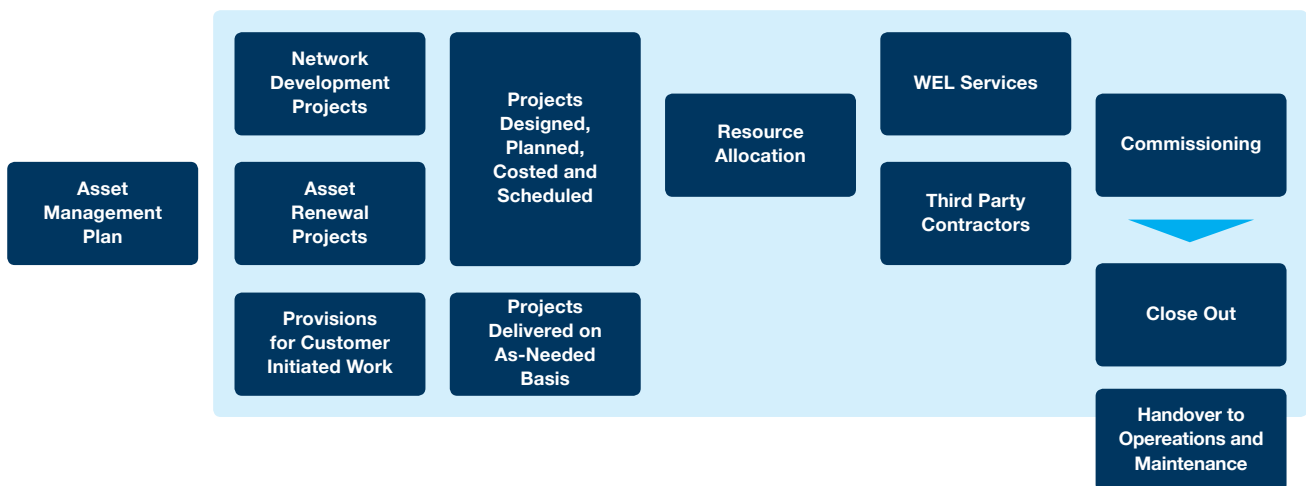


Figure 3.2.2.1 Works Plan

As set out in the AMP, WEL has a reasonable understanding of the volumes of future work in each category which can be anticipated and makes provision for the resources and infrastructure necessary to deliver this work in accordance with agreed schedules. Short term fluctuations in the rate of work are managed with the use of external contractors. WEL utilises its history of project costs and performance to inform its capacity planning to allow for future workloads.

The Works Plan allows WEL to balance resources and investment to meet the demands for work in the different job categories on a risk-prioritised basis, utilising the technical labour available both internally and through external labour contracts. Allowing sufficient lead time before each job commences enables planning and resource scheduling to ensure quality work is undertaken safely.

The specification of each job complies with WEL engineering standards so that the network is developed

and renewed to be safe, reliable and resilient in the future. Meeting these standards relies on consistent processes for defining projects, developing their scope of works and committing to detailed plans. These ensure that the works delivery in the field is safe, has minimum impact on network customers, and is delivered on time and on budget.

As part of our asset management approach, WEL practices continual improvement whereby jobs are reviewed both when in progress and on completion. Assets delivered by the projects are registered in information systems so that they can be maintained in the future. Hence work is not completed until all project deliverables including drawings and maintenance requirements are correctly entered into WEL systems.

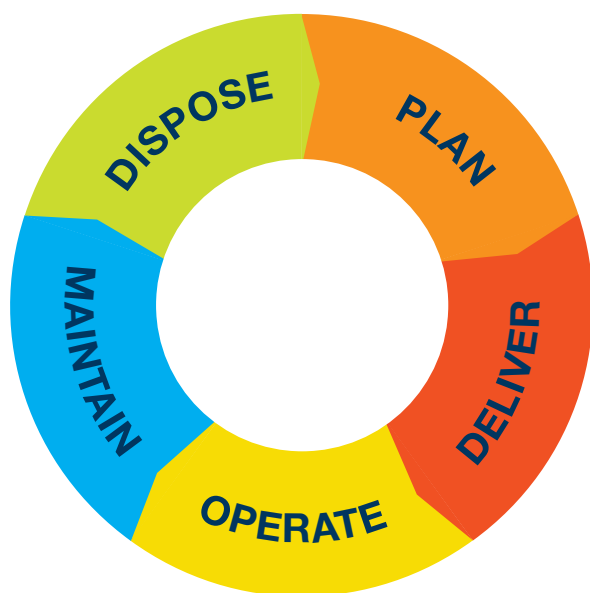


Figure 3.2.2.2. Asset Life Cycle

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 3.2.2.2.

The approach to each of the five asset lifecycle components is strongly linked to the overall strategic approach described in 3.2.2 above.

These are:

- **Plan** – identifying specific network requirements that will deliver on stakeholder expectations for service and price, investigating options and authorisation of expenditure. Our planning processes are discussed in Chapter 4 and our expenditure plans are discussed in Chapters 6 to 9
- **Deliver** – implementation of the planning process through works delivery. This is discussed in Chapter 4.
- **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.
- **Dispose** – efficient, safe and environmentally appropriate

3.3. RISK MANAGEMENT FRAMEWORK

This section describes our approach to risk management. Risk management is a fundamental 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 the key principle in support of our ultimate aim of keeping people safe.

3.3.1. RISK MANAGEMENT POLICY

Our Risk Management Policy identifies risk management as a key requirement when managing both day-to-day operations and longer-term network planning and design. 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 effectively managing risk.

We have developed and maintain a 'risk aware' culture across the business, where staff are empowered and enabled to identify and evaluate relevant risks.

We have in place processes to evaluate, prioritise and mitigate these identified risks. Other than safety related decisions, we seek to balance the costs of mitigation and treatment 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, audit and assurance activity. The full Board is updated about critical risks 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 Business Assurance Manager, the Risk and Audit Lead, 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 approve the treatments. This committee meets on a quarterly basis. Specific actions are then delegated to the relevant managers.

Each staff member is supported by the Business Assurance Team to ensure they understand the risk management process and how it applies to them. This includes being actively engaged in the identification of new risks and ensure these are appropriately escalated for evaluation.

3.3.2. RISK MANAGEMENT FRAMEWORK

Our Risk Management Framework is aligned to the AS/NZS ISO 31000:2009 Standard. It consists of five process steps for systematically managing risk, as illustrated in Figure 3.3.1 below.

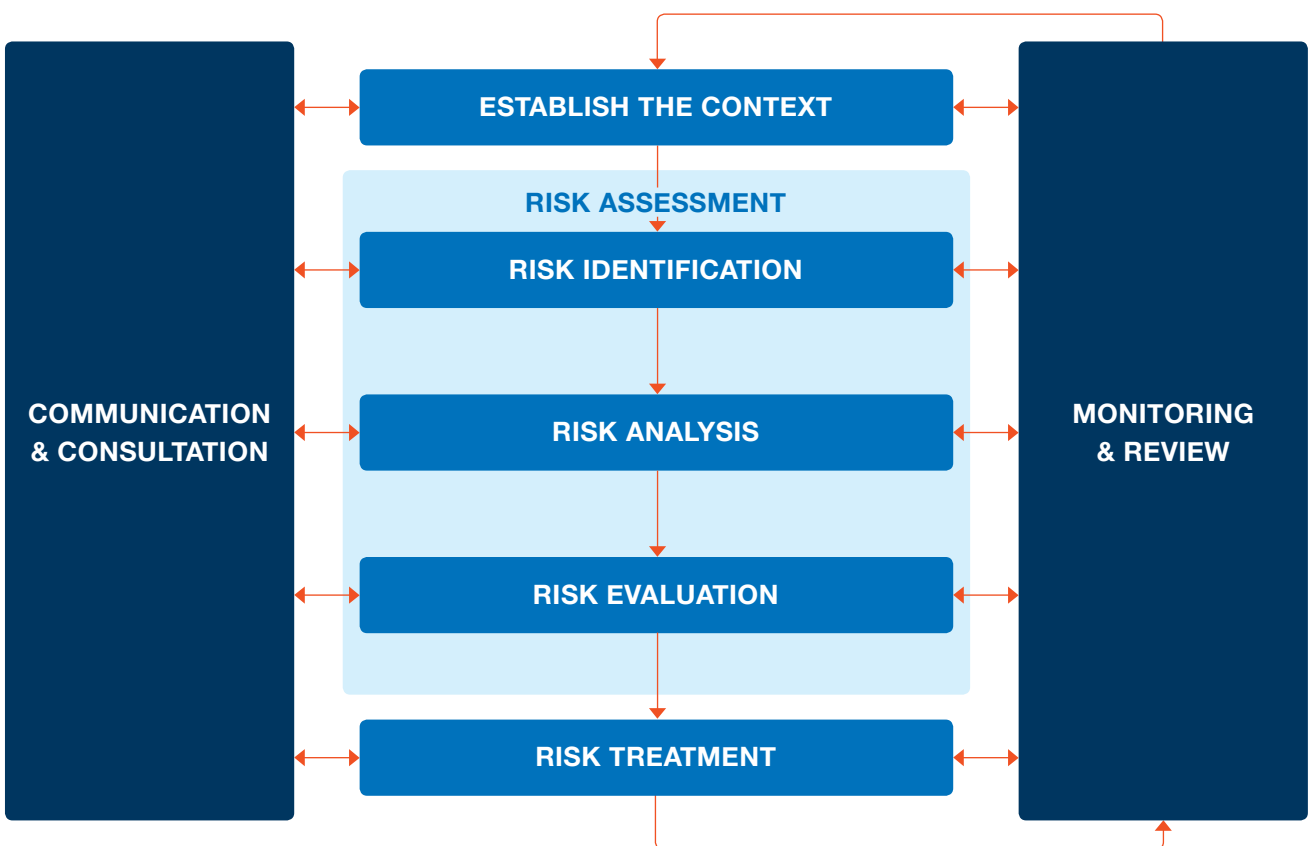


Figure 3.3.2.1 Risk Management Framework

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 in the community e.g. rural or urban, asset age and condition, inspection programmes and data quality.

Risk Identification

Our asset management risks are identified through several mechanisms including 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. WEL notes that under the Health and Safety at Work Act 2015 cost is not considered to be a reason to not proceed with any particular treatment,

but practicability is. The treated risk is then evaluated against the 'inherent' risk to provide a residual risk classification. 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 AS/NZS ISO 31000:2009. 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.

Risk Classification

Figure 3.3.2.2 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.

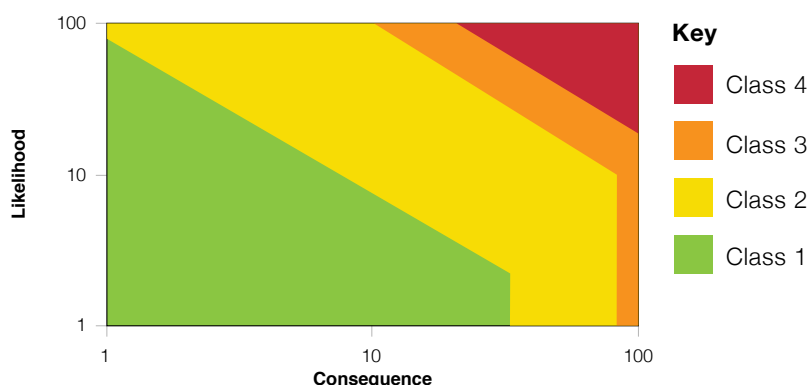


Figure 3.3.2.2 Risk Classification

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 and 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 risk, shown by colour bands in Figure 3.3.2.2 above, and description are:

- **Class 4 (Extreme)** risks are considered intolerable. Risk reduction actions must be applied to reduce the likelihood or consequences of the risk.
- **Class 3 (High)** risks are unacceptable without further controls unless the cost or practicability 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 or practicability of such controls outweighs the benefits.
- **Class 1 (Low)** risks are acceptable.

3.3.3. IDENTIFIED TOP 10 RISKS

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

Risk	Inherent Classification	Residual Classification	Key Mitigations
Sub-optimal investment in assets due to changing patterns in consumer energy efficiency practices and the impacts of emerging technologies	Extreme	Extreme	Strategic Asset Management Approach Project Prioritisation Tool
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 and Competency Processes and Standards
Harm to member of the public through equipment failure	Extreme	Medium	Asset Management Maintenance Works
Harm to member of the public through deliberate contact with the network	Extreme	Medium	Asset Security Maintenance Works Public Safety Management System
Harm to staff or member of the public through defective work	Extreme	Medium	Training and Competency Processes and Standards
Harm to staff or member of the public due to inadequate earthing	Extreme	Medium	Maintenance Design and Construction Standards
Harm through failure of safety equipment	Extreme	Medium	Test and Inspection Purchasing Standards
Harm and or reliability impact from inaccuracy or failure of critical production network systems	Extreme	Medium	Commissioning Process As-built Process Routine equipment testing and calibrations

Table 3.3.3.1 Top 10 Inherent Risks

3.3.4. 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 (PSMS) 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 practicable.

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, the delivery of our works programs and the operation of the assets. WEL Services and our contractors also have a responsibility 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. This is discussed in Chapter 8 along with the asset specific risk.

3.3.5. RESILIENCE AND HIGH IMPACT LOW PROBABILITY (HILP) EVENTS

Although natural disasters and emergency situations are unlikely, they would have a significant impact on our assets and operations. In line with good industry practice and resilience WEL operates an N-1 design philosophy on its major plant, sub transmission network and parts of the distribution network. Zone substations are mostly interconnected therefore have the ability to provide backfeed or alternative supply. HAM and TWH GXPs, although on the opposite sides of the Waikato River, are interconnected at the subtransmission network and parts of the distribution network. This configuration provides good resilience between GXPs.

The zone substation and major network buildings have been assessed for seismic strength and those that fail to reach required standards have been strengthened to IL4 or IL3 depending on risk and importance. Only eight buildings are left to be strengthened and will be completed by 2021. All new buildings are design to meet IL4. Schedules of building seismic strengthening is further discussed in section 2.3.3 and 2.5.1.

Critical equipment spares are reserved for emergency events and are kept at the WEL depot and at several strategic locations across the network. Spare zone transformers are distributed geographically across the network. We have constructed a back-up control room and is further described below in the Disaster Recovery Centre.

All of the above helps us to mitigate risks on a HILP event. We have in place a business continuity plan and is supported by the following:

Lifeline Utility

As a critical infrastructure provider within 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 plan 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 Lifelines Utility Group (WLUG) 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 WLUG, 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. WEL Networks recently sponsored a study on effects of a possible Tsunami on the West Coast of The North Island and participated in the National Civil Defence Exercise Tangaroa.

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 across our network, or when a Civil Defence Emergency is declared. The procedure 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 stand-by;
- 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.
- WEL Networks has adopted the CIMs (Coordinated Incident Management Structure) for dealing with major incidents.

There are specific procedures and designated people to deal with and support each of the following areas:

- Incident Controller
- Operations
- Public Information and Communications
- Logistics
- Wellbeing
- Technology
- Administration Support Services
- Lifelines Liaison

There is also a dedicated Disaster Recovery Centre which allows for all of the above function to continue if the Maui Street is not available for any reason.

Contingency Planning

We have developed contingency plans for the loss of significant assets or groups of assets, including total loss of supply from the Grid. 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 regular 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 both the electricity and the communications network (affecting SCADA) and failure of a Transpower point of supply. Following every exercise we debrief and discuss any potential improvements to be made and record lessons learnt.

Disaster Recovery Centre

We operate our system control centre under normal circumstances from our Maui Street premises. When this is not available for any reason, our Disaster Recovery Centre provides for business continuity facilities or the resources required to manage a major event including full hot back-up of the Network Management, SCADA and major corporate systems. The Disaster Recovery Centre allows full monitoring and control of the network to continue.

3.4. 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.

3.4.1. 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 assessment process. We made this resource available to all key personnel invited to participate in the 2018 assessment.

3.4.2. 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. The main improvements implemented are outlined below.

3.4.3. IMPROVEMENTS IMPLEMENTED

- A work management roadmap was developed and has allowed WEL to balance resources and investment by shifting key responsibilities within teams to meet the demands for work in the different job categories on a risk-prioritised basis.

- CBRM models have been implemented across the key asset fleets and the results are used for the renewal strategy.

- Safety Improvements

A comprehensive audit of our health and safety systems was undertaken in late 2015 that resulted in the development of a two year improvement plan – the Health and Safety Strategic Road Map. Five work streams, with individual executive management sponsors, were designed to address the recommendations from the audit.

Health and Safety meetings with WEL contractors and WEL senior management are held bi-monthly to discuss any safety issues that arise and to share industry safety information.

- For Contract Management – WEL Networks has established a preferred contractor relationship and through a collaborative approach by both companies, efficiency gains will benefit our customers.

We maintain Terms of Trade for all contractors to ensure all parties have a clear understanding of responsibilities for work engagement.

- Resource Management continues to develop through the utilisation of historical resource information and that information contained in the Project Definition Documents. The transparency provided continues to evolve and for the 2019 financial year WEL will have the ability to monitor work completed, in schedule and yet to be delivered across all crafts.
- A project is underway with a focus on lifting the level of customer service within the Customer Initiated Works team. A consultant organisation was engaged to complete an initial review which included customer involvement through interviews and a series of workshops. A roadmap has been provided for WEL Networks to work through.
- WEL Networks has engaged a specialist asset management consultancy to support Maintenance Strategy, Asset Planning, Works Programming and Operations Scheduling to achieve a more robust delivery work flow with improved and more stable planning horizons. The same organisation is also completing a strategic level review of WEL Networks data management framework.

3.4.4. 2018 AMMAT ASSESSMENT

Our 2018 assessment is summarised below. We have undertaken detailed analysis of the responses to gain a deeper understanding of our latest performance assessment.

The results shown below indicate an improvement in the scores over our last assessment undertaken in 2016. This indicates we are obtaining a better alignment to the ISO 55000:2014 standards.

ASSET MANAGEMENT MATURITY ASSESSMENT

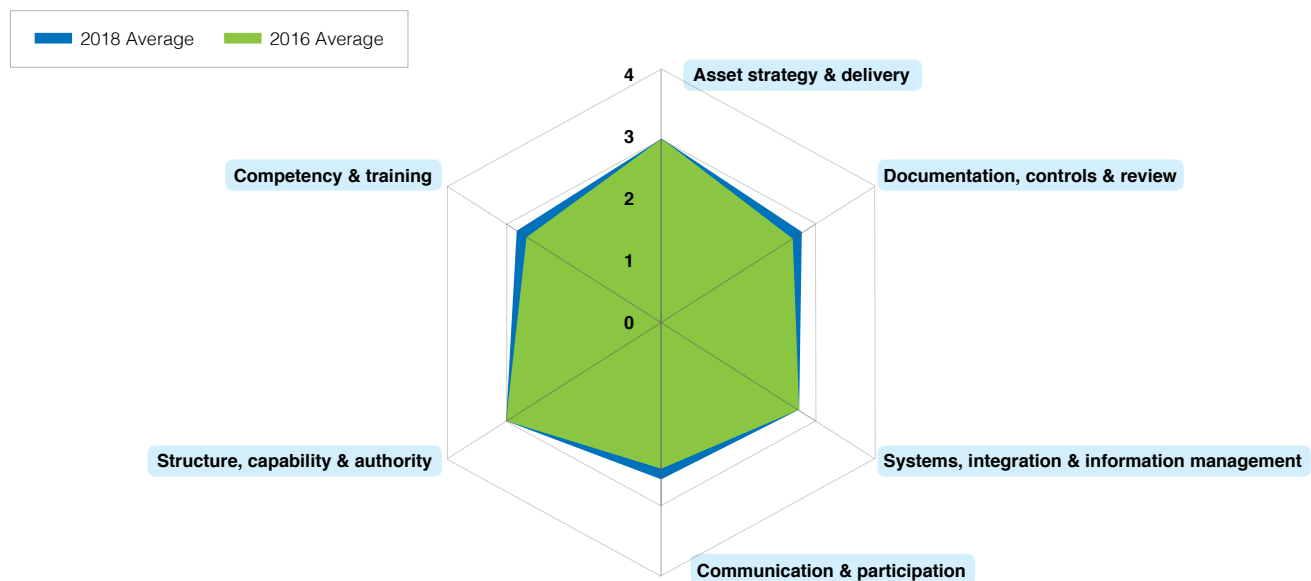


Figure 3.4.4.1 AMMAT Result

This year's survey shows that we have improved in three of the six assessment areas from 2016 namely (1) Documentation, controls and review, (2), Communication and participation and (3) Competency and Training.

While the other three assessment areas remain unchanged specifically (4) Asset strategy and delivery, (5) Structure, capability and authority and (6) Systems, Integration and Information management

In summary, WEL Networks' pro-active approach to implementing improvements in asset management indicates an overall increase in our competencies as asset managers and confirms we are heading in the right direction.



4

ASSET MANAGEMENT GOVERNANCE



4

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.

4.1. 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 requirements.

Our process is fundamentally the same 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:

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

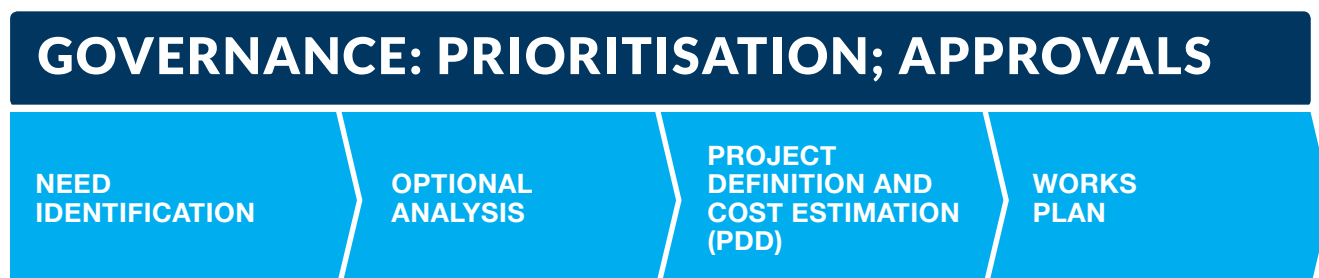


Figure 4.1 Investment Planning Model

The first three planning related stages are described below. The processes employed for investment approvals and works delivery are described in 4.2 and 4.3

4.1.1. NEEDS IDENTIFICATION

Investments are made in response to a number of needs. In many instances an investment, or a series of investments, will meet more than one driver. 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 initiated. The investment drivers are discussed below.

Safety

Investment to address safety concerns and safety related asset issues are a high priority for us. The majority of

safety related risks can be addressed in the design and selection of equipment on the network, through our "Safety in Design" process. 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 may become apparent. In these instances investment to maintain reliability performance is required. Typically this will result in additional network automation, further sectionalising of circuits, backfeed options or the addition of new feeders. These issues are identified as part of our network planning process and it is the responsibility of the Asset Planning and Engineering team to propose and manage these performance issues as describe in Chapter 6.

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 and monitor asset condition and health, which informs maintenance requirements. Field inspections including diagnostic surveys 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

Customers often seek new connections or an upgrade to their existing connection. Network changes are also frequently required to meet the electrical needs of new connections or can be requested due to road

layout changes e.g. widening or safety improvements, or new roads being built e.g. the Waikato Expressway. Customers today are directed in the first instance to the WEL Networks website where they can fill in their application for the required scope of work. Regardless of the channel used, our Customer Initiated Works team will process the request in a timely manner and keep the customer informed of the status of the request. The Customer Initiated Works team is part of the wider Asset Management team and will assess the works required, advise of 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 the policy can be found on our website 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.

4.1.2. OPTIONS ANALYSIS

Following needs 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. Our options review includes both traditional network solutions as well as emerging technologies such as batteries.

Renewals analysis is informed by our CBRM framework and processes as detailed in Appendix B. Accordingly renewals are based on targeting higher 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 needs.

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.

4.1.3. PROJECT DEFINITION DOCUMENT (PDD)

The PDD for each capital project is written and approved to provide the project description and outcomes, scope of work, cost and resource estimations, outage and commissioning requirement and incorporates Safety in Design. Throughout the planning, engineering and design process, the PDD author and reviewers shall consider any issues which may affect the safety of WEL personnel,

contractors, the public and the assets over the project duration as well as the full asset lifecycle.

Following expenditure approval of the PDD (see Section 4.2) and associated budgets, resource planning for detailed design and project construction is used to produce a high level project delivery timeline.

4.2. EXPENDITURE APPROVALS

Expenditure approval is governed by the delegated financial authority structure within WEL. Prior to final 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.

4.2.1. 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 and role 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 the 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 any Board pre-authorised regular payments above this amount e.g. Transpower's monthly charges. The Chief Executive's unbudgeted expenditure limit has been set at \$500,000. The Board may approve greater amounts.

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;
- Project prioritisation tool; and
- PDD documents

Prioritisation

WEL has developed a prioritisation tool for evaluating its capital work. The tool applies a systematic process to all projects.

The tool is based on a risk evaluation and considers the following criteria:

- Health and Safety;
- Network Reliability;
- Network Capacity;
- Environmental;
- Regulatory requirements;
- Outage planning constraints;
- Life cycle cost; and
- Current book value.

The tool calculates a cost benefit ratio from these criteria and provides a ranking. This enables projects with differing drivers to be evaluated in a consistent, transparent and repeatable manner.

4.3. WORKS PLAN

This section describes how WEL manages planned projects, incorporating the capacity to respond to unplanned events. The focus of works delivery is assuring safety as the top priority, and then delivering quality work on time and to budget. This ensures that network assets are commissioned and then maintained to be reliable and deliver their intended function over their expected service life.

The challenges which WEL manages to deliver an on-time and on-budget Works Plan include localised areas of

higher than expected network growth, external events (e.g. storms), third party damage and deterioration of assets throughout the extensive network area.

Notwithstanding the above, we have identified several key opportunities to enhance our works planning and delivery function. These are outlined below and were identified through benchmarking studies utilising external experts and internal subject matter experts.

1. Works Delivery Plan

The Works Delivery Plan is made up of Project, Capital and Opex maintenance work which is delivered by both WEL Services and external contractors. We have enhanced our ability to plan and schedule these work types and maximise the outlook prior to commencement of work to ensure minimal disruption to our customers, maximum resource availability and completion of our Annual Works Plan. The Annual Works Plan will

therefore be delivered without impacting our day to day maintenance program and fault response.

Our works management process (Figure 4.3.1) aims to manage the safe and efficient delivery of Annual Works Plan. It links the asset management planning of WEL through to delivery of work and then to continual improvement, with prudent control of scheduled work and financial outlay.

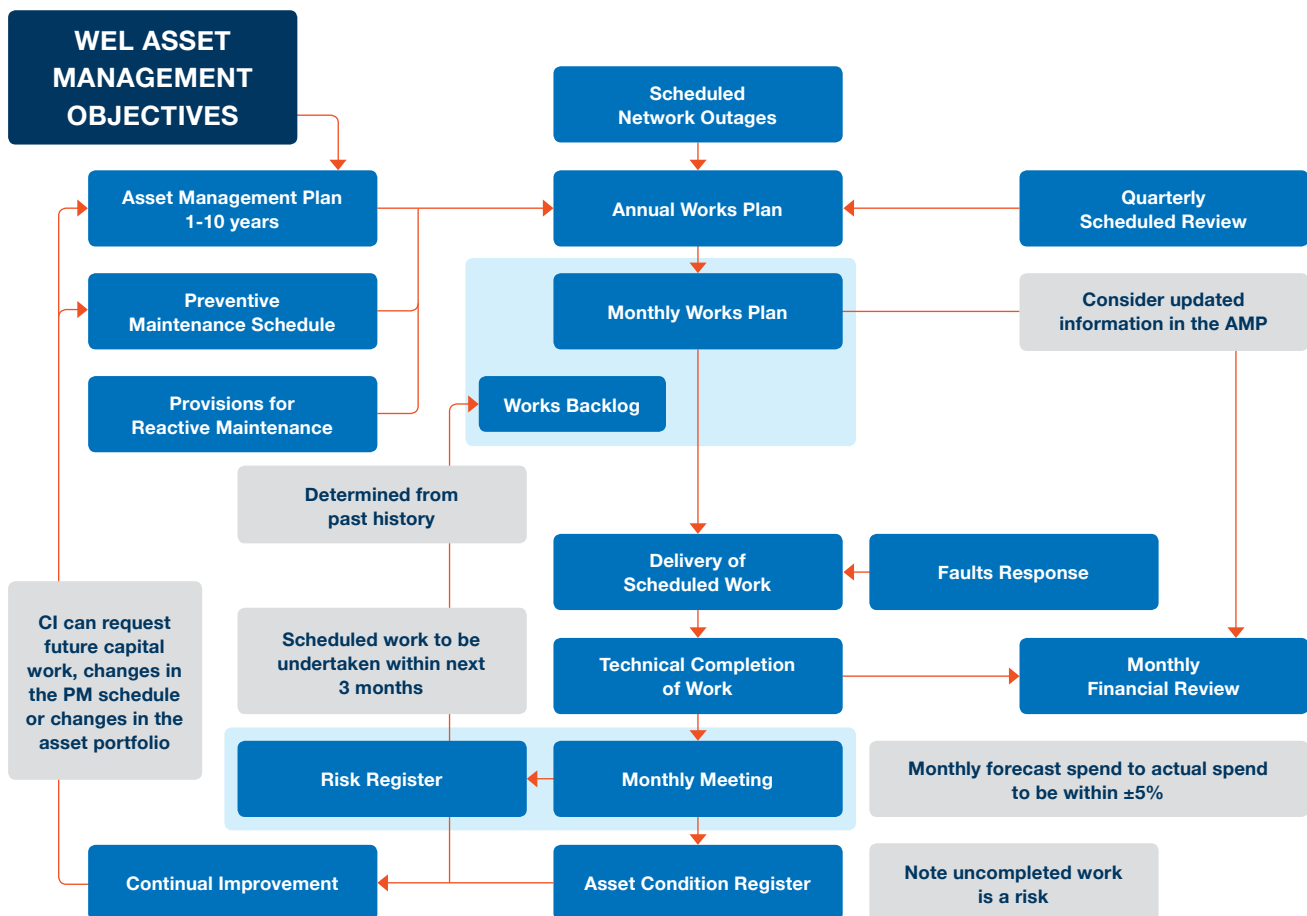


Figure 4.3.1 Works Management Process

At the commencement of the year, the Annual Works Plan is used to determine the resource capacity required in specific competencies and craft types expected to deliver the program of work. The capacities are re-assessed on a quarterly basis to ensure WEL can deliver the work throughout the year. This informs both resource planning for internal teams and establishment of third party contracts.

The monthly work schedule then refines the capacity planning to confirm resources are available to deliver the schedule each month. This ensures resources are

available for customer work as well as the longer term scheduled work for network development and asset renewal.

2. SAP functional location reporting

The functional reporting tool enables us to package work geographically and produce reports on specific suburbs or through electrical connection. This visibility allows us to maximise the resource effort in a particular vicinity i.e. group jobs that are in the same general location or on the same outage area.

3. Work Management Governance

A consolidated and consistent approach to delivering maintenance and capital projects.

