POWERCO

Electricity Asset Management Plan 2019

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Introduction

This section introduces our 2019 electricity AMP and provides an overview of our network.

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1 EXECUTIVE SUMMARY

1.1 INTRODUCING OUR 2019 ASSET MANAGEMENT PLAN

This Asset Management Plan (AMP) outlines our approach to managing our electricity distribution assets during the period 1 April 2019 to 31 March 2029. It is an essential part of our long-term asset planning and investment framework.

Electricity is a key enabler for economic prosperity and a modern lifestyle. Our core business is to ensure that it is delivered to our customers safely, reliably and efficiently. As such, it is essential that we continue to invest in our assets to ensure they are in appropriate condition and of sufficient capacity to meet the needs of our customers in the long term.

We also recognise that society is facing an unprecedented challenge regarding a warming environment. Minimising carbon emissions is a key priority for New Zealand and, by implication, for our customers.

As a company, we are fully committed to helping New Zealand achieve its carbon reduction targets agreed to in terms of the Paris Accord (2015), and the Government's associated target of a 100% renewable energy supply by 2035.[1] We are committed to acting in an environmentally responsible manner in all our investment decisions and operational practices – as witnessed by our recent certification to the ISO 14001[2] standard and our high GRESB[3] score.

However, our impact on carbon reduction is insignificant compared with what we can help our customers, including generators, achieve – through our role enabling them to create, use and save energy as efficiently as possible.

The key to supporting New Zealand's carbon reduction targets will be running our network to open-access principles, offering maximum flexibility to customers with the opportunity to innovate, connect to, and transact over our network without impediment. While future energy market arrangements are still being developed, we will ensure that the network remains safe, operates stably and provides sufficient capacity under any reasonable energy use scenario.

Consistent with our previous AMPs, the 2019 edition sets out the investments to uphold our vision of being a reliable partner, delivering New Zealand's energy future. This AMP builds on the work we undertook in 2017 in preparing a Customised Price-Quality Path (CPP) application, and our subsequent efforts to fulfil our commitment to our customers to deliver our planned investments. In this AMP we also present our plans for the network after the CPP period – from 2024 onwards.

1 Under normal hydrological conditions.

2 ISO 14001 is an internationally accepted standard that provides the framework to put an effective environmental management system in place within an organisation.

1.2 REAFFIRMING OUR CPP COMMITMENT

1.2.1 OVERVIEW

In March 2018, the Commerce Commission made its final determination on our CPP application. Delivery of the investments approved under our five-year CPP plan kicked off on 1 April 2018, and is now well under way. The first four years covered under this AMP focus strongly on how we plan to deliver to our CPP targets during the remainder of the regulatory period.

Working within our regulatory price constraints, during the past decade we lifted investment by almost 60% in response to the ageing of our asset fleets and economic growth in our communities. However, even at this increased level, which exceeded our regulatory allowance, there was mounting pressure for a further step change.

Sitting at the heart of our CPP application was the analysis that indicated the significant challenges we had to address in the future. These included increases in the number of assets that were approaching end-of-life, ongoing growth in the communities we serve, and increased complexity associated with ensuring stable network operation in an evolving energy environment. Therefore, it became necessary to seek permission from the Commerce Commission to raise prices to fund much needed upgrades.

1.2.2 FINAL CPP DETERMINATION

Under our CPP allowance, the Commerce Commission approved expenditure of \$1.27 billion[4] during the five-year period – an increase of 38% on the previous five years. This translates to an initial increase of distribution prices of 4.5%. This decision has allowed us to commit to the investments we outlined in our CPP application and further described in this AMP.

The CPP determination also included a change to our quality standards from those in the Default Price-quality Path (DPP). We now have separate quality paths for unplanned and planned System Average Interruption Duration Index (SAIDI)/ System Average Interruption Frequency Index (SAIFI). Our unplanned quality path also includes a decreasing target over time, aiming for an improvement on historical performance.

3 GRESB is an independent environmental, social and governance benchmark for real assets, defining the global standard for sustainability performance in real assets to assess the sustainability performance of real estate and infrastructure portfolios and assets worldwide.

4 Real 2016 dollars

1.2.3 CPP COMMITMENTS

Our key commitments for the future of our electricity network, supported by the CPP allowances, are summarised below.

Ensuring safe and resilient networks

We remain committed to stabilising the underlying condition and performance of our asset fleets. Our asset renewal, maintenance and vegetation investment is intended to arrest the trends we are seeing:

- In-service asset failures increasing over time for key asset fleets.
- Increasing numbers of end-of-life, under-performing assets remaining in service.
- A poor, and deteriorating, reliability position versus our peers.
- Pockets of network performance well outside reasonably acceptable limits.
- Increasing levels of defective assets and vegetation encroachment.

We set out our plans to deliver safe and resilient networks in Chapters 14 to 21, and 23, of this AMP.

Supporting growth in our communities

Our regions have been experiencing sustained population and economic growth in recent years and, as a result, we have experienced strong demand growth across parts of our networks. Some of the drivers for this growth include the following:

- Bay of Plenty – population growth and horticulture processing volumes.
- Waikato – continued dairy intensification and a shift to snap chilling.
- Taranaki – population growth and dairy intensification.
- Other regions – population growth and changing land-use patterns.

Because of this growth, there are now many locations where we have no practical way of rerouting supply in the event of a key asset failing. The risk and associated cost of a failure has become unacceptably high for our customers. Focused action is necessary, as the number of such scenarios on our networks is unacceptable.

We set out our plans to support growth in our communities in Chapter 11.

Enabling our customers' energy choices

New technology offerings and increasing customer eagerness to take control of their energy options – and thereby reducing their own carbon footprint – are leading to a change in the way energy markets operate. Distribution utilities play a key role in facilitating these changes, while ensuring that basic delivery standards continue to be met.

We believe we will see increased application of the new technology over time, as prices reduce, suitable applications emerge in New Zealand, and the new technology becomes better understood by our customers. At present, the most promising emerging technologies include:

- Electric vehicles (EV)
- Photovoltaic cells (PV)
- Home and network scale energy storage solutions
- Advanced energy and demand management solutions
- The advent of community-based energy trading schemes

Such new solutions will bring benefits to our customers, but they will also increase complexity for distribution network operators. Issues such as local voltage fluctuations, two-way energy flows and increased load volatility will need to be anticipated and addressed. It is important we act now to understand these new technologies and ensure we can accommodate them efficiently on our networks.

We set out our plans to enable our customers' energy choices in Chapter 13.

1.3 PREPARING FOR CPP DELIVERY

1.3.1 OVERVIEW

Delivering our CPP commitments is a large challenge. Not only do we face a much-increased volume of network investment and maintenance work, we have also committed to material improvements in our asset management capability. Since the start of the CPP period, our focus has been on meeting these challenges.

The following sections discuss in further detail what we have been doing on the CPP delivery so far.

1.3.2 INCREASING OUR CAPACITY TO DELIVER

To deliver our network investment programmes, we have:

- Re-organised our Asset Management and Service Delivery teams to ensure we are best structured to plan and deliver our work.
- Increased the capacity of our teams, particularly planners, designers and project managers.
- Established new supporting functions, such as programme management, asset analytics and investment optimisation.
- Increased the number of major service providers we use for network services, and work with them to increase their resources to deliver the higher work volumes.
- Finished the construction of a new Network Operations Centre (NOC), designed to meet the demands of an expanding network, substantially increased construction and maintenance volumes, and growing network complexity.

We are also improving our end-to-end delivery approach. This includes the way we coordinate and communicate the impact of planned customer outages to our customers, as well as managing workflow to allow our service providers to plan and deliver works at the lowest cost.

The improvements we have made in these areas are detailed in Chapter 7.

1.3.3 MONITORING OUR DELIVERY

As part of its CPP approval, the Commerce Commission has instituted additional delivery and asset management reporting requirements in the form of the Annual Delivery Report (ADR). Our first ADR is due in early September 2019, but we are tracking and managing our progress against the requirement measures on an ongoing basis. This is reported at all levels, right up to our Board. The ADR is broken up into four general areas:

- What we are delivering – reporting against our delivery targets, such as pole replacement, inspections, vegetation, defects and major projects.
- How our network is performing – reporting against our SAIDI/SAIFI targets, as well as worst served customer and complaints information.
- Where we are investing – reporting against financial forecasts submitted in our CPP.
- How we are changing – progress updates against our agreed improvement areas, such as New Foundations (SAP implementation), ISO 55001 certification, improvements to our works processes, and getting on top of data quality issues.

As all these areas are important, we must juggle the competing priorities of meeting these targets. The increased management reporting of our CPP delivery is one of the ways in which we achieve this.

1.4 IMPROVING ASSET MANAGEMENT CAPABILITY

1.4.1 OVERVIEW

Our operating costs and network performance compare well against the best utilities in New Zealand and Australia, but we recognise there is more to be done.

Effectively meeting the challenges of an ageing network, unacceptable security of supply exposures, and increasing energy market complexity necessitate an even more mature asset management approach.

We are committed to further developing our overall asset management capability to meet internationally accepted best practice. We have set ourselves ambitious goals in this regard.

We set out our asset management processes, including recent enhancements, in Chapters 5 to 10. Key highlights are discussed below.

1.4.2 ISO 55001

We are committed to obtaining certification to the ISO 55001 asset management standard by 2020. AMCL Ltd recently conducted a gap assessment on our asset management approach against ISO 55001 and the Global Forum on Maintenance & Asset Management (GFMAM) standards.

While we are assessed as ‘competent’ or ‘close to competent’ in most areas, there are some areas where we are still classed as ‘developing’. We are in the process of preparing an action plan to address the gaps identified. These are outlined in Chapter 10.

1.4.3 DATA QUALITY

We are committed to improving and expanding our asset data to support ongoing decision-making and asset management improvements. This will require increased standardisation, expanded inspections, improved information processing, and better auditing processes.

We are expanding the level of auditing we undertake in the field, as well as applying analytical tools to highlight potential deficiencies in data quality. We intend to work towards ‘one source of truth’ across our business and our service providers, with clear data ownership and responsibility allocations.

Our approach to data quality is described in Chapter 10.

1.4.4 NEW FOUNDATIONS

New Foundations is a programme of improvements to our core enterprise systems, as we move to an SAP environment. This is a key initiative that will enable us to have the right repositories and systems to transform asset data into insightful information. Our new enterprise resource planning system will support our ability to efficiently collect, store and analyse asset and network data when commissioned at the start of FY20.

It is a vital component of our asset management capability enhancements and will have a significant impact on our ability to deliver our CPP commitments.

The first phase of this programme is almost complete, which involves replacing our JDE financial system with SAP. During FY20 we will commence phase two of New Foundations, which will include a new asset investment planning and optimisation system.

1.4.5 CONDITION-BASED RISK MANAGEMENT

We have developed Condition-Based Risk Management (CBRM) models for many of our key fleets. It has allowed us to develop improved asset renewal forecasts based on the assessment of asset condition and risk.

We have developed CBRM models for power transformer, circuit breaker, ring main unit and ground-mounted distribution transformer fleets, and are considering expanding our modelling to include underground distribution cables.

CBRM modelling has also highlighted our need to improve asset data and is helping inform our data quality improvement plans.

1.5 LOOKING BEYOND THE CPP PERIOD

1.5.1 BUSINESS AS USUAL

Electricity distribution networks are built to serve customers' long-term interests. While there is much deliberation about changes in the energy environment, a large majority of our customers continue to use centrally generated electricity as their key energy source. We do not predict this changing significantly in the foreseeable future. Therefore, it would be imprudent to materially adjust investment and asset management plans now for an uncertain future.

Accordingly, we will continue to keep a strong focus on the health, capacity and operation of our existing network, as well as expand the network to meet the increased demand of new – and often existing – customers.

In terms of this AMP, it means that investment on asset renewal, maintenance and growth of conventional network assets will also remain paramount in the latter phase of the planning period.

As recognised in our CPP application, a large proportion of our assets are reaching end-of-life – a situation we are starting to address under the CPP programme. This trend will continue beyond the CPP programme, and it is foreseen that renewal expenditure will have to remain at current (CPP) levels in order to ensure stable health and reliability of our network, at least in the medium term. This is reflected in the last six years of the AMP.

Similarly, forecasts are for continued population and demand growth on large parts of our network. We will continue to expand and reinforce the network to cater for the needs of these new customers – this is also reflected in the last six years of the AMP.

While we will continue to seek out the most efficient means of limiting expenditure on asset renewal and reinforcement, including applying innovative new solutions wherever practical, we expect most of our network expenditure will remain on conventional electricity network assets and practices.

1.5.2 CATERING FOR THE CHANGING ENERGY ENVIRONMENT

While noting our expectation that most network expenditure for the latter part of the AMP planning period will remain focused on traditional network investments and practices, we do not underestimate the potential impact of changes to the energy environment.

An important emerging energy industry theme is the so-called 3Ds – decarbonisation, digitisation and decentralisation. These present significant challenges and uncertainties for our industry. Our evolving approach to understanding and addressing this theme is outlined in our network evolution roadmap in Chapter 13.

Particularly important within this AMP planning period, especially towards the latter years, is our contribution to decarbonisation. We are committed to operating in an environmentally sustainable way and minimising our own carbon footprint.

However, as our own energy use is relatively low, and we generate very little electricity, we believe we can make a much bigger contribution to our society's decarbonisation efforts through effectively planning and operating the electricity distribution network in an open-access arrangement. Assisting customers and energy providers to easily conduct energy transactions over our network would encourage distributed and renewable generation.

Additionally, effective demand management, energy storage and tariff incentives will help maximise the utilisation of existing energy infrastructure and defer or minimise future investment. Electricity should also offset other, less environmentally friendly, forms of energy, and the network should facilitate this, for example electric vehicles offsetting the demand for petroleum.

Realising these benefits requires us to operate the network in an open-access manner, with minimal impediments for customers to connect devices or transact on the network. Intense debates about the nature of such open-access networks are under way around the world.

While New Zealand is still some way behind, we are closely following developments particularly in Australia and the United Kingdom. We are committed to working towards providing a completely open-access network, which we see as an essential enabler for any likely future distribution system operator (DSO), or similar arrangement.

Transitioning to an open-access network will require considerable effort and investment, particularly in providing the required visibility, controllability, flexibility and stability of all parts of the network. Given the relatively low uptake of emerging grid edge technology in New Zealand, and the immaturity of the local discussion on future market arrangements, we expect this transition to happen beyond our CPP period.

However, it is important to recognise that New Zealand will not be isolated from changing customer energy consumption patterns and associated emerging market arrangements, and nor would we want to be, as these changes will reflect one of the most effective means we have to achieve our Paris Accord commitments and the Government's low carbon target.

Therefore, we see the near-term future as the ideal time to analyse, test and prepare for the expected future changes to the energy environment. Further out in the AMP period we see the need to start significant investment to achieve the basics of the required open-access network. This will initially focus on additional monitoring and limited automation on our network, particularly on the Low Voltage (LV) side.

This investment in network monitoring is discussed further in Chapters 11and 13.

Why an open-access network?
Our customers are increasingly concerned about the impact of their energy use on the environment. They are interested in how their electricity is generated and how they can use it most efficiently. This local interest is reflected at a national level, with one of the Government's key commitments being a goal of a carbon-neutral electricity supply.

In a fortunate convergence of improving technology and cost-efficiency, our customers have:

- more choice and the power to exercise their values.
- an increasing ability to achieve significant reductions in their energy use footprint.

A key contributor is the ability to cost effectively generate on-premise electricity, through renewable methods such as solar panels or small wind generators.

This not only reduces electricity taken from the grid, but also holds potential for exporting excess capacity to other nearby customers, or allowing customers without their own generation to buy renewably created electricity from local suppliers and communities.

Other key factors are efficiency improvements in energy-hungry devices, and the ability to switch to renewable energy sources, particularly related to transport and heating.

The limits of today's networks
The design of traditional electricity networks, however, limits the extent to which renewable generation, or large variable loads, can be accommodated.

Networks were designed for one-way power flows from large generators to end customers, who used mainly passive appliances. Connecting significant volumes of distributed generation, or large, rapidly varying loads to a network not designed for it, can at times cause serious power quality and network instability issues.

Without substantially changing the nature of distribution networks and how they operate, the only mitigation options for electricity distribution businesses (EDB) are to make major reinforcements to the network or constrain customers in what they can connect and how they can use the network.

Limiting choice is bad for customers.

Conventional network reinforcement is an expensive and, generally, inefficient solution to short-term power fluctuations. Constraining customers in what or how much they can connect to the network will greatly inhibit their ability to manage their use and reduce their electricity carbon footprint – thereby foregoing one of the more important levers New Zealand has to achieve its overall environmental targets.

Networks of tomorrow
In our view, the best way to achieve customers' goals is by operating an open-access distribution network. This will be achieved by:

- applying suitable developing technology.
- much improved visibility of power flows and utilisation.
- increased network automation.
- improved data and analytics.

Essentially this future network would allow customers to be largely unconstrained in what they can connect to the network and how they would use it to support their energy transactions – purchasing and exporting electricity.

Our role will be to ensure that networks have the capacity to cope with our customers' evolving energy needs, while remaining safe, stable and efficient.

1.6 10-YEAR EXPENDITURE FORECASTS

1.6.1 OVERVIEW

We forecast our investment during the planning period to remain at current levels, approximately $278 million per annum. The investments we propose will enable us to address asset condition and security related issues. It will also help ensure we continue to meet our customers' service expectations and support the growth of the communities we serve.

1.6.2 CAPITAL EXPENDITURE

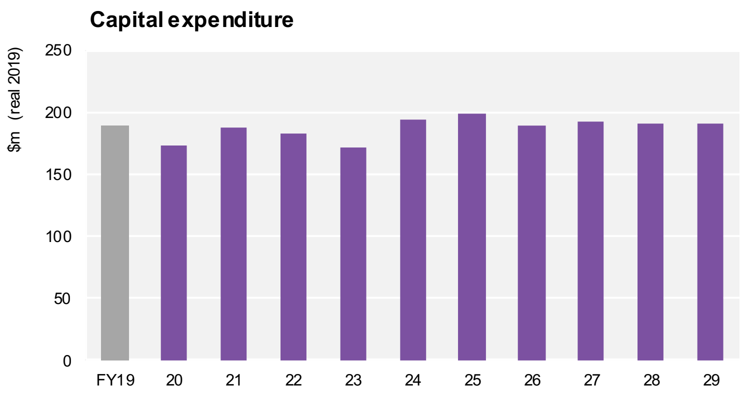
Our planned capital investments for the 2019-2029 period are set out in detail in Chapters 11 to 22. They reflect a targeted blend of investment across growth and security, asset renewal and non-network categories. Key highlights include the following:

- Sustained investment in asset renewals – post CPP expenditure is expected to stay at current CPP levels. We forecast a constant level of expenditure is required to manage the health of our overhead fleets.
- Sustained investment in growth and security – network growth investment is forecast to remain consistent with CPP levels. During the CPP our expenditure

predominantly focused on improving breaches in security of supply. Post CPP expenditure focuses more on improving voltage support on the network. We will also be investing in LV visibility improvements as we shift to an open-access network.

- Reduction of investment in core systems and network technology – we forecast a reduction in IT investment as we complete implementation of a new ERP system early in the CPP period, and as our core systems shift to the cloud. We will continue current levels of investment in our network evolution plan to allow for testing of new and innovative network and non-network solutions.

Expenditure during the CPP period of the planning window is largely consistent with our CPP allowance – limited increases are foreseen resulting from increasing customer connection activity, and potential increase in the volumes of Transpower-initiated outdoor-to-indoor switchgear conversion works. Our expected capital investment during the planning period is set out below.

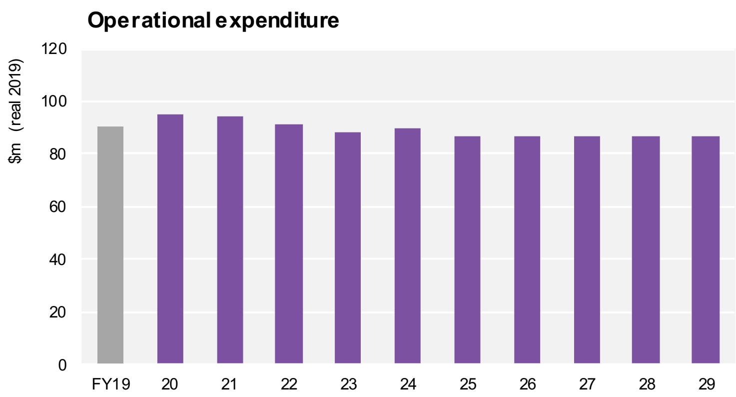


1.6.3 OPERATIONAL EXPENDITURE

Our updated operational expenditure is in line with our previous CPP forecasts. The focus for operational expenditure during the planning period is set out in detail in Chapter 23. Key highlights include the following:

- Addressing maintenance defects – the backlog of outstanding maintenance defects had previously been growing at an accelerating rate. We have arrested this increase and are now reducing the size of the pool to appropriate levels during the CPP period.
- Improved inspection techniques – we have commenced our pole-top photography and LiDAR trials for improved asset condition and vegetation inspection. We are also continuing to implement new techniques to better understand actual asset condition and network risks. Data and information management practices will also be enhanced with our ERP implementation.
- Asset management maturity – we are proposing substantial improvements in the way we practise asset management to reflect industry good practice and to realise improved efficiencies in the future. To achieve this, we are bolstering our internal capabilities and skills. As part of our asset management improvements we intend to achieve ISO 55001 certification by the end of 2020.
- Enhanced capacity – our project delivery capacity is being increased in proportion to the uplift in construction and maintenance work proposed under the CPP. While mostly capitalised, some additional Opex is required. Allowance is made for additional business support staff to assist with the increased business complexity and demands anticipated with enhanced IS systems and increased work volumes.

Our expected operational expenditure during the planning period is set out below.



2 INTRODUCTION

2.1 CHAPTER OVERVIEW

This chapter provides the context for our 2019 AMP. It outlines its purpose and objectives, who it is written for and how it is structured.

2.2 PURPOSE OF THE 2019 AMP

We recognise that the investment decisions we make impact homes and businesses around New Zealand, now and in the future. Therefore, it is important these decisions are transparent and understandable to our customers and other stakeholders.

Our 2019 AMP describes our long-term strategy for managing our electricity assets. It describes our asset management processes and explains how these will help achieve our asset management objectives and meet stakeholder expectations in the coming years. It also sets out our planned investments during the next 10 years, explaining how we will develop our network, renew our asset fleets and undertake maintenance to provide a safe, reliable and valued service to customers.

The 2019 edition of our AMP builds on the work of our 2017 AMP, which documented the work central to our Customised Price-quality Path (CPP) application. The 2019 AMP outlines our subsequent efforts to fulfil the network investment and capability commitments made in the CPP application as we move into the CPP delivery phase. The AMP also describes our plans for the network after the CPP period (2024 onwards). We discuss:

- Our view on the future architecture, function and operation of the network
- Operational and investment needs we foresee after the CPP period to maintain a reliable and safe network
- The likely future needs of our customers and how we intend to evolve to meet these needs
- The challenges and opportunities new technology could bring for electricity networks

2.2.1 AMP OBJECTIVES

The objectives of our 2019 AMP are to:

- Be transparent with our stakeholders to help them understand our asset management approach by providing clear descriptions of our assets, key strategies and planned investments.
- Advise interested parties about potential opportunities to offer alternatives to our proposed investments. We are committed to considering such collaborations where these are practical, will provide the required network support, and are economically viable for our customers.
- Discuss how we will respond to changes in the electricity distribution environment.
- Explain our asset management objectives and targets, and how we plan to achieve them.
- Set out our recent asset management performance and improvements.
- Explain how our asset management plans relate to our corporate mission and vision, our business planning processes, and support our corporate objectives.

2.2.2 AMP PLANNING PERIOD

Our AMP covers a 10-year planning period, from 1 April 2019 to 31 March 2029. Consistent with Information Disclosure requirements, a greater level of detail is provided for the first five years of this period.

This AMP was certified and approved by our Board of Directors on 14 March 2019.

2.3 OVERVIEW OF POWERCO

We operate and maintain the largest network of electricity lines in New Zealand over the largest area of the country, serving about 335,000 connected customers. We are the second largest distributor in New Zealand in terms of the number of customer connections.

We have more than 27,000km of cables and overhead lines that supply customers in Tauranga, Thames Valley, Coromandel, Eastern and Southern Waikato, Taranaki, Whanganui, Rangitikei, Manawatu and Wairarapa.

We are a privately owned utility with two institutional shareholders.[5]

5 Queensland Investment Corporation (58%) and AMP Capital (42%).

2.4 OUR STAKEHOLDERS

As set out above, the main objective of our AMP is to provide information for our stakeholders about how we are managing our assets, and where we intend to invest for future network growth and for maintaining the good health of assets. We explain how our plans and decisions arise and are implemented. We aim to make it a document our stakeholders can readily follow and digest. Our key stakeholders and their principal interests are summarised below.

Table 2.1: Key stakeholders and their main interests

STAKEHOLDER	MAIN INTERESTS
Our customers	Service quality and reliability, price, safety, connection agreements, flexibility, ability to innovate in their energy arrangements and use
Communities, iwi, landowners	Public safety, environment, land access and respect for traditional lands
Retailers	Business processes, price, customer service, reliability
Commerce Commission	Pricing levels, effective governance, quality standards, appropriate expenditure, effective asset management
State bodies and regulators	Safety (WorkSafe), market operation and access (Electricity Authority), environmental performance (Ministry for the Environment)
Employees and contractors	Safe and productive work environment, remuneration, training and development, asset management documentation
Transpower	Technical performance, technical compliance, GXP planning
Our investors	Efficient management, financial performance, governance, risk management
External energy service providers	Business opportunities, effective network access, ability to transact over the network

Further detail on how we meet stakeholders' interests, including how they are identified and accommodated in our processes, can be found in Appendix 3.

2.5 STRUCTURE OF THE AMP

The diagram below sets out the structure of the AMP, including the sections (grey boxes) and the chapters within these. Appendix 14 maps the chapters and appendices to relevant Information Disclosure requirements.

AMP section *AMP chapter*

INTRODUCTION
This section introduces our 2019 electricity AMP and provides an overview of our network.

1 **Executive Summary** Provides context to stakeholders on key factors that influence our investments over the planning period.

2 **Introduction** Explains the purpose of the AMP and provides an overview of our business, our main stakeholders, and the structure of the AMP.

3 **Network Overview** Describes our electricity network and its assets.

SERVING OUR CUSTOMERS
This section explains how we plan to meet our customers' needs, now and in the future.

4 **Customer Strategy** Provides an overview of our customers, what they value, and our strategy to ensure we continue to meet their evolving needs.

MANAGING OUR ASSETS
This section sets out our asset management strategy and network targets, explains our approach to investment decision-making, and describes how we are preparing for an increase in investment during the planning period.

5 **Asset Management Strategy** Explains our asset management philosophy, and the line of sight from our overall company objectives through to our day-to-day activities.

6 **Governance** Explains our approach to asset management decision-making including expenditure governance, investment planning, AMP Development and risk management.

7 **Capital Project Planning and Delivery** Explains our approach to capital project development, planning and delivery, for network growth renewals, defects and non-network projects.

8 **Operations & Maintenance Planning and Delivery** Explains our approach to operations and maintenance planning and delivery.

9 **Network Targets** Outlines our targets for safety, reliability, asset performance and customer service.

10 **Enhancing Delivery Capability** Describes how we are going to deliver the plan and improve our asset management practices.

NETWORK DEVELOPMENT
This section explains how we plan to develop our network, how we use automation to enhance reliability, and how we will ensure the network's readiness for the future.

11 **Growth and Security** Outlines our approach to forecasting demand growth and how we invest to ensure supply security. It provides a summary of our area plans.

12 **Reliability** Explains what we are planning to invest in automation systems to enhance network reliability performance.

13 **Network Evolution** Sets out our plans to develop our network in a way that will enable our customers to access new energy options as energy markets evolve and mature.

FLEET MANAGEMENT
This section explains our approach to managing our network and non-network assets.

14 **Fleet Management – Introduction** Introduces the contents of the fleet management chapters.

15 **Overhead Structures**
16 **Overhead Conductors**
17 **Cables**
18 **Zone Substations**
19 **Distribution Transformers**
20 **Distribution Switchgear**
21 **Secondary Systems**

For each portfolio, we describe:

- High level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition and risks
- Routine maintenance tasks
- Renewal strategies
- Renewal forecasting approaches

22 **Non-network Assets** Sets out the road map for our non-network assets, and how this will meet the future requirements of our customers and the wider business.

23 **Network Opex** Describes our maintenance activities for the period.

CUSTOMER WORKS
This section summarises our approach to consumer connection and asset relocation projects.

24 **Consumer Connections** Explains how we connect new customers to our network.

25 **Asset Relocations** Discusses how we facilitate asset relocations for third parties.

EXPENDITURE FORECASTS
Provides an overview of our Capex and Opex forecasts for the planning period.

26 **Expenditure Forecasts** Provides an overview of Opex and Capex forecasts for the planning period. It explains our inputs and assumptions, and our cost estimation approach.

3 NETWORK OVERVIEW

3.1 CHAPTER OVERVIEW

Our network covers two large, separate regions of the North Island. This chapter provides an overview of the zones, network configurations and assets in these regions.

Chapter 11 provides detailed information on the 13 associated planning areas.

A summary list of our assets is included at the end of this chapter, with more detailed descriptions provided in Chapters 15-21.

3.2 OUR NETWORK

Our network supplies electricity to about 335,000 customer connections across two coastal regions of the North Island. In terms of both supply area and network length, our network is the largest of any single distributor in New Zealand.

3.2.1 NETWORK CONFIGURATION

The operation of the electricity network is comparable to roading. Road capacity ranges from high-volume national highways to small access roads. In a similar way, an electricity network uses high voltages to move large amounts of power over longer distances to service a zone or area. As electricity is distributed to less populated areas, the size and voltage of network assets reduce.

We have lines and cables operating in three distinct voltage ranges:

- **Subtransmission** – mostly 33 kilovolt (kV) but also 66kV and 110kV
- **Distribution** – mostly 11kV but also 6.6kV and 22kV
- **Low Voltage (LV)** – 230V single phase or 400V three-phase

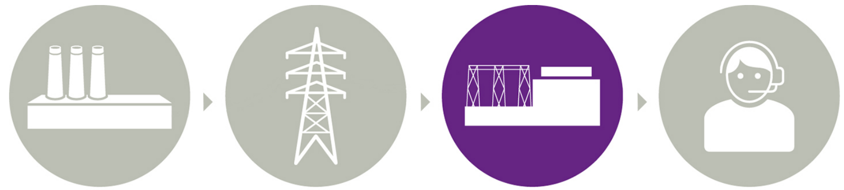
Changing electricity from one voltage to another requires the electricity to flow through a transformer.

For electricity flowing from a subtransmission circuit to a distribution circuit, it passes through a transformer housed in a zone substation. When electrical flow is from a distribution circuit into the LV network, a smaller ground or pole-mounted distribution transformer is used.

3.2.2 TRANSMISSION POINTS OF SUPPLY

Our place in New Zealand's electricity sector is illustrated in Figure 3.1.

Figure 3.1: Our place in the electricity sector



GENERATION	TRANSMISSION (national grid)	DISTRIBUTION	RETAIL
Electricity is generated across New Zealand using water (hydro), wind, geothermal, gas and coal stations.[6]	This electricity is transported from generators to distribution networks using the national grid, owned and operated by Transpower.	Electricity is distributed to homes and businesses via distribution networks. Powerco is one of 29 distribution companies.	Retailers buy electricity from generators and sell it to homes and businesses.

Our network connects to the national grid at voltages of 110kV, 66kV, 33kV and 11kV via 30 points of supply or grid exit points (GXPs). These GXPs are where our network and Transpower meet and interact. The national grid carries electricity from generators throughout New Zealand to distribution networks and large directly connected customers.

GXP assets are mostly owned by Transpower, although we do own transformers, circuit breakers, and protection and control equipment at some sites.

GXPs are the key upstream connection points supplying local communities. Large numbers of consumers can lose supply because of a GXP failure or outage Therefore, along with Transpower, we build appropriate amounts of redundancy into the GXPs by duplicating incoming lines, transformers, and switchgear.

Detail on the GXPs in each zone and associated network maps can be found in Chapter 11.

3.2.3 REGIONAL NETWORKS

Our network includes two separate regions, referred to as our Eastern and Western regions. Both networks contain a range of urban and rural areas, although both are

6 Distributed generation is a growing trend but still only a very small proportion of total generation.

predominantly rural. Geographic, population and load characteristics vary significantly across our supply area.

Our development as a utility included a number of mergers and acquisitions that have led to a wide range of legacy asset types and architecture. This requires an asset management approach that accounts for these differences, while seeking to standardise network equipment over time.

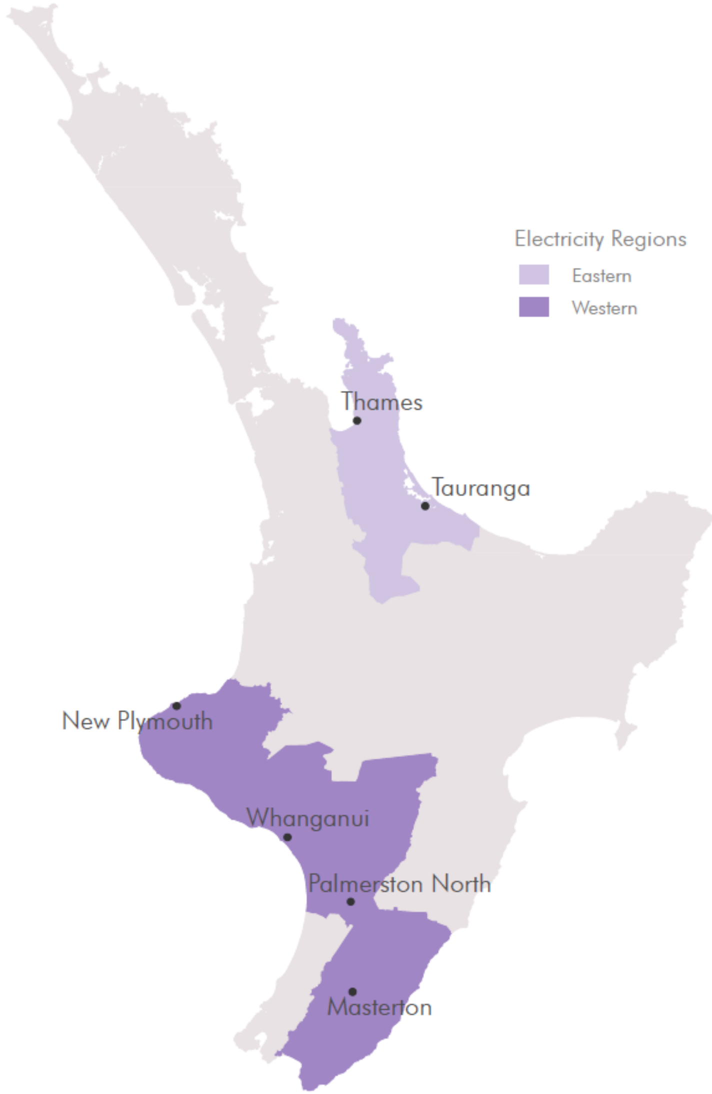
Table 3.1 provides summary statistics relating to our assets in the Eastern and Western regions.

Figure 3.2 provides a geographical overlay of these regions.

Table 3.1: Key regional statistics (2018)

MEASURE	EASTERN	WESTERN	COMBINED
Customer connections	159,680	179,134	338,814
Overhead circuit network length (km)	7,177	14,560	21,737
Underground circuit network length (km)	3,318	2,955	6,273
Zone substations	51	69	120
Peak demand (MW)	466	433	897
Energy throughput (GWh)	2,701	2,398	5,099

Figure 3.2: The regions we cover



3.3 EASTERN REGION

3.3.1 OVERVIEW

The Eastern region consists of two zones – Valley and Tauranga – which have differing geographical and economic characteristics presenting diverse asset management challenges.

Figure 3.3 shows the Eastern region and its planning areas.

For planning and pricing purposes we divide this region into two zones:

- **Valley** includes a diverse range of terrains from the rugged and steep forested coastal peninsula of Coromandel to the plains and rolling country of eastern and southern Waikato. Economic activity in these areas is dominated by tourism and farming respectively.

  From a planning perspective, this region presents significant challenges in terms of maintaining reliability on feeders supplying sparsely populated areas in what is often remote, difficult-to-access terrain.

  Investment priorities have focused on improving network security and resilience, and developing better remote control and monitoring facilities.

- **Tauranga** is a rapidly developing coastal region, with horticultural industries, a port and a large regional centre at Tauranga.

  The principal investment activities in this region have been associated with accommodating the rapid urban growth in Tauranga, maintaining safe and reliable supplies to the port, and supplying new businesses.

The Valley and Tauranga zones are discussed in more detail in the following sections.

Figure 3.3: Eastern network and planning areas

3.3.2 VALLEY ZONE

The Valley zone covers the eastern area of Waikato as far south as Kinleith, plus Waihi and the Coromandel Peninsula.

There are several small towns in the Valley zone and some industrial load. The Waikato region is a predominantly rural, dairy farming region. The Coromandel area consists of rugged, densely forested areas.

The Valley zone has four planning areas:

- Coromandel
- Waikino
- Waikato
- Kinleith

Below we provide further background on the Valley zone, including the characteristics that will drive improvement projects over the planning period.

Coromandel

The Coromandel planning area covers the Coromandel Peninsula and upper Hauraki Plains. All six zone substations in the area are supplied from Kopu GXP. Whitianga and Thames are the largest substations in the area and directly serve the towns of the same name. Other substations are located at smaller towns and settlements serving rural customers.

Subtransmission is dominated by a long 66kV ring serving the Coromandel Peninsula. A smaller interconnected ring serves Thames, with radial lines branching out to other substations.

In the past five years, we have undertaken a number of large projects to improve capacity and security of supply, especially on the long circuits up to Whitianga. Despite this, a number of security of supply issues remain to be addressed.

Developing a more secure supply to the Coromandel

The Coromandel planning area includes rugged hilly terrain covered in native bush. The dense vegetation makes it difficult to access some lines and complete repairs, with helicopters frequently being required. In addition, there are some environmental concerns associated with building new electricity lines across areas of significant natural beauty on the peninsula.

The key driver of the region's economy is tourism, particularly seasonal holidaymakers. There is also some primary agriculture and forestry. Although the permanent population is small, it increases significantly during holiday periods. In some popular resort towns, such as Tairua and Whitianga, there can be a six-fold population increase during these periods. The transient nature of electricity demand poses some challenging technical and economic questions.

We have lifted investment in this area significantly in the past decade and several further upgrades are scheduled during this planning period. Our long-term plan to improve security in the area may include upgrading the main Whitianga line to 110kV.

Waikino

Our network in the Waikino area utilises a 33kV subtransmission system connected to Waikino GXP. Twin circuits serve both Paeroa and Waihi substations, with single radial lines to Whangamata and to Waihi Beach.

The 33kV line to Whangamata is long and the only alternative supply is a limited 11kV circuit sharing some of the same poles. Whangamata has been growing and experiences a large influx of people during holiday periods. Therefore, the security of supply to Whangamata is a key focus of our planning.

The subtransmission network supplying the Waihi region suffers from post-contingent voltage constraints and the problem can worsen with load growth in the area. This impacts on the quality of supply to our customers, so we are also looking at solutions to address this.

Waikato

The Waikato area is quite extensive, reaching from Tahuna in the north to Putaruru in the south. The largely flat to rolling country is used for intensive dairy production. The area is supported by primary industries and urban centres, including Morrinsville, Te Aroha, Waharoa, Matamata, Tirau and Putaruru.

Three GXPs serve this area. In the northern part, Waihou and Piako GXPs connect to nine substations around the Morrinsville-Piako district.

The larger substations at Mikkelsen Rd, Morrinsville, Piako, Waitoa and Waharoa serve the respective urban centres and industrial facilities in these locations. The remaining substations serve surrounding rural districts and two large industrial customers.

Hinuera GXP connects six substations in the southern part of the Waikato area to the grid via a largely radial network of 33kV overhead lines. Hinuera is a single circuit GXP. The security issues associated with this are driving major investments in the 33kV network and GXP works at Putaruru.

Kinleith

The Kinleith area takes its name from the GXP and the pulp and paper mill that dominates the economic activity. The mill's electricity network uses the bulk of the capacity at the Kinleith GXP. Its principal supply is via 11kV switchgear located at the GXP.

Tokoroa is the only substantial urban centre in the area. Our 33kV network from Tokoroa consists of a 33kV ring circuit connecting the two substations at Maraetai Rd and Baird Rd.

Oji Fibre Solutions – a key customer in the Kinleith area

A significant part of our network supplies electricity to the Oji Fibre Solutions pulp and paper mill at Kinleith, near Tokoroa. The network is highly interconnected, beginning at the cable terminations of Transpower's switchgear at the Kinleith GXP and ending at the LV terminals of the supply transformers. The system is mainly underground, comprising 29 11kV feeders and includes one 33kV circuit that supplies Midway and Lakeside substations.

Supply at 11kV is taken from Kinleith GXP for the Kinleith mill site. A cogeneration plant is connected to the Kinleith GXP.

3.3.3 TAURANGA ZONE

The Tauranga zone covers the western Bay of Plenty area from near Athenree to along the coast east of Te Puke, and further on to Pongakawa. This coastal region continues to see growing demand and development – both residential and commercial/industrial.

Tauranga is a major New Zealand city and has significant industrial load, including a major port. The remainder of the Bay of Plenty has predominantly dairy and horticultural industries, particularly kiwifruit and avocados.

The Tauranga zone has two planning areas:

- Tauranga
- Mt Maunganui

Below we provide further background on the Tauranga zone, including the characteristics that will drive improvement projects during the planning period.

Tauranga

The Tauranga planning area includes the parts of Tauranga city and northern rural areas supplied from the Tauranga and Kaitimako GXPs. Tauranga is a very large capacity GXP connecting all substations via a number of dual 33kV circuits with some interconnection, most significantly at Greerton switching station.

The main Tauranga urban substations supplied from Tauranga GXP are Hamilton St, Waihi Rd, Otumoetai, Bethlehem and Matua.

The substations distributed along the northern Tauranga coast are generally of smaller capacity serving the townships of Omokoroa and Katikati, along with agricultural loads, coolstores, rural and lifestyle properties.

Kaitimako GXP supplies the Welcome Bay substation as well as an additional substation recently commissioned at Pyes Pa to accommodate the new urban development.

Other substations may be required if growth within existing urban areas proves higher than expected or more new developments eventuate.

The subtransmission network in the Tauranga region also connects to generation from the Kaimai hydro scheme and embedded generation at a fertiliser factory.

Mt Maunganui

The Mt Maunganui planning area covers Mt Maunganui itself and urban development spreading down the coast. From a planning perspective, this is interconnected with the network at Te Puke, so we treat it as a single planning area.

Mt Maunganui GXP is a fully secure 75 mega volt amp (MVA) capacity grid connection. However, high load growth in the area and the rapid urban spread down the Papamoa coast will require additional grid offtake capacity in the future.

M Maunganui GXP supplies five substations, all designed for twin transformer, urban configuration. Matapihi, Triton and Omanu supply the Mt Maunganui area, while Te Maunga and Papamoa supply the Papamoa coastal strip.

Omanu and Te Maunga substations are relatively new, reflecting our past investment to meet increasing demand.

The existing 33kV network from Te Matai GXP serves Te Puke, Paengaroa and Pongakawa. A new Wairakei substation fed from Te Matai GXP has recently been commissioned, supporting increased demand from the Papamoa coastal strip and transferring load away from Mt Maunganui GXP.

The Papamoa substation will also transfer to the Te Matai GXP in early 2019 to further reduce impending load constraints on the Mt Maunganui GXP and the existing subtransmission circuits.

The area around Te Puke is steadily growing, with a mix of residential development, commercial and industrial. The strong industrial presence around the town and horticulture activities in the surrounding area help bolster the economy in the region. We have two substations – Te Puke and Atuaroa – supplying the load in this area.

The subtransmission network is vulnerable to post-contingent low voltages appearing across the region should a fault occur on the upstream Transpower transmission supply. This impacts on the quality of supply to our customers and the low voltage issue will worsen with load growth over time. Hence, we are developing solutions to resolve this constraint for the benefit of our customers.

3.4 WESTERN REGION

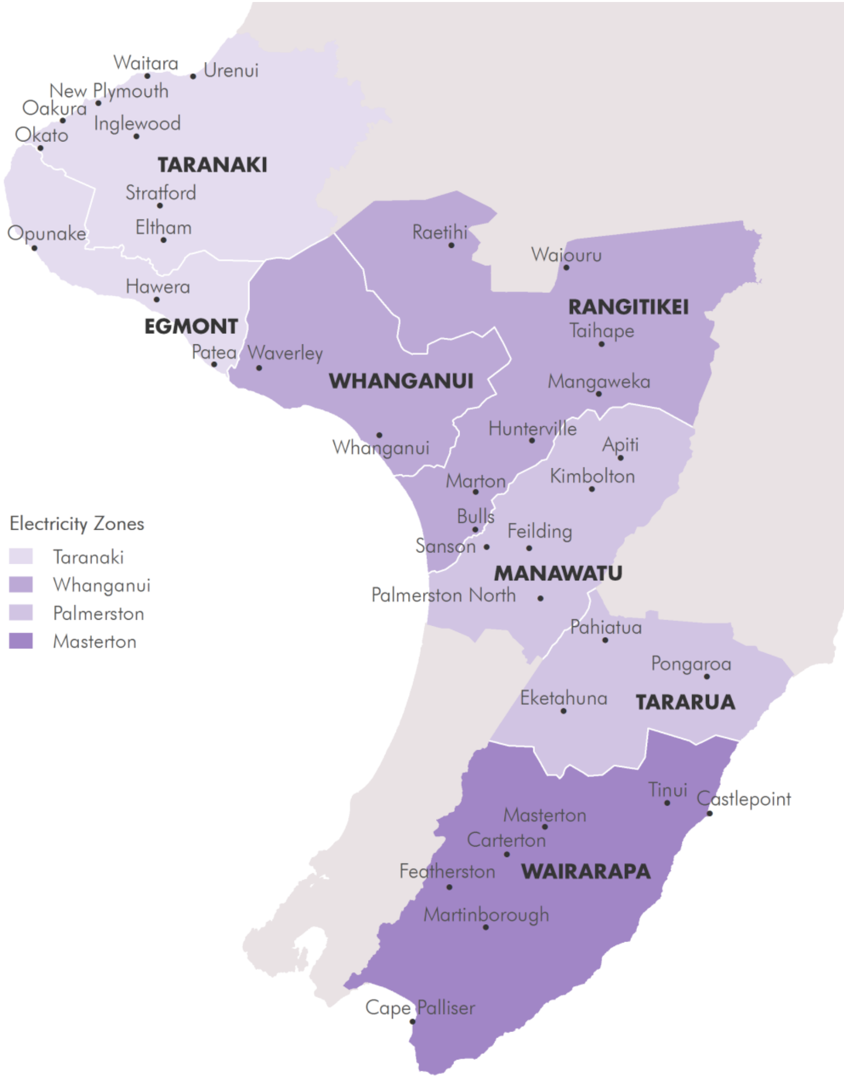
3.4.1 OVERVIEW

The Western region comprises the four network zones described below. Similar to the Eastern region, these zones have differing geographical and economic characteristics, presenting various asset management challenges. Because of the age of the network and, in particular, the declining asset health of overhead lines, extensive asset renewal is required in this region. This renewal is about double the cost compared with what is required in the Eastern region on an annual basis.

- **Taranaki**, which is situated on the west coast plains, is exposed to high winds and rain. The area has significant agricultural activity, oil and gas exploration and production, and some heavy industry.
- **Whanganui** includes the surrounding Rangitikei and is a rural area exposed to westerly sea winds on the coast and snow storms in high country areas. It is predominantly agriculture based with some industry.
- **Palmerston** includes rural plains and high country areas exposed to prevailing westerly winds. It is mainly agricultural with logistical industries, and has a university, with associated research facilities, in the large regional centre of Palmerston North.
- **Wairarapa** is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.

The map in Figure 3.4 shows the Western region network footprint and planning areas.

Figure 3.4: Western network and planning areas



3.4.2 TARANAKI ZONE

This zone comprises two planning areas – Taranaki and Egmont – where we supply the major urban areas of New Plymouth and Hawera. There are also large sites for oil and gas exploration, and intensive dairy farming.

Below is background on the two planning areas.

Taranaki

The Taranaki area covers the northern and central parts of the region, with Eltham and Okato defining the southern limits.

New Plymouth is the largest urban centre. Five urban substations serve the wider city and are supplied from three GXPs. The largest grid offtake at Carrington St supplies Katere substation, Brooklands substation and the City substation, which serves New Plymouth's CBD. All three of these substations have dual 33kV circuits and transformers. Moturoa substation is the only substation off New Plymouth GXP, located at the site of the original power station near the port. Work is under way to transfer Moturoa substation to Carrington St GXP as New Plymouth GXP is being decommissioned.

Bell Block substation is now fed from a dual overhead line from Huirangi GXP.

Huirangi GXP also supplies substations that serve Inglewood, Waitara, some major oil and gas sites, and the surrounding rural community. The 33kV subtransmission is overhead in a meshed configuration with one backfeed line linking through Inglewood to Stratford GXP.

Cloton Rd and Eltham are the only substations of significant size off the Stratford GXP. Five other substations serve rural districts.

Stratford's 33kV subtransmission is entirely overhead and is a highly meshed configuration, which leads to limitations in security because of protection issues.

Egmont

The Egmont area encompasses Hawera and to Warea on the coast. Hawera is the only commercial centre of significant size.

Hawera GXP is located just outside the urban limits and supplies our Cambria substation in Hawera via two dedicated 33kV oil-filled cables. Cambria has recently been upgraded.

In addition, Hawera GXP supplies Manaia and Kapuni substations off an overhead 33kV ring. Livingstone (Patea) and Mokoia substations are supplied from another ring. Mokoia substation has recently been constructed, allowing us to decommission the Whareroa substation located within the large Fonterra plant of the same name. The Patea hydro generation also injects into Hawera GXP.

Three coastal substations – Pungarehu, Tasman and Ngariki – are supplied from Opunake GXP via a meshed network of 33kV overhead lines. Loads and capacities are relatively small, although importantly this network supplies the Maui production station.

3.4.3 WHANGANUI ZONE

The Whanganui zone covers the area from Waiouru in the north to Bulls in the south. Whanganui and Marton have significant industrial load. The rural area has a predominantly mixed farming load.

The Whanganui zone has two planning areas:

- Whanganui
- Rangitikei

Below is background on these planning areas, including the characteristics that will drive improvement projects.

Whanganui

The Whanganui area encompasses Whanganui city, surrounding districts, and north to Waverley along the coast. Whanganui city is the only major commercial centre.

There are three GXPs in this area. Whanganui and Brunswick GXPs are high capacity and are located on either side of the city. Waverley GXP is a small grid offtake directly supplying the local 11kV distribution.

Nine substations are located in and around the city. Peat St is the largest and supplies part of the CBD. Peat St was recently upgraded with two large capacity transformers but, until the second 33kV line project is completed from Roberts Ave, it is supplied by a single high capacity 33kV overhead line from Brunswick GXP.

Hatricks Wharf and Taupo Quay substations are also important to our central city customers. These substations are fed by single 33kV lines from Whanganui GXP and have space for just a single transformer each. There is a high capacity 11kV tie between these substations allowing mutual support.

The remaining substations serving the urban area are Roberts Ave and Castlecliff, off Brunswick GXP, and Beach Rd and Whanganui East, off Whanganui GXP. These are medium-size substations fed by either single radial or interconnected radial 33kV overhead lines. Backfeeds often rely on transfer between GXPs, which limits operational flexibility.

Rangitikei

The Rangitikei area encompasses both the Rangitikei district, which stretches from the coast, through Bulls and Marton and inland to parts of upper Whanganui, and the Central Plateau. Although widespread with differing topography and climate, the area's network characteristics are common. It is sparsely populated with a predominantly rural load served by long and low capacity overhead lines.

Marton GXP is a relatively small GXP that supplies the four substations serving Bulls, Marton and surrounding districts. Mataroa and Ohakune GXPs supply the inland networks that have no connection between GXPs. Ohakune is a shared GXP and feeds the 11kV distribution directly.

The entire 33kV network from either Mataroa or Marton GXP is overhead. Subtransmission is almost entirely radial with dual circuits only to Taihape substation. Substations are all single transformer sites. There is generally a low level of demand growth in the area. Investment in the area is focused mostly on renewal and distribution backfeed upgrades.

3.4.4 PALMERSTON ZONE

The Palmerston zone comprises the two planning areas of Manawatu, which includes Palmerston North city, and Tararua.

Palmerston North is a large urban area that is a hub for many distribution centres, and the surrounding district has significant farming loads.

Below is background on the planning areas, including the characteristics that will drive improvement projects.

Manawatu

The Manawatu area is dominated by Palmerston North city and includes the rural network located on the surrounding plains between the Tararua Ranges and the coast that stretches between Foxton and the Rangitikei River. Feilding and Sanson are included, as is the inland country heading north towards Apiti.

Two high capacity GXPs serve the area with Bunnythorpe GXP located to the north of the city and Linton GXP to the south-east.

Subtransmission is entirely 33kV via high capacity circuits that are predominantly overhead. Use of underground cables is increasing. Multiple circuits, in a variety of configurations, supply the six substations in the city. There is a degree of interconnection between the GXPs at various points across the city but because of inherent operational limitations this is largely reserved for emergency backup purposes. Tararua Wind Farm also injects electricity into two locations on our 33kV network, adding complexity to both protection and operations.

Keith St substation is supplied by two 33kV circuits from Bunnythorpe. These circuits have been interconnected with a further circuit directly to Kelvin Grove substation. Main St substation, which is close to the CBD, is supplied by two 33kV circuits from Keith St substation. Pascal St substation, on the other side of the CBD, takes supply via two 33kV circuits from Linton GXP.

Outlying suburbs and rural areas close to Palmerston North are supplied from the Kelvin Grove, Milson, Kairanga and Turitea substations. All are supplied by at least two 33kV circuits from either Linton GXP or Bunnythorpe GXP.

Wind farm connections

An underground 33kV cable system links 97 wind turbines in the Te Rere Hau Wind Farm and connects them to the Tararua Wind Central Grid Injection Point (GIP). This comprises 28km of 33kV underground cable, 33kV/400V distribution transformers, an optical fibre network and a 33kV switching station.

Trustpower’s adjacent Tararua Wind Farm also injects part of its generation into the above GIP. However, stages one and two of this wind farm have capacity to inject up to 34MW into each of our 33kV networks supplied by Bunnythorpe GXP and Linton GXP. This embedding of generation seeks to maximise the economic benefits of locating generation close to load. It does, however, introduce operational and planning complexities that impact our 33kV networks and nearby substations.

The old Manawatu rural subtransmission network (ex-Manawatu Oroua Electricity Power Board) comprised of open 33kV rings feeding substations around the periphery of Palmerston North. Single 33kV radial feeders from Feilding supply Sanson and Kimbolton substations. Feilding substation is supplied by two high capacity circuits from Bunnythorpe GXP. The 33kV circuits are predominantly overhead on concrete poles and are close to their firm capacity limit.

Tararua

The Tararua area covers the upper Wairarapa, including Eketahuna and Pahiatua, and out to the coast beyond Pongaroa. Terrain is rugged, especially towards the coast, and load is relatively light and widely distributed.

Mangamaire GXP supplies all four substations in the area. Of these, Mangamutu is the largest and most significant and has been upgraded because of increased demand at Fonterra’s plant. Two overhead 33kV lines supply Mangamutu substation.

The remaining three substations are low capacity, rural class, with single transformer and minimal switchgear. All three are supplied from a 33kV overhead ring.

3.4.5 MASTERTON ZONE

This zone comprises a single planning area called Wairarapa, which covers the south Wairarapa from south of Eketahuna to Cape Palliser. The town of Masterton has significant industrial load. Overall the area has a predominantly dairy and sheep farming load, with significant orchard and vineyard activity.

Masterton zone is connected to the grid through Masterton and Greytown GXPs. While both subtransmission networks are 33kV there is no interconnection between them.

Four substations, Chapel, Akura, Norfolk, and Te Ore Ore, are located in or around Masterton township. These are supplied via an open meshed network of overhead lines. Chapel and Akura are the largest with highest security and, along with Norfolk, have two transformers.

Clareville substation, which serves Carterton and surrounds, is supplied via two 33kV overhead lines and has two transformers. The remaining three substations serve light loads in the remote rural areas with a single transformer and a single radial subtransmission line.

Further south, Greytown GXP supplies Greytown from Kempton substation, with a single 33kV overhead line and single transformer. A 33kV overhead subtransmission ring feeds Featherston and Martinborough, with radial tee-offs to two other small rural substations. One of these, Hau Nui, provides interconnection for the Hau Nui Wind Farm via a long radial 33kV line.

3.5 ASSET SUMMARY

This section provides an overview of the asset fleets that we own and operate, including the overall populations of our key fleets.

3.5.1 OUR ASSET FLEETS

We use the term "asset fleet" to describe a group of assets that share technical characteristics and investment drivers. We have categorised our electricity assets into 25 fleets. These in turn are organised into seven portfolios, as set out below.

- Overhead structures
- Overhead conductor
- Cable
- Zone substations
- Distribution transformers
- Distribution switchgear
- Secondary systems

Our approach to managing our asset fleets is explained in Chapter 14.

3.5.2 ASSET POPULATIONS

In Table 3.2 we set out an overview of our asset populations across our full electricity network[7]. The large number of assets in certain fleets, eg poles, gives an indication of the scale of our network and the work we undertake on it. Further detail on these assets, including their condition and ages, is included in Chapters 15-21.

[7] Some population quantities in the table vary slightly to Information Disclosure because of the use of different classifications for fleet management planning.

Table 3.2: Asset population summary (2018)

ASSET TYPE	POPULATION
Overhead network	
Subtransmission (km)	1,507
Distribution (km)	14,804
LV (km)	5,110
Underground cables	
Subtransmission (km)	169
Distribution (km)	2,051
LV (km)	4,456
Overhead structures	
Poles	264,146
Crossarms	424,505
Zone substations	
Power transformers	191
Indoor switchboards	121
Buildings	160
Distribution assets	
Transformers	35,245
Switchgear	41,927
Secondary systems	
Zone substation protection relays	1,782
Remote terminal units	297

Serving our customers

This section explains how we plan to meet our customers' needs, now and in the future.

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4 CUSTOMER STRATEGY

4.1 CHAPTER OVERVIEW

This chapter explains who our customers are[8] and what they care about regarding electricity delivery. It explains how we actively engage with them to understand what they value and summarises the feedback we received in the course of customer engagement.

The expectations of our customers guide our investment and delivery approach. They are a key influencer when setting our asset management objectives and investment plans for the planning period. In the final part of the chapter we explain the links between the service standards our customers tell us they require and processes we use to determine investment requirements on our networks.

4.2 CUSTOMER DEMOGRAPHICS

4.2.1 CUSTOMERS

We are proud to serve more than 335,000 homes and businesses across the North Island of New Zealand. This includes diverse groups of households, businesses and communities. Our customer base includes:

- 23 electricity retailers who have active agreements with us to operate on our network trading as 32 brands
- 337,137 homes and businesses comprising:
  - Residential consumers and small businesses – ‘mass market’
  - Medium-size commercial businesses
  - Large commercial or industrial businesses
- 21 directly contracted industrial businesses, including large distributed generators
- 19 local territorial authorities and the NZTA

The table below sets out Installation Control Point (ICP) numbers by category. It shows the proportion of our customer base in contrast to the volume of electricity used, showing the significant electricity consumption of our larger customers.

Table 4.1: Number of customers (ICPs) and electricity delivered

CUSTOMER TYPE	ICPS	% OF TOTAL ICPS	ELECTRICITY DELIVERED (GWH)	% OF TOTAL ELECTRICITY DELIVERED
Mass market	335,094	99.4	2,640	54.5
Commercial	1,419	0.4	252	5.2
Large commercial / industrial	624	0.2	1,955	40.3
Total	337,137	100%	4,847	100%

Our customers are distributed relatively evenly across our network regions. The largest regional concentrations are in the Bay of Plenty, Taranaki and Manawatu, each having a large urban centre – Tauranga, New Plymouth and Palmerston North respectively.

The mass market segment includes our residential customers and small to medium enterprises. As shown above, the majority of our ICPs are mass market (99%), who account for about 55% of electricity delivered through our network.

We have more than 1,400 medium-size commercial customers. These customers range from medium-size retail and dairy producers through to food processing, ports, and large manufacturing. A further 624 customers have demand greater than 300kVA. These latter customers are classed as large commercial and industrial because of their demand.

During the past three years, growth across all of our customer segments has exceeded our regional forecasts. We have had to refine our forecast load estimates and increase network capacity. Our customer connection teams and processes have been bolstered to ensure we meet this growing need and continue to provide good customer service. How we connect customers to our network is discussed in Chapter 24.

More information on our large customers is provided in Appendix 4.

4.2.2 EMBEDDED GENERATORS

We provide direct network connections for a number of embedded generators. Sixteen of these have export capacity over 1MW, while a further four are classed as industrial cogeneration, where generated power is wholly or partly consumed on-site.

In addition, there are approximately 2,900 distributed generation installations of less than 1MW capacity connected to our network. The combined capacity of these

[8] Under the industry structure, we do not have a direct relationship with most of our end-users. Regardless of this, we consider all homes and businesses connected to our network and those using our services to be our customers.

smaller generators is just over 14MW. Of these, nearly all are domestic photovoltaic (PV) panel installations of less than 10kW capacity.

The uptake rate of small scale distributed generation (SSDG) on our network has risen from about 10 to 70 installations per month in the past four years as prices of PV and inverter technologies has dropped.

Our policy as set out in section 7.2.11 is intended to support and facilitate the appropriate development of distributed generation, while ensuring appropriate control given the potential local impacts on network operation.

4.2.3 ELECTRICITY RETAILERS

Like most New Zealand electricity distribution businesses, we operate an interposed model. That means retailers purchase our services, bundle them with energy supply and the cost of accessing the transmission grid, and provide a bundled price for delivered energy to their customers. We have agreements with 23 retailers used by our customers. Of these, Genesis Energy, Trustpower, and Mercury serve 70% of our customers.

Given the importance we place on our relationship with electricity retailers, we have a dedicated relationship management service in place that focuses on providing them with a high level of commercial and operational support. This helps them provide a quality bundled service to customers and seamlessly resolve any supply issues on their behalf. Working with retailers to deliver a simple and effective energy supply for customers is a key part of what we do.

The retail market is also undergoing considerable change. During the past few years, we have signed agreements with seven new retailers that have very targeted products. This reflects expectations that retail competition will intensify, become more sophisticated and segmented. These changes will most certainly occur during the coming planning period.

4.2.4 OTHER STAKEHOLDERS

We provide network services to a range of other stakeholders. These include the New Zealand Transport Agency and territorial local authorities that require us to move our lines or cables for roading projects. House relocation organisations may also require us to switch off our lines during their operations. Developers require us to provide connection services to housing developments. Our approaches to new connections and relocations are discussed in Chapters 24 and 25.

4.3 CUSTOMER SERVICE PRIORITIES

4.3.1 OVERVIEW

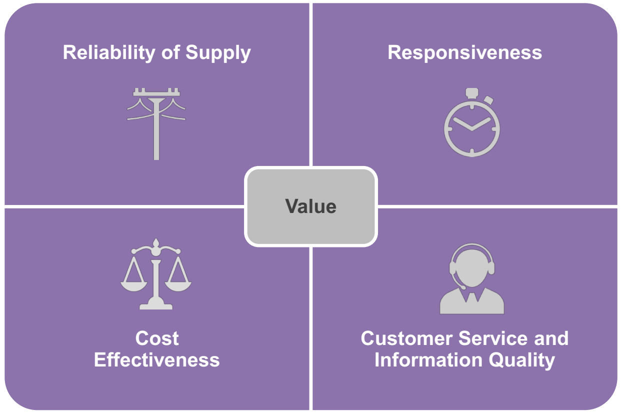
We use a variety of means to engage with our customers and capture their feedback.

These include:

- Having stands at agricultural field days, expos and trade shows
- Direct interaction with larger commercial and industrial customers
- Customer surveys
- Stakeholder meetings and focus groups
- Website, digital services and phone feedback – www.powerco.co.nz and 0800 POWERCO
- Consultation videos published on YouTube
- Consultation documents, such as this AMP
- Community-wide consultation on specific projects

The scale and range of consultation we complete provides us with appropriate insight into the areas of service that our customers value and their evolving expectations. Feedback from our customers typically falls into four key service dimensions as set out in Figure 4.1.

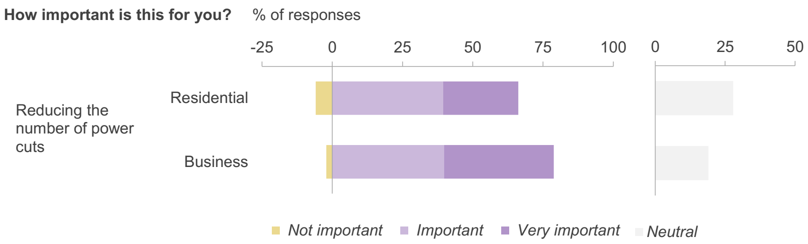
Figure 4.1: The four service dimensions most valued by our customers



4.3.2 RELIABILITY OF SUPPLY

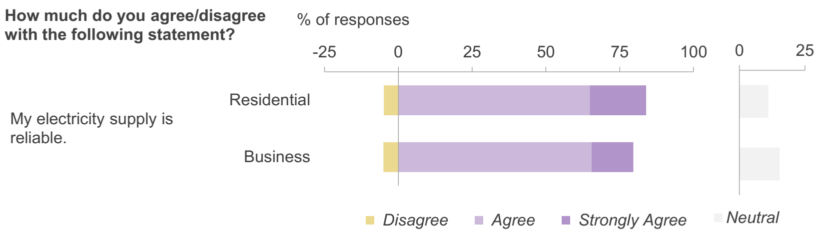
We know from our regular engagement activities that customers place a high value on reducing or avoiding outages. This is especially true for certain groups, such as businesses. Resilience is similarly important, as our customers expect our network to be able to withstand storms and for supply to be restored within a reasonable period. The chart below shows that the majority of our customers would value a reduction in outages.

Figure 4.2: Customer feedback – reducing outages



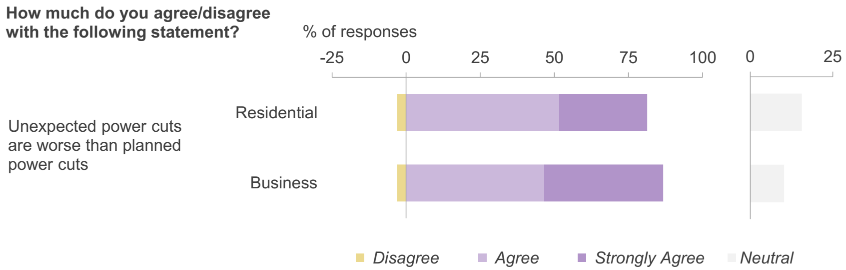
We continually focus on ensuring that the homes, businesses and industries we supply can count on us to keep them connected. While we cannot guarantee that a customer will never experience an interruption, we are committed to being one step ahead and minimising the chances of this occurring. A large majority of our customers think we are succeeding, however we clearly have work to do given a material number of customers disagree. We have also found there is very little appetite from our customers to accept future reductions in reliability.

Figure 4.3: Customer feedback – reliability of supply



When planned outages are needed to undertake work on the network, we do our best to ensure the disruption is as short as possible and does not occur at peak times. We work closely with electricity retailers to ensure affected customers are informed and given plenty of notice.

Figure 4.4: Customer feedback – planned versus unplanned outages



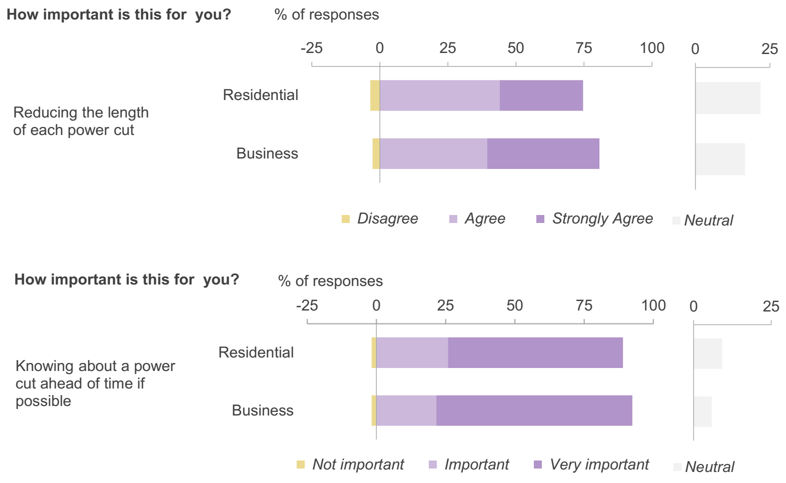
Our surveys indicate that the majority of residential respondents and business respondents regard unexpected outages as worse than planned outages. This customer feedback highlights the importance of addressing asset issues, such as defects and poor performing older assets, before they result in a failure.

4.3.3 RESPONSIVENESS

Unplanned outages occur for a variety of reasons. Some of these are considered to be within our control, such as equipment failures. Others are beyond our control, such as lightning strikes or vehicles hitting poles. Those outages that are within our control are easier to foresee and prevent, and we do everything we reasonably can to eliminate them.

When an unplanned outage does occur, our customers expect us to respond quickly in order to reduce their impact and potential safety risks. The value that customers place on responsiveness is indicated in the survey results below.

Figure 4.5: Customer feedback – responsiveness



It is evident from our customers' feedback that strategies to minimise the number of customers affected, and to minimise repair times in the event of an outage, are highly valued. Therefore, understanding the nature of these events, their causes and how to prevent them remain a key focus. When failures do occur, our main focus is to restore supply as quickly and safely as possible.

4.3.4 COST EFFECTIVENESS

While our customers recognise the importance of investing in the network to ensure that it is safe and reliable, they are also concerned about the price of electricity, as indicated in the following survey results.

Figure 4.6: Customer feedback – asset replacement

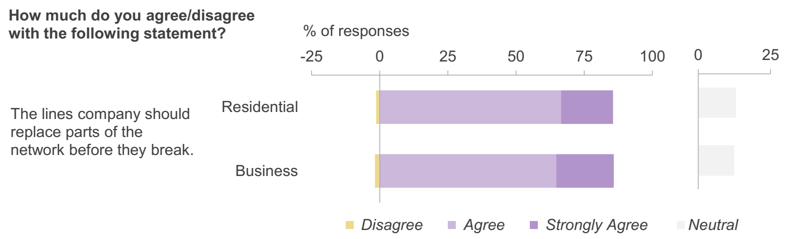
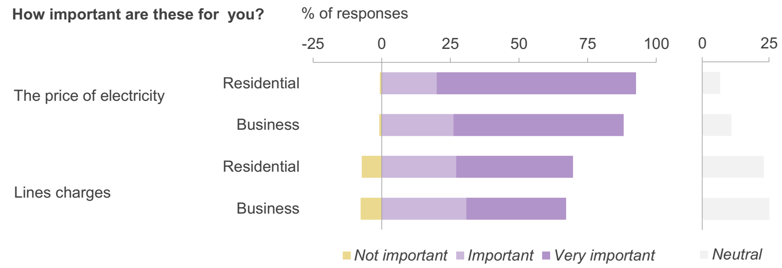


Figure 4.7: Customer feedback – price of electricity and line charges



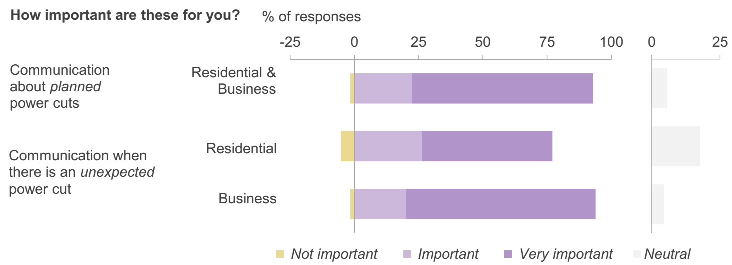
Customers expect our expenditure to be prudent and efficient in order to minimise electricity prices. Therefore, customers expect us to evaluate our decisions carefully so we optimise our expenditure and minimise total lifecycle costs.

4.3.5 CUSTOMER SERVICE AND INFORMATION QUALITY

Our customers value timely and accurate information about their electricity supply. Advances in mobile technology and social media have created an expectation that information should be readily available through a number of alternative communication channels.

As shown in the figure below, the most important information for residential customers is communication in relation to power cuts. Information on upcoming planned power cuts is important to 90% of residential respondents. Information relating to unexpected power cuts is also highly valued by 78% of respondents. The results are similar for business customers who place even greater value on each of these aspects.

Figure 4.8: Customer feedback – communication about power cuts



These results show that communication about power cuts is very important to our customers.

4.4 HOW CUSTOMER FEEDBACK INFLUENCES OUR STRATEGY

4.4.1 OVERVIEW

Feedback from our customers on the service standards they value is a cornerstone of our asset management process.

At their core, the investment proposals set out have been developed to ensure we invest prudently in our networks so that we continue to deliver the level of service our customers require in the long term. This includes our commitment to our customers to ensure the safety of our assets, and to deliver stable reliability outcomes over time.

As part of our Customised Price-quality Path (CPP) proposal we consulted with our customers regarding our specific investment proposals. This was done to determine their service preferences, and explore how they valued our services in terms of the prices they pay and the level of reliability we provide.

The themes of our discussion and the feedback from our customers are set out in the sections below. We continue to test these findings annually to ensure they remain relevant and continue to represent customers' expectations.

4.4.2 SAFE AND RELIABLE NETWORKS

Customer feedback unequivocally indicates they want their electricity delivered safely, reliably and efficiently. Therefore it is essential we invest in our assets to ensure they are in appropriate condition, are safe and reliable, and meet the needs of our customers.

We continually monitor key indicators such as asset health, fault rates, and supply quality to guide our investment and ensure customer expectations are being met. The CPP is allowing us to increase the level of investment to ensure safety and reliability is in line with the expectations of our customers.

4.4.3 FACILITATING CUSTOMER GROWTH

The regions we serve have been experiencing sustained population and economic growth in recent years, and as a result we have experienced sustained demand growth across many of our networks.

Consequently, there continues to be many locations where we have no practical way of rerouting supply in the event of a key asset failing, and where the cost of such a failure is increasingly becoming unacceptably high for our customers. Because this situation affects our ability to provide a secure, stable power supply, our customers recognise the need to continue to expand and augment the capacity of our network to cope with demand growth.

4.4.4 ENABLING OUR CUSTOMERS' ENERGY CHOICES

Customers are increasingly expecting more flexibility and choice in the services they obtain and the way we communicate with them.

While not a strong theme in customer feedback, we are aware that new technology offerings, combined with an increasing consumer willingness to take more control of their energy options, is leading to a change in the way energy markets operate.

This change means we must learn about these new technologies and new energy solutions to enable our networks to support and accommodate the future choices of our customers. This has influenced our strategy to invest in resources to study customer trends and emerging requirements, so we can prepare our network to accommodate them.

4.4.5 LINKING CUSTOMER FEEDBACK TO OUR ASSET MANAGEMENT PROCESS

Our asset management process provides a mechanism that links the service levels our customers tell us they require to the specific investments we make on our networks. Our Asset Management Strategy, objectives and targets combine to provide structure to guide our engineering decisions. Chapters 5-10 describe our Asset Management Framework.

Our network growth and development strategies aim to provide just-in-time capacity by using best industry practice to predict probable load growth and customer demographics. This enables us to meet demand growth without providing more capacity than is needed. Our plans to support growth in our communities are described in Chapter 11.

Similarly, our asset renewal strategies aim to ensure appropriate asset condition and maintain current levels of reliability in the longer term. We aim to achieve this via effective management of the health of our asset fleets through targeted maintenance and renewal. Our maintenance and renewal plans are discussed in Chapters 15-23.

Our plans to adapt to changing customer needs in the face of technological change and to ensure that we are able to anticipate and accommodate customer needs beyond traditional distribution services are set out in Chapter 13.

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Managing our assets

This section sets out our asset management strategy and network targets, explains our approach to investment decision-making, and describes how we are preparing for an increase in investment during the planning period.

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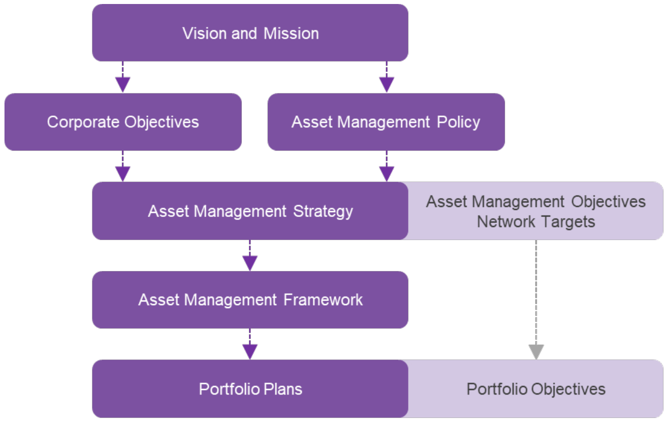
5 ASSET MANAGEMENT STRATEGY

5.1 CHAPTER OVERVIEW

This chapter explains our Asset Management Strategy. It sets out how we translate our corporate vision and overarching objectives into our day-to-day investment and operational decisions. The 'line-of-sight' between corporate objectives and asset management practice is illustrated in Figure 5.1.

Figure 5.1: Our asset management 'line-of-sight'



The key elements in ensuring the 'line-of-sight' for our asset strategy are outlined in this chapter. They are:

- **Vision, Mission and Values –** reflects our purpose and what we stand for.
- **Corporate Objectives –** the overarching goals shaping our future direction and describing the outcomes we are striving for.
- **Asset Management Policy –** this is our pledge of custodianship for our assets. This provides high-level overall direction and guidance for our asset management approach.
- **Asset Management Strategy –** setting out our electricity asset management goals and initiatives to help ensure we achieve our Corporate Objectives.

Outlined in Chapters 6-8:

- **Asset Management Framework** – provides an overview of how we implement our asset management activities. It sets out the structure we use to govern our asset management decisions.

Outlined in Chapters 11-25:

- **Portfolio plans** – provides details of the planned 10-year investment, operating and maintenance plans for our network assets. This is how the Asset Management Strategy will be physically delivered.

5.2 VISION, MISSION AND VALUES

5.2.1 CORPORATE VISION

Our corporate vision below captures the balance we, as a modern electricity distributor, seek to strike between providing a safe, secure and resilient network, supporting growth in the communities we serve, and ensuring our readiness for a changing future.

Powerco, your reliable partner,
delivering New Zealand's energy future

5.2.2 CORPORATE MISSION

Our corporate mission encapsulates our core purpose, which is to deliver electricity safely, reliably and affordably to our customers, now and into the future. We will do so while ensuring an appropriate, sustainable commercial return to our shareholders. It reflects the importance of our other stakeholders to our business.

In profitable **partnership** with our **stakeholders**,
we are **powering the future** of New Zealand through
the delivery of **safe**, **reliable**, and **efficient** energy

5.2.3 CORPORATE VALUES

Our corporate values define us: Who we are and what we stand for. They describe the behaviours we expect from our employees and service providers. These are summarised in Table 5.1**.**

These values define the way we go about our work and what we expect in our relationships with each other. They help define our culture, inform our decisions and give authority to our leaders.

Table 5.1: Our values

Safe	We are committed to keeping people safe.
Trustworthy	We act with integrity. We are honest, consistent and ethical. We trust each other and our external partners and work to be trusted in return.
Collaborative	We work together with our partners, contribute our capabilities and provide timely support and consideration to achieve our collective goals.
Conscientious	We are proactive, hardworking, diligent and thoughtful. We are mindful of the needs of others and of the environment. We take ownership for our actions.
Intelligent	We make informed decisions for the best outcome. We continually seek improvement and innovative solutions from our suppliers and ourselves.
Accountable	We lead. We take ownership of our decisions and responsibility for our actions. We are proactive in identifying and resolving problems.

5.3 CORPORATE OBJECTIVES

While the Vision, Mission and Values define what we aspire to **be** as an organisation, the Corporate Objectives define what we strive to **do** as an organisation. These provide guidance on our priorities. These have been framed around three central themes:

Customer orientation

- We act and invest to support our customers
- We deliver value to our customers

Operational excellence

- We invest to ensure safe, secure and resilient networks
- Asset management drives investment efficiency
- We continually improve organisational performance
- We deliver shareholder value

New energy future

- We enable our customers' energy choices
- We have efficient asset utilisation now and into the future

5.4 ASSET MANAGEMENT POLICY

Our Asset Management Policy sets out high level asset management principles that reflect our Vision, Mission and Values. It highlights our Board's expectations as to how we will manage our assets and make our decisions.

The policy has been developed to ensure we continually focus on delivering the service our customers want in a sustainable manner that balances risk and long-term costs.

Asset Management Policy

Powerco's vision is to be a reliable partner, delivering New Zealand's energy future.

Effective asset management is the cornerstone for the delivery of our vision and underpins our approach at all levels of the organisation.

We will strive to achieve the following asset management outcomes:

- Positioning the safety of the public, our staff and contractors as paramount
- Developing our networks in a way that delivers to the evolving needs of our customers
- Supporting environmentally sustainable and ethical practice, through the selection and life-cycle management of our assets
- Delivering a cost-effective service by optimising asset cost, risk and performance
- Being proactive, transparent, and authentic in our interactions with our stakeholders
- Meeting all statutory and regulatory obligations

We will achieve these asset management outcomes by:

- Developing and maintaining an Asset Management System (AMS) for each of our Electricity and Gas networks, integrated with Powerco's existing management systems
- Preparing and delivering to our plans set out in our Asset Management Plans
- Obtaining ISO 55001 certification by the end of CY 2020
- Managing data as an important asset and implementing a data management governance framework that supports asset management decisions
- Continually enhancing our asset management capability and skills over time
- Recognising the importance of our people and their development

Cont…

Members of the Executive Management Team are accountable for resourcing, and delivering the outcomes of this policy as follows:

- As representatives of the Asset Owner, the Executive Management Team is responsible for setting the Asset Management Policy.
- The Asset Management and Network Transformation General Manager shall own the Electricity AMS and alongside the Service Delivery and Systems Operations General Manager shall be jointly responsible to deliver the outcomes of this policy in the Electricity division.
- The General Manager (Gas) shall own the Gas AMS and shall be responsible to deliver the outcomes of this policy in the Gas division.
- Further roles and responsibilities will be documented in the respective Asset Management Systems.

We strive to be New Zealand's leading asset manager, enabling us to provide excellent customer service, and a consistently safe, reliable and cost-effective service.

5.5 ASSET MANAGEMENT STRATEGY

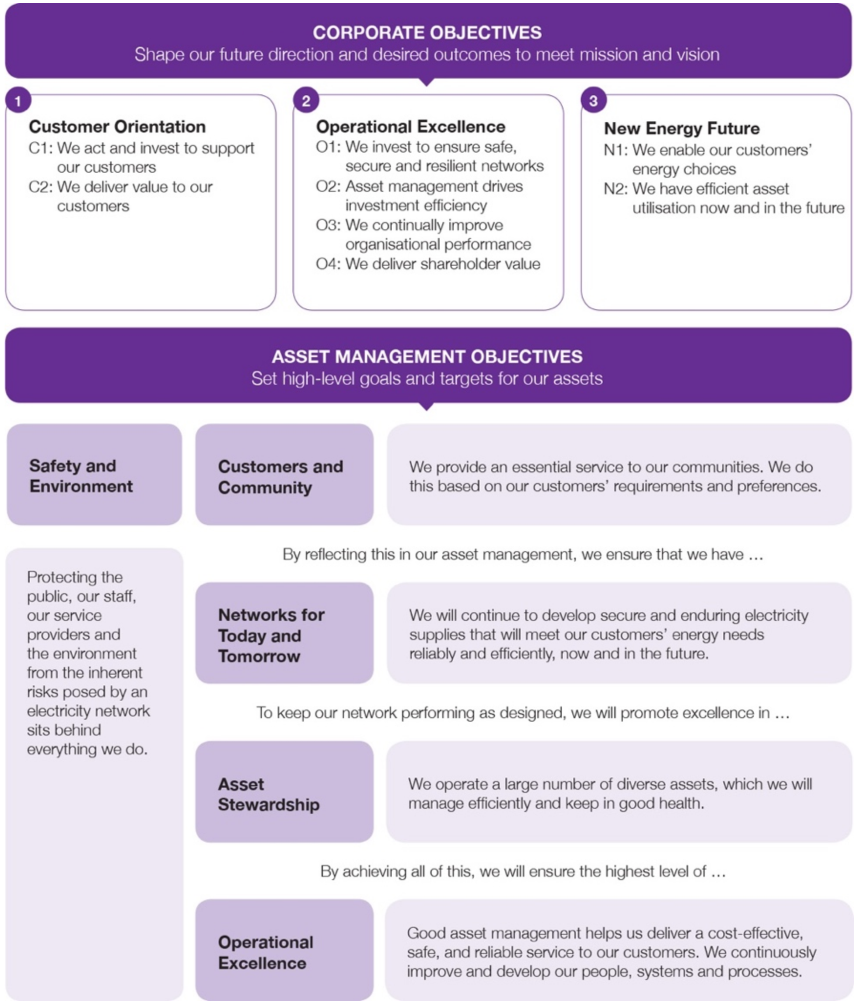
5.5.1 OVERVIEW

Our Asset Management Strategy sets the direction for managing our electricity network assets. It has been developed to achieve the following aims:

- Describe how our Asset Management Policy is used to develop asset management objectives.
- Support the delivery of best value to our customers while sustaining an appropriate commercial return for our shareholders.
- Help us achieve our core function as a lifeline utility by safely and reliably delivering electricity to our customers.
- Drive our continuous improvement programme to ensure we continue to be an efficient, forward-thinking network business.
- Ensure our asset management practices deliver on the overall corporate objectives.

A set of five Asset Management Objectives sit at the heart of our Asset Management Strategy. They reflect our lifecycle asset management approach. This approach considers all aspects of asset decision-making and activities from inception to decommissioning. These Asset Management Objectives and their alignment with the Corporate Objectives are illustrated in Figure 5.2.

Figure 5.2: Our Asset Management Objectives



The sections below describe specific goals of each Asset Management Objective and the initiatives we are taking to achieve our strategy.

5.5.2 SAFETY AND ENVIRONMENT

Our Asset Management Policy reaffirms that the safety of the public, our staff and service providers is paramount. We are committed to developing the leadership, culture and systems to support us in our drive to minimise harm.

We also see ourselves as custodians of our environment. As part of this we ensure possible damage to the environment from our electricity assets and our operations is kept as low as reasonably possible. We encourage the efficient use of energy, support sustainable business practices, and strive to minimise our carbon footprint.

Safety and Environment objectives

Our safety objective is to safeguard the public and ensure an injury free workplace.

Our environmental objective is to cause no lasting harm to the environment.

To help achieve these objectives we have adopted a set of goals, as set out in the following tables. Various initiatives to support the goals have also been defined.

Table 5.2: Safety goals

GOAL	SUPPORTING INITIATIVES
Zero fatalities to staff and contractors	Develop and implement plans to manage critical risk areas for Powerco staff and ensure contractors have similar plans in place for their own staff working on our assets. Enhance contractor approval processes to ensure we utilise the right delivery partners. Mitigate arc flash hazards for high risk assets.
Minimising lost time injuries to staff and contractors **10% year-on-year reduction in Lost Time Injury Frequency Rate**	Ongoing development of safety culture maturity with our service providers, including recording, analysis, trending and reporting of safety-related issues. Review effectiveness of contractor works manual to communicate critical information. Evolve contractor approval process to include design capability assessment. Develop leading and lagging performance metrics for Health, Safety and Environment contractor and subcontractor performance. Phasing out assets that no longer meet modern safety standards or have known operations restrictions in place.
Zero public harm incidents resulting from our network **Zero public harm incidents resulting from our network**	Regular public safety communication with our customers, communities, emergency services and professional bodies. Remove defective assets, especially those in areas of high public safety risk. Targeted renewal programmes to ensure appropriate levels of asset health.
Full compliance with the Health and Safety at Work Act (2015) and applicable regulations	Training for Board members and staff regarding the requirements of the Health and Safety at Work Act (2015). Assess safety leadership in safety critical roles and Executive Management Team with Safety Attribute Testing (leadership and individual).

Table 5.3: Environmental goals

GOAL	SUPPORTING INITIATIVES
Zero significant, avoidable environmental incidents caused by our assets or work practices	Development, implementation and communication of sustainable environmental management principles to employees, contractors and other stakeholders. Identification of environmental critical risks and associated mitigation measures for communication to all stakeholders. Work with our contractors to ensure the reporting, containment and rehabilitation of any environmental incidents caused by our assets. Environmental management planning is core to any project initiation process.

GOAL	SUPPORTING INITIATIVES
All environmental incidents reported in time	Continual improvement in measuring and reporting incidents that have a real or potential environmental impact. Development of systems to better enable contractors and employees to manage environmental incident reporting.
Designing networks and working with customers to promote efficient delivery and use of electricity	Develop and implement energy efficiency campaigns that help moderate our impact on the environment. New materials approved for use on the network are subjected to rigorous MECO9 analysis process for whole-of-life impact assessment.
Full compliance with the Resource Management Act 1991 and any other non-legally binding stakeholder agreements	Conduct planning reviews to ensure assets in environmentally sensitive areas are appropriately selected and installed. Implement system to ensure compliance obligations are well managed.
Continued certification with ISO 14001:2015	Ongoing target to meet all requirements of ISO 14001:2015 to continue to hold certification. Continual self-assessment of systems and procedures, with ongoing improvements where the need is identified.

5.5.3 CUSTOMERS AND COMMUNITY

Good customer service is an essential requirement for any successful business. For an electricity lines business this includes delivering a safe, cost-effective, reliable and resilient electricity supply. But it also covers customer experience-related measures such as responsiveness to customer requests, timely completion of works, effective communication about and during outages, and making it easy to deal with us.

Another core element of our Asset Management Strategy is to engage effectively with our customers and the communities we serve. This ensures our asset management decisions reflect the level of service they desire and at a cost they find acceptable.

We are also aware that emerging technologies will provide our customers with energy alternatives. To be their energy partner of choice, we will have to engage to thoroughly understand their requirements if we are to support them in enabling their energy choices.

Finally, our assets cross private and public land, which has an impact on our customers and communities. It is important that we mitigate this impact, while also optimising our operational costs. This requires effective communication and the support of our communities.

Customers and Community objective

Build a deep understanding of our customers' requirements and preferences. We will then reflect this through excellent customer service, and the types and quality of services we offer.

To support our Customers and Community objective, we have adopted the following set of goals. Various initiatives have also been defined, which will help us achieve these goals.

Table 5.4: Customers and Community goals

GOAL	SUPPORTING INITIATIVES
Effective, regular consultation about price and service quality requirements	Expand our customer focus groups to widen representation in our regular surveys and discussions.
Excellence in customer service, tested against objective performance measures	Targeted surveys of customers after outages or interactions with us to understand and enhance customer experience. Centralise the customer information into a Customer Relationship Management system allowing for collection and management of a wide variety of data and analysis.
Enabling our customers' future energy choices	Increased monitoring and analysis of local and international customer trends and preferences. Transition to an open-access network via targeted technology development and operational practices.
Build effective long-term relationships with landowners and community groups	Regular communication with communities affected by our assets to discuss their rights and their experience. Professional and empathetic communication with landowners where new-builds or renewal works are required.
Proactively communicate planned and unplanned power cuts to our customers	Further improve access to network status information for customers through different communication channels, such as web, mobile apps and social media.
Improving our outage response, especially in remote areas	Targeted improvements in areas of low network performance, providing alternative options where high network reliability

9 Materials, Energy, Chemicals, Other lifecycle considerations

GOAL	SUPPORTING INITIATIVES
	cannot be economically maintained.
Excellence in customer service, tested against objective performance measures	Targeted surveys of customers after outages or interactions with us to understand and enhance customer experience. Centralise the customer information into a Customer Relationship Management system allowing for collection and management of a wide variety of data and analysis.

5.5.4 NETWORKS FOR TODAY AND TOMORROW

Our networks provide a lifeline service to communities. Safe and reliable electricity is essential, and we will maintain this supply to our customers now and in the future.

For today's network it means we must provide electricity supply at a level of service that balances customers' quality requirements with their willingness to pay. Looking forward, this means ensuring that we can support those customers who choose to utilise new energy solutions, such as rooftop photovoltaics (PV) and energy storage, as well as those who wish to continue taking electricity supplies.

In addition, overseas and local studies have shown that effective planning and application of appropriate emerging technologies is essential to realise the opportunities these bring for improved services and cost-efficiency, or to moderate the cost of accommodating new distributed energy solutions. This topic is further discussed in Chapter 13**.**

Networks for Today and Tomorrow objective

We will continue to provide our customers with a safe, cost effective and reliable electricity service that will reflect their preferences and meet their needs today and in the future.

To help us achieve our Networks for Today and Tomorrow objective, we have adopted a set of goals and associated initiatives, as set out below.

Table 5.5: Networks for Today and Tomorrow goals

GOAL	SUPPORTING INITIATIVES
At least maintain overall and disaggregated network reliability at historical levels[10] (unless specific customer requirements indicate otherwise)	Targeted asset renewals and security reinforcements to maintain historical network reliability levels.
Provide a service that reasonably balances our customers' quality expectations and willingness to pay	Refine our network security standards to reflect customer needs, considering emerging customer requirements and willingness to pay.
In a transforming energy environment, continue to provide safe, reliable and cost-effective energy solutions by optimally mixing traditional investments with innovative network and non-network solutions	Develop a detailed future network strategy that sets out our plan for developing the network of the future. Developing our networks to open access principles that will allow our customers maximum flexibility to achieve their energy requirements.
Encourage innovative fresh approaches to traditional issues	Expand our capability and incentives for innovation, including encouraging innovation from staff.
Adopt prudent asset investment approaches given uncertain f uture energy demand patterns	Improve our demand forecasting approach to better reflect demographic, weather and economic trends, and the likely increased complexity of future networks. Review our network architecture based on detailed scenario analysis and adopt the least-regret outcome.
Ongoing improvement in network resilience, reflecting changing community needs	Enhance our networks and communications infrastructure to support future network resilience.

5.5.5 ASSET STEWARDSHIP

Our electricity network is extensive and made up of assets of varying age and condition. Looking after these assets efficiently is essential to the ongoing delivery of a safe, reliable and cost-effective electricity supply.

10 As discussed later in this AMP, we intend to significantly expand our asset renewal programme during the planning period, partly to ensure future network reliability. During these works we expect planned outages on the network to increase, despite adopting all reasonable measures to limit the impact.

To be a good steward of long-life assets requires a thorough understanding of their performance and condition. We need to monitor and maintain assets to ensure they deliver to their required specification over their life and replace them at the appropriate time. It also requires us to be prudent operators, ensuring an asset does not operate outside capacity limits or be used in ways that are unsafe or could shorten its life.

While our network performance appears relatively stable when considered at a summary level, there are increasing signs of poor underlying asset performance driven by asset deterioration. This is evidenced by, among other things, increasing defect rates and Asset Health Indices (AHI) that are trending unfavourably.

Maintaining stable asset health is a key focus. To stabilise and reverse deteriorating performance trends we need to accelerate investment in asset renewal and on our maintenance programmes. We also must improve our asset management support systems and processes to ensure we get the benefits of modern information technology to optimise asset investments. This will allow us to get the most value from our assets, minimise risk and ensure continuing prudent investment.

Asset Stewardship objective

Through effective management and operation our assets deliver a safe and reliable supply to customers in a cost-effective manner, over their expected lives.

To support this objective, we have adopted a set of goals, as set out below. Various initiatives have also been defined.

Table 5.6: Asset Stewardship goals

GOAL	SUPPORTING INITIATIVES
Our assets perform at their designed capacity over their expected lives	Continue to develop our holistic fleet management approach to asset maintenance and renewal. Expand our preventive maintenance programme for each asset fleet, including collecting expanded asset health assessments and defect records.
Well targeted asset renewal plans to cost-effectively ensure safe and reliable performance of our network, also reflecting the needs of the future network	Enable advanced information-driven maintenance and asset renewal decisions. Use diagnostic testing tools such as acoustic testing of wood poles, expanding the application of Condition Based Risk Management (CBRM), Reliability Centred Maintenance (RCM) and further development of AHI.
Effective vegetation management around our networks, with the support of private landowners, councils and roading authorities	Adoption of full cyclical vegetation management. Implement a catch-up programme of work for sections of the network that were previously not part of a cyclical programme.
Increasing asset standardisation, supported by a group of specifications and guidelines that ensure optimal asset lifecycle performance	Continue to standardise the minimum number of assets required to ensure the cost-effective, safe and reliable operation of our networks, and maintain appropriate commercial tension between suppliers. Maintain a comprehensive set of asset standards and guidelines for all asset classes on the network, representing best industry practice.
Consider sustainability factors (environmental, social and governance) when procuring material	Development of a procurement policy that includes a desired supplier code of conduct.

5.5.6 OPERATIONAL EXCELLENCE

Operational excellence is a broad concept that covers many of our activities. From an asset management perspective, striving for operational excellence has relevance to the following areas:

- Putting in place the skills, capacity and supporting systems needed to achieve good practice asset management and service delivery, including network operations, asset maintenance and construction.
- Cost-effectively delivering services to customers in accordance with their needs.

- Effective engagement with stakeholders, including providing accurate performance reports and asset information, supporting regulatory submissions and preparing high quality material to aid company governance.
- Excellence in asset and network data collection, the management and safekeeping of this data, and the processing and analysis of data and information to support effective decision-making.
- Increasing efficiency within our planning and delivery processes to ensure the best value is achieved from our operations.

Operational Excellence objective

Ensure we have the skills, capacity, systems, and processes in place to cost effectively and reliably deliver to our Asset Management Strategy.

To support this objective, we have adopted a set of goals, as set out below. Various initiatives have also been defined.

Table 5.7: Operational Excellence goals

GOAL	SUPPORTING INITIATIVES
Implement leading asset management information practices	Improve data reliability by streamlining processes, providing new tools to report on quality of data, and invest in new field mobility tools for asset data collection.
Ensure cost efficient, valuable services to our customers	Enforce a transparent, commercially competitive approach to all our procurement and contract activities, adhering to best industry practice.
Comprehensive and accurate asset and network data is available to our asset managers and service delivery staff	Develop and implement an asset data quality strategy that will ensure our asset managers and operations staff are provided with comprehensive and accurate asset and network performance data. Combine data from engineering, operations and network performance to support intelligent decision-making.
Our electricity network and databases are secure against cyber-attacks	Improve the security of our databases, ‘intelligent’ assets, and Supervisory Control And Data Acquisition (SCADA) network.
A structured risk framework is applied to our asset management decisions	Grow our asset management capability through judicious recruitment and development of staff, ensuring appropriate competency levels and range of skills. Supplement our risk framework to better quantify risk and ensure an appropriate balance between mitigation and cost.
Employ motivated, competent technical staff to look after our assets	Encourage a culture of continuous learning and innovation.
Achieve ISO 55001 certification	Undertake ISO 55001 gap analysis. Identify and address the necessary steps to achieve, at least, level three maturity on all measures by 2020. Develop skills for ISO 55001 and evolve organisational structures to better align network development, fleet management, analytics and future networks.

5.5.7 PERFORMANCE AGAINST OUR OBJECTIVES

We have developed a group of targets against which progress towards our goals and the success of the supporting initiatives can be measured. These are set out in Chapter 9. Progress against these targets will be reported in future AMPs or updates.

6 GOVERNANCE

6.1 OVERVIEW

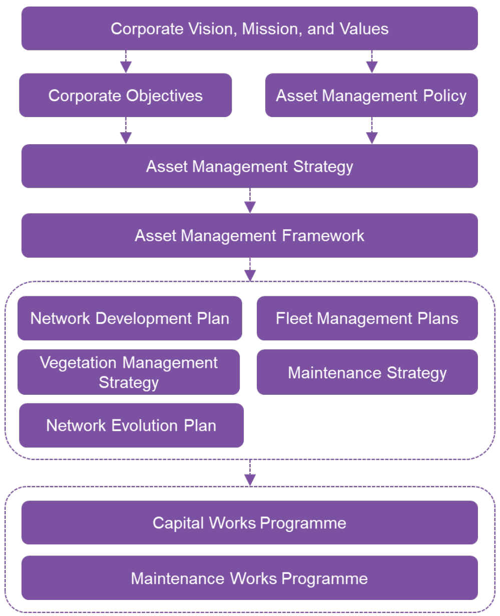
This chapter discusses our asset management governance structures and responsibilities. It considers those processes used to achieve effective management of expenditure and risk, and covers the following key topics:

- Corporate responsibilities
- Asset lifecycle management
- Expenditure governance processes
- Asset Management Plan (AMP) Development and approval processes
- Risk management processes

We are in the process of aligning our asset management practices with ISO 55001. A key facet of leading asset management practice is maintaining a clear 'line-of-sight' between an organisation's corporate objectives, asset management objectives and strategies, and day-to-day activities.

Figure 6.1 shows the hierarchy of documentation underpinning our asset management system.

Figure 6.1: Our asset management documentation hierarchy



6.2 CORPORATE RESPONSIBILITIES

6.2.1 OVERVIEW

Asset management decisions are undertaken using a stage-gated process with the degree of oversight reflecting the cost, risk and complexity of the decision being considered.

A robust framework of responsibilities and controls is in place to ensure decisions align with our corporate vision and associated asset management policy, objectives and strategy.

In this section we describe the principal governance responsibilities.

6.2.2 THE BOARD

Our Board provides strategic guidance, monitors management effectiveness and is accountable to shareholders for the company's performance. From an asset management perspective, it does this by endorsing key documentation, establishing our business objectives and approving the strategies needed to achieve those objectives.

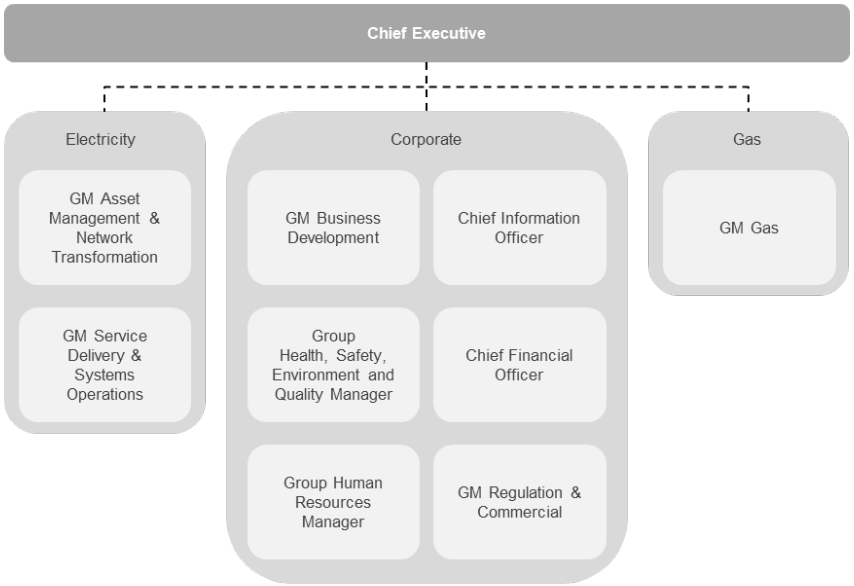
The principal asset management responsibilities of the Board are listed below:

- The Board has overall accountability for maintaining Powerco as a safe working environment and ensuring public safety is not compromised by our assets and operations.
- The Board reviews and approves our AMP, which includes our medium-term (10-year) investment forecasts, and our shorter-term expenditure plans. The Board's Regulatory and Asset Management Committee is responsible for ensuring that our AMP is appropriate, and regulatory requirements are met.
- The Board sanctions operational or capital projects involving expenditure greater than $2 million, and the divestment of any assets with a value greater than $250,000. One of the main factors the Board takes into account when considering a project is its alignment with the AMP.
- The Board receives monthly reports that include performance reports regarding the status of key work programmes, key network performance metrics, updates on high-value and high-criticality projects, and the status of our top 10 risks. It also receives audit reports against a prescribed audit schedule. It uses this information to provide guidance to management on improvements required, or changes in strategic direction.
- The Board's Audit and Risk Committee is responsible for overseeing risk management practices and to review audit findings.

6.2.3 THE EXECUTIVE MANAGEMENT TEAM

Our organisational structure is based on two asset management-focused units – the Electricity and Gas divisions – with the support of six functional units.
The makeup of our Executive Management Team (EMT), which reflects this organisational structure, is illustrated in Figure 6.2. This structure allows the Electricity Division to focus on core activities and decisions and access specialist skills and advice as required.

Figure 6.2: Executive Management Team structure



The **Electricity and Gas** divisions hold overall responsibility for asset investment, operational management and commercial management of each business line.
A detailed breakdown of roles and responsibilities for the Electricity business line is provided in Section 6.3. Support provided from each of the specialist functional units is set out below.

The technical overlap between the Electricity and Gas divisions is limited, although we believe there will be opportunities for dual-energy delivery and optimal energy substitution in the future. Asset management ideas and information are increasingly being shared between the groups to help ensure a consistent approach across the company and as a way to learn from each other.

The **Information Services Business unit** manages IT related non-network assets, as these are normally shared between the Electricity and Gas divisions. This includes asset information, Information Communications and Technology (ICT) infrastructure and telecommunications systems. It provides ICT and systems support for systems that the electricity network relies on, such as the Geographical Information System (GIS), Outage Management System (OMS) and network analysis software.

The **Finance group** is responsible for overseeing our financial affairs, as well as arranging the necessary financing to keep operations going. It works closely with the Electricity Division on areas such as expenditure forecasting and budgeting, tracking expenditure, invoicing and accounts payable. It also provides specialist internal audit support.

The **Human Resources group** assists the asset management function with capability development, recruitment, training, day-to-day human resource management and advice, and performance frameworks.

The **Health, Safety, Environment and Quality team** supports the asset management function by providing direction, framework and targets for managing these critical aspects of our operations. It also assists with investigation of incidents, root cause analysis, and assessing overall health, safety and environment performance. It initiates corrective action as required.

The **Customer, Regulatory, Commercial and Legal group** (reporting to the GM Regulation & Commercial) manages interactions with our regulators, customers and large industrial and commercial customers. The Regulatory team is involved in making regulatory submissions and disclosures – of which the AMP forms part, engaging in the rule-setting processes and ensuring that we understand and comply with regulatory requirements. The Customer team is the conduit for communicating with our customers, communities and stakeholder groups. The Commercial team manages our interactions with retailers, and larger industrial and commercial customers. Finally, the Legal and Property team provides internal legal support services, managing the contractual arrangements, such as commercial agreements, Use of System agreements, and providing easements and access to property for the development of our network.

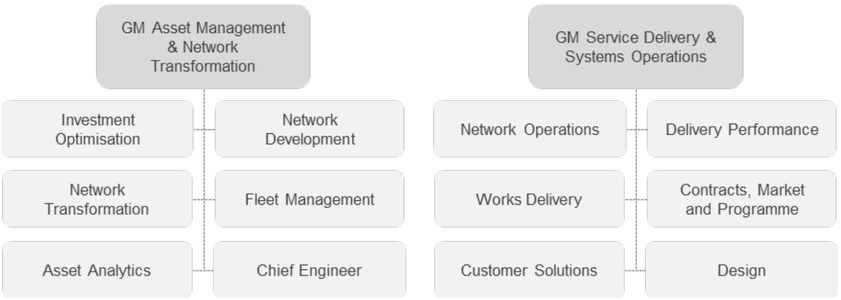
Business Development is responsible for exploring and investing in new products, solutions and services that complement our core gas and electricity network businesses and creates new shareholder value. The scope of this activity extends from traditional energy infrastructure investments through to relevant adjacencies in the energy market and generation arena. Most notable of these is Base Power Ltd, which is our unregulated subsidiary focusing on Remote Area Power Supply (RAPS) solutions.

6.3 ELECTRICITY DIVISION RESPONSIBILITIES

6.3.1 OVERVIEW

The Electricity Division has specialised teams reporting to two general managers, as depicted in Figure 6.3. The GM Asset Management & Network Transformation acts as primary custodian of the network.

Figure 6.3: Electricity Division structure[11]



6.3.2 ASSET MANAGEMENT & NETWORK TRANSFORMATION TEAM

This team is responsible for translating the Asset Management Policy into a practical asset management strategy and plan. It then details the short-term activities required to deliver them, in conjunction with the Service Delivery and Systems Operations teams.

The functions of the Asset Management & Network Transformation team are:

Network Development

The Network Development team is responsible for planning augmentations to the electricity network. This includes developments driven by increasing customer connections and demand, changing demand patterns, or increased network functionality, including increased automation and network communications. The planning processes culminate in the delivery of asset management strategies and documentation, capital expenditure plans, concept designs, project briefs (high level project descriptions and justifications) and rolling work plans.

Fleet Management

The Fleet Management team is responsible for the asset management of existing electricity network assets, which are divided into several fleets. This involves the preparation of renewal and maintenance plans based on performance and condition assessment, conducting specialised engineering studies, preparing asset management strategies and documentation, capital expenditure plans, concept designs, project briefs (high level project descriptions and justifications) and rolling work plans.

Investment Optimisation

The Investment Optimisation team is responsible for ensuring that our electricity investment plans (capital and operating expenditure) achieve an optimal balance in meeting the requirements of our customers, our shareholders, the regulators and the technical needs associated with running a safe, reliable network. Outputs from the team will include network investment analysis, asset risk management, the annual investment plan (network Capex and Opex) and the optimised 10-year investment plan.

Network Transformation

The Network Transformation team leads network activities that are aimed at readying our electricity networks for a changing energy environment. Outputs from the team include scenario development and the associated network impact assessment, emerging consumer trend analysis, research and development of emerging network and non-network solutions, coordinating pilot programmes and proofs of concept for new solutions.

Asset Analytics

The Asset Analytics team supports our asset management, by providing analytical support to the various investment and planning functions in the Electricity Division. This includes the development and support of network and asset analytical tools and models, managing the data required to ensure the effectiveness of these, and analysing asset and network performance information to guide asset management decisions.

Chief Engineer

The Chief Engineer's team is responsible for network asset strategy, asset risk management guidelines, technical reviews and arbitration, and technical support for regulatory submissions, investment policies and design. This team is also responsible for overseeing the introduction of new asset types onto the network, and the development and maintenance of our asset standards.

6.3.3 SERVICE DELIVERY & SYSTEMS OPERATIONS TEAM

This team is responsible for the efficient operation and maintenance of our network as well as the delivery of works plans. In addition, the team manages new customer connections on the network.

Recently, the team has been restructured to support the increased scale of delivery associated with the Customised Price-quality Path (CPP).

[11] Noting that we regularly refine or add functions that will not necessarily be shown in organisational charts.

Network Operations
Day-to-day operation and access to the network is managed by the Network Operations Centre (NOC). This includes controlling network shutdowns and switching, coordinating the response to network outages, managing the load control process, maintaining the Supervisory Control And Data Acquisition (SCADA) system, and ensuring adherence to contractor competency requirements.

Delivery Performance
Amber category defects and day-to-day management of the vegetation management plan are overseen by the Delivery Performance team. It investigates unplanned network outages in the first instance to establish root cause and recommends remedial actions. A maintenance delivery manager ensures the effective and efficient delivery of the scheduled maintenance plan.

Works Delivery
The Works Delivery team manages the day-to day execution of work plans through our three tier-1 service providers, as well as numerous tier-2 suppliers that are accessed through contestable tender processes.

Contracts, Market and Programme
This team manages the contractual relationships with service providers and suppliers, sets and monitors competency requirements, monitors contractor performance and coordinates programme delivery.

Customer Solutions
The Customer Solutions team manages the connection of new customers to our network. This includes the engineering and planning of optimal technical solutions, agreement on commercial arrangements and managing of contractors appointed to do the physical connection work. This team coordinates with the Electricity division to understand the impact on the network of new connections.

Design
The design team supports delivery functions by providing protection, substation and overhead design services, and managing external design consultants.

6.4 LIFECYCLE APPROACH

6.4.1 OVERVIEW

Holistic asset management considers every stage of an asset's lifecycle, including inception and definition, design and construction, operation and disposal.

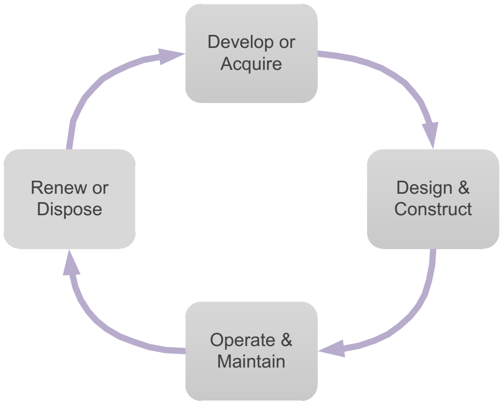
Our Asset Management Framework and Fleet Management Plans consider:

- The means to achieve cost-effective, reliable and practical operation.
- How to maximise the value of an asset over its lifecycle, tangibly and intangibly.
- The ongoing operational, maintenance and refurbishment costs over the expected life of the asset.
- The complexity and cost of decommissioning and removal.
- Any possible environmental impacts at all stages of the asset lifecycle.

6.4.2 OUR ASSET LIFECYCLE

Our interpretation of the lifecycle is shown below in Figure 6.4.

Figure 6.4: Asset management lifecycle



The four stages of the asset lifecycle and where they are addressed in our asset management processes, and the AMP, are described below.

Develop or acquire
This covers the creation of an asset through development or acquisition, spanning the identification of the initial need, assessing options and preparing the conceptual designs. At this point it is handed over to our Design and Works Delivery teams.

New assets are mainly constructed to address:

- Network growth and security (discussed in Chapter 11)
- Network reliability enhancements (discussed in Chapter 12)
- New customer connections and relocations of existing assets (addressed in Chapters 24 and 25)
- Future network needs (discussed in Chapter 13)

Design and construct

This covers detailed design, tendering, construction and project management, commissioning and handover of new assets to the operational teams. How this is carried out for our asset fleets is discussed in Chapters 15-21.

Operate and maintain

This covers the operation and maintenance of our electricity assets. It aims to ensure the safe and reliable performance of our assets over their expected lives. This is discussed in detail in Chapter 23.

Renew or dispose

This covers the process to decide when to renew and/or dispose of assets. Generally, the decision to renew or dispose is considered when an asset becomes unsafe, obsolete, or would cost more to maintain than to replace. How this is undertaken for our asset fleets is addressed in Chapters 15-21.

6.5 ASSET MANAGEMENT GOVERNANCE

6.5.1 OVERVIEW

Each year the focus of our expenditure and associated budget is considered and approved by our Board. Works plans are approved by the GM Asset Management & Network Transformation under delegation, reflecting the Board's direction.

Once work plans are approved, the listed projects are subject to further individual approval based on our Delegated Financial Authority (DFA) policy. Any additional expenditure exceeding financial authority limits triggers further review.

This section describes how asset management decisions are made and approved.

6.5.2 ASSET MANAGEMENT PLANNING RESPONSIBILITIES

We have broadly eight levels of asset management planning activity, ranging from strategic decisions by the Board and CEO, to approval of operations and maintenance decisions by operations staff and field crew. Each layer of governance is designed to provide clear 'line-of-sight' between our Corporate Objectives and asset management activities.

Table 6.1 provides an overview of these expenditure planning governance levels.

Table 6.1: Asset management planning responsibilities

LEVEL	PURPOSE	RESPONSIBLE	DOCUMENTATION
Corporate strategy	Setting high-level objectives and targets for the company.	CEO, Executive	Vision, Mission and Values, Corporate Objectives, Asset Management Policy, Business Plan
Asset Management Strategy	Supports Corporate Objectives, sets asset management objectives, goals and targets.	GM Asset Management & Network Transformation	Asset Management Strategy, Asset Management Framework
Asset Management Plan	The plan to implement the Asset Management Strategy. It sets out the 10-year investment plan, drawing on the short-, medium- and long-term planning documents.	GM Asset Management & Network Transformation	Asset Management Plan
Long-term planning	The plan for development of the network and its bulk supply points to meet the needs of customers in the long term – up to 20 years.	Network Development Manager, GM Asset Management & Network Transformation	Long-term Network Development Plan
Medium-term planning	Fleet, network development and operating activity plans, covering the next 10 years, including expenditure forecasts.	GM Asset Management & Network Transformation, Network Development Manager. Asset Fleet Manager, Investment Optimisation Manager, Asset Analytics Manager, Network Transformation Manager	Network Development Plan, Fleet Management Plans, Maintenance Strategy, Network Evolution Plan, Deliverability Plan
Electricity Works Plan	Planning of Capex and maintenance delivery programmes.	GM Asset Management & Network Transformation, Network Development Manager, Asset Fleet Manager, Operations Manager	Two-year Rolling Works Plan, Annual Maintenance Plan
Detailed project plans	Detailed planning of project and activity delivery.	Network Development Manager, Asset Fleet Manager	Project briefs, business cases and Board papers
Works Delivery and field operations	Oversight of capital project and maintenance delivery.	Works Delivery Manager, Project Managers, Network Operations Manager	Detailed construction schedules, detailed maintenance schedules, outage schedules, tendering material

6.5.3 DELEGATED FINANCIAL AUTHORITY

The Delegated Financial Authority (DFA) policy aligns with our corporate governance charter and group delegations of authority. It sets out expenditure limits that each manager is authorised to approve, the process for approving payments, and the cross-checks built into this. Application of the DFA policy is externally audited on an annual basis.

Expenditure limits apply to capital and operational expenditure, network or non-network, and budgeted or reactive. The typical DFAs for our Electricity Division are listed in Table 6.2.

Table 6.2: Delegated Financial Authority limits

LEVEL	CAPEX LIMIT	OPEX LIMIT
Board	>$2m	>$2m
CEO	$2m	$2m
GM Asset Management & Network Transformation	$1m	$1m
Senior managers[12]	$500k	$500k
Other managers	$250k	$250k

6.5.4 ASSOCIATED PLANNING DOCUMENTATION

The suite of planning documents and processes that underpin our network capital and operating expenditure investment plans are shown in Table 6.3. The outputs of the various plans are consolidated in the Asset Management Plan.

Our Network Development, Fleet Management, and Works Delivery teams are responsible for identifying, justifying and scheduling necessary works. The former two own the plan, while the latter provides advice on deliverability, outage planning and resource availability.

Individual projects are justified and approved using the stage-gated process described in Chapter 7. These projects are added to the rolling works plan. The annual electricity budgets determine the number of projects that can be completed from the rolling works plan for a given year. The budget is subject to challenge and approval by the Board.

By their nature, maintenance management plans do not lend themselves to the same detailed long-term planning as larger capital projects. Maintenance planning is generally done on a portfolio basis, with only activities or programmes that represent material changes to existing practices separately identified in the 10-year plan.

Table 6.3: Capital works plans and horizons

PLAN	HORIZON	PURPOSE	REVIEW FREQUENCY
Long-term Network Development Plan (under development)	20-year	Describes our long-term network development needs, particularly relating to bulk-supply points, major long-term network upgrades and re-architecture plans.	Two-yearly full update, interim summary updates
Network Development Plan	10-year	Sets out growth and security plans, broken down into the 13 planning areas. It also covers network augmentations for automation, reliability and communications.	Annual update, two-yearly comprehensive review
Fleet Management Plans	10-year	Sets out the renewal and maintenance requirements for each of our 25 asset fleets, grouped into seven main portfolios, and the associated projects and programmes.	Annual update, two-yearly comprehensive review
Network Evolution Plan (under development)	10-year	Sets out our plan to evolve to a Distribution System Integrator, covering the intended research, development and proof of concept work to support this. Also addresses innovative applications that are being implemented but are not yet mainstream planning solutions.	Annual comprehensive review and update[13], annual programme update
Deliverability Plan	Five-year	Sets out our approach to ensuring that sufficient resources (contracting and material) are available to undertake the proposed network construction and maintenance works for the next five years.	Two-yearly comprehensive review, annual programme update

[12] The Operations Manager may approve budgeted network Capex and Opex up to $750k.

[13] As new technology and customer applications are evolving at an increasing pace, it is essential to review and update the network evolution strategy more regularly than the conventional business plans.

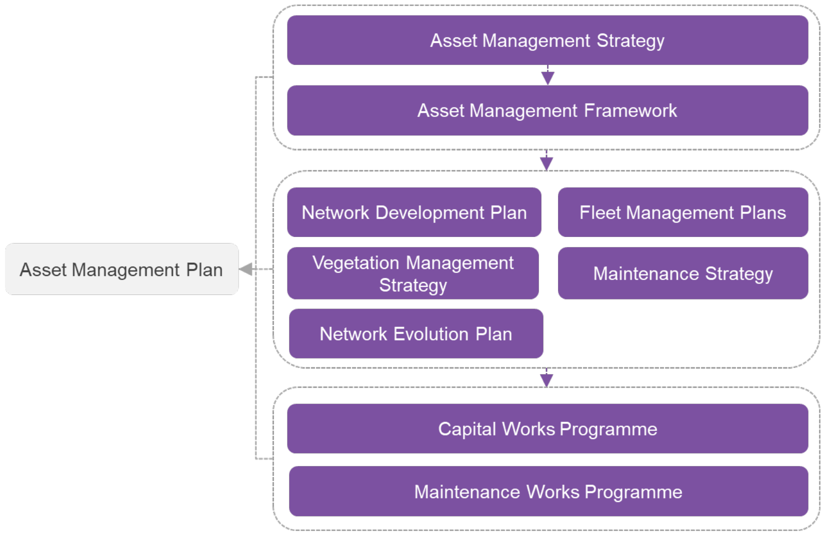
PLAN	HORIZON	PURPOSE	REVIEW FREQUENCY
Electricity Works Plan	Two-year	We have developed a full end-to-end workflow for our planned capital work that moves us from an annual batch process to a rolling delivery model. Capital works projects developed from our needs analysis give us, at a high level, a long-term 10-plus year view of our network needs, with the first five years being further defined, and the initial two years detailed at an individual project level. Reactive replacements (renewal required as a result of unforeseen asset damage) are separately allowed for in the works plan, based on historical run-rates.	Constant. The Electricity Works Plan is a living list of projects that our planners continually revise to keep two years of work available, ahead of our Service Delivery teams.
Business cases and board papers	Project-specific	Details the proposed major project solutions. Formal board papers are prepared for projects requiring board sign-off.	Per project
Project briefs and designs	Project specific	Describes capital projects in sufficient detail to allow detailed designs to be prepared, or in some cases to issue construction tenders. In most cases designs are prepared before issuing tenders.	Per project

6.5.5 AMP DEVELOPMENT AND APPROVAL

Our AMP summarises the key elements of our asset management documentation. It is an important means of explaining our approach to managing our assets to internal and external stakeholders. It aims to meet our Information Disclosure obligations.

It summarises our internal asset management documentation as depicted in Figure 6.5.

Figure 6.5: Internal asset management documentation



Our AMP summarises our strategic asset management documents – our strategy and framework. These documents form the basis of our Asset Management Objectives and are approved at Board and CEO level.

The AMP includes our prioritised 10-year network investment plans, with associated Capex and Opex forecasts. The portfolio plans include our area plans, fleet management plans and our network Opex strategies.

Our works programmes for capital projects and maintenance form the basis of our short-term forecasts. These reflect our asset fleet expenditure forecasts, customer connections forecast, and network Opex forecasts.

The AMP is developed with oversight and input from our regulatory team, which advises on relevant Information Disclosure and certification requirements.

Reflecting its role as a key stakeholder document, the AMP is reviewed by our EMT and ultimately approved by the Board. As part of this process, proposed expenditure plans are again scrutinised and challenged. This may include obtaining the opinion of external independent reviewers and advisors.

6.6 ORGANISATIONAL RISK MANAGEMENT

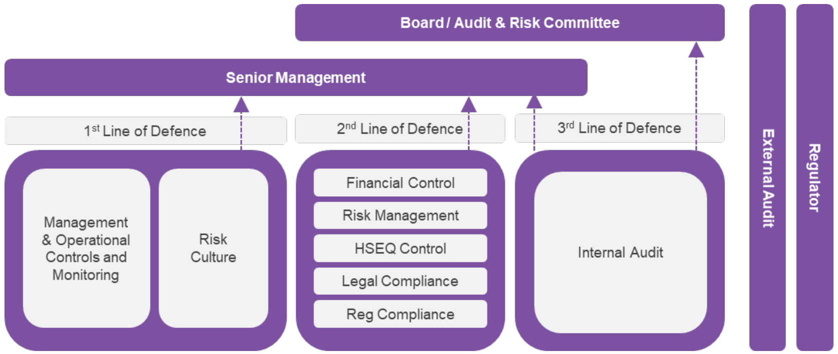
6.6.1 APPROACH

Risk management is embedded within all parts of our organisation's functions and in the decisions we make. To assist with the decision-making process, our risk management approach is based on the Three Lines of Defence (3LoD) model as shown in Figure 6.6. The 3LoD model is being adopted as it enhances clarity of roles and helps improve the effectiveness of risk management systems.

The 3LoD approach is a natural evolution of the highly regulated, safety focused and process driven nature of our industry. In an ideal world, we would require only the 1st Line of Defence to manage all our risks. The 2nd Line of Defence scans the horizon for gaps in the first line and recommends ways to plug them. The 3rd Line of Defence measures the results of the first two lines of defence and reports on their efficacy.

As we progress through our ISO 55001 certification, we expect to better define our processes around the 3LoD framework. This includes better definition of roles and responsibilities and a clear articulation of continual improvement processes and inter-team accountabilities.

Figure 6.6: Three Lines of Defence for organisational risk management



1st Line of Defence

This is the principal area where we focus our risk management efforts. A significant portion of business-as-usual practices, eg standard operating procedures, permit control, and confined space entry, reside in this layer. Section 6.7 highlights in more detail how we manage risks in this layer. This layer includes Line Supervisors and Frontline Staff that conduct work on the network. A significant portion of the effort spent by the EMT and Senior Management also forms part of this layer of defence.

2nd Line of Defence

This includes various compliance oversight functions. The objective of this line is to monitor key risk indicators and tell management where it should focus its efforts. We intend to strengthen the second layer of defence as part of improving our risk management maturity. Functions of this layer include:

- Multiple compliance oversight teams with responsibility for specific types of compliance monitoring, such as health and safety, environmental, regulatory, commercial, legal or HR.
- Risk management team that provides risk consulting and other business support services consistent to the relevant ISO standards.
- Financial control functions that monitor financial risks and financial reporting issues.

3rd Line of Defence

Internal Audit is the 3rd Line of Defence. This function is managed by the Risk and Assurance team consisting of qualified internal auditing staff. Being a small team, most of the assignments are outsourced to independent external assurance providers. The scope managed by the team includes[14]:

- Risks relating to the achievement of our strategic objectives are appropriately identified, evaluated, effectively managed and accurately reported.
- The actions of management, employees, and contractors align with our policies, procedures, and applicable laws, regulations, and governance standards.
- The results of operations or programmes are consistent with our goals and objectives.
- Operations or programmes are being carried out effectively and efficiently.
- Processes and systems enable compliance with the policies, procedures, laws, and regulations that could significantly impact us.
- Business information and reports are reliable and have integrity.

[14] Individual business units may also choose to undertake individual ad-hoc audits to focus on specific tasks and issues. This is considered a 1st Line of Defence

6.6.2 PROCESS

Our staff focus most of their effort managing risks within the organisation. They use various tools, systems and techniques to assist with decision-making within the organisation, but they all have the following in common.

Systems are aligned to the overall corporate objectives

Although there are multiple tools used to understand risk, the risks are broadly categorised into one of the following categories:

- Health and safety
- Environmental
- Asset integrity and performance
- Operational continuity
- Regulatory and legal compliance
- Financial and commercial

Segmenting the risks into the above categories allows us to assess most situations within the business. These categories also allow us to bundle similar risks together and communicate them effectively to all stakeholders.

Analysis of risk is comprehensive

Having in-house specialist skills for IS, Legal, Regulatory and HSEQ gives us the ability to understand the risks from various perspectives and ensure all possible impacts are understood. We also budget for Research and Development (R&D) projects to understand risks now, before they potentially impact us in the future. Combined with the 3LoD structure of the organisation, they provide us with comprehensive coverage against unforeseen risks.

Systems are proportionate to the task being assessed

Within our organisation we use different tools and techniques to assess different types of risks. For example, teams use various risk analysis techniques, such as:

- Condition-Based Risk Management (CBRM) spreadsheets to understand the risks on our medium and high value point assets eg power and distribution transformers, circuit breakers, ring main units etc.
- Demand forecasts, historical fault rates and Value of Energy Not Served (VoENS) calculations for feeder capacity to understand the risk of network constraints.
- Portfolio optimisation of the right mix of non-network projects using a risk-based project prioritisation tool.
- Network Approval testing considering operational risks before accepting new equipment for use on the network.

Risk management is embedded in the DNA of daily activity

The role of our employees, and the industry, has always been to minimise risk for all – the public and us. New standards are written when risks are assessed and understood to embed the learnings into our practices.

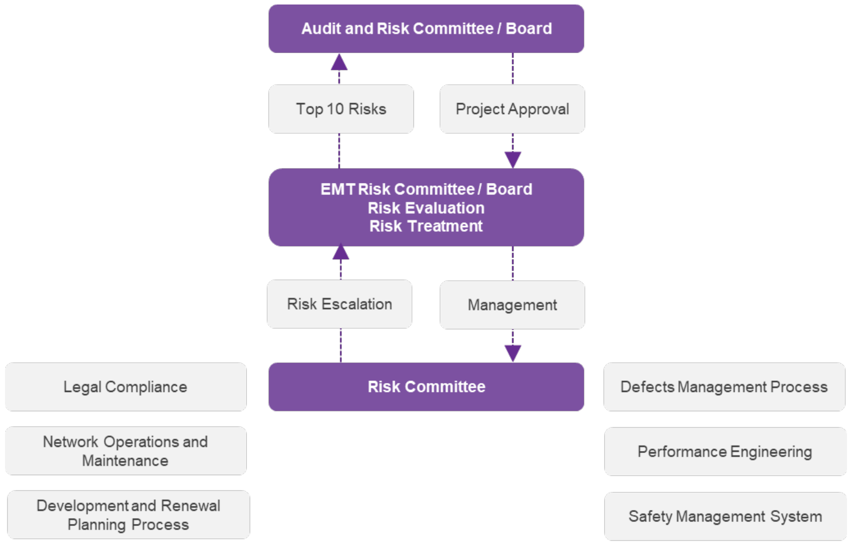
We are evolving our process of articulating and communicating project risks to a wider group of stakeholders. Project prioritisation and cost benefit analysis is an area that we are working on improving. This improves our portfolio optimisation capabilities. It also includes extending our defect criticality framework for small project prioritisation.

Risk is communicated across our organisation

Our Board is accountable for the effectiveness of the risk management framework and its practices. This helps to ensure risk management extends throughout the hierarchy of the organisation. The Board is responsible for governing risk policy development and has an Audit and Risk Committee (ARC) that oversees risk management practices. The executive team reviews risk and audit issues regularly to determine possible changes to the strategic and operational environment.

Our risk management process is illustrated in Figure 6.7.

Figure 6.7: Our risk management process



6.6.3 RISK REGISTER, MONITORING AND REPORTING

Risk registers are used to demonstrate, monitor and articulate the risk management process. The registers are regularly maintained, updated and audited, as well as reviewed by senior management. The highest risks are reported to senior management on a monthly basis. These, together with Electricity Division risks, are reported to the ARC at least quarterly.

Key features of our risk registers include:

Context and objective

Each risk entry is given a unique identifier, pertaining to the area of the business that it belongs to. This provides perspective to the risk and allows us to monitor each risk item throughout its lifecycle.

Risk assessment

This portion of the risk register is used for describing and assessing the risk. Traditionally, this is articulated by the likelihood and consequence assessment framework. We are also introducing a control effectiveness and impact framework that measure asset risks.

Management of risk

This includes details of the actions implemented to manage the risk and the controls put in place. We are considering including nominated risk owners and any internal stakeholders for the risk items in future risk registers.

Monitoring of risk

Subsequent updates to risk items are recorded until they are resolved. This also results in appropriate and constructive reviews of the risk register.

6.7 ASSET RISK MANAGEMENT PROCESSES

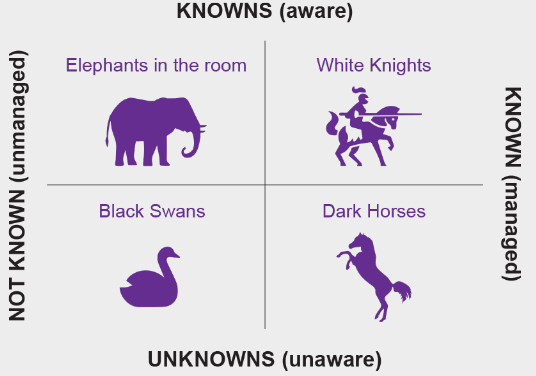
6.7.1 ASSET RISK REGISTERS

With ever increasing knowledge of our assets, changing consumer preferences and continuous improvements in safety and quality standards, the risk landscape on our network keeps changing. Therefore, we do not consider all risks equally.
We prioritise the asset risks we focus our limited resources on. More importantly this includes agreeing on which risks we can tolerate and which we cannot. This allows us to prioritise effort and evolve our business accordingly.

To help us with managing our asset risks, we are in the process of developing fleet-specific risk registers. These will help us understand the risks in our fleets, eg the identification of type issues, identify the need for further quantitative risk assessments and inform our investment and electricity works plans. The asset risk register process will also monitor and review risks by nominating individuals accountable for managing items and reporting on their progress.

Categorising risks allows us to focus resources where needed

Apart from evaluating risks by size, risks can be prioritised based on the status of the risk by tracking it through its lifecycle. The four stages of a risk lifecycle can be considered as follows:



- **Not Known Unknowns (Black Swans):** These are risks that are not on our radar, nor is it usually possible to identify them. They can be considered complete surprises.
- **Not Known Knowns (Elephants in the Room):** These are risks that we know exist but require action to be managed to tolerable levels.
- **Known Unknowns (Dark Horses):** These are usually risks under consideration. They include a lot of uncertainty based on our state of understanding. We are developing our understanding and management of them.
- **Known Knowns (White Knights):** We have a high degree of certainty about these risks. They are considered as facts and are part of the nature of conducting business. These risks are well managed and define our risk appetite.

We are in the process of incorporating the risk status within our asset risk management processes to assist with their prioritisation.

6.7.2 HILP EVENTS

High Impact Low Probability (HILP) events have the following characteristics:

They are high impact

This can be defined as events that have a larger impact than that allowed for in our normal system planning criteria. This includes extended contingency events (ie N-2 or greater), common mode failure events and domino effect failures (ie failures causing subsequent systems to fail). It is hard to predict how these events may eventuate because there are multiple failure modes for them. Well known examples include:

- Penrose cable trench fire
- 220kV earth shackle failure at Otahuhu
- Christchurch earthquake
- Eastern seaboard blackout in the United States

They are low probability

This could be defined as events that have a return period 10 times greater than the life of the asset for common mode and domino effect failures, and/or return period of more than 500 years for extended contingency events. While the probability of individual events may be low, the combined probability of these events is appreciable.

Since the failure mode of these events is unpredictable, most mitigation focuses on impact-reducing activities. Our asset management processes address a lot of HILP risk, including processes such as:

- **Building diversity into our network** not only from an electric circuit perspective (focus of our planning criteria) but also from a geographic and natural disaster perspective.
- **Maintaining our assets to updated codes, eg NBS standards and AS7000,** results in assets being progressively upgraded to ensure resilience to earthquakes and improved response to storm events.
- **Improving our operational response** by having appropriate contingency plans in place for extended contingency scenarios.
- **Taking an active role in Civil Defence and Emergency Management (CDEM) activities** associated with any failure to reduce vulnerability, eg establishing contingency plans to deal with the consequences of, as yet, unknown modes of failure.
- **Considering diversity in our designs** to improve resilience to type issues as well single event failures ie having a mix of cables and overhead lines as they have different failure modes.
- **Geographically diverse and multiple supply points** on the network means that natural disasters will impact only part of our networks. This includes considerations such as creating independent physical routes for redundant circuits feeding important load, or multiple grid exit points limiting the impact of upstream failure to localised areas.
- **Standardised equipment** utilised on our network means equipment can be reallocated/rebuilt easily in the event of failure. Standardised designs and components also make them easy to repair and reconfigure if necessary.
- **Multiple control options** mean that we have alternative control and emergency management capability available if the New Plymouth facility is disabled.

Improving our HILP analysis

The above Business as Usual (BaU) asset management practices provide multiple layers of protection for HILP risks. However, our improving maturity will include new ways to analyse the risk. This includes understanding the impact of natural disasters on vulnerable portions of our network.

We are considering undertaking a lifelines analysis (like the MERIT[15] analysis undertaken by the Wellington Lifelines Group) to better understand these factors. This will allow us to identify the most vulnerable portions of our network, allowing us to target resilience investments.

Incident response

As a ‘lifeline utility’ we have responsibilities under the CDEM Act for maintaining the services provided by our essential infrastructure.

We have an active and formal process of response management in place that covers the full range of natural events that impact our network. Scenario testing has been completed through a range of studies to understand the impact on our networks, including modelling the effect of a volcanic eruption and understanding the susceptibility of essential assets, such as our depots, to liquefaction.

However, it is not enough to consider only our own assets. Many HILP events have outcomes that involve a complex web of infrastructure. We take part in Lifeline Advisory Group meetings where various infrastructure representatives meet to discuss response readiness. At semi-regular intervals we take part in regional exercises to act out response to major events, and participate in actual events.

A recent example was the flooding along the banks of the Whanganui River during which we had to isolate about 160 affected customers from the power supply.

[15] MERIT is a suite of ‘Integrated Spatial Decision Support Systems’, developed by New Zealand Ministry of Business, Innovation and Employment that estimate the economic consequences associated with disruption events

In another event, a substation was flooded because of blockages in the storm water system nearby. This caused the substation to be out of service for several days while it was cleaned up and active management via the local CDEM group was a critical part of our response.

The contingency plans we have in place are discussed in more detail in section 6.7.3below.

6.7.3 CONTINGENCY PLANNING

6.7.3.1 OVERVIEW

Our primary overarching emergency plan and procedures are set out in our Electricity Supply Continuity Plan (ESCP). The ESCP sets out the composition, authority, responsibilities and the reporting structure for electricity emergency response teams and resource allocation. Individual risks are not the focus as procedures are designed to ensure the support structure mobilised is appropriate to the particular emergency situation. Testing of the ESCP and training of staff is ongoing.

The aim of this plan is to sustain electricity network capabilities through abnormal emergency situations by effective network management and practices.

The plan is designed for emergencies, ie events that fall outside of the ordinary operation of the network. Table 6.4 provides an overview of the main plans and procedures that support the effective operation of the electricity network in emergency situations.

Table 6.4: Emergency plans and procedures

OBJECTIVE	DESCRIPTION
Incidents (non-ESCP)	Incidents are relatively common but unpredictable events that can be managed within the normal operating framework of the NOC. These would be handled by personnel as virtually a routine job and would normally not require the presence of a supervisor on-site for the full duration of the operation. Examples include: – Reported lines down or pole fires – 'No-power' calls – Network faults
Emergencies (ESCP)	An emergency is an unplanned event that presents or has the potential to present a major disruption to the normal operation of the network. An emergency is too big a problem to be handled effectively using BaU resources and capabilities, eg without bringing in extra staff who are not on call. Events that may cause, or be lead indicators for, emergency situations include (but are not limited to): – Natural disasters (flooding, earthquake, volcanic eruption, cyclone, tsunami) – Major transmission network or generation failure – Significant natural or human threat or impact to the NOC A network emergency would require the presence on-site of a supervisor and, depending on the situation, a senior manager at the emergency control centre. General guidelines for classification of an event as an emergency situation are set out below: – Loss (or potential loss) of 10,000 customers or 20MVA of load (or greater) where this is likely to be sustained for more than six hours – Loss (or potential loss) of between 5,000 and 10,000 customers or between 10 and 20MVA of load where this is likely to be sustained for more than 10 hours – The declaration of a civil defence emergency – The evacuation of the NOC other than for a fire alarm

Other plans and procedures that support the ESCP include:

- Generic emergency procedures, such as the major network incident and severe weather event procedures.
- Specific emergency plans, such as the Pandemic Preparedness Plan and the Volcanic Ash Recovery Guidance, which outline tailored responses that are appropriate to a specific type of emergency.
- Support systems contingency plans, including the Operational Communications Contingency Plan, SCADA Contingency Plan and the Load Management Contingency Plan, which provide guidance on how to support these critical functions when a failure occurs.

- Civil Defence emergency management and liaison standards, which guide the relationships with the Civil Defence authorities.

A comprehensive set of site-specific substation contingency plans are in place. These identify known local risks and operational options for dealing with local network problems that could arise.

6.7.3.2 MAJOR NETWORK EVENT PROCEDURES

Major network incident and severe weather event procedures outline the generic emergency response process for a wide range of emergencies. They provide guidelines for assessing the extent of the damage or threat, making necessary preparations, and responding to severe weather events and major incidents that cause extensive loss of supply to customers. They provide a basis for communicating and establishing a common understanding of the specific roles, responsibilities and activities to be undertaken in response to incidents.

The procedures scale up to and connect with the more comprehensive ESCP. Depending on the event and its effect, or likely effect, on the network, the NOC will announce an appropriate storm response level – categorised in terms of an R – Readiness, L1 – Level 1, L2 – Level 2, or L3 – Level 3. Based on the storm response level, the procedures provide further guidance on the types and level of activities deemed appropriate in responding to the event.

The procedures provide guidance on three emergency response processes:

- The restoration process
- The strategic management process
- The stakeholder communication process

6.7.3.3 PANDEMIC CONTINGENCY PLANS

We have developed a plan to respond to an influenza pandemic occurring in New Zealand. This plan provides a basis for establishing a common understanding of the roles, responsibilities and activities to be undertaken in response to the pandemic to ensure the operational integrity and continuity of our networks. Because of the unpredictable nature of pandemics, the plan also considers the wider implications for the company beyond its obligations as a lifeline utility provider.

7 CAPITAL PROJECT PLANNING AND DELIVERY

7.1 CHAPTER OVERVIEW

This chapter provides an overview of the frameworks and processes that are used to identify, justify, schedule and implement capital projects on our network and within our organisation. This chapter covers:

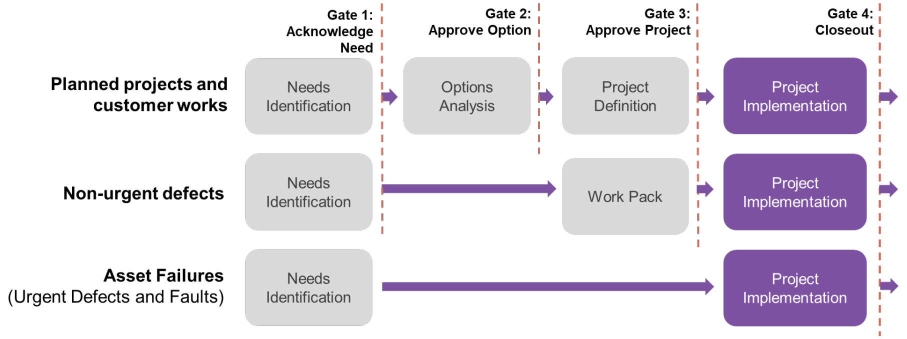
- Approval and governance for network capital expenditure.
- Network development planning for growth and security projects, with proposed projects described in Chapters 11 and 12.
- Asset renewal projects planning and forecasting, with proposed projects described in Chapters 15-21.
- Delivery of network development and renewals works.
- Identification, prioritisation and rectification of defects on the network.
- Approval and governance for non-network capital expenditures.

7.2 WORKS PROGRAMME DEVELOPMENT

7.2.1 OVERVIEW

Network investment planning and implementation follows a stage-gated challenge and approval process, see Figure 7.1. The first three gates ensure appropriate governance is applied and challenges are posed before projects are able to be included in the two-year rolling Electricity Works Plan (EWP). The EWP is developed to reflect as closely as possible the specific investments and investment mix set out in the AMP, considering the latest possible information on network needs and construction status.

Figure 7.1: Network Capex approval stages



The number of gates that a project must pass through differs depending on the urgency and complexity of the works. Planned works pass through multiple gates, including approval to move draft proposals to pre-approved status, upload to the rolling works plan, and approval to send out for consultation before option approval.

To facilitate fast remediation, defects and faults have fewer gates they must pass through.

Projects are prioritised both at the needs identification stage and option analysis stages. Investment proposals are methodically reviewed and challenged to identify and rank them in decreasing cost-benefit order, both within and across growth and security and fleet management portfolios.

7.2.2 GATE 1 – ACKNOWLEDGE NEED

The first approval stage-gate is an acknowledgement of identified investment needs, generally by the relevant team leader. This follows a detailed review of the underlying need and challenge of the assumptions underpinning the rationale for, and timing of, the investments. The approach taken to assessing the need will vary by investment type and size. Some examples of these assessments are:

- **Growth and security** – needs are determined through contingency analysis modelling, using forecast demands and comparing the network's capability against Security of Supply criteria and capacity constraints. Initial assessment is generally undertaken by the relevant Area Planning Engineer, with needs mainly arising from demand growth or new developments. Growth and security needs are assessed on whether the technical analysis is sound, and whether work is aligned with customer requirements and/or reasonable demand growth expectations.
- **Planned renewal** – needs are identified from evaluating renewal drivers, such as condition, obsolescence or lifecycle economics. Needs are assessed based on the risk that the renewal drivers represent in terms of safety, customer service levels, lifecycle economics and environmental impact. Needs analysis also takes into consideration the long-term requirement for the asset, and the effectiveness of the proposed solution in remedying the risk represented by the renewal drivers.
- **Customer connection and relocation** – needs arise from requests for works from customers or other stakeholders such as the New Zealand Transport Agency (NZTA). The need for investment following these requests is assessed by the Commercial team following advice from the Asset Management team.
- **Network Evolution** – research or proof-of-concept needs are assessed on their alignment with our future network strategy and the robustness of the proposal.
- **Non-urgent defects** – needs arise from our condition-based maintenance strategy where scheduled inspections identify assets approaching and falling

below pre-defined serviceability thresholds set out in our inspection standards. We refer to this type of Capex as 'unplanned' as it is carried out in short-cycle time using a continuous process rather than a planned project approach. Condition-based renewal work is prioritised using a criticality methodology that takes into consideration safety, supply quality, lifecycle economics and environmental considerations.

- **Asset failures** – relate to assets that are damaged by third parties, other external factors, or fail during operation. Actual projects are not identified in advance. These works are usually moved directly to implementation.

7.2.3 GATE 2 – APPROVE OPTION

Planned projects and customer works undergo options analysis before the recommended solution is put forward for approval. The recommended solution is checked for consistency with our overall Asset Management Objectives, cost effectiveness, technical feasibility and deliverability.

The approach taken to test the proposed solution will vary by investment type and scope. Some examples are:

- **Growth and Security** – solutions are generally reviewed by the Network Development Manager. This review assesses whether the proposed solution and its timing support our overall Asset Management Objectives. Solutions are challenged based on whether the supporting technical and costing analysis is sound, the solution will meet future demand growth projections, and it represents the least-cost, technically feasible solution. The degree to which non-network solutions were considered is also tested. Refer to Sections 7.3.7 and 7.3.8 for further details.
- **Renewal and Refurbishment** – solutions are generally tested by the Asset Fleet Manager. This review assesses whether renewing the asset(s) and its timing will support our overall Asset Management Objectives. Cost effectiveness and deliverability are important considerations. This may include testing against non-network and/or Opex solutions. Refer to Section 7.4.3 for further details.
- **Consumer connections and asset relocations** – solutions are generally reviewed by the Commercial Manager. However, less rigour is applied to assessment of options as the customer often dictates what is required.
- **Network Evolution** – proposals are generally reviewed by the Network Transformation Manager. Research-based investments are tested to assess the expected learning, potential network benefits, cast and practicality of the activity proposed.

7.2.4 GATE 3 – APPROVE PROJECT

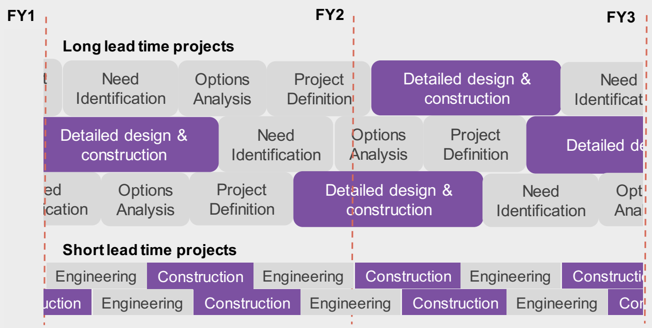
This is the final pre-approval challenge for planned projects, associated budgets and defect work packs. At this stage, projects are subjected to more detailed planning, cost estimation and final scrutiny of options than at the earlier gates.

Once approved via the Delegated Financial Authority (DFA) process (refer to Chapter 6, section 6.5.3), delivery of the project becomes the responsibility of the Works Delivery team, with the project manager having overall responsibility. During execution of a project, there are several further governance steps relating to procurement and progress measurement, scope changes, and works acceptance. Our works delivery processes are described in further detail in section 7.5.

Change to a Rolling Works Plan basis

We have changed our capital works delivery processes to improve transparency, accountability and overall efficiency.

We have developed a full end-to-end workflow for our planned capital works that moves us from an annual batch process to a rolling delivery model. Capital works projects developed from our needs analysis give us, at a high level, a long term 10-plus year view of our network needs, with the first five years being further defined, and the initial two years detailed at an individual project level, forming our EWP.



The previous process required the annual plan to be formed, prioritised and approved, with prioritisation occurring as an annual event. This annual planning cycle created concentrated peak workloads for each part of the delivery chain as the projects moved through the cycle. The new process focuses on regular assessment of priorities, followed by a continuous flow of projects through the process. The EWP becomes a living list of projects that our planners continually revise to keep a rolling two years of work available, ahead of our Service Delivery teams.

Cont…

In the Capital Works Programme our Programme Management team takes the EWP and schedule, and manages the work identified to be undertaken within the rolling two-year window. Projects enter the programme with key metrics such as priority, resource requirements, System Average Interruption Duration Index (SAIDI) impact and dependencies. The team has the flexibility to move the timing of projects forward or backward depending on resource and outage availability, with a bandwidth provided by the project owner.

The programme is then continually updated as and when changes happen to projects.

7.2.5 GATE 4 – PROJECT CLOSEOUT

This is the final step in the implementation of a project. It requires review of as-built documentation, performance against budget and time schedules, and an honest assessment of what could have been done better, to therefore help future projects.

Recent process improvements require a greater focus on capturing the lessons learned throughout the implementation process. Feedback to project planners and designers is automated, so that we reduce our reliance on individuals to follow through.

The feedback includes measurement and reporting on the difference between expected costs and asset number against actuals. These are analysed and the lessons fed back to improve future cost estimates.

7.3 GROWTH AND SECURITY PLANNING

7.3.1 OVERVIEW

Growth and security planning involves anticipating peak customer demand, matching the capacity of our network to it, and maintaining appropriate service levels of reliability and system quality. The reliability of the electricity supply is largely governed by the degree of redundancy, or security, that we build into the network.

We broadly classify our growth and security investments into the following portfolios:

- **Major projects** – Over $5m, generally involving subtransmission or Grid Exit Point (GXP) works.
- **Minor growth and security works,** which includes
  - minor projects between $1m-$5m that typically involve zone substation works and small subtransmission projects.
  - repetitive routine projects below $1m, including distribution capacity and voltage upgrades, distribution backfeed reinforcements (supports automation), smaller zone substation upgrades, distribution transformer upgrades, and Low Voltage (LV) reinforcement.
  - communications projects to support improved control and automation of the network, and provide voice communications to our field staff.
  - investments in network monitoring, communcations and power quality management to support our transition to an open access network.
- **Reliability** – includes network automation projects to help manage the reliability performance of our network.

This section outlines the process we use to identify necessary growth and security-related investments. Projects anticipated during the planning period are detailed in Chapters 11 and 12, and in Appendix A8.

7.3.2 GROWTH AND SECURITY INVESTMENT PLANNING

The objective of growth and security planning is to provide a cost-effective service to customers in the form of:

- Adequate capacity to meet demand, and generation
- Adequate voltage
- A safe and reliable quality of supply

Planning for growth and security investments requires us to anticipate potential shortfalls of capacity, or breaches of our security criteria under forecast demand conditions. We plan for efficient and timely investment in additional capacity and security before reliability is adversely affected.

The considerations in this planning include security of supply, network architecture, asset capacities and how future demand is forecast. From these considerations we produce a growth and security plan for each network area. We refer to these as our area plans. Our approach considers:

- Demand forecasting
- Asset capacity ratings
- Network security standards
- Risk-based options analysis
- Consideration of network alternatives

Ensuring appropriate security of supply is a key focus of this process. Security drives the larger investments related to the subtransmission system and zone substations, which directly impact reliability to large numbers of customers.

The following sections explain these planning processes in further detail.

7.3.3 DEMAND FORECASTING

Growth and security planning is essentially a comparison of asset capacity against forecast demand in the context of security – ie the degree of redundancy required to minimise outages arising from credible contingent events.

Demand changes with time, both in terms of the reasonably predictable and repeatable patterns of daily and seasonal load profiles, and the longer term trends in population, economic activity and consumer behaviour.

Because of the long lead time for major projects, it is essential to forecast the expected demand on all parts of the network several years ahead. This allows us to identify potential security issues well before they occur and schedule timely investments to address these. Demand forecasts are also used to identify the most efficient investment options. This involves considering the longer term demand outlook.

7.3.3.1 APPROACH

Our demand forecasting methodology models load – at a feeder level, which is more granular than in the past – and population and new connection trends. This improves the robustness of our forecasts, especially for loads dominated by residential and small commercial customers.

We also use scenario modelling, which will be important as we increasingly rely on probabilistic network development planning. We will continue to refine our forecasting approach because we need to understand at an early stage the potential impacts of new technology and increased customer choice.

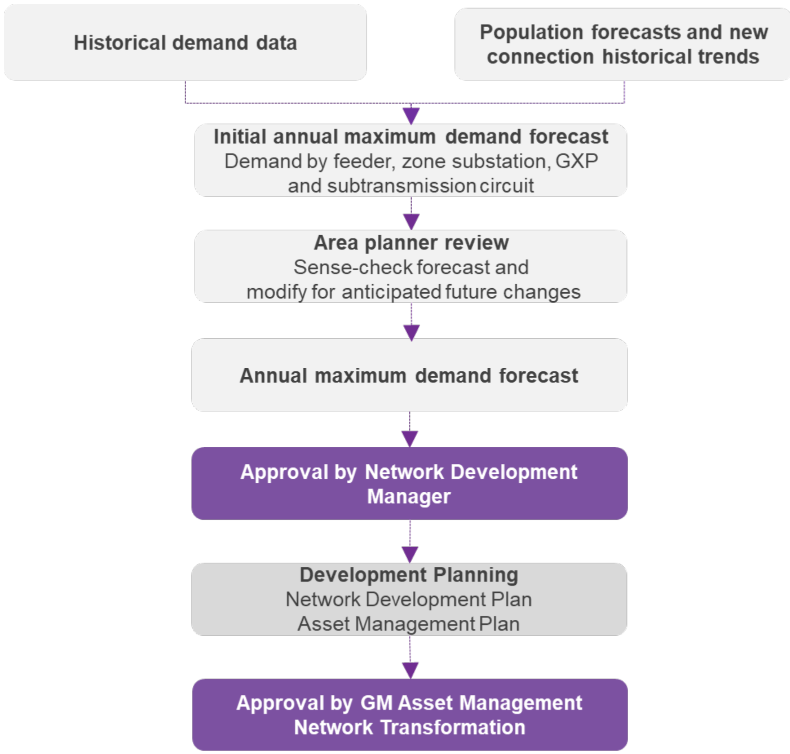
Growth and security planning requires demand forecasts at different network levels:

- 11kV distribution feeders
- Zone substations
- GXP and subtransmission circuits

We use the load forecasts we develop at the feeder level to create aggregate demand forecast at zone substation, GXP and subtransmission level. We estimate existing peak demand based on 90th percentile of filtered and trended historical peaks.

Figure 7.2 shows the key elements of our demand forecasting approach.

Figure 7.2: Demand forecasting approach



The starting point for our demand forecasting approach is distribution (11kV) feeder level forecasts. Our modelling combines NZ Statistics census area population forecasts mapped to each feeder and historical trends in new customer connection trends. This approach works especially well with feeders serving numerous residential and small commercial customers.

Feeders serving one or a few large industrial customers are assumed to have zero growth. If customers indicate a demand increase, with a high degree of certainty, we reflect these as step changes in our base forecasts. No commitment for customer investments is made until formal customer agreements are concluded.

Predicting growth of feeders that serve a mixture of commercial and residential customers is subject to greater uncertainty than other feeder types. We plan to refine our forecast in future by introducing economic activity modelling at the commercial/industrial level.

Once growth rates for feeder forecasts are established, we assess the growth rate for zone substations, GXPs and subtransmission circuits based on the weighted average of feeder growth rates. Existing maximum demand is used as the weighting factor.

We estimate current peak demand based on modelling historical data. For zone substations and more aggregate demand categories, we adjust historical annual peak demands for distortions due to load transfers, both temporary and permanent. We assess current maximum demand as the 90th percentile of these filtered and trend adjusted demand series. This allows for a 1-in-10-year exceedance of the forecast demand peak, a level of risk considered appropriate. Feeders use a different approach that is tailored to their planning process and risk.

We generally consider a 10-year historical period in any analysis to determine trends or establish existing demand levels. This is considered a reasonable balance between stability (a shorter period can create excessively volatile outcomes) and responsiveness, such as to step changes in underlying, customer, demographic or economic activity.

We are considering the future use of our ripple control plant (to control hot water storage heaters) and other potential demand-side resources which may become available through new technology and communication capabilities. For now, our demand forecasts assume that deployment of ripple capability has the same impact as in the past.

Our demand forecast approach introduced scenario analysis to consider alternative future growth scenarios, building on the Ministry of Business, Innovation and Employment's (MBIE) Electricity Demand and Generation Scenarios (EDGS). Scenario modelling will become more important as we increasingly rely on probabilistic network development planning, which will consider the impact of new technologies and future customer choices, including when faced with different electricity pricing structures.

7.3.3.2 IMPACT OF EMBEDDED GENERATION

The impact of renewable embedded generation – photovoltaic (PV) or wind – has been discounted in our forecasts. This is because it is intermittent by nature, and without associated storage it has minimal impact on our predominantly winter peaking demand. Chapter 13 discusses future PV uptake scenarios that may impact future peak demand if combined with energy storage. Wind generation development on our network has been very infrequent, although may be substantial in capacity when it does occur.

Small hydro generation is also very limited in terms of physical opportunities. There is some activity around gas turbine peaking units in Taranaki, and this is subject to the relative economics of the fuel sources. Larger scale generation for any of these sources tends to be connected directly to the transmission grid and therefore does not impact our growth and security planning directly.

Historical demand data includes the net impact of existing embedded generation and ripple control. During the planning period, embedded generation is expected to be below the threshold of significance to peak demand, with a few exceptions that are adjusted manually.

7.3.4 ASSET RATINGS

The ratings, or capacities, assigned to circuits and transformers impact growth and security planning.

While all assets are assigned a specific standard or nominal rating, actual capacities vary in real time, depending on environmental conditions. Recognising load profiles and fault occurrences are also statistical variables – the management of load against capacity is effectively an exercise in risk management.

Standard ratings are therefore assigned at a level of risk that triggers analysis and planning, with sufficient lead time available to ensure network risk can be managed until upgrades are commissioned.

The principles behind asset ratings are universal, but the actual approach is tailored more specifically to the asset characteristics and thermal environment:

- **Zone substation transformers** – our standard assigns a maximum continuous rating and a four-hour rating, which applies to post contingent load transfer in an N-1 context. Our standard ratings for transformers often vary considerably from nameplate manufacturer ratings. This is done to ensure all our transformers are rated according to consistent and appropriate conditions for the New Zealand environment.
- **Overhead lines** – our standard assigns a nominal continuous rating that is used to systematically identify potential future overloads. Short-term ratings, ie a four-hour rating, are not appropriate for overhead lines because of their limited thermal capacity. Because of the influence of environmental parameters, our standard provides a framework for implementing dynamic rating schemes if a risk assessment confirms this is appropriate.
- **Underground cables** – ratings are being reviewed and we will soon issue a new standard. This will assign consistent, systematic standard ratings for planning analysis, and will also set a framework for dynamic or monitored rating schemes using distributed fibre temperature sensing.

7.3.5 NETWORK SECURITY STANDARDS

Security standards are normally defined in terms of N-x, where x is the number of coincident outages that can occur during periods of peak demand without extended loss of supply to customers. At the quantum of load encountered at most of our zone substations, N-1 is the optimal consideration – an outage on the single largest circuit or transformer can occur without resulting in supply interruption.

Zone substation security levels can also be 'qualified' by the time allowed to restore supply by network reconfiguration after an asset has failed. Three of our five security classes are qualified by the allowable switching time before all load is to be restored.

We also consider the size of load at risk in our security standards – with higher levels of redundancy or backfeed capacity required where more customers could be affected by an outage.

As noted above, effective tailoring of security standards for individual customers, especially mass market, is impractical. Our security criteria therefore are defined at zone substation level and above only.

To gauge whether our security criteria are effective in achieving our customers' desired service levels, we need to interpret their feedback on the more general price/quality trade-off, and consider any other industry benchmarks, trends or comparisons.

For example, we have aligned our security standards with the industry's guideline document produced by the Electricity Engineers' Association (EEA). In turn, this EEA guide seeks to set security levels aligned with the United Kingdom standard P2/6, while recognising the characteristics of the New Zealand industry and networks.

The EEA guide to security of supply introduces two approaches to security, and the underlying issue of reliability:

- A deterministic N-x security classification
- A probabilistic, reliability-based approach

In applying our security criteria, we have used a combination of these approaches. Our security standard is essentially a deterministic approach. It provides a consistent and systematic N-x criterion against which we can analyse the performance of all the subtransmission system and zone substations. This identifies any potential needs or issues that can then be ranked according to risk. The subsequent analysis of possible options to resolve these constraints then adopts a more probabilistic, or reliability-based approach. This helps determine the most cost-effective solution.

We use this two-stage approach since the sole application of N-x security criteria, while simple, does not address the subtleties of network architecture, asset performance and the inherently variable nature of key reliability parameters. Fully adhering to the deterministic criteria could result in significant additional capacity investment, without necessarily achieving equivalent benefits for our customers.

Deterministic security classes are a highly simplified representation of all possible fault scenarios and responses. They can only consider criticality (ie the consequence or cost) of an outage if it occurs at peak demand, but not the probability (ie likelihood or frequency of outages). However, they are simple and systematic to apply from a planning or operational perspective, and therefore well suited as a screening tool that identifies all potential needs or constraints above a threshold of risk.

In cases where there is clearly no economic option, we generally do not invest to provide higher than N security. Rural substations fed by a single circuit or with a single transformer, serving a small load, often fall into this category. For these the outage consequences can usually be managed operationally.

The probabilistic approach to options analysis also allows us to consider multiple different demand scenarios. We have recently introduced an upper and lower variant to our base forecast growth rate, drawing off variance seen in national demand growth forecasts published by MBIE. In future, we intend to develop this scenario forecasting and analysis further, so we can model the possible different uptake of new technologies, alongside the more traditional variances in economic and demographic drivers.

Our zone substation security classifications start with the 11kV feeder type (F1, F2, etc) at each substation. The feeder types are determined from the predominant type of customer on each 11kV feeder (see Table 7.3). The zone substation security classes are then determined from Table 7.1, which is a function of both 11kV feeder type and amount of load involved. These classes are shown in demand forecast tables throughout this AMP.

Table 7.1: Substation security class

FEEDER (LOAD) TYPE	ZONE SUBSTATION MAXIMUM DEMAND			
	< 1 MVA	1 – 5 MVA	5 – 12 MVA	>12 MVA
F1	AA	AA	AA+	AAA
F2	A1	AA	AA+	AAA
F3	A2	AA	AA	AA
F4	A2	A1	A1	n/a
F5	A2	A2	A1	n/a

The restoration targets assigned to each of the security classes are set out in Table 7.2.

Table 7.2: Security class restoration targets

SECURITY CLASS	TARGETED RESTORATION CAPABILITY FOR	
	1ST EVENT	2ND EVENT
AAA	100% - without break	> 50% in < 60 mins, remainder in repair time
AA+	100% - restored in < 15 secs	> 50% in 60 mins, remainder in repair time
AA	100% - restored in < 60 mins	Full restoration only after repairs
A1	100% - unlimited switching time	Full restoration only after repairs
A2	Full restoration only after repairs	Full restoration only after repairs

The first four classes (AAA to A1) all require either full or switched N-1 capacity, ie it must be possible to supply the peak load on the substation even with the loss of the single largest normal supply circuit or transformer. The different security classes simply mandate different restoration times.

The A2 class requires only N security. Supply can therefore be via a single circuit or transformer with limited or no backup. This class only applies to a few remote rural zone substations where alternative supply cannot be economically justified.

7.3.6 INVESTMENT TRIGGERS

Investment triggers are prompted by network needs if certain criteria have been met. This prompts a review of options to invest in the network, or non-network options, to restore appropriate levels of capacity or reliability. Growth and security investment triggers (by voltage level) include:

- **GXPs/transmission spurs** that exceed security criteria, effectively N-1.
- **Subtransmission and zone substations** that exceed security criteria, effectively a qualified or switched N-1.
- **Distribution feeders** that exceed guidelines or planning parameters related to voltage profile, thermal capacity of any given section of feeder, and number of connections.

The identification of an investment trigger does not automatically mean a project will be included in the EWP. For growth and security planning, we prioritise the identified needs according to the risk exposed by the constraint. This assists with the ranking and timing of related investments. Given capital and capacity constraints, low risk projects, or projects with low economic value are often deferred.

7.3.7 OPTIONS ANALYSIS

Options analysis is carried out on identified needs. The complexity of the analysis is kept in proportion to the level of risk and cost. We have developed a systematic and objective process to consider potential options. As an example, overhead line upgrade needs have several options, including thermal re-tensioning, re-conductoring, or the installation of new lines or circuits, ie dual circuit. We do not use duplexing.

Options analysis assesses costs over a 20-year period. A lifecycle approach involves consideration of all appropriate cost elements, including Capex, maintenance and losses. The analysis models the economic cost of reliability, where this reflects the cost of unserved energy to customers if supply cannot be maintained. Based on these factors, we identify the most cost effective, long-term solution overall.

We have developed a formal tool and guidelines for undertaking options analysis. This helps ensure that the assumptions and approach remain consistent between options, traceable and documented. The tool also provides built-in unit rates and helps estimate the cost of different options. These rates are aligned with our cost estimation systems.

7.3.8 NETWORK ALTERNATIVES

Increasingly we are considering non-network solutions as alternatives to, or in conjunction with, network investments for the deferment of, or instead of, traditional network investments. Evolving technology and economies of scale are expected to make such solutions more practical and cost effective than more traditional network solutions in the future. Examples that are likely to become more prevalent in future include:

- **Embedded renewable generation**
  - PV, especially at a residential level
  - wind, generally large installations in rural areas
  - hydro and micro hydro, although there are limited viable locations
  - biomass, some specialist possibilities
- **Embedded non-renewable generation**
  - diesel peaking or backup generators (very low utilisation)
  - gas-fired, typically in an industrial cogeneration context
- **Energy storage**
  - At present the most practical energy storage options for distribution networks are large or small-scale batteries, although other options such as heat, water or flywheel energy storage systems are also being considered. Storage offers several potential benefits, especially related to the ability to shave daily peaks, therefore reducing the network’s effective peak demand and/or increasing utilisation. Possible widespread Electric Vehicle (EV) uptake is a potential complementary storage facility, although depending on usage patterns, could also add to peak demand.

- **Demand-side management**
  - Technology offers emerging possibilities ranging from simple variable thermostats through to smart appliances and home energy management systems. Small scale distributed energy storage, eg home batteries, can effectively be treated as a demand-side resource.
- **Power flow**
  - Management/automation involves techniques to improve utilisation and use Special Protection Schemes (SPS), dynamic ratings and voltage/phase management devices.

New technology can complement more traditional demand-side options, such as ripple control, and this is an area we continually review to ensure we identify opportunities as they emerge. Our planning and approval process for larger projects includes a formal review of non-network solutions.

Third party provision of network alternatives

In October 2018 we went to the market with a combined Request for Information and Registration of Interest (RFI/ROI) for a transmission alternative service. The purpose of the RFI/ROI was twofold:

- To seek registrations of interest for supply of transmission alternative services for the Hinuera area.
- Use the RFI process to gather additional information and feedback on the process, information potential proponents require, types of services available, and how the services could be integrated into the electricity market.

The RFI process included good feedback that has improved our understanding of potential transmission alternatives and will be incorporated into the process that will be used for future transmission alternatives.

For the Hinuera Area Supply Reinforcement Project the transmission alternative is a permanent substitution of the transmission solution, not just a transmission deferment. It must be located in a specific area, and it has to cover 100% of the demand that would be interrupted (36MVA). Further details of the project can be found in Chapter 11.

7.3.9 DISTRIBUTION PLANNING

Distribution planning ensures the capacity and voltage profile of 11kV feeders are adequate to meet existing and future needs of our customers.

We use five 11kV feeder classifications, each of which represents the predominant type of load, or customer, served by that feeder. This load type is a proxy for the economic impact of lost supply, and therefore the targeted reliability standards for each feeder type differ according to the significance of reliable supply to customers.

Table 7.3: Feeder classifications

FEEDER CLASSIFICATION	PREDOMINANT CUSTOMER DESCRIPTION
F1	Large industrial
F2	Commercial/CBD
F3	Urban residential
F4	Rural (dairy or horticultural)
F5	Remote rural (extensive agricultural)

There are cases where feeders serve a mix of load types and, where necessary, a mixed classification is applied. Feeder classifications also determine the upstream zone substation load type, from which we work out the zone substation's security classification.

For distribution feeders there is no systematic contingency analysis, as is the case when considering subtransmission and zone substation security. This is because feeders have smaller loads and generally multiple backfeed options. There are some elements of reliability considered, but the focus of analysis for distribution planning is predominantly the capacity and performance of the network under normal configuration.

All 11kV feeders are modelled at regular intervals using the latest demand forecast to assess if there are any breaches of:

- The thermal capacity of any section of the feeder, particularly the first section of the feeder (with the heaviest loading).
- Voltage levels, especially whether the most remote point is below 95% of nominal.

Feeders are also assessed in terms of the number of Installation Control Points (ICP) as part of our reliability planning process. We aim to optimise the deployment of switches, reclosers and sectionalisers to improve quality of supply to our customers. Feeders or switched sections with too many ICPs may lead to lower reliability.

It is of note that our strategy to increase automation, in the form of automatic switching schemes, often triggers the need to increase backfeed capacity in the circuits themselves. This triggers additional development expenditure. For more information on our reliability and automation plans, see Chapter 12.

Other drivers for investing in distribution feeders are:

- Specific backfeed investigations, including inter-substation transfer, which identify opportunities for useful backfeed enhancements.
- Operational field experience, which also identifies practical opportunities to provide additional backfeed to 11kV feeders or substations.
- Customer feedback and complaints that identify localised voltage deviations – sometimes these are symptomatic of High Voltage (HV) feeder capacity constraints.
- Customer inquiries for increased capacity, if these impact feeder loading. This is especially true if more than one customer is affected, such as irrigation or dairy.
- Our guideline that feeder backbone loading is kept below 2/3 of capacity in urban meshed areas so that the load can be split over no more than two other feeders.

Distribution growth and security planning typically results in the following projects:

- Line upgrades and new sections of line (tie lines or new feeders).
- New cables, usually of larger capacity or to provide new 11kV feeders.
- Specific backfeed initiatives (increased capacity or new tie lines).
- Distribution transformer upgrades.
- Feeder voltage support (ie voltage regulators or capacitor banks).

7.3.10 DISTRIBUTED GENERATION POLICY

Our distributed generation policy has been developed to comply with the Electricity Industry Participation Code (EIPC) 2010, Part 6. It details our relevant internal policies, along with pertinent industry rules, regulations and standards.

Our policy is intended to support and facilitate the appropriate development of distributed generation. Two categories of generation capacity are recognised. Less than 10kW can usually be integrated with minimal cost and administrative requirements, while larger than 10kW generally requires more detailed review of possible safety and technical issues. All connections must meet all regulatory, safety, and technical requirements. We must be assured that the connection will not interfere with other customers or adversely affect the safe and reliable operation of the network.

Pricing methodologies are in accordance with the EIPC. For smaller generators, costs are like any other standard small capacity (eg domestic) network connection, generation or otherwise. For larger generators, there is scope to assess any potential benefits in terms of reducing our distribution or transmission costs.

The policy describes the application process, time frames applicable, disputes resolution process, terms of connection, and applicable fees. It also outlines requirements for the recovery of network support or avoided cost of transmission payments available to generators. The policy, together with application forms, links to relevant standards and detailed advice, is published on our website[16].

7.4 ASSET RENEWALS PLANNING

7.4.1 OVERVIEW

This section discusses the renewal drivers leading to project investment decisions, and the forecasting methods that we use to derive appropriate annual budgets for high volume assets, such as overhead lines.

This section introduces our fleet plans in Chapters 15-21 by discussing:

- How we plan for renewals
- The various forecasting techniques used
- The drivers behind individual renewals projects
- The triggers for renewal projects

7.4.2 RENEWAL INVESTMENT PLANNING

The long-term renewal forecasting covers a 10-year planning horizon. It includes high value projects – typically zone substation renewals – identified on an individual basis, and volume-based forecasts for high-volume low unit-cost asset types, such as poles, crossarms and conductors. Volumetric forecasts are converted to individual projects based on the renewal triggers before passing through the relevant approval gates described in Section 7.2.

Renewal Capex comprises both asset replacement (replacement of assets with like-for-like or new modern equivalents) and refurbishment (investments that extend the useful life of an existing asset). It excludes Network Development Capex, which increases the capacity, capability or functionality of our network.

To support our approach to asset renewals we have defined a set of asset portfolios and fleets that form the basis of our intervention drivers and expenditure forecasts. These are set out in Table 7.4 below.

16 http://www.powerco.co.nz/Get-Connected/Distributed-Generation/

Table 7.4: Asset fleet renewal drivers and forecasting methods

PORTFOLIO	FLEET	RENEWAL DRIVER	PRIMARY FORECASTING METHODS
Overhead Structures	Poles	Reliability, Resilience (storm), Condition	Survivor curve
	Crossarms	Safety, Reliability	Survivor curve
Overhead Conductors	Subtransmission Conductors	Resilience (storm), Safety	Type and age
	Distribution Conductors	Resilience (storm), Safety	Type and age
	Low Voltage Conductors	Safety	Age
Cables	Subtransmission Cables	Condition, Environment, Reliability	Type and age
	Distribution Cables	Condition, Reliability	Type and age
	Low Voltage Cables	Reliability (cable) and Safety (pillar boxes)	Historic trend (cable) and defect rates (pillar boxes)
Zone Substations	Power Transformers	Condition, Reliability, Environment	Condition Based Risk Management
	Indoor Switchgear	Condition, Safety	Condition Based Risk Management
	Outdoor Switchgear	Condition, Safety	Condition Based Risk Management
	Buildings	Resilience (Seismic)	Condition and age
	Load Control Injection	Obsolescence	Type
	Other Zone Substation Assets	Safety and Reliability	Programmes
Distribution Transformers	Pole Mounted Distribution Transformers	Safety, Environment	Survivor curve
	Ground Mounted Distribution Transformers	Reliability, Safety, Environment	Condition Based Risk Management
	Other Distribution Transformers	Reliability	Age
Distribution Switchgear	Pole Mounted Fuses	Safety	Survivor curve
	Pole Mounted Switches	Reliability	Age
	Circuit Breakers, Reclosers and Sectionalisers	Condition, Safety	Type and age
	Ground Mounted Switchgear	Condition, Safety	Condition Based Risk Management
Secondary Systems	SCADA and Communications	Obsolescence	Identified assets and type
	Protection	Safety, Obsolescence	Type and age
	DC Supplies	Resilience (Backup)	Type and age
	Metering	Obsolescence	Asset identification and historical rates

7.4.3 OPTIONS ANALYSIS

Most asset renewal is like-for-like replacement and this is not subjected to options analysis – the choice of equipment or technology is governed by our technical standards. However, options analysis may be undertaken when considering bringing forward a renewal project to integrate it with other works.

In other cases, like-for-like replacement may not be appropriate. This can occur when it may be more cost effective to provide an off-grid solution, such as Remote Area Power Supply systems (RAPS) as an alternative to replacing a line, or when an asset is no longer required and should be disposed[17] of, such as a redundant Air Break Switch (ABS). In such cases an options analysis is conducted to confirm the best renewal solution. Asset refurbishment or continued maintenance are also options.

To help us identify the most appropriate renewal option, we undertake technical studies, economic assessments and risk analysis, and consider safety implications, likely performance impacts and lifecycle cost, including capital, maintenance and other operational costs.

7.4.4 RENEWAL PROJECT DRIVERS

7.4.4.1 OVERVIEW

The decision to renew assets considers multiple factors. These factors, or drivers for renewal expenditure, can include condition, non-condition and operational reasons. The drivers also vary between fleets since each fleet has different functionality and serves a different purpose on the network. Often an investment programme will be driven by more than one of these factors.

This section discusses the key drivers for renewals on the network.

17 Asset disposal also has many similarities with capital projects, including consideration of cost, safety, environmental impacts, and project management. Additional aspects that are specific to disposal works include site restoration and termination of all support activities and asset information.

The fleet management plans identify the areas where capital expenditure is warranted from a safety or reliability perspective, or to manage asset health, particularly in the zone substation and overhead structures and conductor portfolios. In many cases programmes of work will have both safety and reliability drivers, which are also both linked to asset health.

7.4.4.2 ASSET CONDITION AND HEALTH

As custodians of the electricity network, it is our responsibility to manage the network in perpetuity. Therefore, we are responsible for addressing asset deterioration as necessary to ensure that our assets remain in a safe and serviceable condition for the long-term capability and operation of the network.

We constantly monitor the condition of assets to assess deterioration and then act where required. The condition assessment methods are fleet specific and can range from the highly specialised, such as partial discharge (PD) and oil tests for transformers, to simple visual assessments, such as concrete pole inspections.

As condition deteriorates, defects may arise, and eventually the asset will reach a state where ongoing maintenance becomes ineffective or excessively costly. At this point we look to replace or refurbish. ‘Type’ issues may be tagged for early replacement, for example when a particular make or model of an asset is found to suffer a particular defect or accelerated degradation.

We use an Asset Health Indicator (AHI) to reflect the remaining life of an asset based on a variety of factors, including condition, age and environment. Asset health is the main driver for our renewals investment, as assets in poor health are at increased risk of failure, leading to additional reliability and safety risks.

We have expanded on AHI concepts by taking a Condition-Based Risk Management (CBRM) approach to identifying highest-risk assets and prioritising renewal expenditure.

7.4.4.3 SAFETY

Some of our renewals programmes, such as our overhead structures and overhead conductor renewal, focus on mitigating safety risks to staff, service providers and the public. We isolate or minimise hazards as much as reasonably practicable.

Safety risks can arise from degrading asset condition, or from environmental factors such as vegetation encroachment. Design of an asset can also have a significant impact, such as in the case of our 11kV zone substation switchgear.

7.4.4.4 ENVIRONMENTAL RISK

Some of our assets can pose environmental risks, particularly those that contain oil or sulphur hexafluoride (SF_6). These risks can drive us to either mitigate the risks, such as through upgrades to oil bunding and containment systems, or to replace assets where the increased failure likelihood leads to unacceptable environmental risk.

7.4.4.5 RELIABILITY

We undertake renewals investment to manage reliability levels for our customers. This includes renewal of poor condition assets, and assets with known failure modes/type issues, such as where a particular asset type/model is found to fail prematurely. We regularly review the performance of our network feeders to target asset renewal in areas of worst performance, ensuring our customers all receive a fair level of service.

7.4.4.6 RESILIENCE

Our understanding of how assets perform in extreme events, such as storms and earthquakes, is always improving. This increased understanding is reflected in our design standards and applied to new assets installed on the network.

The new design standards are not typically retroactively applied to our legacy assets. However, in some instances where the risk is deemed to be unacceptable, it may be necessary to renew assets to the new standards. This includes programmes such as upgrading the seismic ratings of our substation buildings and storm-hardening of the overhead network.

7.4.4.7 OBSOLESCENCE

Renewal may be warranted when existing assets are assessed to be obsolete. This can occur when:

- An existing asset is incompatible with our modern systems and standards, and lacks significant functionality when compared with modern equivalent assets.
- Spares may no longer be available to support the asset, or the asset may no longer be supported by the manufacturer.
- The knowledge within the workforce to maintain the asset is no longer available.

Obsolescence can be the primary driver of renewal of many assets in the secondary systems assets portfolio. In this case, modern assets provide improved functionality and performance that allows us to more efficiently control and operate the network, providing better value to our customers.

7.4.5 FORECASTING METHODS

7.4.5.1 OVERVIEW

We use a variety of methods for forecasting renewals investments, with the different approaches applied to different asset fleets, depending on the characteristics of the asset and the renewal drivers. For example:

- Information availability limits our ability to use some forecasting methods for some asset types.
- A more complex method may be warranted where future renewals expenditure is expected to be high, while lower expenditure asset types will have simpler methods applied.
- Some renewal drivers only suit certain forecast methods, such as obsolescence.

Forecasting methods may not identify specific assets for renewal – we refer to these as fleet-based forecasts. The quantity of asset replacement in these forecasts informs the shorter-term investment planning process, which in turn identifies the assets for replacement and scopes the project activities. The forecasting methods used are outlined in the following sections.

7.4.5.2 CONDITION-BASED RISK MANAGEMENT

Condition-Based Risk Management (CBRM) is a modelling methodology that facilitates the development of asset renewal forecasts based on the combination of asset condition and risk. CBRM is a mature and widely used methodology that now forms the basis of the UK regulator Ofgem's (Office of Gas and Electricity Markets) mandatory condition and risk reporting scheme[18].

CBRM differs from other forecasting methods that we use in that it develops a bottom up estimate of current and future asset health, probability of failure and risk for each individual asset in the fleet. Information used to produce these estimates includes the asset's characteristics (what the asset is), the asset's condition (how the asset is) and the asset's operational context (how failure could affect safety, operational and financial objectives).

Because CBRM is a bottom up methodology, the models may also be used for tactical decision-making regarding how and when to intervene for individual assets within each fleet.

CBRM is a relatively data intensive and complex modelling methodology, so at this time we have only applied the methodology for higher value complex equipment. We have developed CBRM models for power transformer, circuit breaker, ring main unit and ground-mounted distribution transformer fleets. We are considering expanding our modelling to include underground distribution cables.

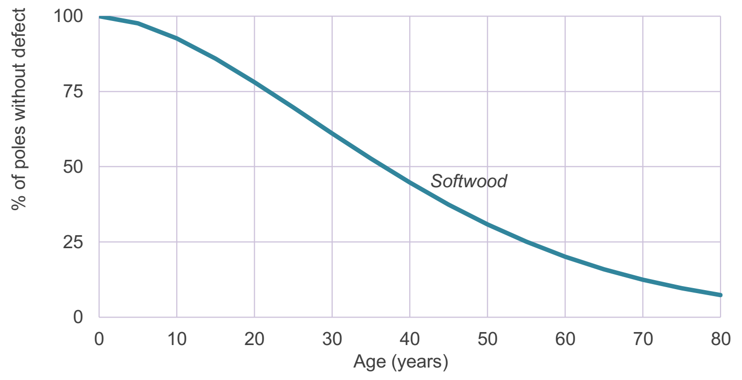
For the purposes of maintaining consistency within this AMP and disclosure requirements we have presented the output of our CBRM models using AHI categories.

7.4.5.3 SURVIVOR ANALYSIS

For large fleets with reliable historical end-of-life data, future replacement volumes may be forecast using survivor curves. A survivor curve model uses information on previous end-of-life asset replacements to build a probabilistic replacement rate curve, which produces a likelihood of failure for an asset of a given age. The replacement rate curve can then be applied to the current population of assets to predict the future number of replacements. This approach assumes that historical asset failure rates provide an appropriate proxy for expected asset deterioration.

A survivor curve-based forecast results in a more accurate forecast of replacement than an age-based model as it recognises that some assets have longer than average lives while others have shorter than average, because of factors such as location or inherent durability. It considers the likelihood of replacement at all asset ages, which provides a smooth replacement rate that still reflects the age profile of the fleet.[19]

Figure 7.3: Survivor curve for softwood poles



[18] DNO Common Network Asset Indices Methodology (Jan 2017) https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf

[19] Comparatively a simple age-based model assumes all replacement happens at one predetermined age, and can produce a lumpy forecast depending on the age profile of the fleet.

7.4.5.4 SPECIFIED PROJECTS/PROGRAMMES

This approach identifies specific projects or programmes that meet specified renewal criteria. We often use this approach where assets have ‘type’ issues or are obsolete, and to mitigate safety risks or meet seismic standards. These programmes are often directly driven by our renewal strategies, for example, ensuring all our pole-mounted transformers have LV fusing by 2023.

7.4.5.5 HISTORICAL RATE AND TREND ANALYSIS

Where it is difficult to individually assess sites or assets to determine renewal needs, we may estimate annual renewal volumes based on the historical rate or trend.

This approach is used for some of our cable assets. For example, we use the historical rate to estimate the number of pillar box renewals required because of motor vehicle incidents. Alternatively, we may extrapolate the historical trend of renewals, such as where we have an ageing fleet with an increasing trend in failures.

7.4.5.6 FAILURE RATE REDUCTION

This approach is used only for forecasting distribution reconductoring requirements. The approach determines the amount of conductor renewal that will be required to achieve good practice reliability for the asset type, assuming we replace conductors in order of failure risk. Actual replacements are then targeted based on the key risk factors – in this case, age, type, and coastal proximity.

The key inputs to the model are historical network faults, excluding faults caused by external influences, and Geographical Information System (GIS) data – age, material, size, and location for each conductor span.

From this data a model of expected conductor failures was developed, which is used to determine renewal requirements for each year of the forecast period. Target performance was derived by considering what average failure rate our distribution conductor would have if the known poor performing types were not present on our network.

7.4.5.7 AGE-BASED

Where we have a large population of assets but do not have sufficient data to develop survivor models or use condition-based forecasting, we may use a more simplistic age-based forecast approach.

This assumes that assets are replaced at the end of their expected life, based on our experience operating the network. Compared with survivor modelling, this can produce a relatively ‘lumpy’ forecast, depending on the age profile of the fleet.

This approach is only used for lower value asset fleets.

Note, that while we forecast renewal volumes using this approach, the actual assets to be replaced are determined in the short to medium term based on condition and other factors.

7.4.6 RENEWAL TRIGGERS

7.4.6.1 OVERVIEW

Understanding when to undertake renewals is crucial for our asset management practices. Our renewal triggers allow us to maximise the useful life of our fleets while minimising the risk of failure on the network.

This section summarises some of the ways we trigger investment to renew our assets.

7.4.6.2 ASSET HEALTH INDICATORS

Each fleet requires a different method of monitoring it. The results of the assessments are translated into an indicator to consistently report an asset’s lifecycle stage based on the assessment. This indicatory is called the AHI. It is an effective way of communicating renewal needs across multiple asset fleets with various stakeholders.

The sophistication of the AHI models is dependent on the characteristics of each fleet. For assets where we have basic information, age can be the determinant. For fleets where we have more comprehensive asset information we can consider factors such as the make and model of the asset and whether it faces any ‘type’ issues, its performance history, defect history, and location. As we mature in our asset management capability, we intend to increasingly use a more blended set of renewal drivers to inform the AHI for all our fleets.

Asset health modelling can be used for comparing investment scenarios, as we can assess how different levels of investment will affect the health of an asset fleet over time, and consider the impact of various funding allocations between fleets.

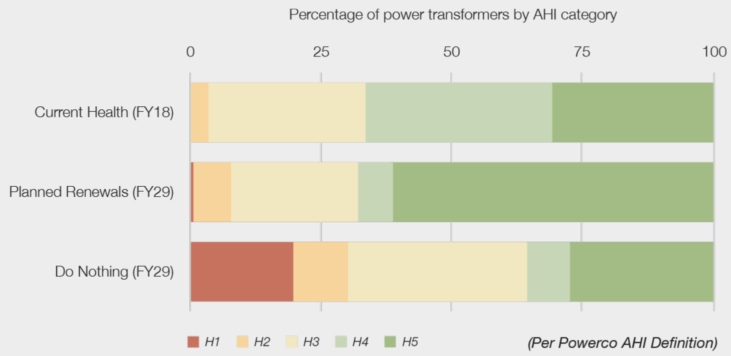
When asset health is combined with criticality, the unmitigated asset risk can be understood (proxies of probability and consequence of failure). We are in the process of developing our asset criticality framework. The criticality framework will allow us to vary the AHI at which we trigger renewals for assets within the same fleet. More information on asset health modelling is provided below.

Asset Health Indices

Asset health reflects the expected remaining life of an asset and acts as a proxy for probability of failure. Asset health is almost entirely an indicator of likelihood or probability of asset failure. Factors such as age, environmental location, operating duty, observed condition, measured or tested condition and known reliability are combined to produce a health index (H1-H5).

AHI	CATEGORY DESCRIPTION	REPLACEMENT PERIOD
H1	Asset has reached the end of its useful life	Within one year
H2	Material failure risk, short-term replacement	Between one and three years
H3	Increasing failure risk, medium-term replacement	Between three and 10 years
H4	Normal deterioration, regular monitoring	Between 10 and 20 years
H5	As-new condition, insignificant failure risk	More than 20 years

The example below shows the projected future asset health based on different intervention options.



7.4.6.3 LEGISLATIVE COMPLIANCE

Certain drivers are considered important enough to be written into law. Therefore we may need to undertake renewals investments to ensure we comply with legislative obligations. Many of these relate to safety and environmental performance, and include:

- Electricity Act and pursuant Electricity (Safety) Regulations 2010
- Resource Management Act 1991
- Health and Safety at Work Act 2015
- NZECP 34: New Zealand Electrical Code of Practice for electrical safe distances
- Electricity Industry Participation Code
- Building Act 2004 (relates to the strength and seismic performance of our buildings)

7.4.6.4 LIFECYCLE COST

In some instances, it may cost more to retain an asset in service than to replace it. The higher costs are generally Opex and can manifest in the form of increased maintenance frequency, expensive refurbishments or unacceptable fault rates – as in the case of linear assets.

The cost to respond to failure of large assets (eg zone substation transformers) reactively can also be substantially higher than replacing the assets in a planned and controlled manner. In these cases, the asset may be renewed to provide an overall lower lifecycle cost.

7.4.6.5 ASSET FAILURE

For certain fleets, such as pole-mounted transformers and LV cables, run-to-failure is a viable strategy. These fleets generally have a low consequence and the customer is better served by getting the maximum useful life from the existing asset.

For such assets, while we monitor multiple drivers for forecasting capital requirements, we may not act until a specific asset fails.

7.5 WORKS PROGRAMME DELIVERY

7.5.1 OVERVIEW

The delivery process is managed by our Works Delivery teams, which specialise in detailed design, procurement, project management and construction, using a combination of internal and external resources.

The increase in work on our network has required improvement of our end-to-end delivery approach. We have improved the way we coordinate and communicate the impact of planned customer outages, and seek to manage workflow to allow our service providers to deliver at the lowest cost.

We are working towards giving our service providers at least six months lead-time for the construction of assigned work. This gives them the time to manage their resources as effectively as possible and, in return, we receive a discount on their labour costs.

The capital works delivery process includes:

- **Detailed design** – converts conceptual designs completed in the planning stage to detailed designs for construction. Much of our detailed design is undertaken by design consultants.
- **Procurement** – manages the tendering of work and negotiating and awarding of contracts.
- **Construction and commissioning** – includes managing of service providers to deliver to time, scope and budget. It also includes commissioning new assets, handover to operations and project closeout. New processes include tightened contingency and change management.
- **Closeout** – processes now include more formal feedback to the planning teams.

7.5.2 WORKS SCHEDULING

Once projects are prioritised in the final stage of the two-yearly rolling planning cycle, an important process of works integration and planning takes place. This focuses on when each project should begin based on its priority, location, size, complexity and the availability of resources.

Resources needed for delivery depend on:

- The level of design work required
- Access and consents issues
- If a planned outage is needed and the impact on customers
- Availability of operations to manage work on the network
- Service provider capability and availability

Projects are coordinated where possible to minimise disruption to customers. It is also important to manage a smooth work flow to service providers, allowing them to be as efficient and effective as possible.

7.5.3 DETAILED DESIGN

We build on early design work to create a complete detailed design for large projects. This includes budget breakdowns, tender drawings, and material lists. We minimise asset diversity by following a suite of design standards, simplifying delivery and achieving uniformity across our network.

The Design team is involved for the duration of the project to take care of tasks such as design variations during construction.

Detailed design is not required in all cases. Where there are standard installations and smaller defect-related jobs, we use the design build services of our service providers. They use our standards to generate compliant, consistent designs.

Safety-in-design

Safety-in-design is a key philosophy applied throughout our design process. It is continually improved through our standards review process. Our technical standards are developed to include health and safety requirements, environmental risk identification, and network risk management requirements.

7.5.4 PROCUREMENT

7.5.4.1 MATERIALS

Most of our contracts are awarded on a design-build basis. We ask service providers to separately itemise material and labour costs so that we have an opportunity to check and negotiate the material costs. It also provides a base against which project costs can be monitored.

We will generally directly procure high-cost items through a competitive tender process.

When assessing procurement opportunities, it is also important to assess the sustainable principles of the supplier, including environmental performance, social presence, quality management and safety performance.

Our technical standards are designed to ensure efficient and streamlined materials procurement by seeking to balance the benefits of standardisation with the benefits of competitive tension between suppliers. This approach is set out in Table 7.7.

Table 7.5: Approach to asset specification

EQUIPMENT CLASS	SPECIFICATION REQUIREMENTS
Class A item-focused	Items within this class are critical to supporting the reliability and performance of the network. Examples are 33kV and 11kV switchgear and power transformers. Class A equipment must be chosen from specific type lists within standards published in our Contract Works Manual. No discretion is allowed when choosing these items.
Class B standards-focused	Class B is a standards-focused group of materials and equipment. These items must be chosen in compliance with our standards. Examples include overhead conductors and underground cable and poles.
Class C functionality-focused	Class C items can be selected in compliance with functional requirements published in our Contract Works Manual. Examples of Class C equipment types include bolts and crossarm braces.

7.5.4.2 SERVICES

We operate a long-term outsourced contract model for faults, maintenance and minor capital works. The most recent iteration of the field services delivery strategy has involved development of a tender panel tasked with delivering appropriate scale, resource certainty and effective price competition. We have worked with our key providers to tailor their resourcing and delivery to future work volumes.

We operate a more traditional principal contractor model for major capital works, which are tendered job by job. We run a closed tender process, offering work to only those contractors who are pre-approved. We use a FIDIC[20] template for the tender process and a standard evaluation form is used to assess each tender.

We limit tenders to those companies who are approved under our approved contractor process. For most of our approved contractors, the general terms and conditions under the FIDIC contract have been pre-negotiated. This aims to streamline the tender process so significant negotiation is avoided with each tender release.

7.5.5 CONSTRUCTION

Service providers must first be approved to work on our network. This ensures an appropriate level of competency throughout the company's systems and processes. It also ensures that the individuals carrying out the work are competent to complete the tasks and work on the network as safely as possible.

We use various methods to monitor our service providers' efficiency while meeting our construction and materials standards. We use professional project managers who monitor cost outcomes against contract conditions and approved budgets, as well as project schedules, safety targets, and environmental performance.

We have been successful at delivering volumes of work in line with targets, including delivering the increased number of CPP projects.

Waste management

Our service providers are responsible for disposing waste material of assets. Consistent with our Safety and Environment objectives we ensure waste materials are disposed of in a responsible manner. Table 7.6 gives an overview of the types of waste materials we manage.

20 Based on material from the International Federation of Consulting Engineers.

Table 7.6: Potential waste materials from asset disposals

DISPOSED ASSET	POTENTIAL WASTE MATERIAL
Overhead line assets	Steel, aluminium, copper, soil, porcelain/glass, copper chrome arsenic-treated poles (CCA), timber, concrete
Underground assets	Cross-linked poly ethylene insulation (XLPE), copper, lead, oil and oil impregnated paper, soil, contaminated soil, poly vinyl chloride (PVC)
Buildings	Building materials, asbestos and contaminated soil
Switchgear/circuit breakers	SF_6, oil, recyclable metals, porcelain
Power transformers	Oil, steel and copper
Distribution transformers	Oil, steel, aluminium, copper, timber and porcelain

In most cases, disposal of assets is a relatively low-cost activity. However, if special disposal requirements exist, these are considered at an early stage. Disposal costs are considered as part of the overall lifecycle costing.

7.5.6 COMMISSIONING

Commissioning is the formal process of handover from the construction phase to the operational state. It represents the point in time at which the network assets become recognised as assets for the purposes of operation and valuation. The commissioning process is controlled by the NOC, with the support of the Works Delivery team and the service provider.

We have a commissioning standard that defines the process for commissioning before livening on the network. The commissioning process includes the scope and methodology for pre-commissioning tests, acceptance tests and handover to operations.

7.5.7 WORKS CLOSEOUT

Once all works are complete, we undertake several project closeout activities, including final capitalisation of the project in our financial system. This confirms asset information systems have been updated (archiving relevant documentation), and a review of lessons learned, including a review of safety performance.

The review process is commensurate with the complexity and risk associated with the project.

7.6 DEFECT PLANNING AND REMEDIATION

7.6.1 OVERVIEW

Defects for some asset fleets form a significant portion of our expenditure. Current stocks of Capex defects[21] are compared against target levels to determine suitable renewals activity targeting defects, considering the defect criticality and urgency (red/amber/green). Target levels are determined by considering defect rectification timing as described in our standards, having a suitable stock for efficient delivery, and an overall assessment of risk, considering safety risk in particular.

The main purpose of the defect process is to restore an asset that is damaged or does not perform its intended function. We undertake defect works to restore asset condition, make it safe and secure, prevent imminent failure, and address defects. Work may be identified during fault response or preventive maintenance inspections.

7.6.2 IDENTIFICATION AND CATEGORISATION

Defects are identified through inspections, which are either scheduled using a time basis or ad hoc for risk assessment purposes. Inspections can use a variety of methods eg visual, acoustic and thermographic.

After a defect is identified, it is categorised through our defect assessment process into red, amber, or green. Red defects are high priority and are dealt with immediately. Amber defects are medium priority – unlikely to cause an immediate fault – and our preferred approach is to fix the problem within 12 months. Green defects are low priority and managed through planned work programmes because they can be scheduled over a longer period.

What are asset defects?

Defect is an industry term that means an asset has an elevated risk of failure or reduced reliability. Defect categories are assigned during inspections and condition assessments.

We use three categories that reflect operational risk.

DEFECT CATEGORY	DEFECT DEFINITION
Red defect	Imminent risk of asset failure that presents an immediate significant hazard to people, property or the environment, or: Will result in an inability to operate network equipment.
Amber defect	Condition not otherwise classified as a red defect that requires permanent repair or renewal of an asset that will fail within 12 months.
Green defect	Condition that requires permanent repair or renewal of an asset that will fail in a period greater than 12 months but less than 36 months.

While resolution of defects within the targeted times reflects good industry practice, our internal processes allow discretion for assets to remain in service provided appropriate risk assessment has been completed.

7.6.3 PRIORITISATION AND DELIVERY

Work is scheduled for completion based on assessed priority. Our asset criticality framework applies the categories of customer impact, financial, environmental and public safety to each asset. This allows each asset to be ranked in terms of the impact of its failure and provides prioritised investment for repair or replacement of high-risk defects.

Fault staff are deployed immediately to rectify red defects. Amber defects are included in work packages to provide efficient delivery of geographically collocated, high-risk repairs. Green defects are generally a long-term indication of degraded condition of the network. They are used to guide investment decisions for renewal works.

[21] Defects can also be remedied through corrective maintenance activities, as discussed in Chapter 23.

Asset criticality

Asset criticality is a proxy for the consequence of asset failure. We have developed an asset criticality standard that defines how we rank assets in terms of failure consequences. We have considered failure consequences across four categories:

- Public safety
- Consumer impact
- Financial
- Environmental

The overall asset criticality is the highest criticality across the four categories. The categories and their respective calibrations are aligned with our overall risk management standard.

7.7 NON-NETWORK ASSETS

7.7.1 OVERVIEW

To govern our non-network investments, we use separate but similar processes to those used for network investment. These non-network investments include assets that support the operation of the electricity business, such as information and technology systems and asset management systems.

Similar to network governance, strong and committed governance of non-network projects is critical to the success of change initiatives undertaken.

Good governance structures and processes help avoid poor project and programme selection at the portfolio level and minimise poor execution at the project and programme level. Our non-network governance and delivery model is consistent with practices used by peer utilities.

All non-network investment decisions are undertaken within a structured and considered process with proportionate oversight. At a high level our governance process is responsible for addressing the following key questions:

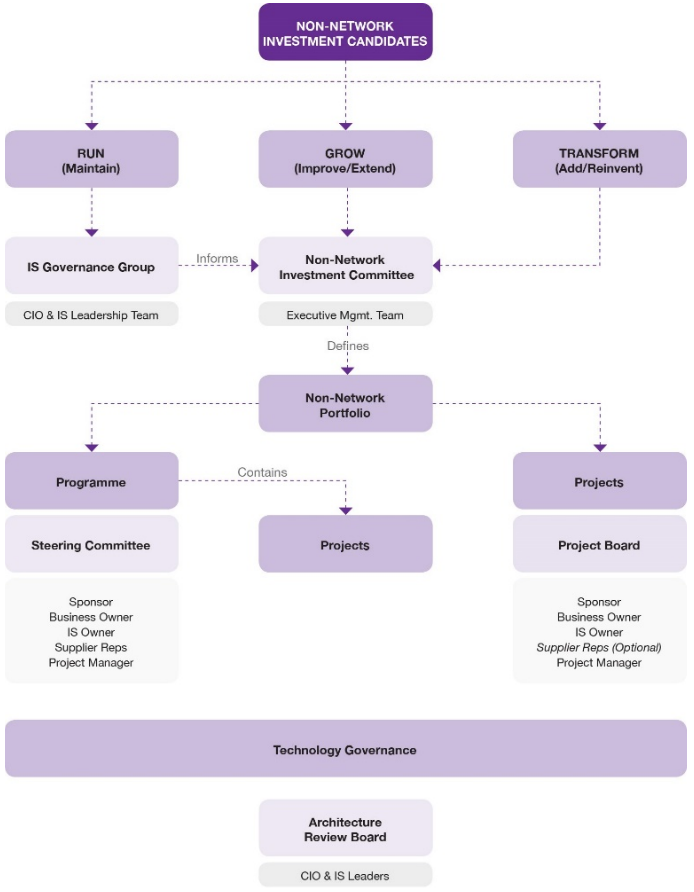
- Which initiatives complement our strategic direction?
- What are the right programmes/projects to undertake?
- How much change can the organisation absorb?
- Which initiatives are the most beneficial?
- What can the organisation resource?
- What can we afford?
- What are the risks and impacts?

The remainder of this section explains how our governance function oversees our processes to identify and deliver non-network initiatives and associated investments.

7.7.2 NON-NETWORK GOVERNANCE GROUPS

We have established several internal governance groups to ensure a prudent approach to delivering non-network assets. The interactions between these groups and our operational and project teams are summarised in Figure 7.4. Their roles are explained in the remainder of this section.

Figure 7.4: Overview of non-network governance groups



IS Governance Group

This group is responsible for planning and prioritising the non-network investment required to maintain and support existing Information Communications and Technology (ICT) capabilities and services. The outputs from this group inform the wider Non-Network Portfolio of Information System (IS) expenditure required to meet existing performance and quality criteria.

Non-Network Investment Committee

This committee is responsible for defining the composition of the Non-Network Portfolio to ensure it delivers maximum value to the organisation. Its key functions are to review and approve expenditure in the form of programmes and projects, and review progress of initiatives within the portfolio to maintain alignment with organisational priorities. This requires a balancing of investment in existing ICT-based capabilities against pursuing development of new capabilities.

Steering Committee/Project Board

The role of these groups is to provide governance to a programme (comprised of multiple projects) or individual project within the Non-Network Portfolio. They maintain oversight of the relevant initiative(s) and act as a guidance function with the appropriate authority to endorse key decisions, govern programme/project-related risks, and ensure continual alignment of the initiative against organisational needs.

Architecture Review Board

This board ensures consistent alignment with business strategies and provides strategic and tactical direction on ICT investments. It fulfils a key technology governance role, supporting the Chief Information Officer (CIO) in setting and implementing our strategic technical architecture.

In addition, the Architecture Review Board assesses the impact of technology change against the following criteria:

- Degree of alignment with our Information Services Strategic Plan (ISSP), ICT strategies and principles.
- Impact on cost of service, security, health and safety, and other operational concerns.
- Constraints that may impact the delivery of the proposed scope.
- Whether solutions should be flagged as obsolete, and monitored to ensure replacement by the agreed disposal date.

8 OPERATIONS & MAINTENANCE PLANNING AND DELIVERY

8.1 OVERVIEW

This chapter describes the activities required to operate and maintain our electricity network. It sets out how we plan and budget for these activities to meet our Asset Management Objectives.

The chapter is structured as follows:

- Section 8.2 outlines the planning process for maintenance, vegetation management and System Operations and Network Support (SONS) activities.
- Section 8.3 outlines how we establish our budgets.
- Section 8.4 describes how we deliver our operations and maintenance tasks.

8.2 NETWORK OPEX PLANNING

8.2.1 OVERVIEW

Operations & Maintenance Planning is a key stage of our assets' lifecycles.

Network operations refers to the activities necessary to ensure the day-to-day safe and reliable control and management of our network. Network operations' primary roles are to ensure the safe continuous supply of electricity to customers through monitoring, switching and load control, and providing contractor access for works required to develop and maintain the network. This centres on our 24/7 Network Operations Centre (NOC) and a dispatch centre that communicates with retailers and the public.

Maintenance refers to activities required to ensure the network continues to operate safely to its required capacity and performance. Maintenance involves monitoring and managing the condition of the network to a safe working condition. It includes routine visual inspections, testing and measurement, routine preventive maintenance, and restoration tasks to remedy defects, degradation or failure.

Network operating expenditure (Opex) consists of three categories of work:

- **Maintenance** (preventive, corrective and reactive)
- **Vegetation management**
- **System Operations and Network Support** (SONS)

The planning approach for each of these categories is discussed below.

8.2.2 MAINTENANCE PLANNING

Our maintenance activities are categorised into three categories:

- **Preventive Maintenance and Inspection**[22] – routine maintenance activities such as testing, inspecting and routine maintenance.
- **Corrective Maintenance** – restoring asset condition or rectifying defects identified through inspection and testing tasks.
- **Reactive Maintenance** – responding to faults and other network incidents, including immediate work to make a situation safe, or to repair failed assets.

Our maintenance standards define required inspections and preventive maintenance activities and the frequency at which these are to be carried out. We use information obtained from inspections to plan our corrective maintenance programme and inform renewal decisions.

We use a maintenance strategy where asset condition is assessed on a scheduled time interval basis with defects, unserviceable assets or assets with deterioration prioritised for rectification using our criticality framework. Using a criticality based approach to prioritisation allows us to allocate our corrective maintenance funds and resources to more efficiently reduce risk and improve network performance.

Criticality based maintenance scheduling

Our maintenance strategy of time-based inspection and preventive maintenance, coupled with condition and criticality based rectification of asset deterioration, unserviceability and defects, represents and, in some regards, exceeds industry good practice.

We recognise, however, that further improvements in efficiency and performance are possible by applying the concept of asset criticality to the selection of time intervals for inspection and preventive maintenance tasks. Such tailoring could allow for critical assets to be inspected and maintained more frequently and low criticality assets less frequently, reducing overall risk at the same or lower cost.

During the planning period we intend to utilise maintenance scheduling capabilities of our new SAP plant maintenance system to explore the benefits of criticality based maintenance scheduling.

[22] Our Preventive Maintenance and Inspection portfolio was previously named Routine Corrective Maintenance and Inspections (RCI). The corrective maintenance component of this work is now part of our Corrective Maintenance portfolio. This change has been made to better reflect the drivers for these activities and the way we plan and deliver these works. Our Information Disclosure schedules reflect the RCI definitions, also consistent with our historical disclosures.

8.2.3 VEGETATION MANAGEMENT PLANNING

Preventing trees and other vegetation from interfering with our assets, particularly overhead lines, is an essential activity necessary to ensure that our network remains safe and reliable. It is also a legislative requirement to maintain mandated clearance distances between vegetation and our lines.

Vegetation in contact with our assets can lead to safety and reliability issues, such as asset failures, outages and fires. We must manage it to ensure the security of supply and safety of the public.

Managing this hazard involves tree inspections to determine the amount of work required, liaising with tree owners regarding the work needed on their property, and trimming and removal of identified trees.

Vegetation management was historically planned on a portfolio basis – individual tree sites were not identified in the plans. The identification happened at the execution stage, and was carried out by the vegetation service providers.

In line with our vegetation strategy, we are transitioning away from our historical, largely reactive, vegetation management approach (addressing issues as they occur), to a more planned approach. This involves more cyclical inspections, whereby all trees will be inspected at pre-determined intervals, typically three years. We are adopting a risk-based approach to vegetation outside statutory clearance zones – where this is likely to pose a safety or reliability risk in the foreseeable future. In addition, we are also considering separating the works identification function from the works execution function.

While these changes will enhance our operational efficiency, they will not change our planning processes, other than to better inform our portfolio expenditure levels.

8.2.4 SYSTEM OPERATIONS AND NETWORK SUPPORT (SONS)

SONS relates mainly to our people – salaries, wages and supporting expenditure. It also covers related network support expenses, such as professional advice, engineering reviews, quality assurance, and network running costs.

SONS planning is generally done on a portfolio level. Annual planning is based on a combination of historical costs and trends supplemented to reflect the future effort associated with projected network growth and renewal.

Where new initiatives or substantial changes to existing work approaches or volumes are identified, these are added to the underlying base and trend plans. This also applies to situations where new work types require the introduction of new skills.

8.3 NETWORK OPEX BUDGETING PROCESS

Our network operating budgets are based on the forecasts set out in our AMP. These forecasts consider historical long-run costs and update these to reflect targeted changes in strategy, and known emerging issues with our asset fleets.

The process we use to set our network Opex budgets each year includes the following key steps:

- The process starts with the 10-year portfolio forecasts (maintenance, vegetation and SONS). These forecasts are updated as part of our AMP process to reflect updated assumptions, changes in maintenance strategies, or known one-off items for the year.
- We load the specific schedules of activities into our Gas and Electricity Maintenance Management System (GEM) scheduling tool to validate the cost of the preventive maintenance budgets and refine the detailed scheduling to reflect the top-level AMP assumptions.
- Reactive maintenance, vegetation management, and SONS budgets are set based on the AMP assumptions and adjusted to reflect any one-offs or known issues for the financial year.
- The budgets are compiled, reviewed by the GM Asset Management & Network Transformation, and presented to the Board for discussion and approval. Once approved the budgets are released within our financial systems for execution.

Capex-Opex trade-offs

A lifecycle-based asset management approach requires a holistic view of asset expenditure. The investments we make regarding Opex play a material role in enabling efficient delivery of capital projects and our subsequent ability to manage them.

Reflecting this, we consider both Capex and Opex requirements as part of our decision-making, including:

- The impact of maintenance activities on asset life and performance.
- Total lifecycle costs, including disposal, when commissioning new assets or replacing/refurbishing existing assets.

In many cases, longer term maintenance and operation costs will be a significant proportion of the lifecycle cost in present value terms. It is important, therefore, that Capex decisions are not made based solely on the up-front capital costs.

8.4 OPERATIONS AND MAINTENANCE DELIVERY

8.4.1 OVERVIEW

Operations & Maintenance Planning activities comprise:

- **Network operations** – includes real time network control, monitoring and event response.
- **Outage planning** – involves planning for equipment outages to enable safe access to network assets.
- **Network maintenance** – is the care of assets to ensure they provide the required capability in a safe and reliable manner – from commissioning through to their replacement or disposal.
- **Vegetation management** – includes monitoring and trimming of vegetation growing in close proximity to our assets.

Operational and maintenance activities are introduced below. Further discussion on network Opex, including our planned expenditure, is included in Chapter 23.

8.4.2 NETWORK OPERATIONS

Network operations is a real time function and is undertaken through our NOC. Network operators monitor network status and system load, and take actions as necessary, including planned and unplanned switching and load control to maintain supply through our High Voltage (HV) network.

Outage Management System

Our Outage Management System (OMS) is a core tool used in managing the NOC workload. OMS derives network status data from the Supervisory Control And Data Acquisition (SCADA) system. OMS is used to manage calls and outage restoration efforts, track interruptions to customers, and provide relevant information to customers through retailers, our website, or an interactive voice recording system.

Using a statistical inference model, OMS produces a predictive outage location based on customer calls and provides NOC staff with geospatial views of the affected customers. This tool is used to improve fault responsiveness.

Switching

Switching is undertaken to disconnect sections of the network for safety isolation to enable maintenance or new connections to be undertaken, or to restore supply in the event of a fault. Most switching involves the 11kV distribution network but, at times, subtransmission switching at 33kV and 66kV is also undertaken.

There are two principal switching methods – remote switching, which is done by the NOC via SCADA, and field switching, which is undertaken by our service provider under the direction of the NOC. Switching is planned and managed through our OMS. Expenditure related to field switching is included within our Corrective Maintenance portfolio.

Dispatch

The NOC also incorporates a dispatch function, where dispatch operators communicate with retailers and customers. They communicate with our Service Providers Service Management Centre (SMC) to dispatch field staff where work is necessary to maintain or restore power supply. Dispatch operators also manage all Low Voltage (LV) outages.

8.4.3 OUTAGE PLANNING

Our NOC has a team of release planners who coordinate the release of our HV network for planned work. They ensure that the work being done can be clearly understood by all concerned and that all recognised measures are in place to ensure safety of personnel and the public.

Outage planning follows a process of release procedures. The procedure is documented and follows operational rules designed to promote system stability and security, and to ensure personnel have sufficient time to safely consider permits and switching instructions necessary for work to occur.

An important focus is to become more responsive to our customers. A key part of this is outage planning with customers, while also enabling reasonable access to the network for work to occur. This includes providing adequate notice of an outage, explaining why the outage is needed and responding to queries and concerns. The process also considers the impact on critical customers, such as schools, hospitals, transportation, and industry.

8.4.4 NETWORK MAINTENANCE

8.4.4.1 OVERVIEW

The bulk of our maintenance activities are completed by our service provider Downer – as part of an Electricity Field Services Agreement (EFSA), our approved vegetation contractors, and other external specialists. The work programme is sourced from:

- The GEM schedule of Preventive Maintenance and Inspection work.
- The defect database, which provides a record of all outstanding defects, from which individual Corrective Maintenance jobs or packages of work are issued.
- The NOC, which issues urgent Reactive Maintenance fault work on an individual job basis to our SMC.

Our service provider, our approved vegetation contractors and external specialists are responsible for ensuring they have sufficient expertise and resources to undertake the assigned works in line with our requirements. They are also responsible for ensuring their staff are trained and qualified to undertake the assigned works. We monitor their compliance with these requirements.

8.4.4.2 QUALITY MANAGEMENT

Our service provider, our approved vegetation contractors and external specialists must provide quality assurance for all works they undertake. Quality management includes supervision and auditing of works to ensure compliance with standards and with contractual conditions.

We independently monitor the completion of service provider, vegetation contractor, and specialist works and undertake sample audits to ensure compliance with our technical and quality standards.

8.4.4.3 FEEDBACK AND MONITORING

Our EFSA provides a mechanism for feedback both from and to our service provider. When undertaking physical works, the service provider identifies issues or ways to improve specific maintenance tasks. Similarly, we identify and advise of technological changes that can assist the service provider to undertake work more effectively and efficiently. Feedback improves our understanding of maintenance requirements and assists with keeping standards relevant and up to date.

Feedback from external specialists helps with planning renewals or operational changes for specialist equipment, such as load control plant.

8.4.4.4 ENABLERS

Planning and delivery of maintenance activities are dependent on having skilled and specialised personnel, particularly in our field workforce, engineering, planning and analytical functions. It also requires us to have the systems in place to efficiently manage the flow of information to support the work processes. In general, engineering, planning and analytical roles are in-house functions, while field work is a service provider function.

8.4.5 VEGETATION MANAGEMENT

The main activities undertaken in the vegetation management portfolio are:

- **Inspections** – cyclic inspections of all subtransmission and distribution feeders to assess tree sites and determine whether trimming or removal is required and if there have been previous tree management activities.
- **Cyclic feeder plan** – prepare plans for contractors to methodically trim or remove vegetation across the network to meet regulatory compliance.
- **Scoping** – work planning, including access to sites, traffic management, outage management, equipment required and resource requirements to perform tree management works.
- **Liaison** – interaction with landowners to agree tree management on their property where trees encroach on electricity network assets.
- **Works management** – the physical works involved in trimming or removal.
- **Audit** – post tree management activity audit checks are made of actual works versus planned works.

All these activities are undertaken by our approved vegetation management contractors apart from the cyclic feeder planning and audit functions, which are performed by our staff. Liaison personnel discuss the scope of work with the tree owner and issue formal notification of the required work.

9 NETWORK TARGETS

9.1 CHAPTER OVERVIEW

This chapter sets out our Network Targets for the planning period. We use these to gauge our performance in delivering our Asset Management Objectives. Our Network Targets set out specific measures and timing to be achieved in delivering our Asset Management Objectives.

We have designed our targets framework to drive improvement in the way we run our business, our networks, and the services we provide to our customers.

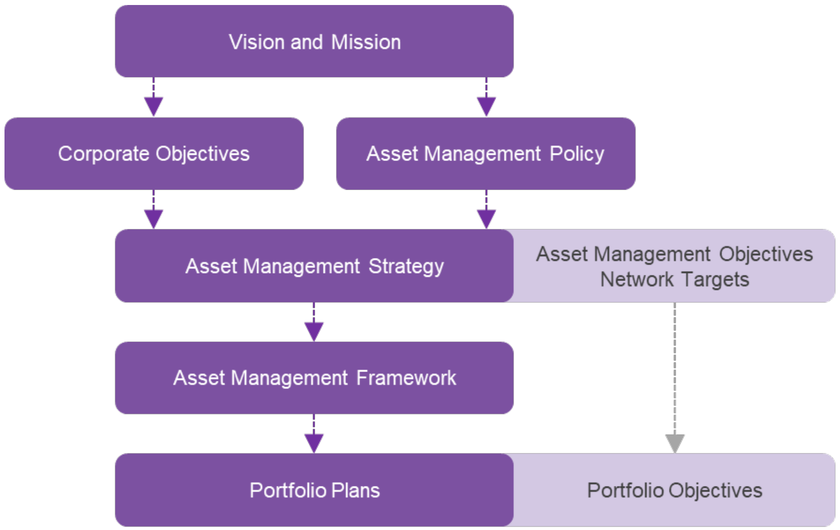
Our detailed plans, such as Network Development and Fleet Management plans, then define how we intend to deliver these targets.

9.2 CONTEXT FOR OUR TARGETS

9.2.1 ASSET MANAGEMENT LINE-OF-SIGHT

In Chapters 5-8 we described our Corporate Objectives, Asset Management Policy, Asset Management Strategy, and Asset Management Framework. This chapter outlines the performance targets against which we measure our success. Refer to Figure 9.1 for context.

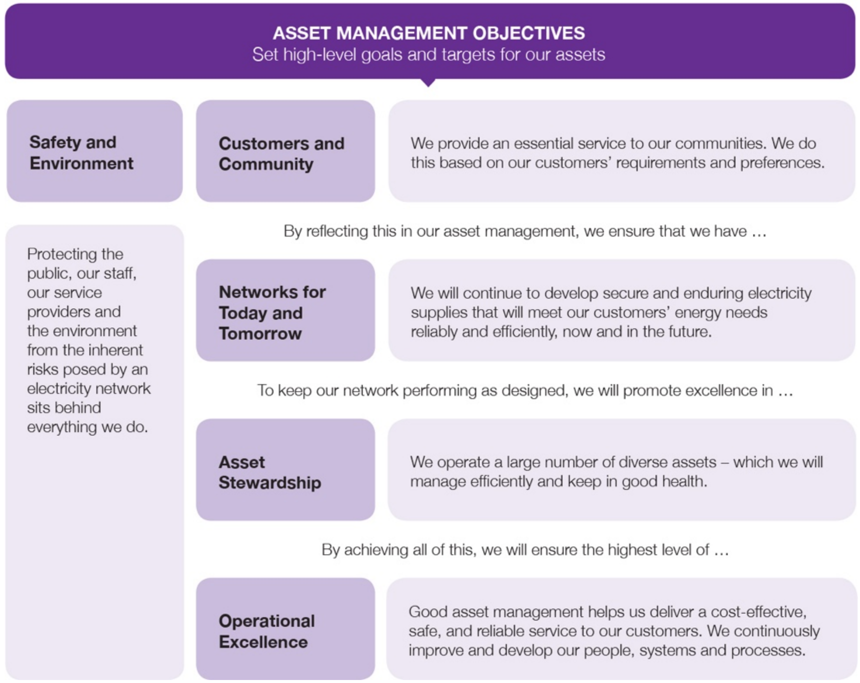
Figure 9.1: Our asset management 'line-of-sight'



9.2.2 ASSET MANAGEMENT OBJECTIVES

Our five Asset Management Objectives sit at the heart of our Asset Management Strategy. These objectives are illustrated in Figure 9.2, and are discussed in more detail in Chapter 5.

Figure 9.2: Our Asset Management Objectives



Our Network Targets set out specific measures and timing to be achieved in delivering our Asset Management Objectives.

Targets play a critical role in our delivery, as they translate directional and aspirational objectives to definitive, time-bound outcomes to be achieved.

9.3 SAFETY AND ENVIRONMENT

9.3.1 OVERVIEW

This section sets out the specific targets we have set for safety and the environment during the planning period. We also consider the basis for these targets and our historical performance against these targets. Lost Time Injury Frequency Rate (LTIFR)[23] is our primary lagging measure of safety performance, but we also have several supporting measures. Leading measures are being developed.

9.3.2 TARGETS

The tables below set out our targets for Safety and Environment and the rationale behind them.

Table 9.1: Safety and Environment targets

INDICATOR	FY19	20	21	22	23	24	25	26	27	28	29
Personnel safety											
LTIFR (LTIs per million hours worked)	2.19	1.75	1.40	1.12	0.90	0.90	0.90	0.90	0.90	0.90	0.90
High Potential Incidents (HPIs) reported and investigated using full Incident Cause Analysis Method (ICAM) within 28 working days	100%										
Safety programme delivery	As per Health, Safety, Environment and Quality (HSEQ) Tactical Plan objectives and targets										
Environmental responsibility											
Medium or higher consequence environmental incidents investigated using ICAM	100%										
ISO 14001:2015	Current certification										
Environmental programme delivery	As per Environmental Management System (EMS) objectives and targets										
SF6 (sulphur hexafluoride) leak rate (% of stock)	<2%										
Legislative compliance											
Legislative compliance	Full										

[23] LTIFR is calculated as the 12-month rolling number of lost time injuries per 1,000,000 hours worked.

Table 9.2: Safety and Environment target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
SAFETY	
Our targets have been set to reflect progressive reduction of harm over time. Understanding that people are fallible, we aim to promote a climate that enables them to 'fail safely' and where harm reduction is possible. Thorough reviews of safety related incidents allow us to remain vigilant via targeted review of our processes and systems.	LTIFR has improved during the historical period. We did not achieve our targets in FY17 and FY18 but expect to achieve the target by FY20. We completed 95% of our safety programme initiatives in FY18.
ENVIRONMENT	
We have set targets that seek to decrease our environmental footprint in relation to the benchmark reporting period of FY17. We have selected the internationally recognised ISO 14001:2015 Environmental Management System Standard as a suitable framework to guide our progress.	We achieved ISO 14001:2015 certification in July 2018, a significant improvement compared with our 2016 AMP where we were certified as Enviro-mark Diamond Level – a nationally recognised standard. We have continually met our targets ahead of schedule since FY17 and have recently reset our targets to further improve our environmental footprint.
LEGISLATIVE COMPLIANCE	
We are committed to achieving full legislative compliance as a minimum.	We consistently achieve appropriate compliance outcomes.

9.3.3 HISTORICAL TRENDS

Figure 9.3 shows our LTIFR since FY16, along with associated lost time injuries (LTIs).[24]

Figure 9.3: LTI/LTIFR historical performance

We have made improvements to our safety processes during past years, as evidenced by completing our safety initiatives. However, we experienced higher than desirable rates of LTIs given our commitment to a harm-free workplace. We will continue to ensure safety sits behind everything we do, to continually improve our safety metrics.

9.3.4 IMPROVEMENT INITIATIVES

lists initiatives we are implementing to further improve performance in this area.

[24] LTIFR data encompasses Electricity Field Operation and Business Services man hours and LTIs only, including those outside the Electricity division.

Table 9.3: Safety and Environment improvement initiatives

FOCUS AREA	INITIATIVE
Phasing out unsafe assets	We are seeking to phase out assets that no longer meet modern safety standards. This is described in more detail in our Fleet Management, Chapters 15-21.
Service provider relationships	We will continue to work in collaboration with our service providers in order to assure best practice is followed and identify opportunities for improvement.
Critical risk assessment	During the planning period we will continue to refine our approach and methodologies to ensure optimal condition of safety-critical assets.
Safety governance	Our work programmes include a focus on the Health and Safety at Work Act 2015, including training for directors and all levels of the organisation.
Fully embedding safety-in-design processes	Our safety programmes include further development of our standards and processes into all our planning and design activities.
Transformer oil containment	We will install oil containment and separator systems for power transformers and selected distribution transformers that do not have these systems.

9.4 CUSTOMERS AND COMMUNITY

9.4.1 OVERVIEW

This section sets out the specific targets we have set ourselves for customers and communities during the planning period. We also consider the basis for these targets and our historical performance against these targets.

9.4.2 TARGETS

Table 9.4 lists the targets we have set ourselves to monitor how well we are serving our customers and communities. Table 9.5 outlines the rationale behind the targets.

Table 9.4: Customers and Community targets

INDICATOR	TARGET FY19-29
Customer satisfaction	
% of customers who consider their supply reliability is acceptable or better	>90%
% of customers who consider their overall electricity supply quality meets expectations	>95%
Power quality	
Voltage within 6% of nominal (% compliance)	100%
Total harmonic voltage <5% at Point of Common Coupling (% compliance)	100%
Power quality customer complaints investigated (% investigated within 24 hours)	>90%

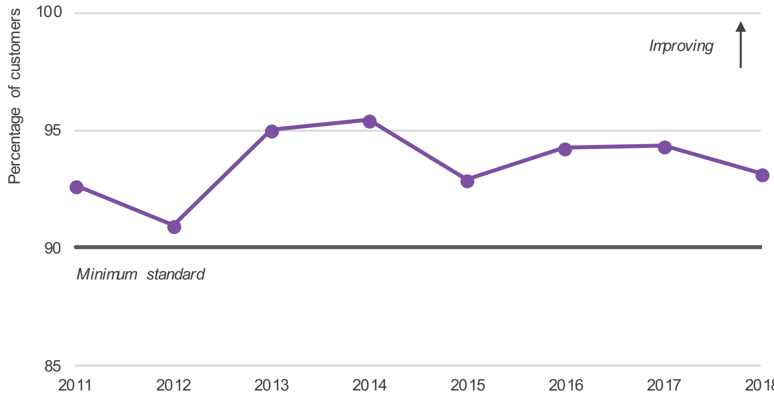
Table 9.5: Customers and Community target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Customer satisfaction	
Targets reflect our commitment to engaging with our customers to understand their needs. Target levels reflect focused improvement over time, in particular during planned and unplanned power cuts.	More than 90% of surveyed customers consistently consider their electricity reliability acceptable. The responses from our quality survey also indicate that more than 95% of customers are satisfied with supply quality.
Power quality	
Our power quality targets are set to reflect industry requirements and, where these are not prescribed, normal industry practice industry guidance. Our power quality target reflects increased focus encouraging proactive management.	At the end of November 2018 we had 37 quality complaints awaiting resolution, for the financial year to date. We are improving our information systems to allow reporting of the timeliness of power quality investigations.

9.4.3 HISTORICAL TRENDS

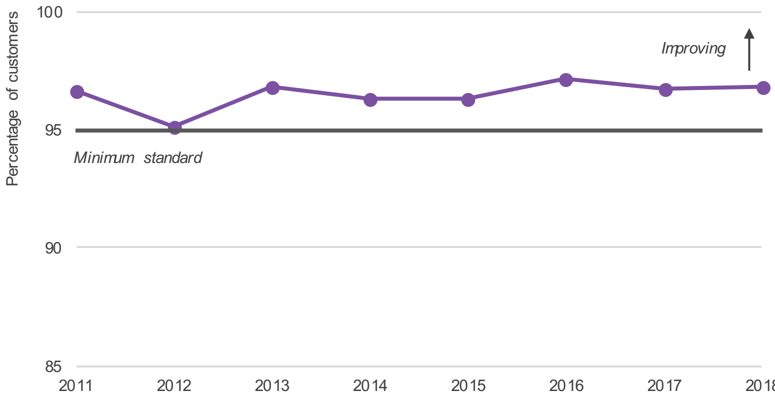
Figures 9.4 and 9.5 indicate how our customer satisfaction measures have performed historically.

Figure 9.4: Percentage of customers who told us their electricity supply reliability is acceptable or better



More than 90% of surveyed customers consistently consider their electricity reliability acceptable. While this is a good result, anything less than 100% shows that some customers are not satisfied with their reliability levels. We are continuing to ensure that areas of the network with poorer performance are improved in line with our customers' expectations.

Figure 9.5: Percentage of customers who told us their overall electricity supply quality meets expectations



More than 95% of customers have told us their supply quality meets their expectations. While this is an excellent result, we continue to investigate ways to improve reliability, response times and technical power quality measures, such as harmonic content.

The 2012 results were the lowest in recent years. We believe this was because field days were held shortly after a major weather event that caused significant disruption. These results reflect a good baseline for our customer service. Even when our network came under stress our good performance was largely maintained.

9.4.4 IMPROVEMENT INITIATIVES

Table 9.6 lists the initiatives we are implementing to further improve our performance in this area.

Table 9.6: Customers and Community improvement initiatives

FOCUS AREA	INITIATIVE
Customer strategy initiatives	An evidence-based customer strategy has been developed to deliver a series of initiatives identified as important to customers. Chapter 4 details our customer research and approach to delivering our customer strategy. The initial implementation focus is on the customer experience during planned and unplanned outages.
Improvement of worst performing feeders	We will continue to prioritise renewal and maintenance work to improve performance on poor performing feeders, as described in section 9.5.3. Examples of this analysis are in Appendix 11.
Service level agreements	Our service provider contracts contain financial incentives for fault response, and we will continue to work collaboratively with our service providers and retailers to ensure the best possible response service.
Outage Management System (OMS) improvements	We are extending the functionality of our OMS with features such as distribution management, storm management and automated switching.
Field mobility and communications	We are extending radio communications and provide field staff with mobile access to real-time information relevant to their task. This will improve fault response times and allow for more timely and informed decision-making.
Low Voltage (LV) network visibility	We are investing in improved oversight and monitoring on our networks to assist in fault identification and resolution. More information on this programme is provided in Chapter 13.

9.5 NETWORKS FOR TODAY AND TOMORROW

9.5.1 OVERVIEW

This section sets out the specific targets we have set to demonstrate that our networks are suitable for today's needs while being ready to meet the needs of tomorrow. We consider current and future network reliability, and the work we are doing to prepare our network for societal changes in energy use.

As part of our Customised Price-quality Path (CPP) determination, we have moved to a new quality System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) path. Increased levels of investment on our network require an increase in the number of planned outages in the short term to ensure stable unplanned outage performance in the longer term.

To incentivise our works programme, we proposed a new quality path that removed the planned outage component, and re-baselined the unplanned component on our performance in the past 10 years. In the final determination, this proposal was adjusted to include a separate planned quality path, and to include a reducing unplanned quality target.

To prepare our network for tomorrow, we have outlined our new Network Evolution strategy described in Chapter 13. The strategy focuses on four principal themes:

- Improving visibility – increasing the level of monitoring on our network, to assess real-time performance.
- Future energy consumers – developing a deeper understanding of changes in customer energy preferences, emerging technologies and energy market products, and integrating this into our network planning and operations.
- Modernising the grid edge – enhancing our network operations through the application of new technology.
- Enhancing response – improving our network's ability to deal with emerging customer applications, changing consumption and generation patterns, and two-way power flows.

The following sections provide more detail on the targets relating to these four themes. They also provide further detail on our unplanned and planned network reliability targets, and also discuss our feeder reliability targets.

9.5.2 TARGETS

9.5.2.1 UNPLANNED RELIABILITY

Our CPP unplanned reliability targets for the five-year period are shown in Table 9.7. These have been set based on an updated 10-year historical period from 2008-2017 and include a 10% and 5% reduction in SAIDI and SAIFI respectively by the end of the CPP period. Normalisation using a boundary value is included.

Table 9.7: CPP unplanned reliability targets

INDICATOR	FY19	20	21	22	23
Unplanned SAIDI					
Cap	191.4	187.4	183.5	179.7	175.9
Target	169.5	166.0	162.5	159.1	155.8
Collar	147.6	144.6	141.6	138.6	135.7
Unplanned SAIFI					
Cap	2.28	2.26	2.24	2.22	2.19
Target	2.12	2.09	2.07	2.05	2.03
Collar	1.95	1.93	1.91	1.89	1.87

Table 9.8 shows our unplanned SAIDI and SAIFI forecasts for the planning period. We use a separate model to forecast unplanned SAIDI and SAIFI. It is based on modelling our historical fault data, and the interactions with our planned work that impact reliability, such as asset renewal, vegetation management and automation investment. As the forecast is based on historical fault trends across different fault types, the forecast is not normalised and is therefore not directly comparable with the CPP targets from above.

Table 9.8: Unplanned reliability forecast for the planning period

INDICATOR	FY19	20	21	22	23	24	25	26	27	28	29
Unplanned SAIDI (Not normalised)	241.7	205.5	201.1	199.8	197.4	195.0	195.4	197.3	198.5	198.5	198.5
Unplanned SAIFI (Not normalised)	2.28	2.29	2.28	2.28	2.27	2.25	2.26	2.28	2.31	2.31	2.31

Our FY19 forecast is based on an in-year projection of unplanned SAIDI and SAIFI. In early FY19, we experienced a high amount of storm activity on our network, resulting in high unplanned SAIDI from April to June.

Our longer term unplanned SAIDI and SAIFI forecast reflects our focus on arresting deterioration and maintaining network reliability at current levels.

9.5.2.2 PLANNED RELIABILITY

Our CPP planned reliability targets are shown in Table 9.9. These targets were based on our modelling of expected planned SAIDI and SAIFI to provide the increased work volumes of our CPP delivery programme.

Table 9.9: CPP planned reliability targets

INDICATOR	FY19	20	21	22	23	5YR LIMIT
Planned SAIDI limit	80.0	84.9	92.3	98.2	99.3	454.7
Planned SAIFI limit	0.34	0.37	0.39	0.41	0.41	1.77

We have revisited our modelling of planned SAIDI and SAIFI, reviewing key assumptions that drive the forecast. Our current planned reliability forecast for the planning period is shown in Table 9.10.

Table 9.10: Planned reliability forecast for the planning period

INDICATOR	FY19	20	21	22	23	24	25	26	27	28	29
Planned SAIDI	84.2	86.6	93.2	98.4	99.4	94.1	90.2	91.3	90.0	90.0	90.0
Planned SAIFI	0.44	0.41	0.43	0.45	0.45	0.42	0.41	0.41	0.40	0.40	0.40

Since FY18, we have had higher planned SAIDI, and especially SAIFI, than what we had modelled for our CPP application. In revisiting our assumptions, changes in live-line work practices[25] have had a greater impact than expected. We have increased the use of other forms of SAIDI mitigation, such as generation, and the use of multiple crews, however these do not mitigate SAIFI. Based on current modelling, we anticipate we will exceed our CPP limits for planned reliability to deliver our works programme. We are continuing to investigate the reasons for the increase in planned SAIDI and SAIFI, and are implementing efficiency programmes to reduce planned SAIDI and SAIFI consumption.

25 In October 2017, we revisited our approach to live-line work practices, introducing an exclusion list of activities and strengthening processes to ensure safety risks are thoroughly assessed before approving live-live permits.

9.5.2.3 FEEDER RELIABILITY

Table 9.11 shows the feeder reliability performance targets by feeder type.

Table 9.11: Reliability performance standards by feeder (customer type)[26]

MEASURE	LARGE INDUSTRIAL F1	COMMERCIAL F2	URBAN F3	RURAL F4	REMOTE RURAL F5
Customers on feeder	5	100	800	500	250
SAIFI (average)	0.33	0.33	0.5	2	3
SAIDI (average)	15	15	23	180	450
Annual auto-recloses	-	-	4	16	24
Annual interruptions	0.5	1.0	1.5	4	6
Feeder Interruption Duration Index (FIDI)	30	60	180	600	1080

9.5.2.4 NEW ENERGY FUTURE

Table 9.12 lists our New Energy Future targets.

Table 9.12: New Energy Future targets

INDICATOR	TARGET FY19-29
Increase in LV monitoring points	2.5% (1,000 monitoring points) before the end of the CPP period (2023), then 20% p.a. post CPP
Proportion of trials/research and development (R&D) that result in change in business as usual (BAU) activity	One third of all pilots result in actionable BAU integration.
Collaborations with wider industry to advance Network Evolution thinking and actions	At least two programmes initiated or under way each year.

9.5.2.5 TARGET COMMENTARY

Table 9.13 outlines the rationale behind our targets.

[26] The reliability performance in the table is for distribution feeders only, and excludes the performance of the network upstream of the feeder.

Table 9.13: Network reliability target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Network reliability	
Reliability on our networks has been generally degrading over time and we are committed to arresting this trend. Therefore, our targets reflect a stabilisation of unplanned SAIDI and SAIFI during the planning period – recognising that planned SAIDI and SAIFI will need to increase.	2018 SAIDI was 205.3, which is above the DPP target but below the cap (210.6). SAIFI was 2.12, which is below the DPP target. Our SAIDI performance (adjusted for weather variability) has been degrading. SAIFI has been generally within target.
Feeder reliability	
Reliability on some parts of our networks falls outside of our desirable range. We are committed to addressing poor performance over time. Our targets reflect the anticipated improvement based on the levels of targeted renewals without our plans.	F2-F5 feeder performance was favourable against our target level of 70% in 2018, with increases in performance compared with previous years, but F1 performance declined to 53%. Further analysis on our worst performing feeders is included in Table 9.14 and in Appendix 11.
New Energy Future	
The targets have been set in order to measure our success in studying, testing, prioritising and implementing technological changes to the network, to prepare us for changes occurring in the electricity industry. The LV visibility target reflects our desire to improve our ability to predict and prepare for anticipated network congestion as a result of changes to customer energy profiles. Improved LV visibility will also enable us to better monitor the health and performance of our assets. Technology trials and pilot projects allow us to test new approaches and cutting-edge technology in order to assess the benefits it may offer to our customers and stakeholders. In setting ourselves a 1/3 adoption rate, we are also committing to trialling only the most promising technologies but also recognising that not all trials are expected to lead to changes in our practices. Our collaboration target is intended to capitalise on the valuable work that our organisations are doing in this space, and to share our own knowledge for the benefit of the industry.	Our Network Evolution strategy and related targets have only recently crystallised, and therefore we are not yet able to meaningfully comment on how we have been performing historically.

9.5.3 HISTORICAL TRENDS

Figures 9.6 and 9.7 set out historical trends for SAIDI and SAIFI against our regulatory targets. The figures reflect weather normalisation of unplanned SAIDI/SAIFI, with planned SAIDI/SAIFI weighted at 50% from 2015.

A clear pattern of deterioration is apparent over time for SAIDI, noting that the change in measurement of planned SAIDI from 2016 reduces the disclosed result (grey dots) by about 20-30 SAIDI minutes per year. The SAIFI result has been relatively stable.

The material differences in reliability results between years relates to the impact of storms and severe weather on our networks.

Figure 9.6: Historical SAIDI performance against regulatory targets

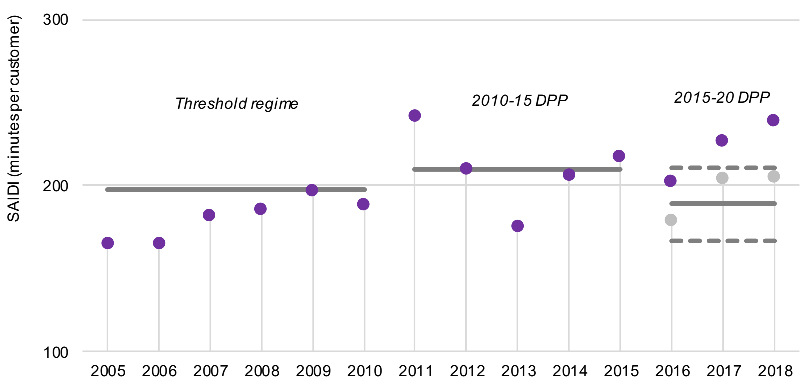
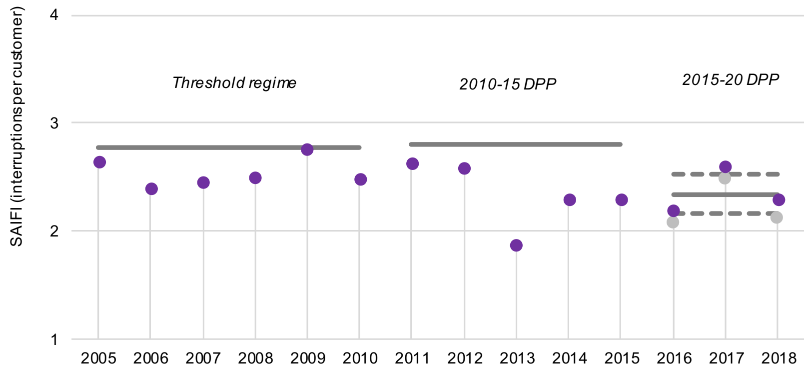


Figure 9.7: Historical SAIFI performance against regulatory targets



We analyse our feeder performance using FIDI reliability standard. FIDI represents the average number of minutes per year that a customer on a particular feeder is without supply. In Table 9.14 we summarise our 2018 FIDI performance.

Table 9.14: Feeder reliability performance in 2018

TYPICAL CONSUMER TYPE	LARGE INDUSTRIAL	COMMERCIAL	URBAN	RURAL	REMOTE RURAL
Feeder class	F1	F2	F3	F4	F5
FIDI limit (mins)	30	60	80	600	1080
Feeders above limit[27]	28	26	39	44	4
Total feeders[28]	60	150	216	208	20
% compliant with standard	53%	83%	82%	79%	80%

Feeder classes F2-F5 exceeded our target of 70% in 2018, but performance of feeder class F1 has deteriorated since the last AMP. Detailed descriptions of our worst performing feeders are contained in Appendix 11, together with reasons and remediation plans.

[27] This is influenced by feeders with multiple feeder types, where we assess all feeders against the highest feeder class. For example, a feeder with F2 and F4 sections may have interruptions on the F4 section only, but this is included in the F2 results. We intend to improve the granularity of this analysis to better reflect the performance of feeders with different class sections.

[28] Feeders exclude those for our zone substation local service supplies.

9.5.4 IMPROVEMENT INITIATIVES

Table 9.15 sets out our improvement initiatives.

Table 9.15: Network reliability improvement initiatives

FOCUS AREA	INITIATIVE
Asset Stewardship	The initiatives listed in the Asset Stewardship area will flow through to network reliability.
Network automation	Our network automation plans are designed to help support stable reliability outcomes. More information is contained in Chapter 12.

9.6 ASSET STEWARDSHIP

9.6.1 OVERVIEW

This section sets out the specific targets we have set for Asset Stewardship during the planning period. We also consider the basis for these targets and our historical performance against these targets.

9.6.2 TARGETS

Table 9.16 lists our Asset Stewardship targets, while Table 9.17 explains the rationale behind them.

Table 9.16: Asset Stewardship targets

INDICATOR	TARGET FY19-FY29
Asset health	
Asset health	Deliver asset renewal volumes/asset health targets as per Fleet Management plans.
Asset failure rates (Faults/interruptions per 100km)	
6.6, 11, 22kV overhead lines	<16 faults <10 interruptions
6.6, 11, 22kV underground cables	<4 faults <4 interruptions
33, 66kV overhead lines	<9 faults <5 interruptions
33, 66kV underground cables	<1.7 faults <1.5 interruptions
Asset utilisation (%)	
Distribution transformer utilisation	30%
Zone transformer utilisation (zone substation peak demand divided by zone substation total capacity)	50%
Network energy losses versus energy entering network	6%
Vegetation management	
Cyclical trimming programme	Cyclical trimming programmes implemented and once cycle complete in all regions by 2024.

Table 9.17: Asset Stewardship target commentary

FOCUS AREA	INITIATIVE
Asset health	
Asset Health Indices (AHI) help ensure the appropriate and stable health of our asset fleets. We have set targets to ensure appropriate outcomes in our Fleet Management plans, as per Chapter 15-21.	The use of AHI techniques is a relatively new initiative for Powerco. For details of the current asset health for our key fleets see Chapters 15-21.
Asset failure rates	
Fault and interruption rates are a useful indicator of the effectiveness of our renewal plans. We have set our targets to reflect levels typically considered good practice within the industry. The selected fault rates also reflect, on average, performance achieved by similar networks in NZ.	The following section contains figures showing how our failure rates compare with other Electricity Distribution Businesses (EDBs). The failure rates of our overhead network are higher than most other EDBs. Our cable failure rates, however, are comparable with the industry average.
Asset utilisation	
Asset utilisation provides useful top-level indicators of the balance between network security and asset use. Our targets are set to reflect the midpoint of the accepted good practice range in the industry, noting all network development projects are subject to project-by-project scrutiny.	Our distribution transformer utilisation is 28% against a target of 30%. Figure 9.15 shows how this compares with the industry averages. Our FY18 zone transformer utilisation was 51.6% against a target of 50%. Our energy loss has been measured at 4.9%, near our target of 6%. Table 9.16 shows how this compares with the industry averages.
Vegetation management	
Tree regulations require us to ensure appropriate vegetation clearances from lines. Our target of moving to a full cyclical trimming regime is designed to ensure full compliance.	Our vegetation-related faults history is shown in Figure 9.17. This year, we are introducing a cyclical trimming programme across the whole network to manage our level of vegetation faults.