This includes:

- **Clearer roles and responsibilities** – We work as a team and know what to do
- **Identifying work** – Skilled eyes in the field and analytics to predict asset health
- **Planning work** – Making the job efficient
- **Scheduling work** – Maximising our people's time in the area and on the job
- **Executing work** – Doing the work safely and effectively with our skilled teams
- **Follow up work** – Find and schedule asset issues during our inspections

4. Performance Reporting

Report lagging and leading indicators are used to determine what can be improved to ensure our network remains safe and reliable. We act on performance trends that fall below benchmarks set by our regulators and business objectives.

At the commencement of each month, the anticipated budget to deliver the schedule of work is confirmed. This is based on estimates of work from the Annual Works Plan as well as provisions for customer work and reactive maintenance. Estimates are refined by detailed planning so that cost estimates are based on precise scope of works, current market labour rates and where necessary, quotations from third parties.

The costs for the month are consolidated at the end of each period and compared to the original budget estimates. WEL targets are estimated to within $\pm 5\%$ each month for actual total expenditure. This can be further broken down into detailed types of work to understand any issues with over or under expenditure.

Within the monthly schedule of work, customer drivers and reactive maintenance are combined with scheduled work from the Annual Works Plan. Monthly schedule compliance is tracked to ensure that all intended work is completed on time. Faults responses and other reactive work that breaks into the month are assessed to ensure

that resources are not unnecessarily tied up, to the detriment of achieving the monthly schedule.

5. Maintenance Strategy

We have adopted a proactive maintenance program using Standard Maintenance Plans (SMP) to ensure the highest quality of work is consistently achieved. We constantly review our maintenance plans to ensure they are identifying probable modes of failure before they occur in service using techniques such as FMECA (Failure Mode Effect and Criticality Analysis)

6. Asset Planning

We have built a consolidated issue register that packages work from multiple sources such as maintenance history, SCADA register, refurbishment and replacement plans, network upgrades, engineering investigations etc. All issues in this register are costed, risk assessed and prioritised based on the consequence of loss of function.

Specification of work from the Annual Works Plan is based on PDD information for growth and security, renewal and scheduled maintenance activities. Specification of work from the Annual Works Plan is based on PDD information for growth and security, renewal and scheduled maintenance activities. Where revisited, all work is planned based on standard designs and construction methodologies, and controlled with good project management processes.

Standardised designs have been developed for sub-transmission lines, zone substation equipment and switchgear. All designs incorporate Safety in Design concepts assisting assets to be safely installed, operated and maintained. Opportunities to develop standardised designs are 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.

7. Continuous Improvement

Our Continuous Improvement (CI) process focuses on registering improvement opportunities and analysing the criteria that prioritises the implementation; such as: effect on the organisation or customers, effort to implement and impact it will have to the organisation or customers once implemented.

We Identify improvement opportunities through:

- Consultation with our teams
- Asset performance measurement
- Asset health measurement
- Incidents reporting and feedback
- Public feedback

On the completion of each month, we formally review the completed work to ensure quality work has been delivered, all requisite information has been handed over and projects may be closed out. We assess whether the work has been delivered to quality and budget.

Technical information consolidated at the end of each month compiles technical data regarding the health of the network assets is consolidated at the end of each month. This supports continual improvement whereby the maintenance strategy for deteriorated assets may be adjusted to extend their service lives and planning commences in the AMP for asset renewal.

Refer to the following section 'Integration and Optimisation' for further detail on how these improvements have contributed to our efficiency and effectiveness.

4.3.1. INTEGRATION AND OPTIMISATION

WEL Networks operates on a Continuous Improvement (CI) framework with an emphasis on Safety, Environmental Impact, Customer Service and Reliability. We understand that the integration and optimisation of our planning process and works delivery is key to achieving our safety, efficiency and cost effective objectives.

As part of our CI process we adopted the ISO 55001 framework as a leading practice benchmark to achieve our business objectives and customer expectations in delivering "good practice" Asset Management. Through benchmarking studies utilising external experts and internal subject matter experts, we have identified several key opportunities to enhance our works planning and delivery function.

Good asset management means that WEL avoids unnecessary expenditure to reserve funds for where they are most needed, and to deliver excellent operations and maintenance to manage down the risk of network failures or late delivery of services.

WEL has invested in improvement of its work delivery processes, reducing the time to identify, plan and then schedule work so that field crews are responding in good time to network and customer issues with well-planned work. Internal streamlining of these processes

has reduced the overhead cost of managing work and freed up technical resources to focus on asset continual improvement. An example of such improvement is the current development of Standard Maintenance Procedures to improve the quality management of preventive maintenance.

Improvement in asset planning now means that WEL has improved intelligence on the forward work which needs to be undertaken. This has both commercial and technical benefits. Improved Works Plan management ensures close control of budgets and optimises the overall expenditure per month. The ability to more closely control the forward schedule of work ensures that work is being specified, designed and planned in good time before it needs to commence.

In addition, WEL is now coordinating resources utilised by both capital projects and maintenance work delivery to ensure resource allocations per month are optimal to deliver on the separate work programs. This has been achieved by improved monthly coordination and will continue to be enhanced with improving forward views of future work.

4.3.2. 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 and to establish delivery timelines across design, planning and scheduling then construction;

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 in Design concepts assisting assets to be safely accessed, operated and maintained. Opportunities to develop standardised designs are 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 the design team and the project manager to effectively manage any safety, delivery risks or complexity;

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.

Design and Construction Resourcing

The Works Delivery Plan establishes our resourcing requirements across available design and constructions resources. The plan determines the projects for internal and external service partner delivery prior to the start of the financial year to ensure appropriate resource availability for full delivery of the Annual Works Plan. WEL Networks has entered into a Partnership Agreement with an external service partner for the mutual benefit of each company. This ensures performance criteria are established early and secures both design and construction resource to meet the forecast workload through the year. Additional sub-contractors supplement both the internal and external service partners.

4.3.3. MATERIALS PROCUREMENT

This section describes our materials procurement activities. The objective of the materials procurement process is to efficiently acquire the materials specified by asset management and WEL Services (WSL) at an optimal cost in accordance with the specification, timeline, quantity and quality required.

The stages of the procurement process are:

- Requirements identification;
- Tender or Request for Proposal or Quotation (RFP, RFQ);
- Approval to proceed;
- Preferred Supplier Agreement established;

- Purchase order raised
- Evaluate and monitor ongoing supply, costs and quality.

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. The processes and business rules for procurement activities have been recorded in our process management systems.

Tendering

We tender all major equipment requirements, generally over the value of \$250,000. The tender process encompasses the assessment of business requirements, establishing timeframes, compiling specifications, selecting suitable suppliers, tender or RFP/RFQ preparation and evaluation, and then submitting a formal written recommendation.

For purchases or categories up to \$2M, a written recommendation approval is sought from the WEL Tenders Committee. Approvals for values over \$2M 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.

4.3.4. WORKS MANAGEMENT

Our works management function has been centralised into two key teams to provide a holistic approach to the delivery of all work types. Contract & Programme Management within Asset Management completes all resource planning and timelines for the annual programme of works, manages Customer Initiated Work and provides Contract Management for all external design and

construction requirements. Within WEL Services, the Works Planning Team manages assigned work priorities to determine work flow for design when required, planning and scheduling prior to being dispatched for construction. Priority 1 works (typically Faults) bypass planning and scheduling directly into the dispatch process as break-in work for a timely response.

The works management handover paths are shown in Table 4.3.4 below:

Work Source	Detail	Handover Path
Maintenance	Proactive maintenance inclusive of asset replacements	Handover is primarily from Contract & Programme Management (WEL Networks) to the Works Planning Team for all WEL Services delivered work.
Customer Driven Capital Projects	Small & large customer works Complex long-term planned projects	Work delivery through external contractors is managed via Contract & Programme Management within Asset Management or handed over to the Works Planning Team for internal service partner delivery.
Faults	Reactive & time limited maintenance	Handover to the Faults Supervisor for dispatch management

Table 4.3.4 Work management handover paths

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

- Design services templates using Conditions of Contract for Consultancy Services as a base

document due to its relative acceptance in New Zealand; and

- Invitation for Tender template based on the New Zealand Standard Conditions of contract for building and civil engineering construction (NZS 3915:2005).



5

ASSET MANAGEMENT PERFORMANCE



5

ASSET MANAGEMENT PERFORMANCE

This chapter describes our performance objectives, initiatives, measures, and targets for the AMP safety, customer experience, cost efficiency and asset performance.

5.1. 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 3. 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. We continually strive to improve our health and safety performance in line with regulatory and legislative requirements and recognise that on-going monitoring, development and effort are required to continue to ensure the safety of our employees and the public. Our Board and Executive Management Team are committed to ensuring company-wide engagement in improving our safety performance.
- **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.

5.2. SAFETY

WEL aspires to being 'Best in Safety'. This underpins our commitment to ensuring the health and safety of our staff and the communities we operate in.

WEL is currently involved in a two year plan of work, the Health and Safety Strategic Road Map. The Road Map was developed after a robust audit of health and

safety systems and performance that was completed in late 2015 by an external consultancy. An annual health, safety and wellness plan has also been developed to address health and safety issues that have been highlighted in our internal reporting and in outcomes from recent OHSAS 18001 and KPMG audits.

5.2.1. SAFETY OBJECTIVES

Our safety objectives are summarised as:

- **Bring ‘Best in Safety’ to life** – Our people will be fully engaged in health and safety and understand our health and safety strategy, objectives and accountabilities.
- **Build Capability** – We will have strong and sustainable leadership in health and safety. We will have the competence to identify hazards and ensure that risks are appropriately controlled.
- **Risk Management** – We will focus on our Critical Risks, ensuring we have effective controls in place across the organisation. We will measure and monitor our controls through our Risk Management framework.
- **Systems and Structure** – We will raise the standard and continually improve our health and safety performance, systems and structure. We will effectively communicate health and safety issues and performance.
- **Contractor Management** – We will ensure our strategic partners are engaged, competent and capable in supporting WEL Networks in achieving our desired objectives. ‘Best in Safety’ will only be achieved when we have all stakeholders personally committed.

5.2.2. SAFETY INITIATIVES

To support these objectives, we are undertaking the following six initiatives:

- 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.

5.2.3. SAFETY MEASURES AND TARGETS

Total Recordable Injury Frequency Rate (TRIFR).

TRIFR is our primary measure of safety performance. TRIFR measures all injuries within a given period relative to the total number of hours worked. In order to standardise the measure it is reported against a base period of 200,000 work hours.

Public Safety Incidents

The potential for public safety incidents on our network continues to be of concern to WEL. In 2016 and 2017 a number of safety initiatives were undertaken in the business to improve awareness of and our response to potential harm to the public:

- Two ‘mini stop-for-safety’ exercises were conducted to assist with identification of safety concern knowledge gaps within the network
- ICAM (Incident Causation Analysis Method) investigations into public safety related incidents
- A concentrated pillar inspection exercise to ensure all currently unsafe equipment was identified and remedied

The targets for our safety measures over the AMP period are set according to what we view as realistic and achievable based on historical performance data along with our aspiration to be “Best in Safety”.

The target performance is set out in Table 5.2.1 below.

Measure Lag indicators	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TRIFR	≤3.5	≤3.5	≤3.5	≤3.5	≤3.5	≤3.5	≤3.5	≤3.5	≤3.5	≤3.5
Injury Severity Rate	≤7	≤7	≤6.5	≤6.5	≤6.5	≤6	≤6	≤6	≤5.5	≤5.5
Public Safety Incidents causing harm	0	0	0	0	0	0	0	0	0	0
Manual handling injuries (sprains and strains) Measure – reduce by 5% per annum	23	22	21	20	19	18	17	16	15	14

Lead Indicators

Near Misses Reported	Measure – Investigation type decided and launched within three working days of receiving the report. Report complete and actions assigned within four weeks.
Executive and Management Site Visits	Conducted and completed as agreed with and site assessments recorded and acted upon within each calendar month
Health and Safety Meetings	H&S Committee: monthly. Service Partners (Contractors): bi-monthly. Senior Leadership H&S Committee: monthly.
Close out of FARS	80% closed out within the month of reporting.

5.2.4. SAFETY PERFORMANCE EVALUATION

The table below shows our safety performance against the targets we set for 2017 and 2018.

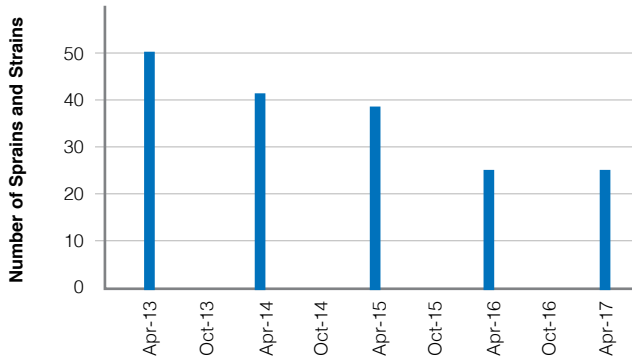
	Goal	Actual
Total Recordable Injury Frequency Rate (TRIFR)	3.00	5.67
Injury Severity Rate	<7	4

OTHER MEASURES

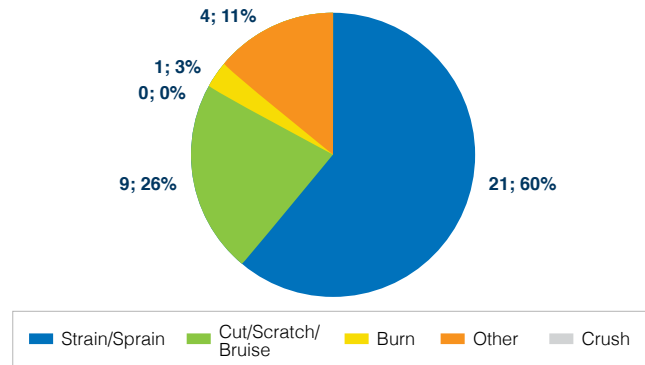
Category	Number
Lag Indicators	
Lost Time Injuries (LTI)	10
Medical Treatment Injuries (MTI)	8
Restricted Work Injuries (RWI)	5
Notifiable Incidents	3
First Aid Injuries (FAI)	27
Motor Vehicle Incidents	7
Environmental Release	1
Lead Indicators	
Near Misses Reported	216
Executive Site Visits	50
Management and Other Site Visits	246
Health and Safety Meetings (3 committees)	32 (from a possible 36)
FARS closed out	554 closed from 582 reported

The main causes of injury in previous years have been sprains and strains relating to manual handling activities and slips and trips. Our focus and efforts are currently on preventing these types of injuries and minimising the injuries sustained when they do occur.

SPRAINS AND STRAINS 2013-2017



INJURIES BY TYPE – JUL-16 TO JUN17



5.3. CUSTOMER EXPERIENCE

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.

5.3.1. 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.

5.3.2. CUSTOMER EXPERIENCE INITIATIVES

Our customer experience initiatives have been categorised into two key 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 throughout Chapter 8 for each asset class in the relevant sub section of the

Asset Renewal Programme;

- Using information gathered from FMECA and RCA outcomes and notifications to initiate improvement initiatives including installation of automated devices that provide thorough fault information. This will both reduce the number of customers affected by an outage and also allow remote fault diagnosis and restoration of some of the customers within a shorter time frame.
- Inclusion of technology and diagnostic testing in maintenance plans and work processes for early

detection of pending failures e.g. UAV flights for difficult access line surveys, hotspot detection and ultrasonic/ acoustic detection on overhead line insulators.

- Investment in network capacity and security. The investment will address localised areas of forecast growth. This is described further in Chapter 6;
- Monitoring Technology. We will actively monitor and assess new technology to maximise the opportunities available from emerging technologies like PV and EV.

- We will continue to leverage the use of data from our Smart Meters in support of our investment decision making processes; and improve customer service by proactively identify and correcting poor power quality and unsafe situations. The use of smart meter data analytics is further discussed in Chapter 10. One example of customer improvement using smart meter data is the reduction of fault call outs. We are able to connect to a smart meter and obtain an instantaneous reading of voltage and current and therefore respond to a customer in real time when they raise an issue as outlined Figure 5.3.2.1 below.

NUMBER OF CALLOUTS ATTENDED DUE TO FAULT WITHIN CUSTOMER INSTALLATION

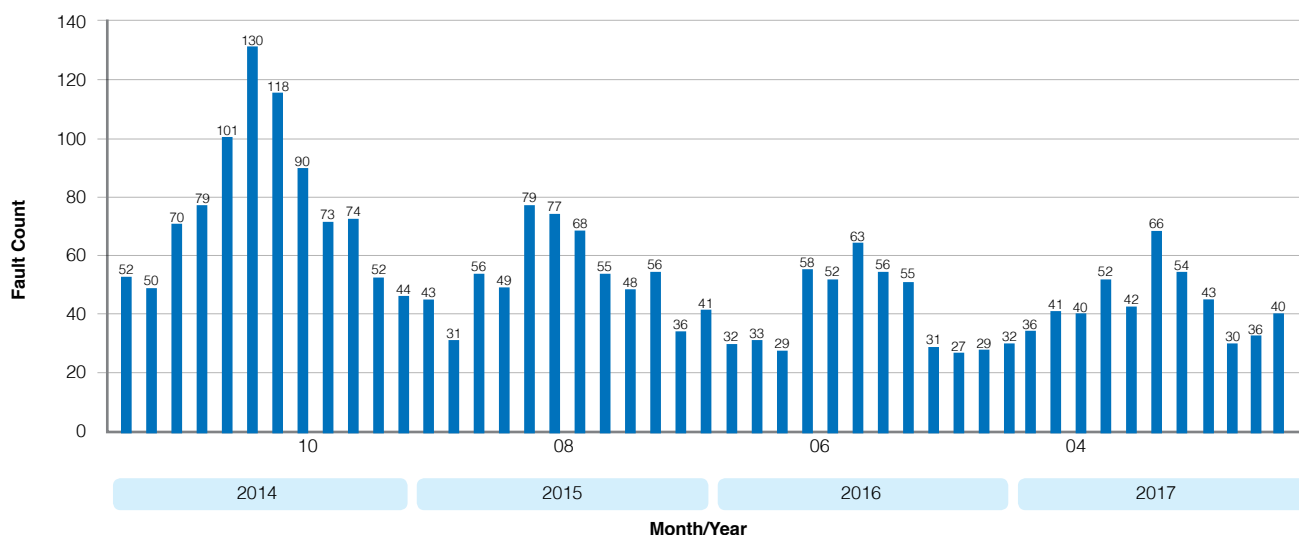


Figure 5.3.2.1 Number of faults attended by WEL staff, which was caused by faults within the customer's installation

Customer Service Initiatives

Our customer service initiatives include:

- Engaging an external consultant to develop a strategic plan and roadmap to achieve Best in Service. This initiative is focussed on Customer Initiated Work.
- 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 understood and 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
- Review our customer feedback process to ensure that the customers' concerns and opinions are clearly identified.

5.3.3. 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 on average a consumer on the network experienced 60 minutes without power in that year. In addition, the targets shown below reflect the Commerce Commission's revised approach on planned outages to have a weight of 50%. This means only half of the duration of planned outages are included in the measure.

SAIFI (weighted) – System Average Interruption Frequency Index (weighted). SAIFI measures the number of times on average a 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.

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.

The impact of the preference to change Live Line work to de-energised work coupled with an increase in the maintenance requirements on our Ring Main Units (RMU), prompted WEL to review and modify WEL's network reliability performance targets set out in our Asset Management Plan (AMP). This has resulted in an increase in the Planned SAIDI targets.

Table 5.3.3.1 sets out the targets for each measure over the AMP period.

Measure	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total SAIDI (weighted)	84.9	84.6	84.2	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Total SAIFI (weighted)	1.49	1.48	1.48	1.47	1.47	1.47	1.47	1.47	1.47	1.47
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)	77%	79%	80%	80%	80%	80%	80%	80%	80%	80%

Table 5.3.3.1 Network Customer Experience Performance Targets 2018 – 2027

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. The maximum times for restoration are detailed below in Table 5.3.3.3 and, apply for the duration of the AMP period.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 5.3.3.3 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%;

Standard 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 10 to 5 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.

Table 5.3.3.4 shows the targets for each measure over the AMP period.

Measure	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Satisfaction	85%	86%	86%	87%	87%	88%	88%	89%	90%	90%
Standard Connection Quote Time (workdays)	5	5	5	5	5	5	5	5	5	5
Non-standard Connection Quote Time (workdays)	30	25	23	22	21	20	20	20	20	20
Complaint Response Time (workdays)	<10	<10	<10	<10	<10	<10	<10	<10	<10	<10

Table 5.3.3.4 Customer Experience Performance Targets 2018 – 2027

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 customers' 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 Table 5.3.2 as only 50% of outages that were planned are included in the SAIDI and SAIFI outcomes.

Measure	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
SAIDI (weighted)	79	83	70	74	65	68	80	93	84	83
SAIFI (weighted)	1.4	1.63	1.12	1.19	1	1.36	1.27	1.45	1.19	1.33

Table 5.3.3.5 Network Customer Experience Historical Performance 2008 and 2017

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

Network Performance

	2017			FORECAST TO DATE (AT AUG 2017)		
Customer Experience Measures	Target	Actual	Variance %	Target	Forecast	Variance %
Urban SAIDI (weighted)	42	49	-15%	50	52	-5%
Rural SAIDI (weighted)	226	244	-8%	236	217	8%
Total SAIDI (weighted)	79	83	-5%	85	83	2%
Urban SAIFI (weighted)	0.59	0.88	-48%	0.78	0.85	-8%
Rural SAIFI (weighted)	4.74	3.53	26%	4.68	3.60	23%
Total SAIFI (weighted)	1.41	1.33	6%	1.49	1.29	13%
Urban Repeat Interruptions (target is 2 or less)	90%	88%	-2%	90%	89%	-1%
Rural Repeat Interruptions (target is 4 or less)	75%	73%	-3%	77%	81%	5%

Table 5.3.3.6 Network Customer Experience Performance 2017 and 2018

Except for rural SAIFI, our performance targets were not met. The failure modes contributing to the total SAIDI are categorised as Condition Related (CR) and Non Condition Related (NCR). Our analysis shows the contribution of CR is 23% and NCR is 77%.

Summary of Condition Related failure SAIDI:

- Significant improvement in CR faults and defective equipment related failure as shown in Figure 5.3.3.1.
- Fewer events in specific asset classes of air break switches, RMUs and insulators contributed significantly to improved SAIDI for 2017.

HISTORICAL SAIDI DUE TO EQUIPMENT FAILURES

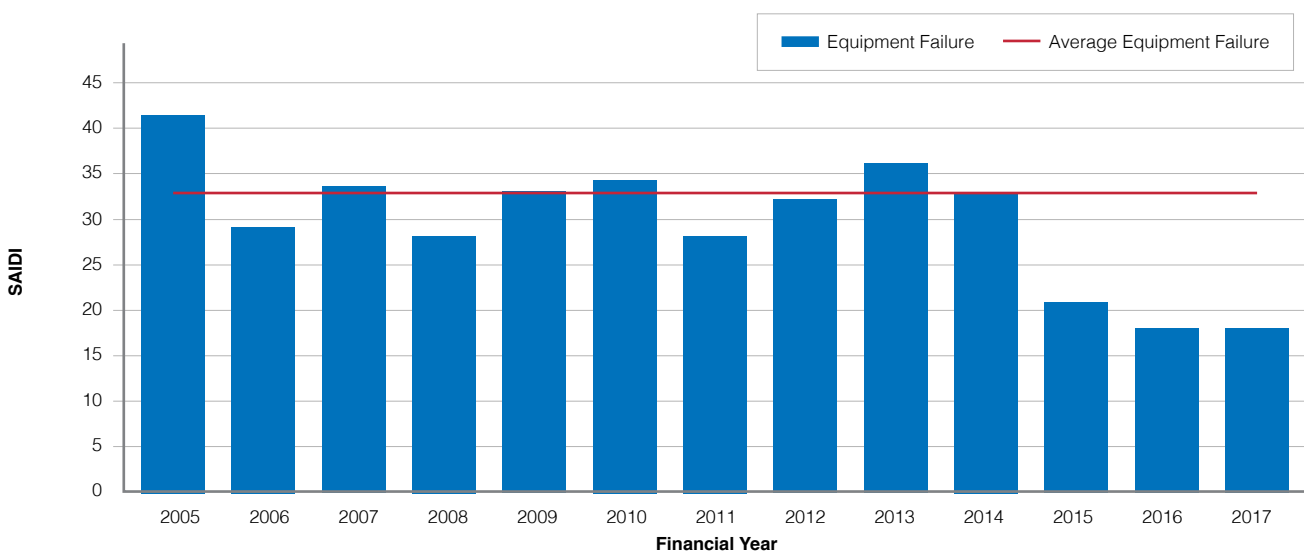


Figure 5.3.3.1 Historical SAIDI due to Equipment failure

Summary of Non-Condition Related failure SAIDI:

- NCR faults have had a major contribution to total SAIDI.
- Pole and overhead line faults contributed significantly to NCR faults.
- 'Car v pole' contributed 97% of the total pole related NCR faults.
- External interference (wind-blown debris, high wind line break and line clashes) contributed to line related NCR faults.

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 inferior service received by affected customers and to address broader issues with these feeders.

Our 10 worst performing feeders (based on SAIDI) during the financial year 2016 and 2017 along with the most recent 5 months' performance of financial year 2018 is shown in Table 5.3.3.7 below.

Rank	Feeders	Area Supplied	2016*	2017*	2018* (YTD as at 30/08/17)
1	TEUCB1	Te Mata/Raglan	5.59	4.51	0.079
2	WEACB6	Rotowaro	4.53	2.84	0.52
3	WEACB2	Huntly	3.13	1.71	0.34
4	WEACB3	Te Ohaki	2.72	2.71	0.014
5	WALCB6	Ngahinapouri	2.61	0.09	0.30
6	HORCB6	Horotiu, Ngaruawahia	2.30	2.49	0.003
7	SANCB2	St. Andrews/ Sandwich Rd	2.17	0.45	0.66
8	HAMCB2822	Hamilton East	2.16	0.17	0.78
9	FINCB3	Kopuku	2.01	0.74	0.094
10	SILCB4	Matangi	2.00	1.53	0.0

Table 5.3.3.7 Top 10 Worst Performing Feeders

* – financial years

An explanation of the performance for each feeder is summarised below together with ongoing initiatives to improve service.

FEEDER	STRATEGY
TEUCB1	Performance of the feeder was mainly affected by external events such as "bird line clashes" and "line clashed due to high wind". Network switch replacements and poor condition conductor replacement have been undertaken in recent years to minimise outages.
WEACB6	Non condition related (NCR) faults such as "car vs pole" events and "wind debris on lines" have affected the performance of this feeder. Proactive replacements of sectionalisers and HV fuses have been initiated in recent years to minimize the impact following an unplanned outage.
WEACB2	The performance of this feeder has been mainly impacted by wind debris on line, "car vs pole" and 16mm ² conductor failures. Conductor issues have been addressed in our reconductoring (in 2016) program and improved performance compared to previous years has been realised.
WEACB3	Tree debris blown onto the lines and "car vs pole" events have affected the performance of this feeder. A number of network switches and RMUs have been installed to minimise the impacts following an outages.
WALCB6	Performance of the feeder has been affected mainly due to external events such as "Car vs pole" and "High vehicle contact with line ". A number of network switches and RMUs have been installed to minimise outages impacts.

HORCB6	External influences such as "car vs pole" events and "tree felled into line" have caused this feeder's poor performance. A number of RMU and network switch replacements have been undertaken in recent years to minimise outage impacts.
SANCB2	This feeder has been impacted by vegetation falling onto the lines, "Car vs pole", failed insulators and 16mm ² copper conductors. Reconductoring projects have been initiated, including automation projects and targeted vegetation control which will improve the performance of the feeder in the future.
HAMCB2822	The performance of this feeder has predominantly been impacted by line clashes, wind debris on line, car v pole and 16mm ² conductor failures. Conductor issues have been addressed in our reconductoring (in 2015) program and performance has improved compared to previous year.
FINCB3	This feeder has been impacted by vegetation falling onto the lines, "Car vs pole", failed insulators and 16mm ² copper conductor failure. Reconductoring projects have been initiated, including automation projects and targeted vegetation control which will improve the performance of the feeder in the future.
SILCB4	he performance of this feeder has predominantly been impacted by line clashes, wind debris on line, car v pole and 16mm ² conductor failures. Conductor issues have been addressed in our reconductoring (in 2015) program and performance has improved compared to previous year.

Table 5.3.3.8 Worst Performing Feeder Strategies

Customer Service

The single customer service related measure where we have historical data is for customer satisfaction.

The results of our performance against our target are shown in Table 5.3.3.9 below.

	2016 SURVEY			2017 SURVEY		
Customer Experience	Target	Actual	Variance %	Target	Forecast	Variance %
Customer Satisfaction	85%	99%	14%	85%	99%	14%

Table 5.3.3.9 Network Customer Experience Performance 2016 and 2018

5.4. COST EFFICIENCY

Our overarching cost efficiency objective is to implement our Works Plan (see Section 4.3), which has been optimised for risk and impact, 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.

5.4.1. 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;
- Investment and repairs are prioritised and optimised using robust methodology to achieve our operational targets in a cost effective way;
- 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.

5.4.2. COST EFFICIENCY INITIATIVES

To achieve our cost efficiency objectives there are a number of initiatives that we are in the process of putting in place.

They include:

- Updated works delivery model, with relevant delivery KPIs;
- Works plan in progress to streamline work throughput for delivery, improve network planning and programme management;
- Vehicle fleet review finalised to optimise fleet size, composition, and ownership model;
- Continuous improvement approaches and performance reporting;
- Asset function location hierarchy in SAP was configured as part of the Maintenance Roadmap project that enables engineers, planners and schedulers to assess and plan works more efficiently through packaging of work based on geographical locations (i.e. regions, suburbs, etc.); and
- Work flow from identification to delivery is streamlined through the implementation of work management process driven from the Maintenance Roadmap project.

5.4.3. COST EFFICIENCY MEASURES AND TARGETS

The measures we have established for cost efficiency are:

Cost Per Customer – operating costs that are allocated to electricity distribution service (in accordance with Information Disclosure requirements), divided by the number of connections. These exclude capex, depreciation, tax subvention payments, revaluation, interest expenses, pass-through, and recoverable costs.

Capital Expenditure Performance – project delivery performance for capital works (excluding customer initiated work, which is variable and reactive in nature) will be measured by comparing the delivered cost of projects with the budget (which has been formulated to deliver the prioritised set of works, and appropriately challenged).

The performance is subject to the following conditions being met:

- Full scope of the project delivered;
- Safety performance is maintained or improved;
- Design and construction standards are met;
- Timeframes are met; As built information and drawings are captured accurately and in a timely manner; and
- Project lessons learnt are captured for the establishment of future project scope inclusive of financials.

The targets are based on achieving the expenditure levels forecast. Table 5.4.3 shows the targets for each measure over the AMP period.

Cost Efficiency	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Cost per customer (\$)	279	278	276	274	273	272	271	270	269	268
Capital Expenditure performance %	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%	± 5%

Table 5.4.3.1 Cost Efficiency Performance Targets 2018 – 2027

5.4.4. COST EFFICIENCY PERFORMANCE EVALUATION

Our performance measures for cost performance efficiency are shown in Table 5.4.4 below.

	2017			FORECAST TO DATE (AT DECEMBER 2017)		
Cost Efficiency	Target	Actual	Variance %	Target	Forecast	Variance %
Cost per Customer (\$)	281	287	(2%)	279	250	10%
Capital Work Delivery (\$M)	16.5	14.6	11%	17.2	15.5	10%

Table 5.4.4.1 Cost Efficiency Performance 2017 and 2018

5.5. 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.