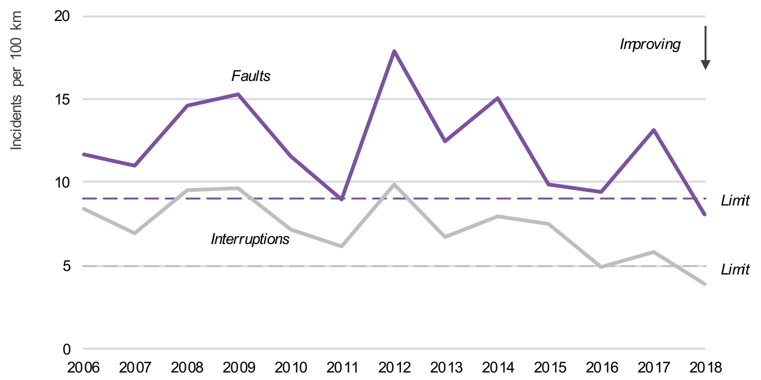
9.6.3 HISTORICAL TRENDS AND BENCHMARKS

9.6.3.1 ASSET FAILURE RATES

Failure trends

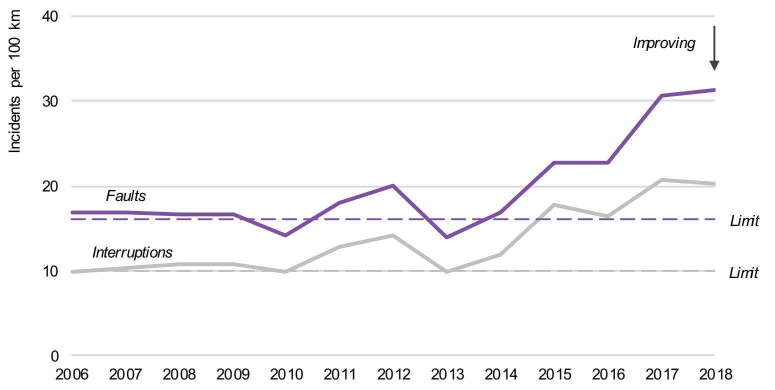
The figures below show our historical fault and interruption performance on our subtransmission and distribution system asset fleets.

Figure 9.8: Subtransmission overhead faults and interruptions per 100km



As shown in Figure 9.8, subtransmission overhead faults and interruptions have consistently been above target during the past decade, however in 2018 we met both our fault and interruption targets. The irregular shape of the trend line reflects inclement weather conditions from year to year. Our targets are designed to improve asset health and decrease the number of subtransmission overhead faults we are experiencing.

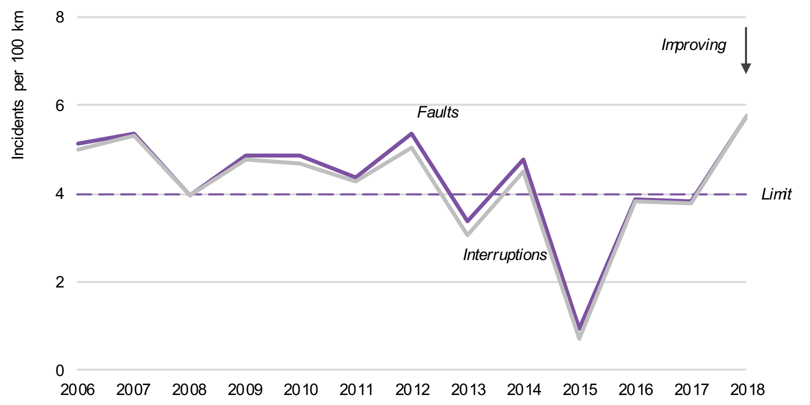
Figure 9.9: Distribution overhead faults and interruptions per 100km



As shown in Figure 9.9, the number of distribution overhead line faults has significantly increased during the past five to seven years, indicating deteriorating asset health and high levels of vegetation-related faults during storm activity. Our targets are designed to improve health, reduce the number of defects and reduce failure rates.

Figure 9.10: Subtransmission underground faults and interruptions per 100km

Figure 9.11: Distribution underground faults and interruptions per 100km

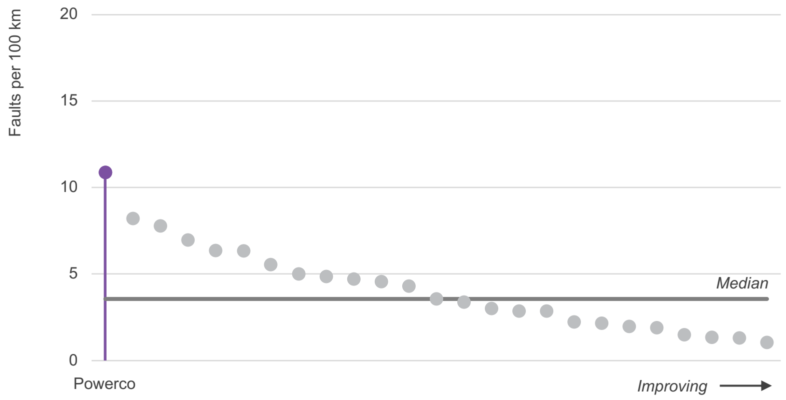


As indicated in Figure 9.10 and 9.11, the performance of our underground circuits is satisfactory, although in 2018 we experienced a higher than average number of distribution cable failures.

Benchmarking

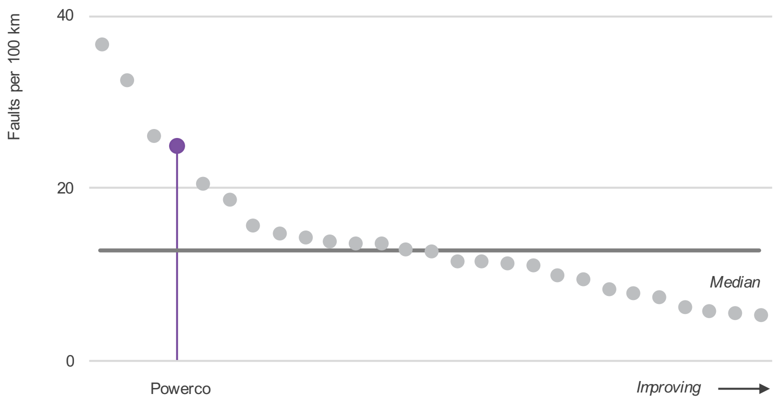
The following graphs show where we sit among our peers in terms of faults per unit length of circuit.

Figure 9.12: Subtransmission overhead line benchmarking (2014-2018 average)



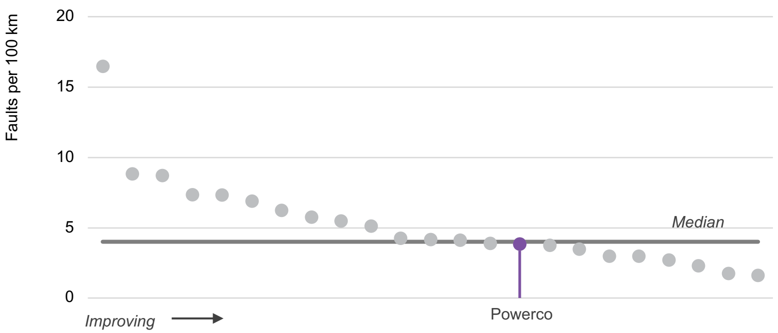
As shown in Figure9.12, the frequency of faults on our subtransmission lines is more than double the industry median. Our performance in this area has been poor for some time. Our targets are designed to reduce the number and duration of overhead line faults.

Figure 9.13: Distribution overhead line benchmarking (2014-2018 average)



As shown in Figure 9.13, the frequency of faults on our distribution overhead lines is almost double the industry median. Our performance has substantially deteriorated during the past five years. Our targets are designed to reduce the number and duration of these types of faults.

Figure 9.14: Distribution cable benchmarking (2014-2018 average)



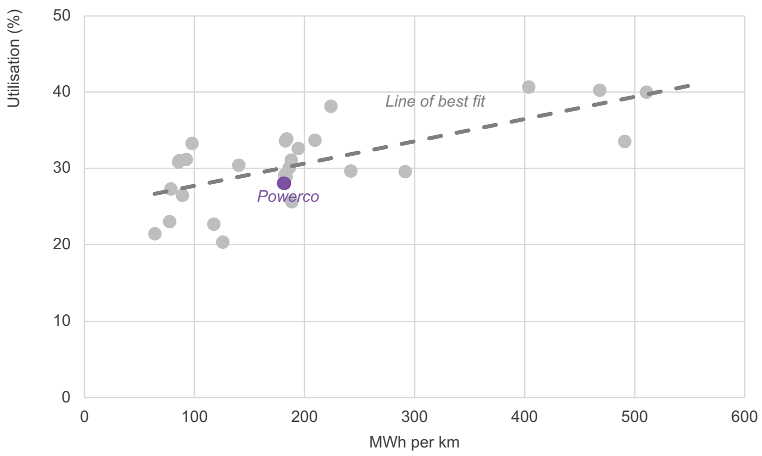
As shown in Figure 9.14, we sit at industry median with respect to faults on distribution cable networks.

9.6.3.2 ASSET UTILISATION

Distribution transformer utilisation

Figure 9.15 shows our distribution transformer utilisation against network load density.

Figure 9.15: Comparison of NZ EDB distribution transformer utilisation and network load density (2018)



We sit close to the line of best fit for us. We use this relationship to inform our distribution transformer utilisation target of 30%.

Zone substation transformer utilisation

Our FY17 zone transformer utilisation was 51.6%. Consistent with previous AMPs, this has been calculated by dividing total zone substation peak demands by the total zone transformer capacity. Zone substation peak demands have generally been recorded in MW. They have been adjusted by a nominal power factor and to restore transferred loads where possible.

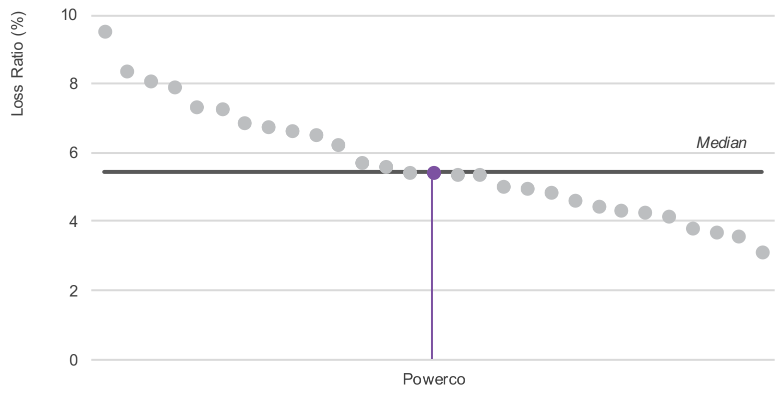
In general, higher transformer utilisation means less operational flexibility. When zone transformer utilisation exceeds 60%, the ability to shut equipment down for maintenance work is constrained. As such, 60% is a high-level indicator for the need to upgrade capacity. Our utilisation target of 50% is an average and reflects that some sites, particularly newer ones, need to have spare capacity to allow for future demand growth.

We do not compare ourselves with other distributors' zone substation transformer utilisation because of large variations in the use of zone substations within the industry. Networks rely, to a greater or lesser extent, on Transpower for their distribution supply. This is further complicated as some zone substations are required to have extra capacity to provide backup services for other zones.

Network losses

Figure 9.16 shows our network loss ratio compared with that of other EDBs.

Figure 9.16: Benchmarking of average network loss ratio (2014-2018)

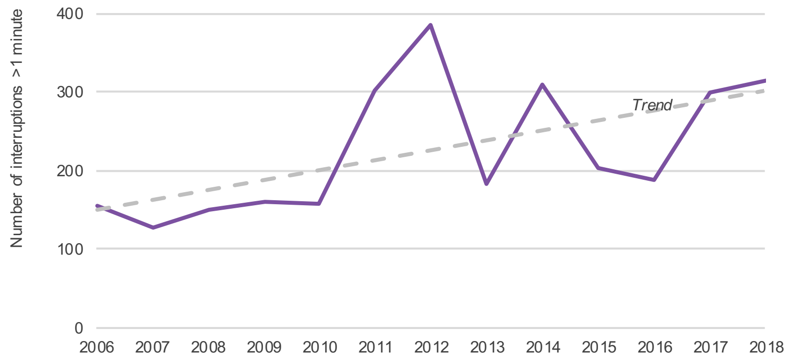


Our network losses are at industry median level and considered satisfactory and appropriate for our network.

9.6.3.3 VEGETATION MANAGEMENT

Figure 9.17 shows our historical vegetation-related interruptions.

Figure 9.17: Number of vegetation-related events causing >1 min outages



The irregular shape of the trend line reflects inclement weather conditions from year to year. However, one can see the overall trend is increasing, indicating an underlying increase in vegetation-related failure risk. Our targets are designed to drive a decrease in the number of vegetation-related faults.

9.6.4 IMPROVEMENT INITIATIVES

Table 9.18 lists the initiatives we are implementing to further improve our asset fleet performance.

Table 9.18: Asset fleet performance improvement initiatives

FOCUS AREA	INITIATIVE
Fleet Management plans	Our Fleet Management plans and associated investment proposals are designed to ensure appropriate asset health outcomes during the planning period. They are also designed to arrest deteriorating fault rate trends and achieve improvements towards the end of the planning period.
Defect backlog resolution	Our plans include targeted initiatives to address defect backlogs. This approach will help ensure proactive replacements of components with a high risk of failure, which will help stabilise and ultimately reverse current unfavourable fault rate trends.
Network Development	Our specific Network Development plans are designed to ensure an appropriate balance between network security and asset utilisation. More information is in Chapter 11.

FOCUS AREA	INITIATIVE
Future network initiatives	The technologies we will trial as part of our future networks programmes should help enhance long term utilisation. This includes initiatives that improve network visibility, help us understand our customers, allows real-time monitoring, improves utilisation of our assets and enhances quality of supply. More information is in Chapter 13.
Vegetation strategy	We are transitioning our approach to vegetation management to cyclical trimming, which is expected to reduce vegetation-related faults over time. The approach is described in Chapter 23.

9.7 OPERATIONAL EXCELLENCE

9.7.1 OVERVIEW

This section sets out the specific targets we have set for operational excellence during the planning period. We also consider the basis for these targets and our historical performance against these targets.

Our objective is to obtain more comprehensive, accurate data to aid high-quality options analysis, so the most cost effective, long-term solutions can be consistently identified. We also intend to continue to refine our area plans to holistically consider all network priorities – renewal, development, customer needs and reliability.

9.7.2 TARGETS

Significant improvements are needed in the way we plan, engineer and deliver projects and run our business to deliver our CPP commitments. Improvements being implemented include:

- Alignment with and certification to Asset Management Standard ISO 55001.
- Development of a Data Quality Framework.
- New Foundations – a programme of activities that will improve our business performance, reduce the number of manual tasks over time, and reset our core software-based processes and systems.

Table 9.19 lists the targets we intend to achieve, and Table 9.20 details the rationale behind them.

Table 9.19: Operational Excellence targets

INDICATOR	TARGET FY19-FY29
Vegetation management	
Self-assessed maturity level	Achieve a self-assessed Asset Management Maturity Assessment Tool (AMMAT) score of at least 3.0 by 2020.
ISO 55001 certification	Achieve ISO 55001 certification by 2020.
Efficiency	
Efficiency gains	Achieve projected efficiency gains.
ERP system operational	
• **Stage 1**	1H FY20
• **Stage 2**	FY20/FY21
• **Stage 3**	FY21/FY22

Table 9.20: Excellence in asset management target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Asset management maturity	
We have proven ourselves as capable asset managers. However, we recognise there is more to do as asset management approaches mature. We consider ISO 55001 certification to be an appropriate good practice target and the year 2020 an appropriate transitional window.	The AMMAT scope proves a proxy for a transition towards ISO 55001 certification. Our approach has matured progressively from a self-assessed average AMMAT score of 2.31 in 2016, to 2.44 in 2017 and 2.53 in 2019. Details and associated 'spider' diagrams are included in Chapter 10.
Efficiency	
Our delivery plans involve a material increase in investment volumes during the planning period. Our plans include specific efficiency assumptions. Our efficiency targets have been set on a portfolio-by-portfolio basis to reflect an achievable but stretch target over and above current performance. Our New Foundations ERP programme is a key enabler of these future efficiencies.	We have not specifically tracked efficiency improvement in previous periods, however industry benchmarking on a cost-per-connection basis demonstrates our performance has been strong.

9.7.3 HISTORICAL TRENDS

We are committed to obtaining certification to asset management standard ISO 55001 by 2020. To help us identify the areas we need to improve, we employed an Australian asset management consultant AMCL Ltd to undertake a review of our asset management systems. This involved a gap assessment as benchmarked against ISO 55001 and the 39 asset management maturity questions posed by the Global Forum on Maintenance & Asset Management (GFMAM).

We were assessed as ‘competent’ or close to competent in most areas. There were several areas where we were classed as ‘developing’. More detail on our asset management maturity trends, including our action plans to address areas requiring development, is outlined in Chapter 10.

9.7.4 IMPROVEMENT INITIATIVES

Table 9.21 lists the initiatives we are implementing to improve our performance.

Table 9.21: Excellence in asset management improvement initiatives

FOCUS AREA	INITIATIVES
Risk-based investment planning	Selected asset fleets will undergo Condition-Based Risk Management (CBRM) analysis to quantify the risk associated with asset failure to justify and prioritise renewal and refurbishment expenditure. We have recently transitioned several of our asset fleets to CBRM analysis, and are planning to transition further fleets as well as develop the maturity of our modelling.
Process refinement	Our business plans include a focus on process refinement to support efficient delivery. We have recently moved from an annual to rolling works plan delivery and are planning enhancements to portfolio optimisation.
Field delivery refinement	We have reset our field delivery arrangements to deepen competition and ensure appropriate resources are available. These arrangements will be progressively refined during the planning period.
Enterprise resource planning	Complete implementation of our New Foundations ERP programme within the next three years. This initiative will include refinement and rationalisation of associated business processes.

10 ENHANCING DELIVERY CAPABILITY

10.1 CHAPTER OVERVIEW

We have embarked on a programme to increase internal and outsourced delivery capacity in order to deliver the amount of work we have committed to under our Customised Price-quality Path (CPP). In conjunction with this effort, we are continuing to improve our asset management practice, including how we manage our asset information, with ISO 55001 certification our medium-term goal.

In this chapter:

- Section 10.2 sets out work under way to lift external field resource.
- Section 10.3 sets out work under way to lift internal capacity and capability.
- Section 10.4 describes the work under way to improve our information management systems.
- Section 10.5 sets our work under way to lift asset management maturity.

10.2 EXTERNAL CAPABILITY

10.2.1 OVERVIEW

We made a strategic decision some time ago to outsource our field work to external service providers, the large majority to Downer Ltd.

Last year, we also entered into long-term service contracts with Northpower and Electrix to help us deliver on our CPP commitments. These agreements secured an additional \$30-\$35m per year of field delivery capacity, with the potential for further growth. They also enhanced the diversity and versatility of our field resource, as well as improving the contestability of field work.

The outsourcing strategy was designed to minimise cost, deliver efficiencies and enable scalability. It also allowed us to benefit from innovation and competition associated with tender markets, fostering demonstrable cost efficiency. It has proved to be a sound approach.

10.2.2 DELIVERY CAPACITY

We have worked with our key service providers to tailor their resourcing and delivery to future work volumes, including the following steps:

- Calculated the specific field resources needed to construct and maintain the network from our CPP work projections.
- Obtained contractual assurance that the required levels of field resources will be available.
- Assessed the impact the service providers' increased field resource requirements will have on the market for these resources in the various regions in which they operate.
- Analysed and addressed the constraints associated with inputs factors related to the delivery of network investment, such as materials, planning/resource consents and land use rights.
- Incorporated a tender panel for larger planned works, sized to deliver appropriate scale, resource certainty and effective price competition.

We are moving to further analyse and optimise our contracting markets during the CPP period to ensure ongoing efficient pricing and resource flexibility. For example, we are currently certifying two additional service providers to perform network switching.

Field resource optimisation

With increasing numbers of service providers involved in the construction of assets on the network, we have improved our work allocation processes in order to optimise the use of available field resources. We consider geographical location, service provider capacity, specific CPP renewal targets, forecast expenditure and planned System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) position.

We are developing new tools to help with this optimisation, so that we can improve delivery efficiency while simultaneously managing internal resource, planned SAIDI/SAIFI and budget constraints.

10.2.3 PLANT AND MATERIALS

Increased investment in the network is driving a corresponding increase in the amount of input material that will be needed.

We have previously assessed the availability of key equipment, such as poles, crossarms, conductors, cable, switchboards, power transformers, voltage regulators, reclosers and ground-mounted switchgear. This assessment concluded there are many national and international suppliers, and that our share of the market is small enough that planned increases are readily achievable.

We are reviewing our procurement processes to develop closer supply chain relationships, greater visibility over the quality of materials, and to ensure that materials are cost competitive and commensurate with our volume of purchases.

10.3 INTERNAL CAPABILITY AND CAPACITY

10.3.1 OVERVIEW

In 2017, we restructured our Electricity business to ensure we can deliver our work plans efficiently and effectively. Key focus areas have been both lifting capability and growing capacity. Subsequent sections discuss this in further detail.

10.3.2 LIFTING CAPABILITY

10.3.2.1 CAPABILITY REQUIREMENTS

In order to deliver our network investment programmes, we have been targeting capability enhancements in the following areas:

- Managing and analysing increasing volumes of network and asset data, building an information basis for sound asset management and network operational decision-making.
- Building our skills related to innovation, research and development, piloting new solutions and developing these to a state suitable for incorporating as business-as-usual.
- Adding a specialised programme management function with dedicated resources to track and facilitate the delivery of our works programme.
- Enhancing our ability to understand customer requirements and emerging trends, and how these could be addressed effectively in our service offerings, and better responding to their requirements.
- Future scenario development and analysis – ensuring that we make informed investment decisions that would lead to least-regret outcomes in the light of changing load patterns on our networks.
- Enhancing our asset management practices, with the aim of being ISO 55001 compliant by 2020.
- Optimising our long-term investment plans, balancing technical, customer, regulatory, risk-management and shareholder considerations.

10.3.2.2 ASSET MANAGEMENT CAPABILITY IMPROVEMENT INITIATIVES

Our plans include a range of initiatives designed to guide development of capability over time. These are set out in Table 10.1.

Table 10.1: Asset management capability improvement initiatives

AREA	INITIATIVE	DESCRIPTION	TIMING
Asset management maturity	ISO 55001 certification	We will identify and address the necessary steps to achieve ISO 55001 certification by 2020.	FY20
Asset strategy	Refined delivery structures	Aligns our asset management activities and network outputs with our overall organisational objectives, including a shift from generalist planning to focused fleet and network development-based planning.	Completed
Asset strategy	Enhanced planning analytics	Lift approach to compiling, processing and mining asset data to inform operational, maintenance and investment decisions.	In progress
Asset strategy	Enhance team capability	Develop our asset management capability through effective recruitment and development of our staff, ensuring appropriate competency levels and breadth of skills.	In progress
Asset information	Asset information strategy	Develop and implement an asset data quality strategy that will ensure our asset managers and operations staff are provided with comprehensive and accurate asset and network performance data.	In progress

10.3.3 GROWING CAPACITY

10.3.3.1 CAPACITY REQUIREMENTS

In order to deliver our network investment programmes, we have targeted capacity enhancements in the following areas:

- Planning, design and project management of network growth and renewal projects.
- Planning and management of increased network maintenance programmes.
- Planning and management of increased vegetation control programmes.
- Management of an increased number of service providers, who will be required to deliver the proposed increased work volumes.
- Managing the day-to-day operation of our electricity network, especially in the face of increased demand for network outages and switching.

The capacity uplift has largely involved adding personnel with skills similar to those already present in the company. This process is ongoing.

10.3.3.2 ASSET MANAGEMENT CAPACITY INITIATIVES

Our plans have included a number of specific initiatives to help streamline delivery. These are set out in Table 10.2.

Table 10.2: Deliverability improvement initiatives

AREA	INITIATIVE	DESCRIPTION	TIMING
Works planning	Works plan process	Enhancement of works planning to enable an extended delivery pipeline.	Complete
Works management	Enterprise resource planning tool	Purchase, configuration and rollout of SAP's financial management, works and asset management systems, together with a mobility solution. We refer to this initiative as its *New Foundations* programme. It is described in detail in Chapter 22.	FY19/20
Facilities	NOC	Construction of a new Network Operations Centre (NOC) building to allow expanded capability.	Complete

10.4 ASSET INFORMATION MANAGEMENT

10.4.1 OVERVIEW

This section considers our approach to asset information management and enhancements we have been making in this area.

We treat information as an asset, with the understanding that quality, timeliness, accessibility and analysis determine the value of that information. From an asset management perspective, the value is derived from being able to make well-informed decisions.

We have made some significant advances in terms of data collection, processing, and mining in recent years. That said, our systems and controls to manage data quality and accuracy are still relatively immature and improvements in this area remain a focus for our Asset Analytics team, supported by all areas of our asset management business.

10.4.2 ASSET DATA

We identify the data needs through consultation with our teams and stakeholders, and by mapping out the business functions and required inputs and outputs. This information is then made available to the business through the systems described in Chapter 22.

Much of the data we use is collected via our asset inspections. We have standards that prescribe the information that must be gathered, including asset condition.

As part of our ongoing asset management work, which is discussed in Chapters 5-8, we will complete targeted enhancements to our asset management information as we improve the quality of our decision-making based on analytics to forecast asset condition, health and criticality.

In the past three years, we have focused on improving data on key assets such as distribution transformers and overhead lines. We have also integrated information on ancillary assets and all available historical construction information into our Geographical Information System (GIS). We continue to update any new information we receive from field work on existing assets.

The biggest asset information gap we need to address relates to our LV networks. This will be dealt with as part of our long-term information management strategy. Asset data deficiencies are reflected in our Asset Management Maturity Assessment Tool (AMMAT, see Section 10.4 and Appendix 2.7), which has shown the feedback loops for information, data quality and structures are not of the highest standard.

Initiatives designed to improve the availability or completeness of asset data are listed in Table 10.3.

Table 10.3: Asset data improvement initiatives

AREA	INITIATIVE	TIMING
Preventive maintenance inspections	Pole-top photography and LIDAR surveys to improve the quality of our overhead line asset information, eg hardware condition, vegetation issues. Acoustic testing of overhead line components, such as conductors, insulators, terminations etc, to locate defects and to diagnose potential faults on key feeders. Acoustic resonance pole testing to determine internal condition of wooden poles.	FY20
Investment modelling	Refine asset health assessment methods to support maintenance and renewal investment decisions.	In progress

10.4.3 INFORMATION MANAGEMENT

We recognise that to improve our delivery capability we will need to improve the management of business information.

Table 10.4 lists the aspects of information management that we are progressing. These are supported by the enabling Information Communications Technology (ICT) systems described in Chapter 22.

Table 10.4: Information improvement initiatives

AREA	INITIATIVE	TIMING
Capture	Develop comprehensive data standards to ensure we capture correct, quality information once, and at source.	In progress
Accessibility	Develop systems for near real-time storage and retrieval of critical information in a range of locations, including supplier and customer portals, cloud systems and with customers.	FY20
Security	Our approach to system security will match information criticality to security and detection measures, so that the more sensitive the information the more layers of security protect it.	FY20
Analytics	This will have significant focus in the period, both with respect to organisational structure and business systems. This will provide tools for analysts and 'knowledge workers' across the business to use asset information to enhance business decision-making.	FY20
Capability	The shift from paper-based to electronic information delivery and the need for more sophisticated data mining is driving a change in the skills required from our people. These are reflected in our recruitment plans and our competency framework development.	In progress

10.5 IMPROVING OUR ASSET MANAGEMENT MATURITY

10.5.1 OVERVIEW

In 2018, we employed asset management consultant AMCL Ltd to undertake a review of our asset management systems. AMCL undertook a gap assessment as benchmarked against ISO 55001 and Global Forum on Maintenance & Asset Management (GFMAM).

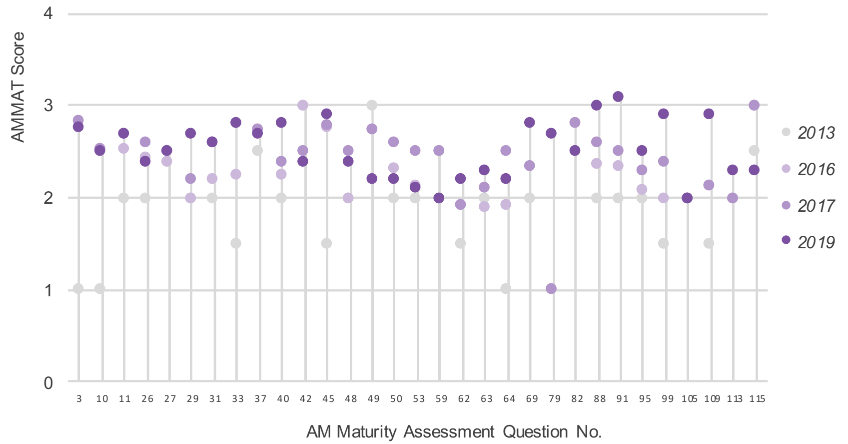
The results of the ISO 55001 gap analysis were mapped to, and normalised against, our Asset Management Maturity Assessment Tool (AMMAT[29]) self-assessment scores.

10.5.2 AMMAT ASSESSMENT

We published our first AMMAT assessment in the 2013 AMP and have repeated the assessment in subsequent AMPs.[30] Overall, we have found the repeated use of the AMMAT approach useful, and some of the improvement initiatives we are implementing originated from the AMMAT assessment.

Figure 10.1 shows the AMMAT results from this year's assessment and compares them with prior scores. Scores range from 0 ('innocent' maturity level) to 4 (excellent maturity level). We mapped the AMCL assessment to the AMMAT scores[31].

Figure 10.1: Asset maturity self-assessment scores 2013-19



The scores shown in Figure 10.1 reflect an honest reappraisal of our asset management maturity when considered in the light of AMCL's feedback. For example, we have reduced our scores in the areas of corporate dissemination of strategy and objectives, competency management, asset management system documentation, information management, and achievement of continuous improvement. However, notwithstanding ACML's feedback, we believe we have achieved modest and, in many cases, marked improvements in asset management practices.

Changes in our measured maturity since the last edition of our AMP are:

- On 13 questions our maturity score increased compared with 2017
- On six questions our score was the same as in 2017
- On 12 questions our score decreased
- Our average score was 2.53 against a 2017 average score of 2.44

In Figure 10.2 we show the scores grouped by assessment areas. We re-assessed ourselves as improving markedly in asset strategy and delivery, marginally declining

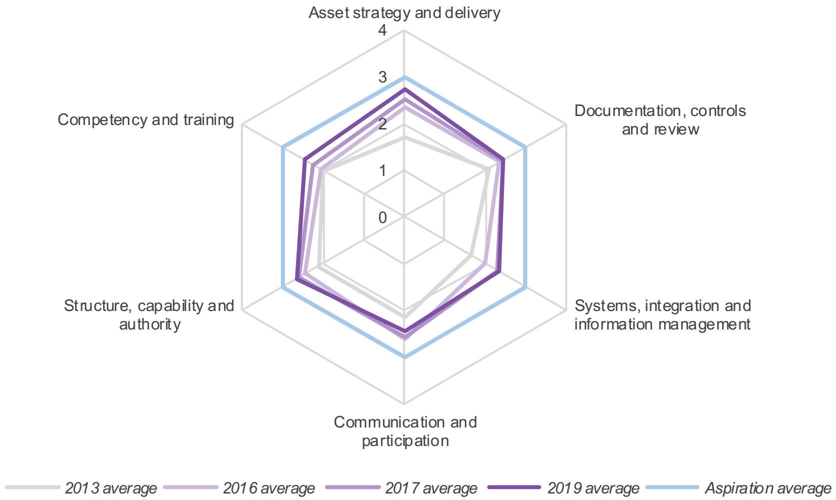
[29] AMMAT is a means to derive asset management maturity scoring for Information Disclosure purposes

[30] As an electricity distributor we are required to undertake and publicly disclose the AMMAT self-assessment results.

[31] AMCL used five maturity categories, with the fourth and fifth representing 'effective' and 'excellent' capabilities. AMCL's 4 and 5 scores have been mapped to the AMMAT's 'excellent' maturity level of 4.

in the area of communication and participation, and modestly improving in the remaining four areas.

Figure 10.2: Summary of asset maturity self-assessment scores by assessment area



The ISO 55001 assessment results are documented in Table 10.5.

Table 10.5: ISO 55001 benchmark scores

PRACTICE AREA	ISO 55001 CLAUSE	SUBJECT	SCORE
Context of the organisation	4.1	Understanding the organisation and its context	3.0
	4.2	Understanding the needs and expectations of stakeholders	2.9
	4.3	Determining the scope of the Asset Management System	2.0
	4.4	Asset Management System	2.5
Leadership	5.1	Leadership and commitment	3.3
	5.2	Policy	3.0
	5.3	Organisational roles, responsibilities and authorities	2.7
Planning	6.1	Actions to address risks and opportunities for the Asset Management System	2.8
	6.2	Asset Management Objectives and planning to achieve them	2.9
Support	7.1	Resources	2.6
	7.2	Competence	2.2
	7.3	Awareness	2.0
	7.4	Communication	2.0
	7.5	Information requirements	2.2
	7.6	Documented information	2.3
Operation	8.1	Operational planning and control	2.8
	8.2	Management of change	2.2
	8.3	Outsourcing	3.3
Performance evaluation	9.1	Monitoring, measurement, analysis and evaluation	2.5
	9.2.1	Internal audit	2.0
	9.3	Management review	2.3
Continuous Improvement	10.1	Non-conformity and corrective action	2.9
	10.2	Preventive action	2.6
	10.3	Continual improvement	2.3

Scores range from 0 ('innocent' maturity level) to 5 (excellent maturity level). This differs slightly from that used in the AMMAT tool, which has a 0-4 scoring range, but for our current purposes is directly comparable. Our final AMMAT average score was 2.53.

10.5.3 IMPROVEMENT INITIATIVES

AMCL justified the scores by commenting on the strengths and deficiencies in our current practice. The identified deficiencies focused principally on:

- Needing to better define the Asset Management System
- Making clearer the links between corporate objectives and day-to-day operations
- Better role and governance definition with respect to ISO 55001 implementation
- The improvements needed to our risk management framework

- Better training and competence frameworks
- Information quality
- Management of change
- Operational planning and control, for example our defect management processes

We have formulated action plans to address these deficiencies. These will also have a positive impact on our AMMAT scoring.

The improvement initiatives are outlined in Table 10.6.

Table 10.6: Asset management maturity improvement initiatives completion by FY21

INITIATIVE	OUTCOME
Asset Management System	Refine the Asset Management System to include: – scope definition – roles and responsibilities – risk management frameworks – better align organisational and Asset Management Objectives – the means of developing a resourcing strategy
Asset Management Policy	To provide guidance on the requirements of Asset Management System framework and governance, and the means of communicating the Asset Management Policy to people throughout the organisation.
Asset Management Strategy	Assess relative positions of asset plans with respect to Asset Management Objectives, setting maturity levels and resource priorities, and establishing review cycles. Develop a lifecycle approach to maintenance strategy, critical spares strategy, and sustainable development strategy.
Process mapping	Link end-to-end project process maps with Asset Management System.
Risk management frameworks	Risks and controls are to be aligned with the Asset Management System and corporate risk management framework. Provide clarity around the 'as low as reasonably practical' (ALARP) risk appetite and how it is used to inform decision-making. Clarify how asset risks are captured, tracked over time and fed back into fleet management plans and business decisions.
Training and competency frameworks	Develop an asset management and project management competency framework.
Information management framework	Develop a management system that effectively manages, governs and assures that necessary asset information quality parameters are being met, and that data is being continuously improved.
Change management	Provide tools and staff to enable management of change to be improved in all processes.
Continual improvement	Develop and authorise an Asset Management Improvement Plan.
Defect management	Continue to improve defects management systems.
Incident investigation	Resolve incident close-out processes and improve points of incorrect management of incidents.
Document management	Refine how documents are controlled and where they are stored.
Strategic resourcing strategy	Develop an enterprise Resource Management Plan.
Supply chain	Develop a procurement and supply chain strategy.

10.5.4 NEW FOUNDATIONS

We are in the process of installing a new Enterprise Resource Planning (ERP) system, implemented via a multi-year programme called New Foundations (NFP). It is a key programme to enhance our asset management capability by:

- Enabling efficient work volume growth by readily scaling up project volumes.
- Lifting asset management capability by integrating financial and non-financial data, performance analytics and workflow from planning through to delivery.
- Improving information integrity by creating a 'single source of truth' for critical data.

NFP is described in further detail in Chapter 22.

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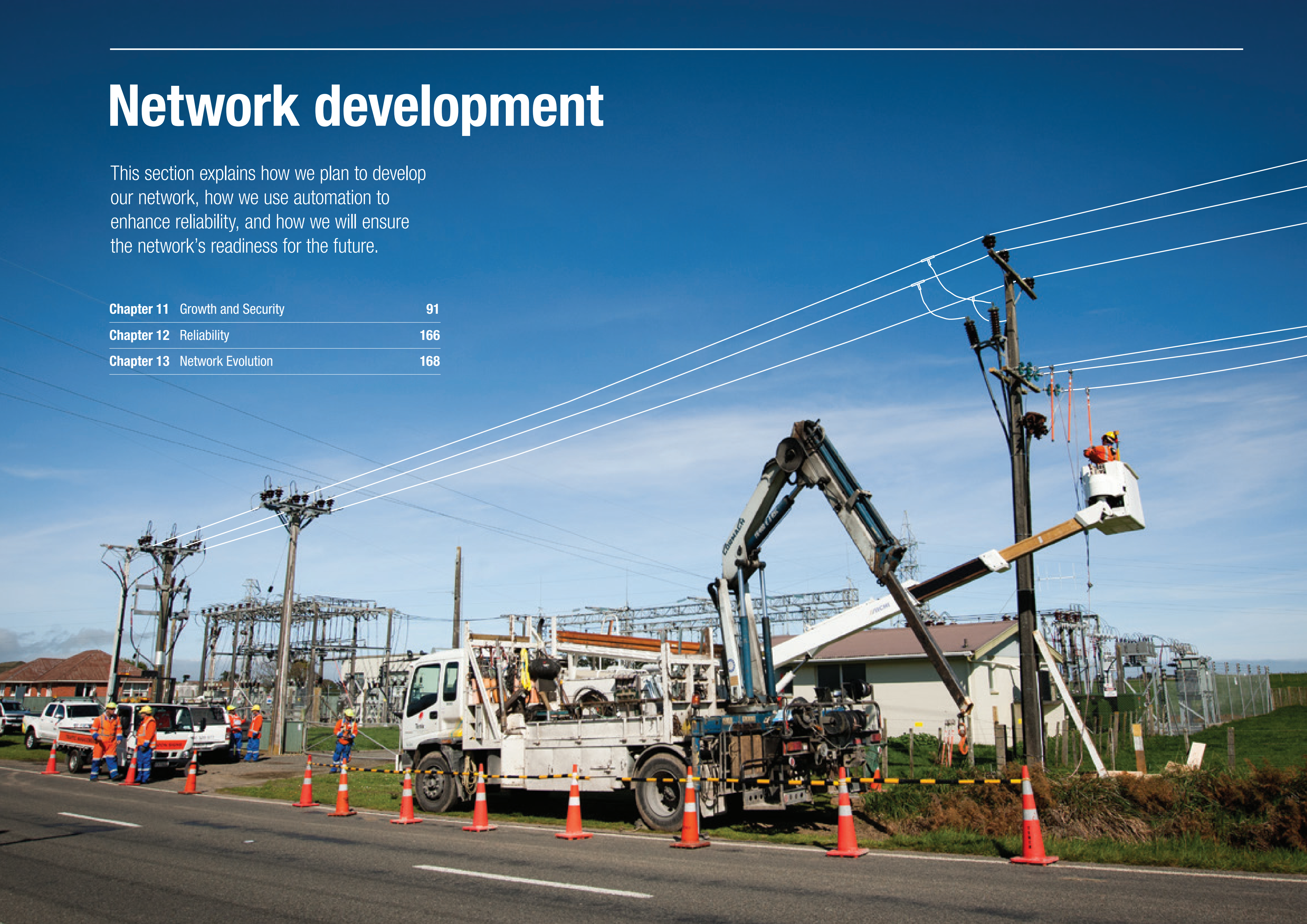
Network development

This section explains how we plan to develop our network, how we use automation to enhance reliability, and how we will ensure the network's readiness for the future.



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11 GROWTH AND SECURITY

11.1 CHAPTER OVERVIEW

This chapter builds on the introduction to growth and security provided in Chapter 7, which summarised our approach to forecasting demand growth and how we invest to maintain supply security. It provides a summary of the resulting area investment plans, our investment in communications infrastructure and ongoing routine growth investments on the distribution network.

Growth and security investment is forecast to grow during the planning period, driven by increasing Installation Control Point (ICP) numbers and demand across our network. In contrast to the reported national trend, most of our network continues to experience sustained demand growth. This is mainly driven by residential growth in areas such as Tauranga, and dairy and industrial growth in Waikato and Taranaki.

For the Customised Price-quality Path (CPP) period, we demonstrated a need to significantly lift our investment in growth and security. This investment is specifically targeted at supporting residential and industrial growth and addressing security related issues. This is informed by the concerns of the customers and communities we serve. We are fortunate to operate in regions where our customer base continues to grow and expand, and we believe we play a critical role in supporting this growth. Our network planning is based on 13 discrete areas, which are described in this chapter, along with our main planned investments in each area.

Although less certain, following the CPP period (from FY24 on) we still foresee continuing growth in our regions, with associated demand growth. The rate of demand growth will be highly influenced by factors such as the uptake of electric vehicles, local generation, energy storage, and the potential for customer energy trading over our network.

These uptake rates are uncertain and could lead to various future scenarios, as discussed in Chapter 13. But for any future scenario there is a clear underlying need to have better visibility of utilisation, power flows and power quality on all parts of the network, including the Low Voltage (LV) network. This is especially true for a network with multi-directional energy flows. The proposed investment associated with implementing this capability and supporting a transition to an open-access network is also discussed below.

11.2 GROWTH AND SECURITY PRINCIPLES

11.2.1 OVERVIEW

We use the term growth and security to describe capital investments that increase the capacity, functionality, or size of our network. These include the following six main types of investments.

- **Major projects** – more than $5m, generally involving subtransmission or grid exit points (GXP) works.
- **Minor projects** – between $1m and $5m that typically involve zone substation works and small subtransmission projects.
- **Routine projects** – below $1m, including distribution capacity and voltage upgrades, distribution backfeed reinforcements (supports automation), smaller zone substation upgrades, distribution transformer upgrades, and LV reinforcement.
- **Open-access network investments** – investments in network monitoring, communications and power quality management to support our transition to an open-access network.
- **Communications projects** – to support improved control and automation of the network and provide voice communications to our field staff.
- **Reliability** – includes network automation projects to help manage the reliability performance of our network. These are discussed in Chapter 12.

11.2.2 STRATEGY AND OBJECTIVES

To guide our strategy for network development we have defined a set of objectives, as listed below. They are linked with our overall Asset Management Objectives in Chapter 5.

Table 11.1: Growth and security objectives

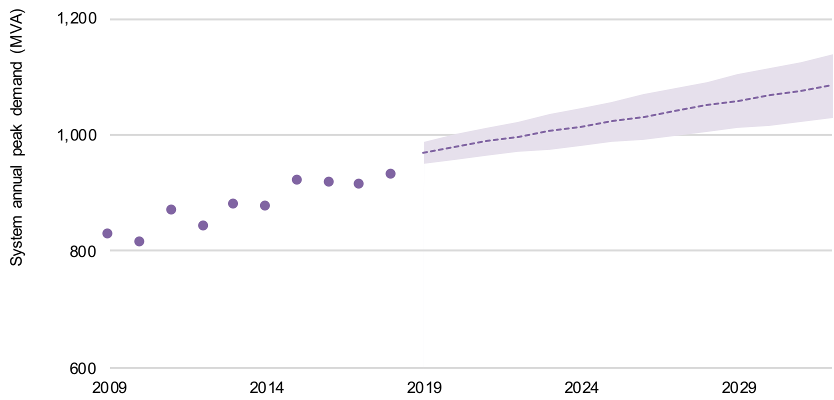
ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Use safety-in-design to ensure appropriate design of the network to provide for alternative supply during maintenance, reducing the need for high-risk live line work. These principles also help ensure the intrinsic safety, ease of maintenance, operations and accessibility of our assets.
	Consider the impact on the environment of our large-scale development projects in our access and consenting approach.
Customers and Community	Minimise planned interruptions to customers by coordinating network development with other works.
	Consult with our customers regarding price/quality trade-offs for major projects. Better align our planning processes and decision criteria with evolving customer needs.
	Adapt to the changing needs of our customers to understand the possible implications of widespread uptake of new technology.
	Work with land owners during our access and consents process.
	Ensure our customer contribution policies are fair, in that they reflect the unrecovered cost of progressing a connection.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Networks for Today and Tomorrow	Prudently introduce new technology on our network, including technology that facilitates innovative customer solutions. Undertake appropriate trial programmes to understand how new technology can assist to more effectively provide our core service of delivering reliable energy.
	Continue with our strategy of using appropriate levels of network automation and remote control to reduce outage times following faults, as well as the number of ICPs affected.
	Continue to review our demand forecasting, security criteria and network architecture to optimise our investment in network infrastructure.
Asset Stewardship	Improve our use of risk-based analysis and lifecycle cost modelling in our development planning.
	Improve our feedback procedure so that field and construction experience is used to help future planning in a more systematic and thorough manner.
Operational Excellence	Obtain more comprehensive, accurate data to aid high-quality options analysis, so the most cost effective, long-term solutions can be consistently identified.
	Continue to refine our area plans to holistically consider all network priorities –renewal, development, customer needs and reliability.
	Continue to update core design standards, which will improve safety and efficiency. Standardisation of components and materials will improve spares and stock efficiency.

11.3 DEMAND TRENDS

Our network has continued to experience steady and sustained growth. Figure 11.1 shows both the historical trend and our forecast of total system demand for the whole network.

Figure 11.1: System demand trend and forecast



The consistent growth exhibited is mainly a result of:

- Steady residential subdivision activity, especially in key areas such as Tauranga and Mt Maunganui.
- Significant changes in the demand of some larger industrial customers, especially from the dairy industry, and the oil and gas industry in Taranaki.
- Smaller contributions from irrigation developments, cool stores, and other agricultural loads.

Growth in each area of our network varies according to demographic changes and economic activity. The maps in Figure 11.2 and Figure 11.3 indicate annual forecast growth rates by planning area for the Western and Eastern regions.

Figure 11.2: Forecast demand growth in Western planning areas

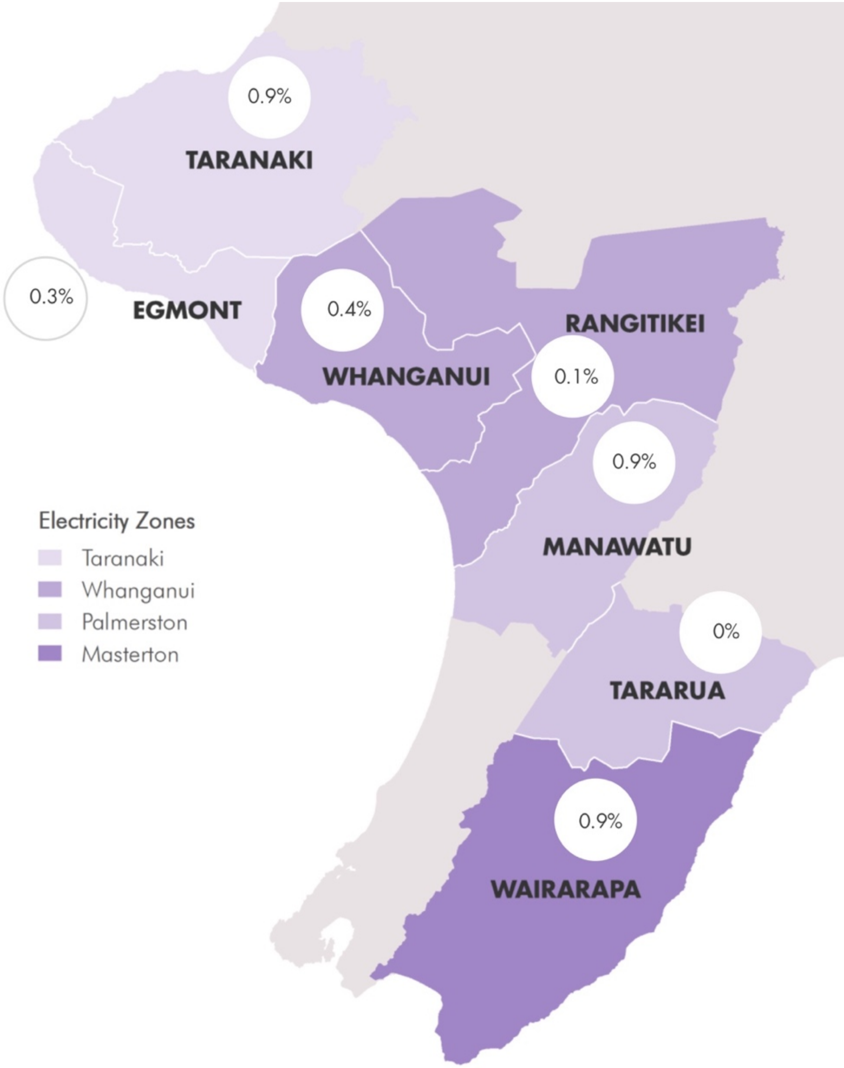
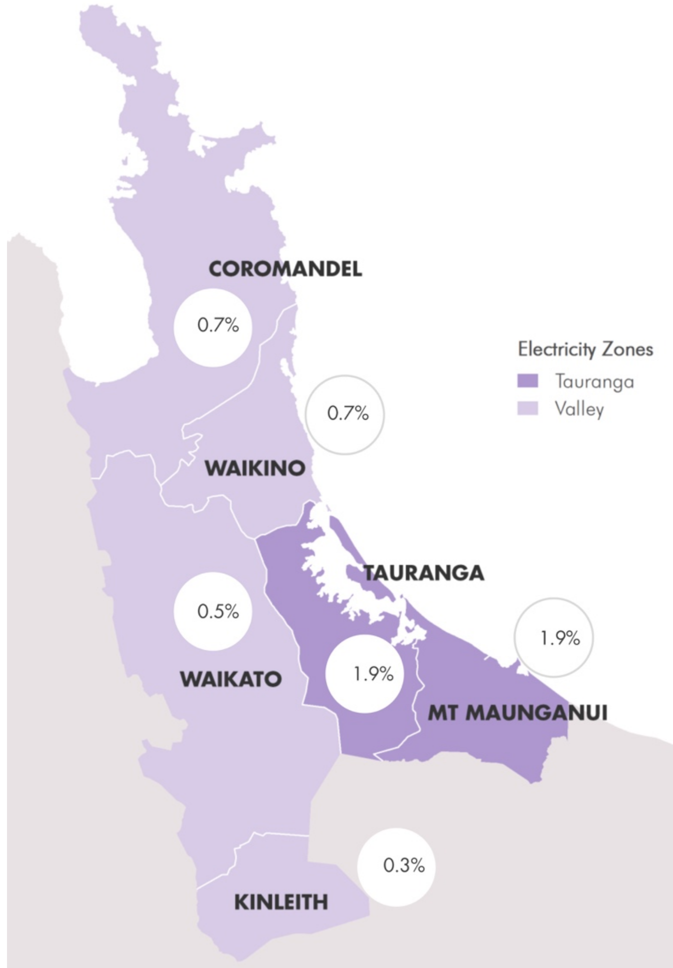


Figure 11.3: Forecast demand growth in Eastern planning areas



Higher growth is evident in areas such as:

- Tauranga and Mt Maunganui – population increase driving residential subdivisions and commercial/industrial developments.
- Coromandel – increased holiday and tourism activity in Coromandel and popular coastal areas.
- Taranaki – industrial, often associated with oil and gas.

11.4 AREA PLANS

To best manage our investment planning, and to improve our focus on local needs and issues, we have divided our network into 13 planning areas. We then produce a comprehensive and integrated development plan for each area.

These area plans are summarised in the following sections. In demand forecast tables, grey shading indicates that peak demand exceeds current firm capacity.

For more detailed descriptions of the options considered for our large growth and security projects, refer to Appendix 8.

11.4.1 COROMANDEL

Strong growth in the Coromandel area has created legacy security issues, which is coupled with increasing consumer expectations regarding the reliability of supply, particularly from holiday home owners on the Coromandel Peninsula. The existing lines and substations face significant capacity restraints and additional investment is required to improve both network security and reliability. Major and minor project spend related to growth and security during the next 10 years is $68.4m.

11.4.1.1 AREA OVERVIEW

The Coromandel area plan covers the Coromandel Peninsula as well as a northern section of the Hauraki Plains. The main towns in the area are Thames, Coromandel, Whitianga, Tairua, and Ngatea.

The economy is largely based on tourism, with some agriculture and forestry. The population is highly seasonal and the annual demand profile is peaky.

The appropriate level of security is also a source of debate given the nature and duration of peak loads, and the inherent economic cost of reliable supply.

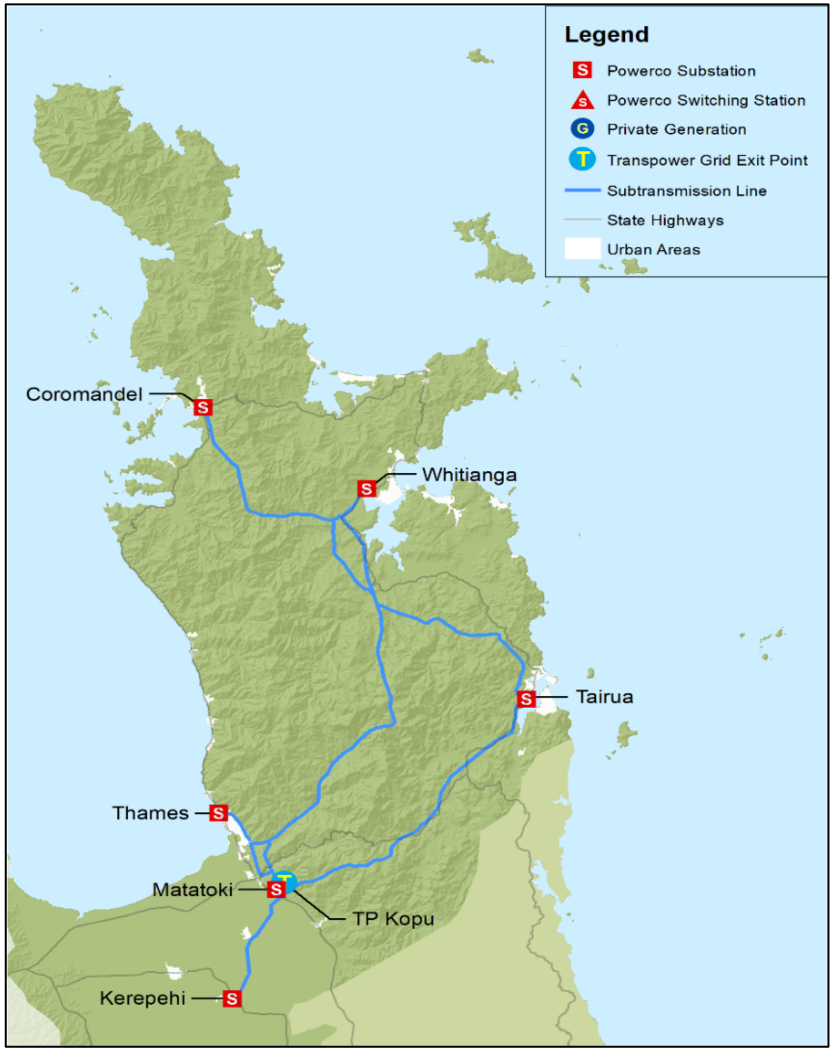
The region is characterised by rugged, bush-covered terrain, with minimal sealed road access for heavy vehicles. This makes access to lines for construction, maintenance and faults difficult and costly. Sensitive landscape and heritage areas also restrict our options for upgrading and building new lines.

Seasonal weather extremes and cyclones can impact the quality of supply. The demand for electricity peaks in the summer when the thermal ratings of overhead lines are limited by the higher ambient temperatures.

The subtransmission circuits in the Coromandel area are supplied from the Kopu GXP, just south of Thames. The area uses a 66kV subtransmission voltage, which is unique across our networks.

The subtransmission is dominated by a large overhead ring circuit, serving Tairua and Whitianga, with a teed radial line feeding Coromandel. A further interconnected ring serves the Thames substation.

Figure 11.4: Coromandel area overview



These ring circuits have been operating in a closed loop after protection upgrades were made. Voltage constraints and, in places, thermal capacity constraints, also severely limit our ability to provide full N-1 security to all substations.

Matatoki substation is directly adjacent to the Kopu GXP. Kerepehi substation is fed from a single radial circuit.

Our subtransmission and distribution networks in the Coromandel area are predominantly overhead, reflecting the rural nature of the area and rugged terrain. Some of the original transmission circuits are very old but we have been working through a programme of upgrading and renewing the circuits during the past decade.

11.4.1.2 DEMAND FORECASTS

Demand forecasts for the Coromandel zone substations are shown in Table 11.2, with further detail provided in Appendix 7.

Table 11.2: Coromandel zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Coromandel	AA	0.5	4.6	4.7	4.9	5.1
Kerepehi	AA+	0.0	10.4	10.6	11.1	11.6
Matatoki	AA+	0.0	4.9	5.0	5.3	5.5
Tairua	AA	7.5	9.1	9.3	9.6	9.9
Thames T1&T2	AAA	0.0	12.1	12.2	12.6	13.0
Thames T3	AA	6.9	1.8	1.8	1.8	1.8
Whitianga	AAA	0.0	17.8	18.4	19.8	21.3

Growth is forecast to be steady, especially on those substations that supply popular holiday towns. This is, to a degree, linked to national economic prosperity, since demand here grows in response to additional holiday accommodation.

Shaded years indicate that the demand exceeds the capacity we can provide with appropriate security. Several of the Coromandel substations already exceed our security criteria in 2018. Our plans are therefore focused more on improving security and reliability for the existing load base as much as catering for additional future load growth.

Thames T3 is part of Thames substation and is a dedicated transformer serving one industrial customer (A&G Price) with customer-specific security requirements. This customer has recently closed a substantial part of its operation and the load has reduced accordingly.

11.4.1.3 EXISTING AND FORECAST CONSTRAINTS

None of the substations in the Coromandel area fully meet our standard security criteria. This is, in part, because of the legacy security criteria used by previous network owners, which reflected the low criticality of the consumer load because of its short peak duration – ie mostly during peak holiday periods/weekends.

Major constraints affecting the Coromandel area are shown below:

Table 11.3: Coromandel constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Coromandel, Whitianga and Tairua substations	Kopu-Parawai and Parawai–Kauaeranga sections of 66kV line are insufficient to supply all three substations for a Kopu-Tairua 66kV circuit outage.	New Kopu-Kauaeranga line
Coromandel, Whitianga, Tairua and Thames substations	Kopu-Parawai 66kV circuit needs to supply all of Thames when the direct Kopu-Thames circuit is unavailable. Overloading occurs when supplying Whitianga, Coromandel and part of Thames.	New Kopu-Kauaeranga line
Coromandel, Whitianga and Tairua substations	Kaimarama-Whitianga 66kV line has insufficient capacity to supply all three substations for a Kopu-Tairua 66kV circuit outage.	New Kaimarama 66kV switching station
Coromandel, Whitianga and Tairua substations	Kopu-Tairua 66kV line has insufficient capacity to supply all three substations for a Kopu-Whitianga 66kV circuit outage.	Kopu-Tairua line upgrade
Coromandel, and Whitianga substations	Tairua-Coroglen 66kV line has insufficient capacity for a Kopu-Whitianga circuit outage.	Tairua-Coroglen conductor upgrade
Whitianga substation, Matarangi feeders	Two existing 11kV feeders supplying Matarangi are overloaded at times, have excessive ICP counts and insufficient backfeed capability.	New Matarangi substation
Whitianga substation, Whenuakite feeders	Two existing 11kV feeders supplying Coroglen, Cooks Beach, Hahei and Hot Water Beach from Tairua North feeder are overloaded at times, have excessive ICP counts and insufficient backfeed capability.	New Whenuakite substation

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Coromandel, Whitianga and Tairua substations	Low voltages during outages of either Kopu-Whitianga or Kopu-Tairua circuits.	Coromandel area voltage support
Kerepehi substation	Single circuit – insufficient 11kV backfeed to meet security criteria.	Backup supply to Kerepehi
Kerepehi substation	Demand exceeds secure capacity of the two transformers.	New substation at Mangatarata
Coromandel substation	Single 66kV circuit with minimal 11kV backfeed.	Coromandel substation alternative supply
Matatoki substation	Single transformer. 11kV backfeed capacity does not provide the required security.	Matatoki second transformer
Tairua substation	Demand exceeds secure capacity of the two transformers.	Note 1
Whitianga substation	Demand exceeds secure capacity of the two transformers.	Matarangi and Whenuakite substations
Coromandel substation	Demand exceeds secure capacity of the two transformers.	Coromandel substation alternative supply
Thames feeders	High ICP counts on existing 11kV feeders supplying the northern area of Thames are excessively loaded and backfeed capability is constrained.	New feeder cable for Thames

Notes:

1. The risk of lost supply with these transformers is minimal and can be managed operationally until future transformer upgrades can be scheduled.

11.4.1.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Coromandel area.

NEW KAIMARAMA 66KV SWITCHING STATION	
Estimated cost (concept):	$5.9m
Expected project timing:	2019-2023

This investment addresses a number of constraints and needs, especially the tee connection of the Coromandel line and the capacity constraint between Kaimarama and Whitianga. Options considered are detailed in Appendix 8.

The preferred solution is to construct a new 66kV gas insulated switchgear (GIS) indoor switching station at Kaimarama consisting of six GIS feeder modules, a GIS bus coupler and a line in-line out GIS stub module, which will be used to connect to a future 110/66kV transformer when conversion to 110kV is required. The switch room building is designed to blend in with its surrounding environment.

KOPU–TAIRUA 66KV LINE UPGRADE	
Estimated cost (concept):	$8.5m
Expected project timing:	2016-22

This project addresses the limitations imposed by the capacity of the relatively small conductor on the 66kV line between Kopu GXP and Tairua substation. This is constrained at peak loads when the Kopu to Whitianga circuit is out of service. The conductor size also adversely impacts voltage quality under contingencies.

Options considered are detailed in Appendix 8.

The proposed solution is to reconductor the existing line. This will be designed for a higher capacity and operating temperature and will remove the existing thermal capacity constraints. The voltage performance will be addressed by separate projects to install reactive support at Whitianga and Tairua.

NEW KOPU–KAUAERANGA 66KV LINE	
Estimated cost (consenting):	$6.9m
Expected project timing:	2018-2024

The existing 66kV line between Kopu and Kauaeranga is constrained in several sections, especially between Kopu and Parawai, which also serves as a backup supply to Thames. The conductor between Parawai and Kauaeranga is also overloaded when used to supply the Tairua, Coromandel and Whitianga substations on the 66kV ring during an outage of the Kopu-Tairua circuit. Furthermore, the conductor between Kopu and Parawai can overload when supplying the Thames, Coromandel and Whitianga substations during an outage of the Kopu-Thames circuit. Options considered are detailed in Appendix 8.

The proposed solution is to install a new 110kV capable line from Kopu GXP to Kauaeranga. This allows the existing line to Parawai to be dedicated to Thames substation and provides additional capacity for the 66kV ring serving Whitianga and Coromandel, plus Tairua also, under contingencies. The new line also provides a 110kV capable circuit from Kopu GXP through to Kaimarama (close to Whitianga). This is part of our strategy to accommodate long-term growth.

Given that construction of the line is expected to be delayed as a result of a Treaty land settlement claim, the interim solution is to reconductor the section from Parawai to Kauaeranga, and thermally upgrade the section from Kopu to Parawai. These projects will allow the proposed line construction to be deferred until the settlement claim is resolved.

WHENUAKITE SUBSTATION

Estimated cost (concept):	$7.1m
Expected project timing:	2018-2023

The two 11kV feeders supplying the coastal area south and east of Whitianga, including the holiday townships of Coroglen, Cooks Beach, Hot Water Beach and Hahei, are severely constrained. The feeders experience high loads, and voltage constraints, during holiday periods and have very limited backfeed. These feeders also contribute to potential overloading of Whitianga substation. Growth rates in this area have been relatively high and are expected to continue. Because of the long feeder lengths, supply restoration times are typically long as field crews attempt to fault-find and fix network faults.

Options considered are detailed in Appendix 8.

The proposed solution is to construct a new Whenuakite zone substation. It is proposed to supply this substation from the existing 66kV Tairua to Whitianga line using a new dual circuit 66kV line with 'in and out' configuration. The new zone substation will supply a number of new 11kV feeders. This will reduce the length of the existing feeders, decrease customer numbers per feeder, and provide adequate capacity for normal configuration, backfeeds and future growth. It is also expected to offload approximately 4MVA from Whitianga substation.

MATARANGI SUBSTATION

Estimated cost (concept):	$8.0m
Expected project timing:	2019-2023

The 11kV feeders supplying the holiday townships of Matarangi and Kuaotunu, north of Whitianga, are constrained and have very limited backfeed capacity. These feeders also contribute to potential overloading of Whitianga substation. Growth rates in this area have been relatively high and are expected to continue. Because of the long feeder lengths, supply restoration times are typically long as field crews attempt to fault-find and fix network faults. Options considered are detailed in Appendix 8.

The proposed solution is to construct a new 66/11kV Matarangi zone substation. A new 66kV capable circuit may be built before the substation and used initially as an additional 11kV feeder. Later, the line would be energised at 66kV to supply a new zone substation with 11kV feeders supplying the immediate area. This project also alleviates future constraints on Whitianga substation, although the Whenuakite substation is expected to provide this same benefit as well.

BACKUP SUPPLY TO KEREPEHI

Estimated cost (concept):	$5.9m
Expected project timing:	2019-2022

Kerepehi has a single 66kV supply circuit. This means that supply is limited to 11kV backfeeds when the 66kV is out of service. The existing 11kV backfeed is not sufficient to meet our security standards.

Options considered are detailed in Appendix 8. We propose to refurbish and reinstate an old 50kV line that runs between Kerepehi and Paeroa and provide a 33kV backfeed via Paeroa. However, this option rests on the successful negotiation of consents and property rights in order to gain permission to upgrade the line. If the initial assumptions around these prove invalid, we may need to re-visit the project scope and options.

TAIRUA-COROGLEN CONDUCTOR UPGRADE

Estimated cost (concept):	$7.7m
Expected project timing:	2023-2027

This project addresses the limitations imposed by the capacity of the relatively small conductor on the 66kV line between Tairua and Coroglen. This is constrained at peak load times when the Kopu to Whitianga circuit is out of service. The conductor size also adversely impacts voltage quality under contingencies.

Options considered are detailed in Appendix 8.

The proposed solution is to reconductor the existing line. This will be designed for a higher capacity and operating temperature, which will remove the existing thermal capacity constraints. The voltage performance will be addressed by separate projects to install reactive support at Whitianga and Whenuakite.

COROMANDEL AREA VOLTAGE SUPPORT

Estimated cost (concept):	$8.4m
Expected project timing:	2023-2028

During a subtransmission outage on either Kopu-Whitianga 66kV or Kopu-Tairua 66kV circuits, voltage levels are constrained at these substations: Coromandel, Whitianga, Tairua, Whenuakite and Matarangi.

The proposed solution is to install voltage support in the form of a Static Synchronous Compensator (STATCOM) at Whitianga and a switched capacitor bank at Whenuakite. Details of the proposed solution are discussed in Appendix 8.

MANGATARATA SUBSTATION	
Estimated cost (concept):	$7.0m
Expected project timing:	2023-2028

Kerepehi transformer firm capacity is forecast to be exceeded later in the planning period. It will not meet Powerco's security of supply requirements. Some of the existing 11kV feeders from Kerepehi substation are long and they are voltage constrained during peak load times when backfeeding during an outage.

Options considered are detailed in Appendix 8.

The proposed solution is to construct a new substation at Mangatarata and offload some of the Kerepehi load to the new substation.

11.4.1.5 MINOR GROWTH AND SECURITY PROJECTS

Below we set out summaries of the minor growth and security projects planned for the Coromandel area.

COROMANDEL ALTERNATIVE SUPPLY	
Estimated cost (concept):	$2.5m
Expected project timing:	2025-2027

The popular holiday area of Coromandel is supplied by a single long 66kV line. Constructing a second circuit is not economic.

During faults on this line, the 11kV backfeed is very limited and most of Coromandel remains without power until repairs are completed. Options considered are detailed in Appendix 8.

The proposed solution is to introduce a standby distributed generation system, sized to support the critical load in the area during emergencies. The standby generation will be capable of remote operation. The generation will be supplemented by 11kV backfeed from Thames zone substation to offer enhanced security of supply to the Coromandel substation.

MATATOKI SECOND TRANSFORMER	
Estimated cost (concept):	$1.7m
Expected project timing:	2024-2027

Matatoki substation is a single bank transformer and the existing 11kV backfeed capacity is limited to support an outage of the existing transformer. This does not meet our security of supply standards.

Options considered are detailed in Appendix 8.

The preferred solution is to install a matching second 66/11kV supply transformer. This option will cater for future growth and development without introducing unusual operating configurations.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required backfeeding capacity are not favoured because of the complexity of upgrading the mix of conductors on some of the lines. In addition, the switching required on the 11kV network to restore supply after a substation outage can take a considerable amount of time.

WHENUAKITE SECOND TRANSFORMER	
Estimated cost (concept):	$1.4m
Expected project timing:	2027-2028

The proposed Whenuakite substation to be built will initially be a single bank transformer substation. The load can be backfed from adjacent zone substations at Whitianga and Tairua in the short term.

Later in the planning period, backfeeding is expected to result in voltage and thermal constraints. An outage of the single transformer will not meet Powerco's security of supply standards.

Options considered are detailed in Appendix 8.

The preferred solution is to install a matching second 66/11kV supply transformer. This option will cater for future growth and development without introducing unusual operating configurations.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required backfeeding capacity are not favoured because of the significant costs involved due to the distance. In addition, the switching required on the 11kV network can take a considerable amount of time to restore supply after a substation outage.

11.4.1.6 OTHER DEVELOPMENTS

Protection systems have been upgraded on the subtransmission circuits to allow the 66kV ring to be operated permanently closed. Future upgrades will involve high-speed communication systems to enable fast inter-trip schemes to operate on the subtransmission network.

The future long-term strategy for development in the Coromandel area is to provide for 110kV supply from Kopu GXP to Whitianga (or alternatively Kaimarama). Operation at 110kV is unlikely to occur until beyond the next decade. However, projects to date and those identified above provide 110kV capable circuits in anticipation of this significant potential voltage change.

Some remote parts of the network north of Coromandel are supplied via single wire earth return (SWER) reticulation. Low voltages are seen on the SWER network during high loads and lead to increased unbalance on the 11kV network. Further load growth will worsen these issues. We propose to progressively upgrade the SWER network to a three-wire three-phase supply but will consult with customers on their price-quality preferences.

High ICP counts on existing 11kV feeders supplying the northern area of Thames are excessively loaded and backfeed capability is constrained. The existing feeder cables also show signs of deterioration. We propose to install additional feeders to reduce loading issues and upgrade existing feeder cables when undertaking condition-based replacement.

Transpower's dual circuit 110kV lines from Hamilton to Kopu, known as the Valley Spur, are forecast to exceed N-1 capacity in about 2022. This has some impact on Kopu security, but the scope of any future upgrades is likely to be outside the Coromandel area.

Transpower indicates in the Transmission Planning Report 2018 that the Kopu GXP transformers are likely to exceed firm capacity in about 2033 and possible refurbishment of the transformers is the likely economic solution. Protection upgrades are proposed to lift the firm capacity limits.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Upgrade of SWER systems	The capacity of the SWER circuits north of Coromandel town is at its limits. As load increases, the situation will worsen. Conversion of the SWER lines to three-phase is the most likely solution but non network alternatives are being considered.
Conversion to 110kV operation	The 66kV Kopu – Whitianga circuit will be 110kV-capable once the Kopu – Kauaeranga line is completed. When 66kV line capacity is exceeded, a possible solution is to convert the 66kV circuit to 110kV operation, which will resolve the issue beyond the planning horizon.

11.4.2 WAIKINO

The Waikino area includes the popular holiday town of Whangamata, which is supplied by a single 33kV circuit from Waihi. We are installing an energy storage system comprising batteries and diesel generator to provide backup supply to the critical loads in the central business district of Whangamata. Major and minor project spend related to security during the next 10 years is $25.1m.

11.4.2.1 AREA OVERVIEW

The Waikino area plan covers the southern end of the Coromandel Peninsula and a small section of the eastern Hauraki Plains.

As with the Coromandel area, much of the Waikino area is rugged, hilly and covered with native bush. It is not heavily populated and road access is quite limited in some parts.

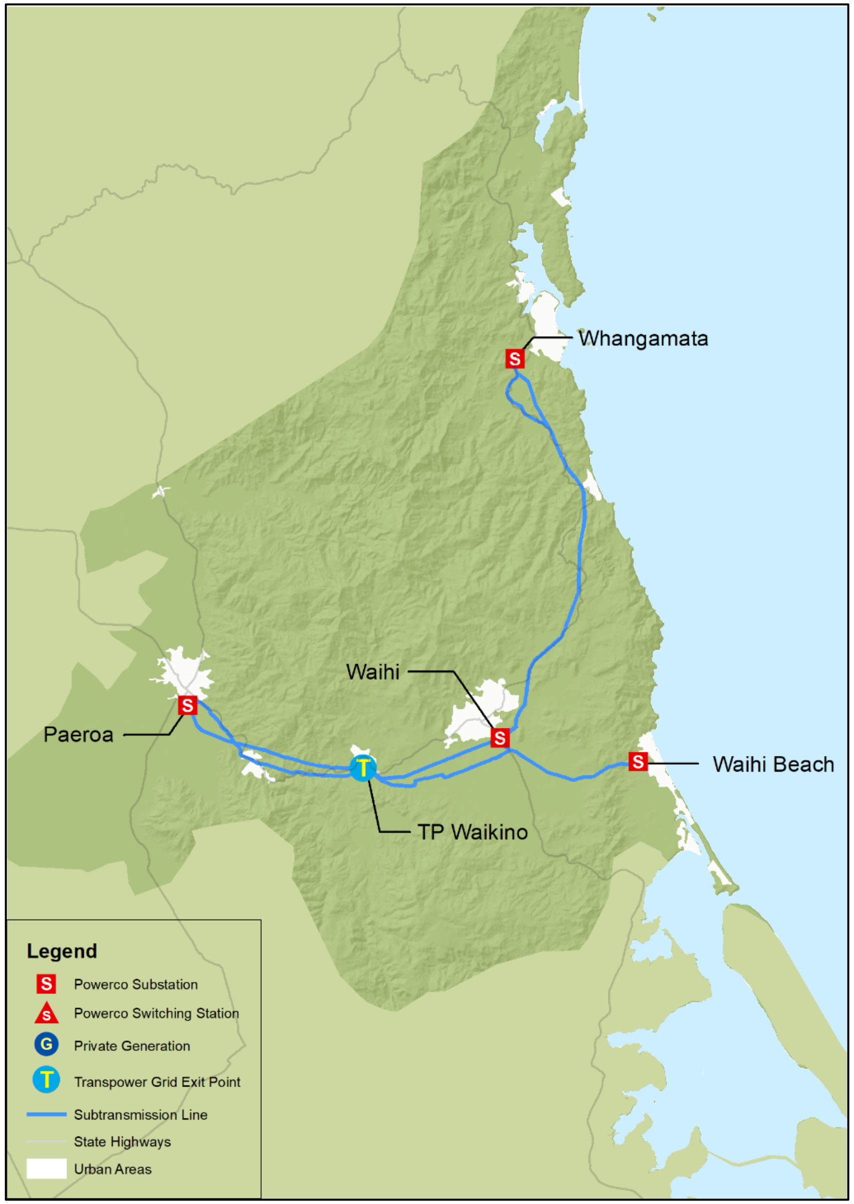
The region has a temperate climate with mild winters and warm summers. Rainfall can be high, and storms often come in from the Pacific Ocean, which can affect network operation.

The main towns in the Waikino area are Paeroa, Waihi and Whangamata. The region's economy is based on tourism, particularly seasonal holidaymakers, with some primary agriculture. The Waihi mine also has a significant bearing on the electrical demand in the area.

This area takes grid supply from the Waikino GXP at 33kV. Zone substations are located at Paeroa, Waihi, Waihi Beach and Whangamata. The subtransmission system has a ring configuration between Waikino GXP and Waihi. A single circuit supplies Whangamata from Waihi. A single circuit also supplies Waihi Beach, with a tee connection to the Waikino GXP-Waihi ring. There are two dedicated circuits supplying Paeroa from Waikino.

The subtransmission and distribution networks are mainly overhead. Occasional extreme weather and rugged, bush-covered terrain make line access and fault repair challenging. Of concern are those substations supplied by single circuits.

Figure 11.5: Waikino area overview



11.4.2.2 DEMAND FORECASTS

Demand forecasts for the Waikino zone substations are shown in Table 11.4, with further detail provided in Appendix 7.

Table 11.4: Waikino zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Paeroa	AA+	6.0	8.4	8.6	8.9	9.2
Waihi	AAA	16.0	18.0	18.3	19.0	19.8
Waihi Beach	AA	3.3	5.9	6.0	6.4	6.8
Whangamata	AA+	0.0	9.8	9.8	10.0	10.2

Growth in the area has been modest in recent years, except on those substations that supply popular holiday towns. Demand growth in holiday locations is linked to general economic prosperity. Strong economic conditions could be expected to drive higher growth rates than those shown.

Shaded values in the table indicate that demand exceeds the capacity we can provide with appropriate security. Of note is that all the Waikino substations already exceed the secure class capacity. Development plans are therefore focused on improving security and reliability for the existing load base rather than specifically catering for load growth.

11.4.2.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikino area are shown in Table 11.5.

Table 11.5: Waikino constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Waikino GXP	TP Waikino supply transformers are close to end-of-life. Low voltages during 110kV Hamilton-Waihou circuit contingency.	Note 1
Whangamata substation	Loss of supply to Whangamata for an outage on the single Waihi-Whangamata 33kV circuit. Main 11kV backup line shares same poles as 33kV.	Whangamata backup power supply comprising battery and diesel generator (in progress)
Waihi Beach substation	Single circuit to Waihi Beach. Insufficient 11kV backfeed when this 33kV circuit is out of service.	Waihi Beach alternative supply

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Waihi Beach substation	Waikino to Waihi Beach tee connection: Outages on the Waikino to Waihi line cause an outage at Waihi Beach. Overloading can occur under some scenarios.	Waihi Beach 33kV tee supply
Waihi substation	Demand exceeds secure capacity of the two transformers.	Note 2
Whangamata substation	Demand exceeds secure capacity of one transformer. T2 transformer firm capacity exceeded.	Note 3
Waihi Beach substation	Single transformer, which does not provide sufficient security.	Waihi Beach supply transformers
Paeroa substation	Demand exceeds secure capacity of the two transformers.	Note 4
Paeroa substation	Expected end-of-life of transformers (x2).	Note 4
Paeroa substation	An outage on one of the subtransmission circuits from Waikino to Paeroa will also result in an outage to its associated supply transformer at Paeroa substation.	Paeroa 33kV bus security
Waihi and Waihi Beach substations	Low voltages during an outage on either Waikino-Waihi 33kV circuits.	Waihi voltage support

Notes:

1. Transpower Transmission Planning Report 2018 – Transpower plans to replace the T2 transformer and carry out an outdoor-to-indoor conversion of the 33kV assets in the near term followed by replacement of the T1 transformer in the period 2026-2028. The new transformer units will have on-load tap changers, which will also address the steady state voltage issues.

2. Waihi substation supplies the Waihi mine. This customer does not require security to all load. Demand side arrangements exist to shed load at the mine if the Waihi substation transformers or supply system upstream has insufficient capacity.

3. T2 transformer capacity upgrade is a solution but a possible alternative solution is to refurbish an existing transformer from Tirau substation. This will be considered based on its asset life.

4. Expenditure for this work is allowed for in the renewal forecasts. Refurbished higher capacity transformers previously used at Maraetai Rd substation will be installed at Paeroa.

11.4.2.4 MAJOR GROWTH AND SECURITY PROJECTS

Below we set out summaries of the major growth and security projects planned for the Waikino area.

WHANGAMATA SINGLE 33KV CIRCUIT	
Estimated cost (consenting):	$20.4m
Expected project timing:	2016-2025

The popular holiday town of Whangamata is supplied from the Waihi substation by a single long 33kV line.

This line is constrained at peak loads. During faults on this line, the 11kV backfeed is very limited and most of Whangamata remains without power until repairs are completed. The 11kV backfeed and 33kV circuit share poles for most of the route, exposing a high risk of common types of failure causing both circuits to be unavailable. Options to increase 11kV backfeed capacity are therefore very limited. Options considered are detailed in Appendix 8.

Consequently, we are installing an energy storage system with backup diesel generation, sized to support the most critical load in the town during emergencies. We will monitor performance on the facility and evaluate the need to consider any other additional or alternative in due course if required. A second line may be one alternative. Expenditure for the alternative has currently been allowed for in the forecast but may be removed if not required in the future.

The proposed energy storage solution provides an ideal platform for Powerco to test a wide variety of concepts in a real-life situation to determine their impact on the wider network.

11.4.2.5 MINOR GROWTH AND SECURITY PROJECTS

Below we set out summaries of the minor growth and security projects planned for the Waikino area.

WAIHI BEACH SUBSTATION SUPPLY TRANSFORMERS	
Estimated cost (concept):	$1.2m
Expected project timing:	2021-2023

The Waihi Beach substation contains a single transformer. The demand has exceeded the transformer's capacity. There is also limited 11kV backfeed, so it does not meet security requirements.

The solution is to upgrade to a two-transformer bank substation utilising the existing Lake Rd transformer, ensuring that the capacity will provide for future demand.

The demand at the substation will exceed the transformer firm capacity even with the installation of the second transformer. However, with existing 11kV backfeed, the security of supply requirements for the substation can still be met.

Alternatives such as increased 11kV backfeed would be costly as Waihi Beach is quite remote from other substations and the 11kV network requires manual switching, during which time the remaining transformer could trip on overload.

WAIHI BEACH 33KV TEE SUPPLY	
Estimated cost (concept):	$2.4m
Expected project timing:	2020-2022

The Waihi Beach substation is supplied via a spur teed off one of the Waikino-Waihi 33kV circuits.

Supply for Waihi Beach is lost if a fault occurs anywhere on the overhead Waikino-Waihi Beach-Waihi 33kV circuit. Conversely, a fault on the 33kV spur line to Waihi Beach will result in Waihi substation running on N (single redundancy) security.

The proposed solution is to build a new 33kV indoor switchroom at Waihi substation and route a new 33kV cable from the new switchroom to the existing tee-off to create a dedicated Waihi-Waihi Beach 33kV circuit. This also allows supply to be maintained to Waihi Beach even if the Waikino-Waihi circuit is out of service.

WAIHI BEACH 33KV ALTERNATIVE SUPPLY	
Estimated cost (concept):	$1.7m
Expected project timing:	2024-2026

The Waihi Beach substation is supplied via a single subtransmission circuit from Waihi substation. There is also an 11kV feeder, underbuilt on the subtransmission circuit, that provides significant backfeed to Waihi Beach.

As the 11kV backfeed and 33kV circuit share poles for most of the route, this results in a high risk of common types of failure causing both circuits to be unavailable.

This means the security class requirements for Waihi Beach substation will not be achieved.

The proposed solution is to install a stand-by diesel generation unit to support the load in the event of a subtransmission outage.

PAEROA 33KV BUS SECURITY	
Estimated cost (consenting):	$3.1m
Expected project timing:	2023-2026

Paeroa is supplied from Waikino GXP via two circuits configured as transformer feeders. An outage on one of the subtransmission circuits will also result in an outage to its associated supply transformer at Paeroa substation.

The project for backup supply to Kerepehi, which is a new Paeroa-Kerepehi 33kV circuit, will initially be connected temporarily to one of the existing Waikino GXP-Paeroa circuits via a pole-mounted circuit breaker at Paeroa as there is no 33kV switchboard at Paeroa.

The proposed solution is to install a 33kV bus at Paeroa substation enabled with fast bus protection schemes and to accommodate the future Paeroa-Kerepehi circuit. This will also improve the security of supply for Paeroa as it reduces the risk of a transformer outage because of a subtransmission circuit outage.

WAIHI VOLTAGE SUPPORT	
Estimated cost (concept):	$1.1m
Expected project timing:	2024-2025

Waihi, Waihi Beach and Whangamata substations are all supplied by two subtransmission circuits from Waikino GXP to Waihi. An outage on either Waikino-Waihi circuits will result in low voltages appearing across the subtransmission network.

The proposed solution is to install a switched multi-stage capacitor bank at Waihi to provide voltage support in the region.

11.4.2.6 OTHER DEVELOPMENTS

Transpower's dual circuit 110kV lines from Hamilton to Kopu, known as the Valley Spur, are forecast to exceed N-1 capacity in about 2022. This has some impact on Waikino security, but the scope of any future upgrades is likely to be outside the Waikino area.

A resource consent application is under way for a significant new wind generation site near Te Aroha. The intention is for this to connect to the Hamilton-Kopu 110kV circuits.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Paeroa transformers capacity upgrade	The proposed Paeroa 33kV bus security project will resolve the risk of a subtransmission circuit fault taking out a Paeroa supply transformer. The risk of a breach of Paeroa's firm capacity is then reduced to the risk of a supply transformer outage, which is a lower probability event. Overloads can be managed operationally through 11kV backfeeds. Also, the transformers can be fitted with fans in the interim to lift capacity until the transformers reach end-of-life. However, if demand in future grows substantially more than forecast, there may be a need to upgrade to larger capacity units as 11kV backfeed capability will deteriorate. We will continue to monitor this situation.
Whangamata transformer capacity upgrade	Firm capacity at Whangamata substation is exceeded during an outage of T1 transformer because T2 is a smaller size. The plan is to utilise the existing Tirau transformer here as it is a matching pair with the Whangamata T1 unit. The Tirau transformer will be replaced with two larger capacity units.

11.4.3 TAURANGA

The Tauranga region has historically had high-demand growth driven by population increases, and we expect this to continue.

Security in the area is generally good with twin circuits supplying most of our substations.

The major projects are driven by increasing demand, which is forecast to exceed the existing capacity on our network.

Major and minor project spend related to growth and security during the next 10 years is $43.5m.

11.4.3.1 AREA OVERVIEW

The Tauranga area covers Tauranga city and the northern parts of the western Bay of Plenty district. Mt Maunganui is considered in a separate area plan.

The Tauranga area comprises two different terrains or environments. Tauranga city includes industrial, commercial and residential land use, while the northern rural landscape tends to consist of rolling country, predominantly used for rural and lifestyle dwellings.

The region has a temperate, coastal climate with mild winters and warm humid summers. Peak demand is in winter, but increased summer activities, including greater use of air conditioning, could see this change to a summer peak in future.

The popularity of this region as a place to live, reflecting the good climate, terrain and coastal setting, is the single biggest reason for development, and is reflected in the high demand growth rates.

Tauranga is a major city and is the economic hub of the area. The recent upgrade of major transport links and continued land development signals confidence in population growth and commerce and industry. Primary production, including horticulture, is also a significant economic activity, with many kiwifruit orchards in the Aongatete and Katikati areas.

The area is supplied from the Tauranga and Kaitimako GXPs. Tauranga GXP is a grid offtake at both 11kV and 33kV.

The Tauranga GXP supplies 10 zone substations: Bethlehem, Tauranga 11kV (TP), Waihi Rd, Hamilton St, Otumoetai, Matua, Omokoroa, Aongatete, Katikati and Kauri Pt. The Kaitimako GXP supplies Welcome Bay substation and the recently commissioned Pyes Pa substation.

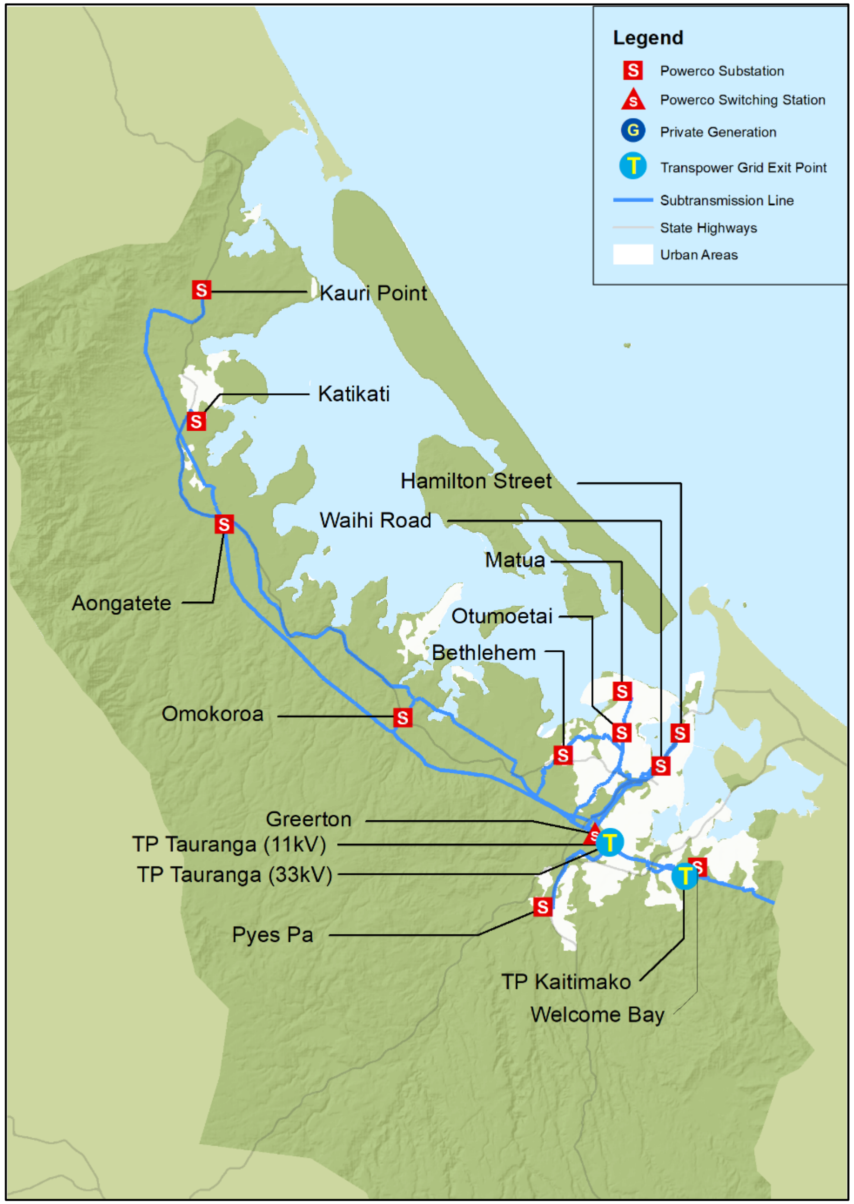
The region uses a 33kV subtransmission voltage. Twin dedicated circuits feed each of the critical inner-city substations of Hamilton St and Waihi Rd.

Twin 33kV high capacity circuits link Tauranga GXP with a major subtransmission interconnection point at Greerton switching station. From this, two circuits supply the northern substations (Omokoroa and Aongatete) via dual circuits, and Katikati and Kauri Point on single circuits from Aongatete. A 33kV ring from Greerton also supplies Bethlehem via Otumoetai. Otumoetai is now supplied from twin radial subtransmission circuits from Greerton, with a single 33kV radial circuit from Otumoetai supplying Matua. The Bethlehem/Otumoetai ring and the twin Omokoroa circuits share poles for several spans out of Greerton, which raises common types of failure risks and protection issues.

Trustpower's Kaimai generation scheme feeds into the Greerton switching station.

The subtransmission and distribution networks in the Tauranga area are mainly overhead, although there are also large areas of underground cable, particularly in the inner city or newer subdivisions. Environmental and urban constraints require most of our new circuits to be underground.

Figure 11.6: Tauranga area overview



11.4.3.2 DEMAND FORECASTS

Demand forecasts for the Tauranga zone substations are shown in Table 11.6, with further detail provided in Appendix 7.

Table 11.6: Tauranga zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Aongatete	AA+	7.2	8.7	9.7	10.7	11.7
Bethlehem	AA+	8.0	10.0	12.0	14.0	16.0
Hamilton St	AAA	22.4	15.9	16.9	17.9	18.9
Katikati	AA	4.6	8.9	9.5	10.2	10.9
Kauri Pt	A1	1.6	3.3	3.4	3.5	3.6
Matua	AA	7.4	9.1	9.2	9.4	9.5
Omokoroa	AA+	13.2	10.4	11.1	11.9	12.6
Otumoetai	AA	13.6	15.4	17.0	18.6	20.1
Pyes Pa	AA+	11.7	8.7	10.1	11.5	12.8
Tauranga 11	AAA	30.0	23.2	26.5	29.7	33.0
Waihi Rd	AAA	24.1	22.1	22.5	22.9	23.2
Welcome Bay	AA	21.4	23.8	26.1	28.3	30.6

The Tauranga area continues to have high growth rates. Substantial investment has been undertaken recently but considerably more is needed, particularly if, as expected, growth rates remain higher than those of a decade ago.

High growth substations – Tauranga 11kV, Bethlehem, Omokoroa and Welcome Bay – are those supplying the major subdivisions. A new substation commissioned at Pyes Pa has offloaded Tauranga GXP supplying the large industrial and residential developments in this area. Bethlehem substation, which offloads Tauranga 11kV and Otumoetai, and where high growth is likely to be concentrated in future.

Omokoroa has substantial areas of land zoned for urban development on the peninsula, and increased growth in this area is expected once developments closer to the city are filled.

Substations supplying the inner city and established urban areas continue to be subject to steady growth from in-fill and intensification. This growth is expected to be higher than the past decade, during which economic conditions were subdued. Also, the tight Auckland property market has the potential to result in considerable growth in Tauranga and Mt Maunganui. Urban intensification signalled by the Tauranga City Council in the Cameron Rd area will increase demand on the Waihi Rd and Hamilton St substations. The Port of Tauranga has signalled considerable growth at its Sulphur Point container terminal potentially justifying the need for a substation at Sulphur Point.

Aongatete and Katikati demand is dominated more by significant increases from coolstore loads, which are being driven by the horticulture market. The kiwifruit market has bounced back since the PSA disease crisis with new high yielding species of kiwifruit now coming on-line.

11.4.3.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tauranga area are shown in Table 11.7.

Table 11.7: Tauranga constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Tauranga GXP	An outage of one of the two Kaitimako-Tauranga 110kV circuits can overload the other circuit.	Note 1
Tauranga GXP and Waihi Rd	Future urban intensification as outlined in Tauranga City Council district plans will drive ICP numbers up. SAIDI risk increases at the 11kV level.	Gate Pa/Hospital substation
Kaitimako GXP	Single transformer at Kaitimako GXP provides no firm capacity.	Note 2
Waihi Rd and Hamilton St	An outage of one of the two Tauranga-Waihi Rd 33kV circuits overloads the parallel circuit. An outage of one of the two Tauranga-Hamilton St 33kV circuits overloads the parallel circuit. Existing 11kV feeders supplying the Port of Tauranga are highly loaded and do not have sufficient capacity to support forecast growth at the port.	Waihi Rd Bus Security project Port of Tauranga capacity reinforcement
Omokoroa, Aongatete, Kauri Pt and Katikati	An outage on one of the two Greerton-Omokoroa 33kV circuits will, in future, cause overloading on the remaining circuit supplying these four substations.	Northern Tauranga reinforcement
Aongatete, Katikati and Kauri Pt substation	An outage on one of the two Greerton-Omokoroa 33kV circuits causes low voltages at Aongatete, Katikati and Kauri Pt.	Northern Tauranga voltage support
Kauri Pt substation	Single Aongatete-Kauri Pt 33kV circuit with insufficient 11kV backfeed to secure all load at Kauri Pt.	Note 3
Matua substation	Single Otumoetai-Matua 33kV circuit with 11kV backfeed to secure all load at Matua.	Note 4
Matua substation	Demand exceeds secure capacity of the T6 transformer	Note 5
Welcome Bay substation	An outage on one of the Kaitimako-Welcome Bay 33kV circuits can cause overloading on the remaining circuit.	Welcome Bay reinforcement
Katikati substation	Single transformer provides no firm capacity.	Katikati substation second transformer
Kauri Pt substation	Single transformer provides no firm capacity.	Note 6
Welcome Bay substation	Demand exceeds secure capacity of the two transformers.	Welcome Bay second substation
Omokoroa substation	Forecast demand will exceed secure capacity of the transformers about 2025.	Apata/Pahoia capacity reinforcement
Bethlehem substation	Single transformer provides no firm capacity.	Note 6

Notes:

1. We are in preliminary discussions with Transpower about possible long-term solutions. Risk in the near term is mitigated by a Special Protection Scheme (SPS), plus the availability of generation from Kaimai Hydro scheme. Transpower is also suggesting the possible implementation of Variable Line Ratings (VLR) as a mitigation measure to lift capacity.

2. The old Welcome Bay circuits from Tauranga GXP provide sufficient backfeed so that the Kaitimako GXP load is secure even with one supply transformer. When load exceeds this backfeed capacity, we will need to investigate a second 110/33kV transformer. With the growth of the Welcome Bay and Pyes Pa loads, the level of security will need to be maintained and will help justify the need for a second transformer at Kaitimako.

3. The installation of a second circuit for Kauri Pt is not economic. Future planning will consider 11kV backfeed upgrades where cost effective.

4. A 33kV cable has been installed between Otumoetai and Matua and is operating at 11kV to provide sufficient backup. When the smaller transformer is upgraded, the cable will be reconfigured to form the second 33kV circuit to Matua. It is proposed that this work will be co-ordinated with the Matua 11kV switchboard replacement in future.

5. 11kV support provides sufficient security at present, but further growth will warrant an upgrade of the 5MVA transformer. This upgrade will be coordinated with the Matua 11kV switchboard replacement.

6. Because of low probability of failure, there is only small risk with single transformer substations or dual transformer substations where firm capacity is marginally exceeded. Options will be considered to increase capacity or install new units as appropriate, in conjunction with transformer relocations and refurbishment, and as is economically cost effective. A second transformer at Bethlehem is planned once load growth exceeds the 11kV backfeed capability.

11.4.3.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major projects planned for the Tauranga area.

NORTHERN TAURANGA REINFORCEMENT (OMOKOROA ADDITIONAL 33KV CIRCUITS)

Estimated cost (concept):	$11.4m
Expected project timing:	2021-2024

This project addresses security of supply to four zone substations – Omokoroa, Aongatete, Katikati and Kauri Pt. These four substations are fed from two 33kV circuits from Greerton to Omokoroa. The lines have been thermally upgraded, but this only defers investment in more capacity for five to six years. An outage of one circuit already causes voltage problems near the end substations, Katikati and Kauri Pt.

Options considered are detailed in Appendix 8. These also include 110kV solutions, which were part of a wider analysis that considered the grid supply to the whole Tauranga region.

The proposed long-term solution is the installation of a third 33kV Greerton-Omokoroa circuit. The circuit will be partly overhead line but mostly underground cable. The solution makes use of an existing overhead line crossing the Wairoa River. The third circuit will require a new switchboard at Omokoroa and a reconfiguration of the 33kV circuits into Omokoroa. Voltage constraints can be addressed through reactive support.

APATA / PAHOIA CAPACITY REINFORCEMENT

Estimated cost (concept):	$5.3m
Expected project timing:	2023-2024

Existing feeders supplying Omokoroa peninsula from the Omokoroa zone substation are exceeding capacity limits and have insufficient backfeed capability to support future growth forecast in this area.

Without significant reinforcement, outages in this area will result in a high SAIDI impact.

Future load growth in the horticulture sector in this area will also pose increased pressure on the existing Omokoroa zone substation.

Options considered are in Appendix 8.

The proposed long-term solution is the construction of a new zone substation in the vicinity of Apata/Pahoia areas which will help offload Omokoroa zone substation and allow for future growth and improved backfeed capability.

WELCOME BAY REINFORCEMENT

Estimated cost (concept):	$5.5m
Expected project timing:	2025-2027

An outage on one of the existing 33kV Kaitimako-Welcome Bay circuits at high load times will overload the remaining 33kV circuit. The existing 11kV backup ensures that security levels can be maintained until about 2027, based on growth forecasts in the area. The existing 11kV feeders are at capacity.

Options considered are detailed in Appendix 8.

The proposed long-term solution is to install a 33kV switchboard at Welcome Bay along with an additional 33kV circuit from Kaitimako GXP and to construct a new zone substation in the area to the east of the current substation. This will cater for ongoing residential development and to reduce overall customer numbers per feeder (refer to Welcome Bay second substation project).

WELCOME BAY SECOND SUBSTATION

Estimated cost (concept):	$9.1m
Expected project timing:	2025-2028

The existing 11kV feeders supplying the Welcome Bay area are highly loaded with high ICPs on every feeder out of Welcome Bay zone substation.

Loop automation has been implemented on many feeders to help minimise the SAIDI risk and reduce outage duration to our customers.

Residential subdivision growth continues to be strong in the area, which will add more ICPs to the existing feeders. The load growth has placed more pressure onto our existing infrastructure to backfeed the area during contingent events on our distribution network.

The growth development in this area has minimal direction outlined in Council district plans as the area sits in between the jurisdiction of two local Councils with pockets of growth spread out across the area. This makes it hard to forecast and target future requirements accurately.

The existing high load already exceeds transformer firm capacity at Welcome Bay substation.

Options considered are detailed in Appendix 8.

The proposed long-term solution is to commission a new second substation in the Welcome Bay region with its 33kV supply coming off the existing Welcome Bay-Atuaroa circuit. The Welcome Bay reinforcement project is a pre-requisite for this project.

GATE PA / HOSPITAL SUBSTATION	
Estimated cost (concept):	$8.9m
Expected project timing:	2024-2028

The urban intensification proposed in the Te Papa peninsula as indicated in Tauranga City Council district plans will drive ICP numbers up on the existing 11kV feeders. This leads to an increased risk exposure to high SAIDI during contingent events on the network.

The anticipated load growth will place pressure on the existing infrastructure and erode the capability to backfeed the area during outage situations.

Options considered are detailed in Appendix 8.

The proposed long-term solution is to construct a new zone substation in the Tauranga South or Gate Pa area near Tauranga Hospital. This will reduce the ICP numbers for each feeder and, therefore, reduce the SAIDI risk. The new zone substation will ensure that the future capacity and security needs of Tauranga Hospital can be met.

WAIHI RD BUS SECURITY PROJECT	
Estimated cost (concept):	$4.6m
Expected project timing:	2019-2022

The existing 33kV circuits supplying Waihi Rd and Hamilton St are anticipated to become capacity constrained later in the planning period based on forecast growth.

An outage of the Tauranga GXP-Waihi Rd circuits will cause the parallel circuit and its associated supply transformer at Waihi Rd to overload during high loads later in the planning period.

Similarly, an outage of the Tauranga GXP-Hamilton St circuits will cause the parallel circuit to overload during high load periods. Port of Tauranga load growth will place further pressure on the N-1 capacity of these circuits.

Options considered are detailed in Appendix 8.

The preferred long-term solution is to terminate the four existing circuits into Waihi Rd substation by installing a new indoor switchboard at the site to implement a 33kV solid bus.

This will improve the security levels at Waihi Rd substation and resolve the N-1 capacity issues of the existing 33kV circuits supplying Waihi Rd and Hamilton St substations.

If the proposed Sulphur Point substation is supplied off Hamilton St substation, it is likely to cause the subtransmission circuits from Waihi Rd to Hamilton St to exceed firm capacity. A possible solution is to supply the Sulphur Point substation direct from the proposed 33kV bus at Waihi Rd.

11.4.3.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor projects planned for the Tauranga area.

KATIKATI SUBSTATION SECOND SUBTRANSMISSION CIRCUIT	
Estimated cost (design):	$1.5m
Expected project timing:	2019-2020

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings.

The substation is supplied via a single 33kV overhead line from Aongatete substation.

The size and nature of the load connected to the Katikati substation that is at risk from non-supply in the event of a 33kV line outage is significant. Some load can be backfed from neighbouring substations, such as Aongatete and Kauri Point, but it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance is limited to low load times.

Options considered are detailed in Appendix 8. The preferred solution is to install a second 33kV circuit to the Katikati substation by laying a cable from the Katikati substation and connecting onto the Aongatete-Kauri Point overhead line, creating a hard tee to Kauri Point. This means that for an outage on one subtransmission circuit, supply can be maintained at the Katikati substation (N-1 security). With this solution, the Katikati substation will meet our required security level.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required backfeeding capacity are not favoured because of the higher overall cost and the complexity of upgrading the mix of conductors on some lines. In addition, the switching required on the 11kV network can take a considerable amount of time for a substation outage.

KATIKATI SUBSTATION SECOND TRANSFORMER

Estimated cost (design):	$1.2m
Expected project timing:	2018-2019

The Katikati substation supplies Katikati township as well as the surrounding horticultural and lifestyle dwellings. The substation is a single supply transformer bank substation.

The size and nature of the load connected to the Katikati substation that is at risk from non-supply in the event of a transformer outage is significant. Some load can be backfed from neighbouring substations, such as Aongatete and Kauri Point, but it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance has to be limited to low load times, which are increasingly difficult to realise.

Options considered are detailed in Appendix 8. The preferred solution is to install a matching second 33/11kV supply transformer. This option will provide full (no break) N-1 security to the Katikati substation (together with the Katikati second circuit, refer to section 11.4.3). This option will cater for future growth and development without introducing unusual operating configurations.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required backfeeding capacity are not favoured because of the complexity of upgrading the mix of conductors on some of the lines. In addition, the switching required on the 11kV network can take a considerable amount of time to restore supply after a substation outage.

11.4.3.6 OTHER DEVELOPMENTS

There are very significant constraints pending on the 110kV circuits from Kaitimako to Tauranga. The Poike tee also causes operational difficulties and reduced security. Because of the complexity and cost of solutions, detailed projects have not yet been formulated, but expenditure of about $30m or more is expected to be needed, starting in the early 2020s. Because of the long lead times and consenting issues, planning work needs to commence soon.

We will continue to monitor land development in this high growth area. Several additional zone substations are nominally identified in our longer-term planning. These include Hospital, Judea, Tauriko, Oropi and Omokoroa urban. Investment is not expected for these until after 2025, but this will depend on growth and subdivision development.

The larger planned developments detailed above cover most of the significant risks exposed by the subtransmission constraints. A number of transformer constraints exist at zone substations, with growth rates determining when these will occur. As appropriate, these transformers will be upgraded, which may involve using refurbished/existing units from other substations.

Specific projects are not identified here because of the fluidity of timing and the interdependence with other drivers. Some replacements can also be done for less than $1m, meaning we can fund these from our routine project allowance.

The Port of Tauranga wharves at Sulphur Point are supplied through 11kV feeders out of Hamilton St zone substation.

The port is the busiest and largest in New Zealand. Accelerated growth in the local economy has prompted the need for further expansion of the port. The anticipated load growth will place pressure on the existing infrastructure.

The proposed long-term solution is to construct a new zone substation at Sulphur Point with 33kV supply initially from Hamilton St zone substation. The new substation will offload demand from Hamilton St at the same time. It will also help to maintain power quality standards across the network.

Since the substation will be a dedicated customer asset, it will be funded from the Customer Connections expenditure.

Growth and security expenditure on 11kV feeder upgrades and new 11kV feeders will be needed throughout the planning period. A substantial part of the routine project allowance (for projects less than $1m) is expected to be needed in the Tauranga area.

New subdivisions must contribute towards the 11kV feeders directly serving those sections, but additional growth and security investment is needed to maintain security in the upstream network. In-fill growth also drives new or upgraded feeders in existing parts of the network.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Northern Tauranga voltage support	Post-contingent voltage constraints at Aongatete, Katikati and Kauri Point will eventuate with increasing load. Voltage support at Aongatete substation resolves the constraint.
Bethlehem substation transformer capacity	Load growth around Bethlehem will eventually overcome the ability to support the single bank substation through 11kV interties. A second transformer is planned to maintain security of supply levels This is expected to fall outside this planning period.
Oropi capacity reinforcement	Residential load growth in the Oropi area will be constrained by the 11kV capacity out of Welcome Bay substation. The preferred solution is to accommodate the growth by commissioning a new substation in the Oropi area. Timing is customer load-driven and we will continue to monitor the situation closely.
Tauranga GXP high fault level	Fault levels at Tauranga 11kV GXP are too high. Likely options to reduce these high fault levels include replacement of the 110/11kV transformers at Tauranga with high impedance transformers or installing Neutral Earthing Resistors (NERs). We will work with Transpower closely to define the solution.
Matua substation transformer capacity	Matua substation second transformer is a ‘hot standby’ spare, capable of only partial substation backup. 11kV support provides the remaining load. As load increases, the existing express feeder will be energised at 33kV, forming a second subtransmission circuit. A larger transformer will be required to maintain security of supply levels. This will be done at the same time as the renewal of the 11kV switchboard.
Pyes Pa substation additional feeder capacity	Additional feeders will be required to provide the rapidly growing 11kV load in the Pyes Pa area. Allowance for three extra 11kV feeders to this growing area will be covered under routine growth. Longer term, load growth may cause the existing Pyes Pa substation to run out of capacity, which will drive the need for a future new zone substation. Refer to Tauriko substation project.
Tauriko substation	Load uptake in the Pyes Pa/Tauriko industrial park is increasing rapidly because of the strong economy in the region. District Council plans also show future residential developments extending beyond Tauriko, eg the Belk Rd, Keenan Rd and Tauriko West developments. The additional load increase will place pressure on our recently commissioned Pyes Pa substation, triggering the need for a new substation sited in the Belk Rd South area. This future substation will support Pyes Pa substation in supplying the rapidly growing industrial and residential load in the area. We will continue to monitor developments in this area.

11.4.4 MT MAUNGANUI

The Mt Maunganui area has historically had a high growth rate, driven by population growth and residential expansion. We recently completed the Wairakei substation, which helps to reduce the load on the Papamoa substation and provides additional capacity to support the growth in the area. The project also offers improved security between the two GXPs at Mt Maunganui and Te Matai. Major and minor project spend related to growth and security in this region during the next 10 years is $23.8m.

11.4.4.1 AREA OVERVIEW

The Mt Maunganui area covers the urban parts of Mt Maunganui as well as the developing Papamoa and Wairakei coastal strip.

Our Mt Maunganui area also encompasses Te Puke and surrounding rural areas down to Pongakawa and the inland foothills. This is because the planned developments will link the Mt Maunganui and Te Puke electricity supplies and it is easier to consolidate the planning in one area.

The Mt Maunganui area shares many of the features of the neighbouring Tauranga area, including terrain, climate and land use. The region contains a long coastal strip and some rugged terrain inland. The coastal area contains severely deteriorated network equipment, which has had an impact on reliability and performance. The inland area is more rugged and presents the usual difficulties in terms of access and maintenance.

The Mt Maunganui CBD is the economic hub, with expansion along the coast to accommodate population growth driven by the attractive lifestyle and climate. In the rural areas, horticulture dominates. Around Te Puke there are many kiwifruit orchards, which use coolstores and pack-houses. The Port of Tauranga is also a major economic driver.

The area is supplied from the Mt Maunganui and Te Matai GXPs.

The Mt Maunganui GXP supplies five zone substations – Matapihi, Omanu, Papamoa, Te Maunga and Triton. The Te Matai GXP supplies five zone substations – Wairakei, Te Puke, Atuaroa, Paengaroa and Pongakawa. The region uses a 33kV subtransmission voltage.

Our subtransmission and distribution in the Mt Maunganui area is predominantly through overhead lines, especially in rural areas, with all new intensive subdivision being supplied through underground networks.

The subtransmission network from Mt Maunganui GXP is predominantly twin circuit architecture. Two dedicated circuits directly feed each of the Triton, Matapihi (adjacent to Mt Maunganui GXP), Omanu and Te Maunga substations. Twin circuits from Te Maunga continue on to Papamoa substation.

Figure 11.7: Mt. Maunganui area overview

The 33kV subtransmission from the Te Matai GXP has a meshed architecture. Dual circuits supply the Te Puke substation. Atuaroa is an urban substation, installed to offload Te Puke, and is normally supplied through a single 33kV circuit out of Te Matai. Its alternative supply comes from the Kaitimako to Te Matai line. Paengaroa is supplied by a single circuit from Te Matai. Paengaroa, in turn, supplies Pongakawa through a single circuit.

An old transmission grid line links Te Matai GXP and Kaitimako GXP (Tauranga area) at 33kV with connections to Atuaroa and Welcome Bay substations. This provides limited backup to Atuaroa and Te Matai itself.

11.4.4.2 DEMAND FORECASTS

Demand forecasts for the Mt Maunganui zone stations are shown in Table 11.8, with further detail provided in Appendix 7.

Table 11.8: Mt Maunganui zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Atuaroa Ave	AA+	0.0	8.4	8.8	9.1	9.5
Matapihi	AAA	24.1	14.6	15.2	15.9	16.6
Omanu	AAA	24.3	16.7	17.1	17.6	18.1
Paengaroa	AA	3.6	5.8	5.8	5.9	5.9
Papamoa	AAA	21.3	15.5	19.7	23.9	28.0
Pongakawa	A1	1.3	5.2	5.3	5.5	5.6
Te Maunga	AA	10.3	9.9	10.7	11.5	12.2
Te Puke	AAA	22.9	20.3	20.9	21.5	22.2
Triton	AAA	21.3	21.3	22.1	23.0	23.9
Wairakei	AA	6.0	6.5	8.4	10.3	12.3

The Mt Maunganui area has one of the highest growth rates in our network. Substantial investment has recently been made to provide new substations and to expand our subtransmission and 11kV feeder networks.

High load growth rates are expected to continue as subdivision development extends down the coast from Papamoa to Wairakei and eventually to Te Tumu. Property section sales have accelerated rapidly in the past few years. This acceleration is not reflected in the base growth rates in the table above, which mostly come from longer term historical trends. The local council has signalled section capacity in the Te Tumu area will be smaller than originally anticipated, but this only affects the final saturated electrical load density, not the immediate growth rate.

The existing urban areas of Mt Maunganui are also expected to have high growth from in-fill and intensification. This shift from urban spread to greater intensification of urban areas is a key element of recent strategic development planning by the council. The ensuing potential for higher demand growth of the existing urban Mt Maunganui substations (Matapihi, Triton and Omanu) is additional to the base growth rates reflected in the table above.

The Rangiuru Business Park has been a focus of past long-term planning. Recent indications are that development of the business park will not begin until about 2022, following uptake of land closer to the city. However, the potential for development to start earlier remains a planning risk.

The Te Puke and surrounding rural load continues to grow steadily, largely in response to kiwifruit and avocado growing operations.

11.4.4.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Mt Maunganui area are shown in Table 11.9.

Table 11.9: Mt Maunganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Mt Maunganui GXP	The N-1 capacity of the 110kV transmission into Mt Maunganui GXP will be exceeded by about 2020. The 110/33kV supply transformer firm capacity will be exceeded by about 2028.	Note 1
Papamoa and Te Maunga substations	An outage on one of the two Mt Maunganui-Te Maunga 33kV circuits causes overloading of the remaining circuit.	Note 1
Triton substation	An outage on one of the two Mt Maunganui-Triton 33kV circuits can cause an overload of the supply transformer on the parallel circuit.	Triton transformers
Te Maunga substation	Single transformer.	Note 2
Te Matai GXP	The 110/33kV transformer firm capacity will be exceeded. An outage on the Kaitimako-Te Matai 110kV circuit will cause low voltages at Te Matai GXP.	Note 3 Te Matai subtransmission voltage support
Pongakawa and Paengaroa substations	Single feeder from Te Matai GXP serves both Paengaroa and Pongakawa – both subs affected by single outage.	Note 4 Rangiuru Business Park project
Pongakawa substation	Single 33kV circuit supplies Pongakawa – insufficient backfeed to secure all loads.	Note 4
Pongakawa substation	Demand exceeds secure capacity of the two transformers.	Note 4
Atuaroa substation	Single transformer. Insufficient backfeed to secure all load at Atuaroa by about 2022.	Note 5 Atuaroa project
Atuaroa substation	Single 33kV subtransmission supply to Atuaroa. Tee connection to Kaitimako tie line. Insufficient backfeed via Kaitimako to supply all of Atuaroa.	Note 5 Atuaroa subtransmission
Te Puke substation	An outage on one of the two Te Matai-Te Puke 33kV circuits can cause overloading on the other (from 2026).	Te Puke bus security upgrade

Notes:

1. Wairakei substation was energised in 2018 to offload some of the Papamoa substation load. The arrangement sees Te Matai GXP supplying Wairakei substation. We expect to commission a new 33kV indoor switchboard at Papamoa substation in early 2019. Papamoa substation will then be supplied from Te Matai GXP via Wairakei substation, with remote changeover flexibility to Mt Maunganui GXP during network contingent events. The offload of Papamoa to Te Matai GXP helps resolve the N-1 capacity constraint of the 110kV transmission into Mt Maunganui, the 110/33kV supply transformer firm capacity issue at the GXP, as well as the N-1 capacity of the 33kV subtransmission circuits from Mt Maunganui to Te Maunga substation.

2. The risk of the outage is low because of the availability of multiple backfeed ties from adjacent substations.

3. Supply transformer firm capacity is inadequate. Powerco's preferred solution is to upgrade the two existing 110/33kV transformers to larger capacity units so that there is enough firm capacity to support the increased load expected because of the Wairakei and Papamoa substations. We will continue to work with Transpower to finalise timing for the project.

4. The small load at Pongakawa cannot justify dual 33kV circuits. The recently established Paengaroa substation will offload Pongakawa and several long 11kV feeders from Pongakawa and Te Puke, improving reliability to customers affected. Transformer capacity will also be adequate following load transfer to Paengaroa. In the longer term, a subtransmission ring incorporating Rangiuru Business Park and Paengaroa would be established to improve security of supply.

5. Atuaroa was built to offload Te Puke substation. Load growth within Te Puke township will progressively increase load on Atuaroa, including transfer from Te Puke substation. As demand grows and exceeds 11kV backfeed capability, the increasing risk will need to be addressed through improvements to Atuaroa subtransmission security and provision of a second transformer. This is not expected before 2022 according to growth forecasts.

11.4.4.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are the summaries of the major growth and security projects for the Mt Maunganui region during the planning period.

TE MATAI SUBTRANSMISSION VOLTAGE SUPPORT

Estimated cost (concept):	$5.9m
Expected project timing:	2023-2025

Post-contingent low voltages are expected across the Te Matai subtransmission system following the loss of a 110kV transmission circuit into Te Matai.

Options considered are detailed in Appendix 8. These include 110kV solutions, and solutions at the subtransmission level.

The proposed long-term solution is the installation of a STATCOM at the new Wairakei substation to provide dynamic fast-response reactive current injection. This would improve post-contingency voltage levels across the Te Matai subtransmission network.

ATUAROA PROJECT

Estimated cost (concept):	$4.6m
Expected project timing:	2026-2028

Atuaroa substation has a single supply transformer. Load growth and voltage constraints limit the capability of backfeeding the substation through our existing 11kV network.

Options considered are detailed in Appendix 8. These include increasing 11kV backfeed capacity and energy storage.

To resolve the security of supply issue, the preferred solution is to install a new 33kV switchboard at Atuaroa substation along with a second supply transformer. An expansion of the existing site to accommodate an outdoor 33kV bus is less likely in this case because of the substation's close proximity to neighbouring residential development.

RANGIURU BUSINESS PARK PROJECT

Estimated cost (concept):	$6.6m
Expected project timing:	2023-2026

The proposed industrial park in the Rangiuru area will drive the need for increased security of supply to the region and to support future load growth.

Options considered are detailed in Appendix 8.

The proposed long-term solution is the construction of a new zone substation, taking supply from the recently installed 33kV Te Matai-Wairakei circuits.

Security of supply to the region can be enhanced further with a new 33kV circuit linking the proposed substation to Paengaroa substation, creating a ring network.

Timing of the project is customer load-driven. We will continue to monitor the situation and work closely with the developer.

11.4.4.5 MINOR GROWTH AND SECURITY PROJECTS

We summarise below the minor growth and security projects planned for the Mt Maunganui area during the planning period.

TE PUKE 33KV BUS SECURITY UPGRADE

Estimated cost (design):	$2.0m
Expected project timing:	2025-2027

Te Puke substation is supplied from Te Matai GXP via two 33kV transformer feeders. An outage on one 33kV circuit could overload the parallel circuit during high load times in the latter part of the planning period and leave Te Puke supplied off one transformer only.

The Te Puke substation supplies the main Te Puke township, as well as the surrounding horticultural and lifestyle dwellings. Te Puke substation has a AAA security class requirement.

Options considered are detailed in Appendix 8. To resolve the Te Matai-Te Puke 33kV N-1 thermal constraint and enhance the security of supply to Te Puke, the preferred solution is to build a new 33kV indoor switchboard at Te Puke to replace the existing outdoor 33kV assets and configure the 33kV as a solid bus.

The existing Te Matai-Atuaroa circuit will terminate onto the new Te Puke 33kV bus, effectively creating a third Te Matai-Te Puke 33kV circuit and a Te Puke-Atuaroa 33kV circuit. Doing this will resolve the subtransmission N-1 capacity constraint between Te Matai and Te Puke.

The new Te Puke switchboard also facilitates the connection of the proposed 33kV Te Puke-Atuaroa circuit project, which enhances security of supply to Atuaroa.

ATUAROA SUBTRANSMISSION	
Estimated cost (concept):	$2.2m
Expected project timing:	2026-2028

Atuaroa substation is supplied from Te Matai GXP on a single 33kV circuit. It has switched backup supply from Kaitimako GXP, but the capacity is limited and will not support the substation load when normal supply fails. Load growth and voltage constraints limit the capability of backfeeding the substation through our existing 11kV network.

Options considered are detailed in Appendix 8.

To improve subtransmission security to Atuaroa, the preferred solution is to construct a new 33kV circuit between Te Puke and Atuaroa substations, providing Atuaroa with dual 33kV supply circuits. This project is reliant on the completion of the Te Puke 33kV bus security upgrade project for connection of the new circuit.

TRITON TRANSFORMERS	
Estimated cost (concept):	$2.7m
Expected project timing:	2023-2025

The existing supply transformers at Triton substation do not have sufficient firm capacity. An outage on one transformer during high load times overloads the remaining transformer and it can potentially overheat. Emergency offloads to adjacent substations are used to mitigate the overload. Triton is not able to meet its security of supply requirements.

Options considered are detailed in Appendix 8.

To resolve the transformer firm capacity issue, the existing transformers will be replaced with higher capacity units.

11.4.4.6 OTHER DEVELOPMENTS

As with the Tauranga area, the high growth from in-fill and greenfield developments will require continued investment in 11kV feeder backbone capacity and new 11kV feeders. These projects are not specifically identified but will be scoped when required in our programme of smaller routine growth and security projects.

Voltage and capacity constraints on the 110kV grid circuits supplying Te Matai GXP have been signalled by Transpower. This is partly because of the additional load transferred from Mt Maunganui. We will continue to work with Transpower on options to address these transmission constraints. Within the planning period, we will aim to resolve the post-contingent subtransmission under-voltage issue with our proposed voltage support project.

We will also continue to monitor the load on the 110kV into Mt Maunganui GXP. While our strategy for the Papamoa project is to avoid upgrades to these circuits, if growth because of in-fill is higher than anticipated, constraints may develop in the next 10-15 years. Costs for additional capacity are extremely high if this is still needed. Securing routes early is essential to mitigating such costs.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Pongakawa substation transformer capacity upgrade	Load at Pongakawa substation exceeds the firm capacity of the transformers. It is proposed to upgrade the transformers to restore adequate security of supply. We will continue to monitor the situation as timing is dependent on the rate of growth in the area.
Pongakawa subtransmission	An outage of the Paengaroa-Pongakawa 33kV circuit causes loss of supply at Pongakawa substation. The proposed solution is to continue upgrading 11kV backfeed capability to the area.
Te Tumu capacity reinforcement	As residential growth continues at pace in eastern Papamoa, a new zone substation will be required to supply the new load for the Te Tumu growth area. Timing is customer load-driven.

11.4.5 WAIKATO

Our Waikato area covers the eastern Waikato region and does not include Hamilton or western Waikato. It is largely an agricultural area, with a strong dairy industry. There are several locations supplied by single circuits that don’t meet our security criteria. Our largest project in this area is to construct a new GXP at Putaruru to improve security. We also have several other projects to increase security and capacity. Major and minor project spend related to growth and security during the next 10 years is $65.9m.

11.4.5.1 AREA OVERVIEW

The Waikato area extends from the Hauraki Plains north of Morrinsville and Tahuna, through the rural land of eastern Waikato and to rural areas south of Putaruru.

The Kaimai Range runs the length of its eastern boundary. The supply area covers parts of the Matamata-Piako and south Waikato districts.

The terrain is flat to rolling pasture land, sprinkled with towns and settlements.

The environment is generally favourable to network construction, maintenance and operations. Peat lowland areas can provide challenges to structural foundations and thermal rating of cables.

The climate is typical of the Waikato region, with mild winters and warm humid summers. Being inland the region is relatively sheltered from extreme weather and coastal influence.

The key element of the region's economy is primary production, with most of the region being high-production dairy country. A number of important industrial and food processing facilities are located within the area. These have been quite instrumental in driving recent demand and network developments.

The significant population centres are Morrinsville, Te Aroha, Matamata and Putaruru. Population growth is modest to static, although associated economic activity brings modest demand growth. The industrial park at Waharoa has had considerable growth in primary and supporting industries. Tirau is subject to tourism activity and the dairy plant is the largest single load.

The area is supplied from the Waihou, Piako and Hinuera GXPs.

Waihou GXP supplies four zone substations – Mikkelsen Rd, Tahuna, Waitoa and Inghams. Waihou is an older GXP and much of the equipment needs replacing or upgrading. Piako GXP was built with the intention of offloading Waihou and helping refurbishment projects.

The new Piako GXP supplies six zone substations – Piako, Morrinsville, Tatua, Farmer Rd, Walton and Waharoa.

The Hinuera GXP supplies six zone substations – Waharoa[32], Browne St, Tower Rd, Lake Rd, Putaruru, and Tirau.

All subtransmission in the region is at 33kV, and mainly via overhead lines. The architecture could best be described as interconnected radial. Very few substations have two dedicated circuits. Most substations rely on switched 33kV backfeeds, often from different GXPs. Therefore, parallel operation of supply lines is often not possible.

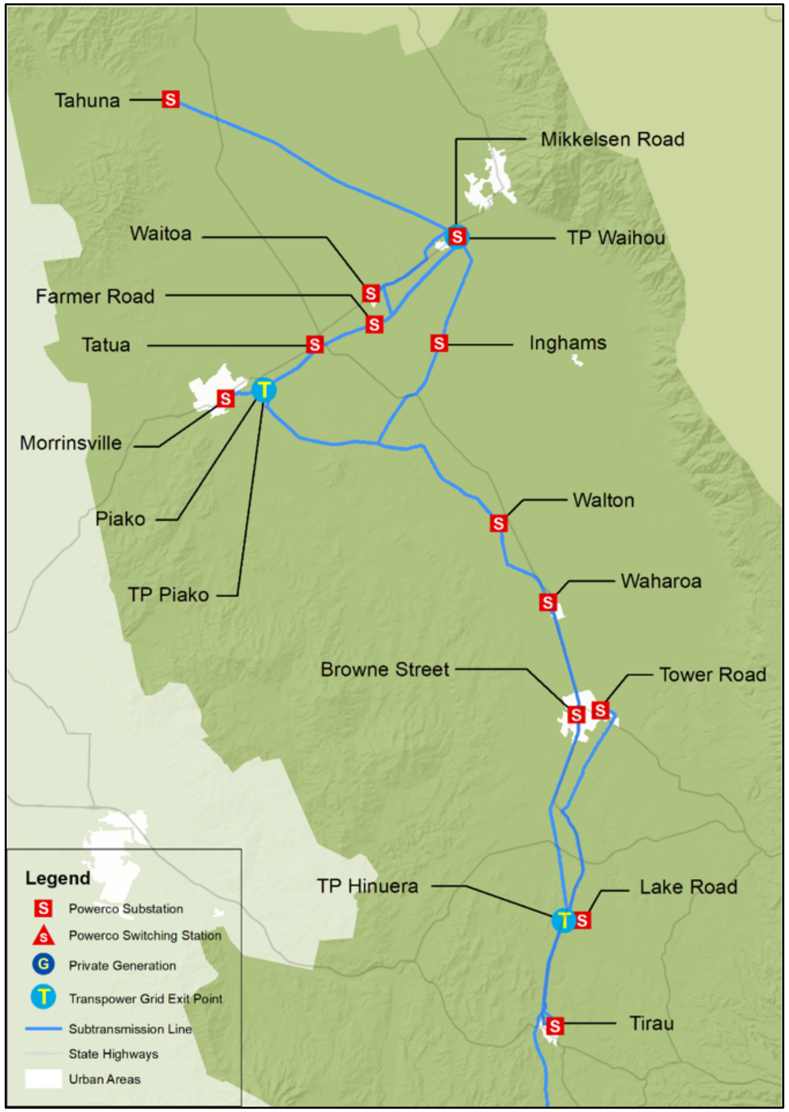
The two dedicated customer zone substations at Tatua and Inghams have security that is specific to the customer, with just single zone transformers. At Waharoa the security is a balance between our nominal security standards and the specific requirements of large customers.

Tahuna and Putaruru are notable in that they are supplied via long, single, 33kV circuits, with no alternative source other than limited 11kV backfeed. For Putaruru, particularly, this is well below our security standards.

The other notable characteristic of this area relates to the 110kV circuits, owned by Transpower that feed the GXPs. The Hinuera GXP is supplied from a single 110kV circuit from Karapiro. This is a legacy of historical grid development and severely limits security to Matamata, Putaruru and Tirau. The Piako and Waihou GXPs, along with Kopu and Waikino, are supplied from dual 110kV circuits on a single tower structure line originating in Hamilton. The capacity of this line impacts the longer-term development.

32 The supply to Waharoa substation is shared between two GXPs, Piako and Hinuera.

Figure 11.8: Waikato area overview



11.4.5.2 DEMAND FORECASTS

Demand forecasts for the Waikato zone substations are shown in Table 11.10, with further detail provided in Appendix 7.

Table 11.10: Waikato zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Browne St	AA	10.6	9.9	10.3	10.8	11.3
Farmer Rd	AA+	0.0	7.0	7.1	7.3	7.4
Inghams	AA	0.0	4.4	4.4	4.4	4.4
Lake Rd	A1	1.7	6.7	6.8	7.0	7.2
Mikkelsen Rd	AAA	19.2	15.6	15.8	15.9	16.1
Morrinsville	AA+	0.0	11.1	11.4	11.8	12.2
Piako	AAA	15.2	15.4	16.1	16.9	17.8
Putaruru	AA+	0.0	11.7	12.1	12.5	13.0
Tahuna	A1	0.7	5.9	6.0	6.1	6.2
Tatua	AA	0.0	4.8	4.8	4.8	4.8
Tirau	AA+	0.0	9.9	10.2	10.4	10.6
Tower Rd	AA+	0.0	8.7	9.4	10.1	10.8
Waharoa T1	AA+	N/A	3.8	3.8	3.8	3.8
Waharoa T2	AA+	N/A	4.9	4.9	4.9	4.9
Waitoa	AAA	18.8	12.4	12.4	12.4	12.4
Walton	AA+	0.0	6.1	6.1	6.2	6.2

Major industrial customers have the most significant impact on demand growth through specific plant or process upgrades.

Recent and imminent activity for major industrial customers includes:

- Zone substations at Inghams and Tatua are dedicated to industrial customers and have recently resulted in significant changes in demand.
- Waitoa substation is a dedicated supply to the Waitoa dairy factory. Possible load increases and generation changes have been signalled.
- Waharoa and Tirau substations each supply a dairy factory. Waharoa has experienced significant changes in load because of other industries.
- Mikkelsen Rd substation supplies Silver Fern Farms' meat processing plant.
- Piako substation supplies the Evonik chemical plant.

Demand growth is generally from small gains in population in urban centres and also from increased dairy activity in some rural areas. Historically, much of the area is a dairy stronghold, but some pockets of more recent conversion to dairy farming have increased the loading on our 11kV feeders. We are monitoring the impact from potential changes to dairy refrigeration requirements on farms.

From the demand forecast table it is evident that several of the Waikato substations already exceed our security criteria requirements. Rather than future growth, several larger investments relate to these legacy security risks, which impose unacceptable economic costs either in terms of the high value load at risk or the large number of customers impacted by poor reliability.

11.4.5.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikato area are shown in Table 11.11.

Table 11.11: Waikato constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hinuera GXP	Single 110kV circuit from Karapiro to Hinuera.	Putaruru GXP and other projects. Note 1
Hinuera GXP	N-1 capacity of the transformers is exceeded.	Putaruru GXP
Waihou GXP	N-1 capacity exceeded in about 2025.	Note 1
Waharoa and Browne St substations	Small conductor between Kereone and Walton constrains backfeed capacity to Browne St and Waharoa substations.	Kereone-Walton upgrade
Waharoa substation	Insufficient capacity for growing demand at Waharoa.	Kereone-Walton upgrade and Waharoa substation transformer upgrade
Browne St and Tower Rd substations	Single 33kV circuits from Hinuera supply each of these two substations in Matamata. The 11kV intertie capacity is not sufficient or fast enough to meet security standards.	Matamata subtransmission
Putaruru substation	Single 33kV Hinuera-Putaruru circuit. Insufficient 11kV backfeed to supply all load.	Putaruru-Tirau upgrade

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Morrinsville substation	Single 33kV Piako-Morrinsville 33kV circuit and insufficient firm capacity for growing demand at Morrinsville.	Morrinsville second circuit and Morrinsville substation transformers upgrade
Tahuna substation	Single 33kV circuit. Insufficient 11kV backfeed to meet security standards.	Note 2
Piako 11kV feeders	Long, heavily loaded feeders from Piako substation. Voltage and capacity constrain both normal supply and backfeeding.	Piako-Kiwitahi feeder
Putaruru substation	Demand exceeds secure capacity of the two transformers. Backfeed is insufficient from adjacent substations	Putaruru substation transformers upgrade
Lake Rd substation	Single transformer. Insufficient 11kV backfeed to meet security standards.	Lake Rd second transformer
Tower Rd substation	Demand exceeds secure capacity of the two transformers.	Tower Rd second transformer
Walton substation	Single transformer. Insufficient 11kV backfeed to meet security standards.	Note 3
Tirau substation	Single transformer. Insufficient 11kV backfeed to meet security standards.	Tirau second transformer
Inghams substation	Single transformer does not meet security standards.	Note 4
Piako GXP	The firm capacity of the two Piako GXP transformers will be exceeded about 2029.	Note 5
Tower Rd, Browne St and Waharoa	As load increases, an outage on either Hinuera-Browne or Hinuera-Tower subtransmission circuits will result in the overloading of the other circuit.	Waharoa substation transformer upgrade Note 6
Mikkelsen Rd substation	An outage of one of the two Waihou GXP-Mikkelsen Rd 33kV circuits will overload the parallel circuit about 2029.	Note 7
Browne St substation	Demand exceeds secure capacity of the two transformers in the latter part of the planning period.	Note 8
Piako substation	Demand exceeds secure capacity of the two transformers in the latter part of the planning period.	Note 8
Maungatautari and Horahora	Single long 11kV spur feeder prone to long duration outages. Low voltages during high load.	Maungatautari area reinforcement

Notes:

1. Putaruru GXP is the main project to address Hinuera's lack of security, ie single circuit. Putaruru-Tirau and Kereone-Walton projects are also needed to fully secure all Hinuera load, but these projects are also driven by local subtransmission constraints. As Putaruru GXP will utilise the existing 40MVA transformer at Piako GXP, a new 60MVA unit will be procured for Piako GXP.
2. Options to establish a second circuit into Tahuna were considered during the analysis of options for Morrinsville, but none of these proved economic for the small load at risk.
3. A second transformer is not economic at this stage as remote loop automation schemes are being implemented to enhance backfeed interties with adjacent substations.
4. Customer-specific security level is acceptable.
5. This issue can be managed operationally. There is enough transfer capacity between Piako and the adjacent GXPs – Waihou and Hinuera.
6. This issue will be addressed by permanently offloading Waharoa substation to Piako GXP. A transformer upgrade at Waharoa is required to facilitate this.
7. The overload is on a short section of overhead line exiting Waihou GXP. It is expected this section will be upgraded when the existing outdoor Waihou 33kV assets are replaced.
8. Manage overload operationally via load transfer to adjacent substations.

11.4.5.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Waikato area.

PUTARURU GXP	
Estimated cost (design):	$25.4m
Expected project timing:	2019-2022

Hinuera GXP is supplied by a single 110kV circuit (25km) from Karapiro. There is limited backfeed capability to support the load should an outage occur on the 110kV supply. The remaining load suffers a lengthy outage during any maintenance or faults on this line or at the associated substation plant.

In addition, the Putaruru 110/33kV supply point project addresses a number of associated constraints:

- The supply transformers at Hinuera GXP have exceeded their secure capacity. Demand growth has been steady.
- Scheduling regular maintenance work on both the supply transformers and the 110kV line has been difficult and the condition of the assets is not well understood.
- A long, single 33kV circuit supplies Putaruru substation from Tirau substation.

More details of the options considered are set out in Appendix 8.

The proposed solution is to construct a new 110kV circuit from Arapuni power station to a new 110/33kV supply point at Putaruru substation. A new 110kV cable will connect the north bus at Arapuni to the new 110/33kV substation, which will have just a single transformer relocated from Te Matai GXP. Our future strategy is that Putaruru and Hinuera will support each other and therefore full N-1 capability is not required at each.

This solution not only provides additional backfeed in the case of a Hinuera GXP outage, but improves security to the Putaruru and Tirau substations.

The Putaruru to Tirau second 33kV circuit, although a separate project, is mainly driven by the overall strategy adopted for the Putaruru GXP. This project will provide sufficient capacity to fully supply Tower Rd from the new Putaruru GXP.

In conjunction with the new Putaruru 110/33kV substation, we will need to relocate, renew and upgrade many of the existing Putaruru substation 33/11kV assets. These are treated as separate projects to the new Putaruru GXP.

KEREONE-WALTON UPGRADE

Estimated cost (concept):	$6.4m
Expected project timing:	2019-2023

Part of the strategy with the Putaruru GXP is that the Browne St and Waharoa substations will be transferred to Piako during an outage of the Hinuera GXP. The capacity of the existing network tie lines is not adequate to fully secure all this load and maintain adequate voltage.

Waharoa substation has faced rapid demand growth through significant changes in load from larger customers, which is expected to continue. The 33kV supply circuits from either the north (Piako GXP) or south (Hinuera GXP) no longer have adequate capacity to supply all Waharoa on their own. As an interim strategy, we have had to split the load at Waharoa across two transformers, each connected off different supply circuits and different GXPs. This effectively leaves customers on N security and exposed to the risk of brief outages following a fault on either circuit or transformer. The limiting constraint is a relatively long section of small conductor 33kV line between Kereone and Walton.

Options considered are detailed in Appendix 8.

The proposed solution involves a new 33kV cable from Kereone to Walton. This is the most economic option that fully secures all load. In conjunction with Putaruru GXP and associated upgrades, it also secures all Hinuera load. The solution improves flexibility by offloading Walton substation on to the Waihou GXP. This will enable the Piako GXP to supply all of Waharoa substation normally, plus Browne St during contingencies in the area.

PUTARURU-TIRAU UPGRADE

Estimated cost (concept):	$6.7m
Expected project timing:	2019-22

The Putaruru and Tirau substations are supplied by a single 33kV line from Hinuera. Expansion of local industries has resulted in load growth at both these substations.

An outage on this line will cause a loss of supply to Putaruru and Tirau. There is very limited 11kV backfeed capability from substations further north, such as Browne St and Lake Rd. Because of these constraints, both substations do not meet our required security levels.

Options considered are detailed in Appendix 8.

The proposed solution involves building a new 33kV underground cable between Putaruru and Tirau substations. This will provide high reliability and capacity between Putaruru and Tirau. It will also form part of a project to provide a backup supply to the Hinuera GXP, via the proposed Putaruru GXP. Because of this project, both the Putaruru and Tirau substations will achieve our security requirements.

MORRINSVILLE SUBSTATION UPGRADE

Estimated cost (concept):	$7.8m
Expected project timing:	2024-2028

Morrinsville substation supplies the town, commercial properties, residential properties and the surrounding rural area. Major industrial customers include Greenlea Meats processing plant and Fonterra. Fonterra alone consumes 2.7MVA of the substation’s capacity. The Morrinsville area has experienced rapid residential and industrial growth. This is expected to continue.

The firm capacity of the transformers is already exceeded. Some backfeed from Piako and Tahuna is available, but this is insufficient to meet the growing demand.

Options considered are detailed in Appendix 8.

The proposed solution involves constructing a new 33/11kV indoor switchroom and upgrading the capacity of the zone substation transformers to meet Powerco’s security class standard.

11.4.5.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Waikato area.

HINUERA OUTDOOR-INDOOR (ODID) CONVERSION

Estimated cost (concept):	$2.1m
Expected project timing:	2020-2021

At Hinuera GXP, a single circuit breaker supplies both Lake Rd and Tower Rd substations. The Tirau and Putaruru supply also comes off a single circuit breaker at Hinuera GXP.

The proposed Putaruru GXP is required to support the Hinuera GXP loads should an outage occur on the 110kV Hinuera supply. Protection systems will suffer from slow protection trip times when Putaruru GXP supports the Hinuera GXP loads, as Putaruru GXP is a weaker infeed.

Powerco's original scope was to partially put indoor the 33kV outdoor yard in order to facilitate the connection of the recently installed Hinuera-Tirau 33kV circuit and the additional circuits to Lake Rd and Tower Rd. It is also a prerequisite for the Putaruru GXP project. This approach was based on the original assumption that Transpower had no plans to renew the outdoor 33kV assets within the planning period.

Transpower has since advised it has scheduled replacement of the outdoor 33kV assets in 2022. As a result, it will be more cost-effective if Powerco carries out the entire outdoor-to-indoor conversion and builds a new switchroom to house the new switchboard.

MATAMATA SUBTRANSMISSION (TOWER-BROWNE 33KV CABLE)

Estimated cost (concept):	$2.1m
Expected project timing:	2019-2020

The Browne St and Tower Rd substations are each supplied through a single 33kV line from Hinuera GXP. Together these substations supply all of the Matamata town, including the CBD. Outages on either of the 33kV lines will cause an immediate loss of supply to both substations. The 11kV intertie capacity between the substations does not provide appropriate security.

The proposed solution is to build a 33kV underground cable circuit between Tower Rd and Browne St substations. This will create a secure 33kV subtransmission ring. This is more cost effective and provides more flexible operational capability than increased 11kV intertie and automated switching. The cost of duplicate 33kV circuits to each substation would be prohibitive.

MATAMATA SUBTRANSMISSION (HINUERA-TOWER RD 33KV LINE UPGRADE)

Estimated cost (concept):	$1.5m
Expected project timing:	2019-2020

Once the Tower Rd to Browne St tie is complete, there will be a 33kV ring between Hinuera GXP, Tower Rd and Browne St substations. At peak loading, the existing Hinuera-Tower Rd line does not have sufficient capacity to supply both substations. In order to provide the required security levels, the Hinuera-Tower Rd 33kV line will need to be upgraded.

The proposed solution is much cheaper than an additional circuit to Matamata. There are no practical 11kV backfeed options. Non-network solutions such as demand side response and load shedding may be possible, but only as a risk management strategy to defer the upgrade.

MORRINSVILLE SECOND CIRCUIT

Estimated cost (concept):	$4.0m
Expected project timing:	2020-2023

The Morrinsville substation is fed by a single 33kV circuit from the Piako GXP. If there is a fault on this circuit there will be an immediate loss of supply to all Morrinsville, including the dairy factory. Some backfeed from Piako and Tahuna is available but does not meet our security criteria.

The proposed solution is to construct a second 33kV circuit from Piako GXP to Morrinsville substation and upgrade the transformers at Morrinsville. This second circuit will ensure supply can be maintained at Morrinsville substation during a subtransmission outage.

Options to create a 33kV ring between Morrinsville and Tahuna (also supplied by a single circuit) were considered but proved too expensive for the risk involved.

PIAKO KIWITAHI NEW 11KV FEEDER

Estimated cost (concept):	$1.7m
Expected project timing:	2023

There are eight 11kV feeders supplied from the Piako zone substation. Two of these, Kereone and Kiwitahi, are long feeders – Kereone is 114km in length. During peak periods there can be low voltage at the end of the feeders. Backfeed capability is severely restricted, which reduces reliability. There is steady growth in the area so the performance of these feeders will deteriorate over time.

The proposed solution is to construct a new 11kV feeder from the Piako substation to supply part of the area fed by the existing Kereone and Kiwitahi feeders. This will offload these feeders by reducing their length, thereby improving the voltage and performance.

TOWER RD SUBSTATION SECOND SUPPLY TRANSFORMER

Estimated cost (concept):	$4.1m
Expected project timing:	2019-2020

Tower Rd substation has only one 33/11kV transformer. The 11kV backfeed from Browne St is not sufficient to meet our security standards.

Tower Rd substation has a programme of upgrades to improve performance and security, including the addition of a second transformer. The substation has been designed to house a second transformer to bring it up to the required security levels.

TIRAU SUBSTATION SECOND TRANSFORMER

Estimated cost:	$2.8m
Expected project timing:	2024-2027

Tirau substation supplies Tirau township, as well as surrounding rural areas. One industrial consumer, Fonterra, takes about 2.3MVA of the substation capacity. The substation is a single transformer substation, but the security class is not met.

The size and nature of the load connected to the Tirau substation is at risk from non-supply in the event of a transformer outage. There is minimal 11kV backfeed capacity from neighbouring substations, such as Lake Rd and Putaruru.

The proposed solution is to install a 12.5/17MVA transformer together with a new transformer pad, bunding, earthing, connecting cables, and protection, and upgrade the existing transformer to a 12.5/17MVA unit. This option will provide full (no break) N-1 supply and will also cater for future load growth.

PUTARURU SUBSTATION TRANSFORMERS UPGRADE

Estimated cost (concept):	$2.4m
Expected project timing:	2023-2026

Putaruru substation supplies the local industries, commercial, residential areas, Putaruru township and the surrounding rural area. Major industrial consumers include Pacific Pine Industries, Kiwi Lumber, Ingham's and Carter Holt Harvey. Several areas have been identified by the South Waikato District Council to be re-zoned as residential and light industrial estate.

Putaruru substation demand is forecasted to reach 13MVA by about 2029. The maximum demand exceeds the transformers' firm capacity. Existing 11kV backfeed capacity is minimal from Tirau and Baird Rd substations. At such demand, this substation does not meet Powerco's security of supply.

The preferred solution is to upgrade the substation transformers to 16/24MVA. This will provide full (no-break) N-1 security and meet the growing demand in the Putaruru area.

WAHAROA SUBSTATION TRANSFORMERS UPGRADE

Estimated cost (concept):	$3.1m
Expected project timing:	2025-2028

In the latter part of the planning period, following the completion of the Browne Rd-Tower Rd circuit, the loss of the Hinuera-Browne St circuit will overload the Hinuera-Tower Rd circuit during high load periods. Similarly, the loss of the Hinuera-Tower Rd circuit will overload the Hinuera-Browne St circuit.

The two existing transformers at Waharoa substation are of different capacities and supplied from different GXPs – Hinuera and Piako. Therefore, putting the two transformers in parallel is not preferred and the subtransmission capacity is insufficient to supply the entire Waharoa load from either GXP during high load times.

The preferred solution to resolve the post-contingent overloading issue is to offload the Waharoa dairy factory load to Piako GXP permanently. This involves upgrading the existing T1 transformer to match the larger unit and replacing the existing 33kV overhead bus with an indoor 33kV switchboard because of the space constraints on-site.

LAKE RD SUBSTATION SECOND SUPPLY TRANSFORMER

Estimated cost:	$2.4m
Expected project timing:	2019

Lake Rd substation has only one 33/11kV transformer. Backfeed at 11kV is very limited and does not meet our security standards.

The proposed solution is to upgrade to two transformers. Additional 11kV backfeed is possible but limited by the large distances to other substations.

MAUNGATAUTARI AREA REINFORCEMENT	
Estimated cost (concept):	$2.5m
Expected project timing:	2025-2026

Maungatautari and Karapiro are areas on the edge of Powerco's network. Supply to the area is from Tirau substation. The ability to provide a secure supply to the area is set back by distance and terrain. In total, 746 ICPs are supplied by the Cambridge Rd feeder, and 11kV backfeed capacity from Lake Rd substation is minimal because of the great distance.

Historically, outages in this area are of long duration. Because of the terrain involved, fault-finding and repair is difficult.

To improve the security of supply to this region, a possible solution is to install two distributed generation facilities – one for each main spur serving the Maungatautari and Horahora areas. This provides for an islanded supply during outages, minimising the SAIDI impact.

11.4.5.6 OTHER DEVELOPMENTS

Associated with the larger projects identified previously to secure the load at Hinuera GXP, a new indoor 33kV switchboard will be installed when building the Putaruru GXP.

The transmission serving the Waikato area is particularly pertinent to our development plans and strategies. As noted already, Putaruru GXP and a number of associated projects are primarily driven by the lack of security of the single Karapiro to Hinuera 110kV circuit. Piako GXP was built specifically to offload Waihou GXP. With Putaruru GXP coming off the north bus at Arapuni, the GXP is unlikely to be affected by network constraints on the wider transmission system, hence ensuring its off-take capacity is not compromised.

The Valley Spur 110kV line's N-1 capacity is forecast to be exceeded by about 2022. Before this occurs, and as demand increases, the line will be voltage constrained during single circuit outages.

In addition, there are several causes for renewal of specific GXP assets.

The following project has been identified as being likely to occur in the latter part of the planning period. The following description represents the most probable solution, but the final solution and optimal timing are subject to further analysis and will be confirmed closer to the time.

PROJECT	SOLUTIONS
Tahuna substation subtransmission supply	Tahuna substation is supplied via a long single subtransmission circuit. 11kV backup is limited. A second subtransmission circuit is unlikely to be economic because of the distance involved. Increased 11kV interconnection is the most likely solution.

11.4.6 KINLEITH

The Kinleith area includes Tokoroa and a major pulp and paper mill at Kinleith. There will be no project spend in the Kinleith area during the next 10 years.

11.4.6.1 AREA OVERVIEW

The Kinleith area covers the southern stretch of the south Waikato district. The northern part of the south Waikato district falls within our Waikato area.

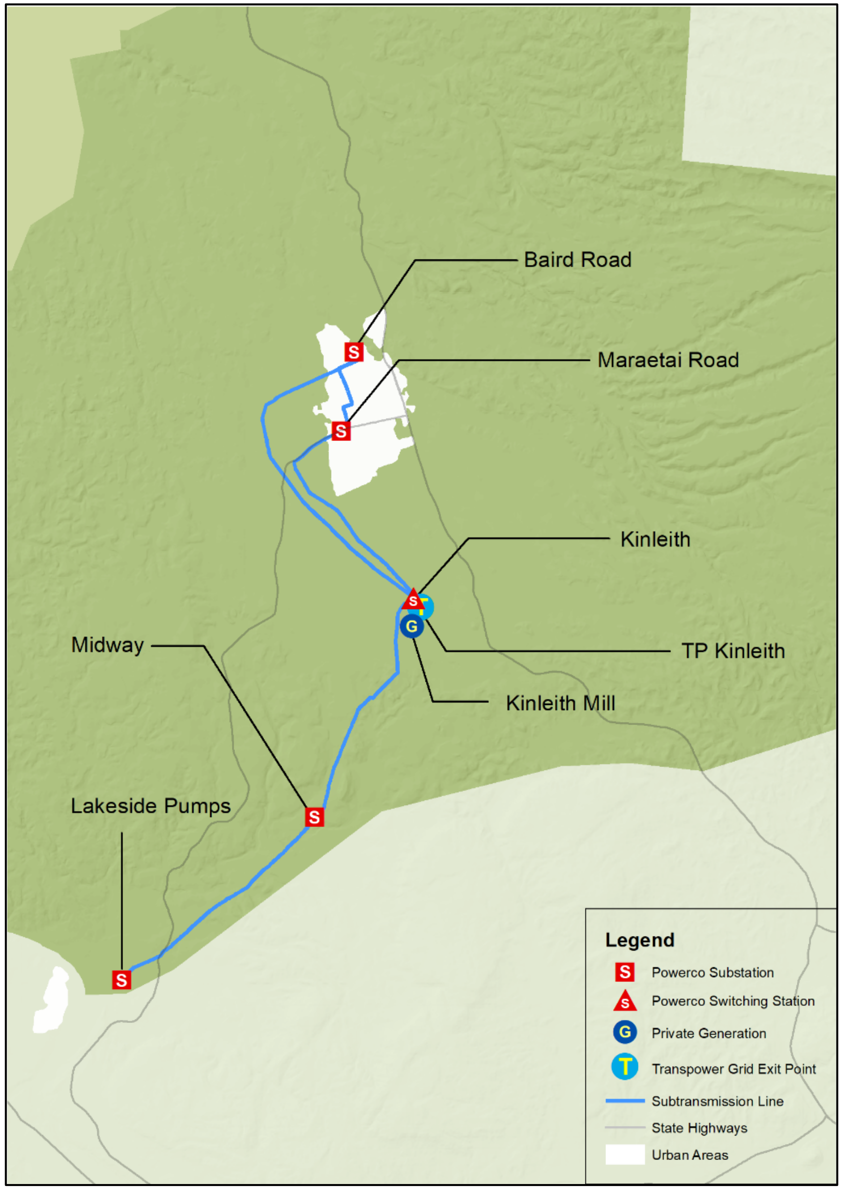
The largest town in the Kinleith area is Tokoroa, which has a population of 13,600.

The area includes the large pulp and paper mill at Kinleith, which has a significant influence on the local economy, industry and employment. Other keys to the district's economy are primary production (dairy farming) and forestry.

The terrain varies from rolling pasture land around Tokoroa to large expanses of pine forests around the Kinleith mill. The climate is similar to other parts of the Waikato, although it is slightly cooler as the area is on the fringes of the central North Island plateau.

The subtransmission and distribution networks in the Kinleith area are mainly overhead.

Figure 11.9: Kinleith area overview



Kinleith GXP is the sole grid supply point for the area. There is no 33kV interconnection with other areas and only limited 11kV backfeed.

Kinleith GXP provides offtake at both 33kV and 11kV. The 33kV supply feeds the Tokoroa substations Baird Rd and Maraetai Rd. There is one 33kV line to each substation. There is also a radial 33kV line feeding Kinleith's Midway and Lakeside pump stations.

The 11kV offtake from Kinleith serves the mill, owned by Oji Fibre Solutions. There are multiple 11kV busses, with some limited degree of interconnection. The mill also operates a cogeneration plant feeding into one of the 11kV transformers.

11.4.6.2 DEMAND FORECASTS

Demand forecasts for the Kinleith zone substations are shown in Table 11.12, with further detail provided in Appendix 7.

Table 11.12: Kinleith zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Baird Rd	AA+	0.0	10.9	11.1	11.6	12.1
Maraetai Rd	AA+	0.0	8.8	8.9	9.4	9.8
Midway/Lakeside	AA	0.0	4.8	4.8	4.8	4.8

Economic growth in Tokoroa is modest. There have been some inquiries regarding a possible industrial park or primary industry near the Kinleith mill, but with no commitment yet these proposals are not reflected in the base forecast.

We are in contact with the Kinleith mill regarding any future development plans. This has been particularly pertinent in the past two years as Transpower plans a major overhaul of the GXP because of ageing equipment and operational constraints. Recently there has been an inquiry from the mill about upgrading its wastewater systems. We are working with the mill to find out what load will be connected and find out what types of constraints could occur on our network. These proposals are not reflected in the base forecast.

There is existing generation and some possible future developments, both of significant importance. However, these are likely to be directly connected to the grid and do not significantly impact the development of our network.

11.4.6.3 EXISTING AND FORECAST CONSTRAINTS

The electricity supply in the area is dominated by demand from the Kinleith mill. This has four 11kV busses at which supply is taken, and two additional supplies at 33kV serving river pump substations. The security provided to the mill and pumps is determined through consultation with the customer, Oji Fibre Solutions.

The two substations supplying Tokoroa township do not fully meet our security criteria because of the single circuit architecture.

Major constraints affecting the Kinleith area are shown in Table 11.13.

Table 11.13: Kinleith constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Kinleith GXP	Firm capacity for 110/11kV supply transformers is exceeded.	Note 1
Kinleith GXP	The 110/33/11kV supply transformers are not able to operate in parallel because of incompatible vector groups. Therefore 33kV supply capacity does not meet the security standard.	Note 2
Kinleith GXP	High earth fault levels.	Note 3
Lakeside and Midway substations	Single circuit to Midway and Lakeside pump substations. An outage on either 33kV circuit will cause loss of supply until repairs are completed.	Note 4
Lakeside and Midway substations	Single supply transformer in each respective substation. No security provided.	Note 3

Notes:

1. The security for the Kinleith mill is determined by the customer, Oji Fibre Solutions, not our security standard. During discussion with Transpower, we have considered possible improvements to security that can be carried out during the proposed replacement work

2. No-break N-1 security for the 33kV bus supplying Baird Rd and Maraetai Rd substations is not possible as the vector group for the 33kV windings on the new T9 transformer and T5 transformer is not identical. The cost of this is prohibitive for the minimal benefits. The configuration requires a short loss of supply to the 33kV load when switching the 33kV bus between the two transformers, which can be managed operationally.

3. Transpower will be installing neutral earthing resistors on the new transformers, which will reduce earth fault levels on our 33kV network and the Kinleith Mill 11kV network.

4. The single circuits and single transformers provide no security to the mill's pump stations (Lakeside and Midway) but this level of security is acceptable to the customer.

11.4.6.4 MAJOR GROWTH AND SECURITY PROJECTS

There are no major growth projects planned for the Kinleith area.

11.4.6.5 MINOR GROWTH AND SECURITY PROJECTS

With the 2017 completion of the 33kV cable ring between Baird Rd and Maraetai Rd substations, no further minor projects are planned for Kinleith area.

11.4.6.6 OTHER DEVELOPMENTS

Transpower is working on detailed designs for a major refurbishment at Kinleith GXP of its existing 110kV, 33kV, 11kV primary equipment and of the Kinleith GXP. Protection upgrades will be carried out at the same time. As part of this, the 11kV feeders to the mill will need to be re-routed to new Transpower 11kV switchgear.

In addition to the cabling, Powerco will implement a staged programme to install differential protection on all 11kV feeder circuit cables. Protection upgrades will be carried out at the same time. The design has been constrained by the need to utilise the existing cable tunnels and by the inability to significantly alter the feeder arrangement on the new switchboard. This work will be coordinated with Transpower and the customer.

As part of the upgrade we will consider improvements to the 33kV switchboard, which may help to reduce the impact of future outages. Transpower's replacement of one of the 33kV supply transformers will also improve voltage quality at our 33kV bus.

Kinleith GXP is also affected by the grid capacity constraints on the 110kV between Tarukenga and Arapuni.

In Tokoroa south, new connections to small industries are on-going, however there is a large amount of industrial land suitable for a major industry. Several inquiries for 6-8MVA load have been received during the past few years, but none have been taken further.

Forestry to dairy farm conversions, once a major impact on feeder loading, have now tapered off.

11.4.7 TARANAKI

The largest development work in the Taranaki area is the alternative supply to our Moturoa substation, as Transpower has decided to exit the New Plymouth substation in the third quarter of 2019. Major and minor project spend related to growth and security in the region during the next 10 years is $38.1m.

11.4.7.1 AREA OVERVIEW

The Taranaki area covers the northern, central and some southern parts of the Taranaki region.

The Taranaki area overlaps three territorial authority areas – New Plymouth district, Stratford district and South Taranaki district.

Taranaki's terrain and climate is generally quite favourable to asset construction, access, maintenance and life expectancy. The exception is the coastal areas, where additional corrosion can affect assets as far as 20km inland.

Severe weather events, such as storms, can have a significant impact on the network. Tornadoes can also occur, although these are infrequent and their impact is localised.

Agriculture, oil and gas exploration and production, and some heavy industry are the backbone of the Taranaki economy. Agriculture is dominated by intensive dairying suited to the temperate climate and fertile volcanic soils.

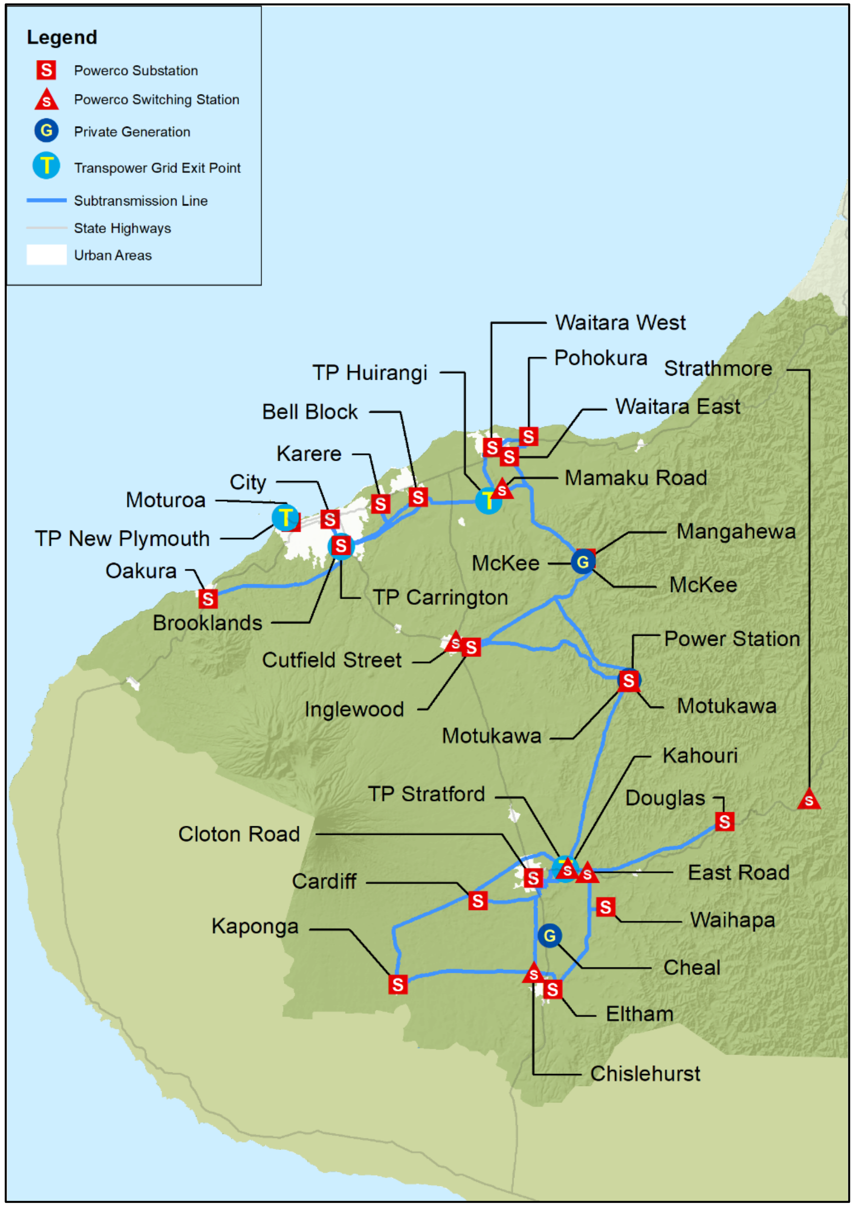
The area is supplied from GXPs at New Plymouth (ex the power station), Carrington St, Huirangi and Stratford.

The subtransmission and distribution networks in the Taranaki area are mainly overhead.

There are some underground networks in the newer urban areas, particularly New Plymouth city.

Subtransmission is mainly meshed or interconnected radial. The notable exception is in New Plymouth, where the five main urban substations are supplied from twin 33kV circuits, and all but one are dedicated circuits directly from the GXP.

Figure 11.10: Taranaki area overview



11.4.7.2 DEMAND FORECASTS

Demand forecasts for the Taranaki zone substations are shown in Table 11.14, with further detail provided in Appendix 7.

Table 11.14: Taranaki zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Bell Block	AAA	24.5	18.8	20.7	22.7	24.6
Brooklands	AAA	24.0	17.0	19.0	19.8	20.6
Cardiff	A1	5.5	1.7	1.7	1.8	1.8
City	AAA	20.1	18.8	19.3	19.8	20.3
Cloton Rd	AA+	13.0	11.2	11.5	11.8	12.1
Douglas	A1	1.7	1.7	1.7	1.7	1.7
Eltham	AA+	11.3	10.4	10.5	10.5	10.5
Inglewood	AA	6.2	5.5	5.8	6.1	6.3
Kaponga	A1	3.0	3.5	3.5	3.6	3.6
Katere	AAA	20.6	15.2	17.2	19.2	21.1
McKee	AA	0.0	1.5	1.6	1.7	1.8
Motukawa	A1	1.3	1.2	1.2	1.3	1.3
Moturoa	AAA	20.7	22.6	22.6	23.8	25.0
Oakura	AA	0.0	3.8	4.3	4.8	5.3
Pohokura	AA	9.2	5.4	5.4	5.4	5.4
Waihapa	AA	1.5	1.2	1.2	1.2	1.2
Waitara East	AA	10.1	5.5	5.9	6.2	6.6
Waitara West	AA	6.4	7.0	7.1	7.2	7.2

Major industrial customers in the area can have a significant impact on the demand forecast. In the Taranaki area the major industrial loads are:

- Port Taranaki and Taranaki Base Hospital, supplied by Moturoa substation.
- McKechnie Aluminium Solutions and Tegel Foods, supplied by Bell Block substation.
- Riverlands freezing works and the Fonterra pastoral foods plant, supplied by Eltham substation.
- The Pohokura natural gas plant, supplied by Pohokura substation.
- The Waihapa petroleum production station, supplied by Waihapa substation.
- ANZCO food processing plant, supplied by Waitara West substation.

We are not aware of any significant changes in demand for any customers. However, such changes usually appear at relatively short notice. We will continue to talk with our larger customers to establish as much lead time as possible for any future developments.

The oil and gas industry impacts demand, both directly and indirectly, and can also drive upgrades for generation opportunities. The 100MW gas plant planned in the Mangorei Rd area will feed directly into the grid, and therefore does not affect our network development. Numerous smaller gas generators have been proposed around the Stratford area, but recent market and economic conditions mean these have been postponed indefinitely. The need to reduce carbon emissions and the moratorium on further oil and gas exploration will also have an impact.

There is a focus on the potential of hydrogen production. The move to hydrogen could have a substantial effect on electricity demand in the region, however large-scale production plants are likely to be grid connected.

Although overall demand growth in Taranaki has historically been quite high, this has been mainly driven by significant changes at specific large customers. Forecast growth from other sectors in the Taranaki area is relatively modest. There is steady population growth in the major population centres, with some new subdivision activity in and around New Plymouth.

Several of the Taranaki substations already exceed our security criteria. This is largely symptomatic of the manually switched radial interconnected architecture, where full N-1 in the switching times specified by our security classes is difficult to obtain. These constraints on security are often quite low-risk in terms of the impact on supply quality.

11.4.7.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Taranaki area are shown in Table 11.15.

Table 11.15: Taranaki constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
New Plymouth GXP	Transpower needs to exit the New Plymouth site and to upgrade the 220/110kV interconnection capability. This has implications on our subtransmission for the Moturoa substation. As Moturoa is the only substation supplied by the New Plymouth GXP, Powerco will need to secure an alternative source of supply.	Moturoa subtransmission
Carrington St GXP	N-1 transformer capacity exceeded – secondary assets. Limitations of secondary equipment mean that firm transformer capacity is exceeded.	Note-1, Moturoa subtransmission
Waitara West, Waitara East and Pohokura	An outage on the Waitara West 33kV line can overload the Waitara East circuit supplying Waitara East, Pohokura and Waitara West.	Waitara East | McKee 33kV
McKee substation (generation)	The tee connection to McKee means capacity is limited when the Huirangi to McKee section is out of service.	Waitara East | McKee 33kV
Oakura substation	The new Oakura substation is supplied by a single 33kV circuit. The 11kV backfeed does not meet the security standard.	Note 2
Eltham substation	The transformer's firm capacity and substation security have been exceeded.	Eltham transformers
Cardiff substation	The single supply transformer does not provide sufficient security. Renewal is scheduled for 2023.	Note 3
Kaponga substation	Demand exceeds secure capacity of the two transformers. Transformers are scheduled for replacement.	Note 3
Motukawa substation	The single transformer does not provide sufficient security and is scheduled for replacement.	Note 3
Waihapa substation	Transformer is scheduled for replacement.	Note 4
Oakura substation	Transformer and subtransmission line do not provide sufficient security.	Note 2
Douglas substation	Transformer does not provide sufficient security.	Note 3
Waitara West substation	Demand exceeds secure capacity of the two transformers.	Note 3
Inglewood Substation	6.6kV network. Non-standard Powerco zone substation.	Inglewood 6.6kV to 11kV conversion project

Notes:

1. Constrained by limitations of secondary equipment (not the transformers) and will be resolved by Transpower ie ODID conversion.
2. Oakura is a new N security substation. 11kV backfeeding capability will reach its limit by 2024. Oakura second transformer and second 33kV line project is addressing this issue
3. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.
4. Expenditure for this work is allowed for in the renewal forecasts, and detailed options will be considered closer to the time.

11.4.7.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Taranaki area.

MOTUROA SUBTRANSMISSION	
Estimated cost: yet to be confirmed	$9.4m
Expected project timing:	2018-2020

Transpower's New Plymouth GXP (NPL) is on land that now belongs to Port Taranaki. Port Taranaki intends to use the site for other purposes and requires Transpower to decommission and exit NPL. Our Moturoa substation is the only load connected to this GXP and will need an alternative source of supply.

To achieve the alternative supply, we are installing two new 33kV underground cables, about 6.5km each, from Carrington St GXP to Moturoa substation, and Transpower is converting the Carrington St GXP outdoor 33kV switchboard to indoor, with two new feeders for these new 33kV cables to Moturoa. In conjunction with this, Transpower is relocating the NPL interconnection site to Stratford GXP (SFD), where it will install a new 220/110kV interconnection transformer and convert the SFD-NPL 220kV circuits to 110kV for diversion to Carrington St GXP.

INGLEWOOD 6.6KV TO 11KV CONVERSION PROJECT	
Estimated cost:	$5.9m
Expected project timing:	2019-2020

The Inglewood zone substation supplies power to Inglewood township and the surrounding rural areas at 6.6kV. The substation contains two 33/6.6kV supply transformers. These two feeders are supplied as transformer feeders from Huirangi and Stratford GXPs, respectively.

As this is a non-standard Powerco zone substation, the Inglewood substation does not meet our required security and performance quality levels.

We have conducted some analysis to consider options for the Inglewood zone substation conversion. Further details are in Appendix 8.

The proposed solution is to replace all of the 6.6/0.4kV distribution transformers in the Inglewood area with dual winding transformers (11/6.6kV-0.4kV) over a 2-3 year period.

OAKURA SECOND 33KV LINE AND SECOND TRANSFORMER PROJECT	
Estimated cost:	$6.0m
Expected project timing:	2024-2027

Oakura supplies Oakura township, Okato township, which is 12km south, and surrounding rural customers – mainly dairy and farming.

Oakura's 2018 demand was 3.5MVA (1,830 ICPs) and expected demand in 2030 is 5.3MVA. The security class is AA, which requires restoration of supply within 45 minutes.

The substation contains one 7.5/10MVA 33/11kV transformer fed by one 14km long 33kV line (mostly overhead).

An 11kV backup supply is from neighbouring Moturoa substation, which would be inadequate for the demand of 2027 and beyond. A large subdivision of about 300 lots next to Oakura substation could also be developed in the next five to 10 years.

We have conducted some analysis to consider options for maintaining Oakura substation security class with future load growth. Further details are in Appendix 8.

The proposed solution is to construct a second 33kV line, of approximately 16km, from Carrington St GXP, along with the installation of a second transformer at Oakura.

EGMONT VILLAGE NEW ZONE SUBSTATION PROJECT	
Estimated cost:	$6m
Expected project timing:	2025-2028

The Mangorei 11kV voltage regulating station supplies three feeders (1,218 ICPs). Its 11kV supply is from Brooklands substation by a dedicated 11kV feeder, Brooklands-5 (1.73km underground and 3km overhead). This line is rated for 33kV operation.

Mangorei's 2018 demand was 3.6MVA and expected demand in 2030 is 4.5MVA.

At 2030 demand, the underground section of Brooklands-5 feeder would reach its limit. In addition, Mangorei's voltage regulator, which was made in 1982, would reach close to its capacity of 5MVA.

Furthermore, Mangorei regulating station is not located at the centre of the load it supplies, and voltage quality on its two feeders is approaching its acceptable limit of 95%.

We have considered several options to resolve future capacity and voltage constraint issues. Further details are in Appendix 8.

The proposed solution is to construct a new zone substation of 10MVA capacity at Egmont Village on land to be purchased. The Mangorei 33kV line is to be extended by about 6km, along Kaipi and Egmont roads, and a new 33kV Circuit Breaker (CB) is to be installed at Carrington St GXP to supply this substation. In the future, this 33kV line could be extended by 7km to join with Inglewood substation 33kV line, which would provide N-1 supply.

WHALERS GATE NEW ZONE SUBSTATION PROJECT	
Estimated cost:	$7.9M
Expected project timing:	2028-2030

Moturoa substation supplies several important loads – Port Taranaki, Taranaki Base Hospital, the Omata tank farm and Moturoa commercial area – within the western area of New Plymouth. There are about 8,900 customers supplied by this substation.

Moturoa's forecast 2030 demand is 24.3MVA. At such levels, Moturoa would exceed the 24MVA capacity of its single transformer. The demand growth is high because of new subdivisions and developments in certain areas of New Plymouth, such as Whalers Gate. In 2030, the demand on neighbouring City and Brooklands substations would also be just 4MVA less than the capacity of each of their single transformers.

The preferred solution is to establish a new zone substation to offload the existing Moturoa substation and, in the future, City and Brooklands substations. The Moturoa subtransmission project 33kV line would initially have spare capacity of 15MVA to supply this new substation.

11.4.7.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Taranaki area.

WAITARA TO MCKEE 33KV LINE

Estimated cost (concept):	$1.9m
Expected project timing:	2020

If the Waitara West line is not available during peak periods, the single 33kV Waitara East circuit from Huirangi GXP has insufficient capacity to supply all four substations – Waitara East, Waitara West, Pohokura and McKee. The tee configuration of the Waitara East/McKee lines also causes protection issues and limits power transfer levels and network security.

The proposed solution is to construct a second 33kV line from Huirangi GXP to the Waitara East substation. This will provide sufficient backup capacity to all four substations on the Waitara ring. It will also allow the Waitara East 33kV circuit to operate independently of the McKee 33kV circuit, enabling generation injection even during an outage on the Huirangi-Waitara East circuit.

ELTHAM SUBSTATION SUPPLY TRANSFORMER

Estimated cost:	$2.1m
Expected project timing:	2021

The Eltham substation supplies Eltham town, the surrounding rural areas, and two significant industrial loads. The substation contains two transformers. The demand has exceeded the secure capacity of the transformers, ie the capacity that can be supplied by one transformer plus available 11kV backfeed.

The solution is to replace the existing transformers with two larger units. This will secure the load at Eltham and provide adequate capacity for anticipated future demand. To meet the desired security, further improvements will be needed to the subtransmission and protection systems.

BELL BLOCK SUBSTATION 11KV OFFLOAD

Estimated cost:	$1.6m
Expected project timing:	2023-2025

The Bell Block substation supplies the Bell Block industrial area and the nearby residential and rural areas. The area offers flat industrial zoned sites, conveniently sited for access to the highway, port and rail at reasonable cost, so further industrial load growth is considered likely. Its security class is AAA, which requires uninterrupted supply in N-1 situation.

Bell Block's forecast 2030 demand is 24.6MVA. At such levels, Bell Block would exceed its firm capacity of 24MVA.

The solution is to offload Bell Block onto neighbouring Katere Rd substation by constructing a 4km long 11kV feeder from Katere substation.

CITY SUBSTATION SUPPLY TRANSFORMER

Estimated cost:	$2.4m
Expected project timing:	2028-2030

The City substation supplies power to New Plymouth CBD and the surrounding urban area consumers – mostly commercial and some residential. The substation contains two transformers, manufactured in 1977. Each has a continuous rating of 20.1MVA. Its security class is AAA, which requires uninterrupted supply in N-1 situation.

City substation's forecast 2030 demand of 20.3MVA would exceed its firm capacity.

The solution is to replace the existing transformers with two larger units. This will secure the load at City and provide adequate capacity for future demand.

INGLEWOOD SUBSTATION SUPPLY TRANSFORMER

Estimated cost:	$2.1m
Expected project timing:	2025-2027

The Inglewood substation supplies power to Inglewood township and the surrounding rural areas. The substation contains two 5MVA transformers.

Inglewood's forecast 2025 demand of 6.1MVA would exceed the secure capacity of the transformers, ie the capacity that can be supplied by one transformer plus available backfeed.

Inglewood's security class is AA, which requires restoration of supply within 45 minutes in N-1 situation.

The solution is to replace the existing transformers with two larger units. This will secure the load at Inglewood and provide adequate capacity for anticipated future demand.

CLOTON RD SUBSTATION SECOND DEDICATED 33KV LINE

Estimated cost:	$1.8m
Expected project timing:	2026-2028

The Cloton Rd substation supplies power to Stratford CBD and the surrounding urban and rural areas. There are 4,260 ICPs supplied by this substation and its 2018 demand was 11.2MVA.

Cloton Rd's 33kV supply is from Stratford GXP by two overhead lines – one is dedicated and the other shares partly with one 33kV line off Eltham substation. The shared 33kV line has a capacity of 16.5MVA.

Cloton Rd and Eltham's expected demand in 2025 is 11.8MVA and 10.5MVA respectively. At such levels, if there was an outage on Cloton Rd's dedicated 33kV line, the other 33kV line's shared part would exceed its capacity.

Similarly, if there was an outage on Eltham's other 33kV line, this shared part would also exceed its capacity. Both Cloton Rd and Eltham security class is AA+, which requires restoration of supply within 15 seconds in N-1 situation.

The solution is to remove the shared part by installing 4km of new 800mm^2 AL 33kV cable from Stratford GXP, along with a new 33kV CB at Stratford GXP.

CLOTON RD SUBSTATION SUPPLY TRANSFORMER	
Estimated cost:	$2.4m
Expected project timing:	2028-2030

Cloton Rd substation supplies power to Stratford CBD and the surrounding urban and rural areas. The substation contains two 10/13MVA transformers. Its security class is AA+, which requires restoration of supply within 15 seconds in N-1 situation.

Cloton Rd's forecast 2030 demand of 12.1MVA would be close to its firm capacity of 13MVA. At times, the substation supports Motukawa, a single transformer substation, which has a demand of 1.3MVA.

The solution is to replace the existing transformers with two larger units. This will secure the load at Cloton and provide adequate capacity for anticipated future demand.

MOTUKAWA 6.6KV TO 11KV CONVERSION	
Estimated cost:	$2.7m
Expected project timing:	2023-2026

Motukawa substation supplies Tarata and Ratapiko townships along with surrounding rural areas at 6.6kV. There are 420 ICPs supplied by this substation and its 2018 demand was 1.2MVA. The substation consists of a single 5MVA 33/11-6.6kV transformer.

As 6.6kV draws more current, the voltage quality on Motukawa's two feeders (Ratapiko and Tarata) is approaching the threshold of 95%.

The neighbouring Inglewood and Midhurst 6.6kV network is being converted to 11kV. Once completed, Motukawa would be the only substation operating at 6.6kV.

Motukawa's present distribution network is rated for 11kV operation.

The solution is to replace the remaining 6.6/0.415kV transformers – 130 out of 163 – with dual wound 11-6.6/0.415kV transformers and then switch the network to 11kV operation.

11.4.7.6 OTHER DEVELOPMENTS

Transpower's grid developments can have a significant impact on network development, as seen with the Moturoa proposal.

Gas-fired generation opportunities can arise. Larger generation of 30MW+ typically feeds directly into the grid, but smaller units can often be embedded in our network. These generation proposals are highly dependent on gas, oil and electricity markets, and are therefore difficult to predict in terms of location and size. Lead time is usually very short, meaning we must quickly reconsider some of our network development plans.

Taranaki has many spot-load increases driven by industrial customers, either those associated with agriculture or with the oil and gas industry. These spot-load increases have limited lead times and are unpredictable in terms of location and capacity.

At the distribution level we will continue to routinely complete lower cost feeder upgrades and, where required, install new feeders. Upgrades are often driven by the need to reinforce feeders for growth or for better performance through improved backfeeding schemes. Long rural feeders often need voltage support, which requires regulators or more permanent conductor upgrades.

The following project has been identified as being likely to occur during the planning period. The following description represents the most probable solution, but the final solution and optimal timing are subject to further analysis and will be confirmed closer to the time.

PROJECT	SOLUTIONS
Motukawa substation second transformer	The Motukawa substation consists of a single transformer. In the case of a transformer outage, it relies on its limited backfeed capability from distribution network. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. The preferred solution is to add the second transformer to the substation.

11.4.8 EGMONT

The subtransmission configuration in this area consists of ring circuits providing adequate security, except the Manaia substation, where we are looking to rectify the short section of single 33kV circuit. A new substation at Mokoia has replaced the Whareroa substation. Major and minor project spend related to growth and security during the next 10 years is $11.9m.

11.4.8.1 AREA OVERVIEW

The Egmont area covers the southern Taranaki region and is part of the South Taranaki District Council area.

The main urban areas are Hawera, Manaia, Opunake and Patea. Hawera is the largest of these and its population figures are reasonably stable. Smaller towns rely more on tourism now that their historical function of being rural service centres has been reduced. The terrain is mostly rolling open country, although there are some remote and steep back-country areas with long distribution feeders. There is reasonable access to most parts of the network.

The southern Egmont area is prone to storms off the Tasman Sea, which can impact severely on the network. As in northern Taranaki, equipment in coastal areas corrodes quickly.

Agriculture and associated support and processing industries drive the economy, with dairy a long established and strong sector. There are also large food processing operations, including Fonterra's Whareroa site and Yarrows The Bakers. Some oil and gas processing is also present.

The Egmont area is supplied from the Hawera and Opunake GXPs through two independent 33kV subtransmission systems. Opunake GXP supplies Pungarehu, Ngariki and Tasman substations through two 33kV ring circuits. Ngariki is common to both rings. Hawera GXP supplies Kapuni, Manaia, Cambria, Mokoia, and Livingstone substations.

A 33kV ring supplies Mokoia and Livingstone. A separate 33kV ring supplies Kapuni and Manaia, although Manaia has a short section of single circuit teed off the ring.

Cambria substation, which is the main substation serving Hawera township, is supplied by two dedicated 33kV oil-filled cables.

Historically, two different power companies owned the Opunake and Hawera networks. The two subtransmission networks are operated at a 50Hz frequency but with different phase angles, so they cannot be interconnected. The subtransmission and distribution networks are mainly overhead.

The major Fonterra plant at Whareroa is connected directly to the 110kV grid.

Figure 11.11: Egmont area overview

11.4.8.2 DEMAND FORECASTS

Demand forecasts for the Egmont zone substations are shown in Table 11.16.

Table 11.16: Egmont zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Cambria	AAA	17.0	15.1	16.8	17.2	17.6
Kapuni	AA+	7.0	7.5	7.4	7.3	7.2
Livingstone	A1	3.0	3.2	3.2	3.2	3.2
Manaia	AA	5.0	7.7	7.7	7.7	7.8
Mokoia	A1	3.1	4.4	4.5	4.7	4.8
Ngariki	A1	3.9	3.8	3.9	3.9	4.0
Pungarehu	A1	4.5	4.5	4.6	4.7	4.8
Tasman	AA+	6.4	7.0	7.1	7.1	7.2
Whareroa	A1	3.1	4.4	-	-	-

Major industrial customers in the area have the biggest impact on the demand forecast through occasional and largely unpredictable significant increases in demand. Apart from this, the forecast demand growth in other sectors in the Egmont area is relatively low.

As with the Taranaki area, generation proposals can also drive capacity upgrades, which tend to be unpredictable and, from a planning perspective, arise at short notice. Proposals also tend to depend on market conditions.

A number of substations already exceed our security standards. As with other areas, our development plans seek to improve our security for existing loads as well as catering for demand growth.

11.4.8.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Egmont area are shown in Table 11.17.

Table 11.17: Egmont constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hawera GXP	i) An outage on the 110kV supply circuit to the Hawera GXP can cause low voltages at the substation. ii) Supply transformer firm capacity exceeded because of bus section capacity limitations.	(i) Note 1 (ii) Note 2
Manaia substation	Section of single circuit from the tee to Manaia substation and the tee connection itself do not meet security criteria.	Manaia subtransmission
Kapuni substation	For a Kapuni 33kV circuit outage, the Manaia 33kV feeder will not, in future, supply both substations at peak demand.	Manaia subtransmission
Pungarehu substation	Demand exceeds secure capacity of the two transformers. Transformer is scheduled for replacement in 2022.	Note 3
Tasman substation	Transformer firm capacity has been exceeded. Transformer is scheduled for replacement in 2023.	Note 3
Livingstone substation	Transformer firm capacity has been exceeded. Transformer scheduled for replacement in 2018.	Note 3
Ngariki substation	Single transformer. The 11kV backfeed does not meet security criteria.	Note 4

Notes:

1. Transpower is investigating possibilities for additional reactive support for use during 110kV outages. Only constrains with no generation.
2. Capacity is limited by a bus section and can be managed operationally using the adjoining Kupe transformer in emergencies.
3. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.
4. Managed operationally.

11.4.8.4 MAJOR GROWTH AND SECURITY PROJECTS

There is one major growth and security project planned for the Egmont area.

CAMBRIA SUBSTATION 33KV LINE AND TRANSFORMER	
Estimated cost:	$4.4m
Expected project timing:	2026-2028

Cambria substation supplies the Hawera CBD and the surrounding urban and rural areas. One major industrial customer, the Hawera Freezing Plant, consumes a significant part – 4MVA – of the demand.

Cambria takes its 33kV supply from Hawera GXP by two pressurised oil cables (installed in 1968). Each cable is three-core aluminium with a cross sectional area of 0.43inch², nominally 277mm^2, and has no manufacturer's rating, but is believed to have capacity of 17MVA.

The substation contains two 12.5/17MVA transformers. Cambria security class is AAA, which requires uninterrupted supply in N-1 situation.

Cambria substation's forecast 2030 demand of 17.6MVA would exceed the capacity of its single 33kV cable and transformers.

We have conducted some analysis to consider options for maintaining Cambria substation security class with future load growth. Further details are in Appendix 8.

The solution is to replace the existing transformers with two larger units and install two 33kV cables with larger capacity cables. This will secure the load at Cambria and provide adequate capacity for future demand.

11.4.8.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Egmont area.

MANAIA SUBTRANSMISSION	
Estimated cost (concept):	$3.2m
Expected project timing:	2022-2023

Manaia substation is supplied by a short section of single 33kV circuit that tees off the Manaia-Kapuni 33kV ring. The tee connection and single circuit expose Manaia to reduced security and higher risk of outages. In addition, the capacity of the Manaia feeder is not sufficient to supply future peak demand for both Manaia and Kapuni, such as if the Hawera-Kapuni circuit is out of service.

Options considered are detailed in Appendix 8.

The proposed solution is a direct circuit between Manaia and Kapuni using a second circuit from Manaia to the tee and reconfiguring as a full ring connection.

While it may not be economically justified to upgrade the Manaia-Kapuni circuits to supply full N-1 security, we will keep options open in terms of future development. A relatively low cost thermal upgrade may be justified if demand increases more quickly than expected. The upgraded support structures on the line will be designed to accommodate a larger conductor if it is required in the future.

KAPUNI AND MANAIA SUBSTATIONS THIRD 33KV LINE	
Estimated cost (concept):	$3.1m
Expected project timing:	2024-2028

Kapuni and Manaia substations take 33kV supply from a ring network, which runs from Hawera GXP to Kapuni, Kapuni to Manaia tee-off, and Manaia tee-off to Hawera. The Manaia tee-off is a single 33kV line, which is 3.5km long. The Manaia subtransmission project, as mentioned above, will construct a second 33kV line from this tee-off point.

The security class of Kapuni and Manaia is AA+ and AA respectively.

The 33kV ring has a capacity of 15MVA in N-1 situation. This capacity is inadequate for the 2030 forecast load growth of Kapuni and Manaia substations of 7.2MVA and 7.8MVA respectively. In addition, Manaia 33kV bus voltage would drop to 89.63% in N-1 situation and Manaia transformer tap position would be just one tap above its limit.

The solution is to replace the Hawera to Manaia tee single overhead 33kV line with a double circuit overhead 33kV line, and to install the Manaia subtransmission project 33kV switchboard at the Manaia tee-off location instead of Manaia substation.

MANAIASUBSTATION SECOND TRANSFORMER	
Estimated cost:	$1.2m
Expected project timing:	2023-2025

Manaia substation supplies Manaia township, as well as surrounding rural areas. One industrial consumer, Yarrows The Bakers, takes a significant part (1.7 MVA) of its load (7.7MVA). The substation contains one 10/12.5MVA transformer.

The size and nature of the load connected to the Manaia substation is at risk from non-supply in the event of the transformer outage. Two-thirds of the substation's load can be backfed from neighbouring substations, such as Kapuni (mostly) and Tasman's 11kV network. But requires the installation of a mobile regulator, which is not readily available as the two in stock are often being used at another site.

The solution is to to install a matching second 10/12.5MVA 33/11kV transformer (option three) together with a new transformer pad and bunding.

11.4.8.6 OTHER DEVELOPMENTS

The following project has been identified as being likely to occur during the planning period. The following description represents the most probable solution, but the final solution and optimal timing are subject to further analysis and will be confirmed closer to the time.

PROJECT	SOLUTIONS
Livingstone substation supply transformers	The demand has exceeded the transformers' capacity, and there is potential for loss of supply at the substation during a transformer fault. There is also limited backfeed capability from the 11kV distribution network. The preferred solution is to replace the existing transformers with two larger units.

11.4.9 WHANGANUI

The subtransmission network architecture in Whanganui city is different to our other areas and does not easily align with our security criteria. Minor projects in the area include a second 33kV circuit to the Taupo Quay and Peat St substations. Minor project spend related to growth and security during the next 10 years is $29.1m.

11.4.9.1 AREA OVERVIEW

The Whanganui area covers the city of Whanganui and its surrounding settlements, which form the Whanganui district.

Whanganui city lies on the north-western bank of the Te Awa O Whanganui – the Whanganui River.

The small South Taranaki town of Waverley is also part of the Whanganui area.

Much of the land outside the city is rugged, hilly terrain surrounding the river valley. A large proportion of this is within the Whanganui National Park. This means that access to these regions, especially following major weather incidents, is difficult, and can result in lengthy outages for remote customers.

The Whanganui district has a temperate climate, with sunshine hours slightly higher than the national average sunshine at 2,100 hours per annum, and about 900mm of annual rainfall. The Whanganui River is prone to flooding in heavy rain.

The Whanganui area also gets hit by occasional storms off the Tasman Sea. High winds cause the main disruption as they can fell trees and throw debris into lines, which leads to widespread and prolonged outages.

The district's economy is driven by agriculture, forestry and fishing. Whanganui city is both the main service centre for the rural district and a self-sustaining commercial entity.

There are several industrial and commercial customers of significance within Whanganui city. However, none are of sufficient size to warrant a dedicated substation.

The area connects to the grid through three Transpower GXPs. Whanganui and Brunswick GXPs supply Whanganui city and surrounding areas. Waverley GXP supplies the town of Waverley.

There are nine zone substations in the Whanganui area, five of which – Blink Bonnie, Taupo Quay, Beach Rd, Hatricks Wharf and Whanganui East – are supplied from the Whanganui GXP. Peat St, Roberts Ave, Kai Iwi, Castlecliff are supplied from the Brunswick GXP. Waverley GXP directly supplies the Waverley township and surrounding areas via 11kV distribution feeders.

Whanganui has a unique and highly meshed subtransmission architecture. Most substations in the city are supplied from single radial lines, often more than two substations per 33kV feeder, but with some alternative switched 33kV capacity.

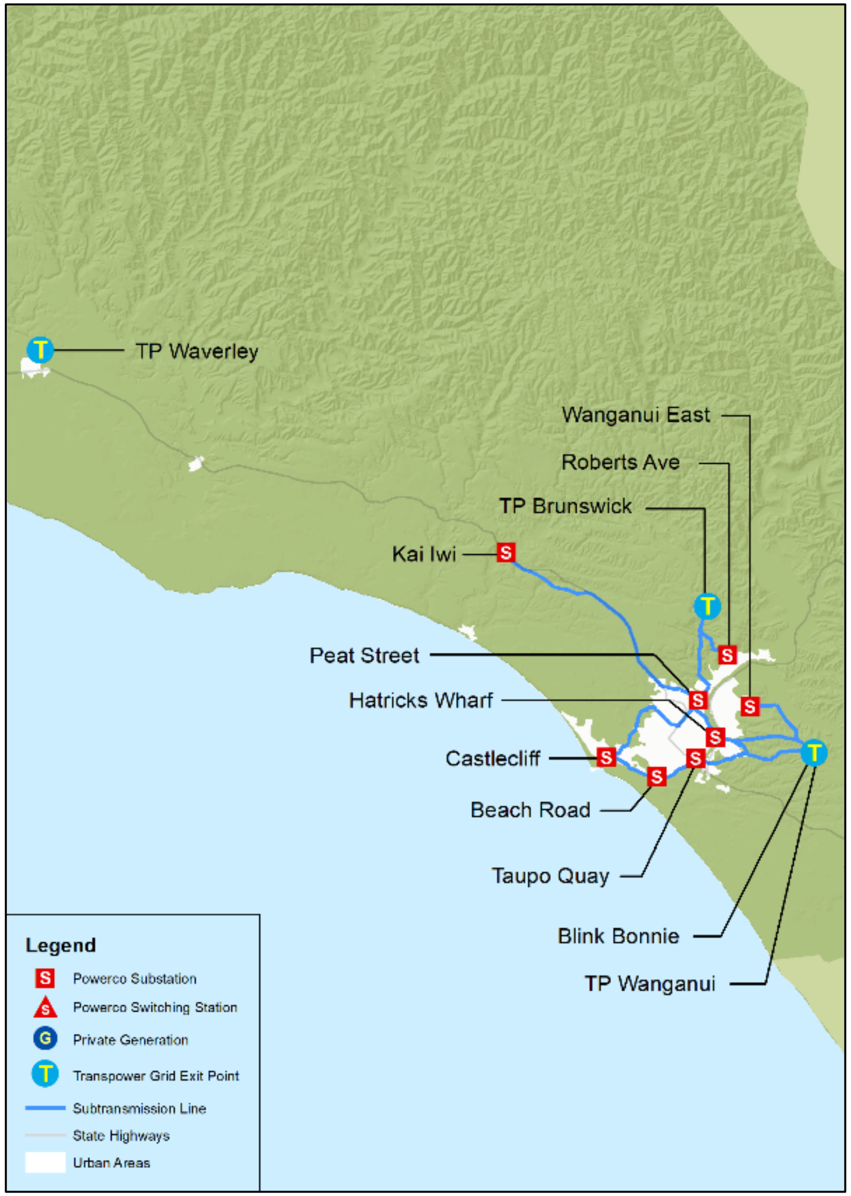
Often the alternative 33kV line is from a different GXP, complicating operations and switching. Protection systems are also a challenge.

With this architecture it is difficult to provide the breakless or quick switching required to comply with our security criteria. From a purely risk-of-supply perspective, the architecture is quite robust and cost effective.

The subtransmission and distribution networks are mainly overhead, even in most urban areas.

There are renewal project intentions to refurbish conductors, poles and river crossing towers between Whanganui GXP and Taupo Quay substations in the near term.

Figure 11.12: Whanganui area overview



11.4.9.2 DEMAND FORECASTS

Demand forecasts for the Whanganui zone substations are shown in Table 11.18, with further detail provided in Appendix 7.

Table 11.18: Whanganui zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Beach Rd	AA+	13.6	10.8	11	11.3	11.4
Blink Bonnie	A1	2.3	4.3	4.4	4.4	4.5
Castlecliff	AA+	8.7	11.3	11.5	12	12.1
Hatricks Wharf	AA+	0.0	12.9	12.9	13	13.1
Kai Iwi	A1	1.0	2.3	2.3	2.4	2.4
Peat St	AAA	0.0	18.8	19	19.5	20.1
Roberts Ave	AA	5.7	7.9	8.0	8.1	8.2
Taupo Quay	AA+	0.0	10.9	11	11	11.1
Wanganui East	AA	3.1	8.1	8.1	8.2	8.3

Recent underlying growth in demand has been modest throughout the Whanganui area. Major industrial customers can have a big impact on the demand through significant changes in load. This is in part behind the high growth rate signalled at Beach Rd in the table above.

The Springvale Structure Plan[33], if fully realised, will be expected to add up to 2-3MW of demand to the Peat St or Castlecliff substations. However, this demand increase is expected to occur over the longer term, and some of it could be perceived as being incorporated into the estimated underlying growth rates.

Growth and security plans are focused on meeting security class capacity, improving security and reliability for the existing load base, and catering for future new load. Growth and security plans need to consider the unique characteristics of the network architecture in the city.

[33] Springvale Structure Plan, Whanganui District Council, April 2012.

11.4.9.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Whanganui area are shown in Table 11.19.

Table 11.19: Whanganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Whanganui GXP	Firm capacity of the 110/33kV transformers is exceeded. Transformers are due for replacement.	Note 1
Brunswick GXP	Single 220/33kV transformer – no N-1 security.	Whanganui GXP to Taupo Quay new circuit Whanganui subtransmission reinforcement Note 6
Waverley GXP	Single 110/11kV transformer – no N-1 security.	Note 2 Waverley GXP single transformer options
Castlecliff substation	Whanganui GXP to Taupo Quay 33kV circuit: Insufficient capacity to supply Castlecliff substation when normal supply via the Brunswick GXP to Peat St and Peat St to Castlecliff 33kV circuits is unavailable.	Whanganui GXP to Taupo Quay new circuit Whanganui subtransmission reinforcement
Peat St substation	Whanganui GXP to Hatricks Wharf 33kV circuit: Insufficient capacity to supply Peat St substation when normal supply via the Brunswick GXP to Peat St 33kV circuit is unavailable. Transformer demand exceeds firm capacity: By year 2029, the firm capacity of Peat St transformers is exceeded.	Roberts Ave to Peat St 33kV circuit Hatricks Wharf to Peat St cable and conductor upgrade Whanganui to Hatricks Wharf river upgrade Upgrade both Peat St transformers
Taupo Quay substation	Whanganui GXP to Hatricks Wharf 33kV circuit: Insufficient capacity to supply Taupo Quay substation when Whanganui GXP to Taupo Quay 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay new circuit Taupo Quay to Hatricks Wharf distribution reinforcement and upgrade Hatricks transformer Whanganui GXP to Hatricks Wharf cable and conductor upgrade Taupo Quay to Beach Rd upgrade
Hatricks Wharf substation	Whanganui GXP to Taupo Quay circuit: Insufficient capacity to supply Hatricks Wharf substation when Whanganui GXP to Hatricks Wharf 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay new circuit Taupo Quay to Hatricks Wharf distribution reinforcement and upgrade Hatricks transformer
Peat St and Kai Iwi substations	Hatricks Wharf to Peat St 33kV circuit: Insufficient capacity to supply Peat St and Kai Iwi substations when Brunswick GXP to Peat St 33kV circuit is unavailable.	Roberts Ave to Peat St 33kV circuit Brunswick GXP to Roberts Ave upgrade
Beach Rd and Taupo Quay substations	Peat St to Castlecliff 33kV circuit: Insufficient capacity to supply Beach Rd and Taupo Quay substations when Whanganui GXP to Taupo 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay new circuit Taupo Quay to Beach Rd upgrade Peat St to Castlecliff cable and conductor upgrade Taupo Quay to Hatricks Wharf distribution reinforcement and upgrade Hatricks transformer
Castlecliff substation	Taupo Quay to Beach Rd 33kV circuit: Insufficient capacity to supply Castlecliff substation when normal supply via the Brunswick GXP to Peat St and Peat St to Castlecliff 33kV circuits is unavailable. Transformer demand exceeds firm capacity: By year 2029, the firm capacity of Castlecliff transformers is exceeded.	Whanganui GXP to Taupo Quay new circuit Taupo Quay to Beach Rd upgrade Upgrade both Castlecliff transformers
Beach Rd and Taupo Quay substations	Beach Rd to Castlecliff 33kV circuit: Insufficient capacity to supply Beach Rd and Taupo Quay substations when Whanganui GXP to Taupo Quay 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay new circuit Hatricks Wharf to Beach Rd new line
Beach Road substation	Taupo Quay to Beach Rd: Insufficient capacity by 2029 to supply Beach Rd and Castlecliff via Taupo Quay.	Taupo Quay to Beach Rd upgrade Hatricks Wharf to Beach Rd new line
Beach Rd and Taupo Quay substations	Brunswick GXP to Peat St 33kV circuit: Insufficient capacity to supply Beach Rd and Taupo Quay substations when Whanganui GXP to Taupo Quay 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay new circuit
Beach Road substation	Brunswick GXP outage: A Brunswick outage with a Taupo Quay constraint might require Beach Rd to be supplied from WGN GXP through Hatricks Wharf, Peat St and Castlecliff.	A new line Hatricks Wharf to Beach Rd
Roberts Ave substation	Outage on Brunswick GXP to Roberts Ave single 33kV circuit can cause a loss of supply to Roberts Ave substation.	Roberts Ave to Peat St 33kV circuit Brunswick GXP to Roberts Ave upgrade
Whanganui East substation	Outage on Whanganui GXP to Whanganui East single 33kV circuit can cause a loss of supply to Whanganui East substation.	Whanganui East substation second transformer and subtransmission supply

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Kai Iwi substation	Outage on Peat St to Kai Iwi single 33kV circuit can cause a loss of supply to Kai Iwi substation.	Kai Iwi 11kV upgrade Note 4
Roberts Ave substation	The single supply transformer does not provide sufficient security to the substation.	Roberts Ave substation second transformer
Hatricks Wharf substation	The single supply transformer does not provide sufficient security to the substation.	Hatricks Wharf to Beach Rd new line Taupo Quay to Hatricks Wharf distribution reinforcement and upgrade Hatricks transformer Note 3
Taupo Quay substation	The single supply transformer does not provide sufficient security to the substation.	Taupo Quay to Hatricks Wharf distribution reinforcement and upgrade Hatricks transformer Note 3
Whanganui East substation	The single supply transformer does not provide sufficient security to the substation.	Whanganui East substation second transformer and subtransmission supply
Blink Bonnie substation	The single supply transformer does not provide sufficient security to the substation.	Blink Bonnie second supply and transformer Note 5

Notes:

1. Transpower asset. Transpower has scheduled a renewal of the transformers in the next 10 years. Load can be transferred to Brunswick to manage the constraint.

2. Transpower assets. The N security issue of single transformer GXP was recently identified as significant risk because of the stated long lead time (33 days) for restoration of supply by Transpower.

3. Taupo Quay and Hatricks Wharf are linked by a high capacity 11kV bus tie. Hatricks Wharf can back feed Taupo Quay in the case of single transformer outage. Taupo Quay sub does not have adequate capacity to backfeed Hatricks Wharf, so the changeover scheme is on manual.

4. A second circuit to Kai Iwi was considered during options analysis, including interconnection with possible new Castlecliff circuits. These options did not prove viable. Instead we will reinforce the 11kV intertie capacity and look to advance non-network options, such as backup generation for critical sites.

5. Expenditure for this work is allowed for in the renewal forecasts, including the appropriate capacity of the replacement units.

6. Transpower is in discussion with Powerco with regards to improvement options for the N-1 security issue.

11.4.9.4 MAJOR GROWTH AND SECURITY PROJECTS

The substations in Whanganui city are supplied through a highly meshed network of essentially radial interconnected circuits. Many of the backfeeds cross GXP boundaries. Multiple substations are often fed from single circuits. The GXPs are not fully N-1 secure and rely on subtransmission backfeeds.

As is notable in the table above, circuit outages on one side of the network can expose constraints on the other side. Constraints on the same circuit can be exposed by multiple contingency scenarios, ie different line outages, and any given line outage can expose multiple constraints on different lines.

In considering network development options we had to consider multiple constraints in one overarching analysis. This essentially determined a high-level future strategy – or set of minor growth and security projects – that would address all the high-risk constraints.

11.4.9.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Whanganui area.

ROBERTS AVE TO PEAT ST 33KV CIRCUIT	
Estimated cost (concept):	$3.1m
Expected project timing:	2020-2021

This project addresses a number of development constraints but most particularly:

- Peat St is the most critical substation in Whanganui but is supplied by a single circuit, meaning security is dependent on backfeed from Wanganui GXP substations. Such cross GXP backfeed arrangements also require break-before-make changeover, which is inappropriate for a substation serving the city's CBD.
- When existing circuits from Wanganui GXP are unavailable there is insufficient capacity through Peat St to secure all substations.
- Kai Iwi is sub-fed from Peat St and loses supply when Peat St does.

Options considered are detailed in Appendix 8.

The preferred project involves the construction of a new 33kV circuit between Roberts Ave and Peat St substations and upgrading the existing 33kV circuit between Brunswick GXP and Roberts Ave substation. This option will create a secure supply to Peat St and Roberts Ave substations, enabling them to meet our security levels.

In conjunction with the Whanganui GXP to Taupo Quay new circuit project, option two will ensure that all of the key Whanganui city substations, including Taupo Quay, Hatricks Wharf, Peat St as well as Beach Rd, Castlecliff and Roberts Ave substations, will meet our required security levels.

The other option, which involves the construction of a new circuit between Brunswick GXP and Peat St substation while providing a secure supply to Peat St substation, will not resolve the security of supply issue at Roberts Ave substation. Hence this option was not favoured.

WHANGANUI GXP TO TAUPO QUAY SECOND CIRCUIT

Estimated cost (concept):	$4.3m
Expected project timing:	2018-2020

This project addresses a number of network constraints but most particularly:

- Taupo Quay and Hatricks Wharf are each fed by single 33kV circuits but the substations are in parallel at 11kV. There is insufficient capacity in either single 33kV circuit to supply both substations.
- The 33kV to Taupo Quay also supplies increasing demand at Beach Rd. This 33kV also needs to supply Castlecliff when the normal supply through Brunswick and Peat St is interrupted. The network capacity is inadequate.
- There are multiple limitations in capacity if trying to backfeed Taupo Quay through Brunswick, Peat St, Castlecliff and Beach Rd. Additional security at Taupo Quay in the form of another circuit would mean such backfeed scenarios would not be needed.
- Peat St is the most critical substation in Whanganui, but if the single 220/33kV GXP transformer at Brunswick is unavailable, Peat St and all other Brunswick load must be supplied from Wanganui GXP. Significantly greater capacity is required, especially on the Taupo Quay circuit, to enable secure supply under such contingencies.

Options considered are detailed in Appendix 8.

The proposed solution is to install an additional 33kV circuit from Whanganui GXP into Taupo Quay. This would operate in parallel with the existing circuit and vastly improve security to Taupo Quay and the dependent substations of Beach Rd and Castlecliff. Even Peat St and Hatricks Wharf would benefit. The solution also helps mitigate the risks exposed by only a single 220/33kV transformer at Brunswick GXP.

Variations to this option will be explored as more detailed analysis takes place closer to the proposed project implementation. Essentially this project sets out our development path for the whole city through establishing much greater security and capacity from the Wanganui GXP. Brunswick can then remain an N secure GXP without compromising reliability.

WHANGANUI GXP BUS B TO HATRICKS WHARF

Estimated cost:	$1.3m
Expected project timing:	2023-2025

This project addresses a particular development constraint:

At the forecast demand for 2029, during a Brunswick GXP outage, supply between Whanganui GXP and Hatricks Wharf has insufficient capacity on both direct buried cables and overhead conductor portion. This line parallels with the WGN GXP Bus A supply to Hatricks Wharf.

The solution project would upgrade capacity to above 23MVA, removing the Brunswick GXP outage scenario constraint.

The solution would be in addition to IR2922, a river crossing cable project under way in 2019 with a $750,000 budget.

An interim year commitment to dual transformers at Brunswick GXP might reduce the risk associated with this forecast constraint.

WHANGANUI GXP BUS A TO HATRICKS WHARF

Estimated cost:	$1.2m
Expected project timing:	2023-2024

This project addresses a particular development constraint:

At the forecast demand for 2029, during a Brunswick GXP outage, supply between Whanganui GXP and Hatricks Wharf has insufficient capacity on the conductor line. This line parallels with the WGN GXP Bus B supply to Hatricks Wharf.

The solution project would upgrade capacity to above 23MVA, removing the Brunswick GXP outage scenario constraint. This would be in addition to IR2922, a river crossing cable project under way in 2019 with a $750,000 budget.

An interim year commitment to dual transformers at Brunswick GXP might reduce the risk associated with this forecast constraint.

HATRICKS WHARF TO PEAT ST

Estimated cost:	$1.2m
Expected project timing:	2023-2024

Hatricks Wharf is centrally located on the subtransmission ring between Brunswick and Whanganui GXP stations. This centrality requires Hatricks to provide bi-directional high capacity lines to Peat St, Whanganui and Taupo Quay.

This project addresses a particular development constraint:

At the forecast demand for 2029, during a Brunswick GXP outage, supply between Hatricks Wharf and Peat St becomes over-loaded on both 630mm cable and conductor portion.

The solution project would upgrade cable and conductor capacity to a minimum 32MVA, providing sufficient contingent capacity to the steadily growing Peat St substation demand.

An interim year commitment to dual transformers at Brunswick GXP would not impact this project, since a commensurate demand reverse supply from Peat St to Hatricks Wharf is also required during a Whanganui GXP constraint.

PEAT ST TO CASTLECLIFF

Estimated project cost:	$1.8m
Expected project timing:	2024-2026

This project addresses a particular development constraint:

Taupo Quay subtransmission forms part of the Peat St, Beach Rd, Castlecliff and Hatricks Wharf ring. At year 2029, forecast demand outage modelling of a malfunction of the Taupo to Beach Rd conductor shows the alternative Peat St to Castlecliff ring loading above rating on both cable and conductor.

The solution project would involve upgrading both the cable and conductor to minimum 24MVA, allowing supply of Castlecliff and Beach Rd substations at forecast demand levels.

WGN GXP TO WHANGANUI EAST

Estimated cost:	$3.0m
Expected project timing:	2027-2029

The Whanganui East substation supplies the residential area on the eastern side of the Whanganui River and rural area to the east of Whanganui City. A security level of AA is intended because of the type of load the substation supplies.

This project addresses a particular development constraint:

The substation is supplied by one single 33kV circuit from Whanganui GXP (N security) and contains one supply transformer. There is potential for loss of supply at the substation for a transformer or subtransmission fault, with limited backfeed capability from the distribution network.

The solution project would involve installing a second subtransmission circuit and a second 17MVA transformer at the substation, improving the substation's security. The supply point of a second circuit would be determined during the concept design stage, with two options visible at present.

Alternatives such as increased 11kV backfeed capability would be costly because of available transfer capacity, even with substantial distribution upgrade.

PEAT ST TRANSFORMER

Estimated project cost:	$3.1m
Expected project timing:	2025-2027

Modelled forecast demand at Peat St past 2029 shows an outage of one transformer could bring the duty close to 100% loading, if growth increases marginally above forecast demand. There is potential for 10/12.5/20MVA Tx loaded to 20.1MVA during a single transformer outage event. There exists a requirement to maintain AAA security class.

The solution project would be to upgrade both Peat St transformers to a capacity that allows substation demand growth beyond 20MVA and firm capacity well beyond 20MVA. The preliminary suggestion is two 30MVA transformers, noting this capacity is beyond the normal Powerco materials range. The project is planned as a contingent for increased growth in demand, reflecting the criticality of this substation to the region.

TAUPO QUAY TRANSFORMER OUTAGE INCLUDING HATRICKS TX UPGRADE

Estimated cost:	$2.6m
Expected project timing:	2023-2025

This project addresses a particular development constraint:

Under a Taupo Quay transformer outage at year 2029 demand forecasts, supply must be sourced through a Hatricks Wharf distribution interconnect. Under this scenario, line loading of the distribution cable is nearing maximum capacity rating and the single Hatricks Wharf transformer exceeds capacity.

Additionally, the conductor portion of converged Whanganui cables, before the river crossing portion, sees demand well above rating. This is to be upgraded under a separate listed project, or supply could be via Brunswick GXP.

The solution project would involve upgrading the interconnecting distribution cable, supplying side conductor and potentially Hatricks Wharf transformer capacity to well above 26MVA to allow for growth.

CASTLECLIFF TRANSFORMERS

Estimated cost:	$2.3m
Expected project timing:	2024-2026

This project addresses a particular development constraint:

Modelled forecast demand for Castlecliff substation at 2029, shows that an outage of one transformer will overload the other under normal configuration. The 10MVA transformer would be loaded to above 12MVA during a single outage event. There exists a requirement to maintain AA+ security class.

The solution project would involve upgrading both transformers to provide firm capacity well above 10MVA, factoring for future growth. A suggested solution would be installing two 17MVA transformers, although exact rating will be decided during the conceptual design phase.

There might be an opportunity to re-use 15MVA transformers from the Kelvin Grove upgrade, condition assessment pending. This would help with cost control.

BRUNSWICK TO ROBERTS AVE CABLE

Estimated cost:	$1.2m
Expected project timing:	2024-2026

This project addresses a particular development constraint:

Supply to Peat St from Brunswick GXP is constrained upon an outage of the 5.49km direct path conductor.

There is a 2019 project delivering a new large capacity cable between Roberts Ave and Peat St substations, which will provide an alternative supply path in the event of malfunction of the main direct conductor.

As demand grows at each of the substations on the Brunswick and Whanganui GXP subtransmission ring, there becomes the requirement to increase capacity between Brunswick GXP and Roberts Ave substations. This would ensure adequate alternative path capacity between Brunswick GXP and Peat St, and substations beyond.

The solution project involves a cable upgrade for the 3.55km conductor between Brunswick GXP and Roberts Ave substation, ensuring adequate contingent supply through Roberts Ave.

ROBERTS AVENUE UPGRADE AND SECOND TRANSFORMER

Estimated cost:	$2.1m
Expected project timing:	2027-2029

The Roberts Ave substation is situated in Aramoho, supplying the Aramoho industrial area and surrounding residential and rural areas.

The substation is supplied by one single 33kV circuit from the Brunswick GXP (N security) and contains one supply transformer.

This project addresses a particular development constraint:

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. There is also limited backfeed capability from the distribution network. The Roberts Ave substation does not meet our required security level.

The solution project would involve installing larger transformers in the substation, improving the substation's security level.

Alternatives such as increased 11kV backfeed would be costly as there is not adequate transfer capacity.

BLINK BONNIE SECOND SUPPLY AND TRANSFORMER

Estimated cost:	$1.7m
Expected project timing:	2028-2030

The Blink Bonnie substation is situated to the east of Whanganui city, adjacent to Transpower's Whanganui GXP. It supplies the rural loads to the south of Whanganui.

This project addresses particular development constraints:

The substation contains a single supply transformer and has N-1 subtransmission switching capability. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from the distribution network.

Because of these constraints, the Blink Bonnie substation does not meet our required security level.

The solution project would be to install a second supply transformer at the substation. This would improve the security level at the substation.

Alternatives such as increased 11kV backfeed would be costly as there is not adequate transfer capacity.

KAI IWI 11KV UPGRADE

Estimated cost:	$1.5m
Expected project timing:	2030

This project addresses particular development constraints:

The Kai Iwi substation is situated northwest of Whanganui. It supplies the Whanganui city water pumping station and the residential area on the east side of the Whanganui River, and rural area to the east of Whanganui. Kai Iwi's security level is A2. Its 11kV backup supply is not adequate for the supply of the substation load, in particular for starting the pumps at the city water supply.

The substation is supplied by one single 33kV circuit from the Peat St substation (N security) and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault.

Because of these constraints, the Kai Iwi substation does not meet our required security level.

The solution project would increase 11kV backfeed through distribution. Because of the long length and high impedance of the conductors, an upgrade to 22kV could be cost effective so remains an option. Alternatively, installing the second subtransmission supply and transformer for the substation would be costly as the substation location is quite remote.

HATRICKS WHARF TO BEACH RD NEW LINE

Estimated cost:	$2.1m
Expected project timing:	2028-2030

This project addresses a particular development limitation:

The existing ring from WGN to BRK encompasses Taupo Quay, Beach Rd, Castlecliff and Peat St substations. This leaves two options for supplying Castlecliff and Beach Rd, one of which heavily loads the main supply lines out of WGN GXP. Supply from Brunswick GXP to Beach Rd, under select scenarios, must pass through Roberts Ave, Peat St, then Castlecliff or Hatricks Wharf and Taupo Quay.

A solution project for a new line between Beach Rd and Hatricks Wharf would provide a more direct route supply option via advancement towards a meshed configuration.

11.4.9.6 OTHER DEVELOPMENTS

Transpower is replacing the 33kV switchboard at Whanganui GXP and has proposed to replace the 110/33kV supply transformers. The capacity of the new units will be determined by considering the future load growth and the need to support Brunswick GXP.

The cross GXP subtransmission backfeeds and meshed nature of the network mean good protection and automation is required, which in turn relies on good communication links. We have recently upgraded these through direct microwave links. The proposed new subtransmission projects will offer more opportunities to improve the communication systems by the installation of fibre cables on some key communication links.

Other proposed projects are listed in the following table.

PROJECT	SOLUTIONS
Taupo Quay to Beach Rd	Taupo Quay subtransmission forms part of the Peat St, Beach Rd, Castlecliff and Hatricks Wharf ring. Taupo Quay can supply Beach Rd. Forecast modelling of a Brunswick GXP outage in 2029 shows this interconnect line loading at 80% rated for the cable and exceeding conductor rating. The solution project would involve upgrading both the cable and conductor to 35MVA, enabling cable and conductor loadings to remain within 65% capacity rated during a Brunswick GXP outage. An interim, year commitment to dual transformers at Brunswick GXP might reduce the risk associated with this forecast constraint
Whanganui GXP to Hatrick's Wharf River Portion	Both Bus A and Bus B supply lines from Whanganui GXP to Hatricks Wharf, converge to a river crossing. Under a Brunswick GXP outage at year 2029 demand forecasts, this river crossing portion of supply line is loaded beyond rating. The solution project for the underground portion is a project under way in 2019. The solution for the conductor portion is to upgrade to a large capacity underground cable, allowing full utilisation of the parallel Bus A and Bus B lines, all the way to Hatricks Wharf substation.

11.4.10 RANGITIKEI

Rangitikei has low historical and forecast growth. Other than the Taihape substation, our substations in the area are supplied by single circuits and do not strictly meet our security criteria. Major and minor project spend related to security during the next 10 years is $12.9m.

11.4.10.1 AREA OVERVIEW

The area covers towns in the Rangitikei district, including Bulls and Marton, and follows the state highway up to Hunterville and Mangaweka. It also includes the towns of Waiouru, Taihape and Raetihi, and the surrounding rural areas.

The terrain is varied with rolling country in Rangitikei changing to more rugged, mountainous terrain in the Ruapehu area where the central plateau and mountains of the Tongariro National Park dominate.

The climate in this region ranges from temperate in the Rangitikei district to sub-alpine in the Ruapehu district. Snow can settle in places over 400m above sea level, such as Raetihi, Waiouru and Taihape. Extreme weather occurs frequently and has a widespread impact on the network, making it difficult to access faults.

The Rangitikei economy is based on primary production and downstream processing. In the Ruapehu district, tourism and primary production drive the economy. Ohakune, with its proximity to the world heritage area of the Tongariro National Park, attracts many visitors for outdoor activities, such as skiing.

Taihape, Marton and Bulls are significant urban centres in the Rangitikei district. Waiouru is dominated by a large armed forces camp.

The Rangitikei area is connected to the grid through Marton, Mataroa and Ohakune GXPs. Both Mataroa and Ohakune GXPs have only a single offtake transformer.

From Mataroa GXP, two 33kV lines supply Taihape substation, while a single 33kV overhead line serves Waiouru. Ohakune is a shared GXP and supplies directly at 11kV.

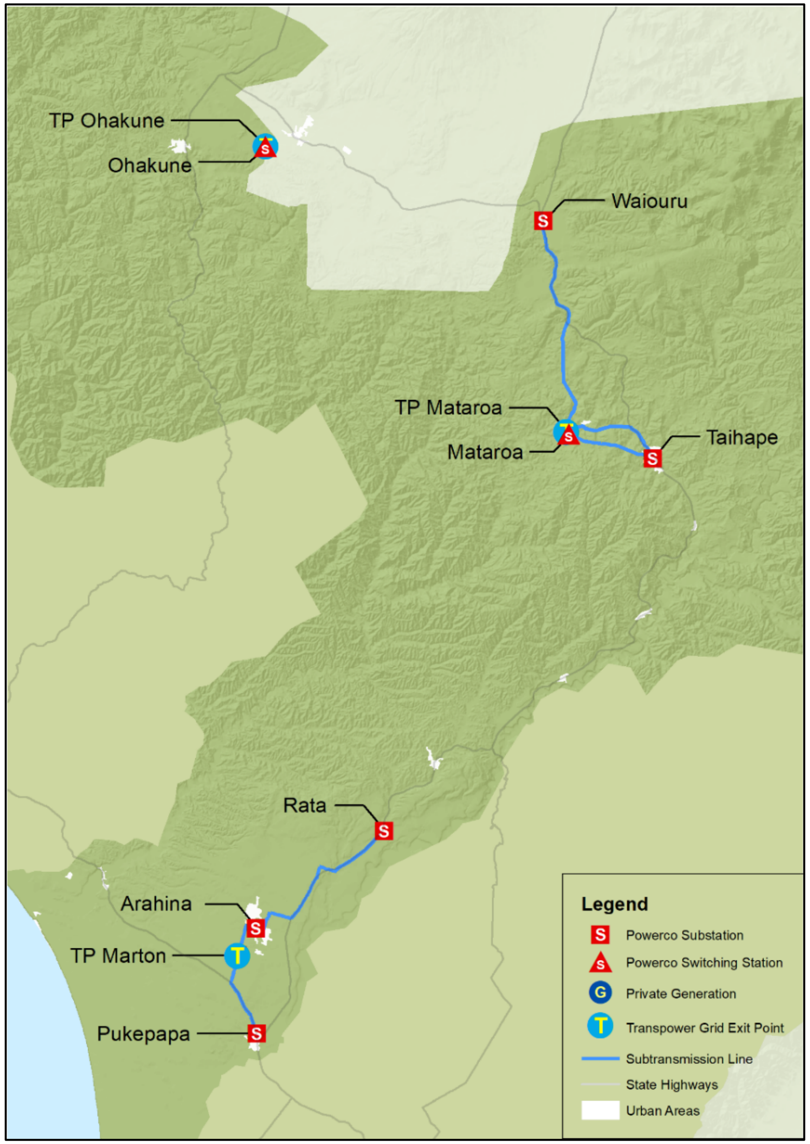
Marton GXP supplies Pukepapa, Arahina, Rata and Bulls substations through radial 33kV overhead lines. Pukepapa substation is directly beside Marton GXP. Arahina substation supplies the Marton township. Rata is sub-fed from Arahina through a single 33kV line and services the upper Rangitikei area around Hunterville.

There is little or no interconnection at 33kV. The subtransmission and distribution circuits are almost exclusively overhead, with long lines and sparse connections reflecting the highly rural nature of the area. Loads and conductors are generally quite small. Voltage constraints are generally more significant than thermal capacity constraints.

Between Pukepapa and Rata there is a 22kV distribution tie that serves as a backup for Rata. The 22kV operating voltage helps mitigate voltage drop over the long distances. Isolating and restoring the network after a fault can be challenging and often time-consuming.

Switching points and lines can be hard to access, and there are very limited backfeed opportunities, especially on long spur lines.

Figure 11.13: Rangitikei area overview



11.4.10.2 DEMAND FORECASTS

Demand forecasts for the Rangitikei zone substations are shown in Table 11.20, with further detail provided in Appendix 7.

Table 11.20: Rangitikei zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Arahina	AA	2.9	8.6	8.7	8.8	8.9
Bulls	AA	4.0	5.5	5.5	5.5	5.6
Pukepapa	A1	3.4	4.4	4.4	4.5	4.6
Rata	A1	0.7	2.9	2.9	2.9	2.9
Taihape	A1	0.7	4.9	4.9	4.9	4.9
Waiouru	A1	0.6	2.9	2.9	2.9	2.9

Growth in the Rangitikei area has historically been low. These are mature rural communities with a relatively static electricity requirement. A step change in demand is anticipated to occur through conversion of generator supplied irrigation loads to mains network supply in the Parewanui region.

As with other rural parts of our network, a lot of substations do not meet our security criteria, even with existing load. Therefore our growth and security plans are focused on improving security and reliability for existing customers, rather than catering for growth.

11.4.10.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Rangitikei area are shown in Table 11.21.

Table 11.21: Rangitikei constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Mataroa GXP	The single supply transformer does not provide sufficient security to the substation.	Note 1 Mataroa GXP single transformer
Ohakune GXP	The single supply transformer does not provide sufficient security to the substation.	Note 1
Parewanui and Lake Alice feeders	Heavily loaded feeders have limited backfeed and high growth because of irrigation.	Lake Alice zone substation
Waiouru substation	Outage on single Mataroa GXP to Waiouru 33kV circuit will cause loss of supply to Waiouru substation.	Waiouru 11kV upgrade Note 2
Waiouru substation	The single supply transformer does not provide sufficient security to the substation.	Waiouru 11kV upgrade Note 2
Taihape substation	Mataroa GXP to Taihape 33kV circuits: Old manually operated switchgear limits parallel operation so security to substation is not met.	Note 3
Taihape substation	The single supply transformer does not provide sufficient security to the substation.	Taihape substation second transformer
Marton GXP	Firm capacity for 110/33kV supply transformers is exceeded. Low supply voltages for outage of one supply transformer.	Note 4
Arahina and Rata substations	Outage on singe Marton GXP to Arahina 33kV single circuit will cause loss of supply to Arahina and Rata substations.	Arahina substation second transformer and subtransmission supply
Arahina substation	The single supply transformer does not provide sufficient security to the substation.	Arahina substation second transformer and subtransmission supply
Rata substation	The single supply transformer does not provide sufficient security to the substation.	Rata 11kV upgrade
Bulls substation	Outage on Marton GXP to Bulls single 33kV circuit will cause loss of supply at Bulls substation.	Bulls substation second transformer Note 5
Bulls substation	The single transformer does not provide sufficient security to the substation. Renewal transformer replacement (scheduled for 2023).	Bulls substation second transformer
Pukepapa substation	The single supply transformer does not provide sufficient security to the substation.	Pukepapa substation second transformer

Notes:

1. Transpower assets. The N security issue of single transformer GXP was recently identified as a significant risk because of the stated long lead time (33 days) for restoration of supply by Transpower. Mataroa TX is approaching end-of-life.

2. N-1 for 33kV circuits or zone transformers are not economic. Options to improve 11kV backfeed will be considered under routine planning.

3. These constraints will be addressed through the fleet renewal planning process.

4. Transpower asset. Auxiliary components are the limitation. Transformers are due for renewal soon. Other projects (Sanson-Bulls) may drive upgrade sooner.

5. Options to improve Sanson security may also bring improvements to Bulls, via a new Sanson-Bulls tie line (refer to option discussion under section 11.4.11).

11.4.10.4 MAJOR GROWTH AND SECURITY PROJECTS

Although there are numerous issues – sections of network that do not strictly meet our security standards – they are all relatively low risk.

Many are related to single zone substation transformers, for which the probability of failure is low and is mitigated by 11kV backfeed capability. Single circuits expose consumer loads to a higher probability of outage, but restoration times are generally reasonable given the network is all overhead.

The network architecture is a reflection of the small loads involved and widely dispersed connections. The cost of improvements to fully comply with the security standards can rarely be justified. As such, there are no major growth and security projects planned on the subtransmission or zone substations during the planning period.

Under our renewal programme we plan to replace the transformers at Bulls and Arahina and the switchgear at Arahina, Pukepapa and Rata.

A project in the Palmerston North area will improve security to Bulls. This project proposes a 33kV interconnection between Bulls and Sanson substations. Refer to section 11.4.11 for further details.

11.4.10.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Rangitikei area.

BULLS SECOND TRANSFORMER	
Estimated cost:	$1.4m
Expected project timing:	2024-2026

The Bulls substation supplies Bulls township, some large industrial customers and its surrounding rural areas.

The substation is supplied by one single 33kV circuit from the Marton GXP (N security) and contains one supply transformer.

This project addresses particular development constraints:

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault.

Bulls is supplied by a 10/12.5MVA transformer. Security class is AA. This substation has difficulty backfeeding across the 11kV for a subtransmission outage.

At year 2029, forecast modelling shows the single transformer at only 47% loading.

This project initiative is intended to improve operational flexibility and security, with resultant improved access for any future maintenance and feeder reliability works.

The project expands the 33kV and 11kV switchgear to install a refurbished second-hand Whanganui East transformer, which will be available late FY19. The addition of this second transformer would ensure full AA security across incomers and transformers.

NEW SUBSTATION LAKE ALICE	
Estimated cost:	$3.0m
Expected project timing:	2023-2026

Bulls and Pukepapa substations supply both residential and commercial customers, via Parewanui and Lake Alice feeders respectively.

This project addresses a particular development constraint:

Demand is approaching voltage support limits on these feeders, but there are still customer load increase requests being submitted for approval.

Significant backbone conductor upgrades would have an impact on SAIDI targets and would likely not provide the step change required.

Discussions have been ongoing for some time with local large irrigators, regarding the prospect of transferring their generator loads onto the main network. Successful conversion would mean a MW scale step change of demand on both feeders.

Some subtransmission extension preparatory work has already been completed along the Lake Alice feeder, in the form of overbuilt line, although this has not been extended back to a substation yet.

The solution project is for a new substation at the end of Lake Alice feeder that will supply potential irrigation conversions from gensets. Since Bulls has more subtransmission spare incomer capacity than Pukepapa, the 33kV supply for the new substation would come from Bulls substation, although it technically could be either Bulls or Pukepapa.

An accompanying project is an interim cable intertie between feeders, plus some hardware installed for future operational segregations.

ARAHINA SECOND SUBTRANSMISSION AND TRANSFORMER	
Estimated cost:	$3.0m
Expected project timing:	2027-2029

The Arahina substation supplies urban and rural loads. It has a security class of A1 but AA is intended.

The substation is supplied by one single 33kV circuit from Marton GXP (N security) and contains one supply transformer.

This project addresses particular development constraints:

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault. A fault on Arahina subtransmission supply will result in an outage on Rata substation as well. There is also limited backfeed capability from the distribution network.

Because of these constraints, the Arahina substation does not meet our required security level.

The solution is to install a second subtransmission supply and transformer at the substation. This will improve the security level.

Alternatives such as increased backfeed would be costly as there is no adequate transfer capacity, even with substantial distribution upgrade.

PUKEPAPA SECOND TRANSFORMER

Estimated cost:	$1.4m
Expected project timing:	2027-2029

The Pukepapa substation is adjacent to Transpower's Marton GXP and supplies Marton's surrounding rural residential and irrigational loads. It is the main backup supply for the Arahina substation and, to a lesser extent, the Bulls substation. Its security level is A1, although demand is forecast to approach 5MW after 2030.

This project addresses particular development constraints:

The substation contains a single supply transformer and has N-1 subtransmission switching capability. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer fault. There is also limited backfeed capability from distribution network.

Because of these constraints, the Pukepapa substation does not meet our required security level.

The solution project would involve installing a second transformer at the substation. This would improve the security level.

Alternatives such as increased 11kV backfeed would be costly as there is no adequate transfer capacity.

RATA 11KV UPGRADE

Estimated cost:	$1.5m
Expected project timing:	2029

The Rata substation supplies Hunterville town and the surrounding rural areas. Most of its distribution network is at 22kV.

The substation is supplied by one single 33kV circuit from the Arahina substation (N security) and contains one supply transformer.

This project addresses a particular development constraint:

The demand has exceeded class capacity, sustained at nearly 3MVA, and there is potential for loss of supply at the substation during a transformer or sub transmission fault.

Because of these constraints, the Rata substation does not meet our required security level.

The solution is to increase backfeed through distribution. This will improve the security level.

Installing a second subtransmission supply and transformer for the substation would be costly as the substation location is quite remote.

TAIHAPE SECOND TRANSFORMER

Estimated cost:	$1.4m
Expected project timing:	2027-2029

The Taihape substation supplies Taihape township's urban and rural load.

The substation contains a single supply transformer and has N-1 subtransmission switching capability.

This project addresses particular development constraints:

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer fault. There is also limited backfeed capability from distribution network.

Because of these constraints, the Taihape substation does not meet our required security level.

The solution project would involve installing a second transformer at the substation. This would improve the security level.

Alternatives, such as increased 11kV backfeed, would be costly as there is no adequate transfer capacity.

WAIOURU 11KV UPGRADE

Estimated cost:	$1.5m
Expected project timing:	2028

The Waiouru substation is situated just south of Waiouru. It supplies the Waiouru Military camp and the surrounding rural areas.

The substation is supplied by one single 33kV circuit from Mataroa GXP (N security) and contains one supply transformer.

This project addresses particular development constraints:

The demand has exceeded the class capacity, sustaining about 2.9MVA, and there is potential for loss of supply at the substation during a transformer or subtransmission fault.

Because of these constraints, the Waiouru substation does not meet our required security level.

This solution project increases the 11kV distribution backfeed capability. Because of the long lengths and high impedances of the conductors, upgrades to 22kV could be a good cost-effective option.

Installing a second subtransmission supply and transformer for the substation would be costly.

11.4.10.6 OTHER DEVELOPMENTS

We will continue to monitor distribution feeder loading and voltages, and schedule any upgrades needed for growth. We will also focus on improving existing reliability, especially through backfeeding and automation. This can require increased capacity of tie circuits.

To improve security performance, even if not fully meeting our standards, increased substation intertie capacity is being investigated for Waiouru, Bulls, Arahina and Rata substations.

We will also monitor possible irrigation developments, especially in the Parewanui region. We are working towards a long-term development strategy that would enable us to construct a Parewanui substation if required. In the interim, we will build a distribution feeder from Bulls. This feeder will operate at 11kV but will be capable of uprating to 33kV if a new substation is required.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Mataroa GXP single transformer	The Mataroa GXP supplies two zone substations, Taihape and Waiouru. These areas are sparsely populated with long, high impedance conductors, and very low capacity backfeeds from other substation feeders. The preferred solution is to deploy a mobile substation for outage periods, and to provide 33kV supply from 110kV.
Ohakune GXP single transformer	The failure of the single GXP transformer could result in outages of up to a month if Transpower's mobile substation was not available. The preferred solution is mobilisation of a mobile 110/33kV substation.
Parewanui zone substation	The Parewanui and Lake Alice areas are supplied by the Bulls and Pukepapa substations via 11kV feeders. The strong growth in this area signals that these feeders will reach their capacity in the future. The preferred solution is to construct a new Parewanui zone substation at the corner of Parewanui and Forest roads.
Waiouru substation security upgrade	The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault. The preferred solution is to increase the backfeed capacity via the 11kV network.
Taihape substation second transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.
Arahina substation second transformer and subtransmission supply	The substation is supplied by one single 33kV circuit from Marton GXP (N security) and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault. The solution is to install a second subtransmission supply and transformer at the substation.
Rata substation security upgrade	The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault. The preferred solution is to increase the backfeed capacity via the 11kV network.
Bulls substation second transformer	The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault. The preferred solution is to install a second transformer.
Pukepapa substation second transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.

11.4.11 MANAWATU

Palmerston North CBD has a meshed network supplied from two high capacity GXPs and uses several 33kV underground oil-filled cables. Some of our transformers at the CBD substations, and the 33kV cables feeding these, have exceeded, or are approaching, their secure capacity.

The largest single growth and security project planned involves building two new 33kV circuits and a new inner-city substation at Ferguson St, with a total estimated cost of $27.4m. There are also a number of other projects planned to upgrade the transformers in existing substations.

Major and minor project spend related to growth and security during the next 10 years is $46.9m.

11.4.11.1 AREA OVERVIEW

The Manawatu area is dominated by the city of Palmerston North, but also includes Feilding and smaller inland and coastal settlements and surrounding rural areas.

Palmerston North city and surrounding areas to the north and west lie on the Manawatu plains.

More rugged, hilly terrain is found to the east of Palmerston North on the Tararua Range and to the northeast on the Ruahine Range. The Palmerston North area has a temperate but windy climate, with consistent wind in the Tararua and Ruahine ranges. Network equipment close to the sea is prone to corrosion.

Wind generation is a major feature in the Manawatu area with three major wind farms to the east of Palmerston North. Tararua Wind Farm has two generation sources feeding into our network at 33kV and has a significant impact on protection and operation of the 33kV network.

Access of the area for fault repair and maintenance is good, especially on the Manawatu plains.

Primary production, such as dairying, is significant to the local economy, although less dominant than in other planning areas.

Palmerston North is the economic hub of the area. The city has had steady growth, with areas such as Kelvin Grove, Kairanga and Summerhill popular for residential development. Further development in these locations is noted in local council planning documents.

Industry and commerce are also strong in the city. The North East Industrial area recognises Palmerston North's position as a transport and warehouse hub – the city being centrally located with immediate access to major transport facilities. In recent times the CBD has had a relatively high growth rate. This is expected to continue given the city's popularity, size and the considerable distance to the next major commercial centres.

Two of New Zealand's major military bases are also in the Manawatu area – the Royal New Zealand Air Force Ohakea base (near Sanson), and the New Zealand Army Linton Military Camp (south of Palmerston North).

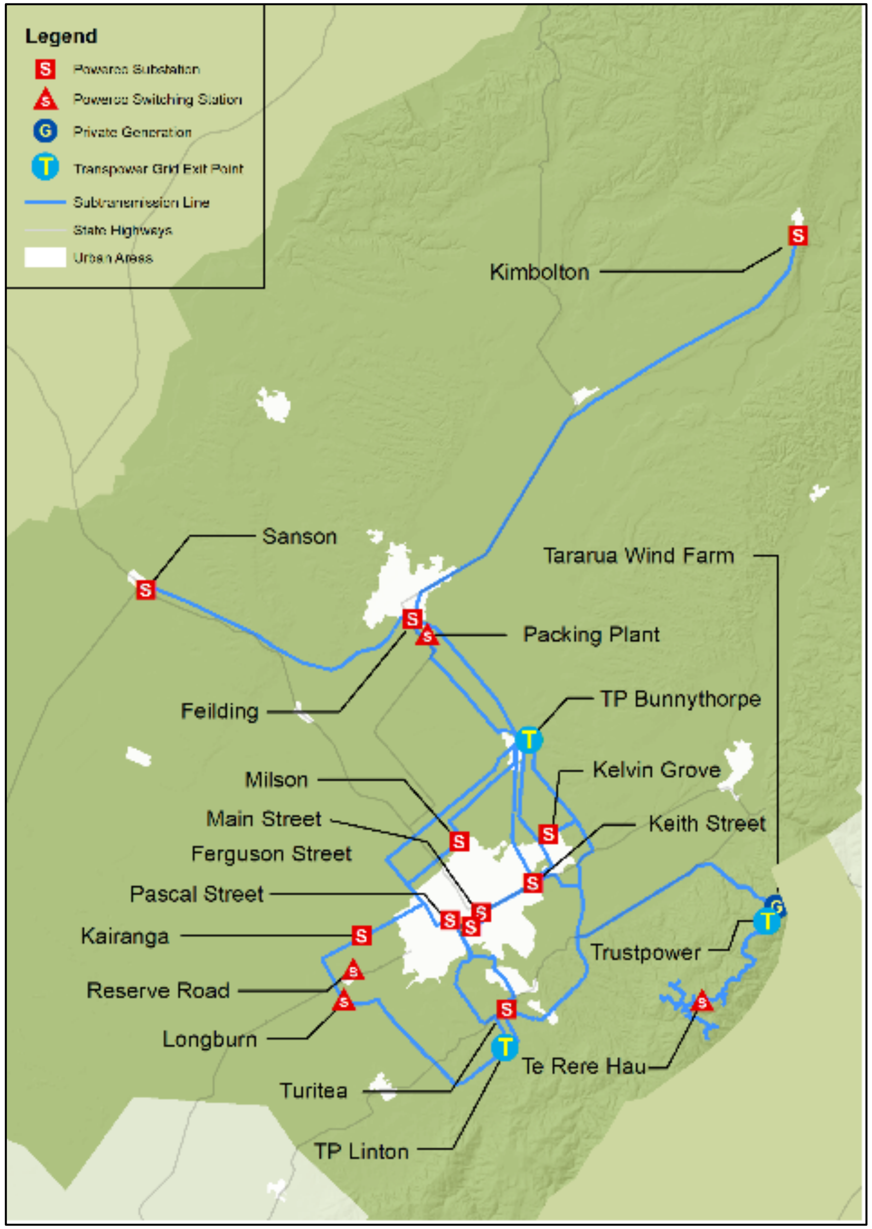
The Massey University complex and associated research centres are also significant contributors to the city's vitality. The Manawatu area is connected to the grid through the Bunnythorpe and Linton GXP substations. Bunnythorpe GXP supplies seven zone substations – Keith St, Kelvin Gr, Main St, Milson, Feilding, Kimbolton and Sanson. The Linton GXP supplies three zone substations – Kairanga, Pascal St and Turitea. Both subtransmission networks supplied by these GXPs have 34MW generation feed from the Tararua Wind Farm.

The subtransmission and distribution networks in the rural areas are mainly overhead. Within Palmerston North city there are some overhead lines, but predominantly circuits are underground.

The 33kV subtransmission network is mostly meshed. The two subtransmission networks from each GXP are operated independently but can be interconnected at several points across the city. City substations generally have full N-1 circuits in either twin circuit or ring circuit configurations. Some ring connections are open because of protection issues or they cross GXP boundaries. The two rural substations, Kimbolton and Sanson, are on single radial spurs.

The 11kV distribution in the city is mainly underground cable, which is a legacy of earlier local council objectives. The network operates independent feeders with multiple manually switched open points to other feeders, ie interconnected radial. One unique feature in Palmerston North is the legacy of tapered capacity, where feeders reduce in capacity from the substation out to the extremities. This can severely limit backfeed and protection settings. We have been addressing this through a consolidated upgrade programme.

Figure 11.14: Manawatu area overview



11.4.11.2 DEMAND FORECASTS

Demand forecasts for the Manawatu zone substations are shown in Table 11.22, with further detail provided in Appendix 7.

Table 11.22: Manawatu zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Feilding	AAA	23.7	22.5	23.5	24.6	25.7
Ferguson	AAA	N/A	-	11.8	12.0	12.2
Kairanga	AAA	19.1	19.2	19.7	20.2	20.7
Keith St	AAA	21.9	19.2	19.6	20.0	20.5
Kelvin Grove	AAA	17.2	19.6	21.7	23.8	25.9
Kimbolton	A1	1.4	2.9	2.9	3.0	3.0
Main St	AAA	17.0	26.8	22.9	23.6	24.2
Milson	AAA	18.1	18.6	20.0	21.3	22.7
Pascal St	AAA	17.0	23.1	16.3	16.6	17.0
Sanson	AA+	0.0	9.1	9.5	10.0	10.4
Turitea	AAA	0.0	16.1	17.2	18.3	19.4

Palmerston North city has had steady growth throughout the past decade, reflecting its importance as a major central North Island city. The growth outlook for the CBD and commercial centre is strong.

The North East Industrial area has been planned as a transport and warehouse hub because of its strategic location in the national transport infrastructure. While initial demand has been modest, we need to plan for the eventual full scale development.

The council's urban development planning anticipates strong residential growth on the southern side of the city around Kairanga. Kelvin Grove is also expected to continue following recent historical growth trends. Summerhill and Massey have also been popular areas for residential and lifestyle development and more expansion is expected, within the bounds of land availability and zoning.

Massey University, the research centre and the Linton and Ohakea defence force bases are significant large capacity customers. We maintain contact with them to ensure the best possible planning of security and supply. It was suggested that the armed forces may consolidate at Ohakea, but that is yet to be decided.

Demand from rural customers has been relatively static, other than in areas where irrigation may develop. Oroua Downs is one area we are monitoring closely as it has the potential to impact on proposed growth and security projects.

11.4.11.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Manawatu area are set out in Table 11.23

Table 11.23: Manawatu constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Bunnythorpe GXP	Firm capacity of the GXP transformers has been exceeded.	Palmerston North CBD
Keith St, Kelvin Gr and Main St substations	The N-1 capacity of the 33kV Keith St and Kelvin Gr subtransmission circuits is exceeded.	Palmerston North CBD
Feilding, Sanson and Kimbolton substations	The N-1 capacity of the two 33kV Bunnythorpe-Feilding circuits has been exceeded.	Sanson-Bulls 33kV
Sanson substation	Single circuit from Feilding to Sanson. There is insufficient 11kV backfeed to meet the security criteria.	Sanson-Bulls 33kV
Main St substation	N-1 capacity of 33kV oil-filled cables is exceeded. Oil-filled cables are a security and environmental risk.	Palmerston North CBD
Pascal substation	Under-rated cable from Manawatu River to Pascal St cannot meet N-1 security criteria.	Palmerston North CBD
Pascal substation	Demand exceeds firm capacity of the two transformers. Substation is highly constrained for space.	Palmerston North CBD
Kairanga substation	Protection issues with operating a closed 33kV ring. A section of cable from Pascal to Kairanga limits N-1 capacity.	Note 1
Kimbolton substation	Single 33kV circuit from Feilding to Kimbolton. The 11kV backfeed capacity does not meet security criteria.	Note 2
Kimbolton substation	Single transformer substation. Replacement of transformer is scheduled for 2022.	Note 2
Feilding substation	Demand exceeds firm capacity of the two transformers.	Feilding transformers
Sanson substation	Demand exceeds firm capacity of the two transformers.	Sanson transformer
Kairanga substation	Demand exceeds firm capacity of the two transformers.	Kairanga transformers
Kelvin Gr substation	Demand exceeds firm capacity of the two transformers.	Kelvin Gr transformers
Kelvin Gr substation	Kelvin Gr substation demand is expected to exceed 24MVA in future. This will cause reliability and lost load issues.	New Ashhurst zone substation
Oroua Downs, Rongotea and Bainesse feeders	High growth because of increasing irrigation loads. Heavily loaded feeders have limited backfeed.	Rongotea zone substation
Turitea substation	Turitea substation requires class AAA. It has switched N-1 from Linton and Bunnythorpe.	Turitea area subtransmission supply
Milson substation	Milson substation demand will exceed its class capacity.	Milson substation supply transformers and subtransmission upgrade

Notes:

1. The oil-filled cables between Pascal and Gillespies Line. With better communications from Linton GXP to the city, it is expected the protection issues can be resolved and it will then be possible to operate Kairanga on a closed 33kV ring.