5.5.1. ASSET PERFORMANCE OBJECTIVES

Our asset performance objectives are to ensure:

- 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 FMECA. These techniques support quantifiable trade-offs between operational expenditure, asset condition and reliability;
- How, when and who we use to deliver our works plan are key inputs in our investment decisions
- Continue to develop new tools and systems for data analytics using smart meter data to improve our services to our customers (discussed further in Chapter 7; and
- 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.

5.5.2. ASSET PERFORMANCE INITIATIVES

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

- A review of our asset management planning and decision making processes to ensure the right capabilities, processes and decision support tools are identified and then implemented
- A review of our maintenance approach particularly in the area of using diagnostic tools to enhance maintenance practices
- Proactive defect repairs through the maintenance review process changes
- Utilize Smart Meter data for operations and planning as described in Chapter 7
- Assessing opportunities to integrate emerging technologies e.g. PV and battery to improve the performance of existing and future network assets.

5.5.3. 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 Factor 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 5.5.1 shows the targets for each measure over the AMP period.

Measure	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
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 5.5.3 Asset Performance Targets 2018 – 2027

5.5.4. ASSET PERFORMANCE EVALUATION

Our asset performance for 2017 and forecast for 2018 is shown below.

	2017			FORECAST TO DATE (AT DEC 2017)		
Asset Performance Measures	Target	Actual	Variance %	Target	Forecast	Variance %
GXP Load Factor (%)	60%	54%	(6%)	60%	56%	(4%)
Transformer Utilisation (%)	35%	30%	(5%)	35%	30%	(4%)

Table 5.5.4 Asset Performance 2017 and 2018

Our load factor performance has remained below target in both years, without any additional capacity being added at GXPs. Our transformer utilisation is forecast to increase in 2018 primarily due to higher peak demand.



6

NETWORK DEVELOPMENT



6

NETWORK DEVELOPMENT

This chapter sets out our approach to network development and describes the plans we have in place for the AMP period.

6.1 OVERVIEW

Our plans have been reviewed and aligned with the requirements of our customers and the overall performance objectives described in Chapter 5. 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 possible that as the operating environment changes the investments forecast for the mid to latter part of the AMP period may need to be refined.

6.1.1 OUR APPROACH

Chapter 3 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 fall under the 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 asset replacement and renewals as discussed in Chapter 8;

Options analysis: Following need identification, potential options that meet the need are formulated and considered. The number of options will vary depending on the type and complexity of need(s). Non-network options and demand management solutions are considered as a potential option and undertaken if practical and cost effective.

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 4.

Key Planning Assumptions and Inputs

The key assumptions informing our network development planning are:

- Future peak demand growth base customer initiated works and forecast in Section 6.2 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 1 and the corresponding performance objectives discussed in Chapter 5;
- Specific individual customer and stakeholder requirements;
- The inputs required to forecast electricity consumption and demand, as set out in Section 6.1.3;
- Voltage requirements and other regulated limits; and
- Equipment ratings based on the manufacturer nameplate ratings as detailed in Section 6.1.2.

OVERVIEW

LEGEND

- Grid Exit Point (GXP)
- Zone Substation
- 33kV Subtransmission
- WEL Networks Boundary



Figure 6.1.1 Overview of WEL Network System

Security criteria

Security criteria set 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 and the reliability performance sought by our customers and stakeholders.

The security criteria used by us are set out Table 6.1.2 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	Maintain 100% of PCD ¹	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 6.1.2 WEL's Planning Security Criteria

6.1.2 PLANNING RISK MITIGATION AND NETWORK ENERGY EFFICIENT OPERATION STRATEGIES

Planning Risk Mitigation

All equipment, with the exception of power and distribution transformers², is factored into our planning based on the capacity rating stated on the nameplate.

The ability to overload transformers for short durations helps to mitigate the residual planning risk, particularly when the load increases faster than expected. The overloading of the transformers is in line with the international standards that the transformers were designed to. If applied within the guidelines of the standards it will accelerate the aging of the transformer but does not greatly increase the risk of failure.

WEL Networks puts considerable effort into ensuring our loading forecasts are accurate and up to date. The process used is detailed in section 6.2. It is rare for the load to increase at a rate which exceeds equipment normal operation conditions.

Many sections of WEL's network have the ability to be offloaded to neighbouring zone substations and feeders. While the prime reason for this is to provide alternate supply in a fault scenario, it can also be used to mitigate planning risk by providing capacity in the short to medium term planning periods. If the neighbouring zone substation or feeder is lightly loaded it will be used as a solution to reduce capital investment.

¹Post Contingent Demand (PCD) is the peak demand after demand reduction through contracted load control services.

²The 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%. Distribution transformers have an emergency overload rating of 150%

Network Energy Efficient Operation

WEL applies a number of strategies around network energy efficient operation, these include:

- **Load management** – A few of the transformers on the network operate in overload at times of peak demand. The use of load control will reduce any overload and therefore improve the efficiency of the transformer. This also reduces the loading on the conductors and further improves the efficiency of the network.

- **Smart meters** – we are utilising the benefits of smart meter for our planning purposes such as proactive power quality and abnormal condition detection, load profiling, identification of distributed generation and revenue assurance. The benefits are described in Chapter 7 for Non-Network Solutions and Support Systems.

6.1.3 INFLUENCE OF EMERGING TECHNOLOGY, DEMAND MANAGEMENT INITIATIVES AND RESIDENTIAL LOAD PATTERNS

Emerging Technology

Solar generation, electric vehicle and battery storage systems are the main examples of emerging technologies with the potential to impact on the design and operation of our network. At this stage, they do not influence our network planning or investment. Chapter 7 describes our plans for these technologies.

Demand Initiatives

We assume that the current level of load control will continue through the AMP period. We would expect that the impact

of demand initiatives is likely to increase over the AMP period, however this is difficult to quantify at this time.

Residential load patterns

The residential load patterns have significantly changed over the last three years because of appliance efficiency and number, lighting technology (LED lights), adoption of heat pump technology, shift of hot water heating to gas and use of electrical technology. With the use of smart meters we can achieve load profiling in the distribution transformers.

6.1.4 PEAK DEMAND FORECAST

Our network delivered 1,219 GWh of electricity as at the end of 2017 financial year with coincident peak demand of 273MW. This peak demand is the principal 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 a reduction in the average amount of electricity being delivered to our domestic customers, flat peak demand across the network and increasing amounts of PV being installed.

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

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.

Establishing Base Demand

The most recent peaks 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 based on the structured development plan by Hamilton City Council. The Rototuna structured plan is supplied from Borman substation. The northern part of the Ruakura structured plan is supplied from Chartwell substation. Rotokauri structured plan will be supplied from Tasman and Avalon substation. Peacockes structured plan will be supplied from Peacockes substation.
- **Waikato District Residential & Agricultural** – growth in these areas is expected to be modest and we have assumed a continuation of the historical trend. Te Kauwhata substation demand is adjusted as a result of the Te Kauwhata Structured Plan.
- **Industrial and Commercial** – our growth forecast is based on applications received and our discussions with developers. Expected growth is also based on the Hamilton City Council structured plan which indicates Horotiu, Pukete, Rotokauri and Ruakura as industrial areas. The CBD will also see growth in commercial establishments.
- **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 improves and distributed generation installations become more prevalent. We have installed a 75 kW solar array on the WEL services building at Maui Street to help improve our understanding of this technology.
- **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;

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.

6.2 CONSUMER CONNECTION

This financial year, WEL produced over 1,100 quotes for potential new load on our network, a 30% increase to the previous year. New subdivisions, commercial

establishments and industrial factories are being developed in the Hamilton City Council's structured plans described in the peak demand drivers.

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

Project / Programme	Investment Need	Estimated cost (in Nominal Price \$000)
New Connections and upgrades	Investment Needed: Accommodate connection request and augment network where required	119,935

Table 6.2.1 Consumer Connection development projects

Consumer Connection Schedule

Customer Connection (\$000 in Nominal Price)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential Customers	12,237	10,733	10,155	9,086	9,298	9,507	9,721	9,940	10,163	10,392
Business Customers	752	663	643	587	594	607	621	635	649	664
Large Customers-Low Voltage 400V	1,472	1,098	1,122	1,148	1,174	1,200	1,227	1,255	1,283	1,312
TOTAL	14,462	12,494	11,920	10,822	11,065	11,314	11,569	11,829	12,095	12,367

Table 6.2.2 Consumer Connection projected capital expenditure

6.3 SYSTEM GROWTH

We expect system peak demand to modestly increase over the AMP period. Table 6.3.1 shows the individual GXP capacity, forecast, and the demand forecast for the AMP period.

GXP	Installed capacity	Firm Capacity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hamilton 11kV	80	44	29	30	30	31	31	31	31	31	31	31
Hamilton 33kV	220	132	135	138	139	139	140	140	140	140	140	141
Huntly 33kV	120	82	26	27	28	28	28	28	28	28	29	29
Te Kowhai 33kV	230	136	103	106	108	110	112	113	114	114	114	115
System Peak			273	281	285	288	290	292	293	293	294	294

Table 6.3.1 GXP demand forecast to 2028

- Our system 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 have been undertaken or will be investigated and implemented:
- Improved load management. Investigations indicate that reductions in the peak demand can be achieved by improving the reinstatement of our load control;
- 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 system growth is described in the network which the GXP supplies. This is outlined further in the following sections.

6.3.1 HAMILTON NETWORK DEVELOPMENT PLAN

Hamilton network is supplied by Hamilton 33kV and Hamilton 11kV. However, they are separated by a phase shift of 30° or 90° depending on the adjacent Hamilton 33kV zone substations and the Hamilton 11kV. This means that we cannot easily and automatically connect Hamilton 11kV network to the Hamilton 33kV network.

This network supplies the council's structured plan in Rototuna, Ruakura and Peacockes as well as CBD developments.

There are a number of residential subdivision developments in the Rototuna, Borman area and in the northern part of the Ruakura structured plan.

Customer distribution as at end of Financial Year 2017

Customer Group	Number of Active ICP	Electricity Delivered (GWh)
Domestic	50006	321
General	5359	99
Small Scale Distributed Generation	383	4
Streetlight and Unmetered	160	6
Large Commercial	392	263

HAMILTON NETWORK

LEGEND

- Hamilton GXP
- Zone Substation
- Hamilton Network
- 33kV Subtransmission

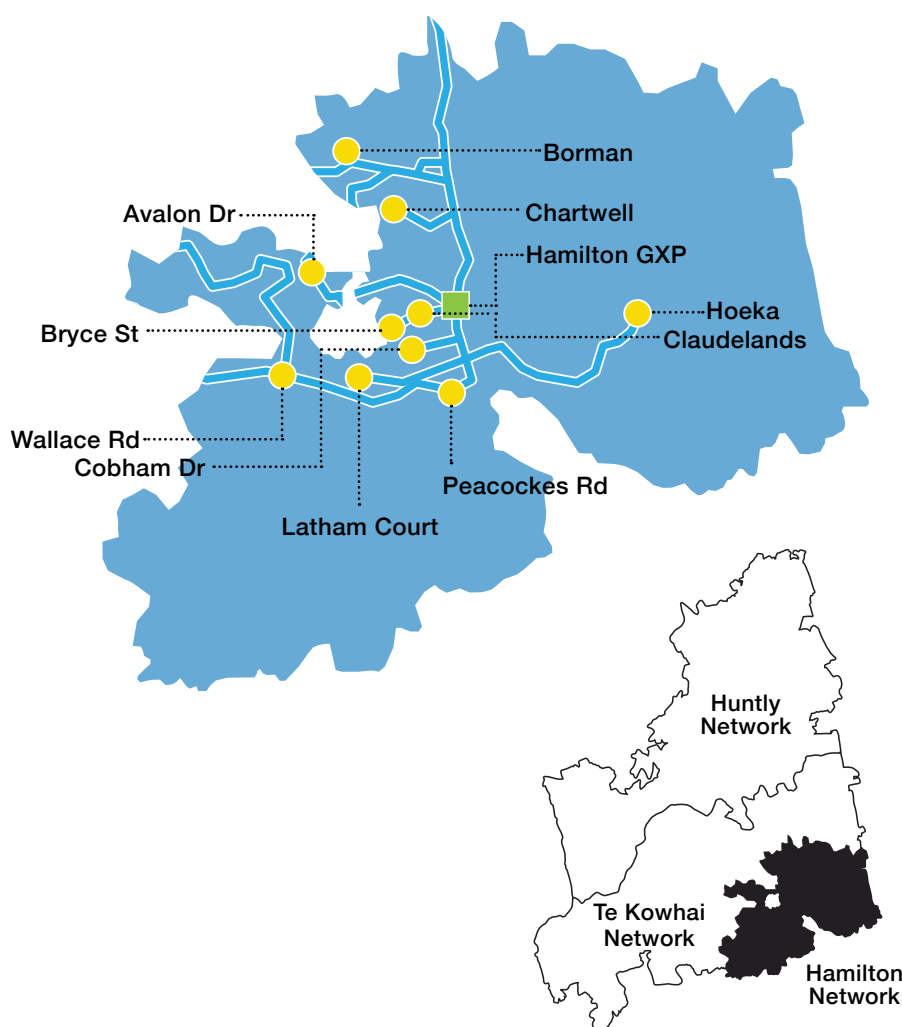


Figure 6.3.1 Hamilton Network

Hamilton Network zone substations demand forecast

Zone Substation	Security	Firm Capacity ¹	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Avalon Dr	N-1	23.8	17.3	17.9	18.2	18.5	18.7	18.9	19.2	19.4	19.6	19.9
Borman	N-1	20.6 ²	15.7	16.8	18.0	19.2	19.9	20.7	20.8	20.9	21.0	21.1
Bryce St	N-1	22.9	14.4	14.5	14.5	14.6	14.6	14.7	14.7	14.7	14.8	14.8
Chartwell	N-1	25.9	16.2	16.5	16.7	16.9	17.3	17.5	17.8	18.0	18.2	18.4
Claudlands	N-1	22.9	20.1	20.7	20.8	20.9	21.1	21.2	21.3	21.4	21.5	21.7
Cobham	N-1	25.9	12.2	12.5	12.5	12.6	12.6	12.6	12.6	12.7	12.7	12.7
Hoeka Rd	N	25.9	7.8	8.0	8.1	8.2	8.3	8.4	8.6	8.7	8.8	8.9
Latham Court	N-1	22.9	17.2	17.2	17.3	17.3	17.4	17.4	17.4	17.5	17.5	17.5
Peacocks Rd	N-1	25.9	14.7	17.9	18.2	18.5	18.9	19.2	19.9	20.6	21.2	21.9
Wallace Rd ²	N-1	15.4	12.8	12.9	13.0	13.0	13.1	13.1	13.2	13.2	13.3	13.3

¹Based on emergency thermal chain rating²Limited by 33kV Overhead Line rating

The following table summarises the Hamilton network system growth projected investment:

Project / Programme	Investment Need	Options Considered	Estimated cost (in Nominal Price \$000)
Asset Specific Pricing Customer Driven Jobs Ruakura Inland Port	Expected demand of the Inland port	New reticulation, New zone substation, Do nothing	4,528
Chartwell Third Transformer and Bus extension	Load growth in the northern part of Ruakura structured plan	Install third transformer, New zone substation, Transfer load, Do nothing	5,956
Crosby Switching Station	Increase capacity to cater for future demands	New switching station, New zone substation to cater for future demands, Do nothing	3,741
Distribution Network Reinforce – Ongoing	Feeders identified with loading and/or security issue	Upgrade feeder, Install new 11kV cables, Install automated switch	5,675
Installation of LV Transformer load monitoring	Lack of monitoring devices. Old devices have faulted	Install new monitoring devices	17
Smart Meters	Smart meters provide the opportunity to provide information on the network that can identify power quality issues	Continue with Smart meter roll out, Do nothing	3,870
Upgrade AVACB4	AVACB4 have exceeded customer number standard (1,200) which resulted in high SAIDI impact	Transfer some customers to AVACB1, Upgrade feeder to increase capacity and install automated switch, Do nothing	608
Upgrade CBD Distribution Ring Feeders	Feeder weak sections limits feeder capacity and ability to supply under contingency	Replace weak sections, Install new feeder, Do nothing	580

Table 6.3.1.1 Hamilton network system growth projects

Hamilton Network Development Schedule

Hamilton Network Development (in Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Asset Specific Pricing Customer Driven Jobs Ruakura Inland Port			535	2,186	1,677	131				
CHA third Transformer and bus extension								239	2,648	3,068
Crosby Switching station							1,186	1,263	1,291	
Distribution Network Reinforce	524	523	535	547	559	571	584	597	611	625
Installation of LV transformer load monitoring devices	17									
Smart Meter	349	357	365	374	382	391	399	408	418	427
Upgrade AVACB4 to provide security					608					
Upgrade CBD Distribution Ring Feeders					580					
TOTAL	890	880	1,434	3,106	3,805	1,093	2,170	2,508	4,968	4,120

Table 6.3.1.2 Hamilton network system growth projected capital expenditure

6.3.2 TE KOWHAI NETWORK DEVELOPMENT PLAN

Te Kowhai network is supplied by Te Kowhai GXP. There are two large embedded generators in this network the 50MW Te Rapa cogeneration and 64MW Te Uku Windfarm and one small generation unit at Hamilton City Council's Waste Water Plant 1MW cogeneration. The 33kV subtransmission is a mesh network where all 33kV subtransmission are interconnected and ringed with the Te Kowhai GXP.

This network supplies the structured plan of Rotokauri, Rototuna and Industrial development in Horotiu and Pukete.

The network has a lot of developments particularly on residential subdivisions in Rotokauri area and industrial developments in Horotiu area.

Customer distribution as at end of Financial Year 2017

Customer Group	Number of Active ICP	Electricity Delivered (GWh)
Domestic	17895	122
General	4516	83
Small Scale Distributed Generation	207	2
Streetlights and Unmetered	65	1
Large Commercial	307	184

TE KOWHAI NETWORK

LEGEND

- Grid Exit Point (GXP)
- Zone Substation
- Te Kowhai Network
- 33kV Subtransmission

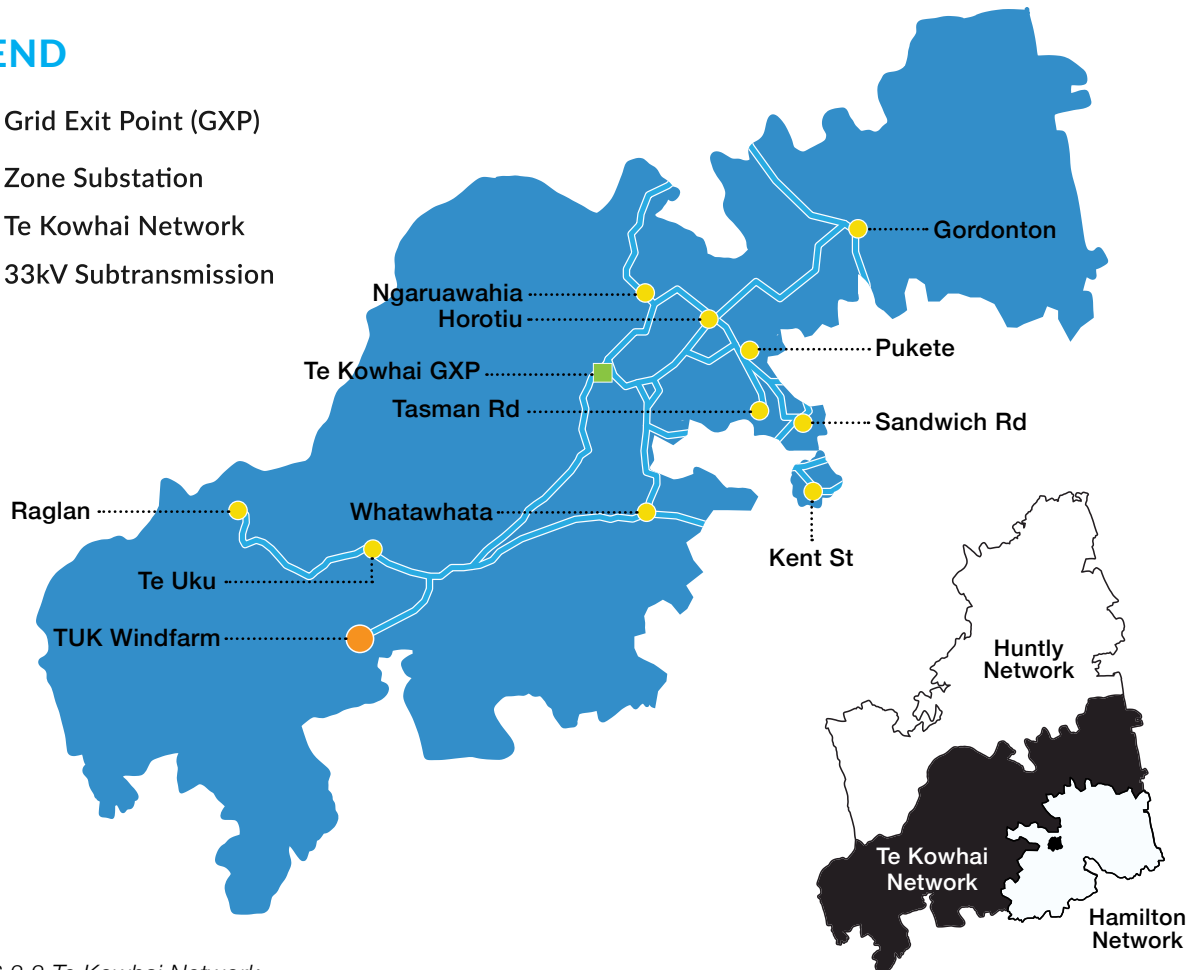


Figure 6.3.2 Te Kowhai Network

Te Kowhai Network zone substation Demand Forecast

Zone Substation	Security	Firm Capacity ¹	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gordonton	N	10	6.5	6.5	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.9
Horotiu	N-1	18	9	10.7	12.3	13	13.1	15.9	16	16	16.1	16.2
Kent St	N-1	22.9	16.7	16.7	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Ngaruawahia	N-1	9	5.7	5.8	5.8	5.9	5.9	6	6	6	6.1	6.1
Pukete – 11kV	N-1	12.6	9.6	10.3	10.4	10.4	10.4	10.4	10.4	10.5	10.5	10.5
Pukete – Anchor	N-1	30	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Raglan	N	11.4	4.9	5.1	5.3	5.6	5.8	6.1	6.3	6.3	6.4	6.4
Sandwich Rd	N-1	28.2	21.5	21.9	22.4	22.4	22.5	22.6	22.6	22.7	22.8	22.8
Tasman	N-1	30	19.4	21.3	23.1	23.8	24.5	25.2	26.3	27.5	28.1	28.7
Te Uku	N-1	5	1.9	1.9	2	2	2	2.1	2.1	2.1	2.2	2.2
Whatawhata	N	22.9	4	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4

¹Based on emergency thermal chain rating

The following table summarises the Te Kowhai network system growth projected investment:

Project / Programme	Investment Need	Options Considered	Estimated cost (in Nominal Price \$000)
Gordonton Substation upgrade study	Solution study to recommend configuration and cost options	Prepare study, Do nothing.	102
Gordonton Substation upgrade	Substation has only one 33kV circuit breaker, with a bypass switch all on one pole, for two transformers. Safety during maintenance, protection upgrade and 11kV asset replacement.	Upgrade substation to present standards, transfer demand, Do nothing.	1,846
Offload HORCB6 by transferring to NGACB5	Large number of customers on a long rural line, therefore a large number of customers on a section of line that is prone to faults	Transfer some customers to NGACB5, Do nothing	354
New Horotiu customer Site Substation	Additional load of new Horotiu customer will cause Horotiu's substation security to be exceeded.	New Zone substation, Increase capacity, Transfer demand, Do nothing.	1,464
Tasman 3rd Transformer and bus extension study	Solution study to recommend configuration and cost options	Prepare study Do nothing	51
Tasman 3rd Transformer and bus extension	Demand growth of Rotokauri structure development	New Zone substation, Increase capacity, Transfer demand, Do nothing.	3,564
TWH GXP Study	Solution study to recommend configuration and cost options	Prepare study Do nothing	153
TWH GXP –TAS 33kV link	Improve security of 33kV mesh due increase demand growth at Horotiu (HOR) and Tasman (TAS) area.	Install 33kV link from TWH to HOR and TAS, Do nothing.	7,717
Te Uku substation upgrade study	Solution study to recommend configuration and cost options	Prepare study, Do nothing.	51
Te Uku substation upgrade	Improve security of 33kV supply, protection upgrade and asset replacement and safety improvements	Upgrade substation to present standards, Transfer demand, Do nothing.	2,319

Table 6.3.2.1 Te Kowhai network system growth projects

Te Kowhai Network Development Schedule

Te Kowhai Network Development (in Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gordonton Zone Substation Upgrade			535	1,312						
Gordonton Zone Substation Upgrade study	102									
Offload HORCB6 to NGACB5			354							
Proposed new Horotiu customer substation		724	615	126						
Tasman 3rd Transformer & Bus extension		946	406				1,435	777		
Tasman 3rd Transformer & Bus extension study	51									
Te Kowhai GXP Study Report	153									
Te Uku Substation upgrade					1,118	1,143	58			
Te Uku Substation upgrade study	51									
TWH-TAS 33kV cables		4,184	2,101	1,432						
TOTAL	358	5,854	4,011	2,870	1,118	1,143	1,493	777		

Table 6.3.2.2 Te Kowhai network system growth projected capital expenditure

We are proposing a new substation for one of our customers which indicated a load increase by 2023. The total aggregated load would take up most of the Horotiu substation capacity, hence the proposed new substation. This step change accelerates the development of the two projects below as it affects the security of the 33kV network.

With this step change plus load growth in Tasman, Pukete and Sandwich areas, the TWH-TAS cabling project is moved forward to 2020-22 (from 2022-25) as the 33kV mesh network requires additional security. This project is in conjunction with the Tasman 33kV bus extension described below.

The Tasman 3rd Transformer and bus extension project is now divided into two phase. The first phase is to install the

33kV bus extension in conjunction with the development of TWH-TAS 33kV cables as one end of these cables will be terminated to the TAS 33kV bus extension. The second phase is scheduled by 2024/25 to 2025/26, to install the 3rd transformer and the 11kV bus extension to supply the estimated growth in Rotokauri and Tasman area. This financial year, at Tasman substation, we will be installing additional 11kV cables between the transformers and the 11kV board. This will increase the firm capacity of the substation to 30MVA, thereby delaying the need for an increase capacity of the substation until 2025.

We conducted a review of the drivers and cost for Gordonton and Te Uku substation upgrade. The review result is a cost reduction and confirmed scheduled upgrade. The projects are primarily driven by both security and asset replacement.

6.3.3 HUNTLY NETWORK DEVELOPMENT PLAN

Huntly network is supplied by Huntly GXP. WEL has formally disconnected from Bombay GXP this financial year, which previously supplied the three northernmost substations.

System growth projects for Huntly network were previously driven by proposed Solid Energy expansions. In the 2016 AMP, due to the insolvency of Solid Energy, we reviewed the security of Huntly network and subsequently cancelled system growth projects

amounting to \$4.4M. This financial year, Kimihia substation which supplies the Solid Energy's East Mine, was decommissioned hence increasing the capacity of the network by 2MW.

At this stage, we do not have indications of a big step change in the Huntly network. The network configuration is more than adequate to supply the requirement including the Te Kauwhata structured plan which will be supplied from Te Kauwhata substation.

Customer distribution as at end of Financial Year 2017

Customer Group	Number of Active ICP	Electricity Delivered (GWh)
Domestic	6282	45
General	2287	32
Small Scale Distributed Generation	49	1
Streetlights and Unmetered	52	2
Large Commercial	76	38

HUNTLY NETWORK

LEGEND

- Huntly GXP
- Zone Substation
- Huntly Network
- 33kV Subtransmission

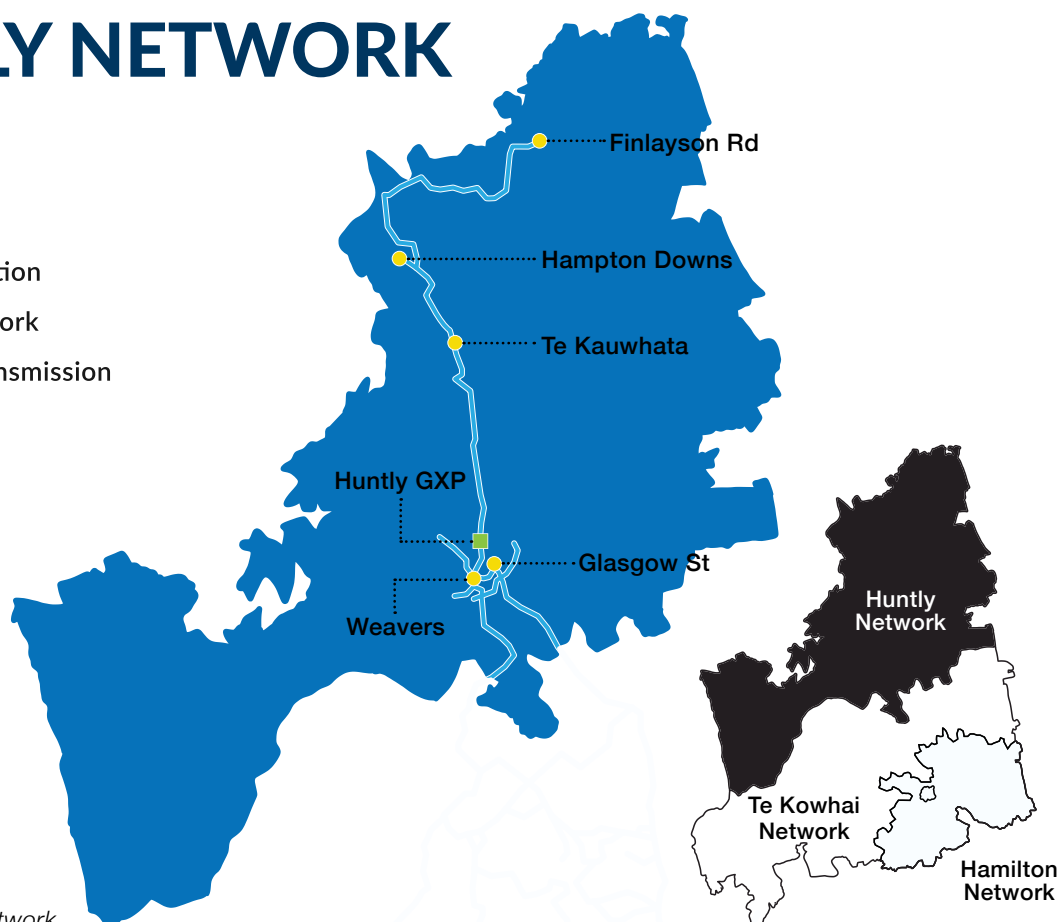


Figure 6.3.3 Huntly Network

Huntly Network zone substation Demand Forecast

Zone Substation	Security	Firm Capacity ¹	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Finlayson Rd	N	9	4.0	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1
Glasgow St	N	12	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	9.0	9.0
Hampton Downs	N	9.1	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Te Kauwhata	N-1	11.8	5.1	7.1	7.3	7.5	7.8	8.0	8.3	8.5	8.8	9.0
Weavers	N-1	9	8.7	8.8	8.8	8.9	9.0	9.1	9.1	9.2	9.3	9.3

¹Based on emergency thermal chain rating

6.3.4 SUMMARY OF SYSTEM GROWTH CAPITAL EXPENDITURE

The 10 year System Growth Investment forecast is shown in Table 6.3.4.1. Work has been undertaken to spread the required capital over the AMP period.