2. Kimbolton's small load and the large distance to the substation prevents a second 33kV circuit. Similarly, a second transformer is unlikely to be economic but options to improve security will be considered when the existing transformer is due for replacement.

11.4.11.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Manawatu area.

PALMERSTON NORTH CBD (FERGUSON SUBSTATION)	
Estimated cost (design and consenting):	$27.4m
Expected project timing:	2016-2023

The Palmerston North CBD is supplied from Pascal St and Main St substations with support from Keith St substation. Pascal St is supplied from Linton GXP. Keith St and Main St are supplied from Bunnythorpe GXP, which has exceeded the firm capacity of the two 220/33kV transformers.

A meshed network of 33kV lines and cables supplies Keith St, and these are approaching their N-1 capacity. From Keith St, two oil-filled 33kV cables supply Main St. These have exceeded their N-1 capacity and recent issues with leaking joints mean these cables are a significant risk in terms of supply security and the environment.

Both Main St and Pascal St substations have already exceeded the firm capacity of their transformers. Expansion at these substations is not practical because of space limitations. The security of Pascal St is further limited by a section of under-rated cable from the Manawatu River through to the substation.

Options considered are detailed in Appendix 8.

We propose a strategy where in future there will be three highly secure substations serving the CBD, all supplied from Linton GXP. To enable this, two new high capacity 33kV circuits are needed from Linton GXP to the city. A new inner-city substation is also required, which we will establish at Ferguson St. Main St substation will be transferred over onto Linton GXP. The under-rated section of 33kV cable into Pascal St will also be replaced.

The combination of these investments will resolve all the existing issues, both in terms of security of supply and the environment. Security will be restored to all substations, particularly the three that serve the CBD. Capacity of the new circuits and substations will be optimised to cater for continued growth, balanced by consideration of potential demand side moderations as new technology emerges. The strategy will also defer any major investment at Bunnythorpe GXP.

Note that this project is happening now with the substation building nearly completed and some 33kV cables already installed.

SANSON-BULLS 33KV

Estimated cost (concept):	$6.0m
Expected project timing:	2022-2023

Sanson substation is supplied through a single 33kV circuit from Feilding. The 11kV backfeed for Sanson is not adequate to meet the security criteria. The restriction this imposes on planned outages means it has been difficult to maintain the 33kV line, and its condition and performance is a risk.

The Ohakea air force base is an important customer supplied from Sanson substation. The base is supplied via a 33kV cable operating at 11kV. The 33kV cable was installed some years ago as part of a plan to eventually link Sanson and Bulls substations at 33kV. In addition to providing the required security of supply to Sanson, this will benefit Bulls security and transfer load off constrained assets at Bunnythorpe GXP and Feilding.

This project covers construction of the remaining 33kV circuits and the substation alterations needed to complete the Sanson-Bulls 33kV link.

The preferred option involves thermally upgrading the Bunnythorpe to Feilding 33kV lines, constructing a new 33/11kV substation at Ohakea, constructing a new 33kV line from Bulls substation to the new Ohakea substation[34] and installing an automatic load transfer facility at Sanson substation.

Further details of the options considered and reasons for adopting this strategy are included in Appendix 8.

SECOND FEILDING ZONE SUBSTATION AND SUBTRANSMISSION

Estimated cost (concept):	$5.8m
Expected project timing:	2025-2027

The Feilding substation supplies Feilding township and the surrounding commercial, industrial, residential and rural load. Its security level is AAA. The demand growth is high in areas covered by Feilding substation. In addition to the risk of exceeding the substation’s N-1 capacity, the high feeder demand growth can cause supply security issues to critical loads in future.

The proposed long-term solution is to establish a new zone substation to offload Feilding substation. This will reduce the length and demand of the feeders and, consequently, reduces the risk of feeder outages.

Our approach to the 33kV supply for a second Feilding zone substation is to build a new 33kV capable line from the existing Feilding substation.

NEW ASHHURST ZONE SUBSTATION AND SUBTRANSMISSION

Estimated cost (concept):	$6.0m
Expected project timing:	2027-2029

The Kelvin Gr substation supplies the commercial, industrial and residential load in Palmerston North city and the rural load to the north of the city. Its security level is AAA. The demand growth is high in areas covered by the Kelvin Gr substation. In addition to the risk of exceeding the substation’s N-1 capacity, the high feeder demand growth can cause supply security issues to critical loads in future.

The proposed long-term solution is to establish a new zone substation, named Ashhurst, to offload the existing Kelvin Gr substation. This will reduce the lengths and demand of the feeders and consequently reduces the risk of feeder outages.

Our approach to the 33kV supply for the new Ashhurst zone substation is to build a new 33kV capable line from Bunnythorpe GXP.

[34] The section between Ohakea substation and Sanson substation will utilise an existing 33kV underground cable.

11.4.11.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Manawatu area.

KAIRANGA TRANSFORMERS

Estimated cost:	$2.2m
Expected project timing:	2023

The Kairanga substation supplies residential, rural and industrial loads in the southern parts of the Palmerston North area. The substation contains two 15MVA rated transformers. The demand has exceeded the transformer firm capacity. High growth demand is expected on this substation because of residential and agricultural developments.

The proposed solution is to replace the existing transformers with two 24MVA units. This will provide adequate capacity for future demand with appropriate security.

SANSON TRANSFORMERS

Estimated cost:	$1.9m
Expected project timing:	2023

The Sanson substation supplies Sanson township, Rongotea and Himatangi areas, and the Ohakea air force base. The substation contains two 7.5MVA rated transformers. The demand has exceeded the firm capacity of the transformers. There is also limited backfeed capability from the 11kV distribution network.

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand with appropriate security.

KELVIN GR TRANSFORMERS

Estimated cost:	$2.4m
Expected project timing:	2021

The Kelvin Gr substation supplies commercial, industrial and residential loads in Palmerston North and the rural load to the north of Palmerston North city. The substation contains two transformers rated 15MVA. The demand has exceeded the firm capacity of the transformers.

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand with appropriate security.

FEILDING TRANSFORMERS

Estimated cost:	$2.6m
Expected project timing:	2021

The Feilding substation supplies the town of Feilding and commercial, industrial, residential and rural loads in the area. The substation contains two transformers nominally rated at 21MVA each. The demand has exceeded the firm capacity of the transformers. Because of limitations in backfeed capability, the security of supply will not be adequate as load grows.

The proposed solution is to replace the existing transformers with two larger units. This plan is likely to be reviewed closer to the expected upgrade date. Our standard large urban transformer capacity is 24MVA, which does not provide much margin for growth over the existing units. However, there may be possibilities to mitigate this by the transfer of load, or if there is lower growth. If not, we will need to consider alternative strategies, including the possibility of building another zone substation.

FEILDING-SANSON SUBTRANSMISSION UPGRADE

Estimated cost:	$1.4m
Expected project timing:	2023-2025

Sanson substation takes its subtransmission supply by one 14.5km long line from Feilding substation. A Sanson-Bulls 33kV interlink project coupled with a new substation to supply Ohakea air force base is on the works plan. This will link Sanson and Bulls substations at 33kV providing the required security of supply to Sanson and Bulls as well as Ohakea. However, the addition of Bulls and Ohakea substation loads has put constraints on the Sanson 33kV supply.

The proposed solution is to increase the thermal capacity of the Feilding-Sanson subtransmission line. This will provide capacity for the future demand.

TURITEA NEW 33KV LINE

Estimated cost:	$2.0m
Expected project timing:	2023-2025

The Turitea substation supplies Massey University, Linton Military Camp, NZ Pharmaceuticals, residential and rural load to the south east of Palmerston North. Its security level is AA but AAA is intended. The substation has switched N-1 subtransmission switching capability from Bunnythorpe and Linton GXPs. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a subtransmission fault. There is also limited backfeed capability from the distribution network.

Because of these constraints, the Turitea substation does not meet our required security level.

The proposed solution is to install the second subtransmission supply for the substation. This will improve the security level.

MILSON-2 33KV LINE UPGRADE	
Estimated cost:	$1.3m
Expected project timing:	2026-2027

The Milson substation supplies the industrial, commercial and residential load in western Palmerston North, including the airport and industrial park. Milson substation takes its 33kV supply from Bunnythorpe GXP by two dedicated 33kV lines, Milson-1 (7.1km long) and Milson-2 (13.7km long). For an outage on Milson-1 line, Milson-2 line can not supply the substation because of thermal capacity constraints. Because of this constraint, the Milson-2 33kV line needs upgrading.

The proposed solution is to upgrade the 13km overhead section of Milson-2 33kV line to improve its capacity and the security of supply.

NEW (THIRD) 33KV LINE BUNNYTHORPE - FEILDING	
Estimated cost:	$2.9m
Expected project timing:	2025-2026

Feilding substation takes its 33kV supply from Bunnythorpe GXP by two lines, one is 8.6km long (FEI East) and the other is 9.1km long (FEI West). Each 33kV line has a conservative rating of 415A (23.7MVA, Butterfly). Feilding's 33kV bus supplies Sanson substation by one 14.5km long line and Kimbolton substation by another 26.5km long line.

Also, Feilding will supply Bulls and Ohakea substations for the upcoming Sanson-Bulls 33kV interlink and future second Feilding zone substation.

The total demand of Feilding, Sanson, Bulls, Ohakea, Kimbolton and Feilding 2 substations on the Bunnythorpe-Feilding circuits will exceed their N-1 capacity.

The proposed solution is to install a third subtransmission line to the Feilding substation from Bunnythorpe GXP. This will provide adequate capacity for the future demand with appropriate security.

11.4.11.6 OTHER DEVELOPMENTS

As noted in the overview section, we have a coordinated programme in place to upgrade small sections of 11kV cable within Palmerston North. This also takes into account renewal needs and substation and feeder backfeed capacities. In some cases, proposed automation of feeder intertie switching may warrant feeder upgrades.

Feeder upgrades will be needed in rural areas, both for growth and ensuring adequate reliability, ie backfeed capability. Most of these involve conductor replacements or voltage regulators.

Significant changes in demand, such as for a rapid and concentrated uptake of irrigation, will likely result in a new substation, ie the Rongotea project described below.

New urban subdivisions generally require continued investment in upgraded upstream or backbone sections of feeders. There is regular communication with Massey University to ensure appropriate supply and capacity. We are also planning an 11kV link between Turitea substation and the inner CBD substations, although this is subject to physical obstacles, such as the river crossing.

The Manawatu area is known for its wind generation. Most of the prime sites appear to have been used and we are not aware of any immediate new developments. The larger scale of wind generation often means these projects connect directly with the grid. Smaller embedded generation is not yet of a nature or scale to have an impact on demand peaks.

We will investigate non-network opportunities, particularly where this might defer major investment, ie cogeneration in central Palmerston North.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solution and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Rongotea zone substation	The Rongotea area is experiencing strong growth in irrigation and other rural activities. Supply to the area is required to have higher security level because it supplies industrial loads. The solution is to build a new Rongotea zone substation.
Milson substation supply transformers Upgrade	The substation contains two transformers and limited 11kV backfeed capability. The demand has exceeded the transformers' capacity. The solution is to replace the existing transformers with two larger units. This will improve the substation security levels.
Kimbolton substation security upgrade	Kimbolton's security level is A2. Its 11kV backup supply is not adequate for the supply of the substation load. The preferred solution is to increase backfeed capacity via the 11kV network.

11.4.12 TARARUA

Other than some industrial activity, the Tararua region has low growth and reasonable security.

Major and minor project spend related to growth and security during the next 10 years is $3.6m.

11.4.12.1 AREA OVERVIEW

The Tararua area covers the southern part of the Tararua district, which is in the upper Wairarapa region.

The district has rugged terrain, especially towards the remote coastal areas. Subtransmission and distribution lines are generally long and exposed.

The area generally has a dry, warm climate. Strong winds can occur in spring and summer. The winds gather strength as they come down the Tararua Range and can be very strong, especially in the coastal areas.

The area receives heavy rain from the south and east, which can cause flooding.

The Tararua area is connected to the grid at Transpower's Mangamaire GXP. The region uses a 33kV subtransmission voltage.

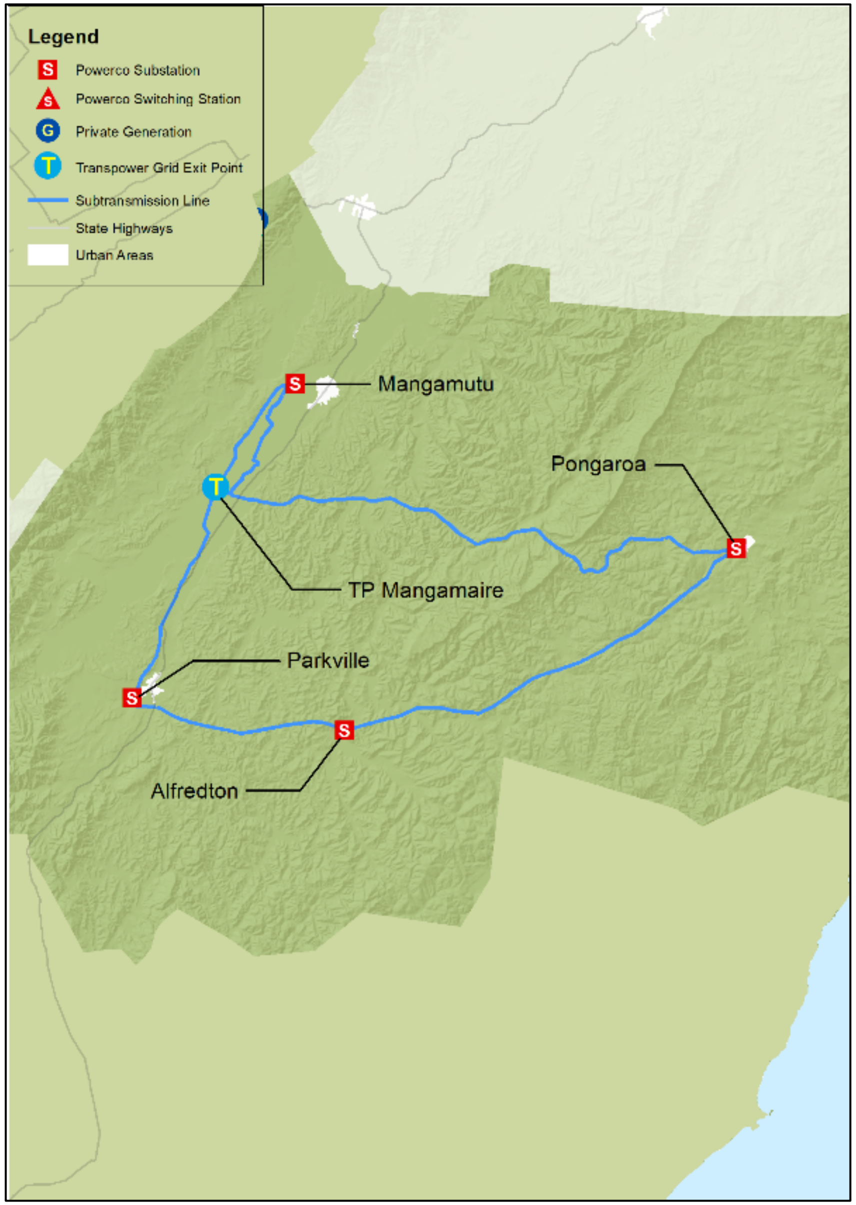
Mangamaire GXP supplies four zone substations – Mangamutu, Parkville, Alfredton and Pongaroa.

The subtransmission and distribution networks are almost entirely overhead.

Downstream of the zone substations the distribution networks operate at 11kV.

These 11kV distribution feeders can be long and sparsely loaded. Locating, isolating and restoring the network after a fault can be challenging and often time-consuming.

Figure 11.15: Tararua area overview



11.4.12.2 DEMAND FORECASTS

Demand forecasts for the Tararua zone substations are shown in Table 11.24.

Table 11.24: Tararua zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Alfredton	A2	1.4	0.5	0.5	0.5	0.5
Mangamutu	AAA	12.8	12.5	12.6	12.6	12.7
Parkville	A1	0.0	2.2	2.2	2.1	2.1
Pongaroa	A2	2.9	0.8	0.8	0.8	0.8

The demand at Mangamutu substation incorporates the now confirmed significant increase in capacity for Fonterra Pahiatua. Underlying growth at both Mangamutu and the other substations is much lower and generally not expected to exceed 0.1%.

Other than Mangamutu, the substations service very small loads with quite low criticality in most cases. These loads are unlikely to justify security upgrades, unless a significant change occurs, such as irrigation. Future demand growth in the Tararua area is expected to be 0.1% per year.

11.4.12.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tararua area are shown in Table 11.25.

Table 11.25: Tararua constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Mangamutu substation	Increased demand at Pahiatua would cause the demand to exceed secure capacity. The existing transformers are scheduled for replacement in 2020.	Note 1
Parkville substation	Single transformer. The 11kV backfeed does not meet security criteria. The transformer is due for renewal.	Note 2
Alfredton substation	Single transformer.	Note 3
Pongaroa substation	Single transformer.	Note 3
Mangamaire-Pongaroa 33kV feeder	Voltage to Parkville substation during contingency is low.	Pongaroa 33kV upgrade

Notes:

1. Upgrades for the Fonterra plant are accommodated through our customer works programme. Any renewal needs will be optimised at the same time.

2. Two transformers to meet security criteria cannot be economically justified. Transformer capacity will be addressed during planned renewal. Parkville substation enclosure has other operational and physical security issues and we may consider an upgrade to the whole site.

3. Two transformers to meet security criteria cannot be economically justified. Transformer capacity will be addressed during planned renewal.

11.4.12.4 MAJOR GROWTH AND SECURITY PROJECTS

PONGAROA 33KV UPGRADE	
Estimated cost:	$4.4m
Expected project timing:	2026-2030

This project addresses a particular development constraint:

The Parkville-Alfredton-Pongaroa ring is very lightly loaded in terms of thermal loading because of the low aggregate demand at the three substations supplied by this ring.

However, this ring comprises 89km of line length in total. The large distance between substations supplied by this ring means that in N-1 conditions the voltage drop can be high.

The solution project would be to upgrade the 33kV supply line from Lamprey to Coyote.

11.4.12.5 MINOR GROWTH AND SECURITY PROJECTS

No minor growth and security projects are anticipated for the planning period. We will continue to monitor distribution feeder loading and voltages and schedule any upgrades to cater for growth. We will also focus on improving existing reliability, especially through backfeeding, new feeder links and automation.

11.4.12.6 OTHER DEVELOPMENTS

Parkville substation supplies Ekatahuna township. Although load growth is flat at present, Ekatahuna is somewhat of a rural transportation hub because of its location.

We have fielded inquiries relating to large scale electric vehicle charging stations in the area. If electric vehicle uptake accelerates, there could be significant load increases that would require increased capacity at Parkville substation and improved security of supply for both the substation and the subtransmission network.

The following description represents the most probable solution but the final solution and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTION
Parkville second transformer	Increase the capacity of Parkville substation and install a second transformer.

11.4.13 WAIRARAPA

The Wairarapa region, overall, has low growth with shifting load centres. While Masterton town comprises much of the region's load, the towns of Carterton and Greytown are growing and are expected to grow further. Load in south Wairarapa also appears to be shifting further southwest.

In addition to the planned growth and security projects, routine expenditure will be needed on distribution circuits.

Major and minor project spend related to growth and security during the next 10 years is $21.3m.

11.4.13.1 AREA OVERVIEW

The Wairarapa area covers the central and southern parts of the Wairarapa district. Masterton is the major urban centre, with a population of approximately 23,500. Other significant towns are Greytown, Featherston, Carterton and Martinborough.

The Tararua Range runs along the western boundary of the Wairarapa area. Adjacent is a low lying area that is generally flat or rolling and in which are located the main urban centres. To the east, the terrain is generally hilly through to the coast.

The Wairarapa area has a dry, warm climate. Strong winds off the Tararua Range can occur in spring and summer. Weather can be extreme in the coastal areas. The area also receives heavy rain from the south and east, which can cause flooding.

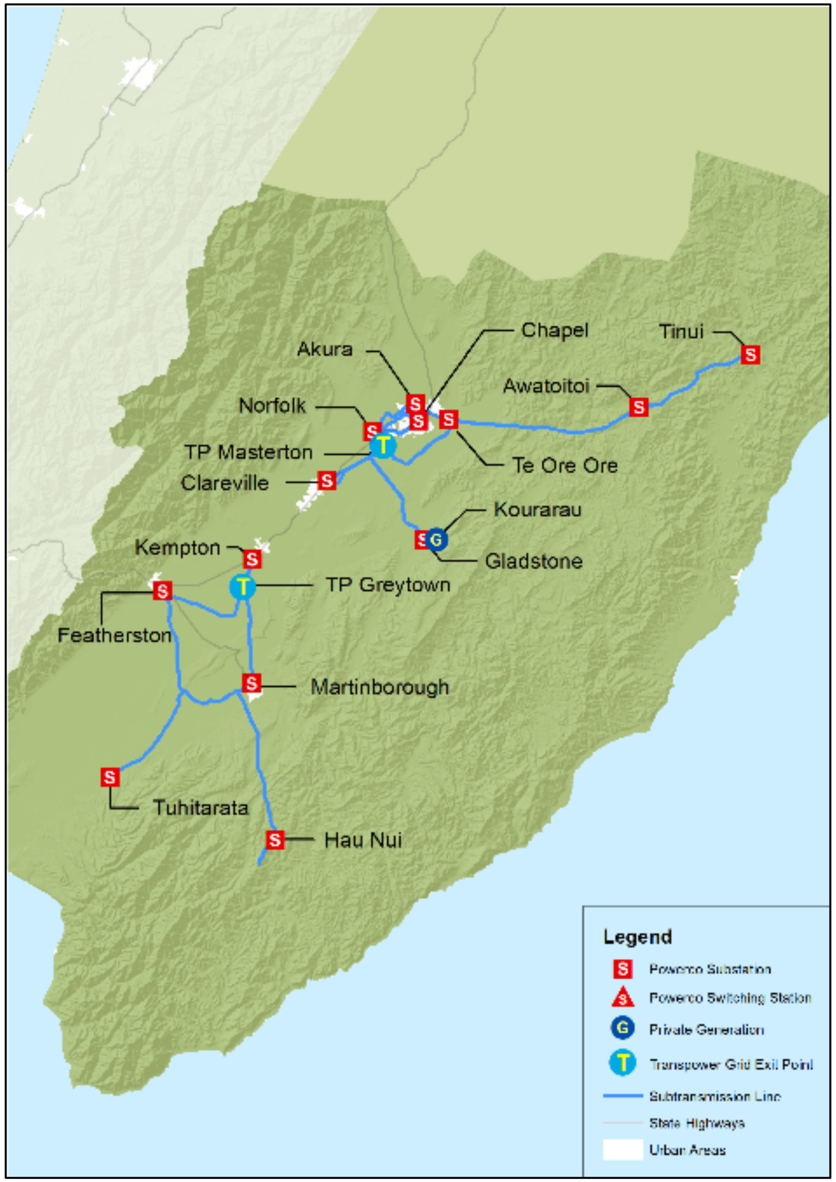
Forestry, cropping, sheep, beef and dairy farming are the backbone of the economy. The area around Martinborough, in the south, is notable for its vineyards and wine, as are the outskirts of Masterton and Carterton. Deer farming is growing in importance.

Lifestyle sections are also becoming popular in the area, particularly as it is just a commute, albeit long, from Wellington.

Wind generation and irrigation could impact this area significantly, especially in regard to the electricity system.

The Wairarapa area is connected to the grid at two Transpower GXPs – Greytown and Masterton. The region uses a 33kV subtransmission voltage.

Figure 11.16:Wairarapa area overview



The Masterton GXP supplies eight zone substations – Norfolk, Akura, Chapel, Te Ore Ore, Awatoitoi, Tinui, Clareville and Gladstone.

The Greytown GXP supplies five zone substations – Kempton, Featherston, Martinborough, Tuhitarata and Hau Nui.

The 33kV network has a meshed or ring architecture in Masterton.

Similarly, a ring connects Martinborough and Featherston with Greytown (Transpower GXP).

Rural substations are generally supplied by single radial lines of quite small capacity. Downstream of the zone substations the distribution networks operate at 11kV.

The subtransmission and distribution networks are almost entirely overhead. Access is reasonable except in the back country and eastern coastal hills.

11.4.13.2 DEMAND FORECASTS

Demand forecasts for the Wairarapa zone substations are shown in Table 11.26, with further detail provided in Appendix 7.

Table 11.26: Wairarapa zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2018	2020	2025	2030
Akura	AAA	9.0	13.5	13.8	14.1	14.4
Awatoitoi	A2	3.0	1.4	1.4	1.4	1.5
Chapel	AAA	13.8	15.3	15.6	16.0	16.4
Clareville	AA	9.4	11.8	12.6	13.3	14.1
Featherston	A1	0.1	4.8	5.0	5.2	5.4
Gladstone	A2	1.4	1.0	1.0	1.1	1.1
Hau Nui	A1	0.0	1.5	1.5	1.6	1.6
Kempton	A1	0.4	5.5	5.8	6.1	6.4
Martinborough	A1	0.1	5.1	5.5	5.8	6.1
Norfolk	AA+	10.6	7.3	7.9	8.5	9.1
Te Ore Ore	AA	6.8	7.3	7.4	7.6	7.7
Tinui	A2	1.3	1.1	1.1	1.1	1.2
Tuhitarata	A1	0.0	3.3	3.4	3.5	3.6

Growth in the Wairarapa area is modest. No significant residential demand increases, such as large subdivisions, are anticipated. Modest major customer demand increase is anticipated from existing industrial customers, but significant step changes are not likely. Major wind generation plants have been investigated but are likely to be at a scale where they would connect directly to the grid.

Irrigation proposals are the most likely to cause significant disruption to our network development plans.

Shaded years indicate that the demand exceeds the capacity we can provide with appropriate security. Of note is that several of the Wairarapa substations already exceed security criteria. Therefore, development plans are focused on improving security and reliability for the existing load base, rather than catering for future new load.

11.4.13.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Wairarapa area are shown in Table 11.27.

Table 11.27: Wairarapa constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Akura, Chapel, Norfolk substations	Masterton GXP-Akura-Chapel-Norfolk 33kV ring. Demand on the ring exceeds N-1 capacity.	Note 1
Akura, Te Ore Ore, Awatoitoi and Tinui substations	Outage on Masterton GXP to Te Ore Ore 33kV circuit can overload alternative circuits.	Note 2
Akura substation	Demand exceeds firm capacity of the two transformers.	Note 2
Clareville substation	Demand exceeds secure capacity of the two transformers.	Note 2
Featherston substation	Single transformer. The 11kV backfeed is insufficient to fully meet security criteria.	Featherston substation second transformer
Martinborough substation	Single transformer. The 11kV backfeed is insufficient to fully meet security criteria.	Martinborough substation second transformer
Te Ore Ore substation	Single transformer. The 11kV backfeed is insufficient to fully meet security criteria.	Note 3
Kempton substation	Single transformer. The 11kV back-feed is insufficient to fully meet security criteria.	Kempton Substation Second Transformer and Subtransmission Supply

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hau Nui substation	Single transformer and single 33kV circuit. The 11kV back-feed is insufficient to meet security criteria.	Note 3
Tuhitarata substation	Single transformer and single 33kV circuit. The 11kV backfeed is insufficient to fully meet security criteria.	Tuhitarata substation security upgrade
Masterton-Norfolk 33kV	33kV capacity is insufficient to meet security of supply criteria.	Masterton-Norfolk 33kV feeder upgrade
Chapel-Norfolk 33kV tie feeder and emergency tie-1	33kV capacity is insufficient to meet security of supply criteria. Note 4.	Chapel-Norfolk 33kV tie feeder and emergency tie-1 33kV feeder upgrades
Masterton-Chapel 33kV	33kV capacity is insufficient to meet security of supply criteria.	Masterton-Chapel 33kV feeder upgrade
Norfolk substation supply transformers	Transformer capacity is insufficient to meet security of supply criteria.	Norfolk substation supply transformers
Masterton-Te Ore Ore 33kV	33kV capacity is insufficient to meet security of supply criteria.	Masterton-Te Ore Ore 33kV feeder upgrade
Clareville 33kV dual supply	33kV capacity is insufficient to meet security of supply criteria.	Re-tension Clareville 33kV dual supply
New Bidwells-Cutting substation and dual supply by re-livening Bidwells 33kV feeder	Tuhitarata substation is supplied by one single 33kV circuit from Greytown and has limited backfeed capability. As the demand increases, the class capacity is exceeded.	New Bidwells-Cutting substation and dual supply
New Pirinoa substation and dual supply	As demand increases, voltage quality issues during normal state, and the ability for restoration of supply through distribution backfeed, will be progressively worse for southern-most loads supplied by Tuhitarata substation feeders Pirinoa and Burnside.	New Pirinoa substation and dual supply

Notes:

1. The risk is low and demand only exceeds capacity under peak loading and for rare fault conditions. Alternative supply options and backfeed capability mitigate the risk.

2. Expenditure for this work is allowed for in the renewal forecasts, and capacity will be considered so as to economically provide for expected long-term load growth.

3. N-1 for 33kV circuits or zone transformers for these substations are not economic. Options to improve 11kV backfeed will be considered during routine planning.

4. Expenditure for this work is allowed for in the renewal forecasts, and capacity will be considered to economically provide for expected long-term load growth.

11.4.13.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Wairarapa area.

NEW BIDWELLS-CUTTING SUBSTATION AND DUAL SUPPLY	
Estimated cost:	$4.2m
Expected project timing:	2023-2028

This project addresses a three separate development constraints:

Firstly, Tuhitarata substation is supplied by one single 33kV circuit from Greytown and has limited backfeed capability. As the demand increases, the class capacity is exceeded. Secondly and thirdly, the (n-1) capacity on Masterton-Featherston 33kV and Masterton-Martinborough feeders is insufficient.

Addressing the first issue by increasing 11kV back-feed capacity to Tuhitarata substation and the other two issues by subtransmission upgrades have been considered, but the solutions are costly and may end up proving to be only a temporary solution. Because of the long lengths and high impedance of the conductors, upgrading to 22kV could be cost effective.

Utilising an existing but out-of-service 33kV feeder to supply a small new substation and to increase the (n-1) capacity of the Greytown sub-transmission network is likely to prove most cost effective while also providing additional 11kV automation opportunities for feeders presently supplied by Featherston, Martinborough and Kempton substations.

NEW PIRINOA SUBSTATION AND DUAL SUPPLY	
Estimated cost:	$6.3m
Expected project timing:	2023-2028

This project addresses three separate development constraints:

Firstly, as demand increases, voltage quality issues during normal state, and the ability for restoration of supply through distribution back-feed, will be progressively worse for southern-most loads supplied by Tuhitarata substation feeders Pirinoa and Burnside.

Furthermore, Hau Nui and Tuhitarata substations have no (n-1) sub-transmission capacity.

The solution is a new substation and dual sub-transmission supply linking the new sub with Tuhitarata and Hau Nui substations. However, strengthening the distribution network could be more cost effective.

11.4.13.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Wairarapa area.

MASTERTON–AKURA 33KV FEEDER UPGRADE

Estimated cost:	$1.0m
Expected project timing:	2023-2026

Security is not adequate and during peak load periods backfeeding capability is limited.

Upgrades to most of the Masterton-Akura-Te Ore Ore 33kV ring circuit are planned. This will provide the substations with adequate security and allow some excess capacity for 11kV backfeeds – the latter being a serious operational issue at present.

MASTERTON-TE ORE ORE 33KV FEEDER UPGRADE1

Estimated cost:	$1.1m
Expected project timing:	2024-2026

Security is not adequate during peak load periods.

The Akura-Te Ore Ore 33kV feeder is being upgraded and has improved security on the Masterton-Akura-Te Ore Ore 33kV ring circuit. A further upgrade to the Te Ore Ore 33kV feeder is planned.

MASTERTON - CLAREVILLE 33KV RE-TENSIONING

Estimated cost:	$1.0m
Expected project timing:	2025-2026

Growth of Clareville-1 and Clareville-2 33kV feeders has been steady.

A re-tensioning of Clareville-1 and Clareville-2 33kV feeders is planned.

NORFOLK SUBSTATION SUPPLY TRANSFORMERS

Estimated cost:	$2.1m
Expected project timing:	2025-2027

The Norfolk substation is situated a few kilometres south of Masterton and supplies a large sawmill, as well as other small industrial and rural loads. The substation contains two transformers.

This project addresses particular development constraints:

The demand has exceeded the transformers’ capacity, and there is potential for loss of supply at the substation for a transformer fault.

There is also limited backfeed capability from the 11kV distribution network. The Norfolk substation does not meet our required security level.

The solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand and improve the security level.

Alternatives, such as increasing the capacity of the 11kV feeders to provide the required backfeeding capacity, are not favoured because of the complexity and cost.

KEMPTON SUBSTATION SECOND TRANSFORMER AND SUBTRANSMISSION SUPPLY

Estimated cost:	$2.8m
Expected project timing:	2026-2028

The Kempton substation supplies Greytown and the surrounding rural area. The substation security level is A1. The substation is supplied by one single 33kV circuit from the Greytown GXP (N security) and contains one supply transformer.

This project addresses particular development constraints:

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or sub transmission fault.

There is also limited backfeed capability from distribution network. The Kempton substation does not meet our required security level.

The solution project is to install a second subtransmission supply and transformer for the substation. This will improve the security level.

Alternatives such as increased backfeed would be costly as there is no adequate transfer capacity.

CLAREVILLE SUBSTATION SUPPLY TRANSFORMERS	
Estimated cost:	$2.1m
Expected project timing:	2024-2026

The Clareville substation supplies Carterton township and the surrounding rural load. The substation contains two transformers.

This project addresses particular development constraints:

The demand has exceeded the transformers' capacity, and there is potential for loss of supply at the substation during a transformer fault.

There is also limited backfeed capability from the 11kV distribution network. The Norfolk substation does not meet our required security level.

The solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand. This will also improve the security level.

MARTINBOROUGH SUBSTATION SECOND TRANSFORMER	
Estimated cost:	$2.1m
Expected project timing:	2026-2028

The Martinborough substation supplies the urban and rural loads around Martinborough. Security level A1 is intended.

The substation contains a single supply transformer and has N-1 subtransmission switching capability.

This project addresses particular development constraints:

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer fault.

There is also limited backfeed capability from the distribution network. The Martinborough substation does not meet our required security level.

The solution project is to install a second transformer at the substation. This will improve the security level. Alternatives, such as increased backfeed, would be costly as there is no adequate transfer capacity.

11.4.13.6 OTHER DEVELOPMENTS

Inquiries relating to large scale electric vehicle charging stations in the area have been received. Likely location for first ultrafast charging station is Chapel St or Renall St in Masterton. Present upgrades to the Masterton-Norfolk-Chapel 33kV subtransmission ring and to Chapel St substation will make available the necessary capacity and security for such a facility.

However, if electric vehicle uptake accelerates, there could emerge a need for more charging stations along State Highway 2 and possibly even State Highway 53. In such a scenario, there would be significant load increases affecting one or more of Clareville, Kempton, Featherston and Martinborough substations. This may necessitate the transformer upgrades planned for Kempton, Featherston and Martinborough substations to use larger transformers.

Furthermore, population overflow from Wellington city is starting to have a growth impact in areas connected to Wellington by rail. Retirement villages and life style blocks add to this mix.

These drivers introduce the possibility of additional work being required on existing subtransmission lines.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following list indicates the most probable solutions, but the final choices and optimal timing are subject to further analysis.

PROJECT	SOLUTION
Masterton-Akura 33kV feeder	Reconductor as opposed to retension.
Featherstone Substation second Transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.
Tuhitarata Substation security upgrade	The substation is supplied by one single circuit from Greytown and has limited backfeed capability. As the demand increases, the class capacity is exceeded. The solution is to increase backfeed through the distribution network. Due to the long lengths and high impedance of the conductors, upgrading to 22kV could be cost effective.

11.5 GRID EXIT POINTS (GXPS) AND EMBEDDED GENERATORS

11.5.1 GXPS

Our network connects to the transmission grid mainly at 33kV, but also at 110kV, 66kV and 11kV. We have 30 points of supply or grid exit points (GXPs). Most assets at GXPs are owned by Transpower, although we do own some transformers, circuit breakers, protection and control equipment. The GXPs supplying our electricity network are detailed in Table 11.28, along with their respective peak load, capacity and security characteristics.

Table 11.28: GXP summary statistics for financial year 2018

GXP NAME	TRANSFORMER NAMEPLATE RATING (MVA)	N-1 CAPACITY SUMMER/WINTER (MVA)	2018 MD (MVA)	N-1 SECURE	2018 MAX EXPORT (MW)
Brunswick (BRK)	50	-	30	No	-
Bunnythorpe (BPE)	83, 83	83/102	92	No	1
Carrington St (CST)	75, 75	65/65	46	Yes	-
Greytown (GYT)	20, 20	20/20	12	Yes	2
Hawera (HWA)	30, 30	30/35	25	Yes	20
Hinuera (HIN)	30, 50	30/40	45	No	-
Huirangi (HUI)	60, 60	74/74	34	Yes	-
Kaitimako (KMO)	75	-	27	No	-
Kinleith 11kV Mill	30, 30, 30	60	77	No	-
Kinleith 11kV Cogen (KIN Gen)	50	-	18	No	31
Kinleith 33kV (KIN33)	20, 30	20	19	Yes	-
Kopu (KPU)	60, 60	59/59	45	Yes	-
Linton (LTN)	120, 100	81/81	55	Yes	16
Mangamaire (MGM)	30, 30	27/27	14	Yes	-
Marton (MTN)	20, 30	20/24	16	Yes	-
Masterton (MST)	60, 60	60/78	44	Yes	-
Mataroa (MTR)	30	-	7	No	-
Mt Maunganui (MTM)	75, 75	63/77	65	Yes	-
New Plymouth (NPL)	30, 30	30/33	20	Yes	-
Ohakune (OKN)	20	-	2	No	-
Opunake (OPK)	30, 30	14/14	11	Yes	-
Piako (PAO)	60, 40	40	40	Yes	-
Stratford (SFD)	40, 40	40/55	26	No	-
Tauranga 11kV (TGA11)	30, 30	30/30	27	Yes	-
Tauranga 33kV (TGA33)	90, 120	90/90	77	Yes	4
Te Matai (TMI)	30, 40	36/38	39	Yes	-
Waihou (WHU)	20, 20, 20	48	31	Yes	-
Waikino (WKO)	30, 30	37	35	Yes	-
Whanganui (WGN)	30, 20	24/24	33	No	-
Waverley (WVY)	10	-	5	No	-

The New Plymouth GXP will be decommissioned in 2020 with all demand transferred to Carrington St GXP.

The supply transformers at Piako are owned by Powerco.

Three of our smaller GXPs (Mataroa, Ohakune and Waverley) have only a single transformer. The three substations have relatively low demand – 7MVA, 2MVA, and 6MVA respectively – and N-1 security cannot necessarily be justified for these, but contingency plans are in place and spares are coordinated to minimise the impact should the single transformer fail.

Brunswick and Kaitimako are larger GXPs but also have just one transformer and therefore only N security. Brunswick has partial backup from Whanganui GXP, the capacity of which is a focus of our future development plans. Kaitimako is a newer GXP and there is 33kV backfeed capability from Tauranga. When the load at Kaitimako exceeds the backfeed capacity a second transformer at Kaitimako will be considered.

Hinuera is a single circuit GXP. Improving the security has been a significant focus of our growth and security plans for the past decade and is the main driver behind our proposed new 110/33 kV supply point at Putaruru.

Bunnythorpe GXP is just in breach of the N-1 transformer capacity. Our major Palmerston North growth and security project will transfer some load on to the Linton GXP and reduce the loading on the Bunnythorpe GXP, within N-1 capacity.

Security at Kinleith GXP is a function of the customer's specific needs. Transpower is undertaking major replacement work at Kinleith.

Tauranga 11kV and Waihou are both on the limit of firm capacity. Pyes Pa effectively transfers load off Tauranga onto Kaitimako, while Waikino load is managed operationally until projects to replace the transformers is completed.

Beyond the GXPs, certain localised grid constraints are of significance to our planning:

- Valley Spur 110kV dual circuit spur line, which supplies our Piako, Waihou, Waikino and Kopu GXPs, is approaching its N-1 capacity.
- 110kV circuits between Tarukenga, Lichfield, Kinleith, Putaruru, and Arapuni are a known grid constraint under certain circumstances and impact the security and capacity available at our GXPs.
- Transpower's proposals for the New Plymouth GXP and North Taranaki transmission may require an alternative grid connection for our Moturoa substation.
- The 110kV circuits to Tauranga are already reaching N-1 capacity and rely on Kaimai generation at peak loads.
- Constraints are expected in the next decade on the 110kV circuits to Mt Maunganui. The Papamoa project has eased the constraints by transferring some load to Te Matai GXP, but a constraint on the 110kV to Te Matai will then emerge
- The Te Matai transformers also need to be upgraded to maintain firm capacity. Longer term, constraints may reoccur at Mt Maunganui also.

Spur acquisitions

Transpower's programme of asset divestment to distributors has lost momentum in the Powerco network area. The previously discussed divestment opportunities for complete spur assets are not being actively pursued because of the need for both Powerco and Transpower to focus resources on other topics. While we have no agreements for any acquisitions of complete spurs in the near future, both parties remain committed to investigating transfers in the future should these prove efficient for our customers.

Transfer of 11kV and 33kV assets to Powerco

Transpower has an ongoing programme for the replacement of existing outdoor 11 and 33kV outdoor structures and switchgear with indoor switchboards. Over the next ten years there are a number of the conversions proposed at GXPs that supply Powerco. There are significant operational benefits for Powerco to own and operate these switchboards. Powerco will be pursuing the transfer of the assets and construction of the new indoor switchboards, where these prove efficient for our customers.

11.5.2 EMBEDDED (DISTRIBUTED) GENERATORS

Table 11.29 lists the generators greater than 1MW in size that are connected to the Powerco networks.

Table 11.29: Distributed generation greater than 1MW by GXP

GXP	CAPACITY [KW]	VOLTAGE	GENERATION NAME	MOTIVE POWER
Tauranga 33	40,000	33kV	Kaimai Hydro Scheme	Hydro
Kinleith	35,000	11kV	Kinleith Cogen	Cogen
Bunnythorpe	34,000	33kV	Tararua Wind – North	Wind
Linton	34,000	33kV	Tararua Wind – South	Wind
Hawera	30,000	110kV	Patea Hydro	Hydro
Hawera	2,500	11kV	Ballance Kapuni	Cogen
Hawera	1,200	11kV	Origin Hawera	Gas
Huirangi	9,000	33kV	McKee (Mangahewa)	Gas
Huirangi	2,000	11kV	McKee (Mangahewa)	Gas
Huirangi	4,800	33kV	Motukawa Hydro	Hydro
Greytown	5,000	33kV	Hau Nui Wind Farm (33kV)	Wind
Greytown	3,850	11kV	Hau Nui Wind Farm (11kV)	Wind
Carrington St	4,500	11kV	Mangorei Hydro	Hydro
Mt Maunganui	4,000	11kV	Ballance Tauranga	Cogen
New Plymouth	1,875	11kV	Taranaki Base Hospital	Diesel backup
Stratford	2,000	11kV	Cheal – 2x1MW units – Stratford injection	Gas
Stratford	1,063	11kV	Cheal – 1x1MW – Eltham injection	Gas
Waihou	4,200	11kV	Waitoa Dairy Factory Cogeneration	Cogen

11.6 PREPARING FOR AN OPEN-ACCESS NETWORK

11.6.1 OVERVIEW

There is much discussion in the industry about customers' changing energy needs and expectations. This is being driven by trends, such as the growing choice and availability of new technology for on-premise storage and generation, uptake of electric vehicles, and society's increasing awareness of the impact on the environment.

The combined impact of these trends on overall electricity consumption on our network is still relatively minor, and is discussed further in Chapter 13. But looking beyond 2023, we anticipate their impact on the network will become noticeable and accelerate at an exponential rate. We want to be part of these changes – supporting our customers in their drive for energy efficiency, and providing them an easily accessible, stable and economic platform to conduct energy transactions. This is the essence of the open-access network.

An open-access network also contributes to New Zealand meeting its carbon emission targets agreed to in the Paris Accord (2015). While our direct impact on carbon reduction is small, we can leverage the capabilities of our network to help our customers, including generators, achieve significant reductions in New Zealand's overall emissions. This will be achieved by running our network to open-access principles, offering customers maximum flexibility and opportunity to innovate, connect to, and transact energy over our network without impediment.

An open-access network promises new opportunities, but will also pose substantial challenges to ensure our network remains safe and stable under the anticipated highly variable load conditions. This will require substantial changes to the way we plan, construct and operate the network. We endorse the work of the Electricity Network Association's Smart Technology Working Group, in particular their views as expressed in the Network Transformation Roadmap. The research and development work that we will undertake to prepare ourselves for implementing this roadmap is described in Chapter 13.

However, that chapter focuses on research and development work. Since we foresee the need for substantial investment in the future to prepare for open-access networks, which will be business as usual, that aspect of our investment plan is included in this chapter, alongside the rest of the network development forecasts. This investment will be based on the learnings from our research and development programmes from Chapter 13.

11.6.2 INVESTMENTS TO DEVELOP AN OPEN-ACCESS NETWORK

New Zealand is still some way behind other developed countries in customer uptake of local generation, electric vehicles and energy storage. The debate about how networks should be operated to facilitate these trends is, therefore, also lagging somewhat. However, we believe that the relatively slow uptake rates of new technology will accelerate, and it is only a matter of time before this will become a material factor for electricity networks, as it already is in parts of Australia, the United Kingdom, the United States and Europe. Our activities to keep abreast of a changing energy world, and the potential opportunities and implications for our network, are discussed in Chapter 13.

One clear network need that we see as common across all future open-access scenarios is to gain good visibility of power flows and quality right across our network – down to the LV level. Closely associated with this, albeit potentially somewhat later, is a need for more automation across our network, to allow us to respond actively to variable demand trends. We anticipate this need regardless of how the energy market may eventually be structured.

Therefore, we intend to commence with substantial investments in a no-regret path to transition to an open-access network post the current CPP period, from FY24 onwards. This includes investments in the following areas:

- **LV monitoring** – we intend to commence rolling out advanced metering across all our LV feeders – providing information on (semi) real-time power flows, voltage levels, power quality, demand patterns and other parameters essential to network operation. To limit costs, we propose to roll out a limited number of meters on each LV feeder (not at every ICP), in a programme that will stretch over five years.
- **Higher voltage network monitoring** – while we have far better visibility of power flows and signal quality on our distribution and subtransmission networks, there are still large areas where improvement is required. This is particularly important from an operational perspective – for example improved accuracy in identifying where exactly a fault occurred – as well as automation and maximising network utilisation.
- **Communications systems** – network monitoring requires supporting communications systems, to transmit the information gathered to centralised databases and to our control centre. This will be expanded alongside the metering roll-out. This is additional to our general communications requirements described in the next section.
- **Analysis support –** managing large volumes of network data, extracting valuable information from this and building systems that will automatically raise alarms when needed, will all require investment in back-office information systems.
- **Power quality management –** as the uptake of customer edge devices accelerates, we anticipate more power quality issues to arise. We therefore include additional (limited) provision for power quality management devices to be installed post FY24, including voltage regulators, capacitor banks, VAR compensators and automatic tap changing schemes.

These investments are included in our Minor Growth and Security works forecast, shown in section 11.9.

If we do not commit to this investment now, in the absence of good visibility across our network, we will have to manage network risks conservatively based on static analysis of worst-case scenarios – we will not compromise on power quality or safety. This will result in limits on the volumes and types of devices that can be connected to our network.

Conversely, with a real-time visible network, we will be far less limited by worst-case assumptions as we will be better able to assess situations as they occur, and respond accordingly. That will allow a much higher level of calculated, controlled and targeted risk-taking, with more tolerance for working closer to our asset's supply limits and associated higher levels of network capacity. This is anticipated to bring improved outcomes for our customers.

Preference for cross-industry collaboration

The bulk of the proposed investment uplift will be on LV metering and monitoring. We fully recognise that the need for this investment would be substantially reduced if we had access to real-time or semi-real-time network information from smart meters. However, at present not only do we not have free access to useable smart meter data, but the availability of real-time data, particularly around power quality aspects, is severely limited. Without substantial upgrades and/or configuration changes to the metering hardware and associated communications systems, the existing smart meter fleet in New Zealand is not suitable to provide the support needed to effectively run open-access networks.

There would be significant opportunity to collaborate with existing meter providers and electricity retailers to avoid duplication of metering installations. This would require agreement on data structures, access to data, what is measured and the frequency of such measurements. While potentially complex, this is not insurmountable and we believe that as a supply industry we could, and should, collaborate to ensure an optimal customer outcome – one that would avoid our customers bearing the unnecessary cost of duplicated metering and supporting installations.

So, while our current expenditure forecast from FY24 onwards assumes that we will be rolling out the required metering on our own, we intend to pursue better outcomes with other industry participants and, based on this, will revise the forecast expenditure in future.

11.7 COMMUNICATIONS INFRASTRUCTURE

11.7.1 OVERVIEW

The communications network asset management plan aims to ensure there is a coordinated approach in the development of the communications network, to better enable our business to deliver its strategic outcomes.

A principal challenge faced is the widely distributed and rural nature of the electricity network, and the lack of terrestrial public network services at many locations. This drives cost into any solution, because the network transport, voice and data communications that are required are often not available unless built by us.

Timely access to data for decision-making is becoming both increasingly important and difficult as more devices producing more data become common at remote locations along our electricity networks, where connectivity and speed can be challenging.

We have also engaged with Powerco's various business units to identify and balance their needs from communications infrastructure. These discussions confirmed there is a need to identify how to engineer sufficient resilience into our systems to meet current needs and maintain the core business processes, while ensuring flexibility and agility to anticipate future needs and respond to new business opportunities.

We need to be considerate of the costs associated with such a development. Our planning approach will help ensure there is due consideration to effectively make trade-offs between current needs, future opportunities and the costs associated with building out a largely rural network.

The communications network asset management plan addresses these challenges. It is designed to help deliver effective protection of our business services, systems and the processes and practices we need to have in place to ensure a reliable, safe and sustainable power supply that promotes safety and wellbeing for our communities.

11.7.2 DRIVERS FOR DEVELOPING OUR COMMUNICATIONS SYSTEMS

Communications infrastructure is a key enabler for the electricity networks of the future. Electricity networks will increasingly require complex multi-layered systems and architecture to support key functions. Communications systems play an important role in facilitating and supporting the way our networks function.

In the future, we will need increasing visibility and a degree of real-time control of many disparate devices that require a reliable, secure, low latency, moderate bandwidth, high density communications network.

This plan has therefore been developed alongside the Network Evolution strategy, as outlined in Chapter 13.

The principles and enablers align with the communications capabilities identified in the network evolution roadmap and the strategic imperatives in the IS strategic plan (ISSP).

When combined, our enablers of Governance, Resilience, Visibility, Collaboration and Flexibility represent a comprehensive response to support our business drivers.

11.7.3 KEY COMMUNICATIONS NETWORK BUSINESS DRIVERS

- Staying safe – delivering safe and reliable supply and ensuring the underlying condition of our networks is maintained and replaced in a prudent and timely way.
- New technology – network evolution, embracing and leveraging new technology and cost-effective asset management requirements.
- Utilising flexible architecture – that enables networks to be designed and delivered in a manner that responds dynamically to changing demands and needs.
- Modernising the grid edge – with distributed technologies that enable new methods of network operations, management and service provisioning.
- Visibility – on our network and assets to prepare for changing consumer needs and enhance asset management and network performance.

11.7.4 COMMUNICATIONS NETWORK PRINCIPLES

Our communications network has been designed based on four key principles. These are:

- Reliable networks – communications engineered for resilience
- Flexible and scalable – agile and responsive to changing needs
- Collaborative culture – a partnership approach
- Leveraging investment – maximise the benefits of infrastructure

11.7.4.1 RELIABLE NETWORKS

We will improve health and safety risk outcomes by providing reliable communications platforms, engineered for security and resilience in the face of natural disasters, with appropriate levels of redundancy and self-healing. Communications network faults will be managed efficiently. We will seek to drive consistency across our networks by having in place robust and well-communicated standards and operational procedures.

11.7.4.2 FLEXIBLE AND SCALABLE

We will invest in flexible, responsive and cost-effective communications architecture that will serve our changing requirements over time. We will be agile in our response to communications requirements and ensure our solutions are scalable. We will minimise risk by seeking diversity in our selection of vendors.

11.7.4.3 COLLABORATIVE CULTURE

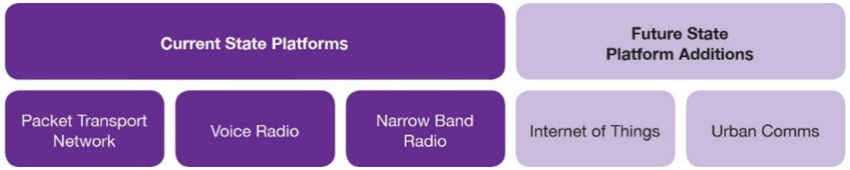
We will take a partnership approach to understand and support business and stakeholder needs, find solutions and identify investments. We will provide access and training for communications services and tools so that Powerco staff are informed and empowered. We will become part of a wider Powerco virtual team and will establish a regular cross-functional governance forum to ensure we make communications investments that will both enable strategic organisational outcomes and support operational needs.

11.7.4.4 LEVERAGING INVESTMENT

We will maximise the benefits of our existing infrastructure to improve the coverage and reach of our networks. This will enable us to provide visibility of network status to stakeholders, which will enable management of risks to people and assets. We will report against agreed service levels and employ an asset management approach to ensure efficient investment and asset management.

11.7.5 COMMUNICATIONS NETWORK PLATFORM

Powerco's communications network comprises three key platforms, as shown below. During the development phase of this strategy, two additional platforms were identified for future inclusion in the network – Urban Communications and Internet of Things.



11.7.5.1 PACKET TRANSPORT NETWORK PLATFORM

The packet transport network (PTN) is the main highway for data and voice communications back into Powerco's NOC. The PTN is a Multiprotocol Label Switching (MPLS) based packet switching network that use uses fibre, microwave and leased line services to transport information. It is a critical component in the operation of Powerco's electricity grid

11.7.5.2 DIGITAL MOBILE RADIO PLATFORM

The digital mobile radio platform allows Powerco's NOC staff to communicate to field contractors in locations where public mobile services are unavailable. As the primary means of communication with field resources, Voice and Radio Platform (VRP) is built with a high level of redundancy to help ensure the health and safety of staff and contractors working in remote locations.

11.7.5.3 NARROW BAND RADIO

The narrow band platform provides both VHF and UHF data services for control and telemetry of the electricity grid. Although it is considered a legacy technology, it is still widely used by Powerco because of the remote nature and geographic spread of its electricity grid.

11.7.5.4 INTERNET OF THINGS

The Internet of Things (IoT) platform is an emerging platform with its ability to use low cost, low power sensors and base stations that can cover a wide geographic area. The sensors are considered disposable and will be rolled out in large quantities and only replaced when a certain percentage have failed. It will likely replace a large percentage of the narrow band platform over time.

11.7.5.5 URBAN COMMUNICATIONS

The Urban Area Communications platform is a combination of multiple technology sets designed to allow communication with a vast quantity of sensors in urban environments, where obstructions are prevalent and space is limited. This fulfils requirements for telemetry, control and distributed automation in the major cities on Powerco's network.

11.7.6 FUTURE ROLLOUTS

Our principal development programmes are built around the communications network platforms as shown in Table 11.30.

Table 11.30: Communications network development programme

FUTURE ROLLOUT PLATFORM	DETAIL
Digital mobile radio platform	Digital mobile radio network additional coverage and capacity
	Implementation of data functionality
Packet Transport Network (PTN) platform	Transport network expansion to all zone substations
	Network segmentation capability to allow flexibility for all services to use PTN
	Transport resilience – east to west microwave link
	Migration of the distributed IP network to PTN
Internet of Things (IoT) platform	IoT pilot
	IoT network build or integration of service
	Expansion of IoT platform
Urban area communications platform	Pilot of urban communications platform technology
	Implementation in major CBDs – Tauranga, New Plymouth, Whanganui, Palmerston North
Other supporting initiatives	
Communications Governance	Implementation of a new communications network governance structure
Communications Service Level Agreements (SLA)	Finalisation of communications SLAs and reporting
Conatal to DNP3 conversion	Complete conatal to Distributed Network Protocol version 3 (DNP3) conversion in the east

11.8 ROUTINE PROJECTS

11.8.1 OVERVIEW OF ROUTINE CAPEX

Routine Capex incorporates the lower cost, usually repetitive projects that address capacity and security. These mostly occur at the distribution level.

Routine Capex projects have shorter lead times and are often more sensitive to changing growth rates and customer or network activity, therefore they are more likely to change in scope at short notice. It is impractical to try to identify individual projects less than one to two years before implementation.

As such, to understand our longer term investment requirements, we need to consider the type of work, the reasons why it needs to be done, and the generic trends in these activities.

Types of projects include those that come from distribution planning analysis (refer to Chapter 7). These projects typically add capacity to existing parts of the feeder network or create additional feeders or backfeed ties. There are also some distribution transformer and LV projects.

Some lower cost zone substation growth and security projects also fall into the routine projects category. These include smaller power transformer upgrades, especially at single transformer substations.

While it is not practical to identify specific projects in the routine class, there are trends and patterns that dominate each planning area. Commentary on these is provided near the end of each area section.

11.8.2 ROUTINE PROJECTS FORECAST CAPEX

Historical expenditure trends on routine growth and security projects have been used to inform appropriate expenditure levels.

Traditionally such expenditure was strongly linked to underlying growth. This is still true for some project types, such as capacity upgrades, voltage regulators and new feeders.

However, in areas of less growth, upgrades to distribution feeder links are often focused on providing additional backfeed capability. This includes new feeder interconnections (or ties) and larger conductors or cables to allow better voltage or thermal capability under backfeed conditions.

Our automation plan (refer to Chapter 12) has required a rise in development investment so that the automated or remote-controlled switching schemes do not overload existing circuits or result in unacceptable voltages. This has brought forward a number of feeder tie and backfeed upgrades.

Some emerging technology (refer to Chapter 13), especially concentrated PV, has the potential to require voltage support to the network. As part of our future network strategies we are developing tactics to address this. In an extreme scenario it could require a significant increase in distribution transformer replacements or LV circuit upgrades. However, the level of impact will be determined by PV uptake rates.

Other drivers for routine project growth and security expenditure include:

- Areas of intensive irrigation.
- Intensive dairy conversion, or existing dairy areas needing to upgrade plant.

Local reticulation for new subdivisions is mostly funded through customer contributions and our customer connections expenditure. However, some upstream feeder development can also be required but cannot be attributed to any specific customer or subdivision. In this case expenditure falls into the routine development category. This type of project mainly occurs in high urban growth areas, such as Tauranga and Mt Maunganui.

11.9 FORECAST GROWTH AND SECURITY CAPEX

Figure 11.4 and Figure 11.5 show the forecast Capex on major projects and minor growth and security expenditure respectively. Few large projects create a 'lumpy' major project expenditure, which is balanced by activity in the minor works.

Figure 11.17: Forecast Capex on major projects

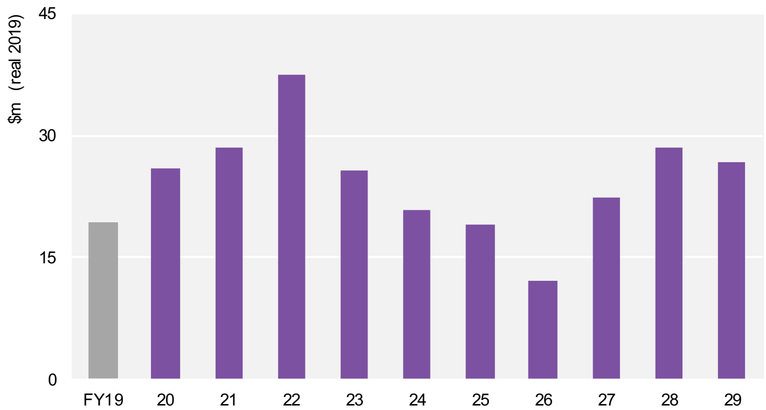
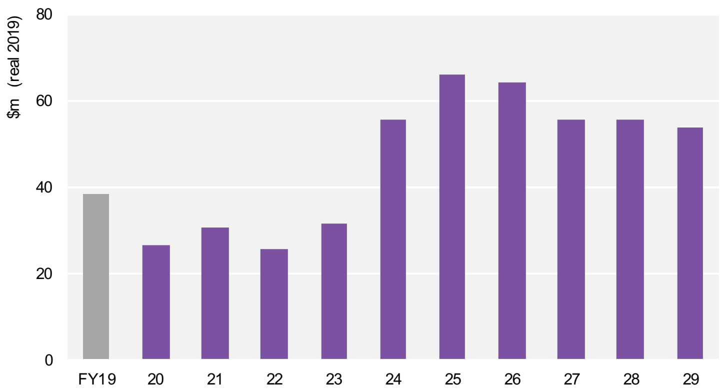
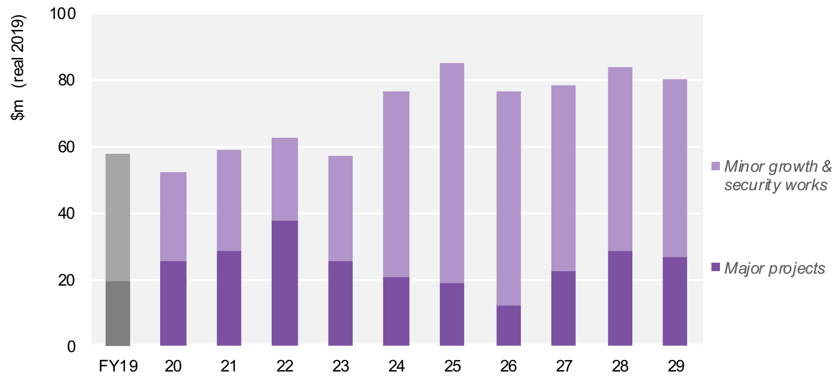


Figure 11.18: Forecast Capex on minor growth and security works



Expenditure on minor growth and security increases significantly in the latter half of the planning period because of the proposed Transpower switchboard replacements and the new expenditure on the rollout of network visibility, as discussed in Chapter 13. The figure below shows forecast Capex on both major projects and minor growth and security works during the planning period.

Figure 11.19: Forecast Capex on major projects and minor growth and security works



With both portfolio forecasts added together, expenditure is expected to increase during the planning period.

12.1 OVERVIEW

Many projects contribute to the long-term reliability of our networks. Renewal projects address reliability concerns of our older assets, while network development projects help enhance reliability by providing alternative options for supply.

For the purpose of this chapter we consider only those expenditures not specifically covered in our other sections – network development plans, fleet management plans, and operational and maintenance plans.

The only expenditure that falls into this category is network automation projects.

We use network automation to help manage the reliability performance of our network. In this context network automation refers to the systems and devices that are used to undertake remote switching and reconfiguration of our networks.

Automation of distribution switchgear allows us to:

- Remotely isolate and reconfigure networks
- Automate fault response actions
- Gain better visibility of network operating conditions
- More easily pinpoint fault locations

Automation is an important investment focus as it provides reliability improvements to be achieved reasonably quickly. This helps us stabilise reliability outcomes on our networks while we work to address and stabilise emerging asset health and network security issues.

12.2 AUTOMATION PLAN

The automation plan for the period covered by this AMP involves deploying a judicious combination of:

- Remote controlled or automated distribution switchgear
- Protection and monitoring devices
- Reclosers and sectionalisers
- Power Quality Measurement Systems (PQMS)
- Distribution Fault Analysis devices (DFAs)
- Line Fault Indicators (LFIs)
- Loop automation schemes, whereby faulted sections are isolated and healthy downstream circuits are automatically restored from an alternative source

We have found from experience that the most benefit is obtained from automation devices if they provide good visibility of network and device behaviour. Therefore, we tend to install smart devices only where we have comprehensive remote monitoring and control capability.

In the 2017 AMP, we specified the exact numbers of each type of device that we would be installing on the network. In this planning period we have taken a more holistic view of network needs and the benefits that each type of device offers. We have been more particular about the locations they will be installed to ensure they are positioned where they will provide the most benefit. We have also been careful to align our network automation efforts with what is intended to be achieved through Network Transformation (Chapter 13).

Our budgets are based on expenditure norms in this area, but the precise mix of devices installed from year-to-year will remain flexible.

Towards the latter half of the planning period, we anticipate the need for enhanced visibility of the performance of our Low Voltage (LV) and Medium Voltage (MV) circuits. This will be primarily driven by the uptake of distributed generation, energy storage and other disruptive technologies, such as electric vehicle (EV) charging. We intend to roll out monitoring equipment across the network to ensure we can address the power quality issues anticipated as a result of these changes.

This initiative forms part of our overall Minor Growth and Security expenditure forecast. The rationale of this rollout is discussed further in Chapter 13.

12.3 ALIGNMENT WITH ASSET MANAGEMENT OBJECTIVES

12.3.1 SAFETY AND ENVIRONMENT

Automation brings substantial benefits in improved reliability, but automatic reclosing of circuits that have been subject to a fault can present risks for the public and workers.

We use a risk-based assessment process to understand and manage the safety implications of automated reclosing schemes, whether on meshed or radial circuits. We do not automatically re-liven circuits where there is a possibility of danger to workers or the public.

12.3.2 NETWORKS FOR TODAY AND TOMORROW

Our focus on networks fit for today and tomorrow helps us ensure our assets provide the services our customers require and provide the benefits that technology can practicably deliver.

Network automation provides several benefits that complement our goal of shaping our networks for the benefit of customers over time.

Specifically:

- Automation helps us improve reliability on heavily loaded or older circuits where faults have a material impact on customers.
- Automation lifts the level of central oversight and control we have on our network, giving us operational flexibility and real-time control.

- Automated switches provide a range of real-time measurements that are complementary and can be used for advanced asset management.
- Automation provides the means to monitor and correct power quality issues, in particular, those issues that are likely to arise through increased distributed generation and two-way power flows.

Overall, new switching and control capabilities, especially when combined with communications, data gathering and data processing technologies, can greatly improve the reliability, flexibility and adaptability of our networks.

As our data availability and reliance grows, integration of field automation devices with modern Outage Management Systems (OMS) such as Fault Location, Isolation and Restoration (FLISR) is essential. Our automation strategy focuses on installing devices that help us to step toward that future while providing immediate reliability benefits.

12.3.3 ASSET STEWARDSHIP

This objective requires we manage our large number of diverse assets efficiently, keeping them in good health.

Network automation systems enable us to remotely reconfigure networks without the need for ground crews. This provides faster restoration times, thereby helping us manage our System Average Interruption Duration Index (SAIDI). They also enable us to pinpoint fault causes and locations accurately, reducing fault crew effort.

All of this reduces costs, improves efficiency and helps us manage our assets effectively.

12.3.4 OPERATIONAL EXCELLENCE

Automation provides us with a range of important short-term benefits that are of value while we move to address emerging issues associated with ageing assets and security-related exposure.

The benefits include:

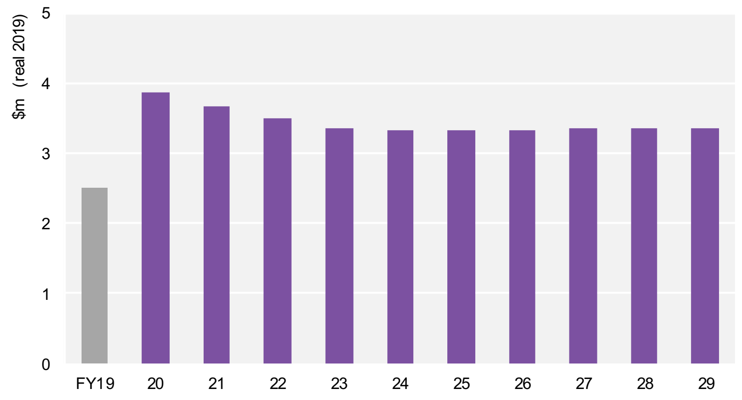
- Shorter outages through faster fault location and reduced time to reconfigure the network.
- Minimising the number of customers affected by faults.
- Reduced costs relating to line patrols, manual switching and manual fault location.
- Reduced likelihood of equipment damage because of overloading, under-voltage or slow protection settings.

Overall, automation is an important investment area to enable us to manage our networks effectively in real time.

12.4 EXPENDITURE FORECASTS

Our forecast expenditure is shown in Figure 12.1. The cost estimates are based on historical unit rates, including costs related to extending the communications network from our backbone network to each remote device. The forecasts do not include the rollout of LV monitoring (Network Visibility), which is included in the Minor Growth and Security forecasts in Chapter 11.

Figure 12.1: Forecast Capex – reliability



The expenditure level reflects the automation density in our rollout works plan. During the planning period we will regularly assess the performance benefits of our automation strategies. We may also have to revise the forecast later in the planning period when considering changes to the technological landscape.

13.1 CHAPTER OVERVIEW

This chapter sets out how we plan to enable our customers to access new energy options as energy markets evolve and mature, while at the same time ensuring they can continue to readily access electricity as they do today. It also describes how we will research and use emerging technology to improve network operations and utilisation, thereby increasing the longer term benefits to customers.

In the following sections:

- We describe the political, market and technological trends that are influencing our network and how we do business.
- We describe how these changes are manifesting themselves in New Zealand and, more specifically, on our networks.
- We describe how lines companies are evolving to support future customer needs and new technologies in an uncertain future.
- We describe our Network Evolution Strategy and pilot programmes as we ready ourselves for change.

We conclude the chapter by outlining our corresponding 10-year Network Evolution investment plan.

13.2 INTRODUCTION

Since our last published AMP, the role of energy systems in decarbonising the economy has been a strong focus across the world. New Zealand has set itself ambitious targets and is making quick progress to form a plan that will lead to a net zero-carbon economy by 2050. As noted by the New Zealand Productivity Commission in last year's *Low-emissions economy* report, *[…] steps will be needed to manage growing complexity and risks to system and service providers' stability, and to ensure a level playing field for different types of technology.*

Our Network Evolution strategy reflects this focus. It aims to enhance the value we offer to our customers and, through this, to the wider New Zealand society, the environment, and the economy. In particular, it recognises the challenges brought by the 3Ds of the energy industry:

- Decarbonisation – breaking down the silos between fuels to achieve a net-zero carbon economy.
- Decentralisation – accepting that the legacy model of unidirectional electricity flows is changing.
- Digitalisation – creating the data and tools enabling smarter ways to generate, distribute and consume electricity.

We recognise that society is facing an unprecedented challenge regarding a warming environment. We are fully committed to helping New Zealand achieve its carbon reduction targets agreed to in terms of the Paris Accord (2015), and the Government's associated target of a 100% renewable energy supply by 2035.

We are committed to being an environmentally responsible business, which is also reflected in our investment decisions and operational practices. But the biggest contribution we, and other electricity distributors, can make towards helping this cause, is by enabling and supporting our stakeholders to create, use and save energy as efficiently as possible. We do not subscribe to the view that distribution assets will mostly become surplus to requirements – instead we see distribution networks providing a vital platform to support flexibility and innovation in our customers' future energy use, meeting New Zealand's decarbonisation challenges.

We see that the key to supporting New Zealand's carbon reduction targets, will be running our network to open-access principles. This will offer maximum flexibility to customers (end users and generators) with the opportunity to innovate, connect to, and transact over our network without impediment. In turn, this will allow the uptake of distributed, particularly renewable, generation to flourish, as well as facilitate other energy efficient applications, such as storage and demand management. While future energy market arrangements are still being developed, we will ensure that the network remains safe, operates stably and provides sufficient capacity under any reasonable energy use scenario.

To achieve this goal, we recognise that the way we design, build, and operate our network has to change. The pathway to change, however, remains filled with uncertainty. The sector is being highlighted as prone to disruption, as technology becomes cheaper, customers' needs and expectations in terms of quality of service change, and environmental pressure increases. Despite these changes, the large majority of our existing customers will continue to expect the same conventional electricity supply they have now. Therefore, we have to strike an effective balance between investing in conventional network assets to maintain expected service, and adapting to emerging technology and changing consumption patterns. We have to make long-term decisions that are economically efficient and in the best interests of our customers.

Our planned Network Evolution investments will expand our suite of customer offerings and offer opportunities to improve network efficiency and reliability. These investments are described in this chapter. However, they will not remove the need for ongoing investment in traditional network maintenance, renewal and growth, which is the focus of most of the rest of this AMP.

13.3 THE CHANGING ENERGY ENVIRONMENT

13.3.1 OVERVIEW

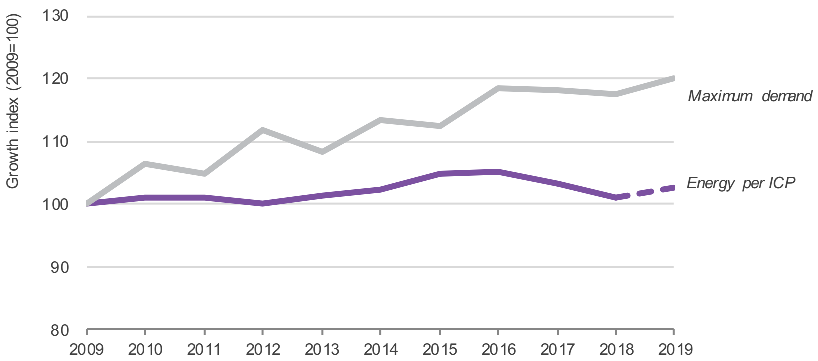
After almost a century, the way electricity is delivered to customers is starting to change.

In a legacy system, such as New Zealand's, the flow of electricity has been almost exclusively from large generators, through transmission and distribution networks, to end customers.

Most smaller customers have essentially been considered as quality takers – the service they have received has been determined by their position on a network, and they have had only limited ability to influence it. This is the reason why electricity networks have evolved and been configured to meet peak demand, offering a one-size-fits all approach to passive or disengaged customers.

New technology in generation and consumption is challenging this model and leading to more stress on the network during peak hours. We are starting to see signs of this on our network. Figure 13.1 demonstrates that although the overall electricity consumption for each customer has not changed materially, reducing in some instances, peak electricity demand, or consumption during the peak demand hours of the day, has been steadily growing during the past decade[35].

Figure 13.1: Average electricity consumption and demand on our network



Note: The figures are based on electricity drawn from grid exit points (GXPs) and do not include the impact of distributed generation. The 2019 consumption is a projection of expected consumption.

35 Annual compound growth in the average consumption per Installation Control Point (ICP, all categories) since FY11 has been 1.2%, while the coincident network peak demand during the same period has grown by 1.9% per year.

This situation is expected to accelerate because of the driving force of the 3Ds – decarbonisation, decentralisation, and digitalisation – transforming the energy supply industry.

We know that decarbonisation will, for example, increase the demand for Electric Vehicles (EV), and that charging requires a significant amount of electricity, often used at peak demand times. Conversely, we also know that decentralisation could bring more small-scale, distributed generation and energy storage facilities, which could reduce energy demand from the network. In addition, digitalisation will create new services that could allow peak lopping – decreasing peak demand, but not necessarily affecting overall energy consumption.

We discuss the most significant trends of the 3Ds in following sections.

13.3.2 DECARBONISATION

Decarbonisation is the challenge to reduce carbon dioxide (CO_2) emissions from the world's activity to fight climate change.

The New Zealand Productivity Commission's *Low-emissions economy* report details pathways for New Zealand to reduce its carbon emissions, in line with the targets of the Paris Accord. It highlights the electricity sector as one of the main impacted sectors. Not only is electricity supply a major contributor of CO_2 (through thermal generation for example), it is also an enabler to allow more carbon-intensive sectors to decarbonise, eg substituting petrol cars with electric vehicles.

Most electricity distribution utilities do not generate significant electricity and are not themselves large electricity users. Therefore, our main role is to encourage and accommodate carbon reduction initiatives by offering end-users and generators the technical solutions and services that this policy decision requires. In particular, we will plan and operate our network as an open-access platform, which will allow customers to connect devices to it as desired, including renewable generation and energy storage devices, and conduct energy transactions over it, while we continue to ensure a stable and safe electricity supply.

Our commitment to support lower carbon emission targets

New Zealand is committed to meeting the carbon emission targets agreed to in terms of the Paris Accord (2015). The government has also announced a target of a 100% renewable energy supply by 2035.[36]

As a company, we are fully committed to helping New Zealand achieving these targets. We are therefore committed to acting in an environmentally responsible manner in all our investment decisions and operational practices – as witnessed by our recent certification to the ISO 14001[37] standard and our high GRESB[38] score.

However, our impact on carbon reduction is insignificant compared with what we can help our customers, including generators, achieve – through our role enabling them to create, use and save energy as efficiently as possible.

The key for us in supporting New Zealand's carbon reduction targets will be running our network to open-access principles, offering maximum flexibility to customers with the opportunity to innovate, connect to, and transact over our network without impediment. While future energy market arrangements are still being developed, we will ensure that the network remains safe, operates stably and provides sufficient capacity under any reasonable energy use scenario.

Additionally, effective demand management, energy storage and tariff incentives will help maximise the utilisation of existing energy infrastructure and defer or minimise future investment. Electricity should also offset other, less environmentally friendly, forms of energy, and the network should facilitate this, for example electric vehicles offsetting the demand for petroleum.

13.3.3 DECENTRALISATION

Decentralisation is the shift from centrally generated, large scale electricity production to distributed, or scattered smaller-scale devices that can often generate, store or consume electricity.

Decentralisation could be a challenge for us both from policy and technical aspects.

Customers expect the ability to offset their own electricity consumption or to sell surplus electricity, while maintaining a connection to our network to cover the times that their devices cannot generate, for example at night.

This requires us to maintain electricity connections at full capacity, even if average consumption levels reduce. Since the bulk of our revenue is traditionally derived from quantum of electricity delivered, this makes network capital cost recovery more difficult. It will require us to consider alternative pricing structures in future, particularly if we are to avoid charging other customers more as a result.

Concentrated clusters of new distribution edge devices[39], such as solar photovoltaic (PV) generators or electric vehicles, can also cause voltage stability or other power quality issues. Older networks, in particular, which were not designed for potential two-way power-flows or rapidly changing, high-peak demands, will need intervention, otherwise we will have to limit the connection of such devices. This would be a last resort and an undesirable situation, as we would not only inhibit customer flexibility, but we would also run counter to achieving carbon reduction targets.

13.3.4 DIGITALISATION

Digitalisation is the substantial and sustained increase in the number of digitally enabled and connected sensors, data and analysis tools available to customers, market participants and asset owners. It will help our stakeholders to understand and manage their energy demand profiles, and also allow them to conduct energy transactions over our network.

The cost of data capture, storage and communication continues to decrease. Low-cost sensors and communication mediums, eg Long Range Wide Area Network (LoRaWAN), are becoming mainstream. With it, artificial intelligence, blockchain, and other capabilities have become more prominent as computing processing power increases.

For asset managers, this trend offers major opportunities to efficiently increase visibility of network condition, utilisation and operational conditions. It will allow us to enhance our service offering, improve network utilisation and reduce potential instability issues that could arise from connecting edge devices. This all would contribute to more efficient and stable network utilisation and support cost effective delivery.

13.4 OBSERVATIONS OF THE NETWORK

While we know that around the world there are many examples of how the 3Ds are fundamentally changing the industry, the speed of the change in New Zealand is still uncertain. In this section, we explore our observations and their practical implications for our network, starting with high-level consumption trends, and distribution edge devices.

36 Under normal hydrological conditions.

37 ISO 14001 is an internationally accepted standard that provides the framework to put an effective environmental management system in place within an organisation.

38 GRESB is an independent environmental, social and governance benchmark for real assets, defining the global standard for sustainability performance in real assets to assess the sustainability performance of real estate and infrastructure portfolios and assets worldwide.

39 Distribution edge devices are new types of end-customer loads connected to the distribution network that were not traditionally prevalent and have characteristics that can cause power signal distortion in different ways to traditional, mainly resistive, customer loads. It includes local generation, particularly PV, electric vehicles, energy storage devices, and the like.

13.4.1 CONSUMPTION TRENDS

As described before, while peak demand is still increasing slowly, the average consumption per Installation Control Point (ICP) on our network remains relatively consistent. This is mainly because of:

- **Energy efficiency –** modern household appliances, including lighting, are becoming more energy efficient. A customer with these devices can enjoy the same, or improved, functionality as in the past, while consuming less energy. Improved building efficiency standards also contribute to lower energy use.
- **Energy awareness –** customers are increasingly aware of their energy consumption and many are taking active steps to reduce it. This is becoming increasingly feasible using smart devices that control the use of appliances, such as lighting, water or space heaters to best match residential patterns.
- **Local generation –** significant improvements in efficiency, along with major reductions in cost, are making it economically and technically viable to bring electricity generation closer to the source of consumption. This includes the ability of customers to generate their own electricity, in part or fully, which is largely done through renewable generation sources, especially solar PV.

We believe this trend will remain true for the next two to three years and that our network will be able to accommodate these changes in the short term. However, in the longer term, network stability and capacity could be at risk. Even if the expected time for that change to eventuate is 10 years, it is a short timeframe when considering the lifecycle of an electricity network. It is essential we understand and prepare for this eventuality to ensure our networks can accommodate related changes.

We will therefore continue to monitor emerging international and local trends, to ensure we remain abreast of these and the potential implications for our network. It will also allow us to adopt promising technologies or solutions that could improve our network efficiency and reliability or reduce costs. Above all, this will help ensure that we remain in touch with our customers and deliver the flexibility and services they value.

13.4.2 SOLAR PHOTOVOLTAIC GENERATION

Residential PV generation is growing rapidly across the world. Uptake rates between countries vary, but have been particularly pronounced in Germany, parts of Australia, the United Kingdom, Denmark and some US states, such as California. This has broadly been in direct response to government mandates to achieve low carbon emission targets, encouraged by way of subsidies, tax incentives or feed-in tariffs (buy-back of excess power generated) to customers. Regardless of the initial driver, the scale of uptake has supported large-scale manufacture and resulted in reduced costs.

Rooftop solar is becoming available at prices that can, in many instances, be economic without subsidy, and the industry is now generally regarded as ‘self-supporting’.

In parallel with small scale, mainly residential, PV generation, there is significant annual growth in industrial or utility scale PV installations. While much of this is also the result of government mandated targets or incentive schemes, in many instances the cost of generating electricity from large scale PV installations is at parity, or sometimes less, than that of conventionally produced electricity.

The International Energy Agency[40] reports that PV electricity production has grown from 4TWh in 2005 to 531TWh in 2017, with the trend accelerating.

Internationally, it is reported that 2.5% of electricity consumed globally in 2017 was produced by PV installations.[41]

By contrast, the uptake of PV in New Zealand, while growing substantially on an annual basis, is still at a much lower level. The Electricity Authority reported that as of 31 March 2018, New Zealand had 18,000 residential customers with installed solar generation, representing a total of about 62MW[42]. This represents a 32% increase in capacity over the December 2016 figure published by Ministry of Business, Innovation and Employment (MBIE) of 47MW[43].

PV uptake on our network is shown in Figure 13.2 and Figure 13.3[44]. At the end of December 2018, the total PV connection proportion on our network was 1.1% (3,780 ICPs), triple the number registered in March 2016.

[40] International Energy Agency, “IEA KeyWorldEnergyStatistics, v 6.1.0, 2018” and “Trends 2018 in Photovoltaic Applications”.

[41] International Energy Agency, “Trends 2018 in Photovoltaic Applications.

[42] Electricity Authority, “Electricity in New Zealand’, November 2018.

[43] MBIE, Energy New Zealand: 2017.

[44] Electricity Authority, www.emi.ea.govt.nz.

Figure 13.2 : PV uptake on our network (percentage of ICPs)

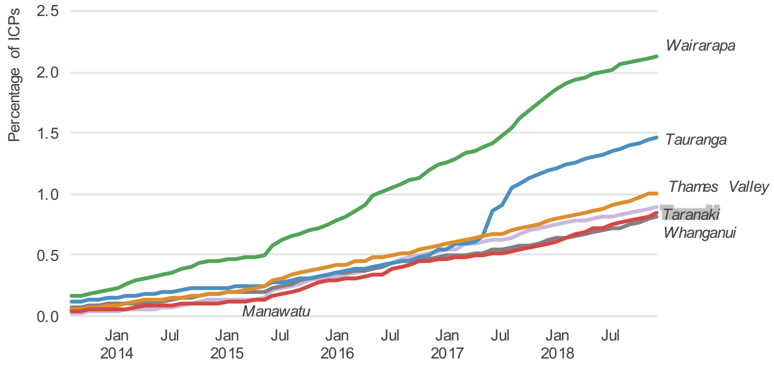
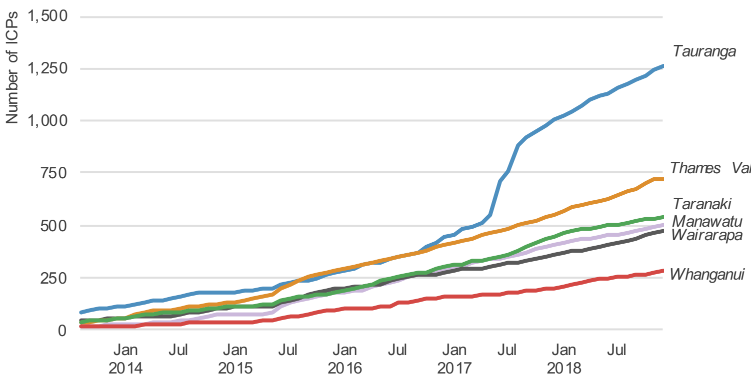


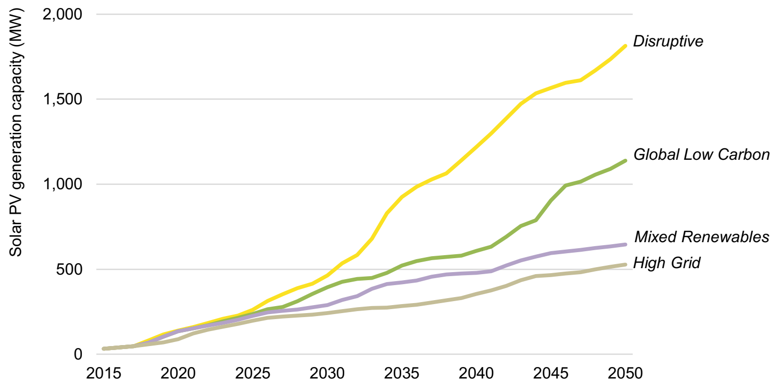
Figure 13.3 : PV uptake on our network (number of ICPs)



In the 18 months ending December 2018, on average there were 75 new solar PV connections per month, up from an average of 52 per month reported in our previous AMP. International literature suggests that when PV penetration reaches about 10% on a network, issues associated with the variability of its output could become material, requiring some form of network investment[45]. At current growth rates, this still appears to be some distance off on our network, although localised clusters of high PV penetration rates would have to be closely monitored.

In August 2016, MBIE provided an updated Electricity Demand and Supply Generation Scenarios (EDGS) model, which included forecasts for the anticipated growth of solar PV generation in New Zealand under various scenarios. The ‘disruptive’ scenario suggests that PV generation could approach 10% of (current) installed NZ generation capacity by about 2035.

Figure 13.4 : Forecast growth of PV installations in New Zealand[46]



13.4.3 ELECTRIC VEHICLES

The use of EVs (full electric or plug-in hybrid) is still in its relative infancy in New Zealand, with a total of 11,000 vehicles registered at the end of 2018. However, as with other emerging technologies, the uptake rate is accelerating, and it is likely that these vehicles will be a regular feature on our roads in the foreseeable future. There is also wide recognition that New Zealand, with its high proportion of renewable electricity generation, is well placed to achieve major carbon emissions reductions from switching its vehicle fleet from conventional fuel to electricity, which may provide further impetus for the uptake of EVs.

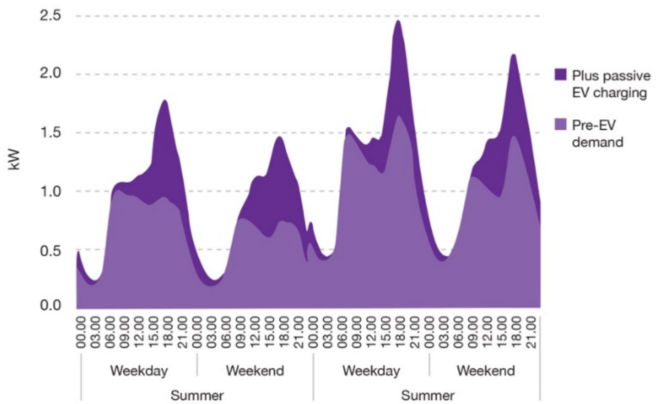
We do not see a material network impact from EVs in the short term. However, as penetration numbers rise, the potential for localised power quality issues increases within the low voltage network. To facilitate EV charging, particularly

45 This relates to issues such as excessive voltage rise at periods of low load, and voltage fluctuations with potential to create network instability. The impact could be reduced if modern inverters allowing volt/VAR correction, or energy storage devices are in wide use.

46 Source: MBIE, “Electricity Demand and Supply Generation Scenarios 2016”, http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016.

at peak demand times and with fast chargers, could require substantial network reinforcement. In 2018, we commissioned a study in collaboration with Unison and Orion to model the impact of EV charging on residential ICP demand [47]. It showed that, without any form of control, the demand could increase significantly, as shown in Figure 13.5.

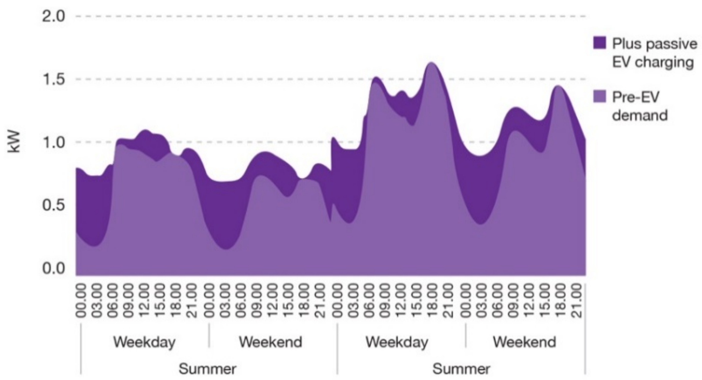
Figure 13.5: Impact of EV charging on an average household demand profile



The study suggested that this increase in demand can be mitigated by the introduction of smart charging. Figure 13.6 shows how smart EV charging can influence the demand profile.

[47] For example, Electric Vehicles in New Zealand: From Passenger to Driver, published by Dr Allan Miller and Scott Lemon, EPECentre, University of Canterbury.

Figure 13.6: Impact of smart EV charging on an average household demand profile



EV uptake and demand response capability at a household level is hard to assess as customers are not currently required to notify the network operator when they have purchased an EV or installed non-significant chargers, ie those that do not require a change in their electricity supply. This lack of visibility has an impact on the efficacy of network investment and reinforcement to accommodate the capacity and quality challenges introduced through EV charging. We are working with wider industry groups to both address the lack of visibility and to improve our ability to monitor and predict EV uptake increases.

13.4.4 ENERGY STORAGE

Energy storage has been a major topic of discussion in the industry since 2015, with a rapidly escalating range of market offerings at both the domestic and utility scale. There are more than 250 battery installations on the Powerco network alone (7.3% of distributed energy resources, DER).

While internationally the main focus is on battery products, other storage mechanisms such as compressed air storage, pumped water storage and various forms of heat storage are also receiving attention, but generally for large scale applications only.

Worldwide, the installation of battery storage capacity is increasing at a significant rate – mainly in utility scale applications, typically in the range of 0.5 to 10MW/MWh, although larger units are increasingly frequent. These are mainly installed by electricity utilities for peak demand management, network stability, standby capacity, or to participate in ancillary service markets. Meeting government mandated targets for renewables and energy storage also plays a major role.

Residential scale applications are expanding rapidly, but the overall storage capacity associated with these is still relatively small. Other than the installation cost, uptake rates for domestic storage systems are also very sensitive to factors such as (the absence of) feed-in tariffs, subsidies, the cost of electricity, and the reliability of supply.

In New Zealand, the uptake of battery storage and other new forms of energy storage is still in its infancy, with only a few major installations in place, although many trials are under way. This situation is expected to change during the planning period although we still don't foresee a major proportion of energy supply assisted from storage devices.

Although the cost of battery storage systems has reduced substantially in recent years and is anticipated to decline further in the foreseeable future, for the vast majority of individual customers it is still significantly more expensive than conventional grid-supplied electricity (by comparable capacity).

In some instances, mainly in remote rural areas, the installation of combined generation and battery storage units is economically feasible and uptake rates in these cases may accelerate. It is also noted that the combination of effective storage and local, mainly PV, generation offers customers a significant degree of flexibility in how they procure and use electricity, which in some cases may override decisions based on economic factors alone.

Overall, we do not believe that battery storage will lead to meaningful levels of grid defection or have a substantial impact on how the electricity network is utilised in this planning period.

In the longer term, our view is that energy storage systems, both at utility and residential scale, will have a valuable role in the provision and use of electricity. They offer significant potential for increased reliability and resilience of supply, potential for deferring network reinforcements and lifting network utilisation, improving network stability and maximising the value from distributed generation sources. It is therefore an area on which we intend to increase our focus, increasingly incorporating storage solutions where these provide economic or reliability benefits to our customers.

13.4.5 DEMAND MANAGEMENT

For years, New Zealand has been a world leader in the application of demand management systems, particularly in its use of water heaters as controllable load. Considerable debate is under way on whether these load control systems should be maintained, expanded, or replaced with newer technology. Hot water control systems continue to play an important part in managing peak demand on our network and avoiding transmission peak charging to our customers.

With improving communications systems and more intelligent home devices, new opportunities are opening up for demand management on the customer side of the electricity meter. While it is not our intent to become involved in customer products, such as home area networks, we will continue to pursue demand management solutions where these offer economic alternatives to network reinforcement.

In particular, we see potential through the implementation of pricing arrangements or through commercial load-shedding agreements to work with customers to reduce peak demand and/or improve network utilisation.

With the advent of large-scale energy storage on our network in future, opportunities will also arise for demand management on the network side. There is increasing opportunity to roll out 'intelligent' devices on the network. These allow more visibility, remote communication, and use of computers to optimise power flows. A better understanding is gained of the real-time performance of the network, increasing the ability to take effective action based on data available. Ultimately this allows networks to be 'run harder', and for electricity demand to be spread more evenly over the day without compromising reliability. This will increase utilisation levels and reduce investment needs.

13.5 DISTRIBUTION NETWORKS OF THE FUTURE

13.5.1 OVERVIEW

The future nature of electricity distribution networks is being widely debated around the world. We subscribe to the New Zealand-specific Network Transformation Roadmap developed by the Electricity Network Association (ENA)[48]. It is backed up by international research in similar jurisdictions, particularly Australia and the United Kingdom.

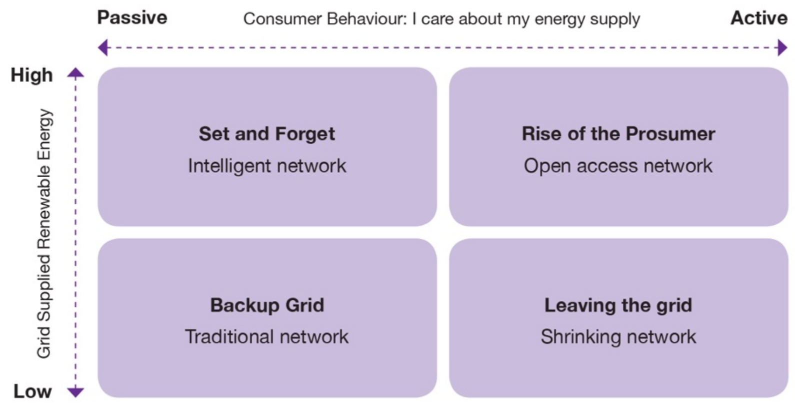
As described in the ENA's study, we recognise that the network of the future will be influenced by two main factors:

- Customer behaviour – how engaged are customers with their energy supply?
- Technology – how much renewable electricity, and associated edge devices, is connected to the grid?

Using this dichotomy, four scenarios were created and are summarised in Figure 13.7. These purposely extreme scenarios are intended to provide clarity in thinking and assessment. It is unlikely that any of these will arise by themselves. A more feasible outcome, however, will be a mix of customer outcomes, possibly leaning more in one direction. To respond to these scenarios, we have devised four possible evolution pathways that can meet each of the challenges and requirements.

[48] Source: ENA, "Network Transformation Roadmap", https://www.ena.org.nz/dmsdocument/403, 2018

Figure 13.7 : Network transformation scenarios adapted from ENA with evolution pathways



13.5.2 TRADITIONAL NETWORK

This is largely the distribution network that we are accustomed to. It has the following characteristics:

- It relies on physical assets to convey electricity from bulk electricity supply points[49] to customers.
- The large majority of customers remain generally passive, not taking much interest in changing their behaviour or interest in their energy supply or how this is achieved – price and reliability are their major considerations.
- Other than providing the electricity conveyance service, distribution utilities traditionally do not participate in energy markets and are compensated only for the assets they provide and operate.
- Although elements of control and automatic disconnection (through protection systems) are in place, traditional networks and their components are largely passive in nature. Network reconfiguration requires human intervention.
- A substantial degree of redundancy is normally built into traditional networks. This is to ensure that peak demand can be met at all times and also provides acceptable levels of reliability. Even if all communications to control centres are lost, these networks will largely keep operating as normal for extended periods.
- Assets are generally sized for the peak demand they are anticipated to experience, which is predetermined at the design stage. Actual measurement of peak power flows in assets is limited.
- Large localised concentrations of customers wanting to connect EV and PV can compromise system stability.

Traditional networks suit the “Backup Grid” scenario.

13.5.3 INTELLIGENT NETWORK

This is the often-touted ‘smart grid’, which is based on the traditional network with extended capabilities for monitoring, measurement, control and automation – and the associated communications network and information systems to support this. There is also a shift from centralised to de-centralised control, relying more on the local ‘intelligence’ of modern devices.

- It relies on physical assets to convey electricity from bulk electricity supply points to customers.
- The large majority of customers remain generally passive, not taking much interest in changing their behaviour or interest in their energy supply or how this is achieved – price and reliability are their major considerations. However, the uptake of renewable generation and storage – mainly as a mechanism to avoid potential price increases, rather than active energy market participation – is likely to increase.
- Distribution utilities still do not participate in energy markets, other than providing the electricity conveyance service. They are compensated for the assets they provide and operate as well as, in many instances, for the reliability of service and for energy efficiency improvements[50].
- Intelligent devices are widespread throughout the network, with associated communications systems. These allow broad visibility of power flows, asset loading, and asset and network performance. They also provide control of devices, which in turn allows much greater network automation. Networks can be reconfigured in real-time to respond to demand patterns, or operational events.
- Because of the improved visibility of actual asset and network loading and performance, and increased possibilities for automation, it is possible to safely increase the utilisation of networks to much higher levels than with purely passive networks. Automation also provides opportunities for easy network reconfiguration after faults, or self-healing networks, that can provide substantial reliability improvements.
- While assets are still sized in accordance with the expected peak demand they will carry, the improved utilisation factors and network flexibility allows a significant reduction in the degree of asset redundancy required (to achieve the same or improved network outcomes).

[49] These are generally points of connection to the transmission grid, but can be direct connections to generators.

[50] This is to ensure that incentives exist to find optimally efficient solutions, rather than stick to traditional network investment solutions.

- Customers can connect their EV and PV, however, technical network limitations may restrict their ability to fully utilise them.

Intelligent networks will suit the "Set and Forget" scenario.

13.5.4 OPEN-ACCESS NETWORK

This next stage expands on the capabilities of the intelligent network to allow for the widespread use of local generation sources connected to the network at multiple points, with associated two-way power flows. It also ensures open-access arrangements for customers to allow them to transact over the network and to connect any device they wish within acceptable safety and reliability limits.

- It relies on physical assets to convey electricity from bulk electricity supply points to the customers, as well as from customer to customer, or customer to bulk supply point.
- In this scenario, customers are actively involved in their energy acquisition, generation, and consumption management.
- It provides network connections for multiple sources of distributed generation devices, and other customer side devices, if these are required to interact with the network. However, the distribution utility does not become involved in the transactions between customers and other parties or in the balance between supply and demand.
- It provides the necessary functionality to maintain network stability, power quality and effective protection under the widely expanded range of operating scenarios associated with the anticipated future arrangements. This may include use of large-scale energy storage on the network.
- As in the past, revenue is earned through providing electricity conveyance, but also from the other network services provided to customers – reflecting, for example, the cost to connect distributed generation, maintain network stability, and provide flexible open-access functionality. Distributors are also likely to transact with customers for value that the customers can add to the operation of the network – for example for demand management capability, and electricity buy-back.
- Building on the intelligent network already in place, network investments and asset sizing will reflect the impact of the evolving electricity demand patterns. This will include consideration of the benefits made possible through transacting with customers for generation or other support services.
- To facilitate all of the above, customer pricing will have to evolve to reflect a far larger degree of individualisation than in the past. This will recognise the varying services that customers may require, the devices they wish to connect and the impact of these on the network, or the network benefits they can offer.
- Customers can connect their EV and PV and maximise their utilisation.

Open-access networks will suit the "Rise of the Prosumer" scenario.

13.5.5 SHRINKING NETWORK

The shrinking network describes the situation where it may make sense for a customer's primary electricity supply to be derived from sources other than the grid – mass defection will then occur. The level of investment on the associated network would drop to a minimum as it would be economically impossible to maintain anything other than an adequate level of safety and meet our minimum legal obligations.

There are few existing larger scale examples of this scenario around the world, and none we are aware of in New Zealand. However, it is potentially possible when individual households, local communities and industries build their own power generation and energy storage facilities, particularly where they are somewhat isolated from the grid.

We also facilitate decommissioning of long rural feeders supplying isolated loads through use of its Base Power alternative, albeit only for individual or very small groups of customers. This benefits both us and the customer.

The shrinking network scenario aligns with the "Leaving the Grid" scenario.

13.6 OUR NETWORK EVOLUTION STRATEGY

13.6.1 OVERVIEW

At the moment, our network finds itself somewhere between the traditional and intelligent network stages as we have many of the initial features of an intelligent network already in place. This includes:

- Modern Supervisory Control And Data Acquisition (SCADA) systems that provide reasonable visibility and remote control of our subtransmission and distribution networks.
- Modern power transformer and switchgear monitoring and control.
- A modern outage management system.
- Extensive automation devices spread across the network.

Our network is not homogeneous. It covers large areas of rural land, coastal township, dense cities, DOC-protected and iwi-owned areas. We do not believe that a one-size-fits-all approach is right for our customers, with many stark differences in customer consumption patterns and network characteristics between especially the higher-density, more urban network areas, and the low-density rural network areas.

We therefore expect that the four scenarios described above will have a different likelihood and outcome in different parts of our network.

For example, it is more feasible – technically and economically – for a small cluster of rural customers at the end of a very long spur line to accept non-traditional electricity supply solutions and go off-grid, than for higher-density parts of the network.

In a city such as Tauranga, the nature and density of load is more likely to make the development of a smart grid necessary.

In our previous AMP, we stated:

> Our goal during the planning period is to evolve to an open-access network. This will include the building and operation of a fully functional intelligent network.

We still believe this will bring the most value to our customers over the long-term, particularly as this will provide the flexibility required to underpin efficient, low-carbon energy options. However, we also recognise the uncertainty around the nature of future energy requirements, technology developments and the rate at which these will manifest on our network.

Our Network Evolution strategy, therefore, in the short-term focuses on a least regret research and investment approach, focusing on maximising flexibility and technology that is likely to be useful under a wide range of future possible demand scenarios. By adopting this approach, we can continue to expand our knowledge base and identify – and implement – valuable new network solutions, without having to substantially lock ourselves in to a particular scenario or network configuration.

We have identified four key themes of work that will enable us to better understand the uncertainties, while creating value for our customers and our network. They are:

- Improved Visibility
- Future Energy Consumers
- Modernising the Grid Edge
- Enhanced Response

Each theme and their indicative investment programmes are described below.

It must be noted that most of these initiatives are in the domain of research and development, with the objective of validating the benefits of a technical solution before a potential network-wide roll out.

For example, we are contemplating the idea of installing a limited number of smart meters around our network, with an associated communications infrastructure. They may double up with the ones already installed for retailers, but will allow us to access network data that existing smart meters are not equipped to provide.

We expect they will provide much improved visibility on network performance and utilisation, particularly on the low voltage side, and will allow us to be technology ready if customers request more services, for example, adding more DER to the network.

If the solution is proven to be technically successful, we will then consider the best way to obtain a similar outcome, in line with our normal investment decisions processes and tests.

In parallel, we keep developing non-network solutions, such as our Base Power solution, which we are implementing at reasonable scale. It is a more cost effective and better power quality solution for remote rural customers, as we avoid having to renew uneconomic and unreliable existing (pre-1992) overhead lines.

Base Power is a fully autonomous, self-healing off-grid power solution for homes, lodges, hill-country farms and communications sites. It typically uses renewable PV generation and energy storage to meet customer needs, supplemented by a diesel generator when necessary.

> **Networks of tomorrow**
> In our view, the best way to achieve customers' goals is by operating an open-access distribution network. This will be achieved by:
>
> – applying suitable developing technology.
> – much improved visibility of power flows and utilisation.
> – increased network automation.
> – improved data and analytics.
>
> Essentially this future network would allow customers to be largely unconstrained in what they can connect to the network and how they would use it to support their energy transactions – purchasing and exporting electricity.
>
> Our role will be to ensure that networks have the capacity to cope with our customers' evolving energy needs, while remaining safe, stable and efficient.

13.6.2 IMPROVED VISIBILITY

High levels of real-time to semi real-time visibility on network performance, current flows, quality of supply and asset utilisation is an essential enabler to run a truly open-access network. At present, this visibility is patchy across the network, and largely lacking on our low voltage networks. We therefore need to improve the situation and will increase monitoring across our network and customers' installations.

This programme will involve:

- Greatly increase monitoring throughout the network.
- Change our approach to how we monitor the HV network, specifically focusing on the versatility of monitoring technology available.
- Dramatically increase the amount of available data related to utilisation, current flows, quality of supply and asset performance on the LV network.

- Enhance communication and information technology to support the increasing volumes of information collected in the field.

Our stakeholders will benefit from this programme through our:

- Ability to provide open-access to the electricity network, allowing two-way power flows and energy transactions to take place over it.
- Improved ability to predict and prepare for network congestion because of changes in customer energy profiles and DER penetration.
- Improved asset management and network operations enabled through better insight into the condition of our assets and how they perform their service on the network.
- Greater efficiency in monitoring and managing the network and assets.

13.6.2.1 INDICATIVE INVESTMENT PROGRAMMES

The following outlines the types of investments targeted within the planning period.

- **Low voltage asset monitoring** – a tiered approach to monitoring the utilisation of transformers, switches and other LV assets throughout the Powerco network. This is an essential programme that will inform future investment plans, as well as provide the inputs for automation schemes and ensure network stability.
- **Enhanced network condition and utilisation monitoring** – incorporating new and different network condition detection methods through expanded sensor types, external sources of network specific data, and improved back office capability.
- **Interfacing with DER resources on the LV network** – developing methods to provide network relevant data to DER resources (and their management interface) and obtain data from these sources. This will include developing methods of exchanging information with local generation, storage and discretionary loads, such as EVs.
- **Expanded communications and information systems** – as described in Chapter 22.

Note, that as part of our network development expenditure forecast from FY24 onwards, described in Chapter 11, we make provision for a systematic roll-out of network monitoring devices across the whole network. We see this as essential to achieving our goal of operating an open-access network. The research programmes we intend to undertake before FY24, will inform the technology choices and business case for the proposed roll-out. We will also identify potential opportunities to share infrastructure with other providers, for example, should the required network insights be available from retailers' smart meters, it may obviate the need for our own infrastructure.

13.6.3 FUTURE ENERGY CONSUMERS

The Future Energy Consumers programme revolves around developing a deeper understanding of changing customer energy preferences, emerging technologies and energy market products, and integrating this into our network planning and operations.

This extends to:

- Collaborating with customers, retailers, and third-party service providers to understand the changes in their expectations from distribution services.
- Procuring and testing beyond the meter assets to understand how these assets interact with network operations and change in customer preference.
- Exploring the potential to obtain and integrate external sources of data that helps us improve demand and customer profiling.

Our stakeholders will benefit from this programme through our:

- Ability to respond, to a greater degree, to specific customer needs.
- Ability to anticipate customer demand trends and maintain a safe, stable supply in the face of this.
- Better targeted network design standards based around customers' actual consumption patterns rather than generic designs.
- Sufficient lead time to prepare our network and services to meet changing market environments.
- Networks remaining open-access to new technologies and customer needs.

Why an open-access network?
Our customers are increasingly concerned about the impact of their energy use on the environment. They are interested in how their electricity is generated and how they can use it most efficiently. This local interest is reflected at a national level, with one of the Government's key commitments being a goal of a carbon-neutral electricity supply.

In a fortunate convergence of improving technology and cost-efficiency, our customers have:

- more choice and the power to exercise their values.
- an increasing ability to achieve significant reductions in their energy use footprint.

A key contributor is the ability to cost effectively generate on-premise electricity, through renewable methods such as solar panels or small wind generators.

This not only reduces electricity taken from the grid, but also holds potential for exporting excess capacity to other nearby customers, or allowing customers without their own generation to buy renewably created electricity from local suppliers and communities.

Other key factors are efficiency improvements in energy-hungry devices, and the ability to switch to renewable energy sources, particularly related to transport and heating.

13.6.3.1 INDICATIVE INVESTMENT PROGRAMMES

The following outlines the types of investments targeted within the planning period.

- **Retailer collaborations** – actively seek opportunities to collaborate with retailers on specific initiatives to pilot new market products that could influence customer expectation and/or utilisation of the network.
- **Researching demand-side energy technologies** – procure, implement and test demand-side DER assets, ie storage, generation etc, to test the impact of these technologies on network utilisation.
- **Obtaining, analysing and integrating external sources of demand data** – procure/obtain customer Advance Metering Information (AMI) data as well as other sources of data to develop new segmentation techniques.
- **In-depth measuring and analysis of customer trends and patterns** – enhancing our understanding of what our customers desire and to optimise our response to this.

13.6.4 MODERNISING THE GRID EDGE

Modernising the Grid Edge is defined as enhancing our network operations and increasing asset utilisation through the application of new technology.

This extends to:

- Enhancing real-time monitoring of asset and network condition, for example, remotely operated inspection drones or remote asset monitoring.
- Increasing asset and network utilisation, for example, applying real-time asset ratings.
- Advanced automation and protection solutions to enable networks to self-heal and minimise interruptions.
- Network energy storage solutions, for demand management and stand-by capability.
- Expanding use of demand-side participation, such as load control, to improve network utilisation, deferring reinforcements.

Our stakeholders will benefit from this programme through:

- Improved reliability of the network.
- Enhanced network utilisation, with associated cost efficiency gains.
- Improved response ability.
- Reduced callouts for investigations on fault causes.

13.6.4.1 INDICATIVE INVESTMENT PROGRAMMES

The following outlines the types of investments targeted within the planning period.

- **Real-time asset ratings –** monitoring the utilisation, temperature and other operating parameters of key assets, particularly where these constrain delivery capacity, in real-time. By understanding the actual situation, it is often possible to increase asset utilisation while still running assets safely. For passive networks, conservative safety factors often have to be built into operating allowances, to avoid asset damage. Real-time capacity monitoring can also inform automation schemes, allowing power flows to be redirected to less constrained areas.
- **Self-healing networks –** by combining appropriate network monitoring, assets with intelligent or remote operating ability, and a solid communication system, it is often possible to develop networks that can automatically self-restore following an outage.
- **Enhanced fault response –** by automatically providing information to the Network Operations Centre on the occurrence and location of an outage, quicker fault response and location times are achievable.
- **Energy storage –** effective energy storage can have multiple network benefits, ranging from the ability to reduce peak demands and provide standby capacity, through to providing voltage or frequency support. At present, distribution scale energy storage focuses on utility or household scale battery systems, although alternative technologies, such as large flywheels, will also be evaluated.

13.6.5 ENHANCED RESPONSE

The Enhanced Response programme relates to the network's ongoing ability to maintain stable operation despite the increased use of distribution edge devices that can interfere with power quality. In particular, we have to maintain voltage levels, frequency and signal distortion within prescribed regulatory limits. This can become challenging when distributed generation, non-linear devices or equipment with large, rapidly changing load profiles, become abundant on the network.

This programme extends to:

- Expanding voltage and frequency control applications.
- Working with customers to expand the use of demand-side management, such as load control, to mitigate against excessive demand peaks.
- Testing design and stable operation of microgrids within our network.
- Designing, implementing and testing automated LV network architecture models to support stable network operations.
- Rethinking our approach to remote rural and/or uneconomic networks and expanding Base Power type solutions.

Our stakeholders will benefit from this programme through our:

- Ability to provide open-access to the electricity network, minimising limits on connected equipment, managing two-way power flows and allowing energy transactions to take place over it.
- Quality of supply and network stability being maintained, despite increased variability in demand and distributed generation, and increasing two-way power flows.
- Reduced impact from planned/unplanned outages.
- Greater certainty around demand response incentives for future Distribution System Operator (DSO) markets.

The limits of today's networks

The design of traditional electricity networks, however, limits the extent to which renewable generation, or large variable loads, can be accommodated.

Networks were designed for one-way power flows from large generators to end customers, who used mainly passive appliances. Connecting significant volumes of distributed generation, or large, rapidly varying loads to a network not designed for it, can at times cause serious power quality and network instability issues.

Without substantially changing the nature of distribution networks and how they operate, the only mitigation options for electricity distribution businesses (EDB) are to make major reinforcements to the network or constrain customers in what they can connect and how they can use the network.

Limiting choice is bad for customers.

Conventional network reinforcement is an expensive and, generally, inefficient solution to short-term power fluctuations. Constraining customers in what or how much they can connect to the network will greatly inhibit their ability to manage their usage and reduce their electricity carbon footprint – thereby foregoing one of the more important levers New Zealand has to achieve its overall environmental targets.

13.6.5.1 INDICATIVE INVESTMENT PROGRAMMES

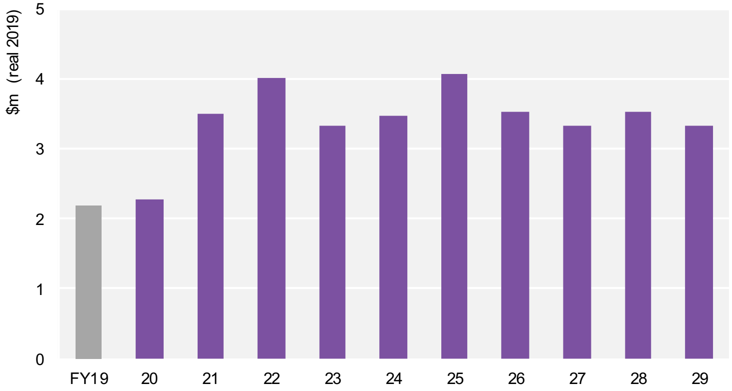
The following outlines the types of investments targeted within the planning period.

- **Energy communities** – testing new forms of network architecture designs, ie microgrids and LV mesh, that enable new methods of distribution service offerings and network operations.
- **Base Power, and other distributed assets** – investigating new methods to respond to changing demand patterns through the network, which include assets that can dynamically respond to network conditions to maintain quality of supply, ie variable tap changing transformers.
- **Innovative network design** – develop new methods of designing networks to improve quality of supply potential through planned and unplanned events, ie loop automation and improved sectionalisation.
- **Monitoring and automatic response to power quality issues** – monitoring the impact of customer devices on network stability and power quality, and developing various solutions to cost-effectively ensure the ongoing stability of the network.

13.7 FORECAST EXPENDITURE

The forecast Capex on Network Evolution activities is set out in in Figure 13.8[51].

Figure 13.8: Forecast Capex – Network Evolution



Historically, our investments in this area have been categorised as part of our general network enhancements expenditure. Since the 2016 AMP we have separated the expenditure out in recognition of its growing importance. Expenditure is forecast to increase as we expand our proof-of-concept trials.

51 In overall expenditure forecasts in Chapter 26, Capex associated with Network Evolution is categorised as 'Other Network Capex'.

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Fleet management

This section explains our approach to managing our network and non-network assets.

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14 FLEET MANAGEMENT – INTRODUCTION

14.1 THE ROLE OF FLEET MANAGEMENT

Fleet management is an integral part of our asset management system. It outlines the renewal investment programmes for each of the asset fleets to help achieve our Asset Management Objectives and targets. Fleet management also helps ensure a disciplined top-down oversight to ensure each fleet is managed appropriately.

Our goal is to manage performance within acceptable bounds, ensure assets are safe and in a suitable condition to remain in service, and minimise the total cost of ownership.

14.2 STRUCTURE OF THIS SECTION

In this section we detail the renewal planning and expenditure for each fleet, based on the governance and planning framework previously described in Chapters 6 and 7.

This section summarises our fleet management plans. The chapters within the section are intended to provide a general overview of the trends, issues and considerations that have shaped our fleet management approach. They show how this translates into our forecast renewal investments for the planning period.

Our network assets are grouped into seven portfolios[52] as shown in Table 14.1. The details for each portfolio are discussed in the following chapters.

Table 14.1 Portfolio and asset fleet mapping

PORTFOLIO	ASSET FLEET	CHAPTER
Overhead structures	Poles Crossarms	15
Overhead conductors	Subtransmission overhead conductors Distribution overhead conductors Low voltage overhead conductors	16
Cables	Subtransmission cables Distribution cables Low voltage cables	17
Zone substations	Power transformers Indoor switchgear Outdoor switchgear Buildings Load control injection Other zone substation assets	18
Distribution transformers	Pole-mounted distribution transformers Ground-mounted distribution transformers Other distribution transformers	19
Distribution switchgear	Ground-mounted switchgear Pole-mounted fuses Pole-mounted switches Circuit breakers, reclosers and sectionalisers	20
Secondary systems	SCADA and communications Protection DC supplies Metering	21

52 These portfolios differ in some respects from the asset categories specified by Information Disclosure. They better reflect the way we manage these assets and plan our investments.

For each portfolio (Chapters 15-21), we set out the key information that has an impact on our investment decisions. The level of coverage in this AMP is less than we have in the detailed fleet management plans we use for internal purposes. The key points covered are:

- High level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition and risks
- Preventive maintenance and inspection tasks
- Renewal strategies
- Renewal forecasting approaches

In the later part of the section we also consider the following:

- Non-network assets, including Information and Communications Technology (ICT), buildings, office fittings and vehicles - Chapter 22.
- Maintenance and vegetation strategies and associated expenditure forecasts – Chapter 23.

14.3 SCOPE OF FLEET MANAGEMENT PLANS

The investments covered by our fleet management plans comprise both asset renewal (replacement of assets with like-for-like or new modern equivalents) and refurbishment (investments that extend the useful life or increase the service potential of an existing asset). They exclude ‘network development Capex’, which increases the size, capability or functionality of our network. This is covered in Chapters 11 to 13.

Renewal and refurbishment are carried out primarily to manage asset deterioration and ensure our assets remain in a serviceable and safe condition. A deteriorating asset will eventually reach a state where ongoing maintenance becomes ineffective or excessively costly, thus requiring the asset to be renewed or refurbished. Other reasons for renewal or refurbishment include managing safety risk or network performance, meeting regulatory and legislative requirements and obsolescence.

During the planning period set out in this AMP, we are committed to increasing renewals-related investments across a number of our key asset fleets, most significantly overhead conductor, poles, and crossarms, in response to the key issues outlined in Table 14.2**.** Renewals expenditure forecasts are contained in each portfolio chapter, and summarised in Chapter 26.

Table 14.2 Emerging issues relating to our asset fleets

AREA	DESCRIPTION
Safety of staff, contractors and the public	Where asset condition and health is degraded, the likelihood of failure increases. This increases safety risk for the public and anyone working on the assets, especially in the case of overhead transmission lines. We prioritise replacement of assets that present elevated safety risks.
Asset health	We use asset health to reflect the expected remaining life of an asset based on a variety of factors, including its condition, age and known type issues. Maintaining appropriate levels of asset health is a key driver for our renewals investment. Assets in poor health pose an increased risk of failure, leading to additional reliability and safety risks.
Reliability	Our renewal investments target assets that have the potential to degrade, or have already degraded, the service reliability because of faults or forced outages. Some of our customers experience interruption levels exceeding our targets. We prioritise our renewal investment in these areas to improve our service.
Obsolescence	Asset renewal can become necessary when existing assets become incompatible with our modern systems and standards, lack necessary functionality or are no longer supported by the manufacturer. We also consider the level of diversity in our fleet, as removing ‘orphan’ models streamlines our approach to maintenance, helping to manage costs. Renewing obsolete assets supports our future readiness objectives and will enable us to deliver our forecast efficiencies.

15 OVERHEAD STRUCTURES

15.1 CHAPTER OVERVIEW

This chapter describes our overhead structures portfolio and summarises our associated fleet management plan. The portfolio includes two asset fleets:

- Poles
- Crossarm assemblies

This chapter provides an overview of these asset fleets, including their population, age, type and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we expect to increase our investment in overhead structures renewals from $36m in 2020 to a peak of $40m in 2022. This portfolio accounts for 42% of renewals Capex during the period.

Increased investment is needed to support our safety and reliability objectives. Failure of overhead structures can have a significant impact on our safety and reliability performance. This increase in renewals Capex is driven by the need to:

- Reduce the number of pole defects to steady state levels.
- Continue to replace poor condition poles and crossarms.
- Address type issues in our pole and crossarm fleet.
- Ensure overhead structures meet current design standards when the associated conductor is replaced.
- Improve resilience to extreme weather events.

Below we set out the Asset Management Objectives that guide our approach to managing our pole and crossarm fleets.

15.2 OVERHEAD STRUCTURES OBJECTIVES

Poles and crossarms are primary components of our network. Combined with overhead conductors, they make up our overhead network (78% of total circuit length), connecting our customers to the transmission system at grid exit points (GXP) and enabling the flow of electricity on circuits of varying voltages.

The performance of these assets is essential for maintaining a safe and reliable network. As most of our overhead network is accessible to the public, managing our overhead structure assets is also critical in ensuring public safety, especially in urban areas.

To guide our day-to-day asset management activities, we have defined a set of portfolio objectives for our overhead structures assets. These are listed in Table 15.1. The objectives are linked to our Asset Management Objectives set out in Chapter 5.

Table 15.1: Overhead structures portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No condition-driven pole failures resulting in injury. No crossarm failures resulting in injury. Dispose of softwood poles responsibly. Ensure hardwood crossarms are sourced from sustainable forests.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Pole and crossarm renewal is targeted at poor performing network areas to improve feeder reliability and manage the overall System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Consider the use of alternative technology to improve reliability or reduce service cost, eg remote area power systems.
Asset Stewardship	Expand the use of asset health and criticality to inform renewals. Reduce the number of pole and crossarm defects to sustainable levels.
Operational Excellence	Improve and refine our condition assessment techniques and processes for poles and crossarms.

15.3 POLES

15.3.1 FLEET OVERVIEW

Our network comprises concrete poles (86%), wooden poles (14%) and a small number of steel poles. We have approximately 264,000 poles on our network.

There is a wide range of poles in terms of height, strength, age, and condition, and a range of failure modes.

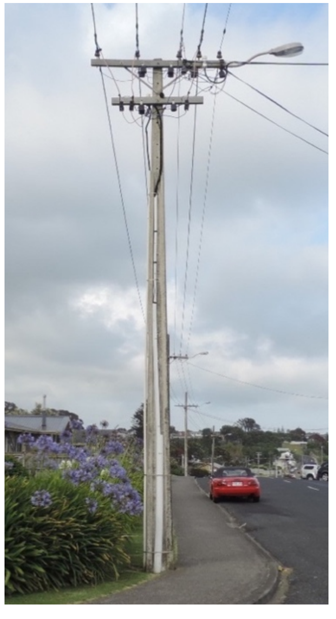
Concrete poles

There are two types of concrete poles – pre-stressed and reinforced. Pre-stressed constitutes most poles on our network (57%).

Pre-stressed poles are a mature technology and are expected to perform their function reliably over a long period.[53] Pre-stressed poles have been used for more than 50 years and are manufactured with tensioned steel tendons – cables or rods. Most new poles installed are pre-stressed and are designed and manufactured to meet stringent structural standards. The pre-stressed poles installed today have a design life of 80 years.

Reinforced concrete poles contain reinforcing steel bars (usually four to six) covered by concrete. These poles were regularly used from the 1960s to 1980s but less so during the past 35 years. These concrete poles have been produced by many manufacturers for different areas of our network, which has resulted in differences in design, manufacture and material quality, leading to differing lifecycle performance.

Figure 15.1: A modern pre-stressed concrete pole and a rural softwood pole



[53] Note: An issue has been identified with a certain type of pre-stressed concrete pole. This is discussed in the condition, performance and risks section.

Wooden poles

Wooden poles can be categorised into three types based on the wood used – hardwood, larch, and softwood.

Many hardwood varieties are used on our networks, most of which were installed before 1985. The species is unknown in some cases and performance varies within and across species. We have found that certain species decay faster than others, some have a tendency to split, some decay from the pole head, some from below ground and others delaminate.

The category of larch poles incorporates species with strength and durability falling between softwood and hardwood, with performance that varies widely. The use of larch poles was phased out from 1990.

Softwood poles are generally pine that has been treated with copper chrome arsenic (CCA). Softwood poles have a shorter life than concrete, hardwood or larch poles. On occasion, softwood poles can deteriorate rapidly and unpredictably. While these poles are lighter and lower cost than others, the inconsistency in lifecycle performance meant we used fewer from the mid-1990s and they are now no longer installed on our network.

The use of wooden poles in the construction of new networks is being phased out.

Our analysis of testing methods has highlighted that there is no single fool-proof technique for assessing the condition of wooden poles, especially softwood, some of which have failed for reasons that are difficult to identify.

The wide natural variances in timber strength mean that wooden poles perform inconsistently. Life extension techniques, such as pole reinforcement, are being considered for poles installed on remote networks, where the costs and complexity of renewal with concrete poles is out of proportion with the projected economic value of the line.

We continue to evaluate better condition assessment techniques for wooden poles to better manage the safety and reliability of those remaining on our network.

Steel poles

We have a small number of steel poles in service. There are two main types – legacy 'rail iron' poles, and modern tubular poles.

Tubular steel poles are more expensive than concrete poles. These are useful for remote or rugged sites as they are light and can be flown in as sections for on-site assembly. However, it can be difficult to assess corrosion on the inside of the pole and below ground. Our policy is to use steel poles only in special circumstances. This will be reassessed should they become price competitive with pre-stressed concrete poles over their lifecycle.

15.3.2 POPULATION AND AGE STATISTICS

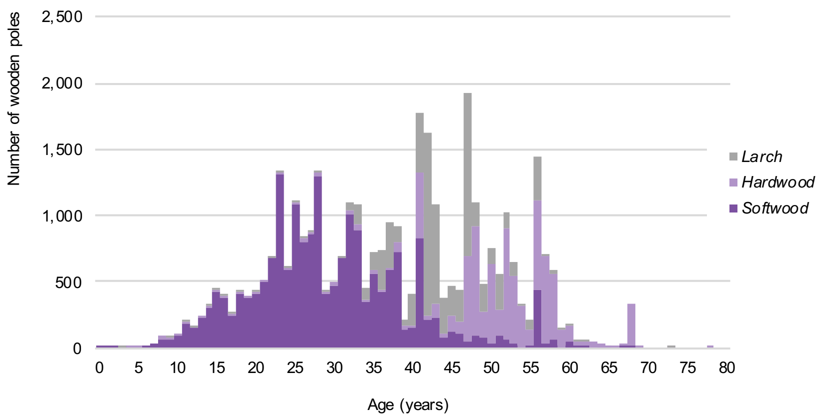
Table 15.2 summarises our population of poles by type. Pre-stressed concrete poles make up more than half of the pole population. While wooden poles make up only 14% of our pole fleet, their large number and age profile means their replacement requires a large investment during the planning period.

Table 15.2: Pole population by type at 31 March 2018

POLE GROUP	POLE TYPE	NUMBER OF POLES	% OF FLEET
Concrete	Pre-stressed	150,289	57
	Reinforced	77,312	29
Wood	Hardwood	8,303	3
	Larch	7,616	3
	Softwood	19,724	7
Steel	Steel	902	0.3
Total		264,146	

Figure 15.2 depicts our wooden pole age profile. It shows that many hardwood and larch poles have exceeded, or soon will exceed, their expected average lives. Our survivorship analysis estimates an expected average life of between 30 and 40 years, depending on type.

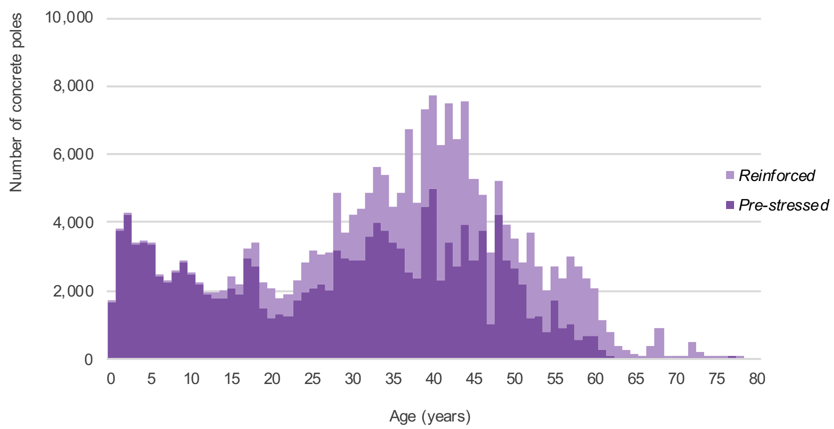
Figure 15.2: Wooden pole age profile



The significant portion of the population age greater than the expected average life is consistent with an increasing rate of defects for these pole types. Softwood poles have an average age of 29 years and many have, or soon will, exceed their expected life.[54] Most poles installed in recent years have been pre-stressed concrete.

Figure 15.3 shows our concrete pole fleet age profile. The reinforced concrete pole fleet has a higher average age than the pre-stressed pole fleet.

Figure 15.3: Concrete pole age profile



The average age of our concrete poles is 33 years. A relatively small percentage of our pole population is older than the industry standard expected life of 60 years, and the 90-year design life of new pre-stressed concrete poles.

The age profile suggests we should have low requirements for age related end-of-life replacements during the planning period. However, we anticipate significant replacements to address poles with type issues caused by poor manufacturing, design or construction practices. These issues are discussed further in the section below.

15.3.3 CONDITION, PERFORMANCE AND RISKS

In-service pole failure is a significant safety issue, potentially exposing the public and workers to hazards associated with falling network equipment, and electrical hazards associated with live conductors dropping on the ground or reduced clearances to ground.

54 Note that actual pole replacement is based on condition assessment and field inspection results.

In-service pole failure is also a significant reliability issue, as pole failure results in the loss of supply or network security. The reliability impacts can be extensive should multiple failures occur during extreme weather events causing extended restoration times.

Structural failure during maintenance or construction works is also a significant workplace safety hazard. We always aim to replace poles before they fail, minimising the safety and reliability risks.

Meeting our portfolio objectives

Safety and Environment: Poles are replaced using condition information before failure, thereby minimising safety risks.

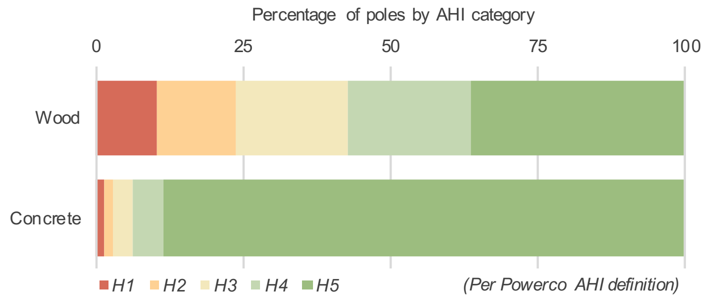
It is important to rectify pole defects promptly. While most pole failures are caused by vehicle accidents and adverse weather, pole failures with existing condition defects or a manufacturing type issue can be triggered under stress, for example through heavy snow falls.

Pole asset health

As outlined in Chapter 7, we have developed asset health indices (AHI) that reflect the remaining life of an asset based on a set of rules. For poles, we define end-of-life as when the asset can no longer be relied upon to carry its mechanical load and the pole should be replaced. The AHI is based on our survivorship analysis and our defect pool.

Figure 15.4 shows current overall AHI for our population of concrete and wooden poles.

Figure 15.4: Wooden and concrete pole asset health as at 2018



The health of our wooden poles is a concern as approximately 43% of the fleet will require renewal during the next 10 years (H1-H3).

In contrast, the concrete pole fleet is in good overall health. Approximately 6% of this fleet is expected to be replaced in the next 10 years (H1-H3).

Pole defects

We carry out regular inspections of our poles to verify their condition and to identify defects that require repair or replacement.

The main pole failure modes differ by pole type. Some common examples are set out in Table 15.3. Our defect process aims to identify these issues well in advance of pole failure to allow planned and coordinated replacement.

Table 15.3: Pole failure modes by type

POLE TYPE	FAILURE MODES
Pre-stressed concrete	Cracking in concrete allows moisture ingress, causing the internal steel pre-stress tendons to rust and lose strength. This loss of strength can lead to unexpected structural failure during adverse weather or maintenance or construction.
Reinforced concrete	Spalling is the loss of concrete via flaking or fragmenting. If the concrete falls away, significant strength remains in the internal reinforcing bar structure. Rusting will occur once the interior becomes exposed, but because of the significant residual strength of the pole there would need to be a large amount of spalling before replacement is warranted.
Steel	Corrosion of steel poles occurs over time at a rate dependent on environmental conditions. This is relatively easy to assess through inspection, although internal corrosion of tubular steel poles and underground corrosion is more difficult to assess.
Hardwood	Decay in hardwood poles occurs below or above ground at the pole head because of moisture. Both areas are difficult to assess and susceptibility to decay varies between species. Cracks may appear as the pole ages in certain environments.
Softwood and larch	Decay in softwood and larch poles typically occurs from the inside out, making it more difficult to identify defects than for other pole types. This means they can appear sound but be in poor condition.

Our inspection and defect process has been in place since 2008.

We have also conducted research to assess the residual strength of legacy concrete pole types. This has identified type issues, which have been added to our defect assessment criteria.

Although we have been carrying out pole renewals during this time, the defect pool[55] is larger than our long-term sustainable level and continued renewals are required to reduce this risk.

Our inspection programme is ongoing, and we expect to find further defects as our condition assessment capabilities improve, our pole fleet ages and its condition degrades. The target level is based on a three-year replacement stock, which allows time for replacement coordination to ensure efficient delivery.

The defect pool contains no urgent ‘red’ defects – these poles are replaced as a priority because of associated safety risks.

Wooden pole testing

To inform our condition-based forecasts, we have trialled a variety of techniques to improve the accuracy of our predictive models. We have adopted the Vonaq acoustic resonance tool for wooden pole testing. Acoustic resonance tools use the relationship between wood structure elastic parameters and resonance frequency behaviour.

Our trials involved poles already earmarked for replacement being tested with several lightweight portable testing devices and then break tested to confirm failure load. The acoustic resonance tests, and specifically the Vonaq tool, showed the highest correlation with the break testing results – the only way to confirm the actual strength/condition of the pole – as well as being the easiest tool to use across the network. The acoustic resonance test outperformed visual inspection results.

We also found that no test proved effective in detecting all ‘poor’ poles. Any new tests will be used alongside existing techniques.

Overall, the results indicate that while current inspection techniques are broadly effective, better information will allow us to improve the timing of our pole renewals, extending the lives of some while also identifying defects not found through current techniques. We will continue our trials and refine our testing approaches.

Meeting our portfolio objectives

Operational Excellence: We have trialled and are implementing improved pole condition assessment techniques to improve defect accuracy and asset renewal timing.

[55] The defect pool includes both serious defects requiring asset replacement, such as rotting poles, and minor defects requiring only minor repairs or remedial work, such as lack of pole signage. This chapter addresses defects requiring full asset replacement.

Type issues

In addition to condition-related defects, we also have several pole type issues[56] within the fleet. We have identified that some pre-stressed concrete pole types have very poor strength under down-line stresses, despite being visually assessed as being in good condition.

Some early manufacture (1960s) of pre-stressed poles used an internal reinforcement spreader between the ground section and the above ground section. The spreader has initiated cracking that has allowed moisture ingress, resulting in corrosion of the pole tendons.

Visually, the poles may appear to be in good condition, but internally the tendons have corroded, reducing strength to the point that they may fail under normal or climbing loads. When the poles are identified in the renewal project areas they are replaced.

Type issues have also been identified within the reinforced concrete pole fleet – primarily premature spalling exposing the reinforcement bars.

Reinforced concrete poles were made by a variety of manufacturers using local materials, such as gravels and sands, with varying degrees of quality control.

As a result, we are not able to verify the design strength for some of these poles. Typically, the poles spall at a rapid rate exposing the reinforcing bars. We ensure that no additional load is added to these poles because of the uncertainties in overall strength.

When this type issue is identified, the poles are replaced in the renewal project areas.

15.3.4 DESIGN AND CONSTRUCT

Most new poles installed on our network are pre-stressed concrete. In some circumstances we use lighter-weight steel poles, for example where a pole needs to be installed using a helicopter.

When performing minor maintenance or renewal works, such as replacing a single pole or crossarm, we use a like-for-like approach, replacing the asset with a modern equivalent of equal or better capability.

When performing larger overhead line works, we undertake design analysis to ensure the new asset is compliant with our design and construction standards, which comply with external rules and standards such as AS/NZS 7000 – Overhead Line Design.

Pre-mature pole replacement – when the pole is in good condition and has no defects – may occur with conductor renewal projects in order for the line to comply.

[56] A type issue is a problem affecting the reliability or safety of a subset of assets, often related to a particular design or manufacturing issue. These are sometimes also referred to as ‘batch’ issues.

The design studies often identify poles that are in 'good' condition but are under strength for the new loadings, especially angle and termination poles.

These additional replacements are likely because of a combination of changes in design loadings and base design assumptions, and more rigorous design, which is made possible by modern software-based design tools.

15.3.5 OPERATE AND MAINTAIN

Poles and crossarms are inspected and their condition assessed as part of overall overhead network inspections. There is little physical maintenance work undertaken on poles. Poles are durable, static, and do not require mechanical or electrical maintenance work.

Our preventive pole inspections are summarised in Table 15.4. The detailed regime for each type of pole is set out in our maintenance standards.

Table 15.4: Pole preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Yearly
Visual inspection of all subtransmission poles as part of overhead network inspections. Alternates between a rapid inspection, ie no digging at ground line required, and a more detailed condition assessment.	2.5 yearly
Visual inspection of distribution and LV poles as part of overhead network inspections, completing a detailed condition assessment. Aerial condition photography to provide identification of condition and defects from a top down view. (Ground inspection cannot provide this detail).	5 yearly

The structure inspection frequency is based on a combination of historically legislated time periods, industry practice and our experience with identifying defects in pole types and pole condition.

The nature of wooden poles makes inspections difficult, as deterioration is typically internal and/or below ground. Testing techniques, such as drilling, can weaken poles and allow moisture ingress, which accelerates deterioration. Modern inspection techniques can identify most poles in poor condition.

All poles need regular inspection because they may be damaged or compromised by a third-party action, age, poor ground conditions or land movement.

A key component of our routine inspections is identifying defects and reporting on asset condition. Where a defect that presents a hazard is detected, the defect is assessed for failure likelihood and prioritised for repair or replacement.

Pole condition (pole asset health) is also a key factor in overhead renewal projects. Monitoring pole asset health will allow us to develop long-term robust pole renewal programmes.

15.3.6 RENEW OR DISPOSE

Renewal of poles is primarily determined by asset condition and the defects process. Defects are identified through our routine network inspections and poles are either replaced reactively, for red defects, or enter our planning processes for replacement through work packages.

We prioritise defects on a risk prioritised basis using our in-house Defect Risk Assessment Tool (DRAT). DRAT systematically assesses defects and the risks presented by them, enabling prioritisation on the basis of criticality and condition.

SUMMARY OF POLES RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates
Type issues	Identified and confirmed by pole type testing

As discussed earlier, our inventory of pole defects exceeds our long-term sustainable level and we need to increase our number of pole replacements to correct this. We aim to have our pole defect pool at a sustainable level by FY25.

Meeting our portfolio objectives

Asset Stewardship: Forecasted pole renewals expenditure will reduce the defect pool to sustainable levels by FY25.

A number of poles are also replaced through our reconductoring programmes.[57] Replacement of overhead conductors, whether for renewal or growth reasons, requires that the design be reviewed to ensure the renewed asset meets design standards.

This often identifies poles that, although in reasonable condition, must be replaced for strength reasons.

Recent changes to our design standards to meet the requirements of AS/NZS 7000, as well as our increasing conductor renewal programme, is driving a significant uplift in pole replacements for this reason.

We are in the process of conducting analysis to better understand the impact of this issue.

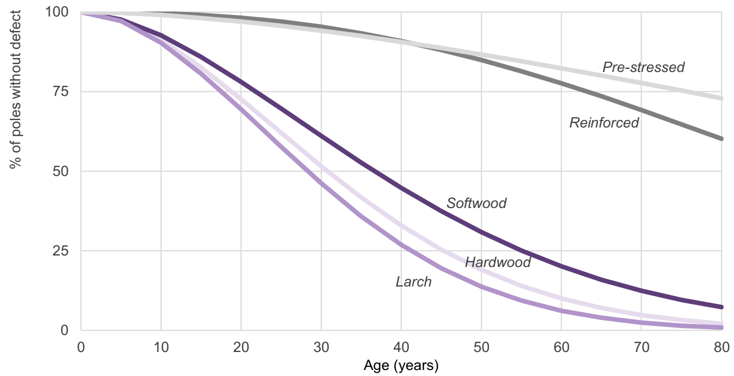
[57] See Chapter 16 – Overhead Conductors

Renewals forecasting

Our pole replacement quantity forecasting incorporates historical survivorship analysis. We have developed survivor curves for each of our pole types and use these to forecast defects and renewal quantities.

A forecasting approach that incorporates defect history is more robust than a purely age-based approach because of the use of historical quantitative data. Figure 15.6 shows our typical pole survivor curves. Each curve indicates the percentage of population remaining at a given age.

Figure 15.5: Pole survivor curves



The survivor curves show that poles require replacement over a wide range of ages. In addition to type, this is influenced by factors such as location, design and manufacture quality.

Our wooden poles tend to require replacement at a similar age to the industry expected life, although with a very wide distribution. Our concrete poles generally do not require replacement until well after their industry expected life.

Volumes of pole renewals are forecast to increase during the next three to five years, primarily to reduce the size of the defect backlog. Longer term levels of defect-based renewal are expected to stabilise at about today's volume.

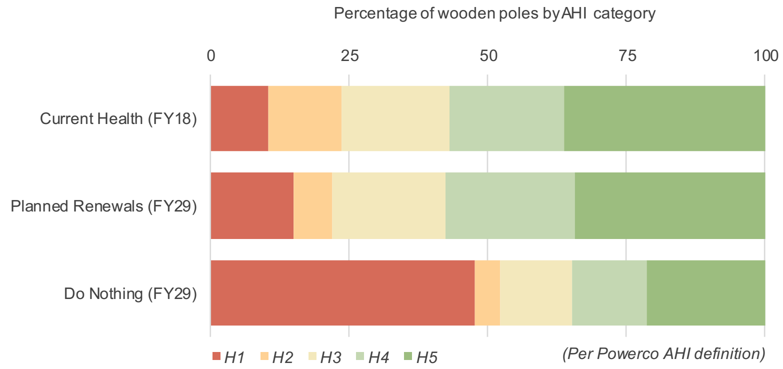
End-of-life pole replacements during the planning period will primarily target wooden poles. As discussed earlier in the condition, performance and risks section, the health of our wooden pole fleet is poor.

Figure 15.7 compares projected asset health in 2029, following planned renewals, with a counter-factual do-nothing scenario. Comparing the planned investment and do-nothing scenarios allows assessment of the benefits provided by our proposed investment.

Our modelling indicates a significant future liability with regards to replacement of ageing wood poles. We are collecting better condition data to allow more detailed analysis of renewal requirements and are considering the potential to apply life extension techniques, such as pole staking, to defer replacement investments.

An equivalent chart for concrete poles has not been provided as the level of renewals is small in comparison to the overall fleet, leading to a relatively small change in health categories.

Figure 15.6: Projected wooden pole asset health as at 2029



A significant number of wooden poles will require replacement after 2029, as indicated by the H1-H3 portion in Planned Renewals (FY29). These will be mainly softwood poles because of their relatively short expected lives.

Pole disposal

Poles are disposed of when they are no longer needed because of asset relocation (eg undergrounding), asset replacement, or following failure. When a pole fails, we carry out diagnostic inspection and testing to assess the root cause of failure. As trends emerge from the failure analysis, we incorporate them into our pole fleet asset management approach.

Requirements for recovery and disposal include safe work and site management processes and appropriate environmental treatment of scrap material. CCA treated softwood poles need to be disposed of at an appropriately licensed facility.

Pole life extension

Modern developments in wooden pole reinforcement are under investigation. As land use changes in the remote networks, such as shifts from livestock farming to forestry and honey production, we are observing that connection density on some remote feeders is declining. Extending the life of the poles in the remote networks will allow deferral of major renewal investments until a time where either further deferral is not practicable or alternative standalone power supplies become more cost effective.

Coordination with network development projects

Pole replacements can be triggered by a need to upgrade or thermally uprate the conductor they are supporting, as part of the develop or acquire lifecycle stage. These upgrades put higher mechanical loads on the poles, often forcing an accompanying replacement to ensure the new conductor is safely supported.

As part of these upgrade projects, we also identify poles in poor condition and coordinate their replacement alongside the conductor upgrade to ensure efficient delivery and to minimise customer disruption. The detailed requirements for each individual upgrade project are confirmed by a full design study.

Meeting our portfolio objectives

Customers and Community: Replacement works are coordinated across portfolios to minimise customer interruptions and ensure efficient delivery.

15.4 CROSSARMS

15.4.1 FLEET OVERVIEW

A crossarm assembly is part of the overall pole structure. Their role is to support and space the insulators that connect to the overhead conductor. A crossarm assembly is made of one or more crossarms and a range of ancillary components, such as insulators, high voltage fuses, surge arrestors, armour rods, binders and jumpers, and arm straps.

From this point, the term crossarm refers to a crossarm assembly including all components.

A pole may have more than one crossarm, such as when 11kV and 400V circuits share the same overhead line. There are significant safety and performance risks associated with crossarm failure.

Figure 15.7: Different crossarm configurations

Our crossarms are typically made from hardwood. Hardwood crossarms have insulating characteristics that limit fault currents. They can be easily drilled, allowing for simple installation of insulators, HV and LV fuse holders, and arm braces. The crossarm fleet also includes a small number of steel crossarms. Like steel poles, deterioration is relatively predictable, and their condition can be more easily and reliably assessed than wooden crossarms.

Crossarm components

Crossarm components, such as insulators, binders, distribution ties, jumpers and armour rods, are needed so the crossarm can carry conductor. Components may be replaced through the defect process as needed (this is treated as maintenance Opex).

However, it is, on average, more cost effective from a lifecycle perspective to replace the entire assembly when a significant component fails or is at end-of-life, because of mobilisation and other fixed costs.

The purpose of insulators is to support the conductor while providing electrical separation, through creepage distance, of the live conductor from the crossarm and pole structure. There are many types of insulators. Those on our network are generally pin, post, shackle or suspension/strain types made from glazed porcelain, glass or polymer.

Binders secure the conductor to the insulator. The modern method to ‘bind’ conductors to insulators is to use preformed ties. Armour rods wrap around the conductor, protecting the conductor from chafing on the insulators as well as providing some dampening for conductor vibrations.

15.4.2 POPULATION AND AGE STATISTICS

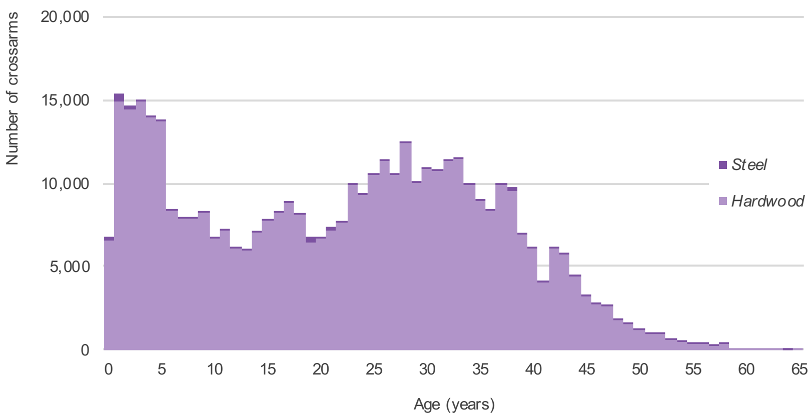
We have approximately 425,000 crossarms in service, of varying sizes and configurations.

Table 15.5: Crossarm population by type and voltage at 31 March 2018

CROSSARM TYPE	VOLTAGE	COUNT	% OF TOTAL
Wood	Subtransmission	16,275	3.8
	Distribution	229,221	54.0
	Low Voltage	173,719	40.9
Steel	Subtransmission	1,651	0.4
	Distribution	2,165	0.5
	Low Voltage	1,474	0.3
Total		424,505	

Figure 15.9 shows our crossarm age profile. Crossarm condition typically deteriorates after 30 years in service. Our analysis reveals that after 35-40 years, the likelihood of defects increases rapidly. Many of our crossarms are older than 40 years, indicating the need for significant renewal investment in the short term.

Figure 15.8: Crossarm age profile



We have compiled the crossarm age profile using different data sources. Data on new crossarms installed since 2000 are taken from the Geographical Information System (GIS). GIS also includes information on some older crossarms captured during regular inspections.

For older assets we have derived crossarm ages from other asset information. For example, it is common to replace a crossarm at the same time as a pole, therefore pole age can be used as a proxy for crossarm age.

15.4.3 CONDITION, PERFORMANCE AND RISKS

In-service failure of a crossarm can lead to dropped conductors or spans lowered to unsafe clearances, presenting a significant safety risk to the public.

Hardwood crossarms typically fail from age-related cracking and loss of strength, or from fungal decay, usually starting on the upper side as a result of exposure to water. Wooden crossarms also fail because of burning caused by electrical tracking from insulator degradation. Failure modes and rates of decay are strongly influenced by environmental conditions.

Crossarm components also fail. Insulators on hardwood crossarms may loosen because of timber shrinkage or decay. Binders fatigue over time and can loosen or break, allowing the conductor to swing free from the crossarm and usually resulting in an outage. These issues are repaired as needed, reactively.

We have identified problems with some types of subtransmission and distribution insulators. Some insulators of two-piece porcelain construction are prone to cracking at the join, leading to separation. Because of the potential safety consequences of these failures, we are proactively replacing crossarms that have these insulators.[58]

Meeting our portfolio objectives

Safety and Environment: Crossarms are replaced proactively using condition and type information, thereby minimising safety risks.

Insulators can crack or completely fail through shock loading, typically caused by adverse weather or tree strikes. Failures can also occur through flashovers, which are more prevalent in areas with high pollution from salt laden air – typically near the coast. These issues are fixed as needed, reactively.

[58] It is cost effective to replace the whole crossarm assembly not just the insulators. These crossarms usually are in poor condition and would need to be replaced in the medium-term anyway.

Crossarms asset health

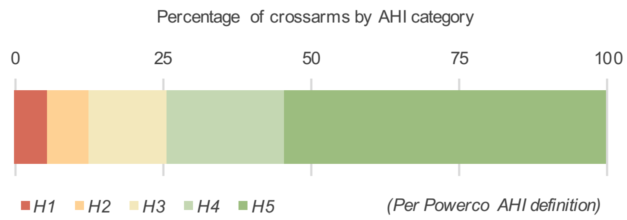
As outlined in Chapter 12, we have developed AHI that reflect the remaining life of each asset. Our AHI models predict an asset's end-of-life and categorise their health based on a set of rules.

For crossarms, we define end-of-life as when the asset can no longer be relied upon to carry its working load, or the insulators can no longer provide adequate insulating capability, and the crossarm assembly should be replaced.

The AHI is based on our survivorship analysis and our current defect pool, and reflects the type issue affecting subtransmission insulators.

Figure 15.10 shows current overall AHI for our crossarm population.

Figure 15.9: Crossarm asset health as at 2018



Approximately 5% of crossarms require renewal in the short term (H1). This is primarily because of the crossarm defect pool and our replacement programme of subtransmission crossarms with two-piece insulators and other type issues.

There are also many crossarms that will require renewal during the next 10 years (H2 and H3). This reflects the large number of older crossarms in our fleet, as shown in the age profile earlier.

Crossarm defects

As with poles, we carry out regular inspections of our crossarms to assess their condition and to identify defects. As with poles, defect levels have been rising and we need to increase our levels of crossarm renewals. Defect analysis shows that crossarms older than 35 years are much more likely to have defects. This means that their risk of failure increases.

We are focused on improving the condition assessment regime for crossarms. We are considering changes to the inspection methods, the measures to address data gaps, and additional training for field staff.

The increasing number of crossarm and hardware related faults on our network supports the needs case for increasing crossarm renewals. The fault trend suggests that the health of our crossarm fleet is worsening.

15.4.4 DESIGN AND CONSTRUCT

While the crossarms on our network are typically made of hardwood, we are exploring the use of steel or fibreglass/polymer in the longer term. The initial cost is higher, but they are likely to have lower lifecycle costs because they last longer, are easier to inspect, and their condition can be assessed with greater confidence.

We are considering different types of hardwood to those used, as current materials are becoming harder to source and more expensive. We are also monitoring developments in polymer insulators for distribution and LV networks.

We also specify post type insulators rather than pin type insulators to avoid the failure modes of hole elongation caused by conductor vibration, as well as the potential for failure at the cement pin interface.

15.4.5 OPERATE AND MAINTAIN

We undertake various types of inspections on crossarms, as set out in Table 15.6. Crossarms are inspected as part of overall overhead network inspections. The detailed regime for each type of asset is set out in our maintenance standards.

Using pole-top photography will allow a higher standard of crossarm health assessment.

Pole-top photography

Visual inspections have traditionally been ground-based. The top side of the crossarm cannot be seen and therefore cannot be accessed for defect or condition. This is also true for the individual components that are supported by the crossarm, such as insulators and conductor binders. Aerial photography will provide more accurate identification of defective equipment, which can be prioritised for repair or replacement. Aerial photography will also provide an assessment of the asset health of the overhead network components for asset renewal planning.

Table 15.6: Crossarm preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Yearly
Visual inspection of subtransmission crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	2.5 yearly
Aerial top photography	As required
Visual inspection of distribution and LV crossarms as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

Crossarm faults usually occur because of age-related deterioration. Fault repairs involve replacement of individual components or complete crossarm assemblies (considered replacement Capex). Preventive inspections identify components that have deteriorated, enabling us to do remedial work before a fault occurs. Typical corrective work includes:

- Replace broken, rotten, or cracked arms. Replace arms where insulator pin has elongated the mounting hole because of wind movement – the use of post type insulators prevents this kind of damage occurring.
- Replace broken or damaged arm braces and bolts.
- Replace individual cracked or failed insulators.
- Replace pin type insulators because of pin corrosion.

Crossarm components are held in stock at service provider depots and field trucks. The individual items are relatively light and can be readily hauled or carried into place to expedite fault repairs.

Wooden crossarms are relatively easy to cut and drill, for insulator pins and mounting holes, from stock timber lengths. Pre-drilled arms, insulators and other components are held in stock at strategic locations.

15.4.6 RENEW OR DISPOSE

Historically, we have taken a mainly reactive approach to crossarm renewal, as determined by the defects process. Some additional replacements were undertaken in critical areas of our networks and others have been replaced during pole replacements.

During the planning period we intend to increase the volume of proactive replacement because of failure-related safety risks, worsening crossarm asset health, and because planned work is more cost effective than reactive work.

SUMMARY OF CROSSARMS RENEWALS APPROACH

Renewal trigger	Proactive condition-based, type
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

We will use DRAT alongside other condition and type information to prioritise renewal work programmes.

In the short to medium term, our works will focus on replacing crossarms already marked as defective, and subtransmission crossarms with insulator type issues. Where possible, we will deliver these renewals as large programmes to ensure cost effectiveness.

Renewals forecasting

Our crossarm replacement quantity forecast incorporates historical survivorship analysis. We have developed a survivor curve for our hardwood crossarms and use this to forecast required renewal quantities.

The analysis reveals that crossarms require replacement over a range of ages. This is likely because of varying environmental conditions on our network and the inherent variability in the quality of hardwood crossarms.

The volume of renewal needs to significantly increase during the next five years to longer term sustainable levels, as indicated by the survivorship analysis. This increased renewal is expected to halt the rise in crossarm related faults.

Meeting our portfolio objectives

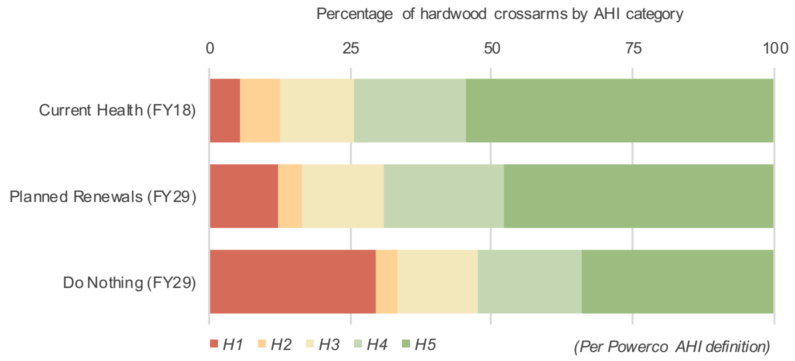
Networks for Today and Tomorrow: Crossarm replacements are forecast to increase, improving the reliability of poor performing feeders and managing network SAIDI and SAIFI.

The volume of crossarm renewals will gradually rise to reduce the crossarm defect pool and complete the replacement programme of type issue subtransmission crossarms.

Longer term, levels of condition-based renewals will be higher than current levels. Renewals will transition to maintaining fleet health rather than improving it.

Figure 15.11 compares projected asset health in 2029, following planned renewals, with a do-nothing scenario. Our investment will lead to an improvement in overall health.

Figure 15.10: Projected crossarm asset health in 2029



A significant number of crossarms will still require replacement after 2029, as indicated by the H1-H3 portion in Planned Renewals (FY29).

Coordination with network development projects

Like poles, crossarms are often replaced as part of overhead line reconstruction projects, such as conductor upgrades as part of network development works. As a crossarm's expected life is short compared with a pole or conductor, its replacement for end-of-life reasons can often be coordinated with these works.

15.5 OVERHEAD STRUCTURES RENEWALS FORECAST

Renewal Capex in our overhead structures portfolio includes planned investments in our pole and crossarm fleets. This will require an investment of approximately $350m.

Levels of identified defects have been steadily rising during the past five years, partly because of the increasing age of assets and partly through the establishment of a more robust inspection process.

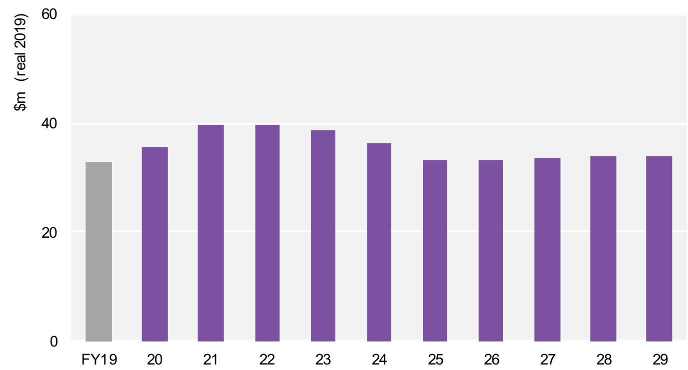
A key driver for pole and crossarm replacement is managing safety risk, as pole or crossarm failure can cause conductor drop, and reduce electrical clearance distances. Unsafe poles and crossarms also present significant safety risks to our field workforce.

Pole and crossarm renewal forecasts are derived from bottom-up models. These forecasts are generally volumetric estimates (explained in Chapter 26). The work volumes are relatively high, with the forecasts based on survivor curve analysis. We use averaged unit rates based on analysis of equivalent historical costs.

Expenditure in this portfolio includes renewals of poles and crossarms to support our reconductoring programmes. More information on our reconductoring programmes is contained in Chapter 16.

Figure 15.12 shows our forecast Capex on overhead structures during the planning period.

Figure 15.11: Overhead structures renewal forecast expenditure



We plan to gradually increase the level of investment during the first five years of the period to allow the mobilisation of additional resources. This forecast reflects the level of investment needed to manage defects within the fleets and includes expenditure on crossarms that have known safety issues. Renewal expenditure will return to a stable level by 2025.

16 OVERHEAD CONDUCTORS

16.1 CHAPTER OVERVIEW

This chapter describes our overhead conductor portfolio and summarises our associated fleet management plan. This portfolio includes three asset fleets:

- Subtransmission overhead conductors
- Distribution overhead conductors
- Low Voltage (LV) overhead conductors

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to increase our investment in overhead conductor renewals from $8m in 2020 to $18m in 2029. This portfolio accounts for 17% of renewals Capex during the planning period. The increase will be gradual to facilitate deliverability.

Increased investment is needed to support our safety and reliability objectives. Failure of overhead conductors can have a significant impact on our safety and reliability performance. This increase in renewals Capex is mainly driven by the need to replace poor condition conductors because of their type, age and accelerated degradation due to coastal environments.

Certain types of distribution conductors on our network perform more poorly than others. Our average distribution conductor failure rate is 1.4 faults per 100km per annum.[59] However, we have three types of conductors with failure rates between 2.7 and 4.0 per 100 km per annum. These types of conductors make up 13%, or 1,872km, of our distribution overhead fleet. During the planning period we will prioritise the replacement of these types of conductors.

Below we set out the Asset Management Objectives that guide our approach to managing our overhead conductor fleets.

16.2 OVERHEAD CONDUCTORS OBJECTIVES

Overhead conductors are a core component of our network and connect our customers to the transmission system via grid exit points. They enable the flow of electricity on circuits of varying voltage levels. Our network is long, predominantly rural, and most circuits (78%) are overhead.

Our three overhead conductor fleets are defined according to operating voltage. The same conductor type (material) is often used across voltages, albeit of different sub-types and sizes. However, the risks and criticality differ by operating voltage. This means they require different lifecycle strategies.

To guide our asset management activities, we have defined a set of portfolio objectives for our overhead conductor assets. These are listed in the table below. The objectives are linked to our Asset Management Objectives as set out in Chapter 5.

Table 16.1: Overhead conductor portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No injuries to the public or our service providers as a result of conductor failure. No property damage, including fire damage, as a result of conductor failure.
Customers and Community	Minimise planned interruptions to customers by coordinating conductor replacement with other works. Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Distribution conductor renewal is targeted at poor performing network areas to improve feeder reliability and manage the overall System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). Consider the use of alternative options and technology to improve customer experience and/or minimise network costs, such as remote area power systems.
Asset Stewardship	Reduce the failure rate of distribution overhead conductors to target levels –as indicated by failure rate modelling – by 2030. Maintain the failure rate of subtransmission and LV overhead conductors at or below today's levels. Increase the use of conductor sampling and diagnostic testing to inform and verify renewals expenditure.
Operational Excellence	Develop condition-based Asset Health Indices (AHI) for all subtransmission overhead conductors. Develop risk-based techniques for prioritising the renewal of distribution overhead conductors. Improve our information of the LV overhead network, including conductor types, ages and failure information.

[59] This failure rate refers to asset related conductor faults and not total overhead line fault performance.

16.3 SUBTRANSMISSION OVERHEAD CONDUCTORS

16.3.1 FLEET OVERVIEW

Subtransmission overhead conductors are classified as the conductors used in circuits operating at 33kV and above, connecting zone substations to grid exit points (GXPs), and interconnecting zone substations.

Figure 16.1: 66kV subtransmission overhead line in the Coromandel

Conductors used at subtransmission voltages are made of aluminium and copper, in various compositions. Annealed copper was the predominant type used on our networks until about 60 years ago, being highly conductive with good strength and weight characteristics.

During the 1950s we started to use all-aluminium conductor (AAC) and aluminium conductor steel reinforced (ACSR) conductors in place of copper. AAC is a high purity conductor but its poor strength-to-weight ratio compared with other types means that today it is usually used in urban areas where shorter spans and high conductivity are required.

ACSR has become the most widely used type of conductor on our network. The ACSR conductor comprises an inner core of solid or stranded steel and one or more outer layers of aluminium strands. This construction gives it a high strength-to-weight ratio making it ideal for long spans, so it is widely used in rural areas of our network.

The steel core that gives the ACSR conductor its strength also makes it more vulnerable to corrosion in coastal areas. Corrosion is reduced by galvanising and grease coating of the core.

In the past five years, all-aluminium alloy conductors (AAAC) have been preferred to AAC conductors. AAAC has also recently become the most used conductor type in new installations, taking over from ACSR. AAAC is stronger than AAC and significantly lighter than ACSR. AAAC also has good conducting properties.

16.3.2 POPULATION AND AGE STATISTICS

There are four types of subtransmission conductors making up approximately 7% of our total conductor length. Table 16.2 shows that only small volumes of copper conductors remain in service.

Table 16.2: Subtransmission conductor population by type

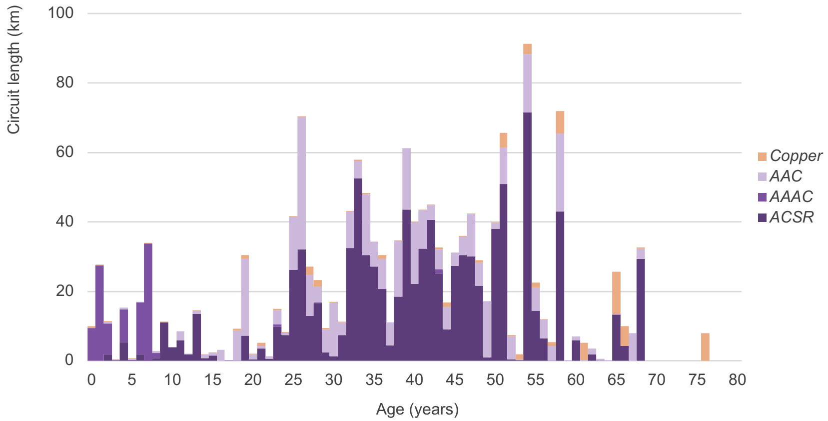
CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	108	7%
AAC	413	27%
ACSR	925	61%
Copper	62	4%
Total	1,507	

Our conductor population is ageing. The majority of our conductors were installed in the 1960s, 1970s and 1980s. The average age of the subtransmission overhead conductor fleet is 38 years. Most remaining copper conductors are 60 years and older.

Significant conductor renewals will be needed during the planning period and beyond, based on an expected life of approximately 60 years.[60] Figure 16.2 shows our subtransmission conductor age profile.

60 Note that actual replacement is a condition-based decision.

Figure 16.2: Subtransmission conductor age profile



16.3.3 CONDITION, PERFORMANCE AND RISKS

Subtransmission conductor failure rates are lower compared with those of our distribution and LV conductors. Subtransmission conductors make up 9% of High Voltage (HV) conductor length but are responsible for only 2% of total HV conductor failures.

Failure rates are lower because subtransmission conductors tend to be heavier and more robust than distribution and LV conductors. Subtransmission conductors are inspected more frequently because of the higher importance in maintaining a safe and reliable supply and a higher ground clearance.

Figure 16.3 shows our subtransmission overhead line fault rate compared with other electricity distribution businesses (EDBs). It shows that we are the worst of the comparison group (averaged over the past four years), with fault rates needing to drop by more than 50% to reach the median of the group.

Figure 16.3: Subtransmission overhead line benchmarking (2014-2018 average)

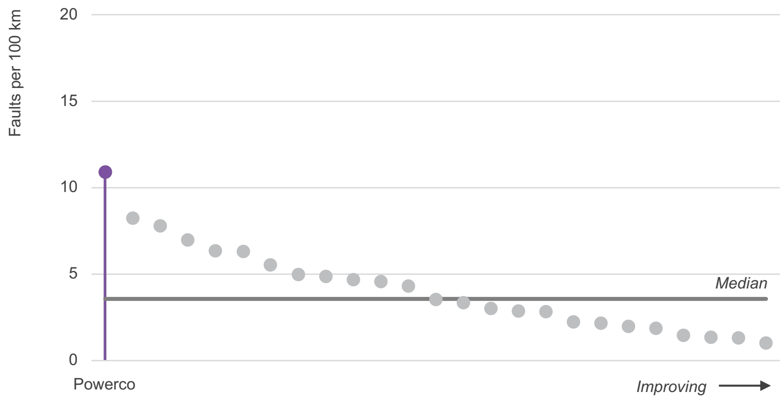


Table 16.3 summarises the common failure modes for all overhead conductors, including distribution and LV.

Table 16.3: Conductor failure modes

FAILURE MODE	DESCRIPTION
Annealing	Annealing is the reduction in minimum tensile strength through heating and slow cooling effects. The effects of heating are cumulative and arise through operation of the line at loads above its rating and design operating temperature. As effects are cumulative, older conductors will generally have relatively lower tensile strength. Copper and AAC/AAAC conductors are more susceptible to annealing, while the steel core of ACSR results in lower annealing rates. Smaller distribution conductors are also more susceptible to annealing.
Corrosion	Corrosion, salt contamination, is one of the main causes of failure on our networks. Copper has good corrosion resistance, but mixed results have been seen with aluminium, including variation within conductors of the same type and size. While ACSR conductors (the steel core) are prone to salt corrosion, this has been managed through galvanising and greasing.
Fretting and chafing	Fretting and chafing is caused by conductor swing causing movement and wear at the contact between two solid surfaces, typically at or near the points of connection to crossarms via the tops of insulators. Binders connect the conductor to the insulators and chafing can occur between the conductor and binder or between strands of a conductor. Armour rods or line guards (sacrificial metal sheaths) are typically used on aluminium conductors at the point of binding to an insulator to avoid this. This issue occurs more on homogenous conductors such as AAC, AAAC or copper. We believe this has a reasonable level of impact on conductor failures on our network.

FAILURE MODE	DESCRIPTION
Fatigue	Conductor fatigue is caused by the flexing of conductors near the insulators. Fatigue is more prominent in long spans (greater than 150 metres) and where lines cross a gully or are on exposed ridges. Continuous 'working' of the conductors causes brittleness over time, resulting in failures. Limiting the amount of conductor oscillation in wind-prone areas is desirable. Vibration dampers are fitted on some lines to mitigate the damage. Copper, AAC and AAAC conductors are more susceptible to fatigue than ACSR.
Foreign object strikes	Foreign object strikes, such as birds, vegetation etc, can break a conductor or weaken it to a point where it fails in high winds. Foreign objects need only damage a single strand of a light conductor to cause a loss of tensile strength of about 15%. Strikes can also cause conductor clashing, which usually results in the loss of a conductor cross section. ACSR conductors are less susceptible to this issue because of the strength of the steel core. Large object strikes, such as from a tree, can also cause complete mechanical failure of the line.
Binder failure	Binder failure allows the conductor to swing free, which means the conductor can contact an alternative phase conductor. The resultant arcing between the two conductors, due to the fault current, can cause the conductor metal to melt and the conductor to break. ACSR conductors are less susceptible to this issue because of the strength of the steel core.

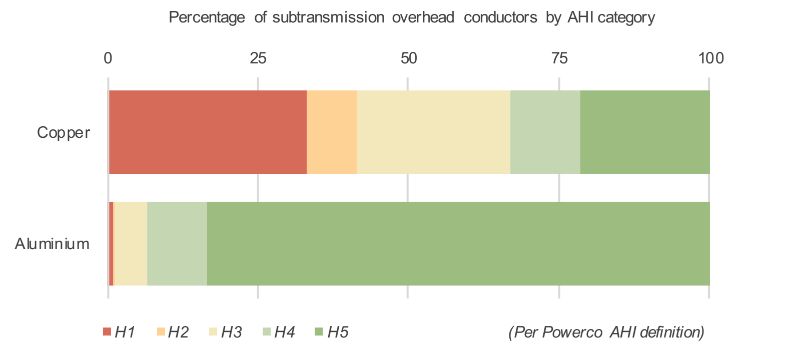
The poorest condition conductors in this fleet are our copper subtransmission conductors and certain ACSR conductors. Our copper subtransmission conductors are ageing and make up the majority of our expected renewals during the planning period. We have recently noticed some accelerated corrosion of ACSR conductors. We suspect that improper greasing during manufacture is causing this. When identified with corrosion, the conductor is prioritised for replacement.

Subtransmission overhead conductor asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end-of-life and categorise their health based on a set of rules. For subtransmission conductors we define end-of-life as when the assets can no longer be relied upon to safely carry their mechanical load and should be replaced.

Figure 16.4 shows AHI for our copper and aluminium subtransmission conductor populations. The AHI for this fleet is based on conductor condition degradation, proximity to the coast, and expected conductor life versus age.

Figure 16.4: Subtransmission overhead conductors asset health as at 2018



The health of our aluminium conductors is very good. Most of the subtransmission conductor fleet is made of aluminium. Of aluminium conductors, only 6% will require renewal during the next 10 years (H1-3).

However, the health of our copper conductors is a concern. Although only 4% of subtransmission conductors are made of copper, 41% of them will require renewal during the next three years, and most within 10 years. These conductors will make up the majority of our subtransmission conductor replacement during the planning period.

Conductor sampling

We have recently started a programme of conductor sampling and diagnostic testing, with the objective of improving our understanding of conductor end-of-life, and how it is influenced by type, age, inland versus coastal environment, attachment points versus mid-span, and other factors.

Samples will be taken from conductors of various ages, types, locations and from different points on the span. A variety of tests will be used that will enable us to build up a profile of each ageing characteristic – external damage, annealing, corrosion, fatigue – by conductor material, location, age and point of span.

This new information will enable us to build up a more accurate picture of how conductor condition degrades. This will be used to improve asset health modelling and more effectively manage public safety and reliability risk while minimising cost through efficient replacement programmes.

16.3.4 DESIGN AND CONSTRUCT

Any subtransmission conductor renewal project includes a project design based on AS/NZS 7000 and associated national standards. The design considers land reinstatement and worksite housekeeping issues to minimise impacts on landowners and the wider public, such as when working alongside a roadway. The design phase also considers future underbuilt 11kV circuits.

Meeting our portfolio objectives

Customers and Community: The impact on landowners of overhead conductor renewal is anticipated and minimised during project design.

Choosing a conductor wire size and material involves considering electrical, mechanical, environmental and economic factors. AAAC conductors are our preferred type because of their light weight and good conducting properties. Where physical loadings are severe, such as long spans, ACSR conductors are used.

16.3.5 OPERATE AND MAINTAIN

Maintenance and inspection regimes applied to overhead conductors generally involve visual inspections and condition assessments. Table 16.4 summarises the preventive maintenance and inspection tasks. The detailed regime for each type of subtransmission overhead conductor is set out in our maintenance standard.

Table 16.4: Subtransmission overhead conductors preventive inspection tasks

INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Yearly
Visual inspection of subtransmission overhead conductors as part of overhead network inspections. Alternates between a rapid inspection, which is a drive-by type inspection to identify defects, and a more detailed condition assessment.	2.5 yearly

Typically, conductors do not require routine servicing. However, they corrode (particularly in coastal locations) and work-harden, becoming brittle because of wind-induced vibration and movement, and thermal cycling. This degradation requires corrective maintenance. Intrusive inspections are performed only when necessary, such as to support a renewal decision.

There is a range of more sophisticated condition subtransmission conductor assessment tools available. These include detecting cross-sectional area changes as an indicator of corrosion of the steel core of ACSR conductors, thermography to identify poor connections and failing joints, and acoustic testing for identification of corona.[61]

We are evaluating the use of these tools in our maintenance regimes across our conductor fleets. The evaluation includes comparing the additional costs to the likely benefits of more optimised replacement programmes and reduced failures.

16.3.6 RENEW OR DISPOSE

We use a condition-based renewal strategy for subtransmission overhead conductors, where degradation is related to their age and location, eg near the coast or otherwise. We use visual inspections to assess conductors for failure modes such as corrosion, fretting, and damage from foreign objects. The number of joints in a span provides an indicator of past failures. For other failure modes, we rely on condition indicators such as failure history, age and location.

As we increase our renewals work on end-of-life conductors, we will progressively adopt new tools and techniques to assess condition, such as conductor sampling. For now, we generally use these tools and techniques only following an in-service failure or where the condition of the asset is suspected to be poor.

Meeting our portfolio objectives

Asset Stewardship: We will increase the use of diagnostic condition assessment tools to inform and verify renewal investments.

Once identified for renewal using the factors discussed above, replacement is prioritised. This is based on an assessment of risk, taking into consideration factors such as the level of network security of supply, the economic impact of conductor failure, and safety risk.

SUMMARY OF SUBTRANSMISSION OVERHEAD CONDUCTORS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Condition, type and age
Cost estimation	Desktop project estimates

Renewals forecasting

Our condition data provides us with a good understanding of the circuits that require replacement during the next three to five years. We expect to focus our renewals work on our remaining aged copper circuits. Forecast renewal quantities beyond

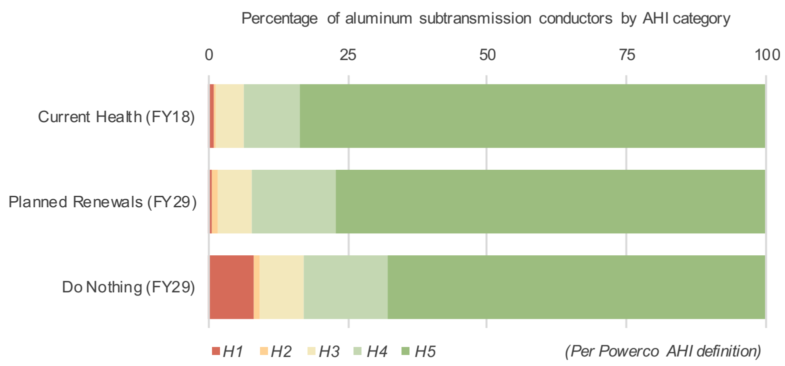
61 Corona is an electrical discharge brought on by the ionization of air surrounding a charged conductor.

this timeframe are mainly age based, as generally our poorer condition circuits are also aged.[62]

By 2027 we expect to have replaced the majority of our remaining copper subtransmission circuits, most likely with AAAC. This means that the asset health of copper conductors will no longer be a concern. We therefore do not provide an AHI projection for copper conductors.

Figure 16.5 compares aluminium conductor projected asset health in 2029, following planned renewals, with a counter-factual do-nothing scenario. Comparing the do-nothing scenario with the planned renewal scenario provides an indication of the benefit that our proposed investments will realise.

Figure 16.5: Projected aluminium subtransmission conductor asset health



The small amount of planned conductor renewal will maintain aluminium conductors in overall good health, indicated by the H1 portion in Planned Renewals (FY29). Beyond 2026 there will be a growing need for aluminium conductor renewal (H2 and H3).

Coordination with network development projects

Subtransmission conductor works are also driven by load growth. An increase in conductor size is often needed to continue to meet demand. Our options analysis considers the costs and benefits of accommodating future demand by increasing conductor size alongside other options, such as thermal re-tensioning, additional circuits or non-network solutions. Conductor condition is also considered in this analysis.

If the conductor requires replacement in the medium-term, the preferred solution might involve replacing it with a conductor of larger size.[63] This means growth and renewal needs are integrated.

Conductor renewal always considers future load growth when selecting a new conductor size. This ensures that, as far as practicable, new conductors will not need to be replaced later because of load growth.

16.4 DISTRIBUTION OVERHEAD CONDUCTORS

16.4.1 FLEET OVERVIEW

Our distribution network overhead conductors operate at voltages of 6.6kV, 11kV and 22kV. This fleet of conductors connects zone substations to distribution transformers and makes up the largest proportion of the overhead conductor portfolio.

Figure 16.6: Distribution overhead line with LV underbuilt

62 We intend to further develop and refine our asset degradation and asset health models.

63 Work and expenditure in this chapter only relates to renewals.

In general, we use the same conductor types at the distribution level as for subtransmission. We also have a small population of steel wire[64] conductors.

The backbone of the main distribution network is formed of medium and heavy conductors.[65] These backbone assets are often replaced when required to meet load growth or solve voltage issues at the ends of the feeders, rather than because of end-of-life. There are significantly fewer failures on these conductors than the small diameter, lightweight types that are typically used on spur circuits.

16.4.2 POPULATION AND AGE STATISTICS

Approximately 68% of our total conductor length is at distribution voltages. Table 16.5 shows the five types of distribution conductors used on our network. As with subtransmission, the main types are ACSR and AAC, although a higher proportion of copper conductors remain in this fleet.

Table 16.5: Distribution conductor population by type

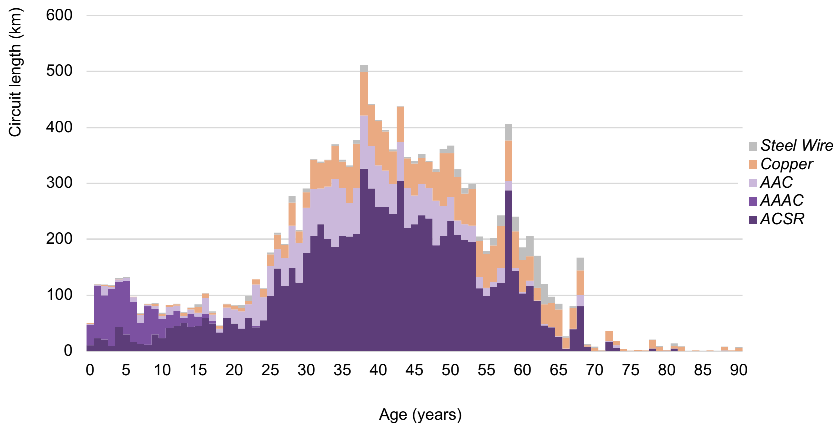
CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	863	6%
AAC	2,393	16%
ACSR	8,470	57%
Copper	2,555	17%
Steel wire	522	4%
Total	14,804	

The average age of the distribution overhead conductor fleet is 39 years. A lot of construction occurred in the 1960s and 1970s, primarily using ACSR and AAC conductors. The 11kV distribution circuits make up most of the distribution network. Many different conductor types and sizes were used to suit particular applications.

Since 2005, we have typically replaced between 50km and 100km of distribution conductors per annum. Most of this work was driven by growth upgrades to backbone circuits.

Figure 16.7 shows our distribution conductor age profile. A significant number of distribution conductors are approaching or have already exceeded their expected life of approximately 60 years, noting that actual replacement is a condition and risk-based decision.

Figure 16.7: Distribution conductor age profile



16.4.3 CONDITION, PERFORMANCE AND RISKS

Overhead conductors, by their nature, create risks to public and personnel, including:

- Lines falling leading to an electrocution risk for people or livestock, either directly or indirectly – livening houses, fences or other structures.
- Lines falling and causing fires affecting buildings, forests and crops.
- Risks related to working at height and working near live conductors.
- Low hanging conductors that pose a contact risk to people, property or livestock.
- Risks to householders undertaking tree trimming who could accidentally touch a live line.

These risks apply to varying degrees across all three conductor fleets. Protection systems are employed, with switchgear at zone substations to protect conductors and isolate supply when faults occur. Other fault discrimination is employed along distribution feeders by way of circuit breakers, reclosers, sectionalisers and fusing.

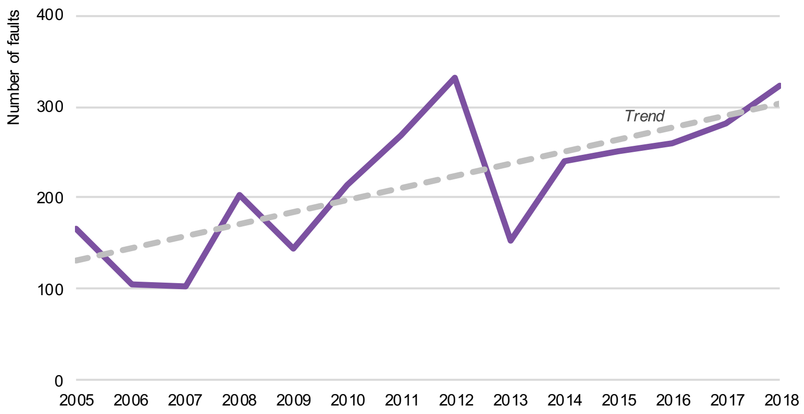
We have traditionally managed risks associated with overhead lines to ‘As Low as Reasonably Practical’ (ALARP) levels. There is an increasing concern that distribution conductor failure rates, and therefore public safety risk, are increasing.

Figure 16.8 shows historical distribution conductor related faults on our network.

64 Steel wire conductors (predominantly No 8 wire) are galvanised steel. They are typically installed in remote rural areas where only a low current capacity is required. They were predominantly installed during the 1950s and 1960s as a cost effective alternative to ACSR and copper conductors.

65 Medium and heavy conductors are defined as those of >50mm^2 and >150mm^2 equivalent aluminium cross sectional area respectively.

Figure 16.8: Conductor related faults on distribution overhead lines



Meeting our portfolio objectives

Safety and Environment: When prioritising conductor replacement and renewal works, public safety and property damage risks caused by potential conductor failures are strongly considered.

Our distribution conductor fault analysis has identified conductor type, age and location as the main drivers of degrading condition and failure. We expect the interaction of several factors, rather than a single factor, to result in faster degradation/poorer performance.

Poor construction methods in the past, for example not installing line guards or armour rods at the time of construction, have caused fretting and chafing of conductors on some networks. The fretting and chafing leads to conductor failure over time.

Our renewal focus for this fleet uses a combination of these factors to prioritise replacement of distribution conductors to reduce overall failure rates.

Smaller distribution conductors (<50mm^2) tend to be less resilient than larger, heavier types. They have lower strength-to-weight ratios and disproportionally high failure rates, regardless of location. Smaller distribution conductors also vary significantly in their performance. Those with an ultimate tensile strength below 10kN tend to have much higher failure rates.

In general, small diameter ACSR conductors perform well, but performance of the smaller light homogenous copper and AAC conductors is consistently poor, regardless of age.

Table 16.6 lists the worst performing conductor types, the length installed on our network and their respective failure rates.

Table 16.6: Poor performing distribution conductor types

CONDUCTOR	KM OF LINE	FAILURE RATE[66]	DESCRIPTION
AAC Namu	701	3.2	Concentrated in Tauranga and Te Puke areas, where it was historically used as the main distribution conductor. Spatial mapping reveals no consistent pattern to failures, which are evenly spread throughout the networks. Fretting and chafing has been excluded as a major failure mode as line guards/armour rods are installed on most of the lines with Namu conductors.
Copper 16mm^2	494	3.3	These types of conductors were used widely. The large quantities of smaller copper conductors in the Egmont and Taranaki regions are likely a key contributor to the rise in conductor faults in those areas as the wire progressively ages.
Copper 7/0.064	677	2.7	

To reduce the number of distribution conductor faults to our target, these conductors will need to be replaced. We target average failure rates[67] of 1.3-1.5 failures per 100km, depending on whether the circuits are in urban or rural areas. Failure rates of our worst performing conductors vary from 2.7-3.2 failures per 100km.[68] The conductor types in the table above perform very poorly compared to our targets.

Our fault analysis also revealed a correlation between age and poor performance. Conductors older than 60 years of age showed higher average failure rates than younger conductors.[69] This finding is consistent with our knowledge of failure modes. Other than foreign object strikes, all failure modes worsen as the conductor ages.

Coastal proximity also has a major impact on conductor life and performance. Figure 16.9 shows that the likelihood of failure increases the closer an asset is to the coast.

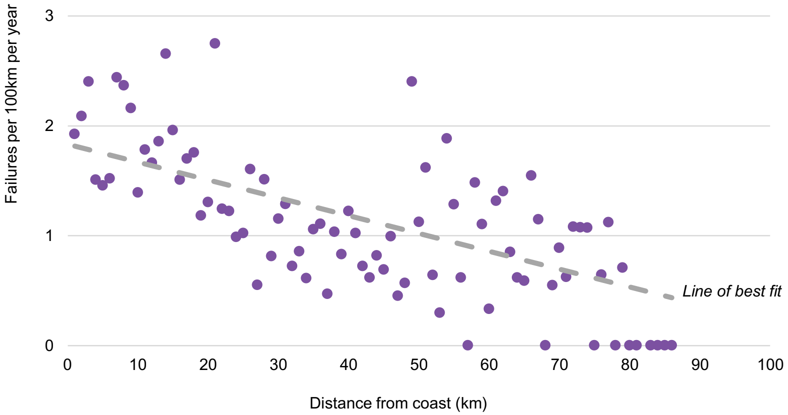
66 The failures rates in the table relate to those attributed directly to conductor failures, not overall overhead line failure rates. Failure rates are measured as failures per 100km per year.

67 The target average failure rates are informed by the historical performance of our well-performing conductor assets. A range is given, as we target a higher level of reliability for our urban circuits compared with rural because of their relative criticality.

68 Conductors on our network, average approximately 1.4 failures per 100km.

69 Only small numbers of conductors are more than 60 years old, therefore our sample for analysis is small.

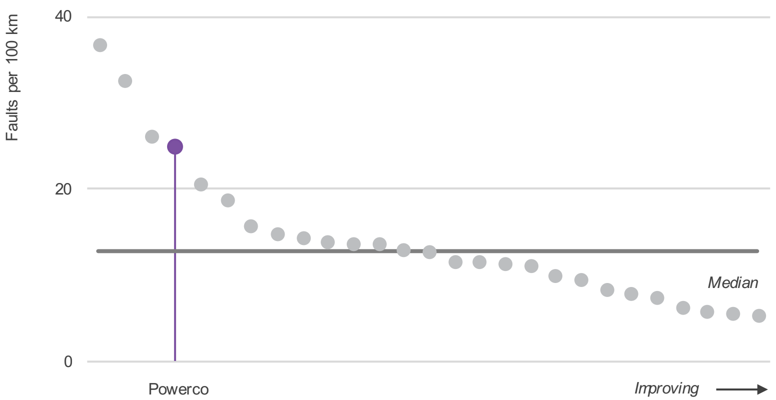
Figure 16.9: Distribution conductor failures and coastal proximity



We found this relationship to be particularly strong within 20km of the coast in the Western region. With other factors constant, we expect conductors to have a shorter life near the coast, particularly for lightweight conductors and those using steel –ACSR and No 8 steel wire.

We can also compare the performance of our network with that of our peers. Figure 16.10 shows distribution overhead line fault rates, including poles and crossarms etc, compared with those of other EDBs during the past four years. We would need to reduce faults by more than 50% to achieve median performance.

Figure 16.10: Distribution overhead line benchmarking (2014-2018 average)

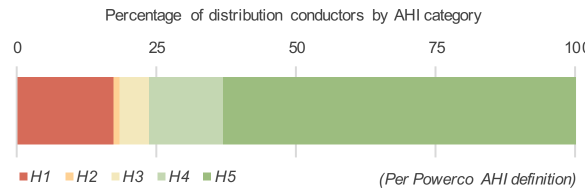


Distribution overhead conductors asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end-of-life and categorise their health based on a set of rules. For distribution conductors, we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical load, and the conductor should be replaced.

Figure 16.11 shows current overall AHI for our distribution conductor population. The AHI is based on historical analysis of failure data, known poor performing types, and expected condition degradation.

Figure 16.11: Distribution overhead conductor asset health as at 2018



The health of the fleet indicates the need to replace significant amounts of conductor (17% of the fleet, H1) in the short term, to improve the health to a more sustainable level, and therefore improve our reliability performance.

16.4.4 DESIGN AND CONSTRUCT

The renewal of smaller diameter distribution conductors with larger and more robust types usually requires a portion of the existing poles to be replaced regardless of their condition.

Where large numbers of poles require replacement, we consider various options. This may include using smaller diameter but stronger conductor types, such as ACSR conductors, that require fewer pole replacements, or conductor types that can be used over longer spans requiring fewer poles. Our design and construction standards set out the alternative designs that need to be considered as part of the options analysis.

As with subtransmission, AAAC conductors are our preferred distribution conductor type because of their lighter weight and good conductivity. Approved sizes include fluorine, iodine and krypton.[70]

[70] These are conductor code names used by manufacturers and the electricity industry.

We also strongly consider the needs and requirements of landowners as part of the detailed planning and design process. We aim to minimise the time spent on landowners' property and ensure no damage is left. We also consider realigning overhead lines to road reserves where practicable and cost effective.

With an expected large increase in reconductoring volumes, we are investigating improved methods for maintaining supply, or limiting supply interruption, while this work is done. We use generators when customers are affected by multiple consecutive outages. Other methods could include the use of temporary bypass cables to maintain supply.

16.4.5 OPERATE AND MAINTAIN

Distribution conductors are inspected less frequently than subtransmission conductors because of their lower criticality. Our inspection regime for distribution overhead conductors is summarised in Table 16.7. The detailed regime is set out in our maintenance standards.

Table 16.7: Distribution overhead conductor preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of distribution overhead conductors as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

Corrective maintenance tasks carried out on distribution conductors are similar to those performed on subtransmission conductors.

Most conductor failure occurs during storms and high winds. Failure is most often caused by external contact or interference, such as trees or wind-borne debris (roofing iron etc), or where a conductor is weakened because of the loss of strands (clashing/bird strike).

Conductor failure because of condition can occur for a number of reasons, including annealing, corrosion, fretting and fatigue, or a combination of these conditions.

Conductor repairs often require unbinding of several spans to enable re-tensioning at a strain pole following mid-span jointing. This results in long repair/outage times. Physical access to poles and mid-span sections because of terrain and other factors can often be difficult, compounding repair/outage times.

Care is needed when re-terminating a conductor following a fault. Field staff must identify and use the correct preformed components. Some sizes of ACSR and AAAC are similar but incorrect preformed component selection can result in an under-strength repair and subsequent failure under tension.

While we have standardised conductor types, a wide range of conductors are used on our network. Sufficient spare conductors and associated fittings are available at strategic locations to expedite fault repairs.

16.4.6 RENEW OR DISPOSE

Although we have increased our levels of conductor replacement during the past three to five years, our volumes have been insufficient to materially reduce failure rates. Our modelling and analysis indicate that without further replacement rate increases, failure rates will continue to rise.

Visual inspections can identify some defect types – some corrosion, fretting, fatigue and foreign object damage. For other failure modes we must rely more on other factors to predict risk of failure. For this fleet, the three key indicators are:

- Age – failures increase from the age of 60 years.
- Type – certain small cross-section problematic homogenous conductor types (AAC Namu and 16mm^2 and 7/0.064 copper) have much higher failure rates than other distribution conductor types.
- Coastal proximity – conductors near the coast exhibit more failures than other comparable conductors.

SUMMARY OF DISTRIBUTION OVERHEAD CONDUCTOR RENEWALS APPROACH

Renewal trigger	Condition-based considering failure risk
Forecasting approach	Failure rate reduction
Cost estimation	Volumetric average historical rate

We are targeting the replacement of distribution conductors that meet these indicators. Safety is our key concern around distribution conductor failure. We prioritise the renewal of conductors in more densely populated areas. Worst performing feeders will also be targeted for conductor renewal.

Meeting our portfolio objectives

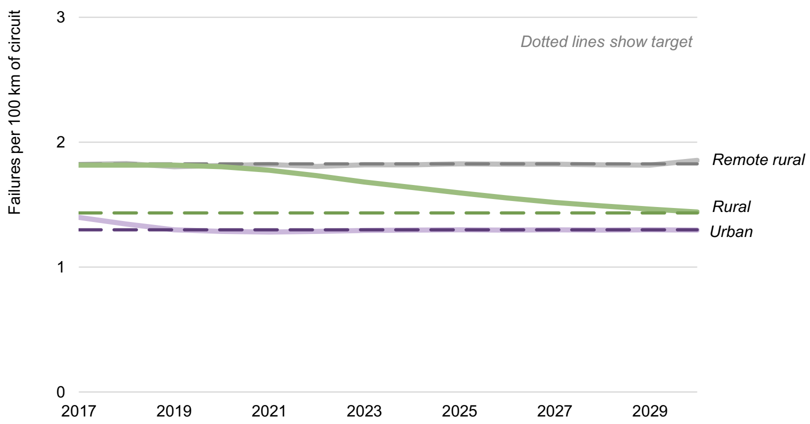
Networks for Today and Tomorrow: Distribution overhead conductor replacements will be targeted in areas of worst performance, improving the reliability of poor performing feeders and managing network SAIDI and SAIFI.

Renewals forecasting

We have modelled expected failure rates for all our distribution conductor spans to help forecast longer term renewal needs and prioritise replacement. Our overall failure rates are higher than good practice levels.[71] We have set ourselves the target of reducing failure rates to good practice levels by 2019 for urban conductors and 2030 for rural conductors, and maintaining remote rural conductor failure rates at today's levels.

Figure 16.12 outlines our modelled improvement in failure rates over time. The figure illustrates that we are prioritising the improvement of urban failure rates first, while ensuring rural rates do not degrade.

Figure 16.12: Distribution conductor expected failure rates



We forecast the amount of conductor renewal required to meet these targets using our modelled failure rates, assuming we replace the worst performing conductors first. This indicates the need for a large step change in renewal quantities during the next 10 to 15 years. Replacement quantities needed are expected to reduce once we reach our failure rate targets. Some ongoing replacements will still be necessary to maintain overall performance at target levels.

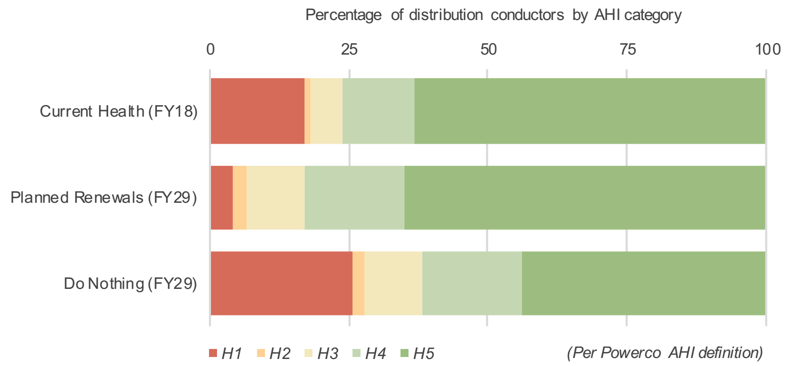
71 As discussed in the Network Targets chapter, our overall distribution overhead line fault target is 16 faults per 100km. Faults have been increasing over time and we exceeded our target in 2015. However, overall overhead line performance is influenced by many factors, including storms, third party interference and vegetation growing near lines. Therefore, we also analysed faults related to the conductor asset only. This analysis uncovered the same increasing trend (see earlier section) with a number of conductor types performing poorly compared to the rest of the population, driving our overall poor performance. Our good practice failure rate targets are informed by the historical performance of our well performing conductor assets.

Meeting our portfolio objectives

Asset Stewardship: Forecasted distribution overhead conductor renewal is expected to reduce failure rates to target levels – as indicated by failure rate modelling – by 2030.

Figure 16.13 compares projected asset health in 2029, following planned renewals, with a do-nothing scenario. Our investment will lead to an improvement in overall health by 2029, as shown by the reduced H1 portion, although not to long-term sustainable levels (in line with our 2030 target).

Figure 16.13: Projected distribution conductor asset health in 2029



Significant numbers of conductors will still need to be replaced after 2029 as indicated by the H1-H3 portion in Planned Renewals (FY29). However, it will not be at the same level as during this planning period.

Coordination with network development projects

Distribution conductor upgrades and installations can be triggered by load growth, such as from residential infill or greenfield development. This often requires either feeder backbone upgrades to a larger conductor, thereby increasing capacity, or new feeders.

When planning the renewal of larger distribution lines, we consider forecast load growth and then appropriately size the conductor to meet credible foreseeable future needs. This reduces the likelihood of needing to upgrade the asset before it reaches its intended life. Voltage and backfeeding ability are also considered where relevant. Some smaller conductor types do not provide scope for backfeeding at an appreciable level of maximum demand.

When renewing remote rural feeders, we consider the use of remote area power supplies (RAPS). This is carried out instead of traditional conductor replacement where the economic benefits are positive.

Remote area power supplies (RAPS)

RAPS provide an option as a modern replacement asset for end-of-line, remote rural distribution feeders. In some situations, there may be just one small customer connected to the end of a feeder that requires replacement. Installing a RAPS unit to supply this customer can be more cost effective than renewing the overhead line. When the end of a remote rural line requires replacement, we undertake an economic evaluation of installing a RAPS compared with overhead line renewal.

A RAPS unit typically includes solar panels, battery storage and a diesel generator. Other types of generation such as micro hydro or wind can also be used. They allow the connected customer to go off-grid with only the generator's diesel tank needing to be kept filled.

RAPS are matched to load requirements, with different sizes of solar arrays, battery storage and diesel generators available. Typically, it is more cost effective to install energy efficient appliances, such as LED lighting, as part of the installation, rather than upsize the RAPS.

We have installed fifteen RAPS on our network, including new versions that use lithium ion batteries for storage. This increases storage levels while reducing costs.

A RAPS unit with a 1.1kW photovoltaic array is shown below.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We are installing RAPS where appropriate on our network as an alternative technology to minimise the cost of asset renewal.

16.5 LOW VOLTAGE OVERHEAD CONDUCTORS

16.5.1 FLEET OVERVIEW

LV conductors operate at 230/400V. Almost half of LV conductors are located within urban areas and a high proportion of network incidents relate to LV conductors.

The types of conductors used in the LV parts of our networks are steel wire, AAC, AAAC, ACSR, and copper. LV conductors can either be constructed with their own poles or underbuilt, whereby the LV line is built under a HV circuit.

Our newer LV conductors are covered in a poly vinyl chloride (PVC) outer sheath, which provides some insulation protection.[72] This helps to mitigate safety risks to the public and reduces vegetation related faults. The LV conductor fleet also includes overhead LV service fuse assemblies. These are the fuses located at the customer connection to protect customer premises and our network from faults.

Figure 16.14: LV overhead circuit

[72] The covering is not sufficient to classify the conductor as electrically insulated, but does provide some mitigation of safety risk by substantially reducing the likelihood of injury or death should accidental contact be made with the conductor.

16.5.2 POPULATION AND AGE STATISTICS

We have approximately 5,100km of LV overhead conductors, of a variety of types, making up 24% of total conductor length. We also have approximately 230,000 overhead LV service fuse assemblies.

Table 16.9 summarises our LV conductor population by type. Most of our LV conductors are made of copper (52%). The AAC conductor is more prevalent in the LV fleet. Its relative lack of strength is less of an issue than for HV conductors as LV spans are typically much shorter than that of distribution, especially in urban areas.

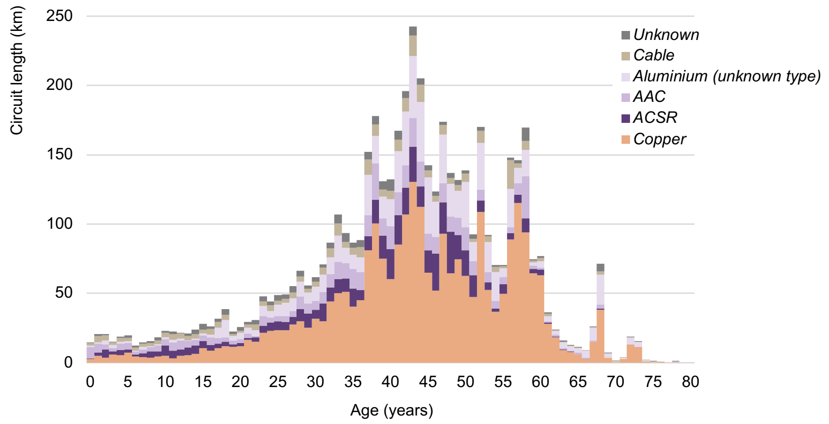
Table 16.8: LV conductor population by type at 31 March 2018

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	7	0.1%
AAC	523	10%
ACSR	551	11%
Copper	2,676	52%
Steel Wire	4	0.1%
Unknown Al	847	17%
Cable	299	6%
Unknown	202	4%
Total	5,110	

Our asset data is less complete for the LV fleet. We are aiming to increase the accuracy of that information through inspections. Some of the conductors recorded in our information systems are of unknown type or the material is known but not the specific alloy or construction. About 21% of our LV conductors are of unknown type.

Figure 16.15 shows our LV conductor age profile. The ageing population indicates that levels of renewal will need to increase.

Figure 16.15: LV conductor age profile



As with the other fleets, significant investment was carried out in the period from 1960 to the mid-1980s. Only a very small amount of new LV overhead network has been built in the past two decades. Most of the new LV build on our network has been underground with almost no LV overhead renewal.

Because of limitations on LV conductor data, we have estimated the age of about half our LV conductors using age data from associated poles.

16.5.3 CONDITION, PERFORMANCE AND RISKS

As discussed previously, failure of an overhead conductor creates large safety risks for the public. This is of particular concern as nearly half of our LV fleet is in more densely populated urban areas. Mitigating this risk is key to our LV conductor fleet management.

LV circuits cannot be adequately protected against earth faults using overcurrent devices. Protection is unlikely to operate for high impedance faults, or may operate but with a long time delay.

The public safety risk of electrocution because of downed LV conductors can be partially mitigated by covered conductors. Our standard requires the use of covered conductors but there are rural and urban overhead LV circuits that still use legacy bare conductors.

Through our overhead line inspections, we identify high-risk LV circuits that have bare conductors, assess the public safety risk because of conductor or binding failure, and prioritise their replacement with covered conductors. These measures cannot completely mitigate the risks but help to bring it down to an ALARP level.

Historically, we have not captured detailed LV fault data for failure analysis. In 2014, we commissioned our new OMS, which captures detailed failure information on our LV network. Over time we will be able to analyse these failures and identify where replacement of conductors should be prioritised.

Meeting our portfolio objectives

Operational Excellence: We are improving our information of the LV overhead network to allow for more informed asset management decision-making.

We believe that conductor type issues are unlikely to be as prevalent for LV conductors as with distribution voltage conductors. Although the same types are used, span lengths are shorter, which means the conductor is supported more and typically under less tension than at higher voltage levels.

Ageing will continue to cause condition degradation, with coastal proximity causing faster degradation. Similar to distribution conductors, we expect LV conductor failure rates to increase from approximately 60 years of age.

LV overhead fuse assemblies

Historically, we have replaced LV fuse assemblies on a reactive basis, when the device fails. However, this causes inconvenience to customers and is not cost effective. There are also public safety risks with running these assets to failure.

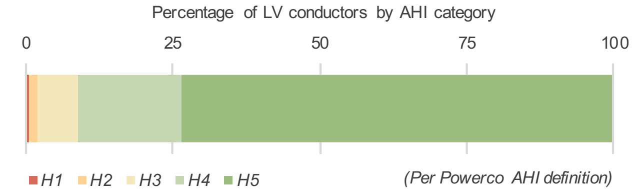
We plan to target replacement based on condition sampling and asset age, using pole age as a proxy. Areas to be targeted for replacement will be identified by analysing fault data and asset age, followed by condition sampling of the devices in the planned target areas.

LV overhead conductors asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorise their health based on a set of rules. For LV conductors we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical load and the conductor should be replaced.

Figure 16.16 shows current overall AHI for our LV conductor population. The overall AHI for this fleet is based on our understanding of the expected life and age of LV conductors.

Figure 16.16: LV overhead conductors asset health as at 2018



The health of our LV conductor fleet is good, with approximately three quarters of the fleet unlikely to require replacement during the next 20 years (H5). However, 9% of the fleet will likely require replacement in the next decade (H1-3), which represents a large increase in renewal volumes. The upcoming renewal need is driving our change from historical reactive replacement of LV conductors to more proactive condition-based replacement.

16.5.4 DESIGN AND CONSTRUCT

Although not a new technology, we are investigating the use of aerial bundled conductor (ABC) for use on our LV network. ABC has been used around the world for many years, but has not seen widespread use in New Zealand. ABC includes all three phases and the neutral wire in a single bundle, with the conductors fully insulated.

The conductor is safer because it is fully insulated. This means that conductor clashing because of tree contact is no longer an issue and it will not arc if in contact with a tree. Installation is also simpler, as insulators[73] and crossarms are typically not required. There is an additional cost for ABC and the visual impact differs from traditional four-wire systems.

We intend to trial ABC conductors on our LV network once research into New Zealand and international experience is complete. These trials will allow us to better understand the relative performance and cost of the product, and customers' visual preferences.

16.5.5 OPERATE AND MAINTAIN

LV network inspections are undertaken at the same frequency as our distribution network. LV inspections pay particular attention to identifying public safety hazards so they can be addressed.

[73] Insulated clamp brackets are still required.

Table 16.9: LV overhead conductor preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of LV overhead conductors, as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

16.5.6 RENEW OR DISPOSE

Limited data on the condition of the LV conductor fleet has meant that its replacement has generally been reactive. Data limitations mean that the key causes of poor condition are difficult to identify. This means that until now a more proactive approach has not been possible.

However, the LV overhead conductor fleet is ageing and an increased focus on safety has meant we are no longer satisfied with a largely reactive approach. Similarly, we are no longer satisfied with a reactive approach to replacement of LV fuse assemblies because of the higher per unit cost and disruption to customers.

SUMMARY OF LV OVERHEAD CONDUCTOR RENEWALS APPROACH	
Renewal trigger	Condition-based, considering failure risk and uninsulated conductor
Forecasting approach	Age
Cost estimation	Volumetric average historical rate

We believe conductor type issues are unlikely to be as prevalent for LV conductors as with distribution voltage. However, coastal proximity and ageing influence failure rates.

We intend to plan for replacement of aged LV conductors, with the priority based on condition and safety risk where relevant information is available. For example, we will prioritise the replacement of uncovered conductors in urban areas.

More detailed fault information from OMS will enable us to better target replacement of conductors with poor reliability. This includes particular types or those in challenging environmental conditions.

Similarly, for LV fuse assemblies, replacement planning will take into consideration fault data for an area, age of the assembly, and condition sampling.

Renewals forecasting

To forecast future renewal needs, we use age as a proxy for condition. Rather than using a simple 'birthday' type age model, we use a statistical distribution modelling approach. This approach reflects, more closely, actual replacement decisions.

It reflects that the need for conductor renewal can be expected to arise at different ages depending on the condition, environment and criticality of the conductor.

The modelling assumes an expected 70-year life for an LV conductor. This is more conservative than the indicative 60-year life of a distribution conductor.

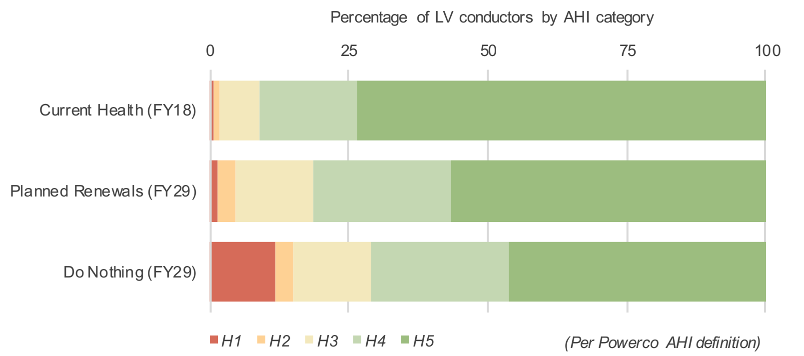
Although conservative, our model forecasts the need for a large step change in LV conductor renewal. We plan to slowly increase renewals from FY19, up to a steady state level in FY23. During that time, we will undertake fault analysis using the improved fault information from our OMS. This will enable us to refine our understanding of the step change required before committing to a large renewal programme.

Longer term, we expect renewal levels to continue to increase, as the large number of conductors installed during the 1960s and 1970s will likely require replacement.

In the case of LV fuse assemblies, we forecast renewals based on a steady state replacement programme of 5,100 units per year, using an expected life of 45 years. The focus on areas with older fuse assemblies and higher fault rates will result in improved asset health. With improved condition data we will be able to refine this forecasting approach.

Figure 16.17 compares projected asset health in 2029, following planned renewals, with a do-nothing scenario. Our investment will appropriately manage health during the next 10 years and support the step change in replacement needed longer term.

Figure 16.17: Projected LV conductor asset health in 2029



The number of conductors that need to be replaced will grow by 2029, as indicated by the H1-H3 portion in Planned Renewals (FY29). This indicates that long-term replacement volumes will need to increase further.

Coordination with network development projects

We coordinate LV conductor renewals with development works through a consultation process. Very little new LV overhead network is constructed, and it is unusual for the LV network to be capacity constrained. We will continue to coordinate growth and renewal investment and monitor developments as the use of grid edge technologies increases.

16.6 OVERHEAD CONDUCTORS RENEWALS FORECAST

Renewal Capex in our overhead conductors portfolio includes planned investments in our subtransmission, distribution and LV conductor fleets. During the planning period, we intend to replace approximately 160km of subtransmission conductors, 3,000km of distribution conductors, and 520km of LV conductors. We will also replace 5,100 LV fuse assemblies each year. This will require an investment of approximately $144m during the planning period.

The key driver for overhead conductor renewal is management of safety risk by addressing declining asset health. Failure of an overhead conductor presents a significant public hazard, as well as having reliability implications.

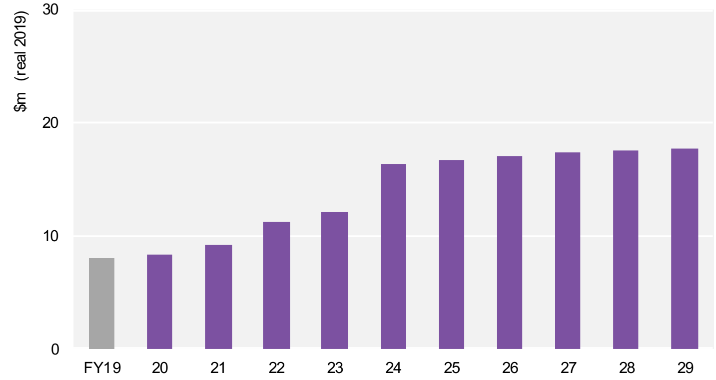
Subtransmission, distribution and LV conductor renewals are derived from bottom-up models. Subtransmission reconductoring projects can be scoped at a high level a number of years before implementation. This means we can carry out desktop cost estimates for each project, taking into account factors such as terrain difficulties, span lengths, and pole and crossarm renewals.

Distribution and LV renewals forecasts are generally volumetric estimates. The work volumes are high, with the forecasts based on failure rate analysis and age information respectively. We use averaged unit rates based on analysis of equivalent historical costs.

Figure 16.8 shows our forecast Capex on overhead conductors during the planning period. [74]

[74] Overhead conductor forecasts represent the cost to replace the conductor only, with associated pole and crossarm costs captured in the overhead structures portfolio. Projects are planned, scoped and delivered as overhead line projects.

Figure 16.18: Overhead conductors renewal forecast expenditure



We plan to gradually increase the level of investment during the next 10 years to allow additional resources to be mobilised. This forecast reflects the increased level of investment needed to renew distribution and LV conductors.

Longer term levels of renewals are expected to remain at these increased levels beyond the 10-year planning horizon, as more conductors built between the 1950s to 1970s require replacement.

During the next five years we will continue to refine our condition assessment techniques to ensure renewals timing is properly optimised. Lessons learned early in the period may allow us to moderate long-term expenditure projections.

17 CABLES

17.1 CHAPTER OVERVIEW

This chapter describes our cables portfolio and summarises our associated Fleet Management Plan. The portfolio includes three fleets:

- Subtransmission cables
- Distribution cables
- Low Voltage (LV) cables

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we forecast investment of $57m for renewing our cables fleets. This accounts for 7% of renewals Capex during the period. The forecast is generally in line with historical levels.

Our cable renewal programme focuses on addressing safety and environmental concerns and maintaining reliability. Renewals projects are mainly driven by 'type' issues and poor condition. Three 'type' issues affect our cable fleets:

- 11kV paper insulated lead covered cables (PILC) with ageing insulation and brittle lead sheaths
- First generation cross-linked poly ethylene cable (XLPE)
- A small number of 33kV subtransmission termination joints

We are developing modelling to identify critical distribution circuits to facilitate better targeting of renewal investment capital. Our modelling will integrate data from condition assessment and diagnostic testing regimes as well as laboratory testing of faulted cable sections to assess condition and failure root causes.

Significant work was undertaken between FY17 and FY19 to replace failing oil-filled subtransmission circuits in the Palmerston North CBD. The remaining circuits are stable and will be monitored for performance and further deterioration.

A number of years ago we embarked on a programme to replace LV pillars with safety-related risks, such as metallic boxes that may become live when degraded as well as those with failure modes that lead to overheating and fire. We have been working to remove these types of LV boxes from our network and plan to increase the rate of renewal during the planning period.

Below we set out the Asset Management Objectives that guide our approach to managing our three cable fleets.

17.2 CABLES OBJECTIVES

Underground cable makes up approximately 20% of our total circuit length. Cable conductors come in various sizes and are usually made of copper or aluminium.

Aluminium is used in most applications because it is less expensive than copper. However, copper conductors offer better current rating than aluminium for a given size. Copper use is limited to short runs where high capacity is required, such as connecting power transformers to switchboards at zone substations.

Several types of cable insulation are used across the subtransmission, distribution and LV fleets. These are XLPE cable, paper insulated, PILC, pressurised oil-filled cables, and poly vinyl chloride (PVC) insulated cables. Cables have one, three or four cores.

To guide our management of cable assets, we have defined a set of objectives listed below. The objectives are linked to our overall Asset Management Objectives from Chapter 5.

Table 17.1: Cables portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No public safety incidents from contact with our cable network. Minimise oil leaks from pressurised oil-filled cables.
Customers and Community	Minimise traffic interruptions when managing cable assets in road reserves.
Networks for Today and Tomorrow	Investigate the use of real time cable ratings using distributed temperature sensing.
Asset Stewardship	Maintain the failure rate of cable assets at or below target levels.
Operational Excellence	Improve our knowledge of the LV cable fleet.

17.3 SUBTRANSMISSION CABLES

17.3.1 FLEET OVERVIEW

The subtransmission cable fleet predominantly operates at 33kV, although we have a small amount of 66kV cable. The assets include cables, joints and pole terminations. The three types of cable used are XLPE, PILC and pressurised oil-filled cable.

17.3.2 POPULATION AND AGE STATISTICS

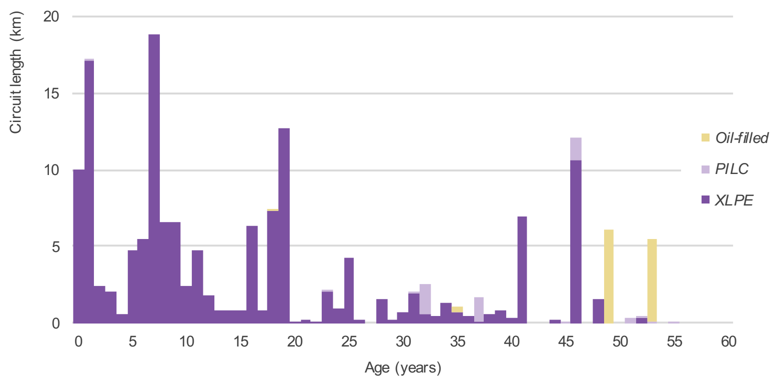
The majority of our approximately 170km of subtransmission cable is XLPE cable. XLPE has been the preferred cable insulation technology for more than 30 years. The table below summarises our subtransmission cable population.

Table 17.2: Subtransmission cable population by type

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	149	89%
PILC	6	4%
Oil-filled	13	8%
Total	169	

The subtransmission cable fleet is relatively young, with an average age of 22 years. The figure below depicts our subtransmission cable age profile.

Figure 17.1: Subtransmission cable age profile



The age profile shows that oil-filled cable has not been installed for many years as XLPE has emerged as the preferred type. XLPE cable requires less maintenance and is more environmentally acceptable. Oil-filled cable has an expected life of 70 years and has generally given good service, however a number of circuits have recently been retired because of ongoing issues with leaks and poor reliability. This is discussed further below.

17.3.3 CONDITION, PERFORMANCE AND RISKS

We have recently retired three of the four 33kV oil-filled cable circuits located in the Palmerston North CBD that were in poor condition. Insufficient conductor clamping strength has led to their joints leaking oil because of thermal cycling. They required significant oil top-ups, and leakage into the environment exceeds acceptable levels. Repair of oil insulated cables requires specialist skills that are no longer available locally. This increases the restoration time in the event of failure to potentially weeks rather than days, when comparing with XLPE cables.

We have retained one circuit, Keith-Main 1, as an in-service backup, as this has shown stable performance with no leaks within the past six months. We will continue to monitor this.

The remainder of the oil cable fleet, from Hawera and Bunnythorpe GXPs, has had good performance. We will continue to monitor this and plan replacement should the condition or reliability decrease.

The majority of the XLPE and PILC fleets are still relatively young, however we do have some second generation early XLPE that we will monitor for performance.

Meeting our portfolio objectives

Safety and Environment: Subtransmission cable circuits with a history of oil leaks are being retired to minimise environmental impacts.

The table below summarises the actions being taken with the affected pressurised oil cable circuits.

Table 17.3: Palmerston North subtransmission cable circuits

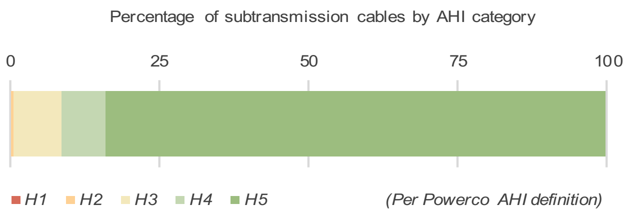
CABLE CIRCUIT	CIRCUIT LENGTH	ACTION
Keith St to Main St (two circuits)	2.7km (x2)	One additional XLPE circuit (3.0km) installed in FY17. Oil-filled cables paralleled to form second circuit. Oil-filled cables become redundant in FY20 because of Palmerston North reinforcement (new Ferguson St substation).
Kairanga to Pascal (underground from Pascal to Gillespie Line)	2.9km	Replaced FY17-18.
Pascal to Main St	1.8km	Cable already removed from service and has been replaced in FY18.

A number of years ago we experienced a high incidence of premature insulation failures on newly installed 33kV terminations because of the presence of voids between insulation layers. This was due to manufacturing or installation problems. We have been monitoring the remainder of the fleet, which has remained stable, so we expect it will continue to perform satisfactorily. We expect our monitoring programmes will detect this failure mode if it arises again.

Subtransmission cables asset health

As outlined in Chapter 7, we have developed Asset Health Indices (AHI) that reflect the remaining life of an asset. Our AHI models predict an asset's end of life and categorise its health based on a set of rules. For subtransmission cables, we define end-of-life as when the asset can no longer be relied upon to operate reliably and without environmental harm, and the cable should be replaced. The AHI considers cable circuit reliability, environmental impacts and asset age. The figure below shows current overall AHI for our subtransmission cable fleet.

Figure 17.2: Subtransmission cables asset health as at 2018



The health of the subtransmission cable fleet indicates that about 9% of the cables will require renewal in the next 10 years (H1-H3). The rest of the fleet is in good health and no further replacement is expected in the next 10 years.

17.3.4 DESIGN AND CONSTRUCT

Most new subtransmission cable circuits utilise XLPE insulated cable with stranded aluminium conductors in two standard sizes – single core $300mm^2$ and $630mm^2$. Because of capacity requirements, engineering signoff has been given to a small number of projects for larger $800mm^2$ and $1000mm^2$ installations. Standardisation assists ongoing fleet management by reducing spares, simplifying the maintenance and repair process and reducing costs. In recent years we have increased our standardisation for the selection of joints and fittings, as these are critical to the long-term reliability of cable circuits.

We are reviewing our management of cable ratings and intend to issue a new standard. This will assign consistent, systematic standard ratings for planning analysis. The standard will also set a framework for real-time rating schemes using distributed fibre temperature sensing.

Real-time asset ratings

Asset ratings are applied by taking into consideration conservative, near worst-case parameters for loading durations and environmental conditions. While this approach gives assurance that cable operating temperatures will not be exceeded, and that asset life will be achieved, it may underestimate the maximum allowable loading for short duration loads, or when environmental conditions are favourable.

We have been installing optical fibre with all of our new subtransmission cables and are testing distributed temperature sensing for the purposes of real-time rating applications.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We will investigate and trial real-time cable ratings for subtransmission cables to increase their effective capacity, using distributed temperature sensing.

17.3.5 OPERATE AND MAINTAIN

While cables are generally maintenance free, we do perform inspections and diagnostic testing. Oil-filled cables require additional maintenance because of their pressurisation systems. Maintenance and inspections for subtransmission cables are summarised below.

Table 17.4: Subtransmission cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Check and inspection of oil pressurisation systems.	Monthly
Cable route inspections. Inspection of cable terminations and surge arrestors. Thermography of exposed cable terminations on oil pressurised cable circuits.	Yearly
Sheath voltage limiter tests of XLPE and PILC cable.	2.5 yearly
Sheath integrity and earthing diagnostic tests.	5 yearly

17.3.6 RENEW OR DISPOSE

We have identified the need to replace the oil pressurised cable circuits in the Palmerston North CBD area because of excessive joint oil leaks and concerns about ongoing reliability. This is summarised above in Table 17.3.

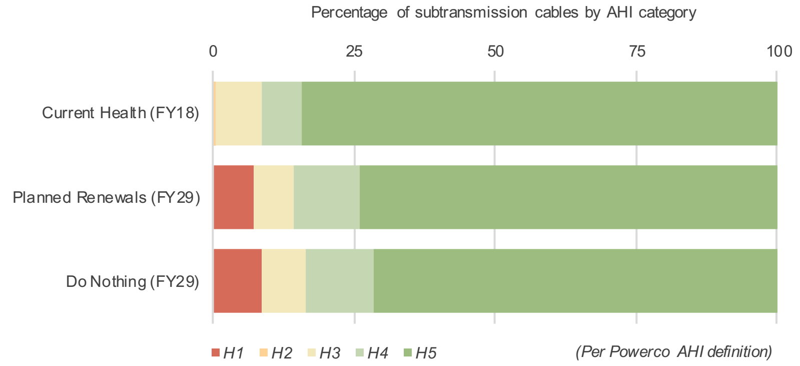
Cost estimates for these projects have been developed from desktop studies of proposed cable routes using typical component costs or 'building block' costs.

SUMMARY OF SUBTRANSMISSION CABLES RENEWALS APPROACH	
Renewal trigger	Environmental and reliability risk
Forecasting approach	Identified projects
Cost estimation	Desktop project estimates

Apart from the issues with our Palmerston North cables, the subtransmission cable fleet is in good condition with no major renewals expected in the medium term.

The figure below compares projected asset health in 2029 following planned renewals with a 'do nothing' scenario. We have completed replacement of the poor condition Palmerston North pressurised oil-filled cable circuits, which has significantly improved the fleet's overall health. During the period we expect to undertake increased monitoring and testing to inform future replacement requirements for our ageing XLPE cables.

Figure 17.3: Projected subtransmission cables asset health as at 2029



By 2029, the oldest of the XLPE circuits will be coming due for replacement, as indicated in the H2 and H3 portion in Planned Renewals (FY29).

Coordination with Network Development projects

New subtransmission cable circuits require significant planning and lead time because of the need for consenting and securing of easements, and the time needed for cable manufacture. Easements for underground circuits are more straightforward than overhead circuits – many councils are restricting overhead lines in urban areas with underground cables the preferred solution.

Subtransmission cable planning involves integrating growth and renewal needs. If a cable circuit requires renewal, we undertake an options analysis to ensure we deliver the best long-term solution. An example of the joint consideration of renewal and growth needs is the cable renewal programme in Palmerston North. An optimal solution has been planned that provides considerable benefits over a like-for-like replacement solution.

17.4 DISTRIBUTION CABLES

17.4.1 FLEET OVERVIEW

The distribution fleet operates at 22kV, 11kV and 6.6kV. The main assets within the fleet are cables, joints and pole terminations. We use two main types of cable insulation at the distribution level – PILC and XLPE.

PILC has been used internationally for more than 100 years and manufactured in New Zealand since the early 1950s. PILC uses paper insulating layers impregnated with non-draining insulating oil. The cable is encased by an extruded lead sheath wrapped in an outer sheath of either tar impregnated fibre material, PVC, or poly ethylene.

PILC cables have a good performance record. Being a legacy technology, a potential risk with PILC cables is the limited jointing experience within our field workforce. Jointing and terminating these cables correctly without defects requires a high level of skill and experience and most New Zealand cable jointers with this experience are nearing retirement. It is difficult for new cable jointers to gain and maintain this practical experience since there are few failures. For this reason, to avoid the need to install potentially unreliable XLPE-PILC transition joints, we may replace short runs of PILC when connected equipment needs to be replaced.

We have found that in some soil types, PILC sheaths can undergo accelerated corrosion, leading to lower fault capability and brittleness. Ageing may also cause the insulating paper to dry out, which makes the cables more difficult to work on and more prone to failure, particularly if the cable is moved or disturbed.

The first generation of XLPE cables was installed from the late 1960s to mid-1970s. These cables have a poor service record because of manufacturing quality problems, with failures caused by 'water treeing'[75] in the insulation, causing it to break down. We have found that some second generation XLPE cables have had premature corrosion of the wrapped screens, leading to failures and early replacement.

As XLPE technology has developed over time, the construction, operational integrity and safety features have improved to a point where the current generation of XLPE cables is favoured over other cable types. Only small quantities of the first generation XLPE remain in service on our networks.

[75] 'Water treeing' results from condensed steam, which was used to assist the poly ethylene insulation to cure as part of the manufacturing process.

17.4.2 POPULATION AND AGE STATISTICS

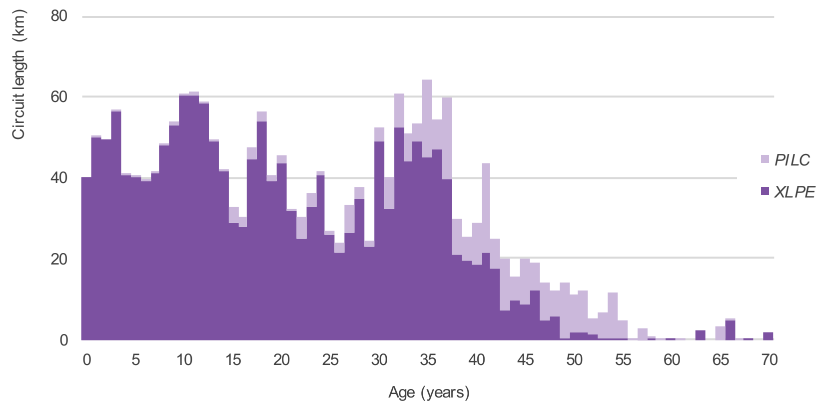
We have approximately 2,000km of distribution cable, of which about 14% is PILC and 86% is XLPE. The following table shows the breakdown of distribution cables by insulation type.

Table 17.5: Distribution cable population by type

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	1,754	86%
PILC	297	14%
Total	2,051	

The figure below depicts our distribution cable age profile. Most cable installed during the past 40 years has been XLPE, with PILC being the predominant type before that.

Figure 17.4: Distribution cable age profile



Significant amounts of distribution cable were installed during the 1980s, coinciding with the general move by district councils to undertake or promote overhead to underground conversion in urban areas.

Overall, the distribution cable fleet is relatively young, most circuits operating well within the cables' expected life[76]. Significant levels of age-related replacement are therefore not expected for at least another decade.

However, we have two known 'type' issues within the fleet that will drive our short-term renewal plans. These are discussed in the next section.

17.4.3 CONDITION, PERFORMANCE AND RISKS

Cable degradation is impacted by a combination of factors including:

- Insulation type
- Outer sheath design
- Loading history
- Cable quality – manufacturing batch issues, transportation storage
- Fault currents through the cable
- Installation type, eg in ducts or direct buried
- Armouring
- Soil type/environment
- Corrosion
- Age
- Third party damage

There are two main 'type' issues that affect the distribution cable fleet. Some of the early 11kV PILC cables installed in the New Plymouth region have brittle lead sheaths that are prone to cracking, allowing water to enter. Any movement of the cables can cause cracking and potential failure. Additionally, where cables are grouped in a common trench, jointing for repairs is difficult, potentially extending restoration times.

The other 'type' issue involves the first generation XLPE cables installed during the late 1960s and early 1970s. These were manufactured using steam-curing, making them more prone to water treeing (caused by partial discharge in the XLPE insulation brought on by the presence of water). Incompatible semi-conductive materials and lack of triple extrusion also contributed to this 'type' problem. There is also some evidence of poor handling of cables during installation. These problems have resulted in sufficient failures to warrant progressive replacement.

[76] Expected lives for distribution cables are 55 and 70 years for XLPE and PILC respectively.

Meeting our portfolio objectives

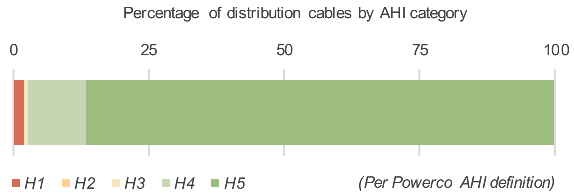
Asset Stewardship: Distribution cables with known high rates of failure are replaced to maintain overall fleet reliability and manage network SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index).

Distribution cables asset health

As outlined in Chapter 7, we have developed a set of AHIs that reflect the remaining life of an asset. Our AHI models predict an asset's end of life and categorise its health based on a set of rules. For distribution cables, we define end-of-life when the asset can no longer be relied upon to operate reliably and the cable should be replaced.

The figure below shows current overall AHI for our population of distribution cables. The AHI calculation is based on our knowledge of specific cable type issues and asset age.

Figure 17.5: Distribution cables asset health as at 2018



The health of the distribution cable fleet is generally very good, with more than 80% of the fleet not likely to require replacement in the next 20 years (H5). Our programmes to replace first generation XLPE are mostly complete, which has led to an improvement in the overall health of the fleet. Approximately 2% of the fleet will require renewal in the short term (H1-H2) because of known problem issues.

17.4.4 DESIGN AND CONSTRUCT

We use three standard sizes of distribution cable – $35mm^2$, $185mm^2$ and $300mm^2$. These cables are multicore aluminium with XLPE insulation. Single core cables and other conductor sizes may be used for specific applications, such as when additional current rating is required or where there are issues with installation bending radii. This standardisation assists in our ongoing management of the asset fleet, improving the ability to carry out repairs and replacements.

17.4.5 OPERATE AND MAINTAIN

Cables are generally maintenance free as most of the length of cable is buried. We perform inspections, and diagnostic acoustic and partial discharge (PD) testing on above ground components, such as breakouts, terminations and risers. We routinely inspect above ground exposed sections of cable and associated terminations to identify defects, degradation or damage.

Our distribution cable maintenance tasks are summarised in the table below. The detailed regime for each type of cable is set out in our maintenance standard.

Table 17.6: Distribution cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Cable riser terminations visually inspected. Thermography and acoustic diagnostic tests of cable riser and breakouts, cast metal potheads.	2.5 yearly

Cable faults most commonly occur because of third party interference, such as digging. When cables or their protection have degraded or been damaged we undertake repairs to avoid a fault occurring. Corrective actions for cables include:

- Replacement of damaged cable riser mechanical protection on poles
- Replacement of cable terminations because of degradation
- Fault repairs because of third party damage or other cable faults

Spare cable and associated cable jointing equipment is held in strategic locations to enable fault repairs to be undertaken.

As part of the Transpower rebuild of Kinleith GXP, we are undertaking additional testing and sampling to ascertain the health of the tunnel cable fleets there, given their high criticality in supplying Oji Fibre Solutions, the pulp and paper mill.

17.4.6 RENEW OR DISPOSE

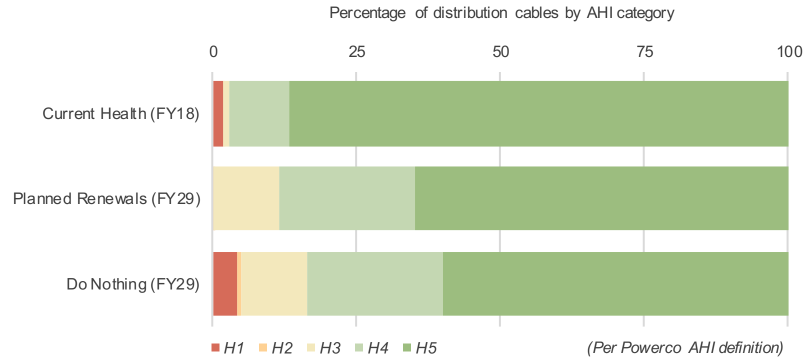
Our renewal approach for distribution cable is for replacement to be based on condition, including 'type' issues and health. As previously mentioned, we have identified two 'type' issues within the fleet – PILC cables with brittle lead sheaths and first generation XLPE cable that is prone to water treeing. We are developing modelling to identify circuits with elevated risk so that we can perform condition testing and, where warranted, proactively replace cables. We are also beginning a programme of post-fault cable sampling that will be used to assist us in better understanding the health of our distribution cable fleet.

SUMMARY OF DISTRIBUTION CABLE RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	'Type' issues and age
Cost estimation	Volumetric, adjusted for terrain

Based on what we know at the moment, distribution cable renewals are expected to remain approximately constant during the next decade as the fleet is in good condition overall. In the longer term, we expect an increase in distribution cable replacement expenditure as significant quantities of XLPE and PILC are expected to reach their renewal age of 55 and 70 years respectively.

The figure below compares projected asset health in 2029, following planned renewals, with a 'do nothing' scenario. Our investment to address 'type' issues and undertake condition-based replacement will keep the health of the fleet stable during the planning period.

Figure 17.6: Projected distribution cables asset health in 2029



Coordination with Network Development projects

We work with the councils and other utilities, particularly those with underground services located within the road reserve, to coordinate trenching works wherever feasible. At times, we bring forward cable replacements to coincide with other excavating or road works. This allows us to replace the cable at a lower cost, limit road traffic disruption and damage to pavement surfaces.

Road safety or widening projects initiated by the New Zealand Transport Agency often drive the need to relocate cables or to put underground an existing overhead line. This work is classified as asset relocation and is discussed further in Chapter 21.

Meeting our portfolio objectives

Customers and Community: Cable development and replacement is coordinated with other excavation works where practicable to minimise road traffic disruption and minimise cost.

17.5 LOW VOLTAGE CABLE SYSTEMS

17.5.1 FLEET OVERVIEW

The LV cable fleet operates at below 1kV (230/400V). The fleet consists of cables, link boxes, LV cabinets, service boxes and pillar boxes. We collectively refer to link boxes, pillar boxes and service boxes as LV boxes.

Customer service lines connect to our LV cable network by a cable from a service box usually located on the property boundary. The integrity of LV boxes is a key public safety concern. We have a variety of styles and materials installed on our network.

Figure 17.7: LV boxes

17.5.2 POPULATION AND AGE STATISTICS

Our LV underground network consists of 6,038 circuit kilometres of cable. This includes 1,856 km of dedicated street lighting circuits and 407 km of hot water pilot circuits.

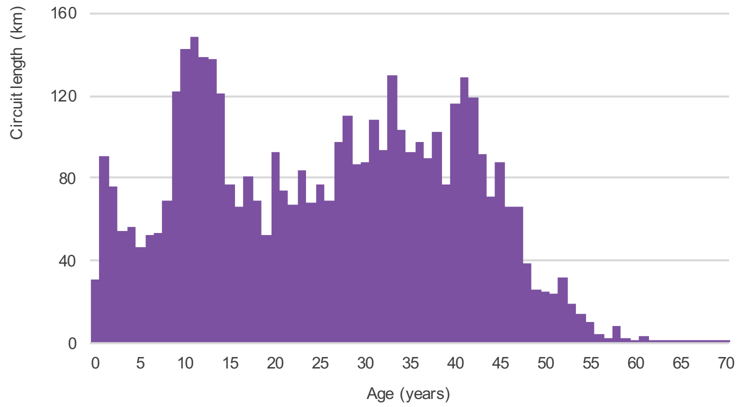
Data on our LV cable fleet is incomplete because before the year 2000 detailed information was normally not recorded. We intend to significantly improve our knowledge of the LV network during the planning period and are undertaking a detailed programme of LV pillar and service box data capture and labelling.

Meeting our portfolio objectives

Operational Excellence: We are improving our knowledge of the LV underground network through asset inspections to improve our fleet management decision-making.

While our information on LV cable types is limited, we have reasonable age information. The figure below shows the age profile of the LV cable fleet, excluding street lighting and hot water circuits. [77]

Figure 17.8: LV cable age profile



The average age of the LV cable fleet is 26 years. As the fleet is relatively young we do not expect a need for significant cable renewal.

17.5.3 CONDITION, PERFORMANCE AND RISKS

LV boxes are predominantly installed in urban areas to supply nearby loads.

As they are above ground and accessible, they can present a public safety risk if not properly maintained. The key public risk is loss of security because of damage, degradation or vandalism, exposing live terminals.

There have been fires in LV boxes because of overheating of contacts and fuses. Older style pull-cap fuses have proven prone to overheating as corrosion occurs between the tinned copper cap and aluminium conductor. In the Tauranga region,

[77] About 10% of the fleet's age is unknown and has been excluded from the chart.

where this problem is most prevalent because of installation practices and the environment, this has led to fires. We now identify these types of installations and have a programme to remedy these sites through our defects process.

A safety issue relating to LV boxes is that those of metallic construction can be inadvertently livened. Affected LV boxes have been identified and replacement is planned through our defects process. Early metallic ‘mushroom’ type LV boxes have caused concerns regarding livening of the metallic cover when the insulation on LV cables internally has degraded. A programme of replacement has removed the majority of this pillar type, and we continue to replace these as they are located.

Through our inspections and surveys we have also identified overcrowded LV boxes, typically at infill developments. These overcrowded LV boxes present a safety hazard to operators during servicing and can lead to overheating. We schedule the replacement of identified LV boxes through the defects process.

Many reported defects and faults are because of physical damage, often caused by vehicles. When LV pillars are installed for new developments, they can be found to be in a poor location after construction has taken place. Although an LV box may initially have been placed in a safe location, new driveways or changes in walls/fencing can leave the boxes more vulnerable to damage. In these cases, solutions such as relocation, replacement with an underground style LV box, or installation of protective bollards can help prevent future failures.

Through our inspections we are continuing to collect LV box defects. These LV boxes will be replaced as part of our ongoing LV safety-related investment programme.

17.5.4 DESIGN AND CONSTRUCT

We use three standard sizes of LV cable – 120mm^2, 185mm^2 and 300mm^2 stranded aluminium cable with XLPE/PVC insulation. Different sizes are used depending on the application and expected load. Voltage drop, fault current capacity and mechanical performance are considered when designing LV cable networks.

LV box types are carefully considered before being approved for use on the network. We use only products that have been through our approval process. We source LV boxes from two manufacturers.

17.5.5 OPERATE AND MAINTAIN

Maintenance of the LV cable fleet focuses on the inspection of LV boxes. The frequency of inspection is based on the safety criticality of the asset, with boxes in areas of higher risk inspected more often.

The table below summarises our inspections of the LV cable fleet. The detailed maintenance regime is set out in our maintenance standard.

Table 17.7: LV cable network preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Thermal imaging of CBD distribution boxes	Yearly
Detailed inspection of LV boxes located near parks, public amenities, schools and business districts	2.5 yearly
Detailed inspection of LV boxes not located near parks, public amenities, schools and business districts	5 yearly

As part of our plan to improve our knowledge of the LV cable network, we are carrying out a programme of LV box data capture and labelling. This programme will ensure that each LV box is identified with a unique operating number, network connectivity is recorded and appropriate safety labelling is affixed. During this programme we will also conduct a detailed condition inspection.

Meeting our portfolio objectives

Safety and Environment: LV boxes are being tracked and labelled to improve our management of assets that are in a public space to minimise safety risks.

17.5.6 RENEW OR DISPOSE

Renewal of buried LV cable is generally managed using a run-to-failure strategy as the consequence of failure is low because of the low number of affected customers. Also the failure of buried cable poses very little safety risk.

As we improve our LV underground network condition information – primarily from improvements in capturing failure data from our Outage Management System (OMS) – we will be able to more proactively target cable known to be prone to failure. We forecast our LV cable expenditure based on historical trend analysis.

LV boxes present a safety risk to the public and their condition is more easily understood through visual inspection. We are continuing our programme of LV box replacement with known ‘type’ issues. There will also be an ongoing need to reactively replace LV boxes damaged by third parties. Forecasts are based on quantities of known defects and historical rates of replacement.

SUMMARY OF LV CABLE RENEWALS APPROACH	
Renewal trigger	Run-to-failure (cable) and condition/type (LV boxes)
Forecasting approach	Historical trend (cable) and defect rates (LV boxes)
Cost estimation	Volumetric average historical rate

LV cable fleet renewal investment is expected to remain relatively constant during the next 10 years. After this, cable renewals may need to increase as larger quantities of cable reach nominal end-of-life. Condition and failure data analysis will help us better understand LV cable life expectancy and plan renewals.

Coordination with Network Development projects

The LV underground network is typically expanded through the addition of new subdivisions. As a greenfield installation, subdivision development costs are much lower than cable renewal. Traffic management costs are avoided and trenching costs are often shared with other utilities.

In Tauranga city, changes to council development plans have resulted in growth being catered for through greater residential intensification, or infill development. This creates overloading of LV reticulation in the older areas of Tauranga and tends to be addressed reactively. Many of the smaller cables may need to be proactively replaced because of load growth rather than poor condition.

As the level of photovoltaic (PV) and electric vehicle (EV) penetration increases, we may also see overloading issues on the LV underground network, particularly where smaller legacy cables have been installed. We will monitor this along with PV and EV development and plan for upgrades accordingly.

17.6 CABLES RENEWALS FORECAST

Renewal Capex in our cable portfolio includes planned investments in our subtransmission, distribution and LV cable fleets. During the planning period we will invest approximately $57m on cable renewal.

Managing safety risk is a key driver of expenditure for LV cable assets. Drivers for replacement of oil-filled subtransmission cables are a combination of environmental, reliability, cost and poor condition. In the case of distribution cable, increasing failure rates because of deterioration of asset health from ‘type’ specific issues are the key drivers for renewal.

Our subtransmission cable renewals are generally derived from bottom-up models and expenditure is derived from cost estimates of planned projects. Distribution and LV cable forecasts are determined from volumetric estimates, which are explained in Chapter 26.