SYSTEM GROWTH CAPEX In Normal Price

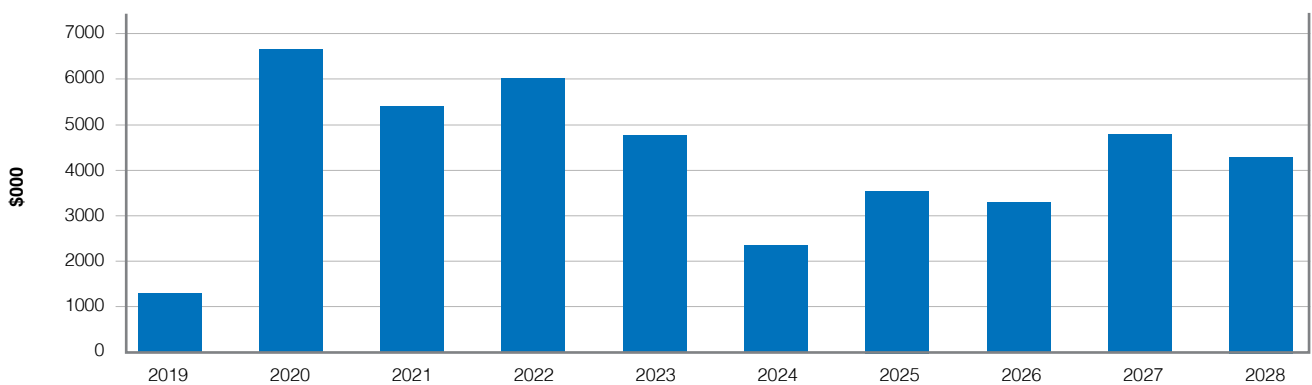


Figure 6.3.4.1 System Growth CAPEX

6.4 RELIABILITY, SAFETY AND ENVIRONMENT

This section is composed of subsections covering quality of supply, legislative and regulatory, and other reliability, safety and environment.

6.4.1 QUALITY OF SUPPLY

The following table summarises the quality of supply projected investment:

Project / Programme	Investment Need	Options Considered	Estimated cost (in Nominal Price \$000)
Battery energy storage system investigation	Investigate benefits and effect of battery storage	Investigate benefits and effect of battery storage	307
Distribution Transformer and LV Feeder Upgrade for power quality projects	Upgrade distribution transformer and LV feeder identified by smart meters to improve power quality	Upgrade distribution transformer and LV feeder identified by smart meters to improve power quality, do nothing	13,107
Network Upgrade Due To Distributed Generation applications	Capacity and security issues due to distributed generation connections to the network	Upgrade network to rectify pre-existing issues	568

Table 6.4.2.1 Quality of Supply projects

Quality of Supply (in Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Battery energy storage system investigation	307									
Distribution Transformer and LV Feeder Upgrade for power quality projects	1259	1202	1229	1257	1285	1314	1344	1374	1405	1437
Network Work Upgrade Due To DG applications	52	52	53	55	56	57	58	60	61	62
TOTAL	1618	1255	1283	1312	1341	1371	1402	1434	1466	1499

Table 6.4.2.2 Quality of supply projected capital expenditure

6.4.2 LEGISLATIVE AND REGULATORY

The following table summarises the legislative and regulatory projected investment:

Project / Programme	Investment Need	Options Considered	Estimated cost (in Nominal Price \$000)
AUFLS scheme change	Compliance to new AUFLS regime	Comply with regulatory requirement, Do nothing	165
Seismic strengthening of substations and switching stations	Safety and compliance	Strengthen buildings to comply	790

Table 6.4.2.1 Legislative and Regulatory projects

Legislative and Regulatory Project Schedule

Legislative and Regulatory (in Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AUFLS scheme change		21	144							
Seismic strengthening of substations and switching stations	103	366	321							
TOTAL	103	387	465							

Table 6.4.2.2 Legislative and Regulatory projected capital expenditure

6.4.3 OTHER RELIABILITY, SAFETY AND ENVIRONMENT

The following table summarises the other reliability, safety and environment projected investment:

Project / Programme	Investment Need	Options Considered	Estimated cost (in Nominal Price \$000)
Air-conditioning for substations	A number of substations have high humidity and temperature issues	Install air conditioning, ventilation, Do nothing	314
Discretionary fibre install	Opportunity to install new fibre cable or duct when there is Council and third party road or footpath works	Install new fibre cable or duct when there is Council and third party road or footpath works, Do nothing	1515
Distribution SCADA, comms and Control	Provide control of LV network for DSO	Provide control of LV network for DSO, Do nothing	897
Fibre routes	Install new fibre to provide redundancy and replace pilot wires	Install new fibre, Install new radio or remain on pilot wires	1456
Garden Switching Station Protection Upgrade	Provide arc flash protection and upgrade comms	Provide arc flash protection and upgrade comms, Do nothing	467
Garden Switching Station Refurbishment	Safety issues, complex management	Upgrade existing switching station, Establish a new switching station, Do Nothing	1734
Garden Switching Station Refurbishment Study	Solution study to recommend best cost options	Prepare study, Do Nothing	51
LV measurement	Provide measuring devices in LV network	Provide measuring devices in LV network, Do nothing	1751
Mesh critical street lighting control	Provide back up to strengthening control given a failure of the ripple plant	Provide backup ripple plant, Do nothing	41
Reliability Projects	Minimise SAIDI minutes	Install new isolation equipment, reconfigure circuit, Do nothing	4260
Site Security Access and Monitoring	Improve security of the substation sites	Improve security, Do nothing	81
Substation Door Upgrade-Pilot project	Safety improvement for emergency egress	Upgrade substation door, Do nothing	190
UFF Provisioning	Provide space on poles to allow for UFF fibre installation where required	Upgrade network to allow for fibre installation, Do nothing	157
Weaver resonant earthing	Loss of supply during single phase to earth faults	Major upgrade of all 11kV feeders in worst performing area in the network, Install Ground fault Neutraliser, Do nothing	51

Table 6.4.3.1 Other reliability, safety and environment projects

Other Reliability, Safety and Environment Project Schedule

Other Reliability, Safety and Environment (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Airconditioning for substations	102	105	107							
Discretionary fibre install budget	153	157	160	164	168	171	175	119	122	125
Distribution SCADA, comms, and control						171	175	179	183	187
Fibre/Routes	345	518	321	273						
Garden Place Switching Station Protection Upgrade							467			
Garden Place Switching Station Refurbishment						857	876			
Garden Place Switching Station Refurbishment Study	51									
LV measurement		178	182	186	190	194	199	203	208	212
mesh critical street light control	41									
Reliability projects (mainly Rural Areas)	139	418	428	437	447	457	467	478	489	500
Site Security Access and Monitoring	81									
Substation Door Upgrade - Pilot project	30	52	53	55						
UFF Provisioning	157									
Weaver Resonant Earthing	51									
TOTAL	1150	1427	1251	1115	805	1851	2360	980	1002	1024

Table 6.4.3.2 Other reliability, safety, and environment projected capital expenditure

6.4.4 SUMMARY OF RELIABILITY, SAFETY AND ENVIRONMENT (RSE) CAPITAL EXPENDITURE FORECAST

RELIABILITY, SAFETY AND ENVIRONMENT CAPEX In Nominal Price

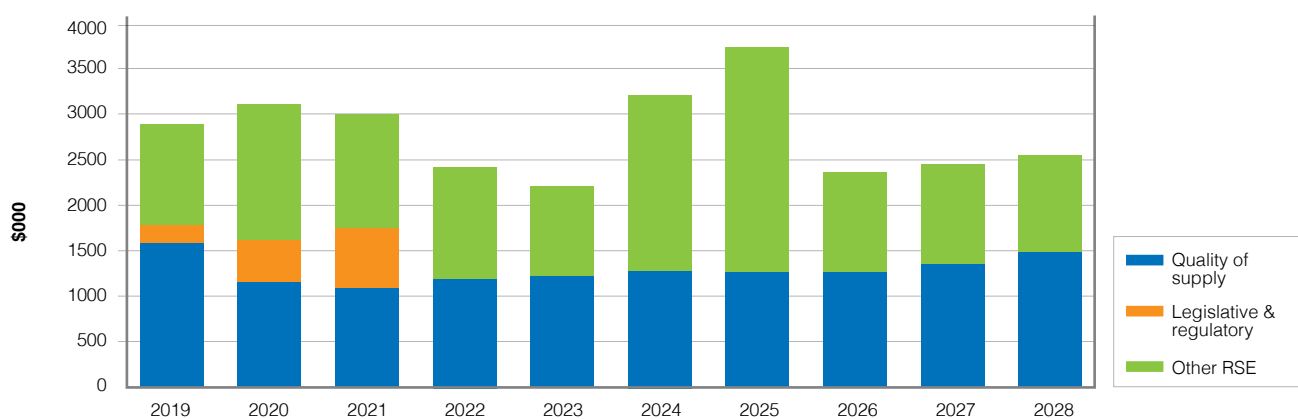


Figure 6.4.4.1 Summary of reliability, safety, and environment projected capital expenditure

6.5 ASSET RELOCATION

Relocations

These are predominantly relocations of our assets associated with the continuing development of the Waikato expressway, other NZTA road works and for works associated with subdivision or land development.

Undergrounding

In some circumstances and upon request, WEL will convert overhead lines to underground cables and will fund up to 50% of the total project cost where there is a

community focus. A maximum annual spend inclusive of WEL contribution is \$500k, beyond which will be 100% cost to the customer.

The following table summarises the asset relocation projected investment:

Project / Programme	Investment Need	Options Considered	Estimated cost (in Nominal Price \$000)
Relocations	Relocation of assets to support the expressway development	Relocate assets	12,712
Undergrounding	Undergrounding of overhead lines	Underground overhead lines	5,673

Table 6.5.1 Asset Relocation projects

6.5.1 SUMMARY OF ASSET RELOCATION AND EXPENDITURE FORECAST

The 10 year capital expenditure forecast is shown in table 6.5.1.1.

Asset Relocation (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Undergrounding	522	523	535	547	559	571	584	597	611	625
Transit Hamilton Bypass	544	523	321							
Hamilton City Council	511	523	535	547	559	571	584	597	611	625
NZTA	511	523	535	547	559	571	584	597	611	625
TOTAL	2088	2091	1924	1640	1677	1714	1753	1792	1833	1874

Table 6.5.1.1 Asset relocation projected capital expenditure

6.6 SUMMARY OF NETWORK DEVELOPMENT CAPITAL EXPENDITURE

The 10 year Network Capital Investment forecast is shown in table 6.6.1 Work has been undertaken to spread the required capital over the AMP period.

NETWORK DEVELOPMENT CAPITAL EXPENDITURE In Nominal Price

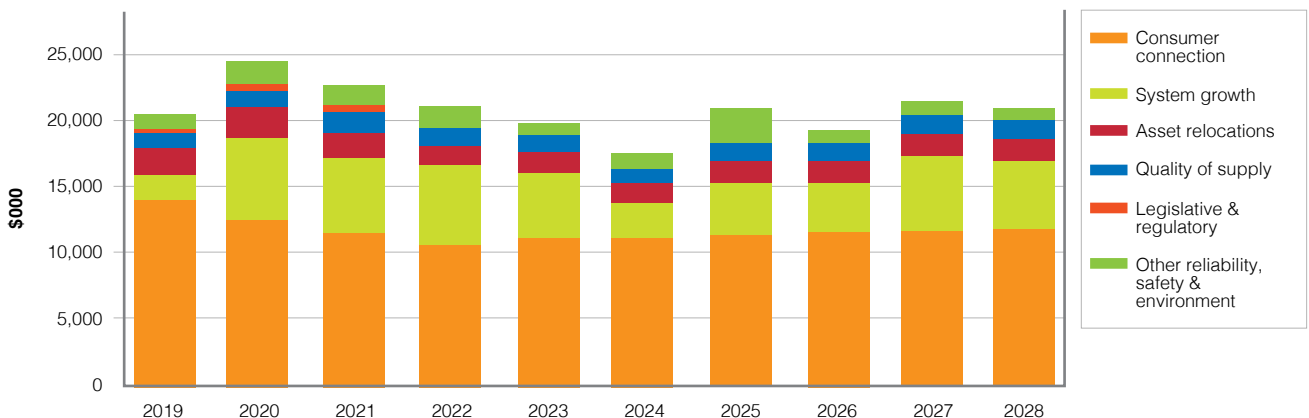


Figure 6.6.1 Network Development CAPEX





7

NON-NETWORK SOLUTIONS AND SUPPORT SYSTEMS



7

NON-NETWORK SOLUTIONS AND SUPPORT SYSTEMS

This chapter sets out our approach to non-network solutions and support systems. The chapter provides an overview of the plans we have in place for emerging technologies such as solar generation and battery storage systems. The chapter also outlines the benefits we have gained from installing our own smart meters.

7.1. NON-NETWORK SOLUTIONS

WEL Networks is investigating and testing solar generation and battery storage to have a robust understanding of their capabilities, impacts and influence on the network. Further, WEL have installed five electric vehicle (EV) charging stations to support the

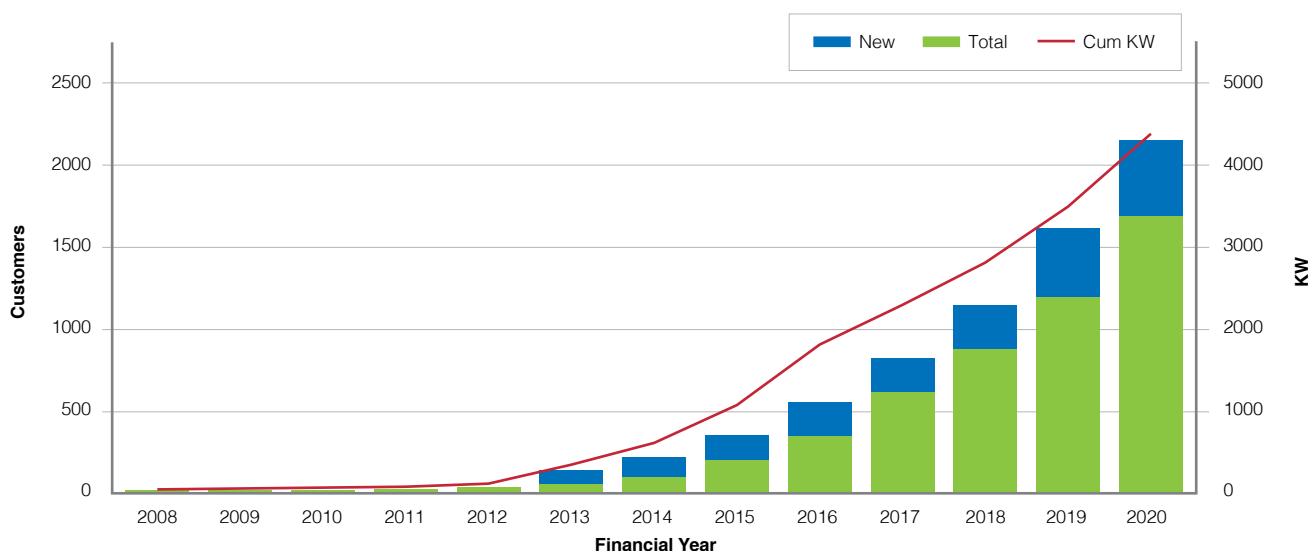
NZ government initiative in promoting the use of electric vehicles. WEL is continuing to develop new systems for smart meter analytics as well as providing these services to other companies.

7.1.1. SOLAR GENERATION INVESTIGATION

Currently, WEL has 534 customers with mounted photovoltaic panels having an installed capacity of approximately 1.6MW. It is forecast that over the next 4 years there will be additional connections totalling a further

2.7MW. The graph illustrates the estimated growth of solar connections and capacity WEL can expect based on current growth rates.

ESTIMATED GROWTH OF SOLAR CONNECTIONS AND CAPACITY



WEL has taken a proactive approach to study the impact of an aggregated group of smaller single installations or a substantial size solar generation installation on the existing network infrastructure. To facilitate the investigation, WEL has assembled 76kW of photovoltaic panels on the roof of

the WEL depot building as a test site. It is expected that the outputs from the investigation would provide WEL a better understanding on how to manage and optimise the network in the future.

7.1.2. BATTERY INVESTIGATION

Energy storage is the enabling technology to greater uptake of variable renewable power generation such as wind and solar. Energy storage has many direct benefits to the distribution network including deferring traditional capital investment, providing ancillary services and providing greater flexibility to renewable generation. WEL Networks is undertaking investigative projects in battery energy storage systems at selected locations on the distribution network. The solar production test facility at the WEL Depot will be the first location that an energy storage system is to be installed. This project will provide WEL Networks with data and information on operating

an energy storage system with renewable generation and how the stored energy can be used to provide ancillary services for the network i.e. peak shaving at a location where this would be advantageous.

WEL recently powered the lights of the 130m NZ cycleway bridge across the Waikato river at Horotiu using an offgrid solution. Utilising battery storage as well as solar and wind generation was an economic method of supplying electricity to this important infrastructure. As technology costs decrease the number of off-grid or battery supported applications is expected to increase dramatically.

7.1.3. SMART METER

WEL has installed 58,000 smart meters in its distribution area since 2011 and is continuing to install smart meters on new connections. WEL has gained significant expertise in developing tools and analytics for meter data and moreover, continues to develop new systems with the aim of becoming the centre of excellence for smart meter data analytics in New Zealand.

This expertise is being used to provide services to EDBs with similar systems. For example a web portal has been created to provide similar tools and reports to SmartCo members. WEL plans to continue to strengthen our smart metering analytics and invest in state of the art analytics tools.

WEL has realised benefits of the tools and data analytics across the network and these can best be categorised as near real time operational and planning benefits.

These are discussed further below.

Smart Metering System

The smart metering systems consist of the core communications and meter management modules supplied by Silver Spring Networks and other data systems built by WEL, to manage meter readings and meter device information in order to meet MEP (Metering Equipment Provider) process and compliance requirements.

Mesh Communications Network and Advanced Meter Management

The Silver Spring Network (SSN) head end hosts a suite of applications that support the WEL smart meter implementation. The head end itself is hosted in the

United States and the contractual arrangement is a "Software as a Service" agreement. 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.

The Advanced Meter Management module within the SSN head end is the main application 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 at selectable frequencies can be performed using web services. Smart Box meter readings and events are obtained at scheduled intervals.

Smart Meter Database and Data Warehouse

WEL is an MEP currently providing metering services to six retailers. To support this function WEL maintains a Metering Equipment database containing all metering equipment details and associated compliance information. Tablet devices are used to field capture meter installation activity and update the database automatically.

All smart meter readings and event data are downloaded from SSN and stored in a Meter Data Warehouse. This provides meter data feeds to Traders for sites where WEL is the MEP, updates to the Registry, and also serves as a data source for reports and analytic tools that use the data for distribution network purposes. This database is linked to the previously mentioned Metering Equipment database and the Network Billing database.

SMART METER OPERATIONAL BENEFITS

Proactive Low Voltage Correction

WEL is able to poll and log (voltage, current, power and power factor) data from the meters remotely at a customer's premises. Therefore, for Low Voltage Complaints (LVC) and other issues which require investigations, this can now be done from the office, without having to install data loggers at the site.

Control Room Operations

The control room has the ability to monitor meter voltages in real time.

This results in:

- Improved fault detection and management: By using smart meter voltage data it is possible to confirm if and where a single HV fuse is suspected of having blown. When power is restored by a fuse or switch being closed it is possible for the operator to check voltages and confirm power is back and at normal levels on all phases. It is no longer necessary to direct a faultman to climb a pole or open a transformer cabinet to measure voltages and confirm power has been restored.
- Improved Network Flexibility: Having the ability to obtain an instantaneous measurement of voltage has improved the flexibility of our network. This can be used to increase the proportion of the network that is back-fed during both planned and unplanned outages.
- Reduction in Response Time: When power is lost to a smart meter it sends out a communication to inform WEL that power has been lost, this is referred to as "last gasp". This signal is fed into our NMS (Network Management System) and simulated as a customer call creating a 'no power' incident. This provides the operator with immediate notification of an outage. This can then be actioned and fault staff dispatched directly to the correct fault site, prior to any fault notifications being received from the public.

Reduction in Fault Call Outs

We are able to connect to a smart meter and obtain instantaneous measurement data. Customer Service Representatives use this when we receive a call of part or no power from a customer to determine if the fault is

on the network side of the meter or within the customer's installation. This has significantly reduced the number of faults that our staff need to attend.

Streetlight Control

The failure of a ripple injection plant on a GXP results in a loss of control of automatic streetlight control. Smart meters have been installed on all streetlight control points and mesh commands used to switch the control contacts were sent through the smart meter communications mesh. This successfully allowed centralised control of the streetlights while repairs to the ripple plant were undertaken. Use of smart meters also provides the ability to remotely confirm the state of a device's switch in real time and also measure the ripple plant signal strength at that device.

Smart Meter Network Planning Benefits

Smart meters allow WEL to identify faults and issues with the network, determine the cause of the fault, categorise the expenditure type and prioritise the work. The main advantage of this is improved service to our customers and better determination of spending priorities.

- **Proactive Power Quality and Abnormal Condition Detection:** The voltage excursion events generated by meters are stored in a data warehouse. These events are analysed and reported on in various ways with the intention of identifying various conditions such as overloaded transformers, overloaded or undersized conductors, incorrectly tapped transformers, loose connections, loose or broken neutrals. A significant number of unsafe conditions have been detected and repaired as a result of this analysis.
- **Load profiling:** The meter load profile information can be aggregated to distribution transformer level and by supplementing this with feeder and GXP profiles, a good approximation can be derived of the distribution transformer load profile. This can indicate overloaded transformers and an assessment can be made of the severity of that overloading (in terms of quantity, timing and duration) and appropriate upgrades planned and prioritised.

- **Identification of DG and unauthorised energy export:** The smart meters can detect energy export and sites reporting this can be compared with known and approved DG sites. Unauthorised sites are subsequently investigated.
- **Revenue Assurance**
 - Load control not working – confirming that load control is operational at a site and is being correctly measured.
 - Tamper – altering of a meter generates tamper events.
- Confirming site capacity – identifying overloaded sites
- Modelling of TOU tariffs with real data
- Meter bypass detection – with the meter in the disconnected state, potential on the load side can be detected.
- **Reduction in Capital Expenditure:** By using smart meter analytics WEL has been able to improve our asset management decision making.
- Future tools are in development such as but not limited to detection of EV charging and solar generation.

7.1.4. EV CHARGING STATIONS

The EV (electric vehicle) is another disruptive technology that is gaining traction around the world and is becoming more prevalent in New Zealand. Switching a large proportion of New Zealand's vehicle fleet to EVs has a number of benefits to the public including a reduction in the use of petroleum. This would reduce New Zealand's reliance on foreign oil, thereby enhancing national security and keeping to a minimum the transfer of wealth to oil-producing countries. EVs are also often cited as being an important component of a society becoming environmentally friendly and aiding greenhouse gas reduction. The New Zealand Government is promoting the use of EVs, with a target of doubling the number of electric vehicles every year to reach around 64,000 by the end of 2021.

Most major vehicle manufacturers intend to produce EVs in the near future. With this level of interest from vehicle manufacturers it is probable that this will translate into a significant shift from internal combustion engine (ICE) powered vehicles to some form of EV.

WEL Networks will be critical in facilitating a large scale EV uptake. EDBs have the means and the ability to connect, control and upgrade the infrastructure where required.

WEL Networks EV strategy consists of three strategic themes which together combine to form the overall strategy:

- **Education and promotion:** Proactively engage in the promotion and public education of EVs.

- **Infrastructure:** Engage with private retailers for the use of car parking space for the installation of a Fast Charging network. Monitor EV uptake and Fast Charge usage for trigger points to determine further investment.
- **Network:** Investigate charging optimum times, to best utilise the current capacity of the distribution network. Utilise the existing smart meter network to identify any clustering issues, and resolve as they present themselves.

WEL Networks has EV smart chargers at 5 strategic sites throughout the Waikato to encourage the uptake of EVs.

- Maui Street, Te Rapa
- Wayside Road, Te Kauwhata
- Bow Street, Raglan
- Innovation Park, Ruakura
- Caro Street, Hamilton CBD

In addition to the above, WEL Networks plans to install EV smart chargers on other sites to be determined. The chargers are currently free to use and are mapped on Plug Share, a free downloadable app for the national electric charging network.

7.2. NON-NETWORK SUPPORT SYSTEMS

WEL Networks has a variety of non-network support systems that enable the business to conduct its day to day activities in an efficient manner. The key systems are Network Management System (NMS), Geographical Information System (GIS), Enterprise Resource Planning (SAP), Network Billing, Electronic Content Manager (ECM), and Mobility services.

In the majority of cases, the non-network support systems are “off the shelf” products configured to accommodate internal business processes. These are supported by internal staff and 3rd party vendors to ensure that the systems remain up to date, secure, and fit for purpose. The Mobility solution has been developed specifically to WEL's needs by a 3rd party vendor who works closely

with the business to maintain and enhance this system. The Network Billing is a bespoke system specifically for use within WEL Networks as 3rd party products were either not available in the market place at the time of implementation or were priced well beyond internal costs relating to system development. The smart meter data system Data Warehouse and Device Database have been developed in house. The Advanced Meter Management module is a 3rd party product and externally hosted.

These systems interface with one another to ensure a consistent dataset is available across the non-network support systems landscape in a format that is meaningful to the users of each system.

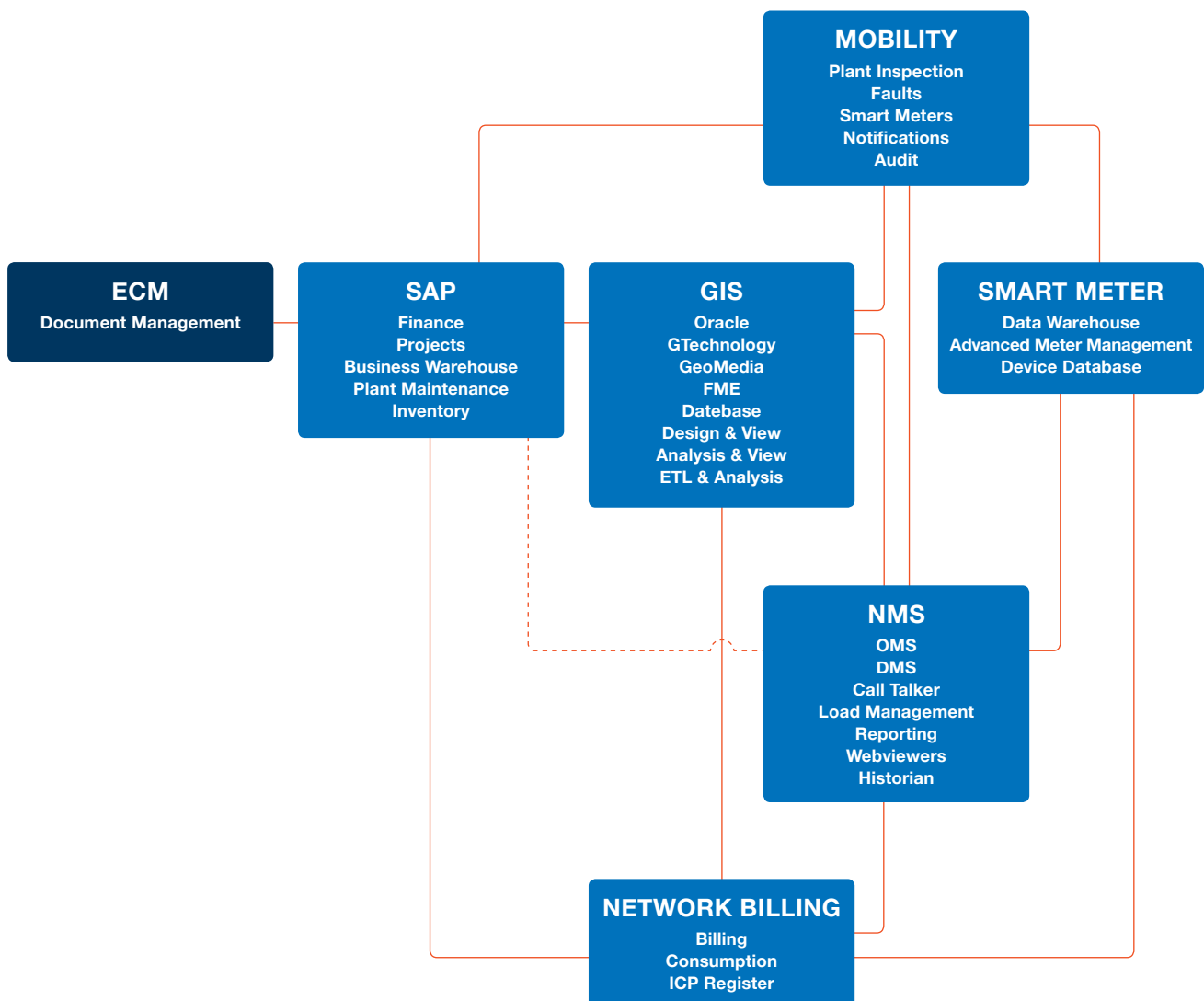


Figure 7.2.1 Non Network Support System

7.2.1. NETWORK MANAGEMENT SYSTEM (NMS)

The NMS enables the fast and efficient control of the electricity network for the operator. It consists of the General Electric PowerOn Fusion software package and data storage systems connecting with our SCADA Devices through an IP based wide area 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 providing effective customer service.

The NMS consists of the following subsystems:

- Distribution Management System (DMS) and Switching Management
- Outage Management System (OMS)
- Trouble Call Taker, with smart meter information integration
- Reporting
- Webviewers
- Historian

These subsystems are described as follows:

Distribution Management System (DMS) and Switching Management

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 through animation of the diagram with the current energisation state. It also controls all switching management steps (preparation, validation and execution) and can enforce built in safety logic throughout all stages. This is a particularly powerful aspect of the system, especially from a safety perspective and enforcement of operational procedures.

Outage Management System (OMS)

The OMS is an application designed to aid in the management, prioritisation, administration and reporting of outages on the network and individual customers. The OMS automatically associates customer 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 meters has been integrated with the OMS to improve fault location by simulating customer calls.

Trouble Call Taker, with smart meter information integration

The Trouble Call Taker records customer calls and provides vital information to the Dispatch Team. 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.

Reporting

The reporting system performs queries over the NMS database using MS SQL Reporting Services and there a large number of system and in-house developed reports tailored for different parts of the business. All network reliability information (SAIDI, SAIFI etc.) is captured by the NMS and is presented in reports. The annual reliability disclosure reports are also automatically generated.

Webviewers

The PowerOn product provides a web based view of the operating single line diagram and a linked geographic view (based on GIS). This provides visibility of the system to a wider audience in the business.

Historian

All analog points with the NMS are recorded and stored within a product called TrendSCADA. This then makes the data available as tables and trends to other users in the business.

The NMS system has recently been upgraded to PowerOn Fusion V5.2.2.9 and consists of multiple application servers distributed over the WEL main office and the Disaster Recovery Centre. There are communication gateways to the WAN (Wide Area Network) at each of these sites. Most of the core system is virtualised on recent high quality hardware. Such arrangements ensure high availability and resilience of the system. There are separate pre-production and development environments.

Some mobility functionality has been developed to allow the dispatch of fault jobs to field devices and the completion of fault reports from the field. The future mobility strategy is under review with a number of possible extensions and improvements being considered.

7.2.2. GEOGRAPHIC INFORMATION SYSTEM (GIS)

The network assets managed by WEL are distributed over a large geographical area, so WEL needs to know and visualise the geographical location of each asset. The WEL GIS using GTechnology Suite enables this by storing the spatial data for each asset (that describes its geographic coordinates) and any associated contextual information which can be presented to users in a variety of targeted ways depending on their needs.

As well as the spatial data, the GIS contains a basic connectivity model enabling users to visualise connected assets spatially and trace the connectivity of the network spatially upstream and downstream to identify connected assets.

Each asset record in the GIS has a spatial attribution that describes the asset, its location, its relationship to other assets, the lifecycle state (e.g. In Service or not), the length of linear assets (e.g. conductors), and the asset's connectivity and electrical state (Open/Closed and which circuit it is connected to).

The asset data is updated in the GIS by means of physical and electronic 'As Builts' and GPS survey data received from within WEL and from external contractors. This data is uploaded or entered into the GIS to keep the asset data up to date. Structured and on-going quality assurance routines are in place to monitor data entered and identify priority legacy data to target for remediation.

The following contextual data is contained in the GIS. Its purpose is to allow core asset data to be viewed and analysed in relation to features that give context to the asset data;

- Landbase information from Land Information New Zealand (LINZ)
- Master Address data from CoreLogic

- Aerial Photography
- Political Boundaries from Statistics New Zealand

The GIS provides data by external interface to NMS (CAD files), SAP (aspatial data) and the Design teams (CAD files) so that there is consistent and unified geographic data used throughout the organisation. WEL GIS data is also automatically extracted for the BeforeUdig organisation to provide detailed GIS plans of WEL's network (alongside other utilities) to ensure the safety of those working near WEL's assets and to protect the assets from damage.

Core back end systems are hosted within a virtualised server environment on recent, high quality hardware. There are separate production, testing and development environments managed within structured system development life cycles. Change management processes exist to protect the production systems and data and to ensure these key information systems are always available to users. WEL is in year 1 of a 3 year site product licence contract with Hexagon, our main GIS vendor.

Recent system enhancements include the addition of street light controller data, the addition of engineering specific reporting, the recording of vertical heights (Z value) and depths collected by survey as well as an updated communication (fibre network) feature. A reporting server for Asset Information has recently been added to the system. This enables daily reporting, analysis and data processing on a separate copy of production data to protect the production GIS systems while allowing reporting to be completed on demand.

The GIS road map details a move to 'web based' mobility viewers in the short to medium term for GIS data to replace the current GNetViewer and GeoMedia viewer solutions with modern, flexible, multi-platform (phone, tablet, web) technologies as part of a wider provision of mobility tools throughout WEL.

7.2.3. ENTERPRISE RESOURCE PLANNING (ERP)

SAP consists of the ERP, Customer Relationship Management (CRM) and Business Warehouse (BW) reporting. The core ERP system supports the finance,

works management and inventory management functionality for the business.

The functionality that is enabled with SAP includes:

- Finance and Controlling
- Project Systems
- Plant Maintenance
- Materials Management and Inventory Management
- Quality Management

The Finance and Controlling module is the central accounting function within SAP and incorporates accounts payable, accounts receivable, asset accounting, banking, general ledger accounting and forecasting and budgeting. The reporting outputs form the company's financial statements from both a business and regulatory requirements perspective.

The Project Systems module is used for managing expenditure against capital projects (both network and non-network). The project managers forecast and monitor the expenditure against the work delivered via the work order process. The costs accumulated from the delivery of the project are capitalised into a number of assets in the financial asset register.

The Plant Maintenance module forms the works delivery component of SAP. Network equipment (assets) is represented as equipment records where maintenance and repair work orders are raised against. Labour, materials and external service costs are recorded against the work orders as the work is completed. There is also a preventative maintenance function that contains the planned maintenance schedules. Work orders are automatically generated ready for the field teams to complete the planned maintenance.

The Materials Management and Inventory Management modules contain the spares inventory. The inventory is restocked based on requirements planning (via work order reservations and other requirements) so there is enough stock on hand for project work and fault breakdowns. Materials Management includes the procurement (purchase orders) functionality. Purchase orders are used to procure inventory, external services, business consumables etc.

The Quality Management module is used to record the site safety auditing tasks against the work performed. Here an evaluation of the performance of the internal field staff and external contractors are able to be measured and reported on.

The ERP solution is integrated with other systems to maintain consistency with the equipment data within the GIS system and to create necessary work orders from the NMS Trouble Call system (for faults/breakdowns). The mobility solution feeds these fault work orders to field staff to assist with information flow and data (repair/cause) collection.

The CRM system is used to manage customer feedback (complaints and compliments) relating to work completed in the field. The CRM system captures the initial feedback and the activities for the resolution of the issue.

The SAP Business Warehouse collates the SAP and non-SAP data and provides the reporting needs for the business. Using analysis tools (both SAP and 3rd party) the data can be analysed accordingly by the business users to locate trends and manage any KPI measures to gauge how the business is performing.

Future enhancements to the SAP system include:

- Upgrade of SAP environments to the latest enhancement packs along with the servers to a later version so the system and its components are kept in vendor support.
- Payroll and extended HR implementation. Investigations are continuing towards replacing the existing payroll system and consideration is being made to utilising the SAP payroll module along with extending the current SAP HR functionality.

7.2.4. NETWORK BILLING SYSTEM

The Billing system is an internally developed system to support the requirements of ICP management, and the retailer and direct billed consumers invoicing calculations.

The system controls different data aspects to meet the billing requirements of the Company which includes:

- **CP information:** This data has a two way synchronisation with the data held by the Electricity Registry. This synchronisation includes ICP details, network pricing category, status and retailer switches.
- **Consumption data:** Receives retailer consumption data for processing the retailer invoices (invoices created in SAP). This includes both Mass Market and TOU billing.
- **Revenue assurance:** Provides revenue assurance of the retailer data supplied. This may be via billing history, ICP Statistics, retailer data interrogation or

comparison with the metering data provided by the smart meters.

- **Customer data:** Holds ICP Customer data supplied by the retailers.
- **System interfaces:** Provides interfaces with the smart meter database, NMS Outage Management system, GIS and SAP.

This system centralises ICP related data obtained from the Registry, traders, GIS and smart meters. It is used to perform energy billing to traders and is a source of data to other systems such as NMS.

This bespoke system was developed in 2016 and caters for all known requirements of the networks ICP management and invoicing. There are no immediate future requirements, functionality or enhancements determined at this point in time.

7.2.5. ELECTRONIC CONTENT MANAGEMENT

Content Server using OpenText (known to WEL staff as Content Manager), is a repository for unstructured corporate data. It provides a controlled location within a defined taxonomy for accessing and sharing information such as agreements, policies, guides, emails, presentations, board books etc. It builds an understanding of the history of the business, its decisions and relationships, including financial, asset/equipment, human resources, board and community.

The compiled history within Content Server dates back to 2004 with specific archive folders for historical documents. Document management ensures that despite

the large number of documents and emails in the system, important items are still discoverable to support good decision making and understanding. Version control applies to all content, providing a single controlled source of the truth and is leveraged by the intranet, SAP and any system that may reference business documents.

It is expected that an upgrade to Content Server version 16 will be performed prior to support for the current version expiring in 2019. Integration between Content Server and SAP (Content Server SAP – Xecm) will be investigated and implemented according to business requirements at that time.

7.2.6. MOBILITY SYSTEMS

The mobility solution is a bespoke solution that provides functionality for electronic data collection from the field.

There are 4 main parts of mobility being used:

- **Inspections:** The preventative work orders are provided to facilitate the collection of maintenance condition data which is stored in SAP as measurement documents. This facilitates the collation

of condition history for the network equipment for detailed planning and lifecycle analysis.

- **Faults:** The breakdown work is assigned to the respective field worker who is able to view important detail such as address, contact details etc. This helps to speed up the response by making sure accurate information that is known is communicated

to the faults technician. At the completion of the repair, notes and repair information is sent back along with damage coding for long term maintenance and fault analysis.

- **Reporting of Defects:** Capturing information about the defect, including observations and any necessary photos which create a notification record in SAP. These notifications are submitted into a planning queue for rapid analysis and corrective work creation as required.
- **Smart Meters:** The certification details are captured electronically along with any job information.

The data is interfaced directly into the metering database via a data validation portal.

Various updates and enhancements to the existing Mobility platform are planned over the coming years. These include but are not limited to electronic time sheets, electronic documents and drawings to the field, electronic forms submission, electronic leave applications from the field, electronic job packs, electronic dispatch, electronic as built data collection, and improvements to the inspections module.

7.3. NON-NETWORK CAPITAL AND OPERATIONAL EXPENDITURE

7.3.1. 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 including major version upgrades for our industry standard software applications including SAP, GTechnology Suite (GIS), Microsoft Office, desktop and server platforms, our document management system (Content Manager) and the NMS.
- **Computer Hardware Capital Expenditure.** This covers the physical computing infrastructure including servers, storage, switches, firewalls and desktops. Desktop, laptop, and tablet computing devices are on a 3-4 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 associated costs into operating expenditure.
- **Motor Vehicles.** The motor vehicle capex is reduced across the period. This directly relates to changing of ownership of utility vehicles from WEL Networks to WEL Services in-line with auditor recommendations. The vehicle costs will now be on-charged by WEL Services and capitalised within each project.

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

Non-Network Capital Expenditure (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Computer Hardware	307	319	321	445	464	483	505	526	549	561
Computer Software	542	1,081	967	1,078	1,123	1,173	1,222	1,275	1,329	1,359
Plant and Equipment	562	575	107	109	112	114	117	119	122	125
Motor Vehicles	102	105	107	109	112	114	117	119	122	125
Total	1,513	2,080	1,502	1,741	1,811	1,885	1,961	2,040	2,122	2,170

Table 7.3.1 Non-Network Capital Expenditure

7.3.2. 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:
 - Asset Management which includes Asset Information and Strategy, Network Planning, Maintenance Strategy, Network Design, Customer Projects, Development and Automation, System Control and Engineering.
 - WEL Services which includes, Field Services, Distribution Design, Capital Projects.
 - Customer Support and Procurement

- **Business support.** This covers areas of the business functions including:
 - Finance, Commercial and Technology which includes, Information Services, GIS, Procurement, Regulatory and Metering Services.
 - People and Performance which includes Health and Safety, Business Assurance, Organisational Development and Human Resources.

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

Non-Network Operational Expenditure (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System operations and network support	8,361	8,549	8,741	8,938	9,139	9,345	9,555	9,770	9,990	10,215
Business support	7,775	7,750	7,925	8,103	8,285	8,472	8,662	8,857	9,057	9,260
Total	16,136	16,299	16,666	17,041	17,425	17,817	18,218	18,627	19,047	19,475

Table 7.3.2 Non-Network Operational Expenditure



8

ASSET REPLACEMENT AND RENEWAL



8

ASSET REPLACEMENT AND RENEWAL

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.

8.1. OVERVIEW OF ASSET REPLACEMENT AND RENEWAL

Delivering our performance objectives, as described in Chapter 5, 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 3, we have taken a risk based approach to renewals with the implementation of Condition Based Risk Management (CBRM).

All major asset groups are now contained within the CBRM model as shown in the list below:

Key Asset Classes with CBRM Model

1. Sectionalisers and Reclosers
2. Network Switches
3. Battery and Power Supply Systems
4. Circuit Breakers
5. Distribution Transformers
6. 11kV Overhead Line Conductors
7. LV Pillars
8. Poles
9. Protection Relays
10. Ring Main Units
11. Crossarms and Insulators
12. Zone Transformers

For assets such as HV fuses (DDOs) that don't have a CBRM model, WEL uses information obtained from inspection and reliability tools such as Failure Mode Effects and Criticality Analysis (FMECA) to assess risks and prioritise the renewal programme.

WEL uses SAIDI as one of the key measures of network reliability. Consequently it is a reliable indicator of the effectiveness of CBRM in managing network performance risk. SAIDI has been used to monitor risk trends following adoption of the CBRM methodology.

There has been a steady reduction in the SAIDI impact attributed to equipment related failures as described in Chapter 5. Of most significance is the reduction in 16mm² copper conductor failures. While the number of these failures is reducing, those that do occur are predominately due to storm events or bird line clashes.

Although WEL is achieving positive results in SAIDI reductions in the equipment failure category, planned SAIDI has had to increase to enable the asset replacement program to be carried out. We have also seen an increase in planned SAIDI due to the introduction of the Electricity Engineers' Association proposal for HV Live Line safe work practice. This has increased the amount of work on HV lines to be undertaken de-energised.

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;
- Improve work delivery efficiency through the work management process 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, supporting tools and analysis that assist maintenance engineers to optimise and rationalise the maintenance plan. In 2017, WEL implemented Standard Maintenance Procedure documents (SMPs) for key assets such as circuit breakers and protection relays. The same SMP template will be utilised for other asset classes.

SMPs will outline the maintenance requirements in the Maintenance Manual in a more detailed and procedural way. This is expected to assist in standardising plant maintenance processes.

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, and recorded in the Computerised Maintenance Management System (CMMS).

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 below.

Condition Score	Remaining Life	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 18 months
1	Unserviceable	Unserviceable but not hazardous. Replace within 14 days
0	Hazard	Immediate action is required to eliminate hazard

Table 8.2.1 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 8.2.2 below.

Defect Rating	Defect Classification	Delivery Period	Definition
1	Red	2 days	Faults / Urgent work required – immediate temporary repairs may be required to 'make safe'.
2	Amber	2 weeks	No customer outages or door knock for low volume of customers.
3		4 weeks	Major customer consulted if outage required, typically Plant Maintenance will be priority 3.
4		12 weeks	Long lead material consideration.
5	Green	12 months	Typically asset replacement works or jobs which could be undertaken as part of capital projects.

Table 8.2.2 Defect Classifications

8.2.2. MANAGEMENT OF SF₆

Sulphur Hexafluoride (SF₆) is a gas used in modern switchgear as an insulating and arc quenching material. We have initiated a review of equipment that could be used as an alternative to SF₆-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 SF₆ gas installed, disposed and emitted into the environment. As at November 2017 the volume of SF₆ installed by our switchgear was 1.35 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 operational 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.

Vegetation Management Operational Expenditure (In Nominal Price \$000)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Vegetation Management	1,360	1,399	1,107	1,130	1,153	823	840	858	875	893
TOTAL	1,360	1,399	1,107	1,130	1,153	823	840	858	875	893

Table 8.2.3 Vegetation Management Operational 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 having a dedicated Faults

team, proactive repairs on defects due to the enhanced diagnostic testing and reduction in line breaks due to the conductor renewal programme.

Service Interruption and Emergency Management Operational Expenditure (In Nominal Price \$000)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Service Interruption and Emergency Management	2,582	2,657	2,711	2,767	2,824	2,882	2,941	3,001	3,062	3,125
TOTAL	2,582	2,657	2,711	2,767	2,824	2,882	2,941	3,001	3,062	3,125

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 includes 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. These are validated annually with our maintenance team to ensure improvements are captured and updated in our plans.

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;
- Introduction of diagnostic testing on primary assets;

- Specification of strategic spare requirements for emergency preparedness;
- Development of a modular substation used for equipment testing, spares and training of technical staff.
- Development of Standard Maintenance Procedures for plant maintenance and corrective works which will improve delivery of maintenance
- Review of the maintenance work flow, including system architecture, processes and reporting.

WEL is currently rolling out improvement on standard maintenance plans (SMP) to ensure they meet the requirements of the (current) asset technology and actual condition. The process covers all asset baseline including poles, conductors, pillars, transformers, substations etc.

The purpose of rolling out the SMP program is to define maintenance which will ensure equipment and systems deliver a safe and reliable service at their required duty and take into account the environment in which they operate. This approach is a key driver of WEL's asset management strategy which is based on a preventive and predictive approach; taking into account the capacity of available resources, access to assets and the balance between safe working assets and life cycle cost effectiveness.

Our Maintenance Strategy Team retains oversight and technical management of the standard maintenance plans and sets the guideline for both internal and external contract maintenance service providers. These teams are obliged to perform maintenance to the high standard set out in the SMPs and provide critical measures and test results back to our maintenance strategy team to perform reliability analytics to ensure our network remains safe and reliable.

Our continuous improvement framework is based on the principle of “data supporting decision making”.

The data we use to improve our services includes:

- Work order history
- Performance KPIs
- SCADA
- Fault register
- Incident register
- Call Centre logs

Ultimately, we seek to not only to make improvements to our network but also internally as a company by improving our processes that ultimately lead to a better service for our customers.

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, environment and financial loss. 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 (e.g. age, asset type, working environment, condition, other factors such as number of connected parties etc.),

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 all of our key assets.

Through the asset planning process, WEL manages scope and budget requirements of renewal work. This is outlined in the Project Definition Document (PDD).

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

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 – The Do Nothing scenario models a hypothetical base case to understand the effects of not undertaking renewals. By year ten the risk is expected to increase rapidly;

Scenario 2 – Model of expenditure previously planned in our 2015 AMP;

Scenario 3 – Is a slight risk reduction over our 2015 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 risks can be eliminated.

ASSET RENEWAL SCENARIOS

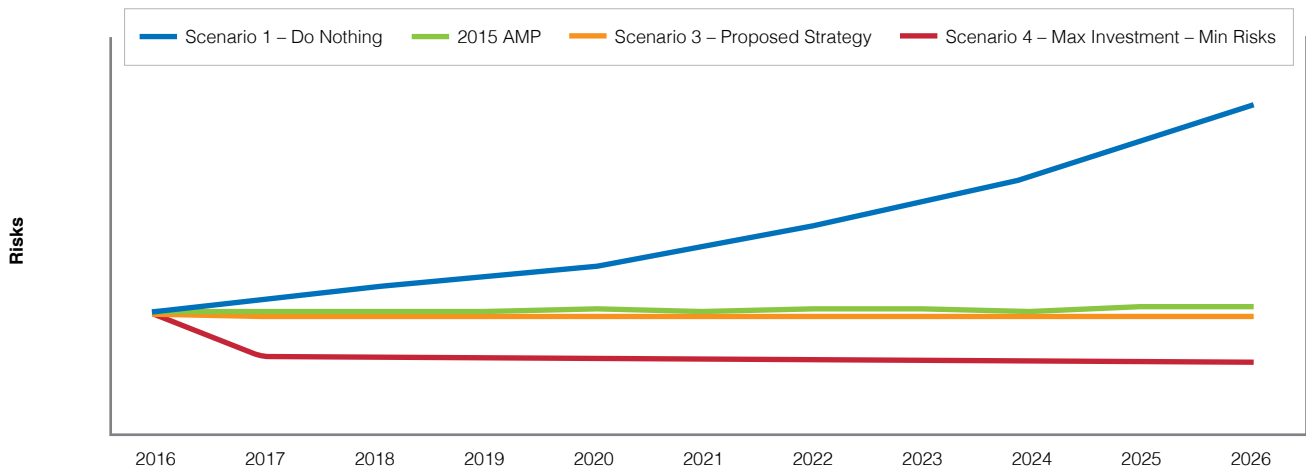


Figure 8.3.1 Asset Renewal – Scenario Risk Profiles

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 the 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 this reason improved specifications as referenced in the EEA guidelines for condition assessment, field data verification and the mobility solution to improve data accuracy has been implemented in our inspection programs.

Asset Monitoring

Diagnostic measurement techniques such as ultrasonic and thermal surveys on overhead lines, PD acoustic surveys on switchgear, and SFRA on zone transformers

provides better asset condition information than simple visual inspections. Asset inspectors have started using unmanned aerial vehicles (UAV) for inspecting overhead line assets particularly on locations with difficult terrain.

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. WEL seeks to extend the working life of its assets past initial service life estimates based on risk assessments and benchmarking reliability and condition of older 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
- Zone Substations
- Distribution and LV Lines
- Distribution and LV Cables
- Distribution Substations and Transformers
- Distribution Switchgear
- Other Network Assets

8.4.1. SUBTRANSMISSION

Subtransmission Lines

Risks and Issues

The principal risks and issues associated with subtransmission lines are:

- 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;
- Visual inspections on an annual basis; and
- Thermal survey on selected circuits on 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. Thermographic surveys are 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.

Subtransmission Poles, Crossarms and Insulators

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;

Maintenance Undertaken

Inspections on subtransmission lines include:

- Detailed inspections every six months for critical feeders not meshed with other lines; and
- Detailed inspections every five years for all other lines;

During detailed inspections, tests are carried out on all earth banks. Recently ultrasonic surveys using a multi-functional PD instrument have also been undertaken.

Maintenance tasks are undertaken to correct any defects identified.

Asset Renewal Programme

Renewal are based on CBRM models and outcomes of the routine inspections undertaken.

Subtransmission Cables

Risks and Issues

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

- Mechanical damage due excavations or directional drilling by third party 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.

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, vacuum or SF6 integrity checks, 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

Renewing CBs involves considerable resource and outages on the network. Therefore where possible other co-located asset renewals are coordinated at the same time. Subtransmission CBs that are scheduled for renewal due to their age and condition will be done in conjunction with 11kV CB replacement are at: Gordonton (2021-22) and Te Uku (2023-24).

A CBRM model has been implemented to assist in renewal prioritisation and forecasting the required level of investment for subtransmission CBs.

Summary of Subtransmission Renewal and Maintenance expenditure

Table 8.4.1.1 summarises subtransmission capital expenditure for the AMP period.

Subtransmission CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
33kV Circuit Breaker										
33kV Crossarms and Insulators	153	183	183	191	195	198	215	219	209	215
33kV Overhead Lines										
33kV Poles-	59	46	38	40	41	41	43	44	36	37
33kV Sub-transmission UG cable										
TOTAL	212	228	221	231	236	240	258	263	246	252

Table 8.4.1.1 Subtransmission Capital Expenditure

Table 8.4.1.2 Summarises Subtransmission Operational Expenditure for the AMP period.

Subtransmission OPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
33kV Circuit Breaker	88	95	96	102	106	111	115	117	122	126
33kV Crossarms and Insulators	6	6	7	7	7	8	8	8	8	9
33kV Overhead Lines	46	49	50	53	56	58	60	61	64	66
33kV Poles	13	14	15	15	16	17	17	18	18	19
33kV Sub-transmission UG cable	81	87	88	93	97	102	105	107	111	115
TOTAL	235	251	256	271	282	296	304	310	324	334

Table 8.4.1.2 Subtransmission Operational Expenditure

8.4.2. ZONE SUBSTATIONS

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 Health Index (HI) and accordingly the life expectancy of the transformer.
- Unbunded transformers may result in uncontained oil spills and therefore soil contamination or other environmental damage. Systematic upgrading of transformer bunding has been included in this AMP.

- Vibration from external factors such as trains. Vibration can cause mal-operation of the mercury switches within the Buchholz 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 three 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 8.4.2 below summarises transformer maintenance plans and their corresponding frequencies.

Frequency	Maintenance	OIL-OLTC ³	Vacuum-OLTC
2 Months	Inspection	X	X
Yearly	Annual DGA	X	X
3 Yearly	Transformer Minor	X	X
6 Yearly	Transformer Major	X	X
3 Yearly	OLTC1 Servicing	X	
6 Yearly			X

Table 8.4.2.1 Summary of Power Transformer Maintenance

³On-Load Tap Changer

Asset Renewal Programme

No zone transformers will exceed their nominal lives within the AMP period. Transformer CBRM models were developed during 2016 and will be used to further analyse the risks and asset renewal requirements.

Zone Substation Switchboards

We have Air Insulated Switchgear (AIS) and Gas Insulated Switchgear (GIS) 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. Fixed-pattern switchgear has been considered to replace the traditional withdrawable CBs to mitigate this risk;
- Surface discharges on voltage transformer compartments and vacuum bottles on 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;

- 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 SF6 gas in GIS switchboards. We are using external service providers for this critical task as they are expert in this field.

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. The following are scheduled for renewal due to their age and condition: Barton (2019), Ngaruawahia (2019-20), Massey St (2021-22), Gordonton (2021-22) and Te Uku (2023-24). Renewing CBs involves considerable resource and outages on the network. Therefore where possible other co-located asset renewals are coordinated at the same time. This includes subtransmission CBs, protection, battery and SCADA systems.

A CBRM model has been implemented to assist in replacement prioritisation and forecasting the required level of investment in switchboards.

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, oil spills and vermin. Substations with outdoor switchyards have higher physical and environmental risk than indoor switch rooms;
- 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 it is therefore difficult to confirm the integrity of the earthing system on those sites. A programme to carry out full earth tests on 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.

In 2016 all building sites were assessed for asbestos, followed by signage and registers installed at each site. Immediate remedial works were undertaken to remove any identified Asbestos Containing Materials (ACM) from these sites.

Asset Renewal Programme

The renewal programme for zone substations equipment includes the continuation of the security system upgrade project to deter copper conductor theft. Zone substations located in rural areas with outdoor switchyards have been prioritised.

Summary of Zone Substation Renewal and Maintenance expenditure

Table 8.4.2.1 summarises Zone Substation capital expenditure for the AMP period.

Zone Substation CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
11kV Circuit Breaker (Upgrade)		143	219	135	69	71				
11kV Switching Station/Zone Sub	185	175	337	96	379	280	132	192	200	205
BAR Switchgear upgrade	513									
GOR Switchgear upgrade			107	153						
MAS Circuit Breakers 11kV			406	142						
NGA Switchgear upgrade	578	314								
TEU Switchgear upgrade					151	160				
Zone Substation Transformer										
TOTAL	1,276	631	1,069	526	598	511	132	192	200	205

Table 8.4.2.1 Zone Substation Capital Expenditure

Table 8.4.2.2 summarises Zone Substation operational expenditure for the AMP period.

Zone Substation OPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
11kV Circuit Breaker (Upgrade)	132	141	144	152	159	166	171	174	182	187
11kV Switching Station/Zone Sub	358	384	391	414	431	452	465	474	494	509
Zone Substation Transformer	303	325	331	350	365	382	393	401	418	431
TOTAL	793	850	866	917	955	1,000	1,028	1,049	1,094	1,128

Table 8.4.2.2 Zone Substation operational Expenditure

8.4.3. DISTRIBUTION AND LV LINES

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
- Spalling of concrete in concrete poles.

Maintenance Undertaken

Inspections are undertaken every five years. Gamma ray imaging was 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.

WEL has enhanced its process in tagging hazardous poles in reference with the EEA guidelines. Red and yellow tag categories have been introduced to distinguish the level of criticality in terms of safety risk and condition of the pole.

Maintenance of poles includes the repair of possum guards.

Asset Renewal Programme

Driven by a CBRM model, between 300 and 400 poles are planned to be replaced annually over the next 10 years. Poles are also replaced as part of other renewal programmes such as the reconductoring projects which are intended to improve rural reliability.

Distribution and LV Crossarms

Risks and Issues

The principal risks and issues associated with crossarms are 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 five years coinciding with pole and conductor inspections. As faulty insulators are difficult to detect by visual inspection, new ultrasonic diagnostic testing has been 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 800 crossarms per year will be replaced in the first two years of the plan, increasing to 1,200 per year. Total number of replacements has been decreased following FMECA and renewal optimisation process. The programme will target most critical crossarms and insulators with the highest risks.

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 16mm² copper conductor fleet is failing earlier than expected 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 16mm² copper conductors prone to breaking while being handled we have ceased 'live line' work on or under these conductors. This will result in a greater number of planned outages to renew this conductor over the AMP period.

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;
- The inspections undertaken on the remaining distribution and all LV conductors are visual inspections every five years;
- More detailed inspections and condition data capture is conducted every five 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, Finlayson, Gordonton, Raglan, Te Uku and Te Kauwhata feeders.

Summary of Distribution and LV Line Renewal and Maintenance Expenditure

Table 8.4.3.1 summarises Distribution and LV Lines capital expenditure for the AMP period.

Distribution and LV Line CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Distribution 11kV OH Lines	3,414	3,806	3,811	4,298	4,392	4,463	4,640	4,733	4,912	5,043
Distribution Crossarms and Insulators	2,908	3,471	3,476	3,630	3,709	3,768	4,081	4,163	3,975	4,081
Distribution Poles- LV Overhead Reticulation	1,112	868	724	756	773	785	816	833	691	710
Medium mixed projects	201	137	137	143	146	149	155	105	109	56
TOTAL	7,634	8,282	8,148	8,827	9,020	9,165	9,692	9,834	9,687	9,890

Table 8.4.3.1 Distribution and LV Lines Capital Expenditure

Table 8.4.3.2 summarises Distribution and LV Lines operational expenditure for the AMP period.

Distribution and LV Line OPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Distribution 11kV OH Lines	221	237	241	255	266	279	286	292	305	314
Distribution Poles	255	273	278	294	307	321	330	337	351	362
Distribution Crossarms and Insulators	114	122	125	132	138	144	148	151	158	162
LV Overhead Lines	483	518	528	559	582	610	627	640	667	688
TOTAL	1,073	1,150	1,173	1,241	1,292	1,354	1,392	1,420	1,480	1,526

Table 8.4.3.2 Distribution and LV Lines Operational Expenditure

The capital renewal expenditure for each asset class in the above table is based on the results of the CBRM modelling and resulting Health Index (HI) and Risk profiles as discussed in Chapter 2.

- Crossarms and Insulators modelling shows an increasing rate of failures over the planning period and therefore to reduce this risk an increasing investment strategy has been adopted. Replacements are prioritised on highest risk items combined into geographical areas for delivery efficiency.
- Distribution and 11kV OH Lines has significant renewal expenditure over the planning period. It was clear that previous renewal investment strategies would result in increasing failure rates and consequential health and safety risks. The main area of concern being the failure of the 16mm² copper conductor. The above investment strategy would ensure the current risk for this asset class will not increase.

8.4.4. DISTRIBUTION AND LV CABLES

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 Partial Discharge (PD) testing. WEL is considering whether to roll out the PD testing programme to other distribution cables following completion of trial testing on trunk feeder circuits by end of financial year 2020.

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, however an allowance has been made to replace sections of cable following a fault.

LV Cables

Risks and Issues

The principal risks and issues for LV cables are 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 this occurs as part of other projects such as upgrades or further LV reticulation development. However an allowance has been made to replace sections of cable following a fault.

Table 8.4.4.1 summarises Distribution and LV Cables capital expenditure for the AMP period.

Distribution and LV Cables CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Distribution 11kV UG cables										
LV Underground cables										
Medium mixed projects	468	320	320	334	342	347	361	245	255	131
Service and Distribution Pillars	1,000	411	412	430	439	413	430	438	455	467
Total	1,469	731	732	764	781	760	791	684	709	598

Table 8.4.4.1 Distribution and LV Cables Capital Expenditure

Table 8.4.4.2 summarises Distribution and LV Cables operational expenditure for the AMP period.