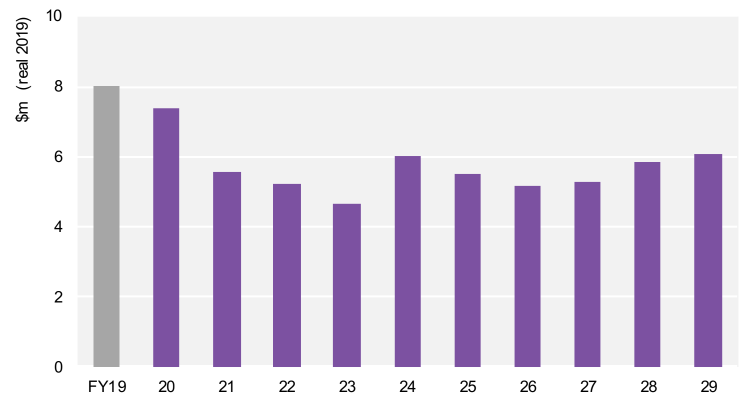
Our forecasts are integrated with renewal needs from other fleets where appropriate, to ensure efficient delivery. For example, the majority of subtransmission cable replacements in the Palmerston North CBD are delivered as part of a programme involving other new subtransmission circuits and zone substation developments.[78]

[78] As the primary driver for the Palmerston North subtransmission cable replacement is condition, this expenditure is classed as renewals.

Distribution cable replacement is often coordinated with ground-mounted switchgear and transformer renewal.

Figure 17.9 shows our forecast Capex on cables during the planning period.

Figure 17.9: Cables renewal forecast expenditure



The forecast renewal expenditure for the cable portfolio is in line with historical levels. Additional expenditure in FY20 is because of the subtransmission cable works in the Palmerston North CBD.

18 ZONE SUBSTATIONS

18.1 CHAPTER OVERVIEW

This chapter describes the fleet management plans for our zone substations portfolio. This portfolio includes the following six fleets:

- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control plant
- Other zone substation assets

The chapter provides an overview of asset population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to invest $111m in zone substation renewals. This accounts for 13% of our renewals Capex during the period.

Increased investment is needed to support our safety and asset stewardship objectives. The increase in renewals Capex is driven by the need to:

– Renew assets in poor condition. Most of the increase is driven by renewal programmes for power transformers, indoor switchboards and outdoor switchgear, which are reaching the end of their service lives.

– Stabilise asset health. Our condition-based risk management (CBRM) models indicate the need for a step change in renewals to bring the fleet risk to a stable position.

– Manage safety risk, particularly for field staff. Some of our 11kV switchboards have a higher than acceptable arc flash risk. Plans to reduce this risk include the installation of arc flash protection and arc blast-proof doors, as well as replacing ageing oil breakers. In some cases, we will prioritise the replacement of the complete switchboard.

Below we set out the Asset Management Objectives that guide our approach to managing our six zone substation fleets.

18.2 ZONE SUBSTATIONS OBJECTIVES

Zone substations take supply from the national grid through subtransmission feeders. They provide connection points between subtransmission circuits, step-down the voltage through power transformers to distribution levels, and utilise switching and isolating equipment to enable the network to be operated safely.

Zone substations play a critical role in our network. Prudent management of these assets is essential to ensure safe and reliable operation. Zone substations provide the bulk supply of electricity for distribution to end users. Supply for many thousands of customers often depends on a few key assets within zone substations.

To guide our asset management activities, we have defined a set of portfolio objectives for our zone substation assets. These are listed in Table 18.1. The objectives are linked to our Asset Management Objectives set out in Chapter 5.

Table 18.1: Zone substations portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No lost time injuries resulting from arc flash incidents. No uncontained oil spills or SF_6 (sulphur hexafluoride) leaks from zone substation assets. No unacceptable noise pollution.
Customers and Community	Ensure design and aesthetics of zone substations integrate with the neighbouring community.
Networks for Today and Tomorrow	Improve compliance with our network security standards.
Asset Stewardship	Procure a mobile substation to help minimise outages during maintenance or planned installation work and provide cover during emergencies.
Operational Excellence	Further develop our use of asset health and criticality to support renewal decision-making, including the use of CBRM.

18.3 POWER TRANSFORMERS

18.3.1 FLEET OVERVIEW

Zone substation transformers are used to transform power supply from one voltage level to another, generally 33/11kV, but some are 110/33kV, 33/6.6kV, 66/11kV or 11/22kV. Capacities range from 1.25 to 60MVA.

The major elements that comprise a zone substation power transformer are the core and windings, housing (or tank), bushings, cable boxes, insulating oil conservator and management systems, breather, cooling systems and tap changing mechanisms. These are mounted on pads that also include firewalls, bunding and oil separation systems.

Figure 18.1: Power transformer installation at Waharoa

18.3.2 POPULATION AND AGE STATISTICS

There are 191 power transformers in service on our network, of which 173 are 33/11kV units. Table 18.2 summarises our population of power transformers by rating.

Table 18.2: Power transformer population by rating

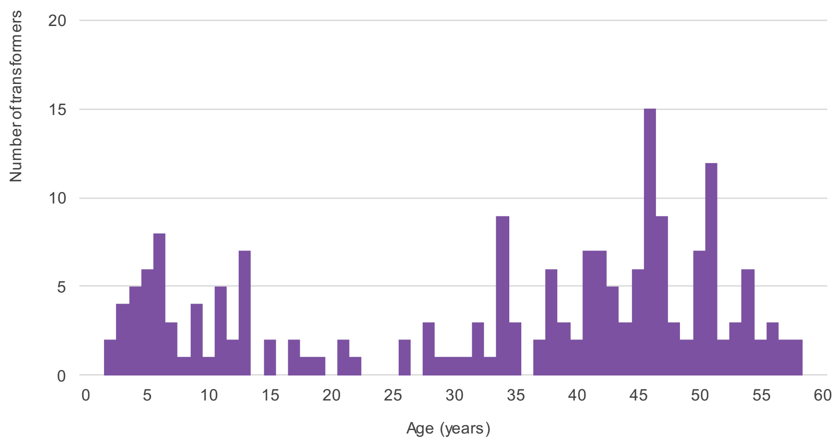
MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
<5	23	11
≥5 to <10	78	41
≥10 to <15	26	14
≥15 to <20	38	20
≥20	26	14
Total	191	

Although we purchase standard sizes and configurations, we have some legacy orphan assets. This limits interchangeability and therefore operational flexibility.

The orphan category includes units with unique vector groups, tap changers with different tap steps. Orphan units will be prioritised for replacement during the planning period based on condition.

Figure 18.2 shows our power transformer age profile. The average age of all our zone substation transformers is 34 years.

Figure 18.2: Power transformer age profile



Some of our power transformers are approaching their expected 60-year life span and will soon likely need to be replaced.

18.3.3 CONDITION, PERFORMANCE AND RISKS

Power transformer failures are relatively rare. The main causes are manufacturing defects, occasional on-load tap changer failures because of mechanical wear, leaking of some of the older radiator types, and tank rust. There have also been several cable termination failures within transformer cable boxes arising from joint type issues and, at times, installation issues. Failure of a power transformer can result in loss of supply or reduced security of supply, depending on the network security level of the zone substation.

A small number of our existing power transformers have inadequate or no oil containment facilities. A transformer that leaks oil may create an environmental hazard through soil contamination.

We are addressing this risk by installing or upgrading oil containment to include both containment (bunding) and separator systems. We intend to continue to retrofit oil containment to all of our power transformer sites that do not already have them, and which are not scheduled for renewal. Implementing these measures may also reduce the risk of fire spreading in the event of a transformer failure.

Meeting our portfolio objectives

Safety and Environment: Power transformer bunding and oil containment systems are being upgraded to reduce the risk of oil spills.

Power transformers asset health

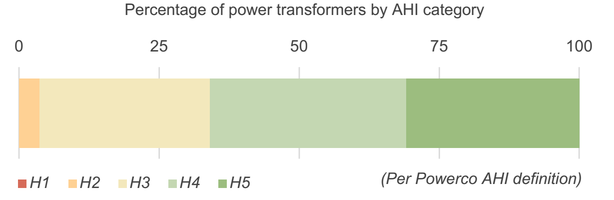
In our CBRM models for our power transformers, we have used a combination of the Asset Health Indices (AHI) and risk profile to determine the optimum replacement schedule.

The risk ranking takes into consideration the combination of the estimated likelihood and consequences of failure. We first prioritise renewal on the CBRM risk ranking followed by the AHI.

Our transformer health is stable, although we are beginning to see loss of reliability of some of our older refurbished units, particularly in relation to tap changers. We are reviewing our approach to the location for these refurbished units as we continue our programme of replacement.

Figure 18.3 shows the overall AHI for our population of power transformers.

Figure 18.3: Power transformer asset health as at 2019



18.3.4 DESIGN AND CONSTRUCT

We have a range of controls during the procurement phase for power transformers that ensures we get quality assets from our suppliers. We work closely with a small panel of transformer manufacturers and conduct design reviews for all new transformers.

To ensure good operational flexibility across the network we order transformers in standard sizes. Standard sizes[79] for 33/11kV transformers are:

- 5MVA
- 7.5/10MVA
- 12.5/17MVA
- 16/24MVA

Sometimes a replacement power transformer is larger than the existing unit or it is anticipated to generate more noise from either the core or cooling fans. In those instances, we undertake acoustic studies before installing the new transformer. Understanding the impact of noise on the immediate community allows us to implement necessary measures to minimise noise pollution.

Meeting our portfolio objectives

Safety and Environment: Noise levels are reviewed when new transformers are installed to minimise noise pollution.

[79] Some units have two cooling ratings. They represent natural and forced, ie with pumps and fans, cooling.

18.3.5 OPERATE AND MAINTAIN

Power transformers and their ancillaries, such as tap changers, undergo routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in Table 18.3.

Table 18.3: Power transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of insulating systems, cooling, bushing and insulators, tap changer compartment, foundations and other ancillaries.	3 monthly
Service dehydrating breathers. External paintwork touch-ups. Automatic voltage regulator operation checks. Buchholz gas check. Acoustic emission, thermal imaging and external partial discharge diagnostic tests.	Yearly
Dissolved gas analysis (DGA) test, insulation and winding resistance tests. Tap changer service.	3 yearly

When power transformers reach mid-life (25-35 years) we have historically undertaken major workshop-based overhauls – generally including major tap changer maintenance, repaint and, if required, re-clamping and drying of the windings. The relatively low cyclic loading of most of our transformer fleet means that thermal ageing of the insulating paper is not usually the limiting factor as to their service life. During overhauls, a new or recently overhauled transformer is installed in its place. This means transformers can be rotated through the network and older transformers moved to less critical sites where the consequence of failure is lower.

Transformer rotations have allowed us to optimise the number of new transformers required on the network for growth reasons and extend the life of the transformer assets. However, many of the overhauled units are now nearing the need for outright replacement, as there have been increased rates of failure, particularly in regards to the tap changer function. The cost of maintenance overhauls has started to increase, and the reliability of these units has come into question, lessening the potential benefits of this programme.

We are reconsidering rotations and the criteria used to assess when it is cost effective to overhaul an aged power transformer. The decision to proceed with an overhaul will continue to be on a case-by-case basis.

Mobile substation

In line with our security of supply standards, many of our rural zone substations have a single power transformer supply. In recent years it has become increasingly difficult to arrange shutdowns because of diminishing distribution backfeed capability. Any maintenance or planned work requires significant network reconfiguration, extensive generation or, worst case, an outage for the communities supplied by these substations.

A mobile substation can reduce and, in some cases, eliminate the need for outages, and can be used as a temporary switchboard in the event of major asset failure or during planned replacement of 11kV switchboards.

We are completing procurement of a mobile substation, planned for completion early FY20. We have also started a programme to install permanent connection points and lay down areas at these key sites to allow straightforward connection of the mobile substation.

Meeting our portfolio objectives

Asset Stewardship: We are procuring a mobile substation to help minimise outages during maintenance or planned installation work, and provide cover during emergencies.

18.3.6 RENEW OR DISPOSE

The overall condition and risk of network impact, via CBRM modelling, is used to schedule power transformers for renewal. Failure of power transformers is to be avoided because of the potential network impacts, depending on the security of the associated zone substation, and the safety risk of fire and explosion.

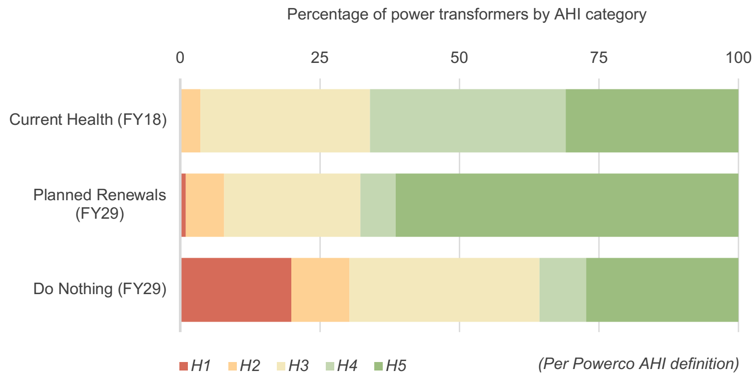
SUMMARY OF POWER TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Asset health
Cost estimation	Desktop project estimates

Renewals forecasting
We have developed a CBRM model to assist us with effectively forecasting power transformer fleet renewal requirements and identifying the required timing for individual transformer replacements.

The power transformer CBRM model is an improvement over our previous models as it develops an estimate of transformer probability of failure using all available asset characteristics and condition information.

The model also estimates the consequences of asset failure in terms of customer impact, safety, costs and environmental harm, allowing decisions to be prioritised based on risk.

Figure 18.4: Projected power transformer asset health as at 2029



Meeting our portfolio objectives

Operational Excellence: Power transformer renewal is informed by condition-based asset health and criticality, which we will continue to refine across our asset fleets.

The forecast for the planning period is based on the CBRM power transformer fleet risk ranking, with final replacement timing and final size determined by coordination with network development in regards to other zone substation primary replacements or upgrades.

As part of our power transformer renewal programme we will upgrade bunding, oil containment and separation systems, install transformer firewalls where there is risk of fire spread, and review and upgrade transformer foundations to ensure appropriate seismic performance.

During the planning period we expect to replace three to four power transformers per year. This will ensure our higher risk transformers are replaced while managing the remaining fleet's health through its lifecycle.

The remaining H1 transformers are at our Tasman and Ngariki substations, which are scheduled for replacement outside of the immediate AMP forecast period. As we are re-evaluating the reliability of our refurbished transformers, these are assessed as H2 and H3.

While the overall health profile shows a decrease, we estimate the planned work programme will lead to an overall reduction in network risk by about 20%.

This is due to refocusing investment on renewing transformers with the greatest consequences of failure, while allowing less critical units to remain in service longer.

Longer term, we expect the number of power transformer replacements to remain at a similar level. A significant number of transformers installed in the 1960s and 1970s will become due for condition and age-based renewal.

Coordination with network development projects
Power transformer refurbishments and replacements are coordinated with network development-related projects to develop an optimised programme.

A part of this coordination is the management of rotation of transformers because of load growth and condition. As an example, a load growth-related transformer replacement project might be coordinated by refurbishing the removed transformer and using it to replace a poor condition transformer at an alternative site. This policy of rotating transformers allows us to manage the loading and condition-related issues without investment in over-capacity.

Power transformer replacements are among the larger projects undertaken within a zone substation and often require civil works to upgrade oil bunding. For delivery and cost efficiency we coordinate other zone substation works, such as outdoor switchgear replacements with transformer projects wherever practicable.

18.4 INDOOR SWITCHGEAR

18.4.1 FLEET OVERVIEW

Indoor switchgear comprises individual switchgear panels assembled into a switchboard. These contain circuit breakers, isolation switches, and busbars, along with associated insulation and metering. They also contain protection and control devices, along with their associated current and voltage transformers.

Indoor switchgear has been used extensively for applications at 11kV. More recently it is also preferred for 33kV applications. Indoor switchgear is generally more reliable than outdoor switchgear. It is more protected from corrosion as it is not exposed to pollution, weather and foreign interference, such as bird strikes. Indoor switchgear also has a much smaller footprint, making it useful in urban environments where it can be housed within an appropriate building.

Figure 18.5: 11kV indoor switchboard at Main St, Palmerston North

18.4.2 POPULATION AND AGE STATISTICS

There are 950 circuit breaker panels within 121 indoor switchboards in service on our network. Most switchboards operate at 11kV, but the number of 33kV boards is increasing. Table 18.4 summarises our indoor switchgear population by type and number of circuit breakers and switchboards.

Table 18.4: Indoor switchgear circuit breaker and switchboard populations by type

INTERRUPTER TYPE	CIRCUIT BREAKERS	SWITCHBOARDS[80]
Oil	322	43
SF_6	214	31
Vacuum	414	47
Total	950	121

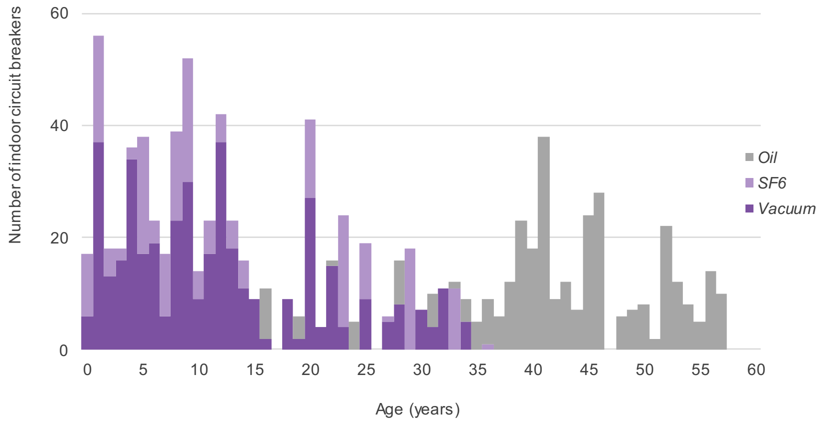
Indoor switchgear technology has evolved over time. Before the 1990s, most switchgear installed used oil as the circuit breaker insulation and arc quenching medium. The older segment of our population is primarily made up of oil-filled switchgear.

Modern switchgear uses vacuum or SF_6-based circuit breakers. We prefer vacuum because of its better lifecycle maintenance and switching characteristics. During the past 20 years most of the switchgear we installed has been vacuum or SF_6-based.

The level of arc flash protection has improved with modern switchboards. They offer arc flash venting, blast-proof switchgear doors, and are installed with dedicated arc flash protection to more quickly isolate a fault. Arc flash containment is now mandatory for new switchgear installed on our network.

Figure 18.6 outlines the age profile of the indoor switchgear fleet.

Figure 18.6: Indoor switchgear (circuit breakers) age profile



We generally expect a useful life of approximately 45-50 years from our indoor switchgear assets. A number of assets already exceed this guide and will likely need replacement during the next 5-10 years.

18.4.3 CONDITION, PERFORMANCE AND RISKS

Indoor switchgear asset health

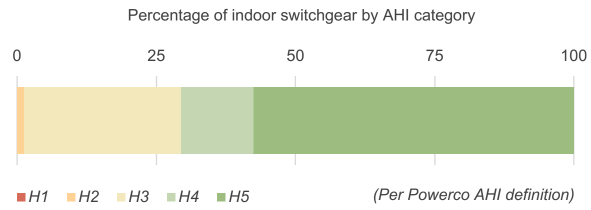
As outlined in Chapter 7, we have developed CBRM models that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules.

For indoor switchgear we define end-of-life as when the asset can no longer operate reliably and safely and the switchgear should be replaced.

80 A number of our indoor switchboards have a mixture of circuit breaker types as retrofit opportunities have arisen in the past. For the purposes of switchboard classification, we have used the majority circuit breaker panel type.

The AHI is calculated using our Condition-Based Risk Management Model (CBRM is explained further Section 7.4.5.2). Figure 18.7 shows the AHI profile of the indoor switchgear fleet.

Figure 18.7: Indoor switchgear asset health as at 2019



About 29% of our indoor switchgear requires replacement during the next 10 years (H1-H3)[81].

Arc flash risk

Arc flash risk is a considerable safety concern for our indoor switchgear fleet. An arc flash is a type of electrical explosion that occurs when there is a phase-to-phase or phase-to-earth fault through the air, such as a flashover or accidental contact.

For well-maintained equipment, it is most likely to occur during work near live parts, such as racking operations, or during operation of switchgear. An arc flash can release a large amount of energy, which can prove fatal or cause serious, permanent injury. It can also cause material damage to the equipment.

We have undertaken arc flash assessments for our 11kV switchboards to determine their risk levels. We have defined a prudent level of arc flash energy[82] to be no more than 8 cal/cm^2. We use this with characteristics specific to each switchgear type to categorise the arc flash risk. There are additional safety risks of secondary oil fire/explosion around switch failures in which the oil is involved.

Table 18.5 summarises the arc flash risk of our 11kV indoor switchgear population, combining arc flash levels and asset health. It highlights that our 11kV switchgear has an increased arc flash risk when considering both the switchboard health and arc flash level, as shown in the yellow, orange and red areas in the table.

81 The CBRM model assumes the fleet is in 'operational condition' and therefore calculates very little assets in H1 health. As the model runs forward in time, asset health degrades and the number of H1 assets increases.

82 Arc flash energy is described in calories per centimetre squared (cal/cm^2). Our limit is based on the Electricity Engineers' Association's (EEA) 'Guide for the Management of Arc Flash Hazards'.

Table 18.5: 11 kV indoor switchgear arc flash risk as at 2019 (% of total asset fleet)

	ASSET HEALTH INDEX				
ARC FLASH CATEGORY	H5	H4	H3	H2	H1
≥ 8 cal/cm^2 (oil switchgear)	1%	0%	5%	0%	0%
≥ 8 cal/cm^2 (not oil switchgear)	15%	%	2%	0%	0%
< 8 cal/cm^2	42%	9%	21%	1%	0%

We mitigate this risk through one of three approaches:

- Isolating and earthing adjacent circuits to the work position when performing maintenance or when work is taking place behind the switchboard.
- Reconfiguring the upstream network to reduce arc flash levels.
- Ensuring personnel working close to the switchboard wear appropriate arc flash rated personal protective equipment (PPE) gear.

All newly installed switchboards have arc flash detection systems, arc containment and arc venting. We will also improve many of our existing switchboards by retrofitting various arc flash mitigations, such as blast doors, arc flash detection systems and arc venting.

We have determined it is not possible to sufficiently mitigate arc flash risk associated with failure of oil equipment, so we are progressively replacing these switchboards in the short to medium term.

Meeting our portfolio objectives

Safety and Environment: Indoor switchboards with arc flash risk have mitigations in place and will progressively be replaced to reduce safety risks to our staff and service providers.

18.4.4 DESIGN AND CONSTRUCT

Our equipment class standards classify indoor switchgear as class A equipment because its function is critical to the reliable operation of the network. Before a new type of switchgear can be used on the network, it must undergo a detailed evaluation to ensure it is fit for purpose.

We predominantly specify withdrawable circuit breakers for indoor switchgear. We have installed a small number of switchboards that are non-withdrawable and these are giving good performance. On that basis, we are evaluating whether we should make further use of these types.

Withdrawable circuit breakers generally are mounted in removable trucks, making them easy to maintain and replace. In the past, this has been important for oil circuit breakers, which require frequent servicing. However, they carry additional safety risk because incorrect racking can cause accidents, as well as potential issues introduced during maintenance.

Non-withdrawable breakers do not provide a visible break. Therefore, a key requirement for such equipment is that any indications are directly driven by the internal mechanism so that these can be relied to accurately reflect operating state.

The reliability of modern units has improved and vacuum and SF_6 circuit breakers do not need to be serviced, therefore greatly improving both the lifecycle cost and reliability. However, the integral nature of these means individual panels cannot easily be replaced.

In addition, non-withdrawable units take up less space and can reduce the cost of new substations.

18.4.5 OPERATE AND MAINTAIN

Indoor switchgear undergoes routine inspections and maintenance to ensure its continued safe and reliable operation. These preventive tasks are summarised in Table 18.6.

Partial discharge detection (PD) is a reliable condition monitoring technique for determining many insulation-related failures that can lead to disruptive failure.

We recently purchased four relocatable continuous online PD monitoring systems as well as increasing the frequency of PD scans to a yearly task. Continuous monitoring is utilised on a needs basis rather than being scheduled cyclically.

If this regime proves to be effective for monitoring insulation breakdown, our standards will be adjusted accordingly.

Table 18.6: Indoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, cabinets and panels.	3 monthly
Operational tests on circuit breakers not operated in the past 12 months. Condition-test switchgear including thermal, PD and acoustic emission scan.	Yearly
Insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. SF_6 gas pressure checks.	3 yearly
Vacuum circuit breaker diagnostic tests eg HV withstand. Switchboard partial discharge test.	6 yearly

18.4.6 RENEW OR DISPOSE

Indoor switchgear renewal decisions are based on a combination of factors, including:

- Switchgear condition – condition of the circuit breakers, busbars and other associated ancillaries
- Known reliability type issues, such as cast-iron pitch-filled boxes
- Equipment obsolescence, eg orphaned boards
- Fault level interrupting capacity
- Arc flash risk, accessibility

We consider these factors holistically, along with the criticality of the zone substation, when we determine the optimum time for replacement.

SUMMARY OF INDOOR SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	Proactive condition-based with safety risk
Forecasting approach	Age and arc flash levels
Cost estimation	Desktop project estimates

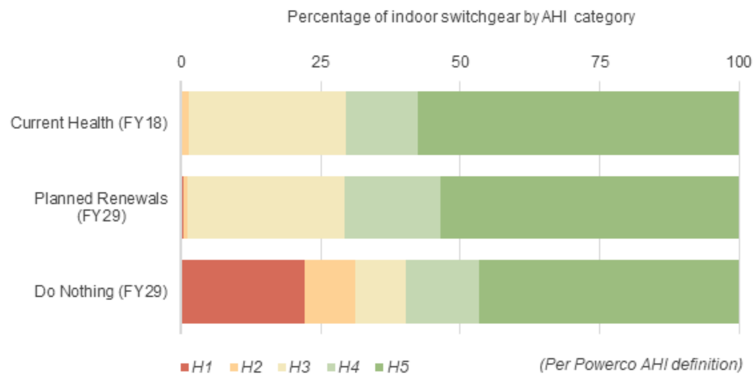
Renewals forecasting

Our indoor switchgear renewals forecast uses switchboard condition, reliability and arc flash risk information as inputs for the CBRM model of the fleet. Longer term, we also use age as a proxy for condition, to help us estimate likely future asset deterioration.

We need to invest significantly in indoor switchgear renewals to mitigate arc flash risks and address the asset health of some switchboards. We expect to replace approximately four switchboards per year for the next 10 years.

Figure 18.8 compares projected asset health in 2029, following planned renewals, with a counter-factual do-nothing scenario. Comparing the do-nothing with the planned renewal scenario provides an indication of the benefit provided by our renewal investments.

Figure 18.8: Projected indoor switchgear asset health in 2029



Overall indoor switchgear asset health will remain stable as we undertake planned replacement and retrofit programmes of switchboards in poor condition and those with high arc flash risk. By prioritising high-risk equipment we expect to achieve a reduction in risk of about 17% by the end of the period FY29.

As mitigating arc flash risk is an important renewal driver for this fleet we also make forward projections of our arc flash risk. Table 18.7 shows our projected arc flash risk in 2029, assuming our planned renewals occur, and indicates that we will have removed the worst arc flash problems from our fleet.

Table 18.7: Projected 11kV indoor switchgear arc flash risk as at 2029 (% of total asset fleet)

	ASSET HEALTH INDEX				
ARC FLASH CATEGORY	H5	H4	H3	H2	H1
≥ 8 cal/cm² (oil switchgear)	0%	0%	0%	0%	0%
≥ 8 cal/cm² (not oil switchgear)	5%	0.2%	0%	0%	0%
< 8 cal/cm²	49%	17%	28%	1%	0.4%

We have identified the need for a site rebuild project[83] for our Triton substation. The substation's indoor 11kV and associated outdoor bus structure date to when the site was established in 1973. The assets have significant condition deterioration and industrial pollution, because of the proximity to the coast, and are now obsolete. The power transformers have also had overheating issues.

Our indoor switchgear forecasts also include expenditure for indoor conversions.[84] These are described in further detail in the outdoor switchgear section below.

Coordination with network development projects

New zone substation projects typically use indoor switchgear because it performs better than outdoor switchgear. In addition, at sites with more than four feeders the installation cost is usually lower. For urban substations, switchgear is installed in buildings that visually integrate into the surrounding neighbourhood, providing as little visual impact as possible.

In some areas, network growth has driven requirements for additional feeders or modifications in network architecture. When undertaking switchboard renewals, future growth requirements are taken into account to ensure any newly installed boards will have sufficient future capacity to accommodate the forecast load growth in the planning period.

Existing indoor switchboards often have their associated protection relays installed on the switchgear panels. Their protection is always replaced along with the switchboard. We align protection relay replacement and switchboard replacement timing to minimise retiring protection equipment before the end of its useful life.

18.5 OUTDOOR SWITCHGEAR

18.5.1 FLEET OVERVIEW

The zone substation outdoor switchgear fleet comprises several asset types, including outdoor circuit breakers, air break switches, load break switches, fuses, and reclosers.

Outdoor switchgear is primarily used to control, protect and isolate electrical circuits in the same manner as indoor switchgear. It de-energises equipment and provides isolation points so our service providers can access equipment to carry out maintenance or repairs.

Circuit breakers and reclosers provide protection and control, while fuses provide protection and isolation only. Non-load break air break switches isolate, but cannot be used to break the load current. Load break switches control and isolate and are used to break load current.

83 This expenditure is included within the indoor switchgear fleet, as this is the largest cost component of the project.

84 Outdoor-to-indoor conversion renewal expenditure is included in this fleet as it involves installing new indoor switchgear. Drivers for these projects are related to the outdoor switchgear and are described in the outdoor switchgear section.

Figure 18.9: Typical outdoor 33kV switchgear bay

18.5.2 POPULATION AND AGE STATISTICS

Table 18.8 summarises our population of outdoor switchgear by type. Circuit breakers are also categorised by interrupter type.

Table 18.8: Outdoor switchgear numbers by asset type at

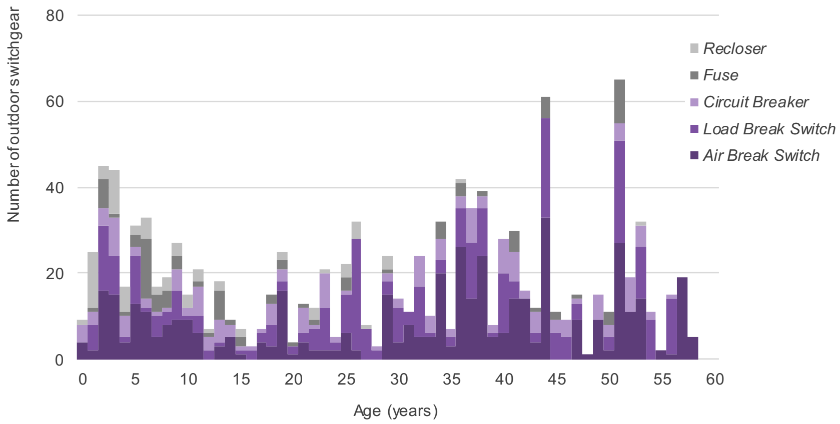
SWITCHGEAR TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Air break switch		453	40
Load break switch		328	29
Circuit breaker		183	16
	*of which:*Oil	104	
	SF_6	62	
	Vacuum	17	
Fuse		96	8
Recloser		78	7
Total		1,138	

Most of our outdoor circuit breakers use oil as the interrupting medium. These circuit breakers have historically given good performance, but many are now exceeding their expected service life. These older circuit breakers may also grow sluggish in operation over time, have intensive maintenance requirements, and replacement parts are in many cases no longer available.

Finally, oil type circuit breakers can fail explosively if not properly maintained. We are progressively phasing out this type of circuit breaker and replacing it with either vacuum of SF_6-based types.

Figure 18.10 shows our outdoor switchgear age profile.

Figure 18.10: Outdoor switchgear age profile



We generally expect outdoor switchgear assets to require replacement about 45 years of age. Therefore, more than 37% of the outdoor circuit breaker fleet is expected to require replacement during the next decade, noting that actual replacement decisions are made on the basis of asset condition and risk.

18.5.3 CONDITION, PERFORMANCE AND RISKS

Oil-based circuit breakers carry additional risks compared with their modern equivalents.

Switching operations, particularly operations to clear faults, degrade the switch contacts and oil, incurring high maintenance costs. There are also some problems with older breaker types becoming slow in operation, leading to protection coordination problems.

Finally, as most types are now obsolete, replacement parts are difficult to source and, if available, can have very long lead times, resulting in support and availability problems.

We have developed a systematic approach to the management of critical spares to help alleviate this issue as we continue through our programme of retiring these types.

To minimise problems, we service our oil circuit breakers after they have performed a specified number of switching operations. The number is determined based on the type of circuit breaker and the fault current breaking energy.

“Dog-box” style circuit breakers typically comprise a SF_6 outdoor breaker within a steel housing. There have been some historical issues with water ingress leading to internal tracking and breakdown. We will continue to monitor this failure mode.

Two-piece porcelain insulators used in many older air break and load break switches have been found to fail while the switch is being operated, creating a significant safety risk. We have placed operating restrictions on these switches to control the risk, and have initiated a programme to replace the faulty insulators. This is coordinated, wherever possible, with zone substation major maintenance.

Outdoor switchgear asset health

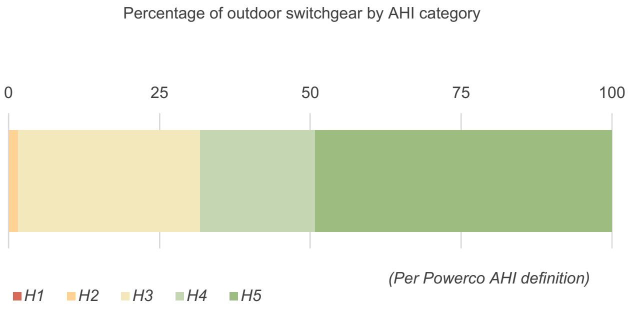
As outlined in Chapter 7, we have developed CBRM models that estimate the current and forecast health of our outdoor circuit breaker fleet, while the lower cost isolators are forecast by simpler age-based AHI measures.

For outdoor switchgear, we define end-of-life as when the asset can no longer operate reliably and safely, and the switchgear should be replaced.

The AHI for outdoor circuit breakers is based on CBRM, discussed in the indoor switchgear condition, performance and risk section (18.4.3).

Figure 18.11 shows the current overall AHI profile for our outdoor circuit breakers.

Figure 18.11: Outdoor switchgear (circuit breakers) asset health as at 2019



The overall health of the outdoor switchgear fleet indicates that approximately 37% of the fleet will require renewal during the next 10 years (H1-H3). A significant increase in renewal investment is required to restore the health of this fleet to preferred levels.

18.5.4 DESIGN AND CONSTRUCT

Like indoor switchgear, outdoor switchgear is classified as class A equipment and undergoes a detailed evaluation process to ensure any new equipment is fit for purpose.

For 33kV circuit breaker replacement, our current standard asset is a live tank SF_6 breaker. SF_6 circuit breakers are the industry standard for HV outdoor applications. However, we are monitoring developments with equivalent vacuum-based circuit breakers. Vacuum circuit breakers would help reduce our holdings of SF_6 gas and its associated environmental risks. We are reviewing our reporting processes because we recently were classified as a major user of SF_6.[85]

Meeting our portfolio objectives

Safety and Environment: We continue to monitor developments in non-SF_6-based switchgear and, when mature, will consider its application to reduce the potential environmental harm from SF_6 gas leaks.

Whenever possible we manage outdoor switchgear replacements at the bay level. This ensures delivery efficiency. Where practicable, replacements are also typically planned to coincide with power transformer replacements.

85 An SF_6 user becomes a major user when it has more than 1,000kg of the gas in stock.

Figure 18.12: Live tank SF_6 outdoor 33kV circuit breaker

18.5.5 OPERATE AND MAINTAIN

Outdoor switchgear undergoes preventive maintenance to ensure safe and reliable operation. We also undertake preventive maintenance based on circuit breaker fault operations for oil type breakers to mitigate against failure modes associated with excess duty.

Our various preventive maintenance tasks are summarised in Table 18.9. The detailed regime for each asset is set out in our maintenance standard.

Table 18.9: Outdoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, air break switches and reclosers.	3 monthly
Operational tests on CBs not operated in the past 12 months. Condition-test circuit breakers, including thermal, PD and acoustic emission scan.	Yearly
Circuit breaker insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. Air break switches thermal scan. Recloser thermal and oil insulation tests.	3 yearly
Air break switches service of contacts and mechanism.	6 yearly
Vacuum and SF_6 recloser checks and insulation tests.	9 yearly
Replace oil (if relevant). Contacts checked and resistance measured.	Operations-based

Outdoor switchgear requires more preventive and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

18.5.6 RENEW OR DISPOSE

Our approach is to replace circuit breakers and other outdoor switchgear equipment on a condition and risk basis. We aim to avoid equipment failure, as network consequences can be large and failure modes can be explosive, creating a safety hazard, particularly with oil-filled switchgear.

SUMMARY OF OUTDOOR SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Age
Cost estimation	Volumetric average historic rate

Renewals forecasting

Our longer-term outdoor circuit breaker renewals quantity forecast uses CBRM-projected AHI and risk as a base for replacement need – our air break and load break switches using age as a proxy for condition.

Older switchgear is more likely to be in poor condition because of exposure to corrosion for longer periods. Its mechanical components are also likely to have more wear leading to slower operating speeds, which can increase clearing times.

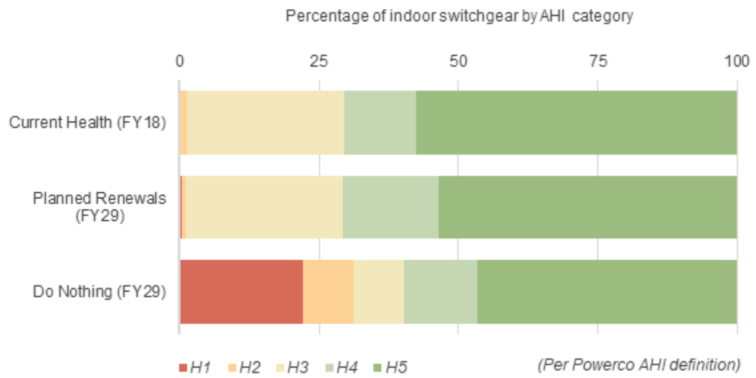
Our renewals forecast also considers that older designs of switchgear generally have fewer safety features, are maintenance heavy, and are less reliable. These problems are compounded as skills and expertise for maintaining these types of equipment decrease, and spare parts become harder to obtain. Our expenditure forecast is based on forecast renewal quantities and average historical unit rates.

Outdoor-to-indoor (ODID) conversion project[86] planning considers a range of drivers, including condition, safety and criticality. The high-level scope of these projects is used to develop an indicative cost estimate. We intend to further refine our quantitative analysis to help identify the need for conversions.

We have identified several substation candidates for ODID conversion. These substations generally have 33kV switchgear in poor condition, are subjected to industrial or environmental pollution, or have cramped overhead buswork. These projects are discussed in more detail in Appendix 9.

Figure 18.13 compares projected asset health in 2029, following planned renewals, with a counter-factual do-nothing scenario. Comparing the planned investment scenario provides an indication of the benefit provided by the proposed investment programme. Our increased investment targeting assets in poor condition will maintain asset health at approximately the current level.

Figure 18.13: Projected outdoor switchgear (circuit breakers) asset health in 2029



Our modelling also indicates that implementation of the plan will result in approximately a 7% reduction in overall network risk by focusing replacement on higher risk assets, driven primarily by high Value of Lost Load (VoLL) assets (single circuit 33kV supplies) because of their lengthy restoration processes.

86 Outdoor-to-indoor conversion project expenditure is classified under indoor switchgear, but is discussed in this section. The drivers for the conversion relate to the existing outdoor assets, not new indoor switchboards.

Coordination with network development projects

Most new zone substations use indoor switchgear as a preference to outdoor switchgear because of its cost, footprint, reliability and safety benefits. We also review existing zone substations for possible conversion to indoor switchgear when undertaking major development work. Where possible, renewal plans are coordinated to accommodate any future architecture or subtransmission feed requirements and changes in architecture.

18.6 BUILDINGS

18.6.1 FLEET OVERVIEW

Zone substation buildings mainly house protection, supervisory control and data acquisition (SCADA), communications and indoor switchgear equipment.

Zone substation sites need to be secure. Buildings and equipment must be well secured for earthquakes and designed to minimise the risk of fire.

We have undertaken a seismic survey of our existing zone substation buildings. This work identified a list of buildings that require strengthening to meet the NZ Building Code. We will address these requirements during the planning period.

Figure 18.14: Masonry constructed building

18.6.2 POPULATION AND AGE STATISTICS

We have 160 buildings[87] at our zone substations. These are built of various materials including concrete, timber and masonry.

18.6.3 CONDITION, PERFORMANCE AND RISKS

As building standards have evolved, the requirements for seismic performance have changed. Older buildings, particularly those made of unreinforced masonry and concrete, are well below today's strength standards.

The seismic performance of our zone substation buildings is important for the safety of our people working in them, and to maintain electricity in the event of a large earthquake or remain fully operational to allow for quick restoration.[88]

We have assessed 123 of our zone substation buildings[89] against the New Zealand Society of Earthquake Engineering (NZSEE) grades. Our standard requires all zone substation buildings to be at least 67% of the new building standard (NBS), equivalent to B grade or better. The study indicated 54 of our buildings require seismic strengthening.

Table 18.10 shows our zone substation buildings by NZSEE seismic grade.

Table 18.10: Zone substation buildings by NZSEE seismic grade

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS	% OF TOTAL
A+	>100	7	4
A	80-100	43	27
B	67-79	19	12
C	34-66	28	18
D	20-33	12	8
E	<20	14	9
Not assessed[89]		37	23
Total		160	

87 This excludes 'minor' buildings, such as sheds.

88 Zone substation buildings are considered a 'frequented location', and carry a considerable community importance due to our function as a lifeline utility. Therefore, these buildings are of an importance level 4 in accordance with AS/NZS 1170.5, along with buildings used for medical emergency and surgery functions and emergency services.

89 Some zone substation buildings were excluded from this assessment as they had previously been assessed, had recently been strengthened, or had been constructed in the past 10 years. These buildings are assumed to be at least at grade B.

Seventeen substations have been confirmed to contain asbestos materials, and a further 16 are presumed or strongly presumed to have asbestos-containing materials.

Approximately 56 substations fit the age profile of having a high likelihood of containing asbestos material but have not yet been surveyed. This may lead to increased compliance costs as we work through our building programmes.

If the material is in a non-friable state and well inspected and maintained, then if not disturbed, asbestos cannot be inhaled and so may remain in place.

We will remove the asbestos from buildings when we are undertaking seismic strengthening, switchboard replacements, building extensions or any other work that may disturb the asbestos.

18.6.4 DESIGN AND CONSTRUCT

When designing new zone substation buildings, we carefully consider the aesthetics of the environment within which they are to be built. While our rural substations still follow more traditional block building designs, in urban areas we make our sites as unobtrusive as possible and design the building to fit in with the surrounding neighbourhood.

A number of our new zone substation buildings in urban areas have been designed to look like modern family homes.

Meeting our portfolio objectives

Customers and Community: Urban zone substation buildings are integrated into the neighbourhood, reducing their visual impact.

Figure 18.15: Urban zone substation building

18.6.5 OPERATE AND MAINTAIN

We routinely inspect our zone substation buildings to ensure they remain fit for purpose and any remedial maintenance work is scheduled as required. Ensuring our buildings are secure is essential to preventing unauthorised access.

Table 18.11: Building preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of building. Check emergency lighting system.	3 monthly
Detailed visual inspection, including weather-tightness, checks of structure, roof, plumbing, drainage, electrics and fittings. Check safety equipment and signs.	Yearly

18.6.6 RENEW OR DISPOSE

Zone substation buildings that do not meet our standard for seismic compliance are part of a seismic strengthening programme scheduled for this planning period. This will ensure our buildings are safe and able to maintain a reliable supply in the event of a major earthquake.

SUMMARY OF BUILDINGS RENEWALS APPROACH	
Renewal trigger	Seismic risk
Forecasting approach	Desktop seismic study
Cost estimation	Historical rates

Our aim is to have all our zone substation buildings up to B grade standard or better by the end of the planning period, although more case-by-case detailed work may show we require more full replacements versus strengthening, which could increase the costs associated with these works. The timing of strengthening projects depends on other work at the zone substation, the current seismic grade of the building, and the relative criticality of the site.

Cost estimates for the strengthening works are based on previously completed works. We intend to further refine these estimates as we complete more strengthening works.

Once the seismic upgrades are complete, other than ongoing maintenance we do not anticipate a need for further works in this fleet in the medium term.[90]

Coordination with network development projects

Zone substation buildings are typically built for new indoor switchgear, either a complete switchboard renewal or a switchboard extension to serve additional feeders.

Planning for these two fleets is therefore done at the same time. We also schedule seismic upgrades to coincide with switchgear works to ensure upgrades are designed with the requirements of the new switchgear in mind.

New greenfield zone substation buildings are planned and designed to meet the needs of the overall development.

18.7 LOAD CONTROL INJECTION PLANT

18.7.1 FLEET OVERVIEW

Load control has been used in New Zealand for the past 60 years. Load control systems are used to manage the load profiles of customers with controllable loads, eg hot water or space heating.

Load control involves sending audio frequency signals through the distribution network from ripple injection plants at zone substations. Ripple receiver relays located at customer main distribution boards receive the signals and turn the ‘controlled load’ on or off.

If configured well, load control systems are highly effective at reducing demand at peak times by deferring non time-critical power usage. Benefits of load control include more predictable peak demand and allowing us to defer distribution capacity increases. Wider benefits include a reduced need for peaking generation plants and transmission deferral.

90 Note that the cost of new buildings or building extensions is covered within the forecasts for the related asset, eg indoor switchgear.

Figure 18.16: Load control injection plant

18.7.2 POPULATION AND AGE STATISTICS

We operate 36 load control injection plants on our network, comprising both modern (and supported) and aged (and unsupported) equipment.

Table 18.12 summarises our load control injection plant population by type.

Table 18.12: Load control injection plant by type

TYPE	PLANT	% OF TOTAL
Modern ripple plant	21	58
Legacy ripple plant	5	14
CycloControl plant	10	28
Total	36	

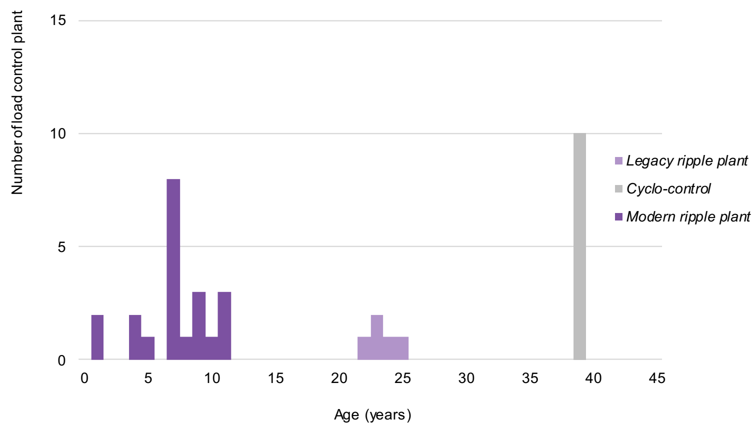
One of the aged types is the CycloControl system, which is a voltage distortion system used in the Stratford and Huirangi regions. Its method of transmitting load control commands differs from all other systems on our networks and has more faults.

These plants have now been superseded by newly installed ripple injection plants. The CycloControl systems will be decommissioned in the near term once relay owners have migrated to the new standard.

Other legacy load control plants, although generally compatible with modern systems, are in poor condition and do not perform as well as modern plants.

Figure 18.17 shows the age profile of our load control fleet.

Figure 18.17: Load control injection plant age profile



In 2008, we undertook a modernisation programme to address issues with our legacy assets, such as lack of technical support and spares. We have used advances in load control technology to optimise the number of plants required, which reduces the total sites needed. The remaining legacy and CycloControl plants were installed from the mid-1970s through to the mid-1990s and will shortly require replacement or will be decommissioned.

18.7.3 CONDITION, PERFORMANCE AND RISKS

Our legacy load control plant is now considered obsolete. To ensure we can operate a reliable load control system the obsolete installations need to be retired.

Some installations use higher ripple frequencies (>400Hz) and are no longer considered good industry practice. They are more affected by non-linear and capacitive loads that are now common in an electricity system. Other legacy systems, including CycloControl, use obsolete code formats. Obtaining spares and manufacturer support is very difficult.

18.7.4 DESIGN AND CONSTRUCT

The standard for current and future plant is the DECABIT channel command format. We aim to exclusively use the DECABIT standard by FY25. The DECABIT standard has proven to be the most reliable and error free standard and is widely used in New Zealand.

Our Tauranga and Valley areas use Semagyr (Landis + Gyr) formats. We recognise the investment made in the past by the owners of these ripple receiver relays and will work with them to achieve the transition.

18.7.5 OPERATE AND MAINTAIN

Because of the specialist nature of load control plant, we have a backup and service support contract that covers our modern static installations. This covers annual inspections, holding of critical spares and after-hours emergency support.

Table 18.13: Load control injection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of plant. Operational tests.	3 monthly
Diagnostic tests, such as resonant frequency checks, signal injection levels and insulation resistance.	Yearly

18.7.6 RENEW OR DISPOSE

Uncertainty over the role and use of load control equipment after the split of line and retail electricity businesses meant we deferred replacing the equipment for some years. The role and use has now been largely clarified and, since 2008, we have returned to replacing load control plant (transmitters). The majority are now of modern technology.

We plan to replace or retire the remaining obsolete legacy transmitters as they operate to different standards, lack spares and are difficult to support. Once these are replaced or retired we expect little further renewal in this planning period. Some future replacements of modern plants will be driven by grid exit point (GXP) transformer upgrades and network reconfiguration undertaken by Transpower.

SUMMARY OF LOAD CONTROL INJECTION PLANT RENEWALS APPROACH	
Renewal trigger	Obsolescence
Forecasting approach	Type
Cost estimation	Average historical rate

Coordination with network development projects

Load control plant continues to play a role on our network in managing peak loads. However, past distribution price structures and instantaneous gas hot water options have eroded the base of switchable load on the electrical network.

The use of our load control plant is in a state of transition. However, we see traditional load control continuing to play a role, alongside new non-network solutions, as alternatives to traditional network capacity upgrades.

18.8 OTHER ZONE SUBSTATION ASSETS

18.8.1 FLEET OVERVIEW

The other zone substation assets fleet comprises outdoor bus systems, fencing and grounds, earthing, lightning protection systems, security systems, and access control systems. We have 120 zone substations and 12 switching stations that contain outdoor buswork, fencing, earthing, lightning protection systems and support structures.

Outdoor bus systems are switchyard structures comprising gantries, lattice structures, HV busbars and conductors, associated primary clamps/accessories, support posts and insulators.

Most of our sites are designed with lightning protection systems to reduce the impact of a lightning strike on HV equipment. Lightning protection comprises surge arrestors for equipment bushings and indoor sites.

18.8.2 CONDITION, PERFORMANCE AND RISKS

A key safety risk in our zone substations is managing step and touch potential hazards during faults. A layer of crushed metal (a type of rock) or asphalt is used to lessen step and touch potential hazards in outdoor switchyards by providing an insulating layer.

Some of our switchyards are grassed, which needs to be replaced with crushed metal. Other sites are no longer compliant with our earthing guidelines to the point where wholesale reinstatement of crushed metal is required. We plan to install or reinstate the switchyard metal on such sites.

Another key risk we manage is access and site security. Fencing around zone substations is very important to keep the site secure and prevent unwanted access. A number of our older sites do not have adequate fencing and security systems compared with modern zone substations. Some fencing needs replacing as the asset is at end-of-life, such as from corrosion. We intend to bring all sites up to our fencing and security standards during the planning period. We will prioritise urban zone substations where the risk of unauthorised access is highest.

Some sites are not adequately protected from lightning strikes. To provide the required protection level we intend to install surge arrestors on the terminals of high-value equipment, such as power transformers.

Modern standards require flexible conductors for primary plant so the conductor can move during seismic events. Some of the primary plant bushings in older substations are connected directly to a rigid bus. We intend to undertake a programme to convert rigid bus to flexible connections.

18.8.3 OPERATE AND MAINTAIN

Our general zone substation preventive maintenance tasks are summarised in Table 18.14. The detailed regime is set out in our maintenance standards.

Table 18.14: Zone substation general preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Site vegetation work – mowing, weeding. Check waterways.	Monthly
General visual inspection of outdoor structures, busbars, site infrastructure, security equipment and fencing.	3 monthly
Detailed visual inspection of site infrastructure. Thermal scan of busbar connections.	Yearly
Detailed inspection of busbar connections, insulators, and bushings. Detailed condition assessment of outdoor structures.	6 yearly

18.8.4 RENEW OR DISPOSE

We plan four programmes of renewal within this fleet, which are:

- Switchyard metalling
- Fencing and site security
- Lightning protection
- Rigid bus conversions

These programmes are planned to continue to until at least FY27.

SUMMARY OF OTHER ZONE SUBSTATION ASSETS RENEWALS APPROACH	
Renewal trigger	Safety and reliability risk
Forecasting approach	Programmes
Cost estimation	Historical rates

18.9 ZONE SUBSTATIONS RENEWALS FORECAST

Renewal Capex in our zone substations portfolio includes planned investments in the following fleets:

- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control plant
- Other zone substation assets

During the planning period we plan to invest $111m in zone substation asset renewal.

A key driver for the replacement of our switchgear assets is managing safety risk, particularly to our field staff. Managing reliability risks from potential equipment failure, indicated by asset condition and health, is a further driver.

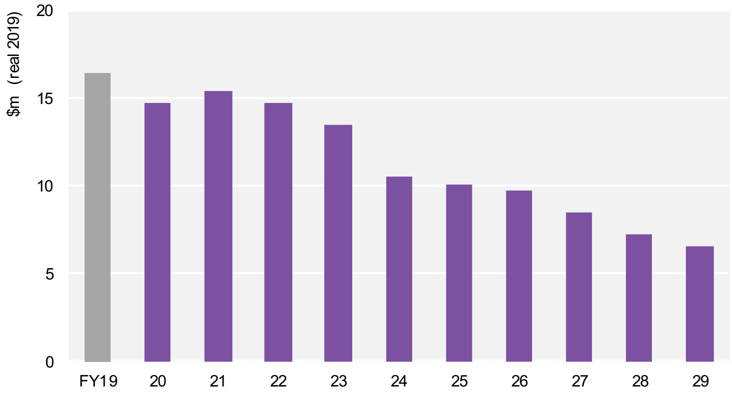
The combination of our six fleet forecasts, derived from bottom-up models, drives our total zone substations renewal expenditure. Although initially forecasted as separate fleets, we combine the model outputs to allow us to identify delivery efficiencies.

We coordinate and align projects so that smaller replacements, such as individual circuit breakers, occur in conjunction with larger replacements, such as power transformers.

We also coordinate zone substation projects with protection relay replacements (covered by our secondary systems portfolio).

Figure 18.18 shows our forecast Capex on zone substation renewals during the planning period.

Figure 18.18: Zone substation renewal forecast expenditure



The forecast renewal expenditure for the zone substation portfolio represents a step change increase relative to historical levels. Most of the increase is because of power transformer, indoor switchboard and outdoor switchgear renewal programmes. It also includes two larger projects at Greerton and Whareroa.

While historically some replacement has been coordinated with growth augmentations, the deteriorating condition of the portfolio means that substantial renewal investment is now warranted.

Further details on expenditure forecasts are contained in Chapter 26.

19 DISTRIBUTION TRANSFORMERS

19.1 CHAPTER OVERVIEW

This chapter describes our distribution transformers portfolio and summarises our associated fleet management plan. This portfolio includes three fleets:

- Pole-mounted distribution transformers
- Ground-mounted distribution transformers
- Other distribution transformers, which include voltage regulators, capacitors, conversion and single earth wire return (SWER) transformers

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we expect to invest $74m in distribution transformer renewals. This accounts for 9% of renewals Capex during the period. The forecast investment is generally in line with historical levels.

Our replacement programme reflects the large number of distribution transformer assets installed during the 1960s and 1970s that have reached, or are approaching, end-of-life.

The investment supports our safety and reliability objectives. Renewal works are driven by the need to:

- Reduce the risk related to some large pole-mounted transformers not complying with standards for seismic resilience, safety, or electrical clearances mandated by ECP34 (New Zealand Electrical Code of Practice for Electrical Safe Distances). We intend to complete a programme of converting these units to ground-mounted equivalents or upgrading the associated poles by FY28.
- Continue our distribution transformer replacement programmes, prioritised using asset condition, defect information and Condition-Based Risk Management (CBRM) modelling.
- Improve the safety of pole-mounted transformers by completing a programme to install a means of Low Voltage (LV) isolation via LV fuses.
- Continue a programme to manage risk and ensure legislative compliance associated with unauthorised public access to our ground-mounted transformers through replacement of 14,000[91] non-standard, ageing or damaged padlocks during the Customised Price-quality Path (CPP) period.

[91] Further replacements will occur in other portfolios, primarily ground and pole-mounted switchgear.

Below we set out the Asset Management Objectives that guide our approach to managing our distribution transformer fleets.

19.2 DISTRIBUTION TRANSFORMERS OBJECTIVES

Distribution transformers convert electrical energy of higher voltage to a lower voltage, generally from 11kV, but in some cases 6.6kV or 22kV, down to 400/230V. Their effective performance is essential for maintaining a safe and reliable network.

Transformers come in a variety of sizes, single or three-phase, and ground or pole-mounted. Our transformers are oil-filled, which carries some environmental and fire risk. Proper lifecycle management of our distribution transformers assets, including correctly disposing of these assets when they are retired, is important for safeguarding the public and mitigating potential environmental harm from oil spills.

To guide our asset management activities, we have defined a set of objectives for our distribution transformers. These are listed in the table below. The objectives are linked to our Asset Management Objectives as set out in Chapter 5.

Table 19.1: Distribution transformers portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reposition pole-mounted transformers to limit risks related to working at heights. Achieve electrical clearances mandated by regulation and consistent with industry good practice. No explosive failures of, or fires caused by, distribution transformers. Installations compliant with seismic codes to avoid injury and property damage. Install compliant LV fusing on pole-mounted transformers. No significant oil spills.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Consider the use of alternative technology to improve reliability or reduce service cost eg transformer monitoring units.
Asset Stewardship	Expand the use of asset health and criticality techniques to inform renewal decision-making.
Operational Excellence	Improve and refine our condition assessment techniques and processes.

19.3 POLE-MOUNTED DISTRIBUTION TRANSFORMERS

19.3.1 FLEET OVERVIEW

There are approximately 27,000 pole-mounted transformers on our network. These are usually located in rural or suburban areas where the distribution network is overhead. The capacity ranges from less than 15kVA to 300kVA.

Recent changes to our standards have set the maximum allowable capacity for a new pole-mounted transformer at 200kVA[92]. This means any pole-mounted transformers greater than 200kVA that require replacement are likely to be converted to a ground-mounted equivalent, if practical.

Following a major change to national seismic standards in 2002, some larger pole-mounted transformer structures are no longer compliant. Those H-pole-mounted installations often do not meet the ECP34 clearance and safety requirements. We intend to continue to replace these with compliant pole-mounted or ground-mounted units.

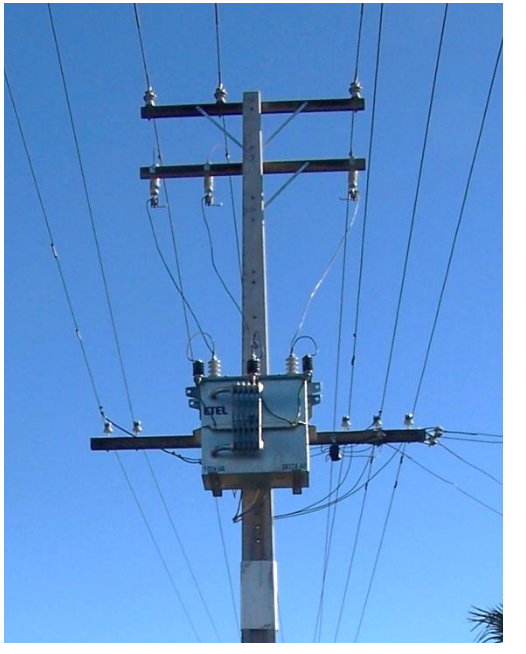
Meeting our portfolio objectives

Safety and Environment: Larger pole-mounted transformers are being reviewed for seismic and ECP34 compliance and will be either strengthened or replaced with ground-mounted units to reduce safety risks.

Pole-mounted transformers are generally smaller and supply fewer customers than ground-mounted transformers. Reactive replacement can usually be undertaken quickly, affecting a relatively small number of customers. Suitable spare transformers are held in stock at service provider depots. This ensures a fast response time to return service.

92 A transformer of up to 1,000kg is acceptable as pole-mounted using standard designs. Those weighing 1,000-1,600kg must have specific design analysis and those above 1,600kg must not be pole-mounted. A 200kVA transformer weighs just over 1,000kg.

Figure 19.1: 100kVA pole-mounted transformer



19.3.2 POPULATION AND AGE STATISTICS

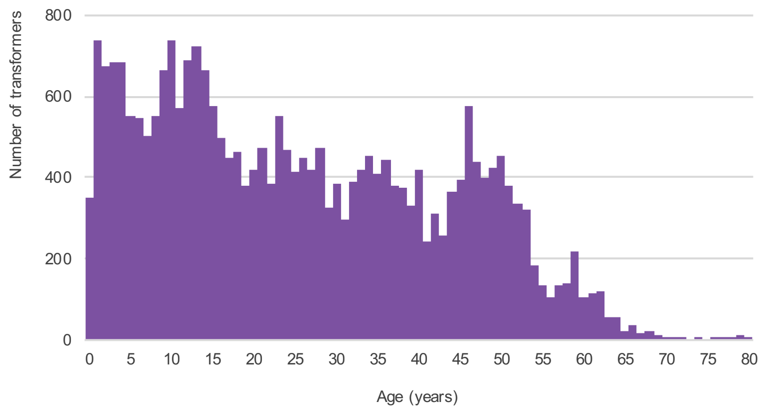
The table below summarises our population of pole-mounted distribution transformers by kVA rating. Most are very small, with more than 40% at 15kVA or below. A transformer of this size typically supplies a few houses in a rural area.

Table 19.2: Pole-mounted distribution transformer population by rating

RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
≤ 15kVA	10,662	40
> 15 and ≤ 30kVA	8,932	33
> 30 and ≤ 100kVA	6,168	23
> 100kVA	1,008	4
Total	26,770	

The figure below shows our pole-mounted distribution transformer age profile. The expected life of these units typically ranges from 45 to 60 years. The fleet age profile indicates that an increasing number of transformers will require replacement during the planning period.

Figure 19.2: Pole-mounted distribution transformer age profile



19.3.3 CONDITION, PERFORMANCE AND RISKS

Failure modes

The main reasons for replacing pole-mounted transformers are age, environment-related deterioration, and random failures caused by third parties eg vehicle accidents or lightning strikes. The predominant causes of equipment degradation are:

- Deterioration of the insulation, windings and/or bushings
- Moisture and contaminant concentrations in insulating oil
- Thermal failure because of overloads
- Mechanical loosening of internal components, including winding and core
- Oil leaks through faulty seals
- External tank/enclosure damage and corrosion

Some of these factors, such as tank corrosion or oil degradation (for some ground-mounted units) inform our Asset Health Indices (AHI) to forecast and prioritise replacement.

Risks

Some of our larger pole-mounted transformer structures do not meet modern seismic standards or meet requirements for electrical clearances documented in ECP34. Non-compliance with seismic requirements creates a safety risk and reduces network resilience should there be a seismic event.

Some of our older pole-mounted transformers do not have LV fuses, which means there is no direct protection against LV faults. When a fault occurs, it is not cleared until it is manually isolated or the High Voltage (HV) fuse operates, increasing the possibility for live LV conductors to be accessible to the public during a wire down or other fault event.

In 2013, we initiated a programme to install LV fuses on approximately 6,700 pole-mounted transformers, predominantly in areas of Taranaki, Valley and Wairarapa, where LV fusing was not installed as the norm. This programme will be completed by 2023.

Meeting our portfolio objectives

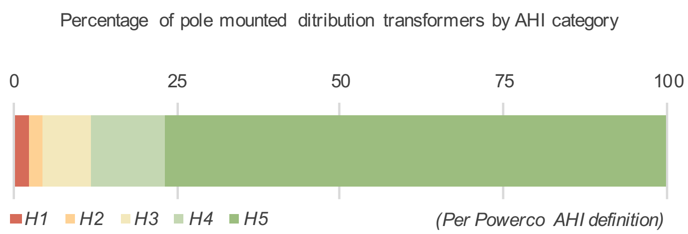
Safety and Environment: Where not already present, LV fuses are being installed on our pole-mounted distribution transformers to improve public safety in the event of a fault on the LV network.

Pole-mounted distribution transformer asset health

As outlined in Chapter 7, we have developed AHIs that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorises its health based on a set of rules. For pole-mounted transformers we define end-of-life as when the asset fails because of condition. The overall AHI is based on survivorship and defect analysis.

The figure below shows current overall AHI for our population of pole-mounted distribution transformers.

Figure 19.3: Pole-mounted distribution transformer asset health as at 2018



The overall health of the pole-mounted transformer fleet is generally good, with few assets requiring replacement. Because of our run-to-failure approach with smaller pole-mounted distribution transformers, we expect to retain a sustainable level of H1 assets to be replaced under reactive/defect processes.

19.3.4 DESIGN AND CONSTRUCT

To improve seismic compliance, where practical, pole-mounted transformers above 200kVA are replaced with a ground-mounted transformer of equivalent or greater size. Refer to Section 19.3.3 for more details. Smaller pole-mounted transformers are replaced like-for-like.

We intend to fit distribution transformer monitors on certain existing and new pole-mounted transformers. For more details refer to Chapter 13 Network Evolution.

19.3.5 OPERATE AND MAINTAIN

Pole-mounted transformers do not require intrusive maintenance. Maintenance is generally limited to visual inspections, with repair or replacement initiated on an on-condition basis. Pole-mounted distribution transformers are usually small and less critical than ground-mounted equivalents. It is often cost effective to replace them when they are close to failure, rather than carry out rigorous maintenance to extend life. Our preventive inspections are summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 19.3: Pole-mounted distribution transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Inspect tank and general fittings for corrosion and inspect earthing connection.	5 yearly

The five-yearly inspection interval for the pole-mounted transformer fleet is based on defects analysis and historical mandated requirements. The interval also coincides with our pole inspection programme providing cost efficiencies.

Typical corrective work on a pole-mounted transformer includes:

- Replacing corroded hanger arms
- Replacing blown fuses
- Replacing damaged surge arrestors
- Topping up oil

Pole-mounted transformers may be repaired or refurbished in the workshop and managed through a rotating spare pool. An appropriate level of spares is kept for each part of the network at service provider depots.

Fault response generally involves replacing transformers that have internal, tank or bushing damage. Defective pole-mounted transformers are taken to spares warehouses where they are assessed for workshop-based repairs or overhaul. A new unit replaces the defective unit.

Repair and overhaul work is undertaken according to our specifications and evaluation criteria to ensure the repair or overhaul works are cost effective. If they are not, the unit is disposed of, and a new unit is added to the spares stock.

Repair work includes electrical and mechanical tasks, tank repairs, painting, and reassembly. Testing is done before and after repair work.

19.3.6 RENEW OR DISPOSE

Pole-mounted transformer renewal is primarily based on condition and legacy design problems, such as inadequate electrical clearances. We accept some in-service failures associated with failure modes that cannot be detected by visual inspection. These failure modes typically do not present a significant safety hazard and the impact on the customer is limited. Renewals may be combined with pole replacement to ensure efficiency.

SUMMARY OF POLE-MOUNTED DISTRIBUTION TRANSFORMER RENEWALS APPROACH

Renewal trigger	Reactive and condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

Our pole-mounted distribution transformer replacement quantity forecast incorporates historical survivorship analysis. We have developed a survivor curve and use this to forecast expected renewal quantities.

The figure below shows a pole-mounted distribution transformer survivor curve. The curve indicates the percentage of transformer population remaining at a given age.

Figure 19.4: Pole-mounted distribution transformer survivor curve

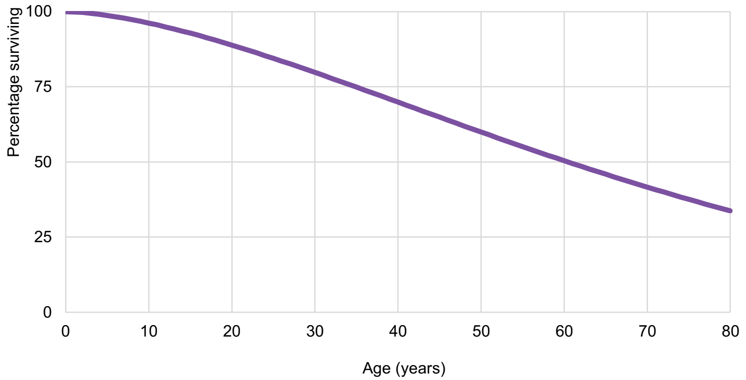
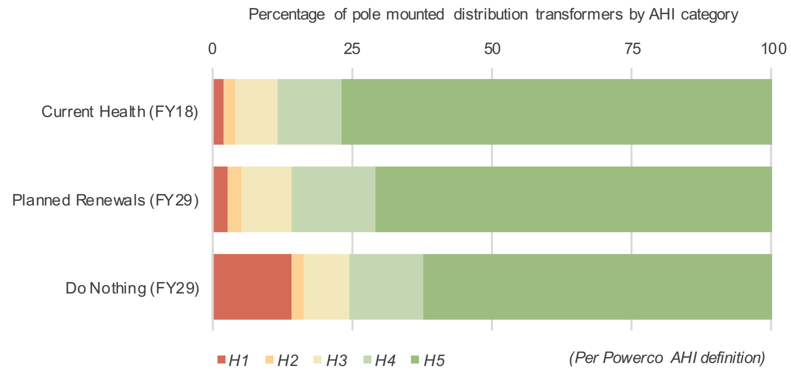


Figure 19.5: Projected pole-mounted distribution transformer asset health as at 2029



We found that pole-mounted distribution transformer replacement occurs over a wide range of ages, primarily because of factors such as type, manufacturer, location or inherent durability. The survivorship forecasting approach is therefore more robust than a purely age-based approach.

We have also identified approximately 279 larger pole-mounted distribution transformers on pole structures that may be at risk of failing during seismic events. We carried out initial risk assessments to prioritise various sites, for example within urban areas, next to major roads etc, and have initiated a programme to convert them to ground-mounted equivalents during a 10-year programme FY18-FY28.

Current standards require LV fuses to be fitted on transformers to protect outgoing circuits. In 2013, we initiated a programme of installing LV fuses on existing pole-mounted transformers that do not have them. This programme is expected to be completed by 2023.

As discussed in Section 19.3.3, our pole-mounted transformer fleet is maintained in good health by our condition-based renewal programme.

The figure below compares projected asset health in 2029, following planned renewals, with a 'do nothing' scenario. Our investment targets the minimum renewal needed to maintain the health of the fleet.

The figure indicates stable renewal levels continuing beyond 2029, as indicated by the H1-H3 portion in Planned Renewals (FY29).

Pole-mounted transformer refurbishment

Suitable units that are taken off the network, e.g. for growth reasons, undergo minor repairs such as repainting, re-gasketing etc before entering the rotable pool of spares.

Pole-mounted transformer disposal

Pole-mounted distribution transformers are decommissioned and disposed of when they are replaced. The principal transformer components of steel, copper and oil are recycled.

The oil in pre-1970 transformers often contained Polychlorinated Biphenyls (PCB), which is now known to be carcinogenic. We believe we have removed all models containing PCB. However, we continue to test older models for PCB before removing oil. Should we find PCB, a specialist disposal company would be employed to undertake removal.

Coordination with Network Development projects

Pole-mounted transformer replacement can be instigated by a range of growth-related factors, including new developments or increases in customer load through customer-initiated works.

In some cases, this can involve larger overhead line projects, including renewal reconductoring and pole replacements. Where possible, pole-mounted transformer renewal is coordinated with larger line upgrade/rebuild projects to ensure cost and customer disruptions are minimised.

Meeting our portfolio objectives

Customers and Community: Pole-mounted transformer replacements are, where possible, coordinated with other works to minimise disruption to customers.

New connections in urban areas, such as new residential subdivisions, are generally underground and use ground-mounted transformers. New connections for single customers in rural areas generally require pole-mounted transformers.

19.4 GROUND-MOUNTED DISTRIBUTION TRANSFORMERS

19.4.1 FLEET OVERVIEW

There are approximately 8,200 ground-mounted distribution transformers on our network. These are usually located in suburban areas and CBDs with underground networks. Ground-mounted transformers are generally more expensive and serve larger and more critical loads compared with pole-mounted transformers.

Ground-mounted transformers may be enclosed in a consumer’s building, housed in dedicated concrete block enclosures or, where outdoors, in fenced-off sites. Additionally, many sites are berm-mounted, with newer dog-bone single pad solutions, or in a variety of legacy enclosure types. If not housed in a building, ground-mounted transformers require separate foundations, along with earthing and a LV panel.

The size of ground-mounted transformers depends on load density, but they are generally 50 or 100kVA in rural areas, 200 or 300kVA in newer suburban areas, and 500kVA to 1.5MVA in CBD areas. Larger units of the fleet – ranging from 2-3MVA and above – are predominantly installed at industrial sites.

Ground-mounted distribution transformers must be secured against unauthorised and public access. A padlock and key system is used for this, but a large number of the padlocks are non-standard or in poor condition. As our register of key holders is incomplete we have concerns over key access by people no longer authorised.

Figure 19.6: 300 kVA ground-mounted transformer

19.4.2 POPULATION AND AGE STATISTICS

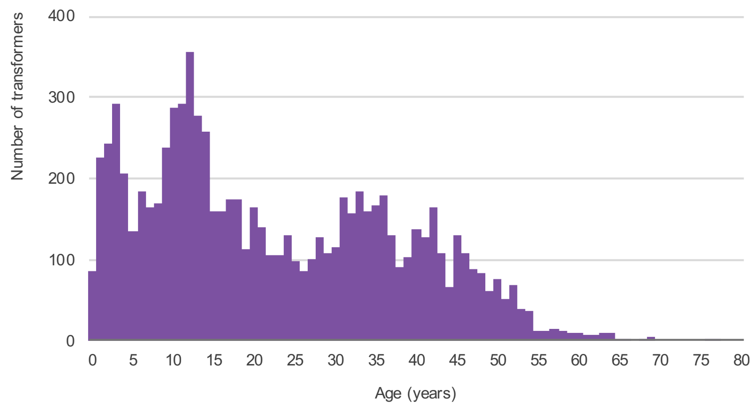
The table below summarises our population of ground-mounted distribution transformers by kVA rating. The smallest units have a size of approximately 100kVA, with larger units used for higher capacity installations.

Table 19.4: Ground-mounted distribution transformer population by rating

RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
≤ 100kVA	2,833	34
> 100 and ≤ 200kVA	1,988	24
> 200 and ≤ 300kVA	1,971	24
> 300kVA	1,473	18
Total	8,265	

The figure below shows our ground-mounted distribution transformer age profile.

Figure 19.7: Ground-mounted distribution transformer age profile



The ground-mounted transformer fleet is relatively young, with an average age of 22 years. Ground-mounted transformers generally have longer expected lives – 55 to 70 years – than pole-mounted units. They are more frequently maintained because of their accessibility and higher criticality, and are often located inside enclosures, providing greater protection from corrosion. Because of this, we expect only a relatively small number of renewals during the planning period.

19.4.3 CONDITION, PERFORMANCE AND RISKS

Failure modes

Ground-mounted transformers are mainly replaced because of equipment deterioration. Some unexpected failures occur and are usually caused by third parties, such as vehicle damage. The predominant causes of equipment degradation are:

- Deterioration of insulation, windings and/or bushings
- Moisture and contaminant concentrations in insulating oil
- Thermal failure because of overloads
- Mechanical loosening of internal components, including winding and core
- Oil leaks through faulty seals
- External tank/enclosure damage and corrosion

LV panels are treated as separate assets. Renewals of LV panels can occur separately to the transformer unit, typically in the case of reactive replacement following a failure. LV panels fail mainly because of overheating or insulation failure. While rare, we have had failures of LV boards, such as a recent failure in Gill St, New Plymouth CBD. We are investigating methods to better detect and identify these points of failure at our critical sites before they occur.

Some legacy LV board types present an increased risk of failure because of bare LV buses, ageing cables and connections, and the presence of deteriorating J-type fusing. We are improving our inspections to identify these types of boards.

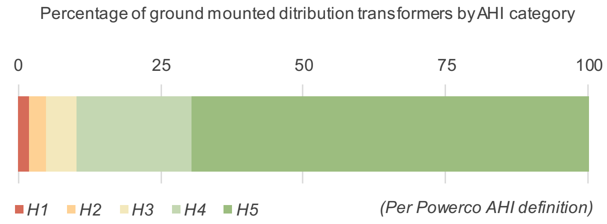
As a secondary programme to our zone substation building seismic strengthening programme, we are investigating standalone distribution substations supplying key parts of the network, such as CBDs, for post-emergency recovery to ensure minimal restoration time.

Ground-mounted distribution transformer asset health

As outlined in Chapter 7, we have developed CBRM models that reflect the health and risk of our asset fleets. For ground-mounted transformers, this defines end-of-life as when the asset fails because of condition drivers.

The figure below shows current overall AHI for our population of ground-mounted transformers as calculated by our CBRM model.

Figure 19.8: Ground-mounted distribution transformer asset health as at 2018



As with the pole-mounted fleet, the overall health of our ground-mounted transformers is generally good. CBRM modelling shows an acceptable level of risk against the fleet, with few assets requiring replacement in the short term to maintain current risk levels. The criticality approach that this modelling allows us to apply has also shown that we may tolerate some additional deterioration of smaller ground-mounted transformers before replacement.

Meeting our portfolio objectives

Asset Stewardship: We are continuing to refine our asset health and criticality approaches to improve our asset renewal decision-making.

Locks and keys

Ground-mounted distribution transformers, and distribution switchgear assets, are made secure by padlocks. We have several legacy padlocking systems that have been inherited from previously separate networks. We do not have complete control over key access to these padlocks as not all keys have been returned by departing staff. Therefore our register of legacy key holders is incomplete. This raises the risk associated with unauthorised public access and prevents us from complying with legislative obligations.

Because of the need to ensure access to our assets is appropriately controlled, we will standardise all padlocks and keys using a high security type that cannot be copied without authorisation. This work will be completed during the CPP period.

19.4.4 DESIGN AND CONSTRUCT

The scope of the transformer monitoring initiative discussed above in Section 19.3 also includes the ground-mounted fleet. Some ground-mounted distribution transformers may be fitted with monitors when renewed. For more details refer to Chapter 13 Network Evolution.

To ensure distribution transformer monitors can be retrospectively installed we will fit new ground-mounted distribution transformers with larger LV frames.

19.4.5 OPERATE AND MAINTAIN

Ground-mounted transformers are more accessible to the public and, because of their size, are more critical as a greater number of customers is usually connected. Additionally, industrial and commercial customers are usually supplied from ground-mounted transformers. Because of this, ground-mounted transformers undergo more maintenance. Our various preventive maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 19.5: Ground-mounted distribution transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection – check asset is secure.	6 monthly
General visual inspection, check transformer tank, fittings for corrosion and damage. Log Maximum Demand Indicator (MDI) readings.	Yearly
Detailed inspection and condition assessment. Oil sample and diagnostic voltage test if >499kVA.	5 yearly

Ground-mounted transformers are managed through a rotating spare pool strategy. Service provider depots have an appropriate stock of spares for each part of the network. Spares are available for fault response and for condition-based replacement.

Defective ground-mounted transformers are taken to the spares warehouses where they are assessed for workshop repairs or overhaul. A new or refurbished unit is used to replace a defective unit. Repair and overhaul work is undertaken according to our standards. Cost criteria are used to ensure the repair or overhaul works are cost effective. If they are not, the unit is disposed of, and a new unit is added to the spares stock.

The installed fleet is maintained using an inspection and condition-based corrective maintenance approach. Typical corrective work includes:

- Re-levelling base pads
- Replacing blown fuses
- Removing vegetation from enclosures
- Removing graffiti

19.4.6 RENEW OR DISPOSE

Ground-mounted distribution transformers undergo condition assessment and inspections to avoid in-service failure, thereby minimising safety risk to the public and the risk of unplanned outages. Ground-mounted distribution transformers are proactively renewed using prioritisation criteria, including failure consequence, safety risk, and security.

Meeting our portfolio objectives

Safety and Environment: We proactively replace ground-mounted distribution transformers before they fail, reducing public safety risks.

SUMMARY OF GROUND-MOUNTED DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

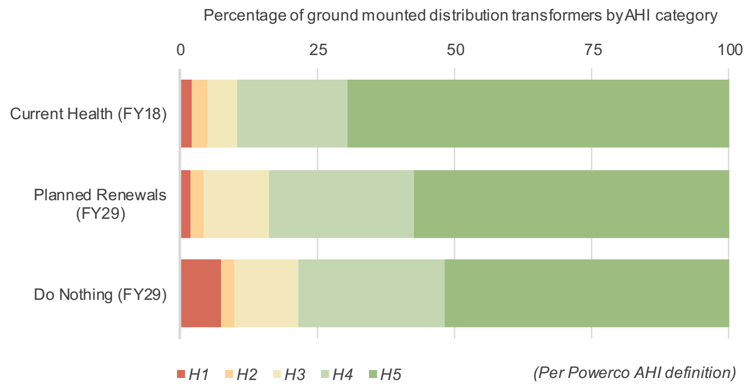
We have recently developed CBRM models to assist in replacement forecasting and replacement prioritisation. This analysis allows us to manage the fleet on a condition and risk basis. As listed in Section 19.4.3, modelling has shown that we are able to maintain the current level of risk without further increasing expenditure by prioritising higher risk assets for replacement and deferring replacement of lower criticality assets.

LV panels are sometimes renewed reactively and not in conjunction with the associated ground-mounted transformer. Our forecast allows for some replacement of LV panels based on historical levels. As part of our drive to improve inspections, we are planning to better identify these types of installations and include these in our renewal programmes, where appropriate.

As previously discussed, replacement of many of the locks securing our ground-mounted transformers is warranted. Our forecast allows full replacement of all locks and keys that have not already been replaced, with the standardised, high security units over the five-year period FY19-23.

As discussed in Section 19.4.3, our ground-mounted transformer fleet is in good health. The figure below compares projected asset health in 2029, following planned renewals, with a 'do nothing' scenario. Note that the current level of investment allows some of our smaller, low criticality units to remain in service with lower health scores, while maintaining a stable risk profile across the fleet.

Figure 19.9: Projected ground-mounted distribution transformer asset health as at 2029



The figure indicates stable renewal levels continuing beyond 2029, as indicated by the H1-H3 portion in Planned Renewals (FY29).

Ground-mounted transformer refurbishment

Life-extending refurbishment is rarely undertaken for the ground-mounted distribution transformer fleet. Such work would include replacing the core and windings, and it is usually more cost effective to install a new transformer.
As with the pole-mounted transformer fleet, good condition units that have been removed from the network because of non-condition reasons, eg network growth and customer-initiated works (CIW), undergo minor repairs, such as repainting or re-gasketing before entering the pool of rotable spares.

Ground-mounted transformer disposal

Ground-mounted distribution transformers are decommissioned and disposed of when they are replaced. The principal transformer components of steel, copper and oil are recycled.

As with pole-mounted transformers, the oil in pre-1970 transformers often contained PCB, which is now known to be carcinogenic. We believe we have removed all models containing PCB. However, we continue to test older models for PCB before removing oil. Should we find PCB, a specialist disposal company would be employed to undertake the work.

Coordination with Network Development projects

Ground-mounted transformer replacement can be instigated by a range of growth-related causes but is most often driven by specific customer requirements through customer-initiated works.

An alternative solution to replacing a transformer for load growth reasons would be to relieve loading by installing an additional transformer. New customer connections, such as new residential subdivisions, are usually underground and the associated distribution transformers are ground-mounted.

19.5 OTHER TYPES OF DISTRIBUTION TRANSFORMERS

19.5.1 FLEET OVERVIEW

Other types of distribution transformers and voltage regulation equipment include conversion and SWER isolation transformers, capacitors and voltage regulators. The population of this sub-fleet is a small part of the distribution transformer portfolio and is quite varied.

Conversion transformers convert between two distribution voltages, as opposed to converting from distribution to LV – for instance, 11kV to 22kV, or 11kV to 6.6kV.

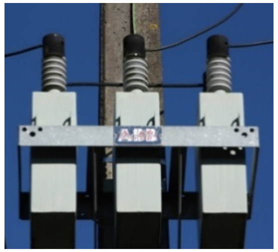
A conversion transformer is like a distribution transformer but is typically of higher capacity and supplies a downstream distribution network. Therefore it has a higher reliability impact than a distribution transformer.

SWER isolating transformers convert from 11kV phase-to-phase to a SWER system at 11kV phase-to-ground. SWER is a cost effective form of reticulation in remote rural areas to supply light loads over long distances. SWER transformers are generally pole-mounted.

Capacitors are used on the distribution network to provide voltage support and reactive compensation where poor power factor exists. Capacitors are generally pole-mounted.

Voltage regulators are typically a pair of single-phase 11kV transformers fitted with controls that are used to adjust (buck or boost) the voltage to load conditions. They are used where the existing reticulation suffers from excessive voltage fluctuation, particularly on long lines where voltage rises with light load and drops with heavier load. Voltage regulators are generally pole-mounted, but we do have some mobile units that can be used to assist in voltage support during distribution backfeed situations.

Figure 19.10: Collection of other distribution transformers


Capacitors


Voltage regulator


SWER isolating transformer

19.5.2 POPULATION AND AGE STATISTICS

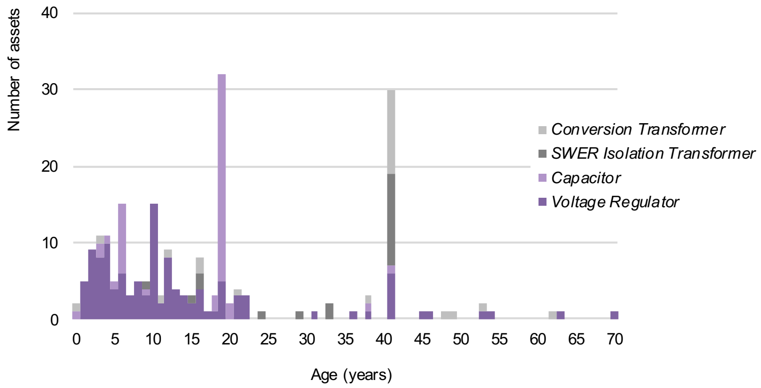
The table below summarises our population of other distribution transformers by type. Voltage regulators make up the largest portion of the fleet. We have been installing these devices during the past 15 years to manage voltage on the network.

Table 19.6: Other distribution transformer population by type

TYPE	NUMBER OF ASSETS	% OF TOTAL
Voltage regulator	119	57
Capacitor	48	23
Conversion transformer	23	11
SWER isolation transformer	20	10
Total	210	

The figure below shows the age profile of our other types of distribution transformers. The population is young, with an average age of 18 years. This is largely because of the recent prevalence of voltage regulators and capacitors. They are used to compensate for undersized and/or long rural lines where load growth has created voltage issues on the network. A small number of assets exceed their expected life of 50 years.

Figure 19.11: Other distribution transformer age profile



19.5.3 CONDITION, PERFORMANCE AND RISKS

These transformers are of similar construction to pole or ground-mounted distribution transformers and, apart from capacitors, their failure modes are similar. Although rare, capacitors can suffer catastrophic failure, which may pose a safety risk to the public. They are therefore maintained more thoroughly than pole-mounted transformers.

Similar to protection relays and Supervisory Control And Data Acquisition (SCADA) Remote Terminal Units (RTU), we expect controllers for voltage regulators will need replacement much earlier than primary equipment.

We maintain an adequate level of spares so that these can be replaced when required.

We have had instances of incorrectly configured regulators failing because of tap-hunting and master/follower mismatches leading to excessive circulating currents. We have standardised our regulator settings to minimise future reoccurrence of this failure mode.

The condition of the fleet is relatively good with no known 'type' issues. We do not anticipate a need for a significant renewals programme.

19.5.4 DESIGN AND CONSTRUCT

We have processes in place that ensure ratings, installation configuration and range of operation are standardised across the fleet.

We use either two (configured two-phase arrangement) or three (configured three-phase arrangement) single-phase voltage regulators banked together to regulate the three-phase distribution network. Voltage regulators are generally configured with ancillary bypass switches and isolator/protection links. Typical ratings are 100A, 150A and 200A nominal capacity.

19.5.5 OPERATE AND MAINTAIN

SWER isolation and conversion transformer maintenance is similar to ground-mounted or pole-mounted transformers. As discussed above, they share physical attributes and failure modes. Voltage regulators, however, contain mechanical switching devices and electronic controls and require a more thorough maintenance regime.

Capacitors are built differently than transformers and have different types of failure modes. They have their own maintenance regime.

Our various preventive maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 19.7: Other distribution transformer preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Capacitors	Thermal imaging scan of connections and leads.	2.5 yearly
	Detailed visual inspection, checking for corrosion, damage, leaks.	5 yearly
	Diagnostic tests, including capacitance measurements, insulation and contact resistance depending on capacitor configuration. Condition assessment of bushings and tank.	10 yearly
Voltage regulators	General visual inspection of voltage regulator and housing, check asset is secure (ground-mounted only).	6 monthly
	Thermal imaging scan.	2.5 yearly
	Inspect tank and general fittings for corrosion. Carry out oil dielectric strength, acidity and moisture testing.	5 yearly
	Winding insulation tests.	15 yearly
SWER and conversion transformers	See pole and ground-mounted distribution transformer maintenance.	

19.5.6 RENEW OR DISPOSE

Our renewal strategy for this fleet is condition-based replacement. Units are generally replaced as part of the defect management process when a significant defect is identified. Some units fail and are immediately replaced to minimise the impact on customers.

SUMMARY OF OTHER DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Age-based
Cost estimation	Historical average unit rates

Renewals forecasting

Our renewals forecast uses age as a proxy for condition. We expect renewals for this fleet to remain approximately constant during the planning period and in line with historical quantities.

Coordination with Network Development projects

There are several alternative solutions for voltage issues, particularly on long rural feeders. It is usually more cost effective to install a voltage regulator than upgrading the overhead line, or to install a Remote Area Power Supply (RAPS) if the line also requires renewal.

As rural businesses, for example the dairy sector, grow and more reactive and voltage support is required, we expect to install more voltage regulators and capacitors on our network.

SWER isolation and conversion transformers are used only in special cases and we do not expect to install many during the planning period.

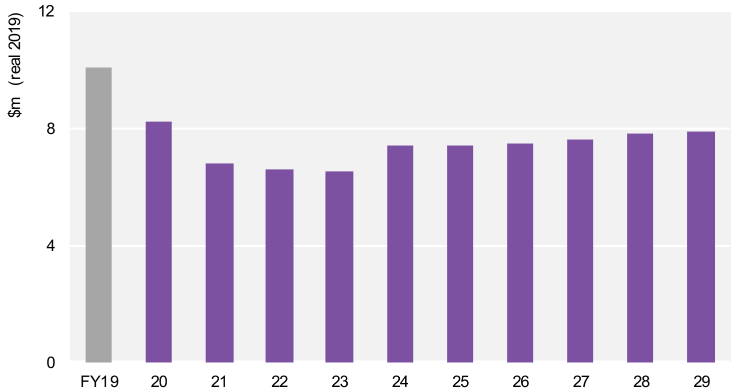
19.6 DISTRIBUTION TRANSFORMERS RENEWALS FORECAST

Renewal Capex in our distribution transformer portfolio includes planned investments in our pole-mounted, ground-mounted and other distribution transformer fleets. During the planning period we plan to invest approximately $74m in distribution transformer renewals

Renewals are derived from bottom-up models. These forecasts are volumetric estimates, which are explained in Chapter 26. The work volumes are relatively high, with the forecasts primarily based on survivorship analysis. We use averaged unit rates based on analysis of equivalent historical costs.

The chart below shows our forecast Capex on distribution transformers during the planning period.

Figure 19.12: Distribution transformer renewal forecast expenditure



Forecast renewal expenditure is generally in line with historical levels. Expenditure in FY19 and FY20 is higher in order to address issues with larger pole-mounted transformers that are not compliant with seismic standards..

20 DISTRIBUTION SWITCHGEAR

20.1 CHAPTER OVERVIEW

This chapter describes our distribution switchgear portfolio and summarises our associated fleet management plan. Distribution switchgear refers to switching equipment generally located externally to zone substations. The portfolio includes four fleets:

- Ground-mounted switchgear, typically ring main units (RMUs)
- Pole-mounted fuses
- Pole-mounted switches
- Circuit breakers, reclosers and sectionalisers

The chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we plan to invest $87m in distribution switchgear renewal. This accounts for 10% of renewals Capex during the period. This includes a substantial programme during the period FY2020-27 to renew circuit breakers at the Kinleith pulp and paper mill.

Increased investment will support our safety and reliability objectives. Renewal Capex is driven by the need to:

– Replace certain types of oil switchgear. Some models of oil switchgear have the potential to fail explosively, require more intensive maintenance, carry environmental risks, and many have exceeded their expected life.

– Address performance issues and deteriorating condition. Several renewal programmes target specific assets for which an issue has been identified, while others deal with general asset deterioration across the four fleets. For example, asset health modelling of our circuit breaker population indicates the fleet is in poor health.

– Manage public safety risk and ensure legislative compliance associated with unauthorised public access to our ground-mounted transformers through replacement of non-standard, ageing or damaged padlocks.

Below we set out the Asset Management Objectives that guide our approach to managing our distribution switchgear fleets.

20.2 DISTRIBUTION SWITCHGEAR OBJECTIVES

The distribution switchgear portfolio contains a diverse population of assets with a wide range of types and manufacturers. Switchgear technology has evolved over time, with generally improving safety and reliability, and reductions in routine maintenance requirements.

Oil switchgear is no longer used for new installations because of a high lifecycle cost of intrusive maintenance, higher operator and public safety risk compared with modern designs, and some environmental risk in the event of an oil spill.

Because of the age of the network we still have large quantities of oil-based switchgear – around 50% of the ground-mounted switchgear fleet is oil-based.

We mitigate risks through routine maintenance, condition monitoring, operating procedures and, where necessary, operating restrictions. Where they are available, we also require the use of remote switching or portable actuators to reduce the likelihood of operator injury.

To guide our asset management activities, we have defined portfolio objectives for our distribution switchgear fleets. These are listed in Table 20.1. The objectives are linked to our Asset Management Objectives as set out in Chapter 5.

Table 20.1: Distribution switchgear portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No injuries or incidents from explosive failure or maloperation of switchgear. No significant oil or SF_6 (sulphur hexafluoride) leaks from distribution switchgear assets.
Customers and Community	Minimise interruptions to customers through equipment failure or maloperation. Ensure that switchgear is available to be used as intended, providing the required network flexibility to minimise customer interruptions during network switching and to facilitate rapid restoration of outages.
Networks for Today and Tomorrow	Increase use of remote switching to further improve fault isolation and restoration times for customers. Continue to evaluate new technology for general or specific use on the network with a view to improving network operation and safety and managing lifecycle cost.
Asset Stewardship	Ensure that fleets are safe to operate and do not place the community at risk. Reduce fleet diversity over time to optimise asset whole-of-life costs and improve safety and reliability by reducing human factor related problems.
Operational Excellence	Complete development of criticality frameworks for distribution switchgear.

20.3 GROUND-MOUNTED SWITCHGEAR

20.3.1 FLEET OVERVIEW

Ground-mounted switchgear provides distribution network isolation, protection and switching facilities. Ground-mounted switchgear includes RMUs, switches, fuse switches, links and associated enclosures. In general, ground-mounted switchgear is associated with our underground network, although some supports overhead sections.

The fleet comprises a range of makes and models with various insulating media associated with the technology at the time of purchase. During the past five years we have predominantly installed SF_6, but historically we have used oil-filled and cast resin switchgear.

Figure 20.1: Ground-mounted switchgear

20.3.2 POPULATION AND AGE STATISTICS

Table 20.2 shows our population of ground-mounted switchgear by configurations and insulating media.

There is significant diversity within this fleet because of the age profile and historical predecessor companies, with more than 20 manufacturers represented.

This diversity increases maintenance costs, the amount of training required for field personnel, and has the potential to affect safety as field personnel are less familiar with each model, which increases the likelihood of errors.

Our replacement strategies include removal of older and less represented models from the fleet to assist operators and maintainers.

Table 20.2: Ground-mounted switchgear population by type

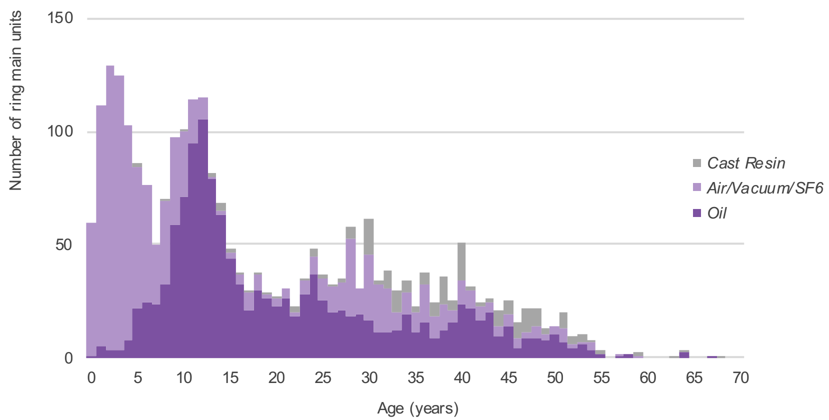
INSULATION TYPE	NUMBER OF RING MAIN UNITS	NUMBER OF INDIVIDUAL SWITCH UNITS
Cast resin	185	8
Air/Vacuum/ SF_6	1,119	114
Oil	1,287	320
Total	2,591	442

Meeting our portfolio objectives

Asset Stewardship: Asset replacement over time will remove older oil and cast resin insulated types, replacing them with safer, lower maintenance modern types. Our replacement programme will also reduce diversity in the ground-mounted switchgear fleet, helping us to manage whole-of-life costs and reduce the incidence of operator-induced errors.

Figure 20.2 shows the age profile of our population of RMUs.

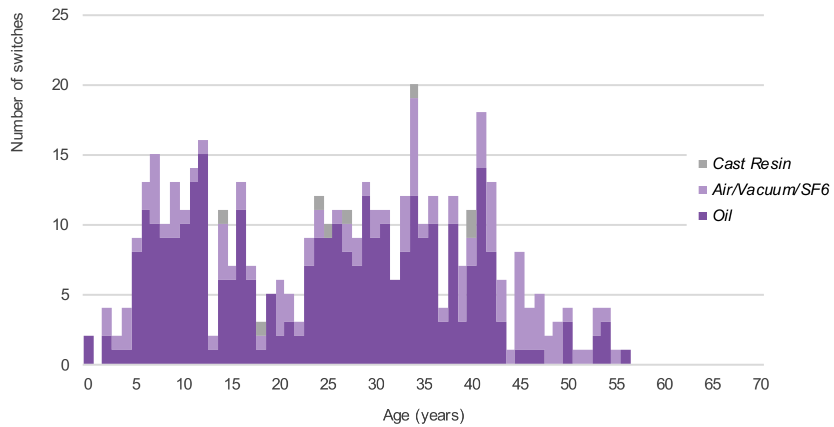
Figure 20.2: RMU age profile



We now install predominantly SF_6 RMUs for improved safety and reduced maintenance requirements compared with older types. We recently approved an SF_6-free cast resin/vacuum device for use on the network (in an approved enclosure), which we have begun installing.

Figure 20.3 shows the age profile of our population of individual ground-mounted switches. These assets are generally older than the RMUs because of past design practices, and they have a much greater level of manufacturer diversity.

Figure 20.3: Individual switch age profile



Many units exceed their expected life of approximately 45 years. We expect an increasing amount of renewals in this area, noting that renewal decisions are based on asset condition and risk.

20.3.3 CONDITION, PERFORMANCE AND RISKS

While in generally good condition, the age of distribution switchgear and the potentially hazardous consequences of failure requires that potential failure modes are understood and appropriately mitigated. Details of potential issues and mitigation measures for each general type are discussed below.

Cast resin switchgear

Cast resin switchgear performs satisfactorily if located in dust-free, dry environments and regularly maintained. If installed in cubicles without heating or in a dusty environment, surface condensation results in electrical tracking and degradation. This issue is prevalent in fog prone areas such as Taranaki, Thames Valley and Waikato.

Condition data for the cast resin switchgear located in the Taranaki region suggests that a significant proportion will require replacement within 10 years, likely reflecting faster degradation in that location.

The design of cast resin switchgear also creates issues because of the way each phase is switched individually. This results in operational constraints when transferring load and presents a potential safety issue for operators. Replacing cast resin switchgear with other switchgear is costly and difficult because alternative switchgear tends to have a larger footprint requiring extensive modification to the substation site. Wholesale removal of the entire population is not necessary at this time, but we expect more intensive condition monitoring and increasing condition-based replacements will be required as the fleet ages.

Oil switchgear

Oil switchgear, if not maintained properly, can fail explosively with fatal consequences to the operator and others in close proximity. To address this risk, we have imposed operating restrictions on certain models of oil switchgear. They should not be switched while live and, if this is not possible, must be switched remotely. We are also reviewing our maintenance practices to ensure they are consistent with international good practice and adequately mitigate risk.

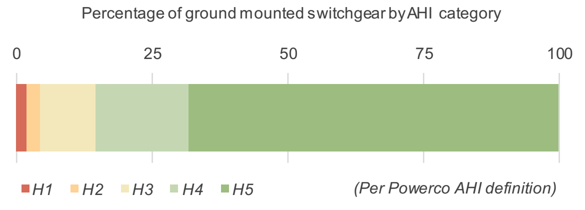
Because of age and obsolescence, most models of oil switchgear are no longer supported by manufacturers. Many have extensive maintenance requirements relative to their modern equivalent asset. It is our long-term intention to phase out oil insulated switchgear units, replacing them with modern low maintenance types with improved operator safety features.

Ground-mounted switchgear asset health

As outlined in Chapter 7, we have developed AHIs that reflect the remaining life of each asset. Our AHI models categorise each asset's health based on a set of rules allowing the prediction of end-of-life.

For ground-mounted switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely. The AHI is based on multiple data sources, including asset age, environmental situation, condition, historical performance and known type issues. Figure 20.4 shows current overall AHI for our ground-mounted switchgear fleet.

Figure 20.4: Ground-mounted switchgear asset health as at 2019



A small proportion of the fleet is assigned health grades of H1 and H2. This is primarily comprised of older oil switchgear, which we are planning to replace. There are also a small number of units for which our asset data is incomplete and for which we cannot calculate an AHI. We intend to address these data problems within the next year.

Locks and keys

There are risks associated with the legacy padlocking systems used to protect our ground-mounted switchgear from unauthorised access.[93] To manage these risks we have a programme to replace all locks and keys with standardised, high security types.

20.3.4 DESIGN AND CONSTRUCT

Ground-mounted distribution switchgear is classified as class A equipment[94] and any new equipment undergoes a detailed evaluation process to ensure it is fit for purpose on our network.

Given the safety risk that switchgear failure presents to both operators and the public, new switchgear is required to be rated for either class A or class B internal arc flash containment (IAC).

IAC class B is equipment that is accessible by the public, and IAC class A is equipment in Powerco-controlled locations accessible only by authorised personnel wearing appropriate personal protective equipment (PPE).

IAC-rated switches and enclosures have been type tested to ensure that in the event of internal failure, arc flash heat and blast energies are diverted or dissipated to such a level that any people near the switch are safe.

New installed switchgear is specified to enable future automation and remote operation capability. Remote operation reduces switching/restoration times and provides greater safety for operators. As remote operation may allow equipment to be operated without an observer, to ensure the area around the switch is clear from members of the public, this type of automation is only applied to new installations with enclosures that are designed with full arc flash containment.

Major SF_6 user

SF_6 is classified as a greenhouse gas, so our SF_6 switchgear requires environmental management. We are now classified as a major user under the ETS as our SF_6 holdings have recently increased to more than 1,000 kg. Requirements of major users include having in place an auditable reporting regime that records SF_6 transactions and holdings. We have implemented systems that meet these requirements.

We are endeavouring to limit new SF_6 usage to only applications without a viable alternative, thereby minimising our environmental impact. Additionally, we are minimising usage because the by-products of SF_6 formed during electrical arcing are toxic, requiring specialist handling in the event of an internal switchgear fault.

93 For more detail refer to the same section in the ground-mounted transformers fleet within Chapter 19.
94 Refer to Chapter 7 for more information on our asset specification and approval processes.

As we now predominantly install SF_6-based RMUs, our SF_6 holdings across all assets has risen to more than 1,000kg. We are now classed as a major user under the Emissions Trading Scheme (ETS) and are required to have in place an auditable reporting regime that records our SF_6 transactions.

To minimise our SF_6 holdings and the potential for harm to the environment, we have recently approved a vacuum circuit breaker-based RMU for indoor use. We expect to adopt this also for outdoor use once a suitable enclosure has been approved.

20.3.5 OPERATE AND MAINTAIN

Regular inspection and maintenance of our ground-mounted switchgear is required to ensure the safe operation of our distribution network. As this switchgear is often located in areas accessible to the public, it is vital the enclosures are always locked and secure.

Our various preventive maintenance tasks are summarised in Table 20.3. The detailed regime is set out in our maintenance standards.

Table 20.3: Ground-mounted switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General inspection of switchgear buildings/enclosures.	6 monthly
General inspection of switchgear condition. Partial discharge and acoustic diagnostic tests.	Yearly
Switchgear service and operating checks. Diagnostic thermal scan.	5 yearly
Oil sample test for oil switchgear.	10 yearly

Maintenance requirements have been determined from manufacturers' recommendations, combined with our experience in maintaining and operating each asset type within our local operating environments. The six-monthly and yearly inspections are non-invasive, whereas the five-yearly service requires an outage on the switchgear, carrying System Average Interruption Duration Index (SAIDI) implications.

Switchgear components degrade over time and with the number of individual operations they perform. Older-style oil switchgear requires more maintenance than SF_6 or vacuum gear. Switchgear is generally berm-mounted and therefore exposed to damage from vehicles. We minimise the incidence of damage by carefully choosing the location of switchgear and, in some cases, by installing protective bollards.

Corrective actions for switchgear include:

- Routine servicing and post fault servicing – oil change, contact alignment and dressing.
- Levelling of switchgear – particularly important for oil switchgear, where changing ground conditions have caused misalignment.
- Fuse replacement (fused switch units) after a fault.

We have recently undertaken an independent review of our maintenance practices for oil-insulated ground-mounted switches. The intent of this review was to compare our practices with international good practice and identify any gaps or improvement opportunities. This is covered off in more detail in the box below.

Ground-mounted switch management – independent review

In March 2018 we engaged an independent consultant to review our operation and maintenance practices, including standards and procedures as well as the capability of our field service providers. The intention of this review was to evaluate our management of the fleet compared with industry good practice. The review identified improvement opportunities for which we are developing implementation plans.

20.3.6 RENEW OR DISPOSE

Renewal plans for ground-mounted distribution switchgear are now developed using our condition-based risk management (CBRM) models.

Renewal decisions are made on a risk prioritised basis combining both the condition and likelihood of failure with the consequences of failure, considering safety, customer service, lifecycle costs and the environment.

This approach prioritises expenditure towards equipment with the highest combined likelihood and consequences of failure, predominantly older oil types situated in publicly accessible areas.

SUMMARY OF GROUND-MOUNTED SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	Proactive condition-based with safety risk
Forecasting approach	Type issues and age
Cost estimation	Volumetric average historical rate

Renewals forecasting

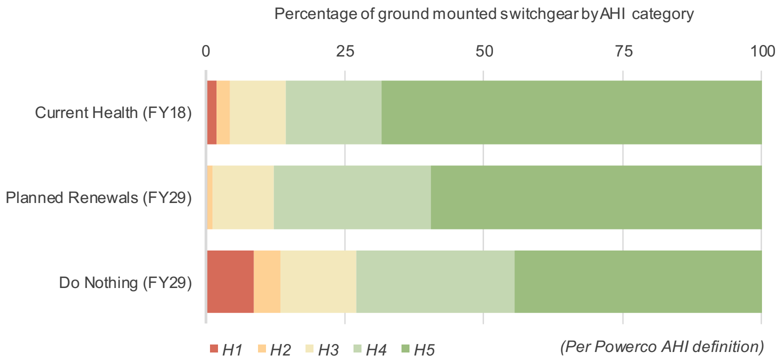
Our CBRM models also allow us to develop forecasts of asset health and risk to determine our future renewal requirements.

Figure 20.5 compares asset health at 2018 against that projected for 2029, following planned renewals (targeted intervention), and a counter-factual do-nothing scenario.

This illustrates the benefits provided by our investment with regards to the fleet asset health profile.

Our planned investment will address existing assets identified as being in poor health, as well as maintaining the overall fleet health profile to acceptable levels.

Figure 20.5: Projected ground-mounted switchgear asset health at 2029



As discussed previously in the condition, performance and risks section, replacement of many of the locks securing our ground-mounted switchgear is required. Our forecast allows for replacement of locks and keys that have not already been replaced with the standardised, high security units during the five-year period FY19-23.

Coordination with network development projects

When existing ground-mounted switchgear is replaced, we use modern equivalent SF_6 or vacuum type RMUs because they have lower ongoing maintenance requirements and have modern safety features.

In urban areas, new distribution substations typically use ground-mounted switchgear to minimise visual impact to the surrounding neighbourhood.

Where possible, we coordinate ground-mounted switchgear replacements with underground cable network or ground-mounted distribution transformer renewals.

This is more efficient and causes less disruption to customers and the community. New switches are procured with remote operation capability so, if required, this capability can be enabled to implement network automation schemes.

20.4 POLE-MOUNTED FUSES

20.4.1 FLEET OVERVIEW

Pole-mounted fuses provide protection and isolation for distribution transformers and, in rural areas, fault isolation for tee-offs supplying low customer density spur lines or cables.

Pole-mounted fuses are non-ganged, single pole devices that are mechanically simple, using mature and proven technology. Some early fuse types, however, are susceptible to corrosion, have insufficient clearance to meet standards for minimum approach distances, and may be susceptible to stress-cracking of insulators. Later and current models have addressed these issues.

Models with noted corrosion and compliance issues have largely been replaced. Models prone to cracking are replaced based on condition.

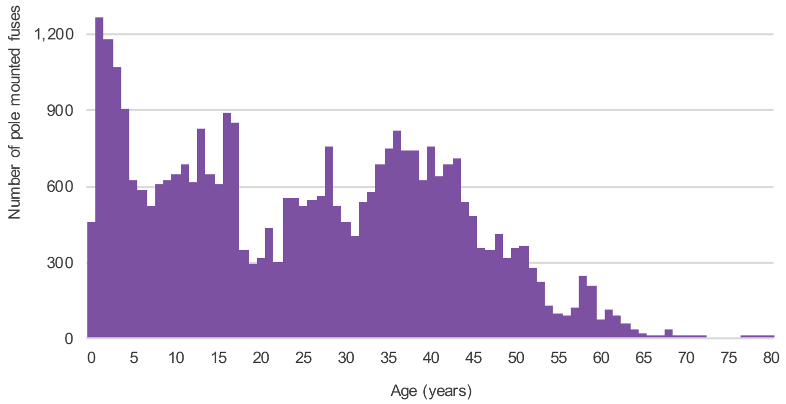
Figure 20.6: Pole-mounted drop out fuse

20.4.2 POPULATION AND AGE STATISTICS

The population of our pole-mounted fuse fleet is approximately 33,000. Many manufacturers are represented, but equipment is all very similar in design and function.

Figure 20.7 shows the age profile of our population of pole-mounted fuses.

Figure 20.7: Pole-mounted fuses age profile



The age profile indicates that a substantial portion of the fleet is older than a nominal asset life of 40 years, suggesting a need for continuing renewal expenditure. The profile also indicates a substantial number of assets less than five years of age, which is the result of new assets and recent renewal expenditure.

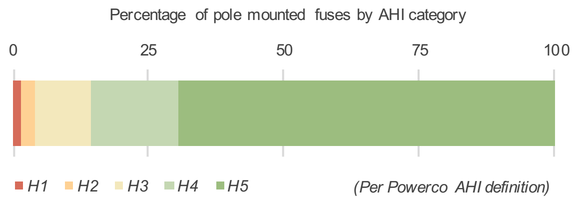
20.4.3 CONDITION, PERFORMANCE AND RISKS

Pole-mounted fuses asset health

As outlined in Chapter 7, we have developed AHIs that represent the remaining life of each asset. Our AHI models categorise asset health based on defined rules. For pole-mounted fuses our AHI is calculated using the combination of age profiles and survivor curves.

Figure 20.8 shows current AHI for our population of pole-mounted fuses.

Figure 20.8: Pole-mounted fuses asset health as at 2018



The AHI profile indicates that the fleet is broadly in good condition with approximately 10-15% likely to require renewal during the next 10 years (H1-H3). The AHI profile also shows some fuses require renewal in the short term (H1). These will be identified and rectified through our condition assessment and defect processes.

Risks

Certain types of pole-mounted fuses present fire risks when installed in dry areas as they can potentially cause sparks should the fuse operate. In the near term, we aim to prioritise the renewal of these fuses in areas of fire risk.

20.4.4 DESIGN AND CONSTRUCT

Fuse selection is based on the specific protection and operating needs of the network. When a distribution line is renewed, fuses supplying spur lines may be replaced with more effective devices, such as reclosers or sectionalisers to enhance network operability and reliability.

The fuses used on our network must comply with industry standards. Before a new type of fuse can be used on the network it must be evaluated to ensure the equipment is fit for purpose.

20.4.5 OPERATE AND MAINTAIN

Our pole-mounted fuse fleet is inspected as part of our overhead line inspections, which check for damage, corrosion, and deterioration. Any remedial work is managed via our defect process. The inspection task and frequency is summarised in table 20.4. The detailed regime is set out in our maintenance standard.

Table 20.4: Pole-mounted fuse preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection for corrosion and defects.	5 yearly

20.4.6 RENEW OR DISPOSE

Our renewal strategy for pole-mounted fuses is based on a combination of observed condition and known type issues. If an inspection identifies a defect, the fuse is scheduled for renewal as part of the defect management process. Alternatively, we may target the renewal of know problematic types or types nearing end-of-life during network renewal projects. Some fuses are replaced reactively after a fuse link operation because of their poor condition.

The consequences of failure are minor, and replacement can be carried out quickly. We also proactively replace ageing fuses as part of our overall pole replacement programme.

SUMMARY OF POLE-MOUNTED FUSES RENEWALS APPROACH	
Renewal trigger	Reactive and condition based
Forecasting approach	Survivor curve
Cost estimation	Volumetric average historical rate

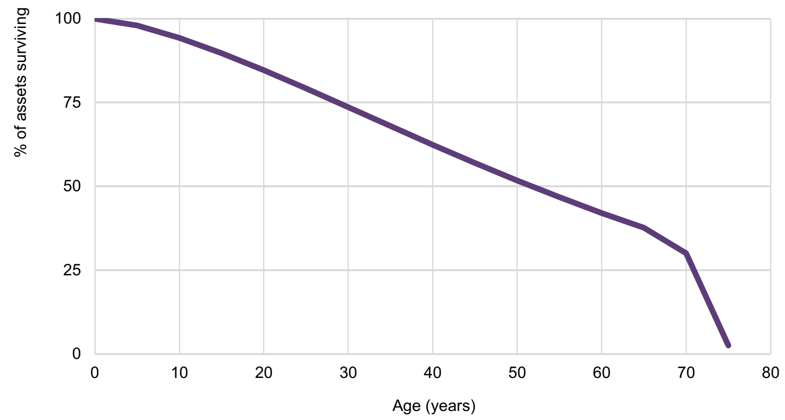
Renewals forecasting

Our pole-mounted fuse replacement quantity forecast is based on survivorship analysis using survivor curves developed from historical replacement data.

During the past 10 years we have collected detailed information on the fuse disposals and failure modes. Our survivor analysis reveals that fuse replacement age varies, primarily because of location and inherent durability. Our forecasting approach incorporating a survivor curve is therefore more robust than an age-based approach that purely relies on standard asset lives.

Figure 20.9 shows the pole-mounted fuse survivor curve. The curve indicates the percentage of population remaining at a given age.

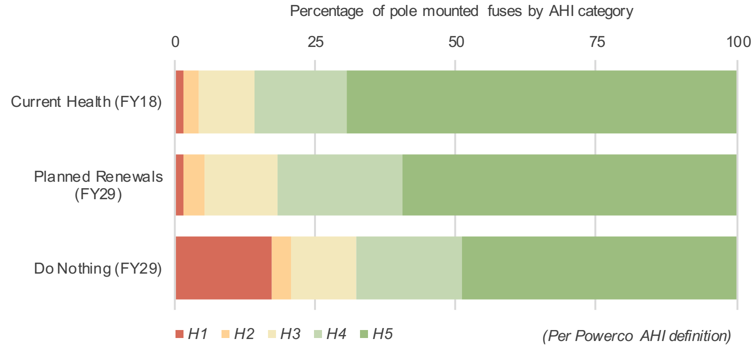
Figure 20.9: Pole-mounted fuse survivor curve



Because of the age profile (Figure 20.7) and the above curve, we expect annual pole-mounted fuse renewals to remain relatively constant during the planning period. As we inspect and replace further fuses we will use this data to refine our modelling.

Figure 20.10 compares projected asset health in 2029, following planned renewals, with a counter-factual do-nothing scenario. Comparing the do-nothing scenario with the planned renewals gives an indication of the benefit provided by the proposed investments.

Figure 20.10: Projected pole-mounted fuse asset health as at 2029



Coordination with network development projects
Before renewing a network fuse, we review the ongoing need for equipment in that position. This review may find that a fuse should be upgraded to a recloser, installed elsewhere, or retired.

We are progressively introducing fuse-savers – an electronically controlled, single-phase fault interrupting device. Fuse-savers are designed to be partnered with a fuse on a spur distribution line to provide a one-shot attempt to clear a downstream transient fault. The partnered fuse is protected from intermittent transient faults and will rupture if the fault is permanent.

The main application of a fuse-saver is the protection of fused rural or remote rural distribution spur lines that have a history of transient faults. If the initial rollout proves successful, these will allow us to improve network performance for these spur lines and reduce costs related to fuse callouts.

When fuse assemblies require end-of-life replacement, where possible we coordinate this work with overhead line reconstruction projects to minimise costs.

20.5 POLE-MOUNTED SWITCHES

20.5.1 FLEET OVERVIEW

The pole-mounted switch fleet comprises Air Break Switches (ABS), vacuum insulated isolators and SF_6 gas insulated isolators.

Air break switches (ABS)
ABS are typically three-phase, ganged manual switches that can be operated using a handle mounted at ground level. They are used for network configuration, including sectionalising feeders to find and isolate faults, as open points between feeders, and for allowing worker access to the network for maintenance or construction works.

Because of the exposed nature of their mechanisms, these switches require regular maintenance to ensure they operate correctly.

A standard ABS has limited capacity to break load current. It is usually opened for sectionalising while the line is de-energised. Load break capability can be added to the standard switch to improve its load breaking capability, but this is still limited to relatively light loads.

ABS have undergone various design and material specification improvements over time. Newer types have improved alignment, which has reduced maintenance requirements and operating issues, and have better corrosion performance.

We continue to install ABS in applications where remote-control capability is not essential and load break capability is not required. However, as the technology matures we expect to eventually stop installing new ABS and transition to either enclosed SF_6 or vacuum switches.

Vacuum and SF_6
Vacuum or SF_6 insulated switches are modern equivalents of ABS that have been used where remote control is required, and where high load currents need to be switched.

They are considered safer and more reliable to operate when compared with an ABS because, firstly, the mechanisms are enclosed leading to a much lower maintenance requirement than traditional ABS and, secondly, contact separation speed is assisted by use of springs and is not operator dependent.

There have been some early issues because of mounting design and tank corrosion, but this is expected to be resolved in the longer term. Our fleet of vacuum and SF_6 switches is relatively young. They can be specified with motorised operation and full automation capabilities.

Figure 20.11: Air break switch (ABS)

20.5.2 POPULATION AND AGE STATISTICS

We have approximately 5,000 pole-mounted switches on our network. There is significant diversity in our ABS fleet with many manufacturers represented. The diversity increases the costs of maintaining equipment, the amount of training required for field personnel, and the safety risks they face because they are less familiar with each model.

Table 20.5 summarises our population of pole-mounted switches by type.

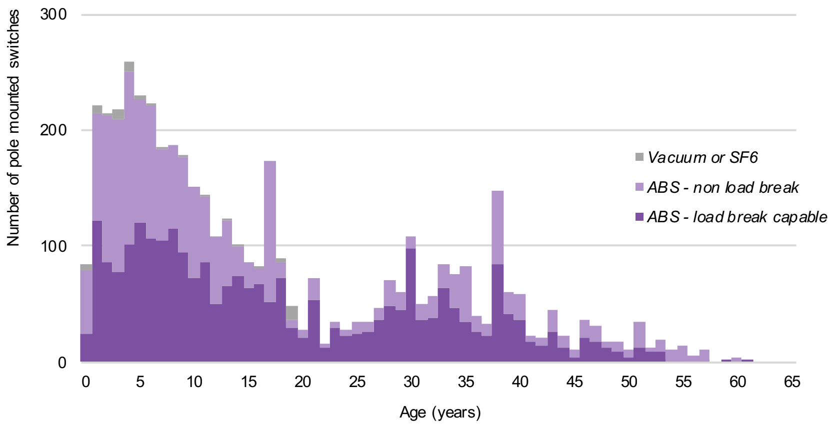
Table 20.5: Pole-mounted switch population by type

TYPE	NUMBER OF ASSETS	% OF TOTAL
ABS – non load break	2,254	44
ABS – load break capable	2,769	54
Vacuum or SF_6	59	1
Total	5,082	

As we have only recently started installing vacuum and SF_6-based switches, the number in use is small – approximately 1% of the fleet population. As ABS are replaced with vacuum or SF_6 switches, their share will grow.

Figure 20.12 shows our pole-mounted switch age profile. Only a small proportion of pole-mounted switches exceed their nominal 45-year expected life.

Figure 20.12: Pole-mounted switch age profile



We have undertaken significant ABS renewal to replace poor condition switches and those with insufficient maintenance, in part because of the difficulty in obtaining shutdowns. This is reflected in the large number of younger ABS on the network.

20.5.3 CONDITION, PERFORMANCE AND RISKS

Risks

Pole-mounted switches have several known performance issues. Operating a defective ABS can cause failure, resulting in a flashover. Standard operating practice is to check the switch as thoroughly as practicable before operating. Operators are required to wear PPE.

The design of older ABS is such that faults can result in contacts welding together. Older designs can also cause corrosion or rupturing of flexible jumpers. This failure mode does not present significant safety risk and is addressed either reactively or through routine maintenance.

Another issue relates to operating mechanisms that tend to seize up when switches are not operated. This is addressed through our maintenance regime, which specifies periodic operation of switches, coupled with scheduled maintenance.

Some older quadrant wire switch types, used in the Thames Valley and Tauranga areas, can have their operating wires deteriorate and break during operation, making the switch inoperable.

In the worst case, this can leave the switch in a partially open state, leading to switching delays and larger outage areas. These are being included in replacement plans when located.