Distribution and LV Cables CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Distribution 11kV UG cables	154	165	169	178	186	195	200	204	213	219
LV Underground cables	73	78	80	84	88	92	95	97	101	104
Service and Distribution Pillars	114	123	125	132	138	144	148	151	158	163
Total	342	366	373	395	411	431	443	452	471	486

Table 8.4.4.2 Distribution and LV Cables Operation Expenditure

8.4.5. 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, vermin, 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. Incidences are identified from staff and public reporting and during the network inspection program. 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 and pad mounted transformers are inspected every five years. 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:

- Downloading of maximum demand data annually, timed to occur at peak load times;
- Annual inspection;
- Thermal imaging and ultrasonic 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.

We have developed a tool to aggregate smart meter data to their corresponding distribution transformers and will use data loggers where this is not possible.

Asset Renewal Programme

WEL have instigated a renewal programme from FY 2015-16 to 2018-19 to replace aged transformers with very poor condition (i.e. severely leaking, rusting badly, etc).

A CBRM model has been implemented to assist in renewal prioritisation and level of investment for distribution substations and transformers.

Summary of Distribution Substations and Transformers Renewal and Maintenance expenditure

Table 8.4.5.1 summarises Distribution Substations and Transformers capital expenditure for the AMP period.

Distribution Substations and Transformer sCAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Distribution Transformers(11kV/400V)	1,171	609	610	637	651	661	687	701	546	560
TOTAL	1,171	609	610	637	651	661	687	701	546	560

Table 8.4.5.1 Distribution Substations and Transformers Capital Expenditure

Table 8.4.5.2 summarises Distribution Substations and Transformers operational expenditure for the AMP period.

Distribution Substations and Transformers OPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Distribution Transformers (11kV/400V)	769	825	841	890	926	970	998	1,018	1,061	1,094
TOTAL	769	825	841	890	926	970	998	1,018	1,061	1,094

Table 8.4.5.2 Distribution Substations and Transformers Operational Expenditure

The capital renewal expenditure for distribution transformers in the above table is based on the results of the CBRM modelling and resulting HI and Risk profiles as discussed in Chapter 2.

8.4.6. 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 SF6 gas leakage from GIS units. High levels of partial discharges and mechanical interlock failures have been observed on the older oil-filled RMUs. A recent issue with a particular model of RMU has been discovered and is due to an 'over-travel' of mechanism during operation which poses a significant safety risks;

ABS: Older, manually operated ABSs are a safety risk to the operator during switching. The most common failure for an 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 of sectionalisers that have been installed over recent years. These units have not operated reliably, increasing fault restoration times. These types of sectionalisers have been phased out in 2017 and replaced by a vacuum type sectionaliser; 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 five years. Inspection and testing consists of visual inspections, earth testing, vegetation control, oil level, SF6 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 five years and include visual inspections of insulators, arc horns/chutes, contacts and handles. Earth testing is undertaken at the same time. Operations and function checks are carried out on selected switches that are critical to the network (e.g. Open Points).

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 based on the outcome of CBRM analysis.

Major servicing is undertaken every six years. Servicing includes changing the insulating oil in oil filled circuit breakers, 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 SF6 type RMU is included within the AMP period;

ABSS: approximately 20 units each year, prioritised by risk, are planned to be renewed. In addition, a programme has been implemented to replace manually operated ABSS with SF6 gas-insulated switches over the AMP period. Vacuum switch units will also be considered due to environmental risk posed by possible SF6 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;

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.; and

HV Overhead Line Fuses: Renewal of these assets is primarily driven by the need to renew other larger components, primarily crossarms.

Summary of Distribution Switchgear Renewal and Maintenance expenditure

Table 8.4.6.1 summarises Distribution Switchgear capital expenditure for the AMP period.

Distribution and Switchgear CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
11kV Air Break Switch	585	761	762	796	813	909	945	964	1,092	1,121
11kV Reclosers and Sectionalisers	366	381	381	398	407	413	430	438	455	467
11kV Ring Main unit	648	913	1,067	1,114	1,139	1,157	1,203	1,227	1,273	1,308
TOTAL	1,600	2,055	2,210	2,308	2,359	2,479	2,578	2,629	2,820	2,895

Table 8.4.6.1 Distribution Switchgear Capital Expenditure

Table 8.4.6.2 summarises Distribution Switchgear operational expenditure for the AMP period.

Distribution and Switchgear OPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
11kV Air Break Switch	112	120	122	130	135	141	145	148	154	159
11kV Reclosers and Sectionalisers	143	154	157	166	173	181	186	190	198	204
11kV Ring Main unit	358	384	392	415	432	452	465	474	494	510
TOTAL	614	658	671	710	739	774	796	812	847	873

Table 8.4.6.2 Distribution Switchgear Operational Expenditure

The capital renewal expenditure for each asset class in the above table is based on the results of the CBRM modelling and resulting Health Index (HI) and Risk profiles as discussed in Chapter 2 and detailed in section 8.3 above.

8.4.7. OTHER NETWORK ASSETS

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. In 2017, a complete visual inspection of all 23,000 LV pillars was undertaken across the whole network to identify any that posed a safety risk or any other risk associated in this asset class. This programme was initiated following a safety alert where a metal lid securing screw was identified as 'live' in one of the LV pillars.

Asset Renewal Programme

LV Pillars will be renewed based on their type, age and condition with priority given to fibreglass type pillars. Remedial works following the comprehensive inspection programme undertaken in 2017 has been planned and carried out based on the priority.

WEL is considering an underground pillar design to replace service pillars that have a high risk of being hit by a vehicle.

Service and Distribution Pillar CBRM models were developed during 2016 and will be used to further analyse the risks and asset renewal requirements.

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 maintained at nine yearly intervals to coincide with bus maintenance; and
- For all other relays, 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 also 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 integration of protection, SCADA/communications and switchgear renewals. This is reflected in the proposed 10-year spend profile.

A CBRM model for relays has been developed during 2016 and will be used to further analyse the risks and asset renewal requirements.

SCADA and Communication Devices

Risks and Issues

The principal risks and issues associated with our SCADA and communication devices are primarily related to weak communication signals. Weak signals can be caused by incorrect positioning of antenna, vegetation interference, failed RTUs and batteries, 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 by 2020.

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.

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 replaced.

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 banks 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 have been developed for battery and charger systems in 2016. It is expected that the outcomes of the risk analysis will enable further mitigation of risks in this asset category.

Summary of Other Network Asset Renewal and Maintenance expenditure

Table 8.4.7.1 summarises Other Network Assets capital expenditure for the AMP period.

Other Network Asset CAPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CLA protection relays upgrade	893									
Protection Relays		175	694	183	285	331	103	245	209	215
SCADA & Comms		304	274	127		298		88	91	93
FDL -STE fibre link	63									
WHI-CIV and BAR-CIV fibre link	281									
TOTAL	1,238	480	968	310	285	628	103	333	300	308

Table 8.4.7.1 Other Network Assets Capital Expenditure

Table 8.4.7.2 summarises Other Network Assets operational expenditure for the AMP period.

Other Network Asset OPEX (In Nominal Price \$000)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Protection Relays	191	205	209	221	230	241	248	253	264	272
SCADA & Comms	277	297	302	320	333	349	359	366	382	394
TOTAL	468	502	512	542	564	591	607	620	646	666

Table 8.4.7.2 Other Network Assets Operational Expenditure

The capital renewal expenditure for each asset class in the above table is based on the results of the CBRM modelling and resulting HI and Risk profiles as discussed in Chapter 2 and as detailed in the previous sections.

8.5. OVERALL EXPENDITURE SUMMARY

8.5.1. MAINTENANCE EXPENDITURE

The 10 year maintenance expenditure forecast increases slightly from 2021 to the end of the AMP period as shown in Figure 8.5.1.

The increase is primarily due to:-

- Voltage investigation and corrective works required following smart meter data analysis;
- Field data verification and accelerated inspections to improve the accuracy of asset condition data;
- Increased diagnostic testing such as Corona inspection and pole scan programme resulting in a slight increase in preventive maintenance costs across the AMP period; and
- Proactive repairs on WEL's LV network including service lines inspections.

MAINTENANCE EXPENDITURE In Nominal Price

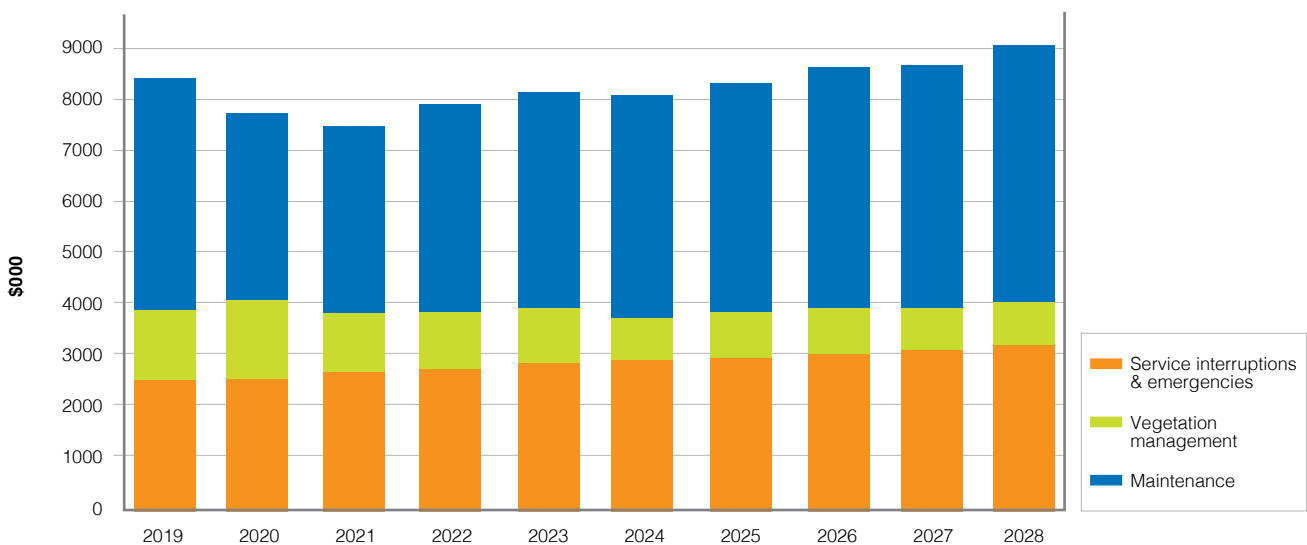


Figure 8.5.1 Maintenance, Vegetation and Faults Expenditure Profile

8.5.2. RENEWAL EXPENDITURE

The 10 year renewal expenditure forecast is predominately driven by the CBRM models for most of the asset categories. Further review of the substation assets such as circuit breaker and protection relays has driven renewal programme in these asset classes.

The major variances over the planning period as shown in Figure 8.5.2 are due to:

- Circuit breakers and Switchgear – renewal of Barton and Ngaruawahia switchgear from 2018; and increase in budget to replace old Te Uku and Gordonton 11kV and 33kV circuit breakers
- Ring Main Units – proactive replacement of RMUs to address equipment reliability issues
- Network Switches – increase in switch replacement to mitigate ageing fleet
- Distribution and LV Lines – decrease in reconductoring projects due to smarter mitigation on spur lines
- Crossarms and Insulators – decrease in budget due to the outcomes of Failure Mode, Effects and Criticality Analysis (FMECA)
- Distribution Transformers – increase in renewal to address critical units identified through recent inspections
- Poles – increase in renewal programme due to issues identified through the targeted inspections and pole testing undertaken; yellow tagged poles will be replaced in this programme
- LV Pillars – increase in replacement following the accelerated inspection of all LV pillars in 2017

RENEWAL EXPENDITURE In Nominal Price

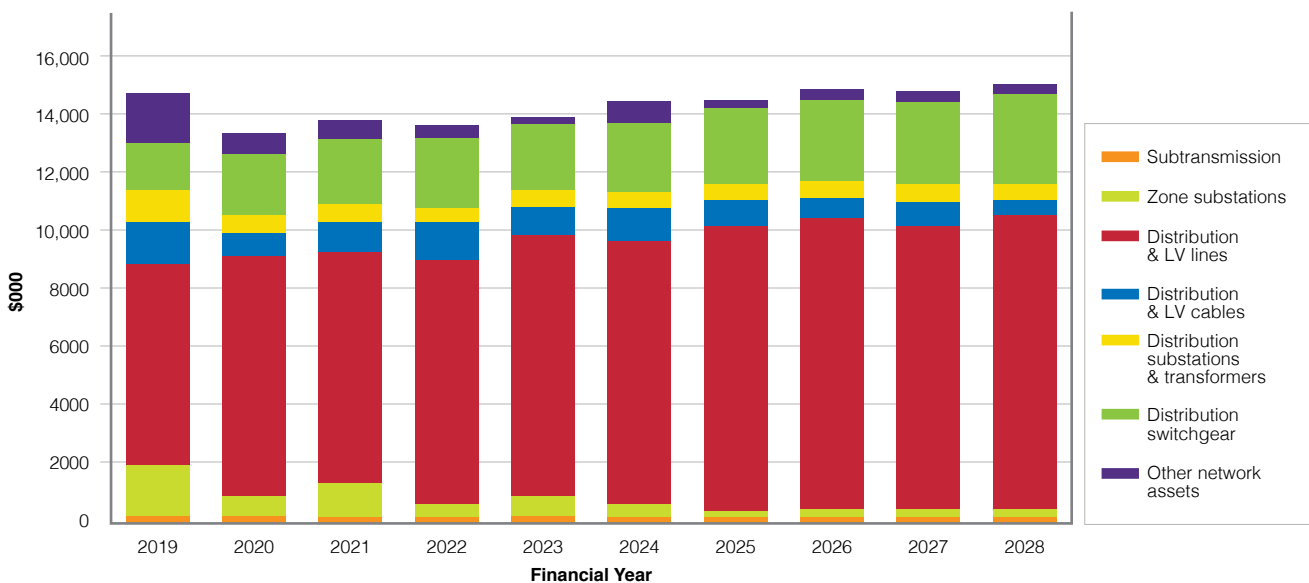


Figure 8.5.2 Renewal Expenditure Profile

9

SUMMARY OF EXPENDITURE FORECASTS



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. All 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 2018 to 31 March 2028.

As explained previously, the notation adopted in each table refers to financial year-end. For example, the 1 April 2018 to 31 March 2019 financial year is referred to as 2019.

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 is 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 expenditure. These are labour and materials.

The per annum 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 on Assets by category.

CAPITAL EXPENDITURE ON ASSETS In Nominal Price

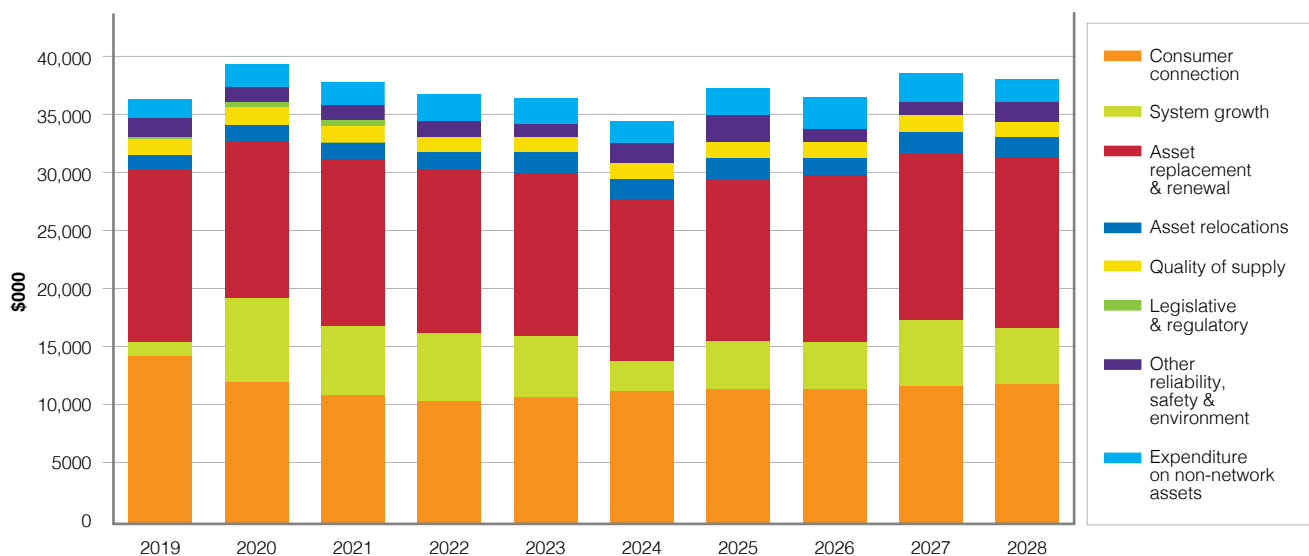


Figure 9.2. 10 Year Capital Expenditure

9.2.1. CONSUMER CONNECTION

Forecast customer connection capital expenditure is summarised in the table below.

CONSUMER CONNECTION In Nominal Price

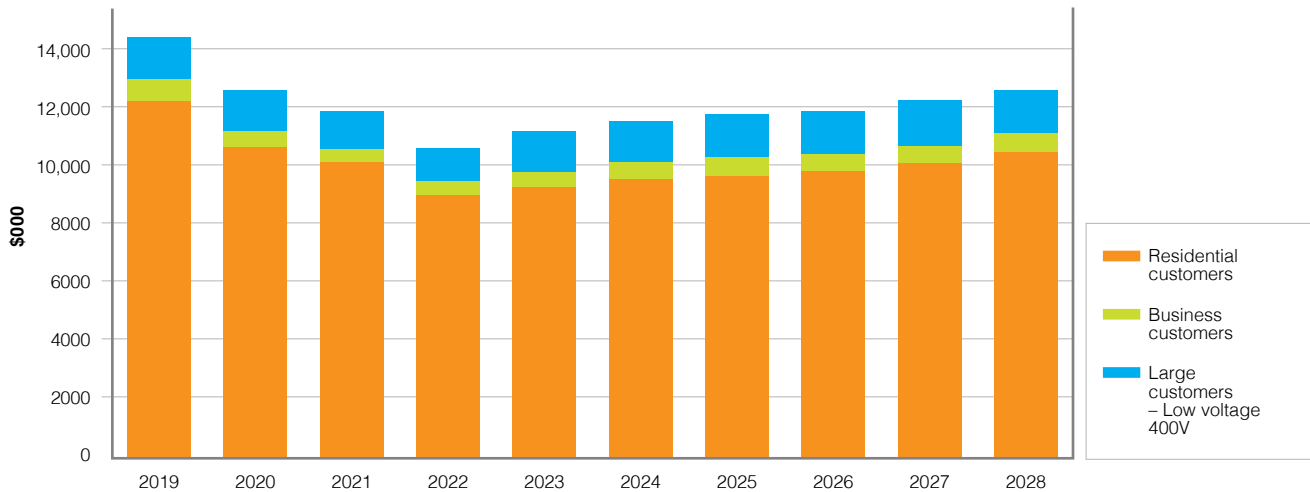


Figure 9.2.1 10 Year Consumer Connection Capital Expenditure

9.2.2. SYSTEM GROWTH

System growth capital expenditure in Commerce Commission categories.

SYSTEM GROWTH In Nominal Price

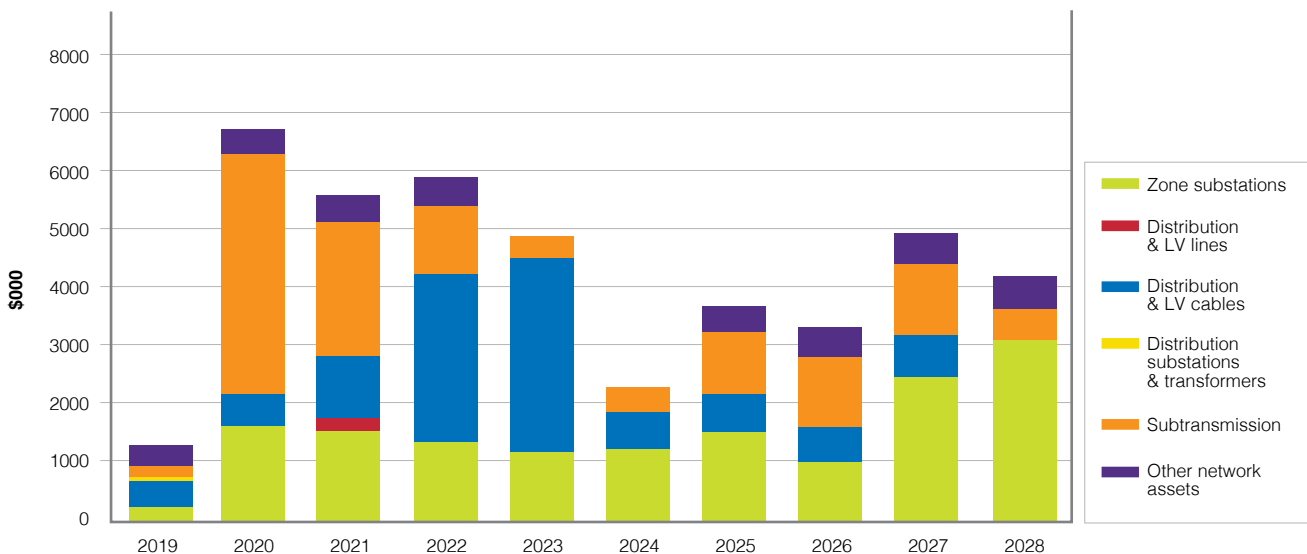


Figure 9.2.2 10 Year System Growth Capital Expenditure

9.2.3. ASSET REPLACEMENT AND RENEWAL

The breakdown of ARR capital expenditure according to Commerce Commission categories.

ASSET REPLACEMENT AND RENEWAL In Nominal Price

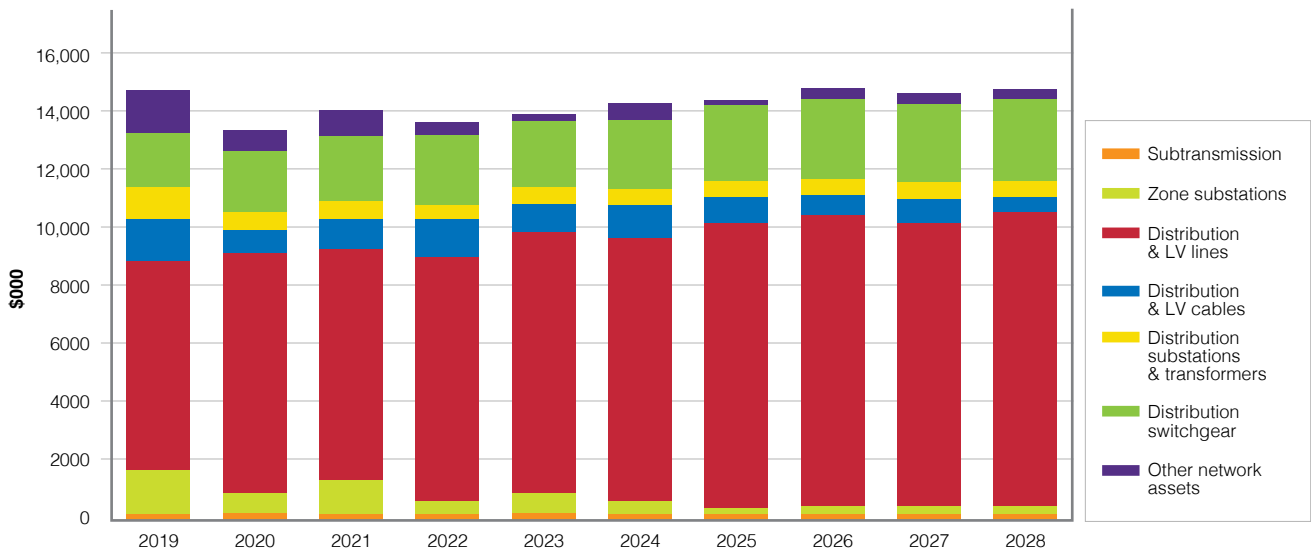


Figure 9.2.3 10 Year Asset Replacement and Renewal Capital Expenditure

9.2.4. ASSET RELOCATION

Asset relocation capital expenditure by activity is summarised in the table below.

ASSET RELOCATION In Nominal Price

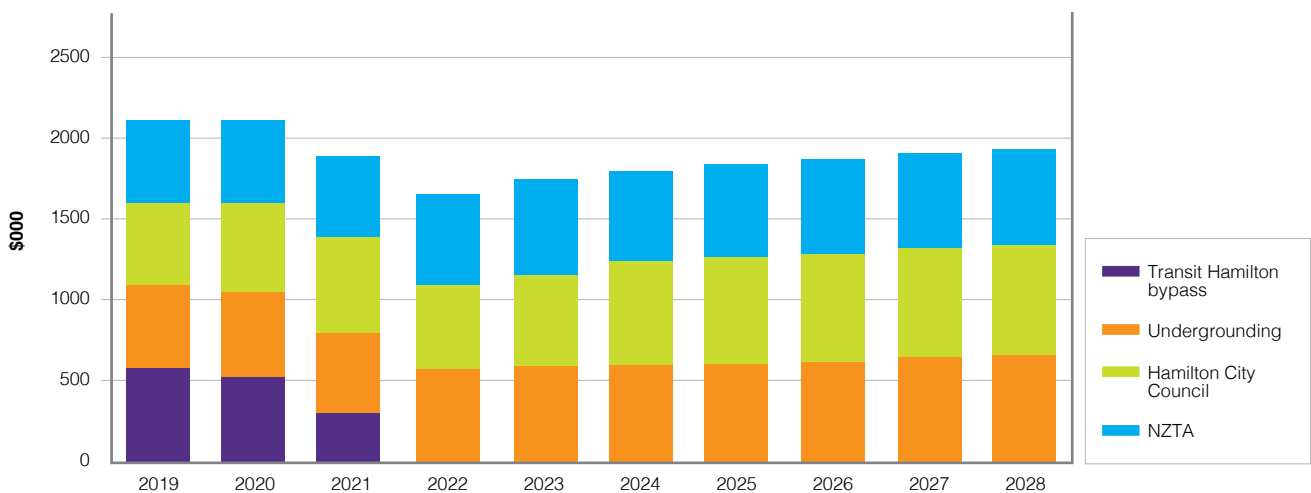


Figure 9.2.4 10 Year Asset Relocation Capital Expenditure

9.2.5. QUALITY OF SUPPLY

Quality of supply capital expenditure by activity is summarised in the graph below.

QUALITY OF SUPPLY In Nominal Price

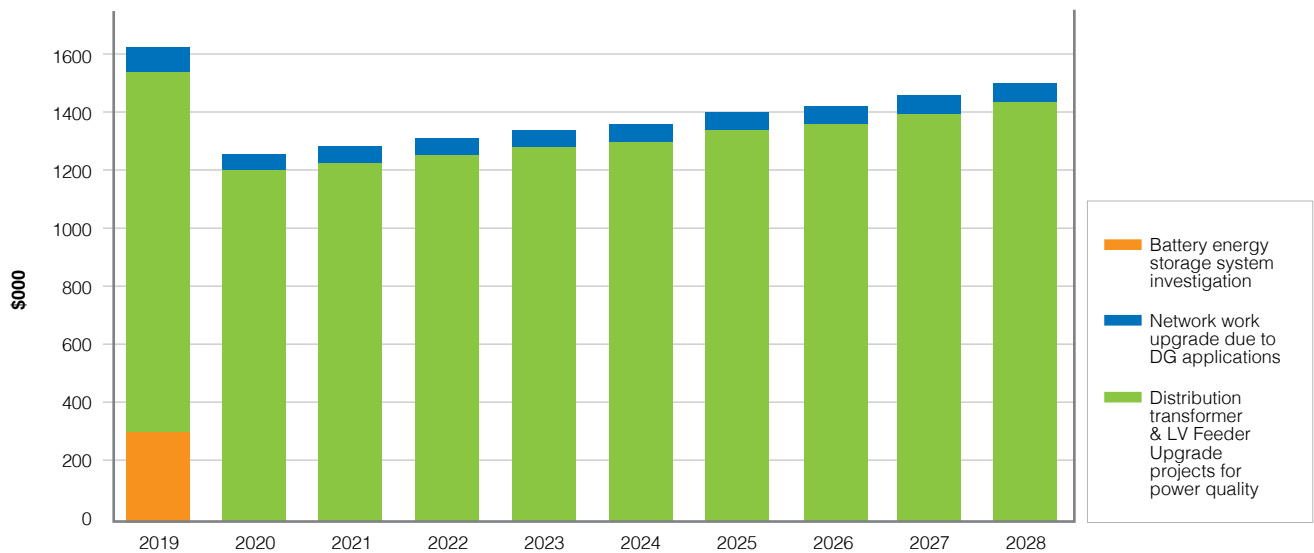


Figure 9.2.5 10 Year Capital Expenditure

9.2.6. LEGISLATIVE AND REGULATORY

Legislative and regulatory capital expenditure by activity is summarised in the graph below.

LEGISLATION AND REGULATORY In Nominal Price

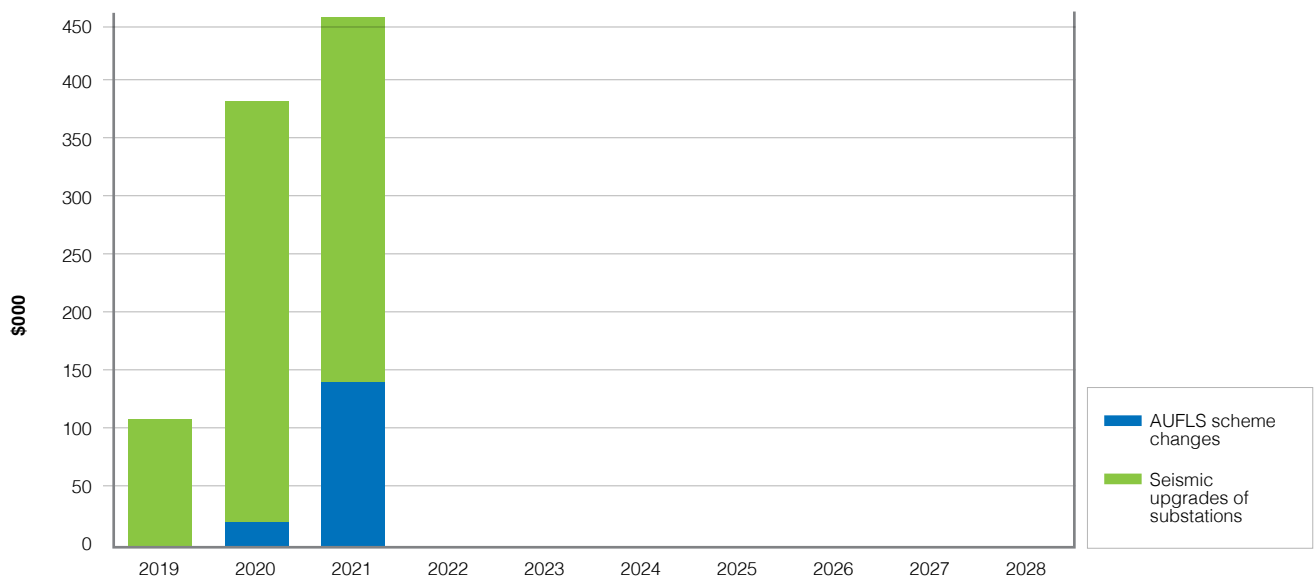
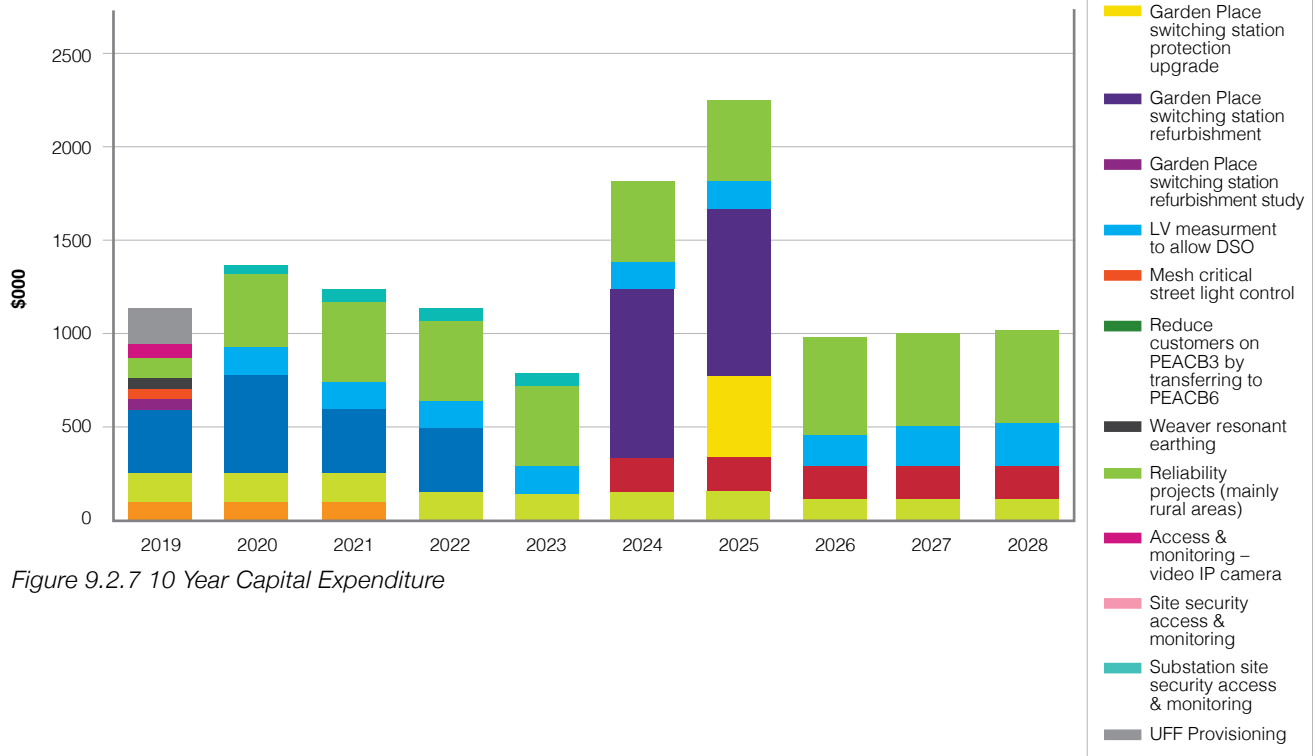


Figure 9.2.6 10 Year Capital Expenditure

9.2.7. RELIABILITY, SAFETY AND ENVIRONMENT (RSE)

RSE capital expenditure by activity is summarised in the graph below.

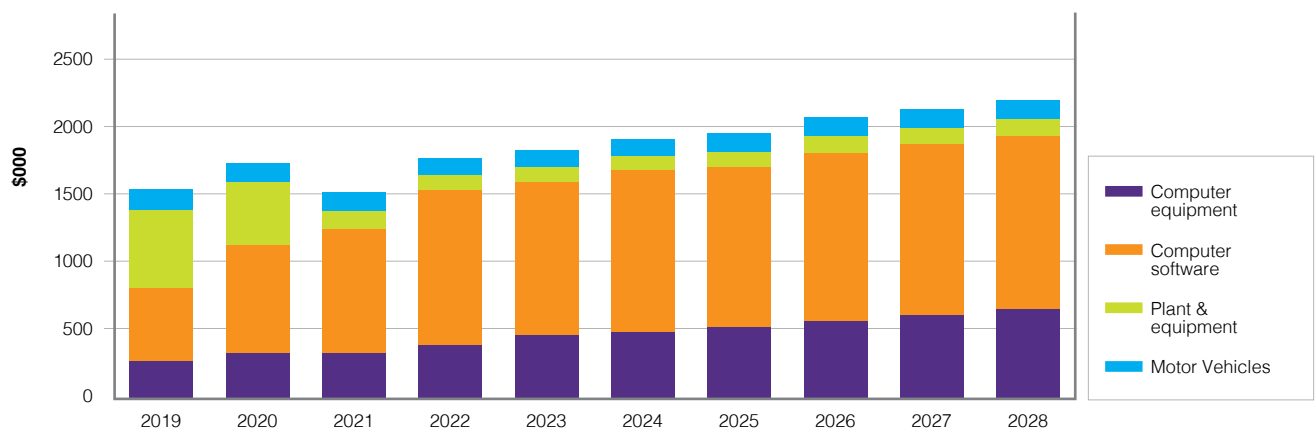
OTHER RELIABILITY, SAFETY AND ENVIRONMENT In Nominal Price



9.2.8. NON-NETWORK CAPITAL EXPENDITURE

The breakdown of non-network capital expenditure by asset type is summarised in the graph below.

NON-NETWORK CAPITAL EXPENDITURE In Nominal Price



9.3. OPERATIONAL EXPENDITURE

This Section provides an overall summary of the forecast operational expenditure by category.

OPERATIONAL EXPENDITURE ON ASSETS

In Nominal Price

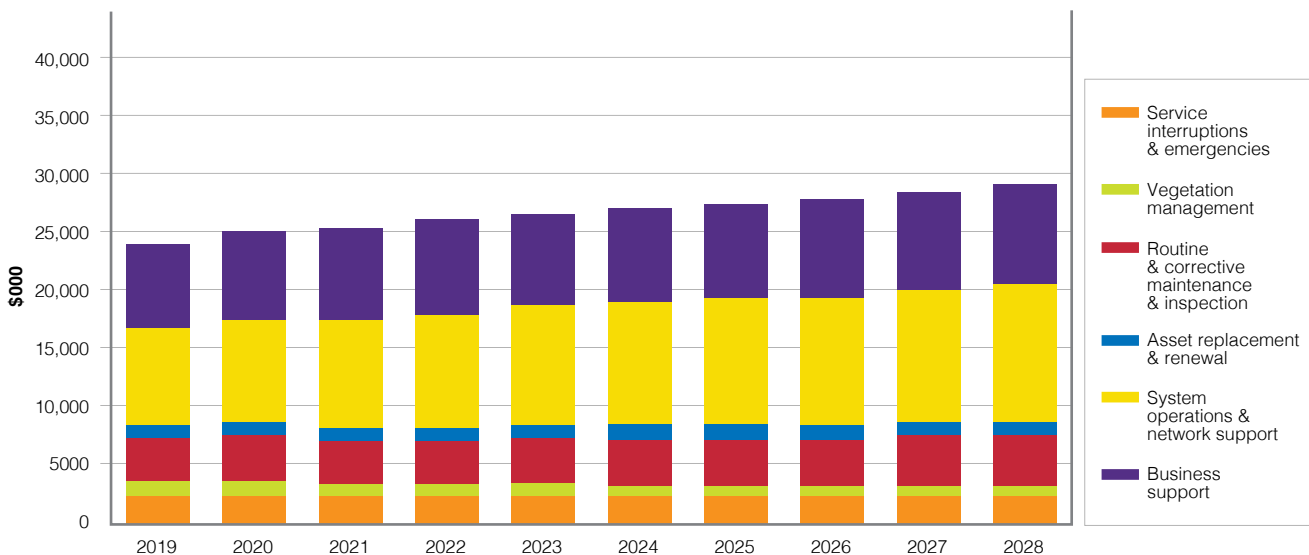


Figure 9.3. 10 Year Operational Expenditure

9.3.1. NETWORK OPERATIONAL EXPENDITURE SUMMARY

The expenditure is shown according to the regulatory categories specified by the Commerce Commission.

NETWORK OPERATIONAL EXPENDITURE

In Nominal Price

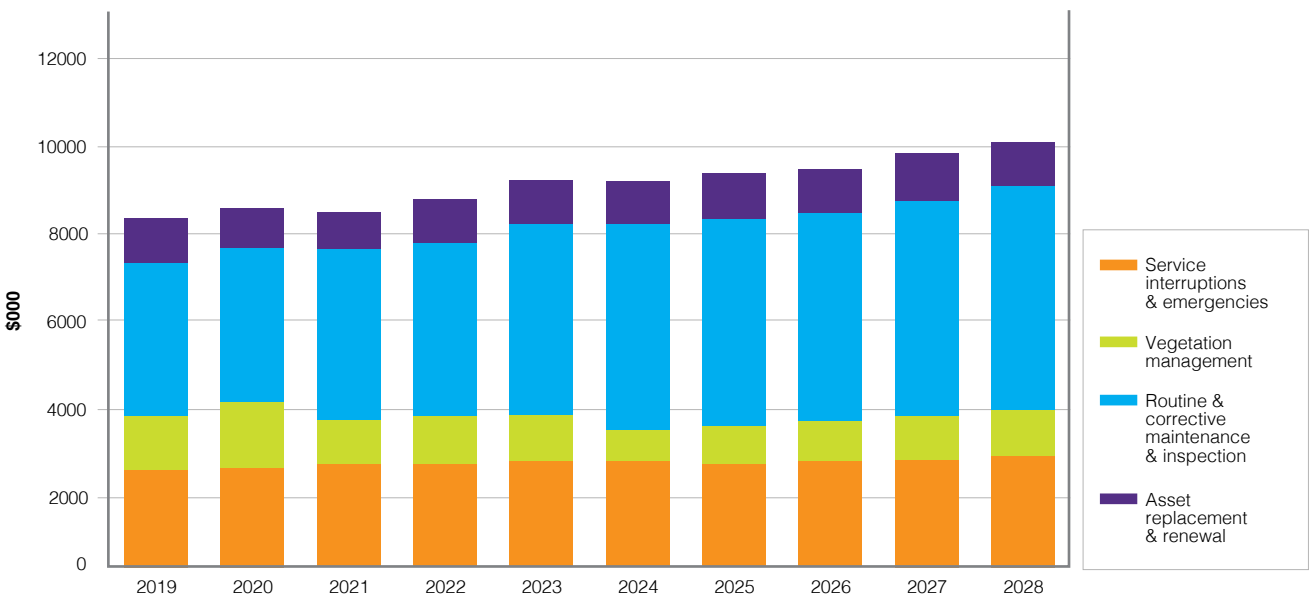


Figure 9.3.1. 10 Year Network Operational Expenditure

9.3.2. NON-NETWORK OPERATIONAL EXPENDITURE

The breakdown of non-network operational expenditure by Commerce Commission expenditure category is summarised below.

NON-NETWORK OPERATIONAL EXPENDITURE In Nominal Price

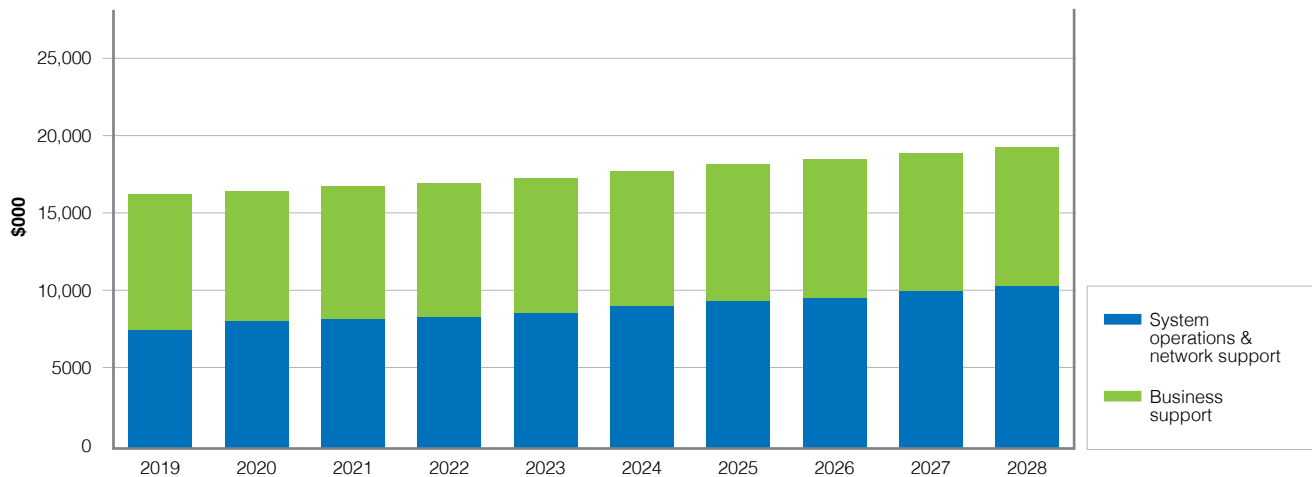


Figure 9.3.2. 10 Year Network Operational Expenditure





10

INFORMATION DISCLOSURE SCHEDULES 11a-13



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.

Company Name	WEL Networks
AMP Planning Period	1 April 2018 – 31 March 2028

sch ref

	Current Year CY for year ended 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23	CY+6 31 Mar 24	CY+7 31 Mar 25	CY+8 31 Mar 26	CY+9 31 Mar 27	CY+10 31 Mar 28
11a(i): Expenditure on Assets Forecast	\$'000 (in nominal dollars)										
Consumer connection	14,498	14,462	12,494	11,920	10,822	11,065	11,314	11,569	11,829	12,095	12,367
System growth	237	1,248	6,734	5,445	5,976	4,923	2,236	3,663	3,284	4,968	4,120
Asset replacement and renewal	12,951	14,598	13,016	13,958	13,604	13,929	14,444	14,241	14,636	14,507	14,709
Asset relocations	3,880	2,088	2,091	1,924	1,640	1,677	1,714	1,753	1,792	1,833	1,874
Reliability, safety and environment:											
Quality of supply	1,190	1,618	1,255	1,283	1,312	1,341	1,371	1,402	1,434	1,466	1,499
Legislative and regulatory	67	103	387	465	-	-	-	-	-	-	-
Other reliability, safety and environment	1,588	1,150	2,427	1,251	1,115	805	1,851	2,360	980	1,002	1,024
Total reliability, safety and environment	2,845	2,872	3,069	2,998	2,427	1,146	3,223	3,762	2,414	2,468	2,523
Expenditure on network assets	34,411	35,268	37,404	36,245	34,458	33,740	32,931	34,988	33,955	35,871	35,593
Expenditure on non-network assets	833	1,513	1,730	1,502	1,741	1,811	1,885	1,961	2,040	2,122	2,170
Expenditure on assets	35,244	36,782	39,134	37,747	36,209	35,550	34,815	36,949	35,995	37,993	37,763
plus	430	-	-	-	-	-	-	-	-	-	-
less	7,211	6,625	6,003	5,678	5,108	5,223	5,340	5,461	5,583	5,709	5,838
plus	-	-	-	-	-	-	-	-	-	-	-
Capital expenditure forecast	28,463	30,157	33,132	32,069	31,101	30,328	29,475	31,488	30,411	32,284	31,925
Assets commissioned	31,581	27,040	28,649	31,475	30,465	29,546	28,811	28,001	29,914	28,891	30,670
For year ended	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23	CY+6 31 Mar 24	CY+7 31 Mar 25	CY+8 31 Mar 26	CY+9 31 Mar 27	CY+10 31 Mar 28
11a(ii): Expenditure on Assets Forecast	\$'000 (in constant prices)										
Consumer connection	14,498	14,143	11,950	11,150	9,900	9,900	9,900	9,900	9,900	9,900	9,900
System growth	237	1,221	6,442	5,093	5,467	4,405	1,956	3,135	2,749	4,066	3,298
Asset replacement and renewal	12,951	14,276	12,449	13,056	12,446	12,463	12,639	12,187	12,250	11,875	11,775
Asset relocations	3,880	2,043	2,000	1,800	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Reliability, safety and environment:											
Quality of supply	1,190	1,583	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Legislative and regulatory	67	101	370	435	-	-	-	-	-	-	-
Other reliability, safety and environment	1,588	1,124	1,365	1,170	1,020	720	1,620	2,020	820	820	820
Total reliability, safety and environment	2,845	2,808	2,935	2,805	2,220	1,920	2,820	3,220	2,020	2,020	2,020
Expenditure on network assets	34,411	30,491	35,776	33,904	31,533	28,815	28,815	29,942	28,419	29,361	28,493
Expenditure on non-network assets	833	1,480	1,651	1,405	1,593	1,620	1,643	1,678	1,707	1,737	1,737
Expenditure on assets	35,244	31,971	37,431	35,309	33,126	30,435	30,458	31,620	30,126	31,098	30,230
Subcomponents of expenditure on assets (where known)											
Energy efficiency and demand side management, reduction of energy losses		342	342	342	342	342	342	342	342	342	342
Overhead to underground conversion	136	500	500	500	500	500	500	500	500	500	500
Research and development											

Difference between nominal and constant price forecasts

Current Year CY for year ended 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23	CY+6 31 Mar 24	CY+7 31 Mar 25	CY+8 31 Mar 26	CY+9 31 Mar 27	CY+10 31 Mar 28
-	319	544	770	922	1,165	1,414	1,669	1,929	2,195	2,467
-	-	292	352	518	569	780	528	535	502	822
-	322	567	902	1,158	1,466	1,805	2,054	2,386	2,632	2,934
-	45	91	124	140	177	214	253	292	333	374
-	-	-	-	-	-	-	-	-	-	-
-	35	55	83	112	141	171	202	234	266	299
-	2	17	30	-	-	-	-	-	-	-
-	26	62	81	95	85	231	340	160	182	204
-	64	134	193	207	226	403	542	394	448	503
-	777	1,628	2,341	2,935	3,552	4,116	5,046	5,536	6,510	7,100
-	33	75	97	148	191	236	283	333	385	433
-	811	1,703	2,438	3,083	3,742	4,351	5,329	5,869	6,895	7,533

for year ended

Current Year CY 31 Mar 18 31 Mar 19 31 Mar 20 31 Mar 21 31 Mar 22 31 Mar 23 31 Mar 24 31 Mar 25 31 Mar 26 31 Mar 27 31 Mar 28

11a(ii): Consumer Connection

Consumer types defined by IOR*

Residential Customers	12,230	11,968	10,266	9,499	8,313	8,319
Business Customers	1,971	735	634	601	537	531
Large Customers - Low Voltage 400V	269	1,440	1,050	1,050	1,050	1,050
Large Customers - Medium Voltage 11kV	28	-	-	-	-	-
[IOR consumer type]						

*Include additional rows if needed

Consumer connection expenditure

less Capital contributions funding consumer connection

Consumer connection less capital contributions

14,498	14,143	11,950	11,150	9,900	9,900
4,319	4,803	4,097	3,827	3,428	3,428
10,179	9,340	7,853	7,323	6,472	6,472

11a(iii): System Growth

Subtransmission

Zone substations

Distribution and LV lines

Distribution and LV cables

Distribution substations and transformers

Distribution switchgear

Other network assets

System growth expenditure

less Capital contributions funding system growth

System growth less capital contributions

-	150	4,002	1,965	1,310	-
110	200	1,598	1,455	1,315	1,000
4	-	-	331	-	-
-	512	500	1,000	2,500	3,063
-	17	-	-	-	-
-	-	-	-	-	-
123	342	342	342	342	342
237	1,221	6,442	5,093	5,467	4,405
1	-	-	-	-	-
236	1,221	6,442	5,093	5,467	4,405

11a(iv): Asset Replacement and Renewal

	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
\$'000 (in constant prices)						
Subtransmission		207	218	207	211	211
Zone substations	581	1,248	604	1,000	481	535
Distribution and LV lines	9,826	7,466	7,921	7,622	8,076	8,071
Distribution and LV cables	261	1,436	699	684	699	699
Distribution substations and transformers	323	1,145	582	570	583	582
Distribution switchgear	1,458	1,564	1,966	2,068	2,112	2,110
Other network assets	502	1,210	459	905	284	255
Asset replacement and renewal expenditure	12,951	14,276	12,449	13,056	12,446	12,463
less						
Capital contributions funding asset replacement and renewal	362	195	195	195	195	195
Asset replacement and renewal less capital contributions	12,589	14,081	12,254	12,861	12,251	12,268

11a(v): Asset Relocations

	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
\$'000 (in constant prices)						
Undergrounding	136	511	500	500	500	500
Transit Hamilton Bypass		532	500	300	-	-
Hamilton City Council		500	500	500	500	500
NZTA		500	500	500	500	500
Relocations	3,744	-	-	-	-	-
*Include additional rows if needed						
All other project or programmes - asset relocations						
Asset relocations expenditure	3,880	2,043	2,000	1,800	1,500	1,500
less						
Capital contributions funding asset relocations	2,528	1,481	1,450	1,290	1,050	1,050
Asset relocations less capital contributions	1,352	562	550	510	450	450

11a(vi): Quality of Supply

	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
\$'000 (in constant prices)						
Battery energy storage system investigation	119	300	-	-	-	-
power quality	776	1,232	1,150	1,150	1,150	1,150
Network Work Upgrade Due To DG applications	6	51	50	50	50	50
Power Quality - Works required to correct customer complaints	289	-	-	-	-	-
[Description of material project or programme]						
*Include additional rows if needed						
All other projects or programmes - quality of supply						
Quality of supply expenditure	1,190	1,583	1,200	1,200	1,200	1,200
less						
Capital contributions funding quality of supply	1					
Quality of supply less capital contributions	1,189	1,583	1,200	1,200	1,200	1,200

11a(vii): Legislative and Regulatory

Project or programme*	
AUPLS scheme changes	
Seismic upgrades of substations	
[Description of material project or programme]	
[Description of material project or programme]	
[Description of material project or programme]	
*Include additional rows if needed	
All other projects or programmes - legislative and regulatory	
Legislative and regulatory expenditure	
Capital contributions funding legislative and regulatory	
less	
Legislative and regulatory less capital contributions	

Current Year CY
for year ended 31 Mar 18

CY+1

31 Mar 19

CY+2

31 Mar 20

CY+3

31 Mar 21

CY+4

31 Mar 22

CY+5

31 Mar 23

\$000 (in constant prices)

-	-	20	135		
67	101	350	300		
67	101	370	435	-	-
67	101	370	435	-	-

for year ended

Current Year CY

31 Mar 18

CY+1

31 Mar 19

CY+2

31 Mar 20

CY+3

31 Mar 21

CY+4

31 Mar 22

CY+5

31 Mar 23

11a(viii): Other Reliability, Safety and Environment

Project or programme*	
Airconditioning for substations	
Discretionary fibre install budget	
Fibre/Routes	
Garden Place Switching Station Protection Upgrade	
Garden Place Switching Station Refurbishment	
Garden Place Switching Station Refurbishment Study	
mesh critical street light control	
Reduce customers on PEACB3by transferring to PEACB5	
Reliability projects (mainly Rural Areas)	
Site Security Access and Monitoring	
Substation Door Upgrade - Pilot project	
UFF Provisioning	
Weaver Resonant Earthing	
LV measurement	
Arc Flash	
*Include additional rows if needed	
All other projects or programmes - other reliability, safety and environment	
Other reliability, safety and environment expenditure	
Capital contributions funding other reliability, safety and environment	
less	
Other reliability, safety and environment less capital contributions	

\$000 (in constant prices)

113	100	100	100	100	-	-
-	150	150	150	150	150	150
-	337	495	300	250	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	50	-	-	-	-	-
-	40	-	-	-	-	-
-	-	-	-	-	-	-
560	136	400	400	400	400	400
673	79	-	-	-	-	-
-	29	50	50	50	50	-
-	153	-	-	-	-	-
48	50	-	-	-	-	-
-	-	-	-	-	-	-
194	-	170	170	170	170	170

for year ended

Current Year CY

31 Mar 18

CY+1

31 Mar 19

CY+2

31 Mar 20

CY+3

31 Mar 21

CY+4

31 Mar 22

CY+5

31 Mar 23

135

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Best in Service Best in Safety

Company Name
WEL Networks
AMP Planning Period
1 April 2018 – 31 March 2028

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref

		Current Year CY										
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
		\$'000 (in nominal dollars)										
		2,342	2,582	2,657	2,711	2,767	2,824	2,882	2,941	3,001	3,062	3,125
		1,381	1,360	1,399	1,107	1,130	1,153	823	840	858	875	893
		2,205	3,475	3,740	3,824	4,046	4,211	4,421	4,534	4,627	4,844	5,006
		2,205	818	862	868	921	959	995	1,035	1,056	1,077	1,099
		8,133	8,234	8,658	8,510	8,863	9,146	9,121	9,349	9,541	9,858	10,123
		8,177	8,361	8,549	8,741	8,938	9,139	9,345	9,555	9,770	9,990	10,215
		7,413	7,750	7,750	7,925	8,103	8,285	8,472	8,662	8,857	9,057	9,260
		15,590	16,136	16,299	16,666	17,041	17,425	17,817	18,218	18,627	19,047	19,475
		23,723	24,370	24,957	25,176	25,904	26,571	26,938	27,567	28,168	28,905	29,598

\$'000 (in constant prices)

	for year ended	Current Year CY										CY+10 31 Mar 28
		31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	
Operational Expenditure Forecast												
\$'000 (in constant prices)												
7		2,342	2,530	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551
8		1,381	1,332	1,343	1,041	1,041	1,041	729	729	729	729	729
9	Service interruptions and emergencies	2,205	3,405	3,591	3,598	3,731	3,805	3,914	3,933	3,933	4,035	4,086
10	Vegetation management	2,205	802	827	817	849	867	881	898	898	898	898
11	Routine and corrective maintenance and inspection	8,133	8,069	8,313	8,007	8,172	8,264	8,075	8,111	8,111	8,213	8,264
12	Asset replacement and renewal	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177
13	Network Opex	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413
14	System operations and network support	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590
15	Business support	23,723	23,659	23,903	23,597	23,762	23,854	23,665	23,701	23,701	23,803	23,854
16	Non-network opex											
17	Operational expenditure											
18												
19												
20												
21												
22												
23	Service interruptions and emergencies	2,342	2,530	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551
24	Vegetation management	1,381	1,332	1,343	1,041	1,041	1,041	729	729	729	729	729
25	Routine and corrective maintenance and inspection	2,205	3,405	3,591	3,598	3,731	3,805	3,914	3,933	3,933	4,035	4,086
26	Asset replacement and renewal	8,133	8,069	8,313	8,007	8,172	8,264	8,075	8,111	8,111	8,213	8,264
27	Network Opex	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177
28	System operations and network support	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413
29	Business support	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590
30	Non-network opex	23,723	23,659	23,903	23,597	23,762	23,854	23,665	23,701	23,701	23,803	23,854
	Operational expenditure											

	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 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36	31 Mar 37	31 Mar 38
\$'000 (in constant prices)																						
19		2,342	2,530	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551
20		1,381	1,332	1,343	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041
21		2,205	3,405	3,591	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598	3,598
22		2,205	802	827	817	817	817	817	817	817	817	817	817	817	817	817	817	817	817	817	817	817
23		8,133	8,069	8,313	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007
24		8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177	8,177
25		7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413	7,413
26		15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590	15,590
27		23,723	23,659	23,903	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597	23,597
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47																						
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* Direct billing expenditure by suppliers that direct bill the majority of their consumers

Difference between nominal and real forecasts

41																						
42																						
43																						
44																						
45																						
46																						
47																						
48																						
49																						
50																						

WEL Networks

Company Name

1 April 2018 – 31 March 2028

AMP Planning Period

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref

		Asset condition at start of planning period (percentage of units by grade)										% of asset forecast to be replaced in next 5 years	
		Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)					
Voltage	Asset category	Asset class											
7													
8													
9													
10	All	Overhead Line	0.24%	1.52%	23.95%	74.25%	-		3	0.82%			
11	All	Overhead Line	2.82%	11.07%	22.04%	64.07%	-		3	17.48%			
12	All	Overhead Line						N/A					
13	HV	Subtransmission Line	-	-	54.87%	45.13%	-		1	-			
14	HV	Subtransmission Line						N/A					
15	HV	Subtransmission Cable	0.42%	1.04%	11.74%	86.80%	-		1	-			
16	HV	Subtransmission Cable						N/A					
17	HV	Subtransmission Cable						N/A					
18	HV	Subtransmission Cable						N/A					
19	HV	Subtransmission Cable		0.81%	1.21%	97.98%	-		1	-			
20	HV	Subtransmission Cable						N/A					
21	HV	Subtransmission Cable						N/A					
22	HV	Subtransmission Cable						N/A					
23	HV	Subtransmission Cable						N/A					
24	HV	Zone substation Buildings						N/A					
25	HV	Zone substation Buildings						N/A					
26	HV	Zone substation switchgear						N/A					
27	HV	Zone substation switchgear						N/A					
28	HV	Zone substation switchgear						N/A					
29	HV	Zone substation switchgear						N/A					
30	HV	Zone substation switchgear						N/A					
31	HV	Zone substation switchgear						N/A					
32	HV	Zone substation switchgear						N/A					
33	HV	Zone substation switchgear						N/A					
34	HV	Zone substation switchgear						N/A					
35													
36													

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
37				No.	-	-	22.92%	77.08%	-	3	-
38				km	12.05%	4.03%	18.33%	65.59%	-	2	5.31%
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	-	-	-	-	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	-	-	-	N/A	-
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	4.90%	8.94%	86.16%	-	1	0.25%
44	HV	Distribution Cable	Distribution UG PILC	km	-	4.90%	8.94%	86.16%	-	1	1.04%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	100.00%	-	3	28.86%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	44.07%	55.93%	-	4	8.14%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.63%	0.74%	1.80%	96.83%	-	4	1.49%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	2.82%	14.32%	82.86%	-	3	7.41%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.24%	4.97%	8.18%	86.61%	-	3	2.17%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.85%	7.06%	19.54%	71.55%	-	3	4.75%
53	HV	Distribution Transformer	Voltage regulators	No.	0.14%	13.13%	29.88%	51.86%	5.00%	3	25.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	11.11%	10.25%	7.61%	71.03%	-	1	0.06%
56	LV	LV Cable	LV UG Cable	km	-	0.24%	29.67%	70.09%	-	1	0.20%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	9.58%	17.85%	72.58%	-	1	0.08%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	N/A	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	8.72%	19.11%	72.17%	-	3	15.16%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	5.88%	-	84.12%	10.00%	3	3.53%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	-	30.00%	70.00%	-	3	-
63	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Company Name
WEL Networks
AMP Planning Period
1 April 2018 – 31 March 2028

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

12b(i): System Growth - Zone Substations

	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (Type)	Transfer Capacity (MVA)	Utilisation or Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation or Installed Firm Capacity +5 years %	Installed Firm Capacity Constraint +5 years (Cause)	Explanation
7										
8										
9	Avonlea Dr	17	24 N-1		12	73%	24	79%	No constraint within +5 years	Limited by 33kV OH conductor to 20.6MVA
10	Borman	16	21 N-1		16	76%	21	97%	Subtransmission circuit	Load increase due to natural growth
11	Bryce St	14	23 N-1		14	63%	23	64%	No constraint within +5 years	
12	Chartwell	16	26 N-1		16	63%	26	67%	No constraint within +5 years	
13	Claudehills	20	23 N-1		20	88%	23	92%	No constraint within +5 years	
14	Cobham	12	26 N-1		12	47%	26	49%	No constraint within +5 years	
15	Emmerson Rd	4	8 N		4	53%	8	54%	No constraint within +5 years	
16	Glasgow St	9	10 N		9	88%	10	89%	No constraint within +5 years	
17	Gordonton	7	10 N		7	65%	10	67%	No constraint within +5 years	
18	Hampton Downs	2	9 N		2	20%	9	21%	No constraint within +5 years	
19	Horrellu	9	18 N-1		9	50%	18	73%	No constraint within +5 years	
20	Kent St	17	23 N-1		17	73%	23	73%	No constraint within +5 years	
21	Kimble	4	10 N		-	38%	10	-	No constraint within +5 years	Disconnected from Sept 2017
22	Latham Court	17	23 N-1		13	75%	23	76%	No constraint within +5 years	
23	Hooka Rd	8	26 N		8	30%	26	32%	No constraint within +5 years	
24	Ngaruawahia	6	8 N-1		6	76%	8	79%	No constraint within +5 years	Offloaded HAM 11 kV
25	Peacocks Rd	15	26 N-1		12	57%	26	73%	No constraint within +5 years	
26	Pukeite - Anchor (major customer)	18	30 N-1		-	58%	30	58%	No constraint within +5 years	3-winding TX - owned by Contact Energy. With embedded generation.
27	Pukeite - WEL's 11kV	10	13 N-1		10	76%	13	83%	No constraint within +5 years	3-winding TX - owned by Contact Energy
28	Baglan	5	11 N		3	43%	11	51%	Subtransmission circuit	Limited by the incoming 33kV OH conductor. Transfer capacity is limited due to voltage regulation issue.
	HAM 11 kV GWP	29	44 N-1		21	67%	44	68%	No constraint within +5 years	
	Sandwich Rd	22	28 N-1		22	78%	28	80%	No constraint within +5 years	
	Tasman	19	26 N-1		19	75%	26	95%	Transformer	(Emergency rating of 25.9MVA, and will be upgraded to 30MVA in this financial year (FY18).
	Tre Kaurahata	5	10 N-1		5	51%	10	78%	No constraint within +5 years	
	Tre Luku	2	10 N		2	19%	10	20%	No constraint within +5 years	
	Wallace Rd	13	15 N-1		13	83%	15	85%	Subtransmission circuit	Limited by the incoming 33kV OH conductor to 15.4MVA identified
	Weavers	9	8 N-1		9	116%	8	120%	No constraint within +5 years	(Emergency rating of 9MVA)
	Whatawhata	4	23 N		4	17%	23	18%	No constraint within +5 years	

* Extend forecast capacity table as necessary to disclose all capacity by each zone substation

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.

Company Name	WEL Networks
AMP Planning Period	1 April 2018 – 31 March 2028

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Residential Customers
Business Customers
Large Customers - Low Voltage 400V
Large Customers - Medium Voltage 11kV
Large Customers - High Voltage 33kV
Asset Specific Customers
Unmetered Customers

Connections total

*include additional rows if needed

Distributed generation

Number of connections

Capacity of distributed generation installed in year (MVA)

12c(ii) System Demand**Maximum coincident system demand (MW)**

plus	GXP demand
	Distributed generation output at HV and above
less	Maximum coincident system demand
	Net transfers to (from) other EDBs at HV and above
	Demand on system for supply to consumers' connection points

Electricity volumes carried (GWh)

less	Electricity supplied from GXPs
plus	Electricity exports to GXPs
less	Electricity supplied from distributed generation
	Net electricity supplied to (from) other EDBs
less	Electricity entering system for supply to ICPs
	Total energy delivered to ICPs
	Losses
	Load factor
	Loss ratio

for year ended	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
	1,210	1,095	1,110	1,125	1,140	1,155
	165	165	165	165	165	165
	14	13	10	10	10	10
	3	18	13	13	13	13
	8	(4)	(3)	(3)	(3)	(3)
	1,400	1,287	1,295	1,310	1,325	1,340

205	250	312	391	488	510
1	1	1	2	2	2

for year ended	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
	227	273	281	285	288	290
	44	-	-	-	-	-
	271	273	281	285	288	290
	271	273	281	285	288	290

949	926	923	918	914	910
116	116	116	116	116	116
437	437	437	437	437	437
(15)	(15)	(15)	(15)	(15)	(15)
1,285	1,262	1,259	1,254	1,250	1,246
1,225	1,203	1,200	1,195	1,191	1,188
60	59	59	59	59	58

54%	53%	51%	50%	50%	49%
4.7%	4.7%	4.7%	4.7%	4.7%	4.7%

Company Name

WEL Networks

AMP Planning Period

1 April 2018 – 31 March 2028

Network / Sub-network Name

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref

		Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
8	for year ended						
9							
10							
11	SAIDI						
12	Class B (planned interruptions on the network)	42.9	42.9	42.9	42.9	42.9	42.9
	Class C (unplanned interruptions on the network)	63.4	63.1	62.7	62.7	62.7	62.7
13	SAIFI						
14	Class B (planned interruptions on the network)	0.30	0.30	0.30	0.30	0.30	0.30
15	Class C (unplanned interruptions on the network)	1.34	1.33	1.33	1.33	1.33	1.33

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB's self-assessment of the maturity of its asset management practices.

<div>Company Name WEL Networks</div> <div>AMP Planning Period 1 April 2018 – 31 March 2020</div> <div>Asset Management Standard Applied</div>						
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	WEL's original Asset Management policy was agreed by the Board and authorised by the Chief Executive in 2007. It has been recently updated in November 2015 and is due for review prior to November 2018. It was used to guide the development and delivery of the approved AMP. All key staff are aware of the Asset Management Policy and how it contributes to the AMP.	1. Do we have an Asset Management policy to cover: Safety, reliability, quality, security, efficiency, environment, risk management, legislation and align with other policies? 2. Have the AMP policies documented and authorised and reviewed regularly? 3. How well the AMP policies been communicated? 4. Where I can find it?	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg. as required in PAS 55 para 4.2 f). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There is a strong linkage to company strategy and evidence of alignment with other organisational strategies. Stakeholder requirements are identified through customer survey and consequently there is a large focus on improving our rural network performance.	Do we have a process for asset management development to ensure that its asset management strategy is consistent with asset management policy and other appropriate organisational policies and strategies, and the needs for stakeholders?	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.
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 have a number of tools to evaluate asset lifecycle, the most significant being condition based risk management. This applies from each asset's initial purchase, taking into account total life cycle costs to CBRM which determines the overall health of the assets.	This relates to the life cycle of the asset from Planning, Design, Construction, Operation, Maintenance, Disposal and Renewal. Each of these phases should incorporate Asset Management and other relevant policies and strategies. In most cases these are spelt out within the AMP but it needs to be clear. In each of these sections within the AMP there should have a statement aligning them with the policies and strategies.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Asset lifecycle decisions are made using CBRM and HMECA to allow for the trade off between capital and operational expenditure, risk, reliability and safety considerations. Planning falls directly out of the AMP, which prioritises spend based on lifecycle condition.	Lifecycles are generally well covered in AMP but checks should be made by senior managers to satisfy themselves this is the case.	The organisation's asset management strategy and supporting working documents.
						The organisation's asset management plan(s).

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

<div>Company Name</div> <div>AMP Planning Period</div> <div>Asset Management Standard Applied</div>						
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why
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?	2.5	The AMP and its projects and maintenance spend plan are communicated and approved through our project definition documents. This information goes to those stakeholders who require the information for work and strategy planning purposes and directly to external parties as required by Regulation. The AMP is also available to all through the company intranet.	The AMP should be communicated to relevant stakeholders. As the AMP contains details of work, both long term and short term (with higher level of detail for nearer work), end users are the relevant stakeholders and should be consulted as to effects the work plans may have on their activities. This usually involves major users who may have their own plans to change their operations in the future. The consultation must be recorded and evidence provided the outcomes have been considered in the AMP.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The Asset Planning and Engineering Team are responsible for the creation and renewal of the AMP every year. To facilitate this, an annual works delivery plan is produced which in turn clearly defines the delivery responsibilities in terms of resource and timeline.	The asset management team structure should clearly designate responsibilities and authorities for the delivery of the AMP actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.
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	The annual works delivery plan outlines resource requirements based on negotiated delivery timelines. Annual budgets are set to allow resource allocation, both in house and contracted. It is then up to the service providers to manage resources to implement the plan.	Financial estimates are provided in AMPs for the expected work to be completed. Once established, detailed discussion should be included as to the forward planning developed to ensure areas of risk are identified to achieve the asset management strategies and objectives.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.
						Record/document information Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
						The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
						The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.

33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Business continuity and disaster recovery plans are in place and various scenarios are tested regularly. Emergency stock is held at various sites in case of the primary equipment becomes unavailable. Priorities for systems to return to service after an event are documented.	The AHMAAT requirement is for a Plan to get Critical Assets back on line after a disaster. To provide evidence this will be achieved, regular written reviews of the Plan are required along with evidence of simulated events, training, communication and consultation.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.
<p style="text-align: center;">SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)</p>								
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	Accountability for delivery of the AMP strategy sits with the GM Asset Management. This is delegated through to the engineering and support teams for operational delivery. Authority, responsibility and accountability are defined for each person or role which enable the asset management team to manage and deliver the AMP strategy, objectives and plans.	<p>This function has a specific requirement to appoint a manager within the organisation to have the authority to ensure the company delivers on its asset management policies, strategies and plans.</p> <p>This question is intended to apply to the delegation of responsibilities to a senior level manager.</p> <p>However because a senior level manager will not always have the time to focus attention on day to day asset management, focus should be on the clarity in which a top level manager has delegated responsibility to a third level manager fully involved in the day-to-day management of the asset. It is preferable the authorisation is identified below.</p>	<p>In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfill their responsibilities. (This question, relates to the organisation's assets eg. para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).</p>	<p>Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.</p>	<p>Record/document information</p> <p>Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.</p>
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	<p>A resource planning framework has been established in the asset management team. The operational model in use by WEL includes both in-house and external resource.</p> <p>Decisions are made throughout each AMP period on the most effective delivery mechanism for required works. This optimises in-house resources and provides reliable workstreams for our preferred contractors.</p>	<p>If resources are identified in the AMP, top managers demonstrate sufficient resources are available when approving the AMP. Functional responsibilities for critical duties should be described and need to be tied back to training and competency and defined in the individual position descriptions.</p>	<p>Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.</p>	<p>Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.</p>	<p>Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.</p>

42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.5 The AMP is considered to be one of our core strategic documents and planning and budgeting around our network assets falls out of the detail in the plan. Work delivery expectations are clear and communicated through staff forums (i.e. staff info) and meetings.	Operating budgets for EDBs are based on the requirements of their AMP. The budgets are approved by top management and senior managers provide performance reports against budget on a monthly basis. Any differences and hence perceived risks to future asset management strategies and objectives need to be identified and action plans put in place.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg. PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walkabouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.5 Performance of WEL's contractors are closely monitored through their KPIs. We manage contractors with a robust contractor on-boarding process, establishment of preferred contractors, a contractor performance management system and a competency matrix. This ensures that requirements and expectations are met.	In most cases of outsourcing, contracts are in place setting out requirements and performance expectations. The contracts need reference the asset management policies and strategies outlined above. EDBs need to record evidence of regular reviews of the contract performance, operation progress, equipment calibration and other relevant issues.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg. PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The management(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name AMP Planning Period Asset Management Standard Applied					
Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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	An annual works plan based around the AMP is created and implemented. It clearly defines the human resource requirements on a monthly basis. Through the resource planning process and plan WEL is effective in matching competencies and capabilities to the asset management requirements including the plan for both internal and contracted activities.	Asset management activities should be broken down to the extent a defined amount of human resources can be allocated for each activity, including the competence levels required. This analysis should be included in the AMP. This appears to be an area of concern for the Commerce Commission with a national shortage of resources looming so it would be worthwhile ensuring conformance in some detail.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	WEL Services field staff competency matrix is managed by the H&S Team and a contractors matrix is in development. The competencies required for positions within the Asset Management team are defined in position descriptions. Competencies are confirmed 6 monthly for WEL staff and for each contract or project for our contractors. Records are held in our secure systems.	Most EDIs rely on competency for asset management through experience and qualifications and provide regular training to remain competent. In a lot of cases, the records for this level of staff are not complete and staff are not formally authorised as competent by the company.
50	Training, awareness and competence	How does the organisation ensure that persons undertaking direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	The competencies required for positions within the Asset Management team, Maintenance Team and field service teams are outlined for each job. Competencies are matched to work tasks by the Dispatch teams. Any competency shortfall is identified and addressed as required. Competency checks are carried out and confirmed at preset intervals.	Staff competency should be reviewed regularly to ensure up to date asset management techniques are employed by staff who are fully trained in the new technologies. Records of this progression should be maintained and regular reviews undertaken and development plans put in place
					There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external
					Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.
					Record/document information Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
					Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.
					Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, coordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
					Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.
					Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

<div>Company Name</div> <div>AMP Planning Period</div> <div>Asset Management Standard Applied</div>					
Question No.	Function	Question	Score	Evidence – Summary	User Guidance
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	Two way communications is in place for all relevant stakeholders. Contract managers have regular operational and management meetings with preferred contractors. The AMP is publicly available to anyone via our website	Pertinent information in the AMP must be communicated to employees and contractors. In smaller EDBs the employees usually develop certain sections of the AMP but may not be aware of other pertinent information. Contractors may not be aware of the AMP and act solely on their contractual obligations. EDBs must make a conscience effort to ensure consultation and engagement is developed with all relevant stakeholders.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The AMP, policy, process documents and strategies are all regularly reviewed in line with externally certified WEL	This function requires documentation (in one form or another) for all the functions above and evidence the documentation is reviewed and up-to-date. EDBs now have document control systems thanks to the new safety management system requirements and asset
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 WEL asset management systems contain the necessary information that supports effective asset management. The WEL systems include the GIS, NMS and ERP. Which gaps are identified, the required changes are made to each system's metadata. Frequent audits and reviews of operating effectiveness are undertaken and continual improvement initiatives are regularly implemented. Asset data is backed up in accordance with the WEL ISSP.	asset information includes asset registers, drawings, contracts, licences, legal, regulatory and statutory documents, policies standards notes and instructions, procedures, operating criteria, performance and condition data and asset records. Most EDBs cover the bulk of This requirement in their GIS, standards, standard drawings and procedures are common. the management of This information is critical and This includes availability of the information to those parties requiring it. Good backup systems are required for computer stored data.
				Effectively used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).
				The organisation's strategic planning team. The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).
				The documented information describing the main elements of the asset management system (process(es)) and their interaction.	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
				The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers effectively implemented.	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.

63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	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. Where misalignment or inconsistencies are identified, they get addressed. There are XPIs around the time taken to get asset information populated into the systems.	What controls are in place to ensure the information is up-to-date? The AMP is up-to-date but what about the GIS, standards and drawings etc. This function is difficult to control in small EDBs with limited resources and reliance is placed on an experienced and stable work force. However, the comments in Q62 above still apply.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg. s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
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Company Name
AMP Planning Period
Asset Management Standard Applied

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
64	Information management	How has the organisation's information system is relevant to its needs?	3	Frequent audits and reviews of operating effectiveness of all asset management systems are undertaken by internal and external parties and continual improvement initiatives are regularly implemented.	There is no predetermined level of information management. Each EDB must settle on what is appropriate for the size of the organisation and describe what that level and associated process might be. It does, however, need to be demonstrated appropriate processes are systematically	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	WEL has a number of processes to ensure its assets are risk assessed and documented. It includes CBAM modelling, reviews of risks during PSAMS NGS/7901 assessments, risk and audit reviews on top risk items, safety in design processes, notification processes and measurement point data capture, structured PM plans, RCA and FMECA studies and the AMP processes.	Most EDBs have addressed the issues of risk management in their AMP. This function requires EDBs to demonstrate appropriate documentation exists across the life cycle of the asset.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg. para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Comprehensive Risk review is under way to ensure that optimised processes are in place to better link risk information with asset plans. Parts of this process are currently undergoing review to make it less reactive.	To manage risk effectively, consideration of risk should be embedded into all activities of asset management. EDBs should keep the results of risk identification, assessments and controls up-to date and document where lack of risk control could affect the delivery of asset management objectives and strategies.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisation's risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.

82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	There is a good level of regulatory oversight and mechanisms for keeping up-to-date with regulatory changes. The Executive have to report and confirm that all legislative and regulatory requirements have been met on a quarterly basis. Any breaches are reported to the Board.	EDBs a subject to high levels of regulation so, in general, should have this function under control. Executives generally report regularly to the board on compliance issues so have controls in place to ensure direct accountability, competencies, reporting and review cycles.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg. PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es)).	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives																																				
<p align="center">SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)</p> <table border="1"> <tr> <td>Question No.</td><td>Function</td><td>Question</td><td>Score</td><td>Evidence—Summary</td><td>User Guidance</td><td>Why</td><td>Who</td><td>Record/document information</td></tr> <tr> <td>88</td><td>Life Cycle Activities</td><td>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?</td><td>3</td><td>We have a suite of process documents that ensure the AMP plans are implemented for the whole asset lifecycle. Process documentation is version controlled and regularly reviewed by the respective subject matter experts to ensure it is up to date.</td><td>This function requires a documented process to ensure the life cycle activities in the AMP are carried out under specified conditions that are consistent with the asset management policies and strategies. It includes controls in place for cost and risk minimisation.</td><td>Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg. PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. 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The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).</td></tr> </table>									Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information	88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	We have a suite of process documents that ensure the AMP plans are implemented for the whole asset lifecycle. 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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 and the ICAM investigation model. Agreed actions from non-conformities are put into the AIR system for implementation and monitoring. All outages causing greater than 0.3 SAUDI minutes are investigated, 0.5 minutes are reported to the Executive. Significant outages or issues may result in the event being recorded in the company risk register.	This requires a documented process for investigation of asset failures, incidents and nonconformities and, in particular, requires clearly defined responsibilities and authorities for these activities. A process for feedback of non-conformance is required	Widely used AM standards require that the organisation establishes implements and maintains processes for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.
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Company Name
AMP Planning Period
Asset Management Standard Applied

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	WEL has an internal audit process, defined in our quality management system, which looks at various aspects of our business. In addition we have external specialists review our asset management systems. The business process audits and field quality and safety audits are carried out as BAU.	A documented audit process of the asset management system (not just the AMP) should be planned, established, implemented and maintained. The audit should be conducted by personnel competent in the audit process and ideally be independent of those having direct responsibility for the asset management activities.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg. the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation investigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Outcomes from RCA investigations are captured in the AR and FAR systems, within which corrective and preventive actions are identified and documented once complete. Asset failures are captured in SAP via notifications. These lead to jobs which then get scheduled. All job progress is captured as a business kpi.	Investigation of asset failures, incidents and nonconformities should establish root causes. Preventative action is required to ensure similar failures do not occur in the future. A documented process is required, including responsibilities, competencies and authorities, to ensure processes and systems include feed-back loops to prevent future similar failings.	Having Investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and Incident Investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews

113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.5	The business is certified to the ISO 9001 quality management standard that requires continual improvement as fundamental to how we operate. This principle is used when reviewing any of the controlled document suite. In alignment with this Standard, we use the AMP prioritisation tool to assess the risk value for assets. We have considered the following quantifiable risk values: • Health and Safety • Network Reliability • Network Capacity • Environmental • Voltage Compliance • Financial • Planned Outage	This function looks beyond audit and review processes for continual improvement. A review process may say things are being done according to plan and an audit may confirm this but continual improvement requires definite actions to look for improving processes and systems. The introduction of new technologies, updating systems and monitoring of international advancements all support continual improvement.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
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?	2.5	The business is certified to the ISO 9001 quality management standard that requires continual improvement as fundamental to how we operate. This principle is used when reviewing any of the controlled document suite. In alignment with this Standard, we use the AMP prioritisation tool to assess the risk value for assets. We have considered the following quantifiable risk values: • Health and Safety • Network Reliability • Network Capacity • Environmental • Voltage Compliance • Financial • Planned Outage	This function looks beyond audit and review processes for continual improvement. A review process may say things are being done according to plan and an audit may confirm this but continual improvement requires definite actions to look for improving processes and systems. The introduction of new technologies, updating systems and monitoring of international advancements all support continual improvement.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefits to the organisation?	3	WEL actively engages internally and externally with other asset management practitioners, professional bodies, industry forums and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments. We review the standards implemented by other EDs to see if they are of use to WEL.	How does the organisation go about acquiring knowledge about new systems, processes, new technologies, opportunities, staff skills and environments?	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg. by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.



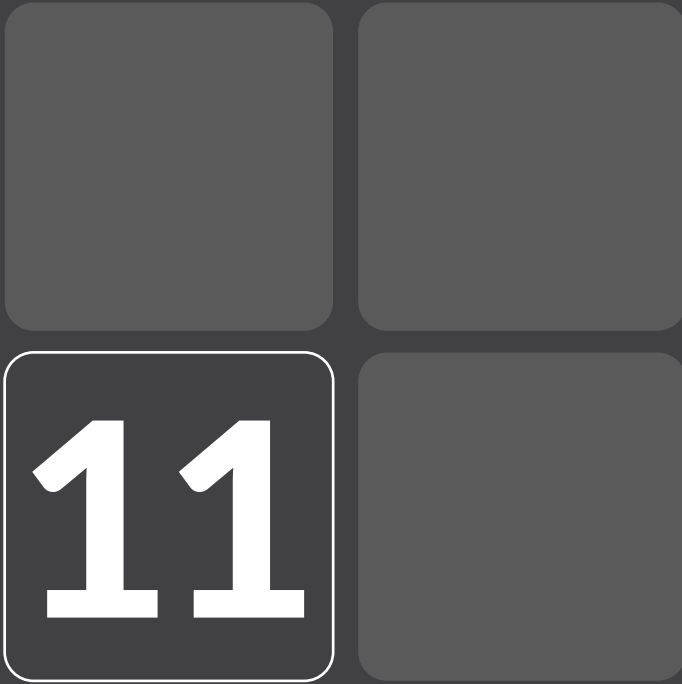
SAFE JOB START

Form with various sections and checkboxes, including 'Checklist of the work area', 'Signatures', and 'Personnel who arrive on site after work has commenced'.

Checklist of the work area

Signatures

Personnel who arrive on site after work has commenced



APPENDIX



APPENDIX A: GLOSSARY

Abbreviation	Description
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air Break Switch
AC	Alternating Current
ACSR	Aluminium Conductor Steel Reinforced
AHI	Asset Health Index
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
GIS	Geographic Information System
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
MW	Megawatt

Abbreviation	Description
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
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
SF6	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
WLUG	Waikato Lifelines Utilities Group
XLPE	Cross linked polyethylene

APPENDIX B: CONDITION BASE RISK MANAGEMENT (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 below 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.

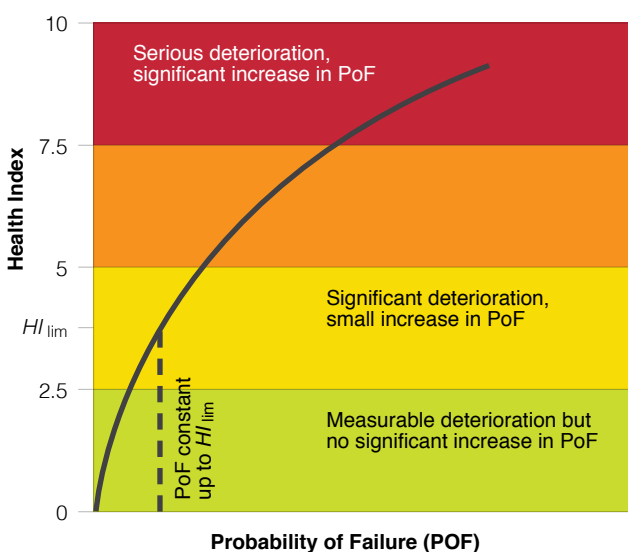


Figure B.2 Relationship between AHI and PoF

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 Safety	<ul style="list-style-type: none"> Potential loss of system availability Number of fatalities Number of major injuries
Financial (e.g. Cost Of Repairs / Replacement)	<ul style="list-style-type: none"> Number of minor injuries Money (\$)
Environmental Impact	<ul style="list-style-type: none"> Volume of oil spilled Volume of SF₆ 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 'effect of uncertainty on objectives' 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:

Risk	Scenario
Do nothing	Assumes no investment within the planning period
Current	The current year's investment
Re-prioritised	Optimum investment using CBRM outcomes with the current year's investment
Higher spend, No risk increase	Simulates that year-10 (Y10) risks are maintained in the current year's (Y0) level with higher investment requirement
Highest spend, Minimum risks	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.	Executive 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.	1.1.2
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.	Executive Summary
3.3.2	States the corporate mission or vision as it relates to asset management.	Executive Summary 1.1.2
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process.	Executive Summary 3.2; 4.1
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management.	Executive Summary 3.2; 4.1
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes and plans.	Executive Summary 3.2
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.	Executive Summary
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	Executive Summary
Stakeholder Interests		
3.6	The AMP must include a description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates:	1.2.3; 3.1
3.6.1	The AMP must include a description of how the interests of stakeholders are identified.	1.2.3; 3.1
3.6.2	The AMP must include a description of what these interests are.	1.2.3; 3.1
3.6.3	The AMP must include a description of how these interests are accommodated in asset management practices.	1.2.3; 3.1
3.6.4	The AMP must include a description of how conflicting interests are managed.	3.1.1
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:	1.1
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.	1.13
3.7.2	Executive—an indication of how the in-house asset management and planning organisation is structured.	1.13
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.	1.13; 4.3
Assumptions		
3.8	The AMP must include all significant assumptions.	6.1.1; 8.2.1; 8.3.2; 9.1.2

Reference	Requirement	Ref
Systems and Information Management Data		
3.8.1	All significant assumptions must be quantified where possible.	6.1.1; 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.	6.1.1; 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.	
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.	6.1.4; 9.1
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.	9.1
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.	6.1.4; 9.1.2
Asset Management Strategy and Delivery		
3.10	The AMP must include an overview of asset management strategy and delivery.	3.2
3.11	The AMP must include an overview of systems and information management data	7.2; 7.1.3
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.	8.2.6; 6.1.3
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.	8.1; 8.2; 8.4
3.13.2	Planning and implementing network development projects.	4.1; 4.2; 4.3
3.13.3	Measuring network performance.	5.2; 5.3
3.14	The AMP must include an overview of asset management documentation, controls and review processes.	3.2.2; 7.2
Communication Processes		
3.15	The AMP must include an overview of communication and participation processes.	3.4; 3.1
Financial Values		
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	9.1.2
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 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:	1.2
4.1.1	The region(s) covered.	1.2
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities.	1.3.1
4.1.3	A description of the load characteristics for different parts of the network.	1.2.2

Reference	Requirement	Ref
Sub-networks		
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	1.2.2
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.	1.2; 6.3
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.	1.2; 6.1.1; 6.3; 6.3.1; 6.3.2; 6.3.3
4.2.3	A description of the distribution system, including the extent to which it is underground.	1.2
4.2.4	A brief description of the network's distribution substation arrangements.	1.2; 2.4; 2.5
4.2.5	A description of the low voltage network including the extent to which it is underground.	1.2; 2.5
4.2.6	An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	2.7
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.	2.2–2.9
4.4.2	Description and quantity of assets.	2.2–2.9
4.4.3	Age profile.	2.2–2.9
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.	2.2–2.9
Network Asset Information by Asset Category		
4.5	The asset categories discussed in subclause 4.4 should include at least the following:	
4.5.1	The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (iii).	2.2–2.10
4.5.2	Assets owned by the EDB but installed at bulk electricity supply points owned by others.	2.10
4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand.	2.8.1
4.5.4	Other generation owned by the EDB.	2.8.1
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.	5.2–5.5

Reference	Requirement	Ref
Network Development Planning		
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.	5.3.3
7	The AMP must include performance indicators for which targets have been defined in clause 5 above should also include:	
7.1	Consumer oriented indicators that preferably differentiate between different consumer types.	5.3.3
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.	5.4; 5.5
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.	3.1; 5.1; 5.2-5.5
9	Targets should be compared to historic values where available to provide context and scale to the reader.	5.2-5.5
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.	5.3.3
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.	6.1.1
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.	6.1.1
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.	4.3.2
11.4	The use of standardised designs.	4.3.2
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.	6.1.2
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.	6.1.2
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.	4.1; 4.2
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.	6.1.4, 6.3
11.8.1	The AMP must explain the load forecasting methodology and indicate all the factors used in preparing the load estimates.	6.1.4
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.	6.1.4–6.3
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.	6.3

Reference	Requirement	Ref
Distributed Generation		
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.	6.1.3
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:	6.3
11.9.1	The reasons for choosing a selected option for projects where decisions have been made.	6.1
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.	6.3–6.4
11.9.3	The consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	5.5.2
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-	6.3–6.4
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.	6.3–6.4
11.10.2	A summary description of the programmes and projects planned for the following four years (where known).	6.3–6.4
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period.	6.3–6.4
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.	6.1.3; 7.1
Non-network solutions		
11.12	A description of the EDB's policies on non-network solutions, including-	6.1.1; 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.	6.1.1; 7.1
11.12.2	The potential for non-network solutions to address network problems or constraints.	4.1.2; 7.1
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-	8
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.	4.1.1; 8; Appendix B

Reference	Requirement	Ref
Risk Management		
12.3.2	A description of innovations made that have deferred asset replacement.	4.1.1; 8; Appendix B
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—	
13.1	A description of non-network assets.	2.9; 7.2
13.2	Development, maintenance and renewal policies that cover them.	7.3
13.3	A description of material capital expenditure projects (where known) planned for the next five years.	7.3
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	7.3
14	AMPs must provide details of risk policies, assessment, and mitigation, including:	
14.1	Methods, details and conclusions of risk analysis.	3.3
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.	3.3.5
14.3	A description of the policies to mitigate or manage the risks of events identified in subclause 14.2.	3.3.5
14.4	Details of emergency response and contingency plans.	3.3.5
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.	5.2.4; 5.3.4; 5.3.5; 5.4.4; 5.5.4; 7.1; 8.1
15.2	An evaluation and comparison of actual service level performance against targeted performance.	5.2.4; 5.3.4; 5.3.5; 5.4.4; 5.5.4;
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.	1.1.2; 3.4.4
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.	3.4.3; 5.2.4; 5.3.4; 5.3.5; 5.4.4; 5.5.4;
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 document
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	1.1.3



APPENDIX D: DIRECTOR CERTIFICATION

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pursuant to clause 2.9.1 of Section 2.9

We, Rob Campbell, and Carolyn Steele being Directors of WEL Networks Limited certify that, having made all reasonable enquiry, to the best of our knowledge -

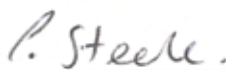
- a) the following attached information of WEL Networks Limited prepared for the purposes of clause 2.6.1 and 2.6.5(3) of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination; and
- b) the prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.



Director

21 December 2017

Date



Director

21 December 2017

Date



Best in Service
Best in Safety

CONTACT US

Freephone: 0800 800 935

Main Office: 07 850 3100

114 Maui St, Te Rapa, Hamilton 3200
PO Box 925, Hamilton 3240

wel.co.nz