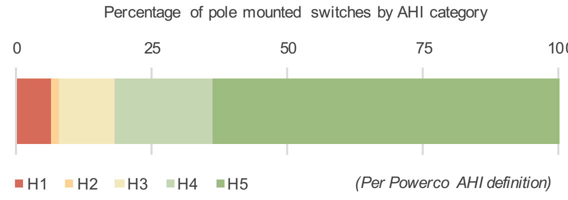
We have some installations where distribution ABS were installed underneath sub-transmission overhead lines. During load breaking operation of the switch, there is a risk that arcing during operation could lead to flashover to the circuits above, leading to explosive switch failure and loss of supply. We are in the process of identifying high-risk sites that we will programme for replacement with enclosed switches.

Pole-mounted switches asset health

As outlined in Chapter 7, we have developed AHIs that reflect the remaining life of an asset. Our AHI models categorise asset health based on a set of rules. For pole-mounted switches, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switch should be replaced. The AHI is primarily calculated using asset age and typical expected life.

Figure 20.13 shows current overall AHI for pole-mounted switch fleet.

Figure 20.13: Pole-mounted switches asset health as at 2018



The figure indicates that about 18% of our fleet will require renewal in the next 10 years (H1-H3). About 7% of pole-mounted switches have already exceeded their expected life and likely require replacement (H1) in the near term.

Locks and keys

There are risks associated with the legacy padlocking systems used to protect our pole-mounted switchgear from unauthorised access.[95] To manage these risks we will replace all locks and keys that have not already been replaced with the standardised, high security units.

20.5.4 DESIGN AND CONSTRUCT

In addition to replacements with modern flicker-style ABS, we have started introducing vacuum and SF_6 switches in corrosion-prone areas in place of standard ABS. If these perform well, we will adopt sealed SF_6 or vacuum pole-mounted switch types for most switch replacements. This change in approach will be phased in during the next five years. This will allow for further trials and for personnel training for updated operating procedures.

Even when specified for manual operation only, there are considerable benefits to SF_6 or vacuum pole-mounted switchgear. Only periodic visual inspections are required compared with the more intensive servicing of ABS. The increase of SF_6 volumes on the network needs to be monitored because of the environmental risk.

A manually operated SF_6 or vacuum switch costs approximately the same as an ABS to purchase and install, although its lifecycle costs are considerably less. Fully automated versions cost more but provide remote switching benefits. When renewing an ABS, we will consider these additional benefits and select the best configuration for its function on the network. We are also trialling other modern switch types.

[95] For more detail refer to the same section in the ground-mounted transformers section of this chapter.

20.5.5 OPERATE AND MAINTAIN

Our ABS maintenance regimes differ depending on the location of the switch and the load it is serving. Switches in built-up areas undergo more frequent inspections and servicing compared with rural switches. Our preventive maintenance tasks for this fleet are summarised in Table 20.6. The detailed regime is set out in our maintenance standards.

Table 20.6: Pole-mounted switch preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
ABS – built up area	Operation and major maintenance of contacts, pantographs, mechanisms. Contacts and jumpers thermal scan. (Both tasks done 5 yearly, but alternate 2.5 years apart).	5 yearly
ABS – rural area	Visual inspections of contacts, pantographs. Inspect, lubricate and operate switch.	5 yearly
	Operation and major maintenance of contacts, pantographs, mechanisms.	10 yearly
Vacuum and SF_6	External visual inspection and thermal scan.	5 yearly

20.5.6 RENEW OR DISPOSE

Our renewal strategy for pole-mounted switches is condition-based replacement. Switches with identified defects are scheduled for replacement as part of the defect management process.

We are also collecting data on some poor performing types of ABS, such as the quadrant-wire models, which we will incorporate into our renewal plans. Should a switch fail, it is replaced immediately on a like-for-like basis to minimise the impact on customers.

SUMMARY OF POLE-MOUNTED SWITCHES RENEWALS APPROACH	
Renewal trigger	Proactive condition-based and type issues
Forecasting approach	Age
Cost estimation	Volumetric average historical rate

In reviewing our approach to this fleet, we have considered potential areas of improvement to allow us to better ascertain switch condition. We are trialling alternative inspection methods, including acoustic testing and high-resolution aerial photography to improve data quality. In addition, better implementation of our inspection procedures via training of field personnel is expected to improve the quality of incoming information.

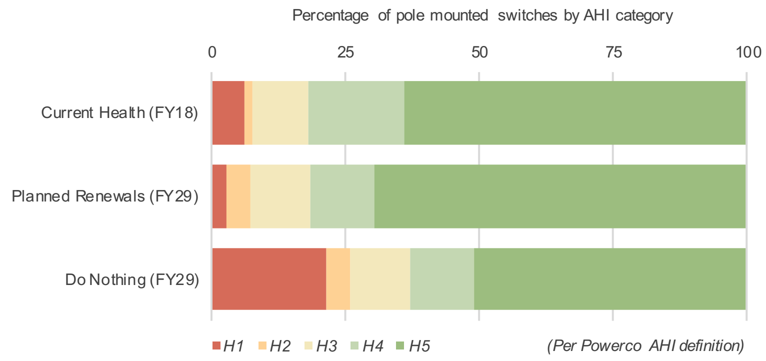
Renewals forecasting

Our renewals forecast uses age as a proxy for condition. ABS are relatively simple mechanical devices that are exposed to the elements, and therefore their condition worsens over time through corrosion and mechanical wear.

We expect annual renewal expenditure for pole-mounted switches to remain approximately constant during the planning period.

Figure 20.14 compares current asset health with projected asset health in 2029, following planned renewals, and a counter-factual do-nothing scenario. Comparing the planned renewal profile with the do-nothing profile provides an indication of the impact our renewal investments will have during the period. Our planned renewal programme will result in an overall reduction in the number of poor condition switches compared with the current health profile.

Figure 20.14: Projected pole-mounted switches asset health as at 2029



As discussed previously (condition, performance and risks section), replacement of many of the locks securing our pole-mounted switchgear is required Our forecast allows full replacement of all locks and keys that have not already been replaced with the standardised, high security units during the five-year period FY19-23.

Coordination with network development projects

Before renewing a pole-mounted switch, we review the ongoing need for the equipment in that position.

Where feasible, we coordinate pole-mounted switch replacements with overhead line reconstruction projects. This allows for more efficient delivery and minimises costs. We also take the opportunity to replace these switches with automation-capable devices where this aligns with the automation plan for the network.

20.6 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

20.6.1 FLEET OVERVIEW

Circuit breakers, reclosers and sectionalisers are used when distribution switchgear needs to fulfil a protection function, such as the isolation of network faults. This type of switchgear often includes controllers that can be programmed for distribution automation schemes.

Circuit breakers

Circuit breakers, in the context of this fleet, are associated with distribution substations.[96] Circuit breakers are not widely used on the distribution network but are typically installed within major customer facilities. Of note is the Oji Fibre Solutions site at Kinleith, which houses 26 switchboards.

Circuit breakers at major customer sites take on a similar function to those located in a zone substation. They provide isolation of faults on downstream circuits and equipment, and allow for access to the customer network for maintenance and construction works. We operate three types of circuit breakers – oil, SF_6 and vacuum.

Reclosers

Reclosers are pole-mounted devices with on-board protection capability. They are designed to detect downstream faults and isolate the faulted part of the circuit before the upstream supply circuit breaker reacts. This reduces the area affected by a fault. They can also be set to be more sensitive to downstream earth faults than feeder CB protection, which improves safety.

The term recloser refers to the device's ability to attempt to automatically restore supply for transient faults. It will 'reclose' on the faulted section to automatically restore supply if the fault has self-cleared. The objective is to clear transient faults caused by tree branches, vermin or windblown debris and avoid lengthy outages.

96 Zone substation circuit breakers are discussed in Chapter 18.

Figure 20.15: A pole-mounted sectionaliser

A recloser at the boundary between an urban area and outer rural sections protects the higher density urban portions of feeders from the higher fault rate typical of rural sections.

Technology of these devices has undergone a great deal of change over time. Most of the advances relate to the electronic control functionality, which now has greater capability to support distribution automation. The electronic controls require management of firmware and settings, and the control equipment will likely require replacement before the switchgear itself.

Sectionalisers

Sectionalisers are like reclosers. They are generally pole-mounted with limited, simpler control equipment. A sectionaliser differs from a recloser in that it does not have the capability to interrupt fault current. It opens after the upstream circuit breaker or recloser has reacted to the fault. It then isolates the downstream portion of the feeder during the brief period when the feeder is de-energised. The upstream device then recloses to restore supply to the upstream portion.

20.6.2 POPULATION AND AGE STATISTICS

Table 20.7 summarises our populations of circuit breakers, reclosers and sectionalisers, split by interrupter type. This split is important because oil-based interrupters have higher safety risks. In addition, older recloser types have limited protection functionality, reducing their flexibility.

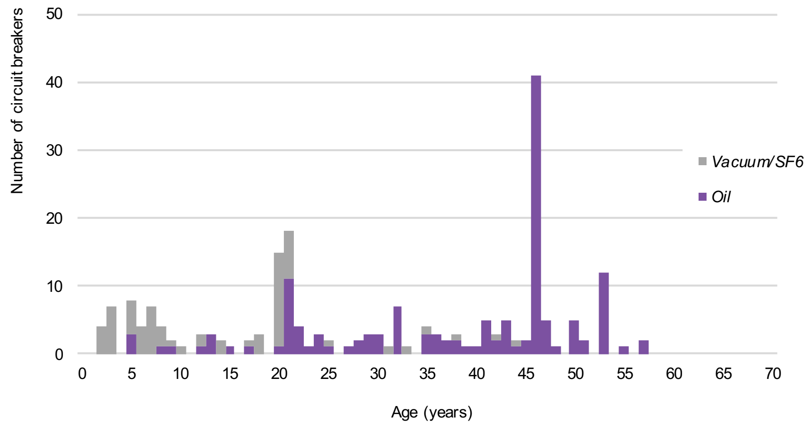
Approximately 70% of the circuit breaker fleet is oil-based, almost half of which is located at a single customer site at Kinleith.

Table 20.7: Circuit breakers, reclosers and sectionalisers population by type

TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Circuit breakers	Oil	145	20
	SF_6/vacuum	66	9
Reclosers	Oil	5	1
	SF_6/vacuum	340	48
Sectionalisers	Oil	9	1
	SF_6/vacuum	147	21
Total		712	

Figure 20.16 shows our circuit breaker age profile. Our circuit breakers are ageing, with a large number close to or exceeding an expected life of 45 years.

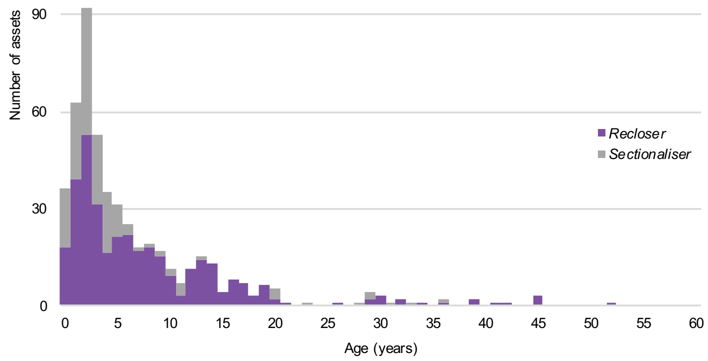
Figure 20.16: Circuit breaker age profile



Older assets in the age profile are mostly the oil-filled circuit breakers at the Kinleith site. A planned replacement programme at that site from 2020-2027 will remove many of these. Oil-filled circuit breakers are no longer purchased. All new circuit breakers are SF_6 or vacuum types.

In contrast, our reclosers and sectionalisers are newer and many have been installed in the past 10 years as part of our automation programmes, we have been installing larger amounts of these devices to reduce the size of outage areas under fault scenarios. This fleet is therefore expected to require little renewal during the planning period. In the longer term we expect replacement requirements to increase as the fleet ages and controllers require replacement.

Figure 20.17: Recloser and sectionaliser age profile



20.6.3 CONDITION, PERFORMANCE AND RISKS

Oil type circuit breakers present risks, including safety and loss of supply from explosion, fire, arc flash and oil spills. The safety and of loss of supply risks are significant at the Kinleith site because of the importance of the load, and the potential for non-Powerco authorised people to enter switchrooms with shared facilities not controlled by Powerco, such as LV reticulation, and other services.

The 11kV fault levels at Kinleith are some of the highest on our network, although a future Transpower neutral earthing resistor (NER) will reduce this. This, coupled with the deteriorating circuit breaker asset health, and the longer protection operating times prevalent at the site, presents a high arc flash safety risk.

Some of the oil type circuit breakers are manually operated. This is considered unsafe especially given arc flash risk. Some switches have interlocked circuit earthing facilities for which we do not have information regarding the fault rating. We have prioritised these circuit breakers for replacement.

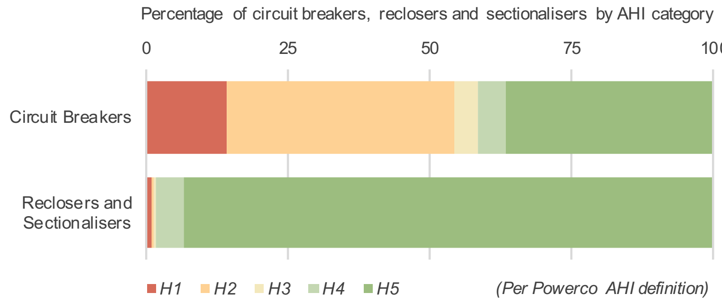
Our older recloser types, such as early KFEs or OYTs in our Wairarapa area, do not provide the functionality or visibility we require of modern reclosers. This can cause issues in regards to lack of clarity of network state, extending restoration times.

Circuit breakers, reclosers and sectionalisers asset health

As outlined in Chapter 7, we have developed AHIs that reflect the remaining life of each asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For circuit breakers, reclosers and sectionalisers we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switchgear should be replaced. The AHI is based on our knowledge of condition and reliability or safety issues, such as arc flash risk related to oil switchgear (discussed above), and asset age.

Figure 20.18 shows current overall AHI for our population of circuit breakers and reclosers/sectionalisers.

Figure 20.18: Circuit breakers, reclosers and sectionalisers asset health as at 2018



The asset health of the combined recloser and sectionaliser sub-fleet is very good. Less than 2% (H1-H3) will likely require replacement in the next 10 years.

In contrast, the health of our distribution circuit breakers is considered to be poor and a significant risk. This is based on our experience of operating this switchgear and the experience of others within the industry.

As such we have categorised many of our oil circuit breakers as having type related issues requiring replacement.

There are also a considerable number of aged circuit breakers at Kinleith, where arc flash levels are high and also require replacement. We are planning significant investment in this area to improve our circuit breaker asset health.

20.6.4 DESIGN AND CONSTRUCT

Circuit breakers, reclosers and sectionalisers are classified as class A equipment. Any new equipment undergoes a detailed evaluation process to ensure it is fit for purpose. This includes construction material checks, such as grades of stainless steel, which from previous experience have proven critical in ensuring the assets reach their intended expected life.

20.6.5 OPERATE AND MAINTAIN

We regularly inspect and test our circuit breaker, recloser and sectionaliser assets to ensure their safe and reliable operation. Oil-based devices require more intensive maintenance and, therefore, cost more to operate. As we replace oil-based circuit breakers in poor condition with modern SF_6 or vacuum devices, the volume of maintenance work will decrease.

Table 20.8 summarises our preventive maintenance tasks for this fleet. The detailed regime is set out in our maintenance standards.

Table 20.8: Circuit breakers, reclosers and sectionalisers preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Reclosers and sectionalisers	Inspections and tests of actuator/RTU batteries. Communications check.	Yearly
	Thermal imaging scan.	2 ½ yearly
	Major contacts and tank maintenance of oil reclosers. External inspections of vacuum and gas interrupter units.	5 yearly
	Interrupter condition tests and major maintenance of mechanisms for vacuum and gas devices.	10 yearly
Circuit breakers	General visual inspection. Operational tests.	Yearly
	Major contacts and tank maintenance of oil circuit breakers. Vacuum and gas interrupter contacts wear and gas pressure checks. Operational, acoustic and partial discharge tests.	5 yearly
	Vacuum and gas circuit breaker interrupter withstand tests.	10 yearly

20.6.6 RENEW OR DISPOSE

Renewal of circuit breakers, reclosers and sectionalisers is based on asset condition and type-related safety or performance issues. Safety issues include certain types of oil circuit breakers that are prioritised for replacement either because of design issues with the equipment or stricter risk tolerances, such as for arc flash.

SUMMARY OF CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based with safety risk
Forecasting approach	Type issues and age
Cost estimation	Volumetric average historical rate

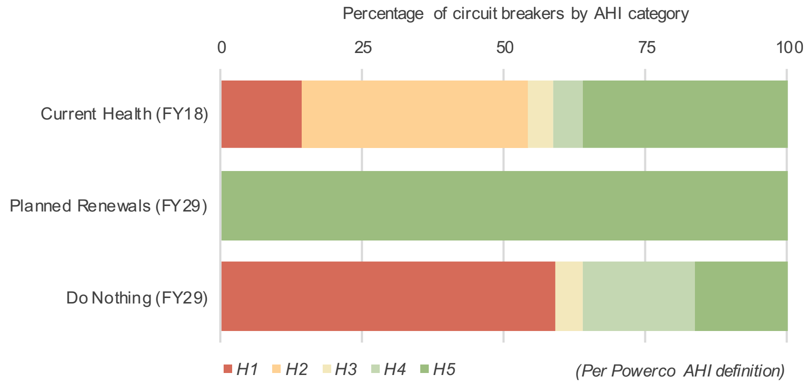
Renewals forecasting

Our renewals forecast uses age as a proxy for asset condition. Over time, insulation degrades, mechanical components suffer wear and enclosures corrode. This makes age a useful proxy, also capturing that older designs of switchgear generally have fewer safety features, such as arc flash containment. The evolution in design of switchgear has improved safety and reliability.

The renewal need for this fleet is higher than in the past. This is because of the need to renew oil circuit breakers that have safety issues, and the significant quantities of circuit breakers requiring renewal at Kinleith. Once this has been completed expenditure levels are expected to return to earlier levels.

Figure 20.19 compares current and projected asset health in 2029 of the circuit breaker sub-fleet, following planned renewals, with a counter-factual do-nothing scenario. Comparing the planned renewal profile with the do-nothing profile provides an indication of the benefit provided by our investment. Projected recloser and sectionaliser asset health is not shown because of the small number of expected renewals during the planning period.

Figure 20.19: Projected circuit breakers asset health as at 2029



Coordination with network development projects

The increasing use of network automation is a key part in the development planning of this fleet. Network automation seeks to improve network SAIFI and SAIDI performance. It improves the network's sectionalising capability following faults and through providing better network operational visibility. This is achieved through the targeted installation of additional reclosers and sectionalisers. Our network automation programme is discussed in more detail in Chapter 12.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We are increasing our use of automation devices, such as reclosers and sectionalisers, to improve fault isolation and restoration.

20.7 DISTRIBUTION SWITCHGEAR RENEWALS FORECAST

Renewal Capex in our distribution switchgear portfolio includes planned investments in our ground-mounted switchgear, pole-mounted fuses, pole-mounted switches, and circuit breakers, reclosers and sectionalisers fleets.

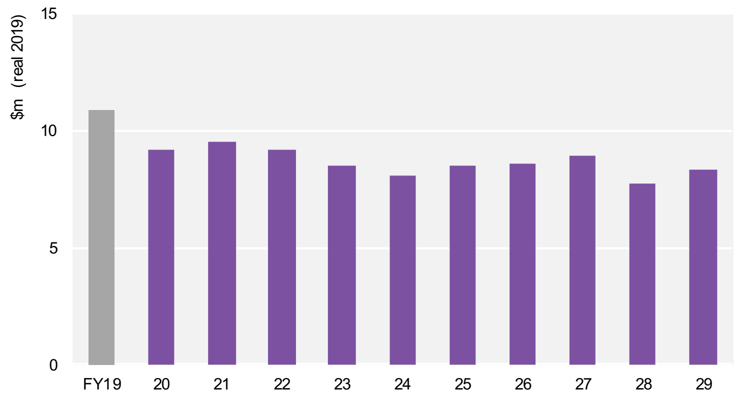
During the planning period we intend to invest approximately $87m in distribution switchgear renewal. Safety is a key driver of renewal, particularly of our oil-filled ground-mounted switchgear and oil-filled circuit breakers.

Distribution switchgear renewals are derived from bottom-up models. These forecasts are generally volumetric estimates (explained in Chapter 26).

The work volumes are relatively high, with the forecasts based on survivor curve analysis, type issues and asset age. We primarily use averaged unit rates based on analysis of equivalent historical costs for like-for-like replacement. For new technology, costs have been estimated based on purchase and installation costs.

Figure 20.20 shows our forecast Capex on distribution switchgear during the planning period.

Figure 20.20: Distribution switchgear renewal forecast expenditure



The forecast renewal expenditure is generally in line with historical levels. Additional expenditure from FY20-27 is required for the circuit breaker renewal programme at Kinleith.

Elsewhere, the investment in the distribution switchgear fleets remains relatively constant during the planning period. Further details on expenditure forecasts are contained in Chapter 26.

21 SECONDARY SYSTEMS

21.1 CHAPTER OVERVIEW

This chapter describes our secondary systems portfolio and summarises our associated fleet management plan. The portfolio includes four asset fleets:

- SCADA and communications
- Protection
- DC supplies
- Metering

This chapter provides a description of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to invest $26m in secondary systems. This accounts for 3% of renewals Capex during the period. This is an increase on our current spend, mainly driven by our Extended Reserves programme. Levels of renewal in the other secondary systems fleets are in line with historical expenditure.

The main driver for asset replacement in the secondary systems portfolio is obsolescence. Capex is driven by the need to:

- Replace our legacy electromechanical and static protection relays, which suffer from increasing unreliability, a lack of spares, lack of support from manufacturers, and provide inadequate functionality compared with modern equivalents.
- Consolidate the communications protocols for our Supervisory Control And Data Acquisition (SCADA) system, which requires the replacement of SCADA base station and remote radios.
- Control and operate the network more efficiently to provide better value to our customers. Modern assets are more functional and perform better.
- Replace several legacy remote terminal units (RTU) that do not provide the functionality required for our network.
- Meet regulatory requirements in relation to the new Extended Reserves arrangements.

Below we set out the Asset Management Objectives that guide our approach to managing our secondary systems fleets.

21.2 SECONDARY SYSTEMS OBJECTIVES

Secondary systems are crucial for the safe and reliable operation of our electricity network. Their replacement cost is usually lower than the primary equipment that they control or monitor, but their useful lives are shorter than the assets in other portfolios. Some are technically complex and require a high degree of strategic direction and careful design to operate effectively.

Protection assets ensure the safe and correct operation of the network. They detect, and allow us to rectify, network faults that may otherwise harm the public and our field staff, or damage network assets. Our SCADA and communications assets provide network visibility and remote control, allowing our operators to efficiently and effectively operate the network.

To guide our management, we have defined a set of objectives for our secondary systems assets. These are listed in Table 21.1. The objectives are linked to our overall Asset Management Objectives as set out in Chapter 5.

Table 21.1: Secondary systems portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Effective protection of primary systems. No injuries or incidents resulting from incorrect operation of protection systems. The SCADA system allows reliable control and monitoring of the electricity network at all times.
Customers and Community	High Voltage (HV) metering units provide accurate consumption information for appropriate billing and meet the requirements of the Electricity Industry Participation Code.
Networks for Today and Tomorrow	Increase our levels of SCADA and monitoring, in particular giving better visibility of the distribution and Low Voltage (LV) networks to anticipate and effectively manage capacity and voltage pinch points enabling increasing levels of distribution automation. Trial the use of smart devices to understand their potential operational, asset management and customer benefits.
Asset Stewardship	Direct Current (DC) supply systems provide their specified carry-over time in the event of an outage.
Operational Excellence	Continue to use improved asset information gathered and recorded by modern numerical relays.

21.3 SCADA AND COMMUNICATIONS

21.3.1 FLEET OVERVIEW

The SCADA system provides visibility and remote control of our network. Its coverage includes major communication sites and zone substations, as well as distribution assets, such as voltage regulators and field pole-top and ground-mounted switches. A central master station communicates with RTUs over a communications system made up of various carriers, such as radio, microwave and fibre optic cable. RTUs interface with the network equipment, such as transformer control units and circuit breaker control systems.

The technology is diverse as it was installed by a range of preceding network companies with different standards and requirements. We have undertaken significant work to improve standardisation.

Master stations

The master station is essentially a central host computer server that manages the SCADA system. We have two master stations – the primary one is located in New Plymouth and the backup in Auckland.

Our network is the result of amalgamating many networks. We previously ran multiple master stations from several vendors. During the past decade, we have standardised and consolidated the SCADA network into one system.

We have selected an industry standard communications protocol – Distributed Network Protocol version 3.0 (DNP3) – as our standard communications protocol.

In 2009, the Eastern region SCADA platform was upgraded to incorporate legacy networks. In 2014, the Western region was converted to DNP3, which made it compatible with the Eastern region's upgraded SCADA platform. These upgrades provide a single flexible platform that will meet the network's SCADA needs for the foreseeable future.

Remote terminal units (RTUs)

RTUs are electronic devices that interface network equipment, such as transformer control units, DC supplies, protection relays, and recloser controls, with SCADA. They transmit telemetry data to the master station and relay communications from the master system to control connected devices.

A range of different RTUs are used across the Eastern and Western networks. The majority of RTUs are modern devices, providing adequate service. However, a small number of devices in the Eastern region communicate via the Conitel protocol rather than the preferred DNP3 protocol. The remaining Conitel protocol devices will be transitioned to the new standard as their corresponding radios and base stations are replaced.

There are also a small number of legacy RTUs at zone substation sites and load control plants. These are being prioritised for replacement as they lack DNP3 communications capability, are proprietary hardware, and are incompatible with modern numerical relays.

The change of communication protocol has allowed Intelligent Electronic Devices (IED) installed on the network to now communicate directly with the SCADA master without the need for an interposing RTU. This has allowed the number of RTUs to remain relatively stable even though the number of SCADA devices continues to increase.

Figure 21.1: A modern RTU

Communications

The communications network supports our SCADA system as well as our protection, metering and telemetry systems. Examples of its use include data exchange between field devices and the SCADA master station, and between protection relays at multiple substations (protection circuits).

The communications network consists of different data systems and physical infrastructure, including fibre optic circuits, UHF point-to-point digital radios, microwave point-to-point digital radios, point-to-multipoint VHF/UHF repeaters and Ethernet IP radio circuits.

While some analogue technology also remains in use, we are progressively moving to digital systems to provide a communications network that better meets our needs. Any remaining analogue equipment will be prioritised for replacement during the planning period.

We have recently implemented a digital microwave backbone to cover the Eastern region.

This system provides a communications network capable of carrying both voice and SCADA data while also providing the ability to implement Ethernet circuits to selected substations.

Several DNP3 repeaters have also been installed at various locations around the region, so this leaves only a small number of RTUs still using the Conitel protocol over analogue radio systems. In the Western region, a new DNP3 digital radio system is used.

The scope of the communications network also includes the infrastructure that houses communication systems, including masts, buildings, cabinets and antennae. Infrastructure services are leased from service providers or shared with third parties.

Figure 21.2: Communications mast with associated radio antennae

21.3.2 POPULATION AND AGE STATISTICS

During the past five years, we have undertaken a number of projects to modernise our RTUs in order to provide acceptable levels of service. In the planning period, we intend to focus on replacing any remaining legacy RTUs. Although they have provided good service, they no longer provide the functionality we require.

Table 21.2 summarises our population of RTUs by type. [97]

Table 21.2: RTU population by type

TYPE	RTU	% OF TOTAL
Modern	290	98
Legacy	7	2
Total	297	

Converting the remaining eastern RTUs from Conitel to DNP3 is a lower priority. We expect to convert one or two channels each year (average of 12 RTUs per channel).

As these modern Conitel RTUs already support the DNP3 protocol, these channel conversions require the replacement of the associated SCADA radios to DNP3-capable units.

At the end of this programme, we will have the SCADA network standardised on the industry standard DNP3 protocol. Use of the open DNP3 standard allows direct connection of some IEDs to the SCADA master without requirement of an intermediary RTU.

Age information for our communications network is sparse, and is typically inferred from related assets, drawings of the installations, or eras of RTU types. While this information is seeded from the Geographical Information System (GIS), we are working to improve our records.

21.3.3 CONDITION, PERFORMANCE AND RISKS

Condition

Condition is generally not a significant factor in determining the replacement of RTUs, with functionality, technical obsolescence and supportability being the dominant factors.

A small number of legacy RTUs on the network are based on proprietary hardware, software and communications protocols. They cannot communicate with modern numerical relays using standard interfaces (serial data connection). Instead, they

[97] This population excludes telemetered sites with IEDs directly connected to the SCADA network, such as those on modern automated reclosers.

rely primarily on hard-wired connections that are more prone to failure, are difficult to maintain and troubleshoot, and require specialist knowledge to understand how they work.

These RTUs rarely fail but a lack of experienced service personnel and original, first-use, spares increases risk.

Risks

With regard to the SCADA system, the key risk is loss of network visibility and control. We prefer to operate equipment remotely for several reasons, including safety, speed of operation and improved operational visibility. Lack of status information from the field can lead to switching errors, such as closing on to a faulted piece of equipment or circuit.

Another significant risk is of a third party gaining control of our switchgear through a cyber-attack on our SCADA system. The increasing risk of a cyber-attack on our network is driving us to improve the security levels of our SCADA system. As more devices become visible and controllable on the network, such as automation devices including reclosers, the potential safety, reliability and cost consequences from an attack on the system become increasingly serious.

Improving our levels of cyber security is a key theme of our Information Services Strategic Plan (ISSP) and is discussed in more detail in Chapter 22.

Meeting our portfolio objectives

Safety and Environment: We continually review the security of our SCADA against cyber-attack to ensure the operational safety of the network.

21.3.4 DESIGN AND CONSTRUCT

Technology changes are affecting SCADA in a number of ways. As numerical protection relays and other IEDs become more prevalent and powerful, more data is collected. This requires alternative polling strategies to manage data requirements and increased communications bandwidth.

There is potential to use the cellular radio network for engineering access where coverage exists, or fibre optic cables, where available, for some RTU communications. Wide area network communication could be used between main centres and communication hubs.

Improvements in interface standards and protocols will enable the easier transfer of data between systems. Internet-based inter-control centre communications protocol is a new technology that will allow us to see Transpower's circuit breaker statuses, indications, and analogue data on our SCADA without the need to go through a third party.

We will monitor these changes in technology closely to ensure that any benefits to our SCADA system can be promptly identified and implemented as appropriate.

The latest standard RTU types that we are installing provide remote engineering access (REA) support for most of our numerical relays. REA allows our technicians and protection engineers to access relay event information remotely, removing the need to download the data at site from the relay. This could potentially reduce the time required to understand and react to a fault – reducing the length of power outages for customers.

In terms of communications, moving from analogue to digital technology will allow for greater data throughput and manageability. Greater intelligence within the communications system, between IED-controlled switches and the master station, will allow for automatic fault restoration.

21.3.5 OPERATE AND MAINTAIN

SCADA and communications assets are regularly inspected and tested to ensure their ongoing reliability. Operational tests are carried out to ensure the communications equipment remains within specifications, including checks to ensure transmitting equipment is within radio licence conditions.

Table 21.3: SCADA and communications preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Communications equipment, including RTUs	General equipment inspections to test asset reliability and condition. Transmitter power checks and frequency checks. Site visual inspection for dedicated communications sites, checking building condition and ancillary services. RTU operational checks.	6 monthly
	Visual inspection of communication cables/lines, checking for condition degradation. Attenuation checks. Antennae visual inspections, with bearing and polarity verified.	Yearly
SCADA master station	Maintenance covered by specialist team.	As required

21.3.6 RENEW OR DISPOSE

SCADA and communications asset renewal is primarily based on functional obsolescence. As detailed earlier, we have a small number of legacy RTUs on the network that are based on proprietary hardware and communications protocols. They are unable to communicate through standard interfaces with modern IEDs. There is a lack of knowledgeable personnel and a lack of spares to undertake related work. The replacement of these legacy RTUs is a high priority.

Other communications assets, such as radio links and their associated hardware, are also typically replaced because of obsolescence. Modern primary assets and protection relays have the ability to collect an increasing amount of data that is useful for managing the network. To support this, legacy communication assets are replaced with modern, more functional assets.

Our future communications strategy is discussed in more detail in Chapter 11. Some condition-based renewal is also carried out, typically for supporting communications infrastructure, such as masts and buildings.

SUMMARY OF SCADA AND COMMUNICATIONS RENEWALS APPROACH

Renewal trigger	Functionality based obsolescence
Forecasting approach	Identified assets
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewal forecasts are based on identifying asset types that require replacement (see discussion above). This includes the legacy RTUs, SCADA radios and base stations that still operate on Conitel or other non-supported protocols.

The renewal forecast of supporting communications infrastructure is an estimate of the expected annual replacement quantity based on historical renewals.

Longer term, we expect SCADA and communications renewals to remain at least at current levels. Future capability requirements and an expansion of the communications network are likely to increase the renewal need.

Coordination with network development projects

The SCADA system already provides real-time monitoring and control at our zone substations. The system is largely mature and fully developed. As discussed above, our Eastern and Western systems are on a common platform.

Specific SCADA system needs are considered as part of network development. For example, a zone substation project includes developing the SCADA RTU, configuration and communications. Similarly, our network automation programme[98] is extending the control and monitoring capability to selected distribution switches.

21.4 PROTECTION SYSTEMS

21.4.1 FLEET OVERVIEW

Protection assets ensure the safe and appropriate operation of the network. They detect and isolate network faults that could otherwise harm the public and our service providers, or damage network assets.

Protection relays or integrated controllers are used to detect and measure faults on our HV electricity network. Protection relays communicate with circuit breakers, either directly or through SCADA, to clear and isolate faults. When working correctly, they can have a significant impact on improving network performance.

Protection systems include auxiliary equipment such as current and voltage instrument transformers, communication interfaces, special function relays, auxiliary relays and interconnecting wiring.

Protection relays have evolved over time and this fleet can be broken down into three main technologies – electromechanical, static and numerical protection devices.

Electromechanical relays

Electromechanical relays are a legacy protection technology that have provided many years of reliable performance. While simple to operate, they are not as functional as more modern protection technology. As their name suggests, they operate on electromechanical principles – coils and magnets driving mechanical components, such as rotating discs and relays, to define relay characteristics.

Figure 21.3: Electromechanical relays providing transformer protection

[98] We discuss the network automation programme in Chapter 12.

Electromechanical relays require ongoing calibration because of ‘drift’ of components. They have an expected life of approximately 40 years. Most electromechanical relays on our networks have been in service for more than 30 years and some more than 45 years.

Static relays

Static relays gain their name from the absence of moving parts to create the relay characteristic. Essentially, they are an analogue electronic replacement for electromechanical relays. They use analogue electronic devices rather than the coils and magnets in electromechanical relays.

Being solid-state they can have improved sensitivity, speed and repeatability compared with electromechanical relays. Electronic components, however, are susceptible to deterioration and drift because of time and temperature affecting the performance and reliability of relays and introducing unreliability.

Static relays have an expected life of approximately 20 years. Spare parts can be difficult to obtain, and repair is challenging and typically not economic.

Numerical relays

Numerical relays convert measured analogue values into digital signals. Being digital computer technology, these relays are extremely flexible. They can be programmed and configured to provide a wide range of protection applications. They also have multiple control inputs and relay outputs available.

Numerical relays have significant advantages over previous technologies. These include the ability for data to be accessed remotely and the ability to be integrated directly into the SCADA system.

Numerical relays also offer real-time and historical information about the power system, the protection and control systems, and selected substation equipment, such as fault location and type, before, during and post fault currents and voltages, and relay status.

Furthermore, numerical relays include self-testing features, which can alert network operations should the relay become non-functional. This near continuous testing substantially increases the overall availability of numerical relays when compared with electromechanical or static types.

Numerical relays are the universal choice for new protection and control installations today. Modern numerical relays are extremely reliable and offer vastly improved functionality at reduced cost compared with those available in the past.

As they are an electronic device, at approximately 20 years, the expected life of a numerical relay is shorter than electromechanical relays. Obsolescence is also a driver for replacement, which is typically dictated by protocol, software and firmware, and compatibility with other devices.

Figure 21.4: Modern numerical relays

21.4.2 POPULATION AND AGE STATISTICS

In recent years, substantial numbers of electromechanical and static relays have been replaced. Numerical relays are now the dominant relay type, making up 57% of the population.

As further systems are upgraded there will also be a reduction in the total number of relays in the fleet, as numerical relays can be programmed to provide multiple protection functions that currently require several individual electromechanical relays.

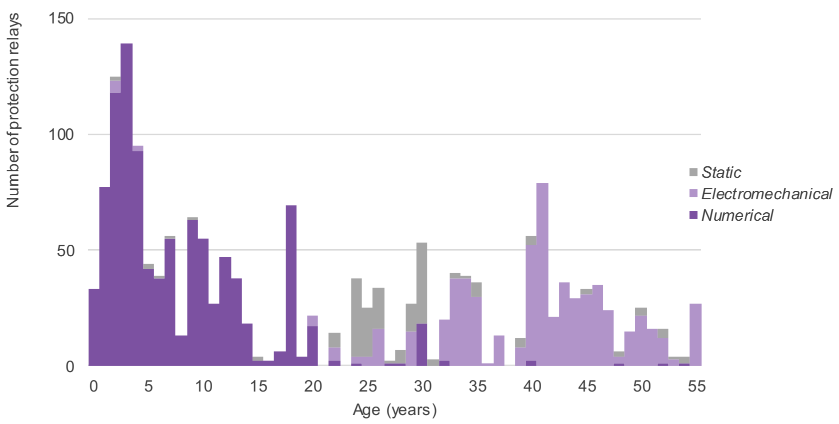
Table 21.4: Protection asset population by type

TYPE	RELAYS	% OF TOTAL
Electromechanical	619	35
Numerical	986	57
Static	177	8
Total	1,782	

The type of relay used on the network has changed over time as technology has evolved. Electromechanical relays were generally superseded by static relays approximately 30 years ago. During the past 20 years, we have almost exclusively installed numerical relays. The first generation of these numerical relays will begin to require renewal during the next five years.

Figure 21.5 shows the age profile of our protection relays population. Many electromechanical relays exceed 40 years of life and are now due for replacement.

Figure 21.5: Protection relay age profile



21.4.3 CONDITION, PERFORMANCE AND RISKS

Condition

While older relays are proven and have a long life, they are partially mechanical and wear out with use. Experience and routine tests suggest electromechanical relays are prone to poor performance and reliability after their expected life of approximately 40 years. Such relays may suffer from sticky contacts, inconsistent timing, and/or sluggish operating times. As a result, they may not reliably detect and discriminate network faults.

In contrast, newer numerical relays can provide much greater functionality, richer information and higher reliability and system stability. However, they have a shorter life because of their microprocessor-based technology. Excessive heat may also cause them to fail, which we manage by using air conditioning.

Numerical relays generally provide an indication when they malfunction, which allows maintenance intervals to be extended.

Risks

The key safety risk for the protection fleet is that a fault does not clear because of a faulty relay. This can put the public or service provider in danger, cause network equipment failure, extended outages, or overload.

Backups are in place, but these are designed to take longer to clear the fault to ensure protection discrimination. However, longer fault clearance times can sometimes result in fires or live power lines on the ground. Numerical protection relays can be configured to operate faster than the other types, but this may reduce the margins for protection coordination. However, the functions they provide can assist in determining the fault location, reducing restoration times.

Meeting our portfolio objectives

Safety and Environment: We continually review our protection coordination to ensure faults are cleared in a fast but reliable manner.

Regulatory compliance

The Electricity Authority is implementing new requirements for Extended Reserves. The new requirements include tripping on the rate of frequency decay, which requires a more sophisticated relay unit. A very high percentage of our existing load shedding relays are many decades old and incapable of meeting the new specifications.

To meet our obligations, we need to replace and re-programme existing under-frequency relays at approximately 100 substations. This is forecast to occur during the 2020-23 period.

21.4.4 DESIGN AND CONSTRUCT

Protection system design must balance many competing requirements to ensure the overall system is effective. These requirements include:

- **High reliability** − the protection equipment must operate correctly when required, despite not operating for most of its life.
- **Stability** − the protection equipment must remain stable when events that look like faults occur, eg power swings and current reversals, and continue to operate the way it should during the length of its life.
- **Dependability** − relays should always operate correctly for all faults for which they are designed to operate.
- **Security** − relays should not operate incorrectly for any fault, eg an out-of-zone fault.
- **Sensitivity, speed and selectivity** − individual protection equipment must operate with the appropriate speed and coverage as part of an overall protection scheme.
- **Safety and reliability of supply** − the protection scheme must provide safety to the public and field staff, as well as minimising damage to the network equipment. Correct operation is the key to providing reliable supply.
- **Simplicity** − the protection system should be simple so that it can be easily maintained. The simpler the protection scheme the greater the reliability.

- **Lifecycle cost** − an important factor in choosing a particular protection scheme is the economic aspect. The goal is to provide protection and supporting features consistent with sound economic evaluation.

21.4.5 OPERATE AND MAINTAIN

We regularly inspect and test our protection assets to ensure they remain ready to reliably operate in the event of a fault.

Electromechanical relays require more detailed inspections because of their mechanical nature and possible degradation in performance. Numerical relays require less detailed and fewer frequent checks, so cost less to maintain. They are also able to provide alerts regarding their condition, prompting a maintenance callout if necessary.

Our preventive maintenance schedule for protection relays is outlined in Table 21.5. The detailed regime is set out in our maintenance standards.

Table 21.5: Protection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of protection assets, checking for damage, wear and tear. Any alarms, flags and LEDs reset.	3 monthly
Detailed condition assessment and operational checks for **electromechanical and static relays**. Perform diagnostic tests relevant to relay function, eg overcurrent, distance.	3 yearly
Detailed condition assessment and operational checks for **numerical relays**. Perform diagnostic tests relevant to relay function, eg overcurrent, distance.	6 yearly

21.4.6 RENEW OR DISPOSE

Our strategy is to replace electromechanical and static relays on the basis of either functional obsolescence or the availability of effective vendor support.

Older technology relays continue to work but, unlike numerical relays, do not provide the modern functionality we require for the improved operation of the network. They also have high maintenance costs and few spares, and reliability may reduce with wear (for electromechanical relays).

First generation numerical relays will soon no longer provide the required functionality, and we are concerned about their potential reliability degradation from deterioration of electronic components.

SUMMARY OF PROTECTION RENEWALS APPROACH	
Renewal trigger	Functionality based obsolescence
Forecasting approach	Age
Cost estimation	Project building blocks

Meeting our portfolio objectives

Operational Excellence: Protection relays are renewed, in part, to enable new functionality available in modern devices, allowing us to utilise the improved asset information they gather.

Renewals forecasting

Our renewal forecast is based on age as a proxy for obsolescence. Our older relays have limited functionality and are more likely to become unreliable, although the likelihood is low.

Our forecast identifies relay renewal quantities and accounts for projects where associated primary assets are replaced, eg switchboard replacements, to ensure efficient delivery. This may mean some relay replacements are brought forward or deferred for a period.

The forecast also includes expenditure from 2020-23 for the replacement of load shedding relays, to ensure compliance with the new Extended Reserves requirements. The forecast is based on desktop assessments of our zone substation load shedding needs, the number of feeders, and a bottom-up engineering estimate of the costs of a replacement system.

Forecast renewals are higher than historical levels because of the need to retire our electromechanical and static relays and replace them with modern numerical devices, and the significant expenditure for the replacement of load shedding relays from 2020-23.

Longer term, protection renewals, excluding load shedding replacement, are expected to remain at these levels as increasing numbers of first generation numerical relays require replacement. In addition to providing better functionality, numerical relays have lower maintenance costs.

Coordination with network development projects

Protection relay replacement work is, as far as practical, coordinated with zone substation works – typically power transformer or switchboard replacements. Where this work is driven by network development requirements, the protection systems may also be replaced, depending on the technology and condition of the existing relay assets.

21.5 DC SUPPLIES

21.5.1 FLEET OVERVIEW

Our DC supply systems are required to provide a reliable and efficient DC power supply to the vital elements within our network, such as circuit breaker controls, protection equipment, SCADA, emergency lighting, radio, metering, communications and security alarms. DC supplies are located within substations and communication sites on the network.

Our DC supply assets comprise a large range of systems and configurations. This is the result of amalgamations of legacy networks over several decades. Some schemes are not fully compliant with our DC supply system standards. These are generally reconfigured to achieve compliance when major items such as batteries or chargers are replaced.

The general DC supply system can be divided into two main components – the battery bank and the battery charger, along with its associated monitoring system and cabling.

Most of the chargers use technology that monitors several parameters, such as battery voltage and battery condition, and are fitted with remote monitoring facilities. All components have to provide effective and reliable service, as redundancy is not generally built into DC supply systems. The systems vary in power rating and complexity based on load and security requirements.

DC supply systems are used in five key areas:

- SCADA and communications (12V, 24V and 48V DC)
- Circuit breakers mounted in distribution substation kiosks without SCADA (24V, 36V, 48V)
- Supply for switchgear (24V, 36V, 48V and 110V)
- Supply for protection equipment (24V, 48V and 110V)
- Backup supply for grid-connected repeater stations and cyclic storage for solar powered repeater stations

In recent years, we have made a significant investment in replacing many DC supply systems that were found to have inadequate capacity, were in poor condition, lacked spares, or no longer provided the functionality we required, such as self-diagnosis and monitoring.

As such, our existing DC supply systems are generally up-to-date technology and provide acceptable levels of service.

Figure 21.6: DC charger and battery bank

21.5.2 POPULATION AND AGE STATISTICS

Table 21.6 summarises our population of DC supply systems by type. DC systems have been installed using many supply voltages because of different load requirements and network amalgamation. We expect the diversity to reduce as we replace non-standard voltage systems with modern equivalents.

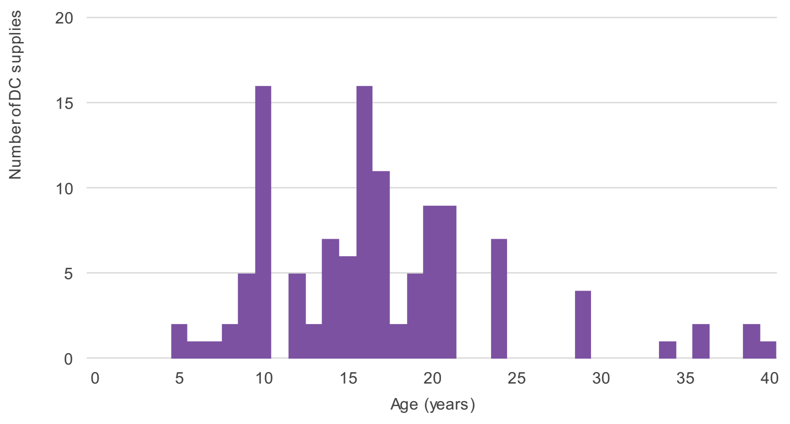
Table 21.6: DC supplies population by voltage

VOLTAGE	DC SYSTEMS	% OF TOTAL
110V	73	43
48V	25	15
36V	1	1
24V	17	10
12V	2	1
Communications[99]	50	30
Total	168	

[99] Communication DC supplies refer to 48V DC rectifiers with 12V and 24V DC converters.

Figure 21.7 shows the age profile of our population of DC supplies. Most of our DC supply assets are newer than their approximate 20-year expected lifespan. A small number have provided reliable service beyond 20 years of life but, with an increasing risk of failure, these will be prioritised for replacement.

Figure 21.7: Zone substation DC supplies age profile



21.5.3 CONDITION, PERFORMANCE AND RISKS

The various DC supply systems on our network have generally provided acceptable levels of service. However, as improved performance can be achieved from some newer equipment, we are now more prescriptive with DC supply system requirements and aim to standardise our systems as far as practicable. In doing so, we have removed all high-ripple content chargers from service and have moved to using gel batteries for their improved deep cycle properties.

The most common modes of failure of the charger systems is dry solder joints and capacitors swelling within the power circuitry. The consequence of failure is high, which can include lack of protection at substations and lack of control. The need to revert to manual operation can put workers at increased risk from switchgear failure and arc flash.

21.5.4 OPERATE AND MAINTAIN

We undertake regular inspections and testing of our DC supply systems to ensure they operate reliably and provide backup supply during outages. Our preventive inspection regime for DC supply systems is outlined in Table 21.7. The detailed regime is set out in our maintenance standard.

Table 21.7: DC supplies preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of **zone substation** DC systems. Check batteries for distortion, correct electrolyte levels and secure connections. Charger alarms operational, giving correct statuses.	3 monthly
Visual inspection of **radio repeater and communication hub** DC systems. Check batteries for distortion, correct electrolyte levels and secure connections. Charger alarms operational, giving correct statuses.	6 monthly
DC system detailed condition assessment and diagnostic tests. Charger and battery type, capacity and performance correct for site load. Test battery discharge, charging current and voltage. Check charger float voltage and float and boost currents.	12 monthly
Distribution actuator DC system detailed condition assessment and diagnostic tests. Charger and battery type, capacity and performance correct for site load. Test battery discharge, charging current and voltage. Check charger float voltage and float and boost currents.	2.5 yearly

Experience shows that the average life of lead acid batteries is approximately seven years, while for gel/absorbent glass mat batteries it is approximately 10 years.

21.5.5 RENEW OR DISPOSE

DC supplies are critical assets as failure means we potentially lose visibility and control of our field sites. We therefore aim to proactively replace DC supplies once they no longer provide the functionality expected or the capacity required. This ensures continued reliability and performance.

Chargers are assumed to have a 20-year expected life. Renewal before this time sometimes occurs because of additional demand on the system, such as protection upgrades, where the additional DC load triggers the need to upgrade.

Meeting our portfolio objectives

Asset Stewardship: DC supply systems are replaced to ensure specified carry-over times can be met in the event of an outage.

A small number of condition-based renewals are undertaken reactively as solder joints and components fail over time.

SUMMARY OF DC SUPPLIES RENEWALS APPROACH	
Renewal trigger	Capacity/functionality based obsolescence and condition
Forecasting approach	Age
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewals forecast is based on age as a proxy for the replacement drivers discussed above. Older DC systems are more likely to require improvements in carry-over time[100] and do not have modern features, such as intelligent chargers with battery condition monitoring. Condition-based replacement is also related to age because heat-related ageing to the charger circuitry will worsen over time.

Replacement levels are forecast to be steady over the long term. Replacements will be coordinated where possible with other zone substation work, such as switchgear or protection.

21.6 METERING

21.6.1 FLEET OVERVIEW

The metering fleet is comprised of three sub-types – grid exit point (GXP) and HV metering units, and ripple receiver relays.

GXP metering provides 'check metering' of power supplied from Transpower at GXPs. We have replaced most of the older and unsupported meters that were used for monitoring network load at our GXPs. Because of their technology, the few remaining older meters are limited to providing only kWh data in the form of impulse to the SCADA and load management systems.

Modern GXP meters are able to communicate via the DNP3 protocol and provide remote access functionality and rich data, eg peak and average kVA, and power factor.

HV metering units are used to transform and isolate high voltages and currents, through the use of voltage and current transformers, into practical and readable quantities for use with revenue metering equipment. They are used to provide revenue metering information where customers are directly connected to the HV distribution network. The units have no moving parts and are normally not subjected to overload, required to interrupt fault current, or subjected to thermal stress.

HV metering units may be pole-mounted, stand alone, embedded in ring main units (RMU) or other ground-mounted switching kiosks, or form part of the equipment in a zone substation.

We own a small number of ripple receiver relays. They are used to control water and space heating as well as street lighting. Ripple receiver relays are not metering equipment as such, but are included in this fleet for convenience. They receive audio frequency signals from load control plants, also known as ripple injection plants, in order to switch on or off the load they control.[101]

21.6.2 POPULATION AND AGE STATISTICS

Table 21.8 summarises our population of GXP meters by type. Our GXP meter replacement programme has upgraded the majority of metering units to modern ION meters. A small number of legacy metering units remain, which are being prioritised for replacement.

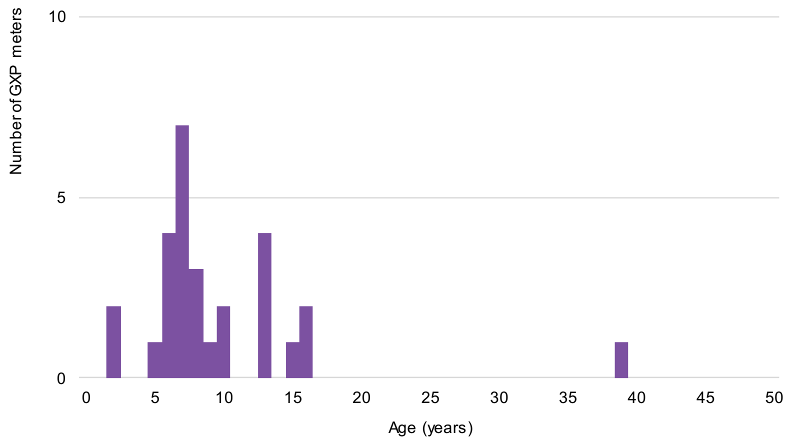
Table 21.8: GXP metering population by type

TYPE	SUB-TYPE	GXP METERS
ION meter		25
Legacy	Enermet	1
	L&G FF34	2
Total		28

In addition to the GXP meters, we have 99 HV metering units and approximately 1,500 ripple receiver relays.

Figure 21.8 shows the age profile of our GXP meter population. The young age of the GXP metering fleet reflects recent modernisation of the assets. There is one remaining legacy check metering unit that is now scheduled for replacement in FY20, corresponding to Transpower redevelopment work taking place at Kopu GXP.

Figure 21.8: GXP metering age profile

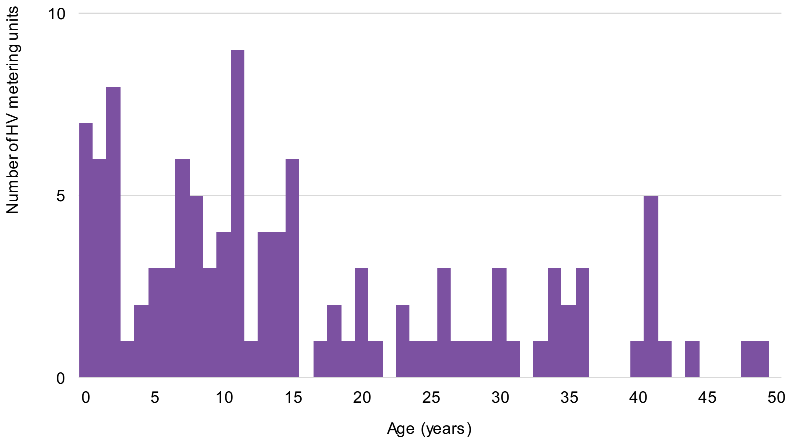


[100] 'Carry-over time' means the time the DC system can supply the connected load in the event of an outage.

[101] We discuss our load control plant fleet in Chapter 18.

Figure 21.9 shows the age profile of our HV metering unit population. The HV metering unit fleet is relatively young. Experience has shown that life spans of more than 20 years are common for most metering units, with replacement or upgrade normally being related to changes in the load profiles of connected customers. In the absence of other information, we assumed that units located within switchboards have a life of 40-45 years, similar to the associated switchgear. There are three meters more than 40 years old that will likely require replacement during the planning period.

Figure 21.9: HV metering unit age profile



21.6.3 CONDITION, PERFORMANCE AND RISKS

HV metering unit accuracy is important as the units are used for calculating distribution charges. Any metering inaccuracy may result in overcharging customers or lost revenue. The metering units are required to meet the accuracy standards prescribed in Part 10 of the Electricity Industry Participation Code (2010). All of the instrument transformers we own that are used for this purpose are compliant. These assets are therefore in good operable condition.

21.6.4 OPERATE AND MAINTAIN

We regularly inspect our metering assets to ensure their ongoing reliability. The re-calibration tests carried out on HV metering units every 10 years are particularly important. They must be conducted to ensure compliance with the participation code. These tests are only carried out by certified service providers.

Our preventive metering inspection tasks are summarised in Table 21.9. The detailed regime is set out in our maintenance standards.

Table 21.9: HV metering preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of metering units installed within switchboards. Check cabling for damage and ensure secondary terminal block enclosure is sealed.	Yearly
Detailed inspection of ground and pole-mounted metering units. Check external condition and signage. Check cabling for damage and ensure secondary terminal block enclosure is sealed.	5 yearly
Perform metering equipment re-calibration tests to comply with participation code.	10 yearly

GXP meters do not undergo preventive maintenance but provide alerts when they are faulty.

21.6.5 RENEW OR DISPOSE

Obsolescence is the primary driver for renewal of metering assets. A small number of legacy GXP meters have limited functionality and accuracy, exceed their expected life and are only able to provide kWh data in the form of impulse to the SCADA and load management system. Unlike modern meters, they do not provide easy and reliable access to a range of information. They are not supported and few spares are available.

HV metering units are replaced because of capacity related obsolescence or they no longer comply with the participation code. HV metering units at customer sites are typically located within a switchboard. They must be adequate to meet the needs of the customer installation, which may change over time.

SUMMARY OF METERING RENEWALS APPROACH	
Renewal trigger	Capacity and functionality based obsolescence
Forecasting approach	Asset identification and historical rates
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our GXP metering renewals forecast is based on our scheduled replacement of the remaining legacy meters during the next two years. After this, the entire fleet will consist of modern devices and we expect no further renewal during the planning period.

We believe our HV metering units are in good condition. Our renewals forecast is based on the historical rate of renewals and we do not expect an increase during the planning period.

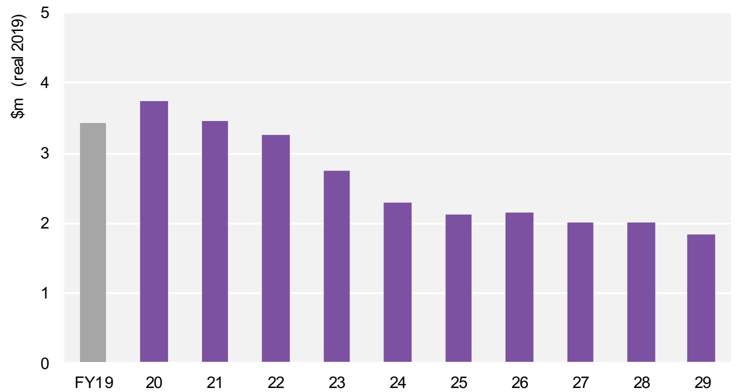
21.7 SECONDARY SYSTEMS RENEWALS FORECAST

Renewal Capex in our secondary systems portfolio includes planned investments in the SCADA and communications, protection, DC supplies, and metering fleets. During the planning period we intend to invest $26m in secondary systems renewals. Key drivers are functionality, meeting regulatory requirements, and investing in smart ripple receiver replacements.

Most renewals are derived from bottom-up models, based on identified replacement needs, asset age and historical replacement rates. These forecasts are generally volumetric estimates, which is explained in Chapter 26. We typically use averaged unit rates based on analysis of equivalent historical costs, along with building block costs for protection replacements.

Figure 21.10 shows our forecast Capex on secondary systems during the planning period.

Figure 21.10: Secondary systems renewal forecast expenditure



The forecast renewal expenditure is higher over the FY20 to FY23 period, primarily because of the need to comply with the new Extended Reserves requirements and the need to modernise our protection and RTU fleets. Longer term, we expect an underlying renewal level of $2-3m per year, although large one-off upgrades, such as to the SCADA system, may result in increased expenditure.

22.1 CHAPTER OVERVIEW

Non-network assets include assets that support the operation of the Electricity business, such as information and technology systems and facilities. This chapter describes our approach to forecasting demand for Information and Communications Technology (ICT) services and the investments that are required to enable the wider Asset Management Plan and Network Evolution. It also discusses our other non-network assets, such as office buildings and vehicles.

ICT investment is forecast to grow during the planning period, driven by the need to enable Customised Price-quality Path (CPP) growth and renew our applications and communications portfolio to strengthen our core business operations. We will also enable new capabilities, such as the operation of distributed energy resources, cyber security, customer experience and advanced analytics.

This chapter is structured as follows:

- 22.2 – Information Services asset management
- 22.3 – Information Services needs analysis
- 22.4 – Technology platform architecture
- 22.5 – Planned ICT initiatives and investments during the period
- 22.6 – ICT expenditure forecasts
- 22.7 – Facilities portfolio approach and forecast

22.2 INFORMATION SERVICES ASSET MANAGEMENT

22.2.1 OVERVIEW

Information Services covering ICT assets are key enablers to the Powerco Business Plan and Electricity and Gas Asset Management Plans.

We use the terms Run, Grow and Transform to describe the main categories of investments to maintain and improve the functionality of information and technology services within Powerco. Different investment governance is applied to each of the three portfolios, as described in Chapter 6.

- **Run** – investments used to “run the business” include technology foundation, eg IT asset refresh, disaster recovery, and investments to address regulatory and compliance issues, including cyber security. The primary goal of run investments is to “keep the lights on” and mitigate operational risks.
- **Grow** – the majority of business unit requests are “grow the business” investments. These improve or extend business processes and capabilities with the goal of return on investment.
- **Transform** – investments to add or reinvent our business capabilities with the goal of creating new business models, revenue or channels that transform the business.

22.2.2 STRATEGY AND OBJECTIVES

Our strategy is to build a modern, secure and flexible digital technology platform that provides a solid business foundation to take Powerco into an increasingly dynamic future.

We will achieve this by delivering nine ICT business services, supporting each of the strategic themes. These business services also correspond to the seven platforms described in Table 22.2.

Table 22.1: ICT business services

SERVICE	DESCRIPTION	OBJECTIVE	STRATEGIC THEME
Technology advisory	Reliable technology guidance to support investment growth and ensure Information Services is “doing the right things” and also “doing things right”.	Measurable business value from non-network solutions.	Operational Excellence
Cyber security	Management of cyber security risk to protect the integrity of our network assets and enable future Network Evolution.	Reduction in cyber security risk.	Operational Excellence New Energy Future
Customer experience	We provide valued digital services to our customers to generate trust, gather new intelligence and position for future growth.	Increase direct customer contact.	Customer Orientation
Employee experience	We enable collaboration and enhance employee productivity to improve organisational performance.	Increase employee efficiency.	Operational Excellence
Business ecosystem	We seamlessly exchange value with our trading partners to enable supply chain growth and agility.	Works delivery against plan (time/cost/output/quality).	Operational Excellence New Energy Future
Data & analytics	We enable a data driven organisation that makes decisions in the long-term interest of customers.	Cost reflective tariff structure in place. System architecture for open access network implemented.	Customer Orientation Operational Excellence New Energy Future

SERVICE	DESCRIPTION	OBJECTIVE	STRATEGIC THEME
Business systems	Supporting business growth and lifting our asset management capability through industry standard processes, automation and visibility of business performance.	Out-performance against corporate model (measure of business productivity). ISO 55000 compliance.	Operational Excellence
Technology	We reduce operational risk by managing a secure, resilient environment, supported by cost effective infrastructure and communications.	Mission-critical systems uptime. Corporate systems uptime.	Operational Excellence
Internet of Things (IoT)[102]	We connect people and devices to improve safety and drive operational efficiency through remote control and rich data insights.	Increase automation, communications and network control.	New Energy Future

22.3 INFORMATION SERVICES NEEDS ANALYSIS

We have worked with our stakeholders to capture and analyse demand for information services during the planning period. The resulting demand is summarised here, organised by strategic theme.

22.3.1 CUSTOMER ORIENTATION

- Multi-channel customer service and new works management systems will streamline business processes to support growth while reducing cost of service.
- A focus on customer experience around planned and unplanned outages will improve engagement satisfaction and provide new sources of customer intelligence.
- Data and analytics services that protect customer privacy will enable demand-side research to help us better align pricing, tariffs and customer contributions with evolving customer and market needs.
- Cyber security capability that ensures customers are confident their data is safeguarded and used responsibly, maintaining Powerco's status as a trusted partner.

[102] The Internet of Things (IoT) is the network of physical objects that contain embedded technology to communicate, sense or interact with their internal states or the external environment.

22.3.2 OPERATIONAL EXCELLENCE

- A new Enterprise Resource Planning (ERP) system will bring industry standard business processes and more automation to the planning, delivery and management of the works programme, property and consents and financial management capabilities. This will increase the volume of work per employee and improve contract performance through robust works planning and scheduling. It will enable the capture of a consistent time series of asset data upon which to base future asset management and operational decisions.
- The consumption management and billing systems delivered by ERP will support a transition from grid exit point (GXP) to installation control point (ICP) based billing, future tariff models that encourage the efficient use of our network, as well as the potential for direct customer billing and dynamic tariffs.
- To advance Health, Safety, Environment (HSE) performance in response to regulatory changes and increasing work volumes, we need to improve HSE competency management processes, risk and incident management (getting HSE data and real-time network status information in the field), as well as analysis and reporting.
- ERP will also automate Human Resources (HR) business processes to scale-up recruitment and onboarding, and help build a high-performance workplace through improved learning, leadership and talent development processes, workforce planning and employee analytics.
- We must help scale network operations by extending tools that help manage network access and availability, as well as provide new tools to manage operational risk, such as switch order management.
- We will invest in a business ecosystem technology platform to make it easier to integrate and connect customers and trading partners, such as service providers and retailers, to increase automation and supply chain volume and agility. This same platform can then be extended to connect places, systems, data, things and algorithms, to improve customer service, share information and create new products or services.
- Evolving our cyber security maturity while ensuring there is a coordinated, governed risk management approach. Cyber risk management will be embedded into all new initiatives, so we can manage and monitor our operational risks in a dynamic, changing environment.
- Creating a culture of digital safety through awareness and training of our staff, contractors and supply chain to help protect Powerco's operations from cyber security threats.
- We actively collaborate with our industry peers and government agencies to improve the overall cyber security maturity of the industry within New Zealand through the creation of voluntary standards, sharing of threat information, and learning how others mitigate common risks.

- Using data governance, combined with the new ERP and field mobility tools, we will streamline network information management business processes to improve data quality and timeliness. We will also extend our data and analytics platform to support new data sources, for example lidar and sensor data, improve the repeatability of regulatory reporting, and provide easy to use tools that aid high quality options analysis and the consistent identification of the most cost effective, long-term investments.
- Investment growth and an ageing workforce mean dilution of Powerco "know-how" and culture that is critical to sustaining our leadership position in the energy industry. Easy to use collaboration and information management technologies will help to leverage our existing know-how, create greater connectivity across operating locations and decrease non-essential travel. Social computing can be used to help build company culture and develop knowledge sharing networks.

22.3.3 NEW ENERGY FUTURE

- Powerco's vision of an open-access network requires new capabilities to operate distributed energy resources. Our smart grid will use an advanced distribution management system and intelligent assets, such as automated switches and control relays, to manage power flows in all directions across both high and low voltage networks. This will require accurate network information, including low voltage, and investment in an IoT platform comprising scalable communications, layered cyber security and the ability to discover, manage and analyse data from the field in real-time for business purposes, such as the calculation of dynamic tariffs.
- We will increase investment in our cyber security programme to manage cyber risks within our tolerances, while also opening the path for intelligent devices that improve network control and capture asset performance data.
- Our secure by design principle will contribute to a security conscious, digitally safe organisation that uses cyber security as an enabling function to achieve business objectives.
- Flexible, scalable data and analytics services will enable research on network assets and, in combination with customer and market data, inform the future network architecture.
- The growing importance of our network as an open-access platform will drive new business opportunities. We expect the IS contribution to be focused on customer experience, business ecosystem, data and analytics and IoT.

22.4 TECHNOLOGY PLATFORM ARCHITECTURE

22.4.1 CURRENT STATE

Earlier Information Technology (IT) strategies were based upon a "best of breed N-tier architecture" in which Powerco built or acquired point solutions to meet particular business needs and managed the integration itself.

This has resulted in a complex IT systems architecture that is overly complex, difficult to support, expensive to maintain and difficult to change to satisfy new business needs.

22.4.2 FUTURE STATE

We have been working to standardise our ICT environment to improve reliability, simplify operations, reduce costs and enable business agility. We are doing this by reducing the number of configurations, customisations, products and suppliers that we support.

We have also adopted a platform[103] approach where all the information and technology capabilities that will be required to support Powerco's business throughout this planning period are assembled into seven logical groups or platforms. This forms our future state architecture as shown in Figure 22.1 and will see the addition of three new platforms: Customer Experience, Business Ecosystem and Internet of Things. The seven technology platforms also map to the seven pillars or strategic workstreams in Table 22.1.

We have also adopted a "cloud first" strategy for non-mission critical IS services. This means that all new applications will be either Software as a Service (SaaS) or cloud hosted, and we will integrate solutions using integration Platform as a Service (iPaaS) and cloud-based Application Programming Interface (API) management. Existing systems will transition to the cloud over time. Cloud will help to drive standardisation, reduce implementation time, and bring operational benefits important for a midsize organisation such as Powerco.

Our approach for real-time systems, which includes operational technologies such as Supervisory Control And Data Acquisition (SCADA) and Network Operations Centre (NOC) communications is to continue to host on-premise.

It is important to note that we have not specified a separate cyber security platform as this is a component of each of the platforms.

We have started to build the customer experience, business ecosystem and IoT platforms as these did not exist previously. We will do this incrementally as required

[103] A logical grouping of technologies that allow a community of partners, suppliers and customers to share and enhance digital processes and capabilities or to extend them for mutual benefit.

to deliver business initiatives, for example, to improve service provider integration for ERP.

We also plan ongoing investment to modernise and/or extend each platform to meet new business requirements.

Figure 22.1: Technology platform architecture (future state)

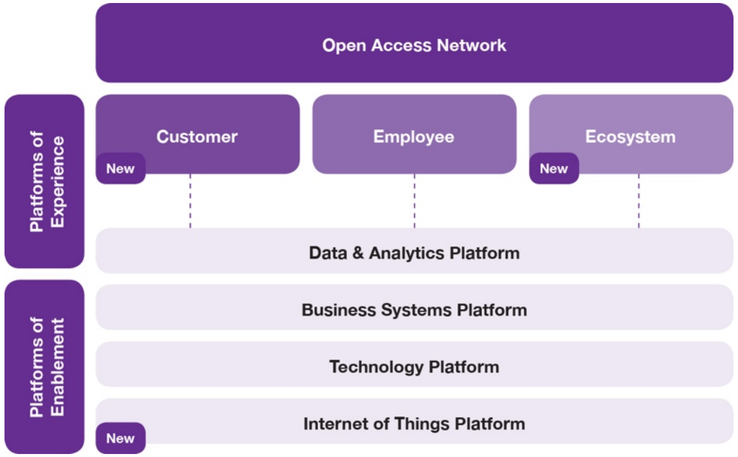


Table 22.2: IS architecture

TERM	DESCRIPTION	KEY SYSTEMS
Customer Experience platform	Contains the main customer-facing elements, such as customer portals, multichannel commerce and customer apps.	Salesforce CRM, SiteCore Experience Platform
Employee Experience platform	Consumerised tools and services to aid employee engagement, collaboration and productivity.	Microsoft Office 365 email, teams, Sharepoint, Skype for Business, Cisco Unified Communications
Business Ecosystem platform	Supports the creation of, and connection to, external ecosystems, marketplaces and communities. API management, control and security are its main elements.	Boomi, SAP PO/PI, Microsoft Azure API Gateway
Data & Analytics platform	Contains information management and analytical capabilities. Data management programs and analytical applications fuel data-driven decision-making, and algorithms automate discovery and action.	Business Objects Reporting, Tableau Online, SQL Server Datawarehouse, Google Cloud Platform
Business Systems platform	Supports the back office and operations, such as ERP and core systems. For Powerco these include:	JDE/SAP, ESRI GIS, Clearion vegetation management, Junifer Billing, Customer Works management system, OSII SCADA & OMS, Safety Manager, Autocad, Meridian, OSI PI, SharePoint
Technology platform	Traditional infrastructure and communications services (telephony, collaboration, corporate network).	Hytera DMR, Zetron Radio Console, Juniper WAN, Cisco LAN, Microsoft Hyper-V, Microsoft SCOM, CyberX, CrowdStrike
Internet of Things	Connects physical assets for monitoring, optimisation, control and monetisation. Capabilities include connectivity, real-time data processing/analytics and integration to core and operational (OT) systems.	HiveMQ MQTT broker, OSI PI

22.5 PLANNED ICT INVESTMENTS DURING THE PERIOD

The main ICT investments by technology platform are described below.

22.5.1 CUSTOMER EXPERIENCE PLATFORM

We are reviewing the processes and systems to improve how we communicate with customers during planned and unplanned outages. Implementing these improvements will require new system integrations and enhancements to the existing website and mobile application.

In 2020, phase 2 of New Foundations will establish new systems for customer works, customer contact, customer/contractor websites integration, customer complaints and customer relationship management that we can use to synchronise all the interactions that we have with our customers, regardless of which part of Powerco they are dealing with.

We have planned for an advanced customer interaction project in 2024, to manage and automate customer service requirements individually as their service requirements become increasingly varied. This is not possible with our current tools, which segment customer interaction in terms of the engineering characteristics of our network rather than customer preferences.

22.5.2 EMPLOYEE EXPERIENCE PLATFORM

In 2018, we modernised our employee experience services by renewing end user devices together with a lifecycle upgrade of the operating system and office tools. In 2019, we will complete a major upgrade of our video conferencing and telephony systems. In 2019 and 2020, we will upgrade and extend existing employee collaboration services. Lifecycle upgrades to these services are planned during the remainder of the planning period.

22.5.3 BUSINESS ECOSYSTEM PLATFORM

Powerco is part of a complex supply chain and integration services are required to improve information flows, take cost out of the supply chain and, ultimately, enable an open-access distribution platform.

In 2018, we adopted a new hybrid integration strategy to leverage our investment in the new ERP and also enable the rapid development of new cloud-based integration services to a wide range of external stakeholders. We will continue to extend this platform via incremental developments throughout the planning period.

22.5.4 DATA & ANALYTICS PLATFORM

We rely upon a highly complex data warehouse environment comprising multiple data repositories, technologies and manual processes for our reporting and analysis needs. In 2021, we will migrate from the legacy environment to New Foundations for the majority of our business reporting.

In 2019, in parallel we will build a new cloud-based analytics environment that will provide the data science capabilities required to obtain the customer and asset insight Powerco needs to identify business improvements and plan for the future of our network.

22.5.5 BUSINESS SYSTEMS PLATFORM

The technologies comprising the Business Systems platform are further categorised into ERP and Real-Time Systems (RTS). The most significant investment during this planning period is the new ERP system, implemented via a multi-year programme called New Foundations. New Foundations is described in the ERP section, with additional investments also called out for RTS.

ERP

This IS service comprises the largest proportion of planned ICT expenditure. In 2018, work began on implementation and migration to an ERP system. This is scheduled to be completed by 2022. This will enable us to manage increasing work volumes efficiently, as well as synchronise asset data in one place. Following the implementation of each phase of the programme, we will be able to retire our JDE financial system and constellation of bespoke supporting systems for work and asset management planning that evolved to complement it.

The pre-built integration between work and asset management available in a modern ERP (and related other business activities) will simplify the task of aligning work management to changing customer and asset needs. It will also improve our ability to provide accurate and timely information about the condition and state of all our assets. Ultimately, this will allow us to implement advanced analytic approaches to asset management planning and optimise the effectiveness of our asset-related expenditure against the value of the services that it delivers and the risks and costs of doing so.

This first phase goes live in 2019.

In 2020, our legacy billing system will require a lifecycle upgrade. The replacement tools are expected to allow us to bill for use of system at an ICP level using cost-reflective prices. As part of this project, we will retire satellite point solutions for customer billing, moving their functionality into a standard application framework –possibly the ERP if it offers suitable capability.

The focus for asset management from 2019 to 2021 is to implement new advanced asset management capabilities on top of the core capabilities provided with ERP. This covers integrated investment planning and optimisation, and will allow the retirement of many point applications.

The Customer Experience capabilities delivered by New Foundations are described in section 22.5.1.

Table 22.3 lists the activities that we will be undertaking during the three phases of our ICT systems upgrade process.

Table 22.3: Proposed ERP phasing

PHASE 1	PHASE 2	PHASE 3
Plant maintenance	Advanced asset management (part 1)	Advanced asset management (part 2)
Business-to-business integration with suppliers	Customer Relationship Management (CRM)	Advanced analytics for predictive maintenance
Geographic information integration	Human resources (part 1)	Human resources (part 2)
Mobility (part 1)	ICP management and billing	Enterprise health and safety
Project management	Phase 1B	Quality management
Materials management		Real estate (including easements)
Service management		Business planning and consolidation, budgeting enhancement
Purchasing		Treasury

PHASE 1	PHASE 2	PHASE 3
Sales		Mobility (part 2)
Finance		Risk management
Asset accounting		Contract management
Accounts payable		Invoice and expense management
Accounts receivable		
Human resources (baseline)		

Phase 1 is planned for FY18 and FY19, phase 2 FY20 and FY21, and phase 3 in FY21 and FY22.

Real-Time Systems (RTS)
RTS primarily support our network operations.

In 2018, we completed the first phase of automating our network operations with a major upgrade to the Outage Management System (OMS) and also implemented a new voice console system for NOC. Because of the extended duration of the OMS project, the Switch Order Management project has been deferred to 2021.

The second phase of our network operations modernisation is planned for 2022 to 2024. We will implement an advanced distribution management system to provide the core smart grid platform that will allow us to maintain network quality and reliability as our customers take increasing advantage of distributed energy resources, such as solar photovoltaic (PV) generation and local battery storage.

Alongside the growth in our communications network infrastructure, we need to invest in a data platform to process increasing volumes and variety of data from an increasing number of sensors both in real-time for network operations and also to enable trending and forecasting for asset management.

From 2019, we begin a programme of work to extend our data historian.

IoT data services will be an area of continued focus throughout the planning period.

22.5.6 TECHNOLOGY PLATFORM

We have invested extensively in our infrastructure services in the past few years as part of our risk management and service standardisation initiatives.

While our data centre investment remains valid in the long term to support our real-time operational systems, we are developing a Cloud Strategy to map out a path to the cloud for our corporate systems. The first major system to be hosted in the public cloud will be the new ERP system, while we have also adopted cloud analytics and integration technologies. The Cloud Strategy will reduce the on-premise systems footprint, so we are reviewing options for our secondary data centre.

22.5.7 IOT PLATFORM

Investments in communications infrastructure to enable network automation and control are profiled in Chapter 11.

22.6 ICT EXPENDITURE FORECASTS

22.6.1 OVERVIEW

We distinguish between two ICT portfolios.

- **ICT Capex** – portfolio includes investments in ICT change initiatives and network related ICT. It covers the ICT programmes and projects that ensure our processes, technology and systems help deliver our Asset Management Objectives.
- **ICT Opex** – portfolio covers ICT costs associated with operating our business. It covers software licensing, software support, public cloud services, data centre costs and network running costs.[104]

Our expenditure forecasts are based on historical costs, expected unit cost, and price trends. We have worked with trusted suppliers to determine unit costs for current technologies or their likely replacements.

22.6.2 TRENDS IN ICT EXPENDITURE

There are two main trends that will impact ICT expenditure during the planning period – the evolution to an intelligent grid and the adoption of cloud services.

Evolution to an intelligent grid
Powerco's strategy to evolve a more intelligent grid and open-access network will come with a commensurate increase in ICT costs, both Opex and Capex, during this planning period. This will increase communications network, data services and cyber security costs, with the largest component pertaining to communications costs.

Examples of new requirements:

- Power quality and protections device data from substations so that network planning can see power quality trends and transients to build and respond to those events.
- Video monitoring at major sites so that we can determine safe working and network equipment condition.
- Automated field network recovery via smart assets, so that unplanned outage durations are minimised.

104 ICT Opex is included as part of our business support expenditure forecasts (refer to Chapter 26).

- Thousands of field devices constantly feeding measurements back to Powerco data services, so that we can manage power flows and constraints on the network right down to low voltage level.
- Devices as close as practicable to our customers, so we can view what's happening at the fringes of our grid.

In most cases, the trend is for the ICT costs to be purchased as a service with a commensurate increase in operating costs. In the event that we are able to use capital intensive solutions, there will still be an increase in operating costs associated with operating and maintaining these systems.

At this stage, it is difficult to fully quantify with any accuracy the impact on our future operating costs. Using our communications fleet as an example, we forecast that operational costs will increase by approximately $150,000 per year during this Customised Price-quality Path (CPP) period, continuing to grow at this rate or higher through the next regulatory period.

Public cloud services

Since approximately 2010, computer applications and infrastructure have been made available as services from one or more public cloud providers. Cloud services are attractive because they reduce the time to implement new technology capabilities and, therefore, increase business agility. In many instances today, and increasingly in the future, the cloud will be the only method of consuming application or infrastructure services.

Utilities have been slow to adopt cloud services but are now rapidly moving their corporate applications to the cloud. In 2018, Powerco established a "Cloud First" Strategy, which will see all new solutions implemented using public cloud services and most of the remaining corporate systems migrated to the cloud. For example, Powerco implemented MYOB PayGlobal software as a service in 2016 and recently migrated its email and personal file storage to Microsoft Office365. The new ERP system will use a combination of infrastructure and software as a service.

Cloud services change the ICT Opex/Capex by:

- Avoiding the need for upfront capital expenditure on hardware and software, replacing it with a subscription fee paid for the services used.
- Increasing communications costs (leased) as more network capacity is required between Powerco's offices and the cloud providers.

While investment is shifting from traditional Capex to Opex (hardware purchase replaced by infrastructure as a service) the overall total cost of ownership is neutral to positive and provides additional benefits relating to implementation time, operational improvements, scalability and flexibility.

It is important to note that our approach for RTS, which includes operational technologies such as SCADA and NOC communications, is to continue to host these in our own data centres. There is no current proven cloud model for these services.

The target is for the majority of Powerco's applications to be migrated to the public cloud by FY21. During this transition, IS will absorb additional operational costs as it continues to operate its own infrastructure and also consumes cloud services.

As Powerco is still relatively new to cloud services, it is difficult to predict the impact of the cloud on our operational expenditure.

An IT benchmark of 162 utilities from around the globe (Gartner, December 2017) shows that, on average, utilities spend 5% of total ICT budget on public cloud services, and Gartner predicts that public cloud spending is expected to grow at a compound annual growth rate (CAGR) of 16.5%.

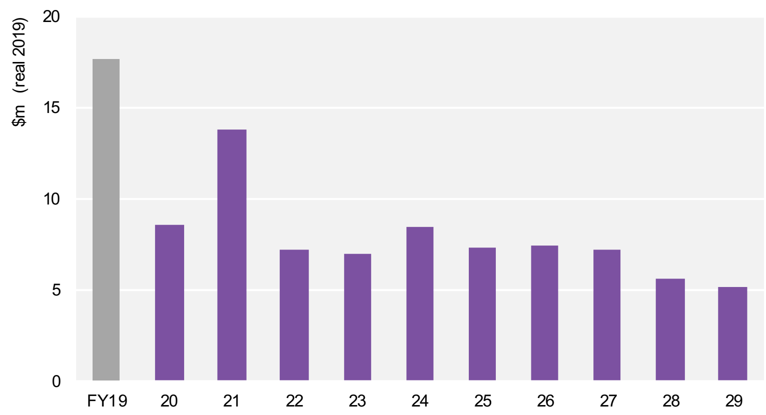
In FY18, Powerco spent 1% of ICT budget on public cloud services.

Given the accelerating demand for IS to deliver new technology services faster, better and more cost effectively, it is reasonable to assume that the overall ICT Opex/Capex split will continue to shift in favour of Opex, largely because of increases in public cloud computing and associated network spend.

22.6.3 EXPENDITURE FORECASTS

Figure 22.2 shows how our forecast ICT capital expenditure for the planning period.

Figure 22.2: ICT Capex forecast



The increase in capital expenditure in the early years of the planning period is due largely to our ERP investment, and later in the middle years to build-out an Advanced Distribution Management System (ADMS).

Following this, annual average capital expenditure will remain at slightly above historical levels because of ICT investment to support the evolution of an intelligent grid and the cost of maintaining an increased number of digital capabilities upon which our business now depends.

22.7 FACILITIES

22.7.1 OFFICES AND DEPOTS

Our facilities management programme aims to ensure our offices and depots:

- Are safe and secure for our employees and contractors.
- Are functional and fit for purpose.
- Can support future staff growth.
- Support improved productivity and efficiency.
- Are cost effective.

We have five major regional offices in four cities that match our broad geographical coverage and ensure that we are close to our assets and the work being undertaken across our network. In addition to this, we currently have a New Foundations Project office as the project was not able to be accommodated in existing facilities.

Our corporate office is in the New Plymouth CBD (Liardet St) and we have a second location on the outskirts of New Plymouth (Junction St), where most of our New Plymouth staff are located. Our five major regional offices and our depot locations are shown in Table 22.4.

Table 22.4: Office and depot facilities

LOCATION	OWNERSHIP
Junction St office and depot (New Plymouth), Mihaere Dr office and depot (Palmerston North). Depots – Coromandel, Masterton, Pahiatua, Taihape, Raetihi.	Owned
Grey St office (Wellington), Liardet St office (New Plymouth), Tauranga office, New Foundations project office (New Plymouth), Whanganui office (future).	Leased

The increased staff and contractor numbers because of the CPP has put added pressures on many of the facilities. Therefore, our facilities strategy is focused on addressing these demands to ensure we are providing environments that support our teams.

Junction St will continue to be upgraded accommodating the increase in numbers and providing facilities for project teams, while the main corporate office in Liardet Street will be renovated.

The Tauranga and Palmerston North offices have reached capacity, so new offices are required to handle the growth. We also desire a greater presence in the Whanganui region so will provide new offices for the team that is working out of the Downer offices.

22.7.2 NETWORK OPERATIONS CENTRE

In the past 12 months, a new purpose-built Importance Level 4 (IL4) building has been constructed to house NOC. This building will support the growth of our control room operator desks from four to eight, which is essential to effectively monitor our network, especially with the increase in asset maintenance, renewal and vegetation management.

22.7.3 VEHICLES

There are 48 vehicles in our fleet that are dedicated solely to the Electricity Division. Another 10 vehicles support corporate functions.

The number of vehicles is expected to increase during the next few months as new roles in the Electricity teams are filled. Most of the corporate vehicles have recently been replaced with either fully electric or plug-in hybrid electric vehicles (PHEV), with the remainder to be replaced in the next couple of months.

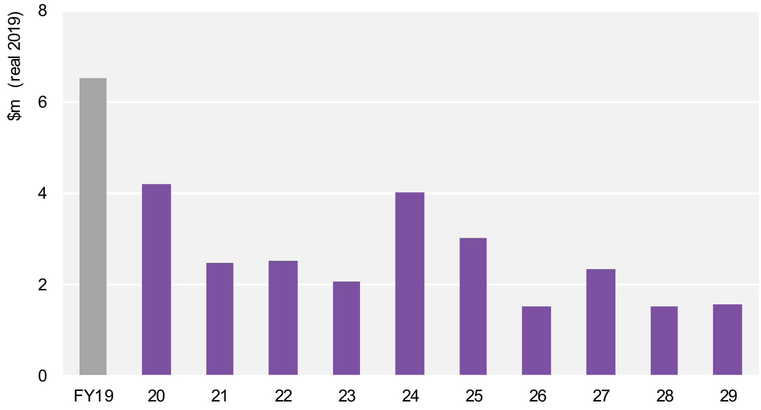
All but five vehicles are leased on full maintenance lease terms.

The vehicles have been selected based on several criteria, including safety, fit for purpose, and cost, and with input from our drivers. As vehicles are replaced, they are being fitted with the EROAD GPS system to prompt for positive driver behaviours and help ensure compliance and effective vehicle utilisation.

22.7.4 FACILITIES EXPENDITURE FORECAST

Figure 22.3 shows our facilities Capex forecast.

Figure 22.3: Facilities Capex forecast



One of the key drivers of facilities Capex continues to be the upgrade of the Junction St facility to accommodate the continued growth at this office and ensure that the facilities can accommodate scalable operational needs.

The upgrade of the Liardet St offices and new offices in the Whanganui, Palmerston North and Tauranga regions will ensure our staff are well supported in modern and productive environments.

Another driver for the increase in facilities Capex is the introduction of the new IASB standard, IFRS 16 Leases, which came into effect on 1 January 2019. This requires leases to be recognised as Capex on the balance sheet.

23.1 CHAPTER OVERVIEW

Network operational expenditure plays a central role in ensuring we deliver our Asset Management Objectives and achieve our asset management targets. Appropriate and well-focused operational expenditure helps ensure our assets are maintained appropriately and that we have the information necessary to support effective expenditure in other areas.

We plan to increase our investment in operational activities during the planning period. This will help us arrest and control emerging issues on our networks, such as higher than desired defect numbers and unacceptable rates of vegetation encroachment. It will also help ensure that activities key for effective asset management, such as inspections and condition assessment, are developed to support appropriate and well-targeted renewal programmes.

Increased levels of Capex investment in the key renewal, security, and reliability areas necessitates an enhanced approach to asset management and works delivery capability. By investing in these capabilities, we can be more efficient in the way we target and plan investment works and deliver a net benefit overall. Our plans for the period include progressive enhancement of our asset management functions, which is reflected in our System Operations and Network Support (SONS) portfolio.

This chapter describes our three portfolios of maintenance activities, vegetation management and SONS. For each of these portfolios we set out our forecast Opex for the planning period.

23.2 MAINTENANCE PORTFOLIOS

For planning and budgeting purposes, we group our maintenance work into three network Opex portfolios. These are:

- **Preventive Maintenance and Inspection**[105] – this portfolio deals with routine maintenance activities such as testing, inspecting and asset servicing.
- **Corrective Maintenance** – this portfolio is mainly concerned with fixing defects, after they are identified and scheduled appropriately, through activities such as replacement of defected asset components or minor assets.
- **Reactive Maintenance** – this portfolio is about responding to faults and other network incidents, including immediate work to make a situation safe, or to repair broken assets.

The figure below summarises how we categorise our maintenance activities.

[105] Our Preventive Maintenance and Inspection portfolio was previously named Routine Corrective Maintenance and Inspections (RCI). The corrective maintenance component of this work is now part of our Corrective Maintenance portfolio. This has been done to better reflect the drivers for these activities and the way we plan and deliver these works. Our Information Disclosure schedules reflect the RCI definition consistent with our historical disclosures.

Figure 23.1: Our maintenance portfolios

Preventive Maintenance and Inspection
- inspections
- servicing
- condition assessments

Corrective Maintenance
- defect rectification
- repairs
- replace minor components

Reactive Maintenance
- fault response
- emergency switching
- first response

23.3 PREVENTIVE MAINTENANCE AND INSPECTION

23.3.1 OVERVIEW

Preventive Maintenance and Inspection works are undertaken on a scheduled basis to ensure the continued safety and integrity of our assets, and to compile condition information for analysis and renewal planning. It is our most regular asset intervention process and is a key source of feedback in our Asset Management System.

The main types of activities are set out below:

- **Inspections** – checks, patrols and testing to confirm the safety and integrity of assets, assess fitness for service and identify follow-up work.
- **Servicing** – regular maintenance tasks performed on an asset to ensure its condition is maintained at an acceptable level.
- **Condition assessments** – activities performed to monitor asset condition and to provide systematic records for analysis.

Our maintenance standards are the cornerstone of our maintenance regime. Our standards incorporate knowledge of specific maintenance, operational and service requirements. Maintenance practices and scheduled intervals, as recommended by equipment manufacturers, are reflected in our standards. Our standards also consider the regulatory requirements for safety and integrity inspections and reflect optimal operational experience developed during the past decade.

Preventive maintenance and inspections work frequencies for each of our asset types are specified in our maintenance standards. These activities are then scheduled in our Gas and Electricity Maintenance Management (GEM) system. GEM uses our asset register to create schedules of work. It also stores the data collected from the field as a record of our maintenance activity for the scheduled asset.

The Preventive Maintenance and Inspection portfolio also includes other activities such as 'stand-overs' and cable location when third parties are working close to our network. These activities are critical for safe network operation.

23.3.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified several high-level objectives for our Preventive Maintenance and Inspection activities.

Table 23.1: Preventive Maintenance and Inspection portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Ensure our inspection regimes effectively identify safety hazards. Protect the integrity of our network assets by monitoring and managing the activities of other parties.
Customers and Community	Minimise planned interruptions to customers by coordinating servicing with other works. Minimise landowner disruption when undertaking maintenance.
Networks for Today and Tomorrow	Consider the use of alternative technology to improve effectiveness or reduce cost of inspections and servicing.
Asset Stewardship	Maximise asset life by ensuring that required maintenance is undertaken. Ensure that deteriorating components are identified for repair or replacement in a timely manner. Ensure that high-quality, complete asset data is available.
Operational Excellence	Improve the quality and completeness of asset data through improved inspections and innovative techniques.

23.3.3 PREVENTIVE MAINTENANCE AND INSPECTION INITIATIVES

As set out in Chapter 10, we are looking to improve our asset management approach. As part of these efforts we have identified several opportunities to improve our overall scheduled maintenance performance. More significant additions and changes to Preventive Maintenance and Inspection activities are set out below.

Table 23.2: Preventive Maintenance and Inspection improvement initiatives

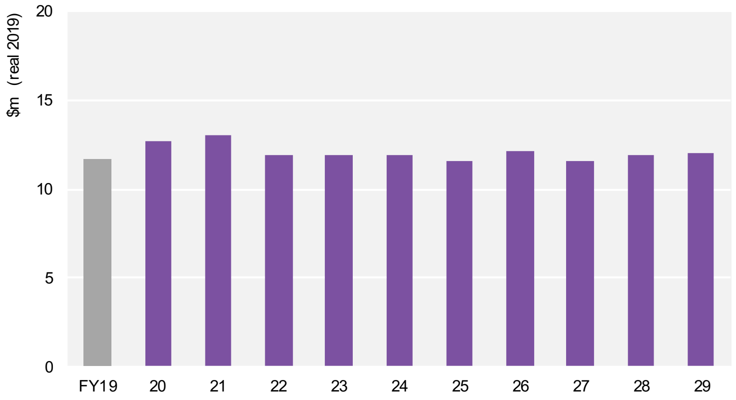
INITIATIVE	COMMENT
Pole-top photography	We are planning to introduce enhanced pole-top inspections. This involves a cyclical pole-top photography programme for all overhead lines to enable identification of unknown defects, which will improve our overall asset condition knowledge and allow us to proactively act on it. The images will be captured using high-quality digital cameras attached to a helicopter or Unmanned Aerial Vehicle (UAV).
Improved asset data collection methods	Refining and expanding the standards, methodologies and processes for collecting field data on the condition of our assets will improve asset data quality. This will enable us to make better decisions on required maintenance and renewal, and sharpen our focus on areas where the network or assets are not performing as expected.
Expanded sub-transmission line patrols	We are planning to extend our scheduled rapid inspection programme to cover selected subtransmission lines and critical feeders. All defects that are assessed to have the potential to cause an outage will be recorded. Defects identified through the inspection process will be assessed by performance engineers and will be scheduled for rectification in order of relative priority.
Acoustic testing of overhead line components	Acoustic testing of overhead line components is one of the proposed new technologies to be introduced that will deliver additional, previously unavailable condition data. It will enable us to identify insulator defects and incipient faults that cannot be detected by our visual ground-based inspection process.
Wood pole acoustic resonance testing	Acoustic resonance testing will supplement the visual assessment process and will provide accurate and non-subjective structural condition data for wood poles.
Expanded partial discharge (PD) testing	This initiative involves a cyclical PD testing programme for all zone substation switchboards, transformers, outdoor circuit breakers and exposed cables within substations to ascertain the electromagnetic signature of these assets. PD testing will identify assets that need remedial work or replacement before any abnormal condition results in a fault.
High Voltage (HV) fuse element replacement	This involves proactive fuse element replacement for HV DDO fuse assemblies where these are fitted to our distribution lines running through forested areas. When a fuse blows, the molten fuse element can be expelled from the fuse assembly and can fall to the ground resulting in a fire hazard.

INITIATIVE	COMMENT
Low Voltage (LV) pillar box data capture	We have a programme under way of capturing LV pillar box information (fuse type and size), identifying the asset location, labelling the box and uploading the captured data to the Geographical Information System (GIS). Having accurate pillar box information reduces time to find assets for repairs. The information also provides detail of asset types and customer types connected to our network. Minor repairs will also be undertaken where necessary (repairs classified as corrective maintenance).

23.3.4 PREVENTIVE MAINTENANCE AND INSPECTION OPEX FORECAST

Our Preventive Maintenance and Inspection forecast is shown in Figure 23.2. Increased levels of investment in this area reflect the considerable value of this activity in achieving investment efficiency in other areas, such as asset renewal.

Figure 23.2: Forecast Preventive Maintenance and Inspection expenditure



23.4 CORRECTIVE MAINTENANCE

23.4.1 OVERVIEW

The Corrective Maintenance portfolio includes corrective interventions, triggered by asset condition. Our Corrective Maintenance portfolio includes corrective maintenance that was previously included in the RCI portfolio of work.

The main types of corrective activities are set out below.

- **Reactive repairs** – unforeseen works to repair damage and prevent failure or rapid degradation of equipment.
- **Asset replacements** – the replacement of minor, low-cost assets or asset components.
- **Defect management** – correcting condition-based defects that are identified from Preventive Maintenance and Inspection and Reactive Maintenance activities.

23.4.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high-level objectives for our Corrective Maintenance activities.

Table 23.3: Corrective Maintenance portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Ensure asset replacements are undertaken in a timely manner. Reduce safety hazards by prioritising safety-driven corrective work, particularly red defects.
Customers and Community	Minimise planned interruptions to customers by coordinating maintenance with other works. Minimise landowner disruption when undertaking maintenance.
Networks for Today and Tomorrow	Maximise asset life by ensuring that required maintenance is undertaken. Consider the use of alternative technology to reduce cost of corrective works.
Asset Stewardship	Ensure that deteriorating components are repaired in a timely manner. Reduce the number of amber defects to an inventory of no more than six months.
Operational Excellence	Undertake works in a coordinated manner to ensure economies of scale and scope. Review and modify our defect assessment process to improve data accuracy and fault risk exposure.

23.4.3 CORRECTIVE MAINTENANCE INITIATIVES

Our defect assessment and prioritisation process depends on staff identifying specific condition details of a range of assets. Assessments and prioritisation are somewhat subjective and there is room to improve consistency. We have identified several improvement opportunities, with the more significant items listed below.

Table 23.4: Corrective Maintenance improvement initiatives

INITIATIVE	COMMENT
Defect control	Our investment plans include a targeted approach to reduce amber defect pools to a level that reflects six months of typical delivery volume. The introduction of more scientific, systematic field inspection methods will also identify more defects and risks, which we have projected will require a step-change in Opex to address. This is discussed in Preventive Maintenance and Inspection improvement initiatives.
Storm hardening	This programme involves the storm hardening of critical sub-transmission and distribution lines in storm-prone areas. Structural components of these lines will be renewed or maintained to prevent storm-induced damage from wind or from wind-borne foreign objects.
Distribution transformer repairs	Corrosion occurs on ground-mounted transformer tanks, cubicles and associated kiosks because of location and environmental conditions. With this programme we plan to remediate corroding transformers through proactive permanent repair, before oil leakage can occur.

23.4.4 CORRECTIVE MAINTENANCE OPEX FORECAST

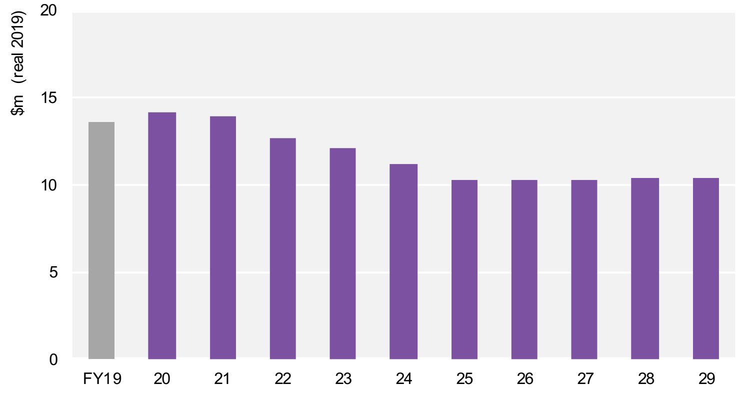
Our Corrective Maintenance Opex forecast for the planning period is shown in Figure 23.3. As discussed above, this varies from disclosed Corrective Maintenance expenditure because of the corrective maintenance component that was previously contained within RCI.

As we have improved our inspection regime, and as a direct result of more assets being operated at near end-of-life, we have seen a steady increase in the number of amber defects. As a result, our defect pool is larger than we would prefer, and this increase indicates a higher risk of asset failure and associated faults.

During the planning period, our aim is to reduce the amber defect pool to a level of no more than six months' work to help ensure resolution within target times.

The necessary short-term focus to reduce defect pools and implement improved processes for the management of defects is reflected in our planned investments. In the longer term we expect expenditure in this category to reduce as defect numbers reduce and we utilise more efficient ways of managing defects.

Figure 23.3: Forecast Corrective Maintenance expenditure



23.5 REACTIVE MAINTENANCE

23.5.1 OVERVIEW

The Reactive Maintenance portfolio involves reactive interventions in response to unplanned network events.[106]

The main types of activities are as follows:

- **First response** – involves the attendance of a service provider fault person to assess the cause of an interruption, potential loss of supply, or safety risk. They assess the cause of the fault and may undertake switching, or cut away a section of line to make safe or to alleviate the imminent risk of a network outage. The provision of standby fault personnel for first response work is included in this activity.
- **Fault restoration** – is undertaken by the service provider fault person and includes switching, fuse replacement or minor component repair in order to restore supply.

Reactive Maintenance work is prioritised and dispatched by the Network Operations Centre (NOC) with the physical work carried out by our service provider. There is limited forward planning for Reactive Maintenance work other than ensuring there are sufficient resources on standby to respond to network faults.

[106] The Reactive Maintenance portfolio does not include second response, which is covered under the Corrective Maintenance portfolio.

Our service provider operates a service management centre, which is used to receive instructions and directions from the NOC to quickly and effectively dispatch fault response staff and additional resources as needed. Staff levels are set to ensure target fault response times can be achieved.

Reactive Maintenance work volume is driven by a variety of factors, including asset condition, weather, environmental conditions, the levels of work being undertaken in other portfolios, such as Corrective Maintenance, and our protection philosophies.

23.5.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high-level objectives for our Reactive Maintenance activities.

Table 23.5: Reactive Maintenance portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reduce fault response time to reduce the potential for public safety incidents. Reduce safety hazards by prioritising safety-driven faults.
Customers and Community	Minimise landowner disruption when responding to network faults. Reduce fault restoration times to ensure we return supply to customers quickly.
Networks for Today and Tomorrow	Consider the use of alternative technology to reduce cost of reactive works and improve fault response times.
Asset Stewardship	Minimise outage events and durations to support our overall reliability objectives. Ensure that faults are repaired in a timely manner.
Operational Excellence	Improve dispatch processes and field work communications to reduce fault response times.

23.5.3 REACTIVE MAINTENANCE INITIATIVES

Our Reactive Maintenance work is dependent on technology to enable a timely response from information available to the NOC and our service provider staff through communications systems, Supervisory Control and Data Acquisition (SCADA) and the Outage Management System (OMS). Effective management is critical to ensuring safe outcomes on our networks, so we have identified several improvement projects that will enable us to better meet our Reactive Maintenance objectives. The more significant items are listed below.

Table 23.6: Reactive Maintenance improvement initiatives

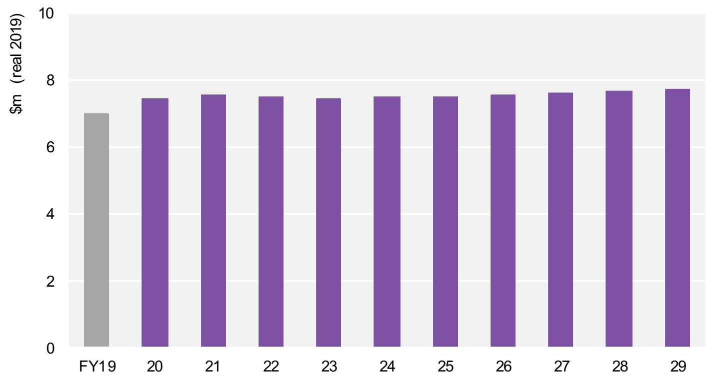
INITIATIVE	COMMENT
Increase in-field resources	To allow us to effectively respond to outages within reasonable timeframes, we need to increase the available field service resources. This is necessary to ensure that existing reliability levels can be maintained.

23.5.4 REACTIVE MAINTENANCE OPEX FORECAST

Our Reactive Maintenance expenditure forecast for the planning period is shown in Figure 23.4. Our forecasts reflect additional investment in personnel to ensure required service standards and response times can be achieved.

While it is reasonable to assume fault rates will increase in the short term until renewal programmes arrest current adverse trends, we have assumed these factors will be offset by improvements in vegetation management and other reliability-focused programmes.

Figure 23.4: Forecast Reactive Maintenance expenditure

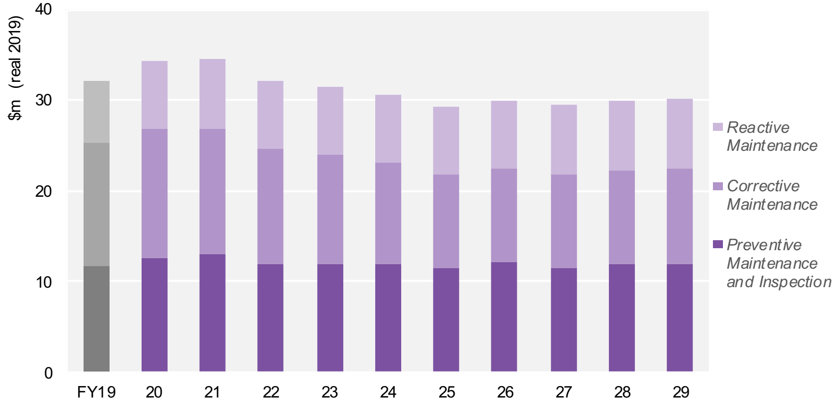


23.6 OVERALL MAINTENANCE EXPENDITURE

Changes in our overall maintenance forecast during the planning period are influenced most heavily by Preventive Maintenance and Inspection expenditure. This is primarily because our focus is on improving condition assessment information to support improved expenditure and efficiency outcomes in other areas.

A moderate increase in Corrective Maintenance expenditure also has an impact on overall forecast expenditure, bringing amber defects into our target range.

Figure 23.5: Overall maintenance expenditure



23.7 VEGETATION MANAGEMENT

23.7.1 OVERVIEW

Compliance

Network operators are required to meet several compliance obligations in respect to vegetation management. Key among these are the Tree Regulations[107], which prescribe the minimum distance that trees must be kept from overhead lines[108], and set out responsibilities for tree trimming.

Following an initial cut or trim, tree owners have an obligation to maintain their trees to keep them clear of our network. Our contractor liaison staff identify trees that need cutting and issue appropriate notification to tree owners. We have an ongoing responsibility to ensure that tree owners act. Where tree owners fail to act, we are obliged to trim trees to remove any danger.

Tree regulations

The Electricity (Hazards from Trees) Regulations 2003 require us to identify trees or vegetation that is within the growth limit zone of any network conductor and to issue a notice to the tree owner advising of trimming/clearance requirements. These regulations specify both the tree owner's and our responsibilities with regard to actions and cost.

Under the Tree Regulations, breaches of minimum clearance distances must be corrected in a prescribed time. We largely respond to issues as we become aware of them, whether it be through line inspections, notification by affected parties, or after faults. This practice is still common in New Zealand, but good practice involves a more proactive approach – to have ongoing, regular visibility of the status of vegetation around lines and acting to prevent issues from arising. Moving to this cyclical approach is part of the strategy we are adopting.

Newly planted or self-seeded trees are also subject to an initial trim or removal at our cost. Wherever possible we remove self-seeded trees and apply growth retardant to minimise the ongoing vegetation management cost.

Performance

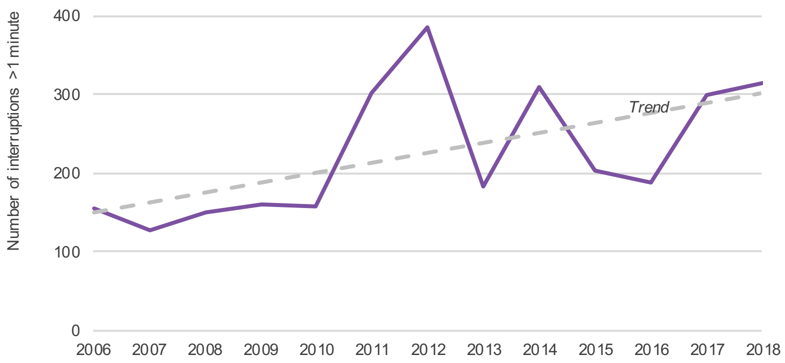
Outages caused by vegetation are a significant contributor to our overall System Average Interruption Duration Index (SAIDI) and System Average Interruption

107 Electricity (Hazards from Trees) Regulations 2003 (SR 2003/375)

108 The New Zealand Electrical Code of Practice for Electrical Safe Distances (NZECP 34) sets minimum safe electrical distance requirements for overhead lines, including the minimum safe approach distances for the public, and requirements for workers who need to work within this distance.

Frequency Index (SAIFI). Our network performance is being adversely affected by an increasing number of interruptions caused by vegetation – see Figure 23.6.

Figure 23.6: Number of vegetation related events causing >1 min outages



A management review of the reasons for this trend has concluded that, in retrospect, our approach to trimming has been overly reactive and at too low a volume. Public safety has also been of concern as tree owners attempt to undertake tree trimming and removal work themselves.

Cyclic planning and management of tree trimming is highly effective in reducing outages and notifying tree owners about the vegetation risk in a timely and targeted manner.

23.7.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high-level objectives for vegetation management.

Table 23.7: Vegetation management portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reduce the potential risk of incidents involving tree owners who undertake trimming work. This is to improve public safety and comply with regulations. Reduce safety hazards by prioritising higher risk trees.
Customers and Community	Minimise landowner disruption when undertaking tree management. Improve relations with tree owners to better align incentives around the timing and scale of vegetation management. Provide a resilient network by endeavouring to supply all customers at all times by managing avoidable faults.
Networks for Today and Tomorrow	Reduce the number of vegetation related faults on our network to avoid interruptions (intermittent and permanent) that may affect increasing quantities of sensitive, smart equipment.
Asset Stewardship	Reduce damage to network assets caused by vegetation to enable assets to achieve expected life. Reduce vegetation related interruptions to support our overall reliability objectives. Achieve good practice vegetation management through enhanced cyclical work programmes.
Operational Excellence	Improve the efficiency of our vegetation management delivery approaches. Achieve efficiencies by utilising data such as Light Detection and Ranging (LIDAR) to direct investment.

23.7.3 VEGETATION MANAGEMENT INITIATIVES

Powerco has started several key improvement initiatives in order to meet the objectives through efficient work practices. Key initiatives under way are outlined in Table 23.8.

Table 23.8: Vegetation management improvement initiatives

INITIATIVE	UPDATE
Cyclical trimming Develop and implement a full cyclical trimming programme.	A full cyclical trimming programme has been developed for all distribution network feeders and implementation is under way. This adds to the existing cyclic programmes for subtransmission and high-risk urban network. LV network vegetation management remains reactive, such as priority management of climbing risks and bare conductors where fire risks are high.
Risk-based approach Develop a risk-based approach for trees beyond the mandated clearance limits	Definition of the risk-based approach to vegetation assessment is under way, including considering industry guidelines with a view to achieving greater than mandated clearances, based on assessed risk for targeted sites. This is expected to progress further with the addition of LIDAR information.

INITIATIVE	UPDATE
Improved public liaison Shift to an independent liaison function	In our initial assessment for this initiative, it became apparent that there was a significant amount of re-work involved in shifting to an independent liaison model. It was therefore decided to change the initiative to improved stakeholder engagement as shown below.
(New) Improved stakeholder engagement	We are working closely with the forestry industry and other electricity industry representatives to educate forest owners and harvesters about adequate set-backs in order to protect lines while also ensuring their crops are profitable to harvest.
Improved public education Develop an enhanced public safety programme	We ran a campaign to educate the rural communities in Taranaki after ex-Cyclone Gita took out many fall distance trees, which are outside the regulatory growth limit zones. There is an ongoing need to educate tree owners about safety issues, their responsibilities and the effects they have on the communities they live in.
(New) Trimming and felling efficiency improvements	We are working with the primary regional contractors to deliver efficient tree management. These techniques provide increased safety of the operators as well as increased productivity, as more trees are cut per day. Equipment now used as standard includes large diggers with tree shears, tracked all-terrain elevated work platform (EWP), shelter trimmers and mulchers as well as heli-spraying to manage regrowth and maintain corridors.

Tree shears provide controlled felling near power lines.

A tracked all-terrain EWP (elevated work platform) allows easy access to trees as well as minimising the impact on surrounding land.

23.7.4 VEGETATION MANAGEMENT FUTURE IMPROVEMENT INITIATIVES

We have identified two key initiatives that will improve efficiency of delivery of the vegetation management strategy. These initiatives are under review and their implementation is expected to begin in the next financial year.

Key initiatives to achieve this are outlined in Table 23.9.

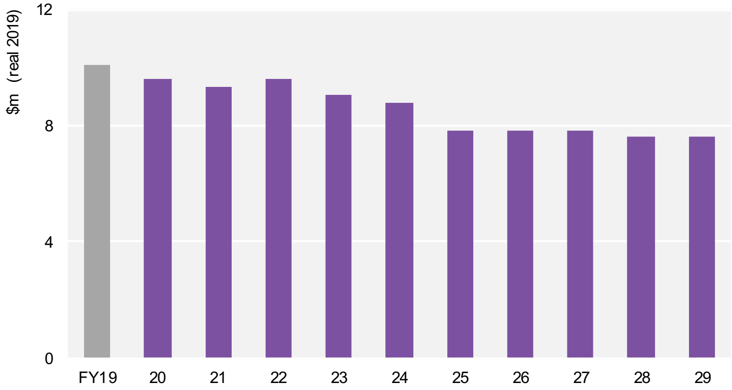
Table 23.9: Future vegetation management improvement initiatives

INITIATIVE	COMMENT
Disconnected system access	Powerco uses Clearion to store all vegetation management information. Efficiency improvements have been identified through moving to the disconnected platform. This will allow Powerco primary regional contractors to issue notices, scope, and plan works as well as audits post-work from field devices.
LIDAR information	LIDAR technology provides accurate distance assessment of vegetation encroachment on the electricity line network. It also provides accurate distance assessment of any physical items, such as buildings. We have plans to perform a trial with LIDAR and utilise data to plan works. This will likely review the cyclic versus risk approach to vegetation management.

23.7.5 VEGETATION MANAGEMENT OPEX FORECAST

Our vegetation management Opex forecast for the planning period is shown in Figure 23.7. Increased expenditure relates to the expected increase in effort to meet compliance obligations and arrest the increasing trend in vegetation-related faults.

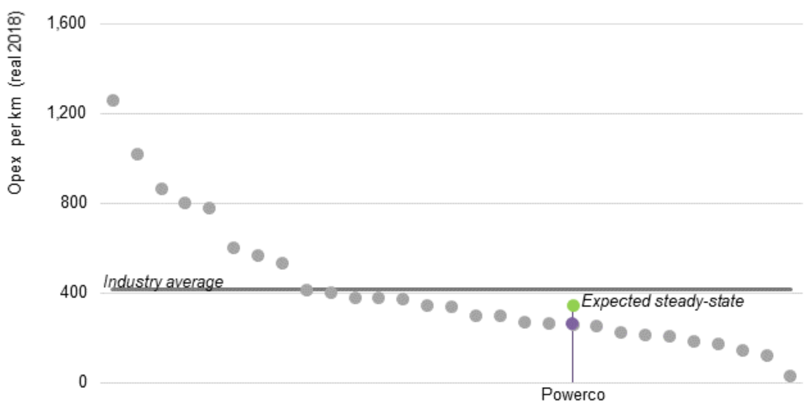
Figure 23.7: Vegetation management expenditure



We will require higher expenditure in the first six years of the trimming programmes to implement our new cyclical and risk-based approach. Once these programmes have been embedded, we anticipate a sustainable position will be achieved.

Figure 23.8 compares our current (purple dot) and steady state (green dot) vegetation management expenditure per kilometre of overhead line with other Electricity Distribution Businesses (EDB). It shows that our forecast steady state expenditure per kilometre is more in line with, but below, the industry average.

Figure 23.8: Vegetation Opex per km of overhead line compared with other EDBs (FY14-18 average)



23.8 SYSTEM OPERATIONS AND NETWORK SUPPORT (SONS)

23.8.1 OVERVIEW

Our SONS investment plans include a material increase in expenditure and work volumes during the planning period.

To support these increased work volumes, we have made appropriate provision to lift our internal capability. The main increases will come from work related to:

- Network engineers – to plan and scope additional works
- Project managers – to manage construction in the field
- NOC resource – to manage network access for construction
- Associated project support functions

Our investment plans also include targeted capability enhancements to support efficient delivery over time. Particularly the following:

- Improved analytical capability to enable more targeted asset planning
- Developing proofs of concepts for future network technology and applications
- Enhancing our asset management maturity over time
- More focus on changing customer needs

Specific capability and capacity requirements are outlined in Chapter 10.

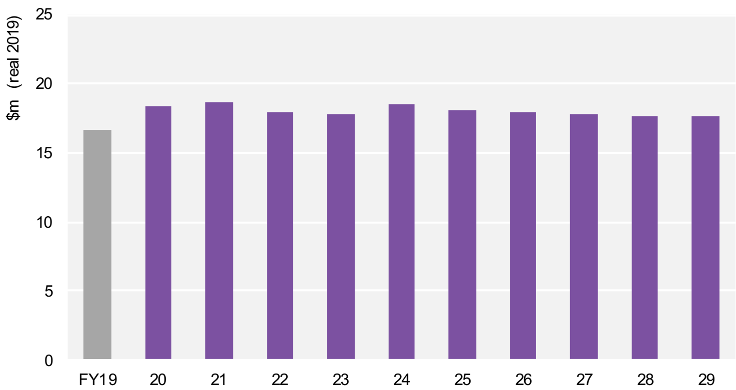
23.8.2 FORECAST EXPENDITURE

Forecast increases in SONS expenditure reflect our targeted focus on lifting capacity and capability. Increases are influenced most heavily by capacity enhancements to support increased work volumes.

Towards the end of the period, expenditure reduces because of reductions in network Capex programmes, and because of targeted improvements in delivery efficiency.

Figure 23.9 shows our forecast SONS Opex for the planning period.[109]

Figure 23.9: Forecast Systems Operations and Network Support Opex



[109] People in the SONS portfolio also support and enable capital works. Expenditure relating to capital works is capitalised in accordance with our capitalisation policy and included in the relevant capital assets.

Customer works

This section summarises our approach to consumer connection and asset relocation projects.

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24 CUSTOMER CONNECTIONS

24.1 CHAPTER OVERVIEW

This chapter explains our approach to connecting new customers and how we forecast expenditure for these connections. The process we use to connect new customers is designed to ensure the cost of connection is economical, and that connections can be completed in a timely way.

- Sections 24.2 and 24.3 include an overview of our connection process and how these works are funded.
- Section 24.4 sets out our forecast expenditure for the planning period.

Further detail on our customers and how they impact our investment plans can be found in Appendix 4

24.2 OVERVIEW OF CUSTOMER CONNECTIONS

Every year, several thousand homes and businesses connect to our electricity network.

New connections require investment in network infrastructure.

Residential connections range from a single new house to subdivisions with hundreds of residential plots. We also connect a range of businesses and infrastructure, from small connections, such as water pumps and telecom cabinets, to large connections, such as factories and supermarkets. The customer connections portfolio also includes works for customers, typically commercial, who want to upgrade the capacity of their existing electricity supply.

The expenditure we directly incur in connecting new customers – net of any contribution they make – is defined as consumer connections Capex.

24.3 OUR CONNECTION PROCESS

24.3.1 OVERVIEW

Residential customers requiring a new connection will generally first contact an electrician. Some electricians will manage the entire connection process, while others will direct customers to our customer service team.

When a customer contacts us, we supply them with our list of approved contractors. These contractors work with the customer to determine what is required for electricity supply and provide a quote for the work. The contractor will obtain approval from us for their proposed design concept and notify the customer of any special requirements, such as easements.

The benefit of this system is that it allows the customer to seek competitive quotes from more than one approved contractor. The customer can then be confident of getting a fair price and good customer service. Ensuring contestability and customer choice is a key aim of our connections process.

Some larger businesses or large subdivision developers will contact us directly to discuss their connection requirements, or work with large industrial power specialists who are familiar with our requirements and standards for connection. We work with these larger providers to facilitate connection of these larger loads.

Our customer connection process is set out on our website.

24.3.2 FUNDING

Where a customer connection request, whether it be for a new connection or an upgrade of existing assets, impacts assets owned by us, we contribute towards the cost of constructing those assets. This is because we receive some benefit from ongoing network charges and, in some cases, new assets benefit our existing customers.

In most cases, customers requesting new connections fund the majority of the cost. This is to ensure that these customers pay a fair amount for the assets that are used to serve their connection over its lifetime, and ensures our existing customers are not disadvantaged. We generally require contributions for the following works:

- Extensions or reinforcements that solely benefit individual customers.
- Network connections that require new assets to be built.

We have a customer contribution policy that we follow to determine the need for and amount of contribution. We publish a guide online to explain this.

In calculating contributions, it is important to demarcate our assets from the customers'. Customer service lines, the assets inside a customer's property boundary, are owned by the customer and we do not contribute towards their construction. In these circumstances, a service fuse is required and we contribute a nominal amount to complete this connection. This type of investment is not considered by us to be of a capital nature and is not included in our Capex forecasts.

Consumer connection Capex contributes to network development at Low Voltage (LV) and distribution levels. However, incremental growth from existing customers can lead to upgrades at distribution level, which are funded by us. Similarly, reinforcement of our network at subtransmission levels is funded through our system growth expenditure.

24.4 FORECAST EXPENDITURE

Below we set out and explain our forecast consumer connections Capex for the planning period.

24.4.1 EXPENDITURE DRIVERS

Consumer connection Capex is largely driven by growth in population (residential) and the overall economy (commercial/industrial). Specifically, investment levels tend to be driven by the following:

- New residential properties driven by population growth, land supply and Government policy that impacts small connection requests, and large subdivision developments.
- Growth in commercial activity impacts requests for new premises and load changes as businesses seek to expand operations.

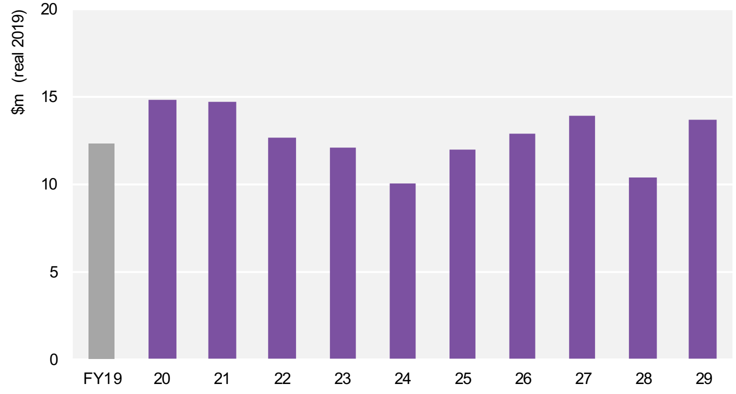
24.4.2 FORECAST CAPEX

Consumer connection Capex is externally driven with short lead times so our ability to accurately forecast medium-term requirements based on known projects is limited. As such, our forecast is based on trending historical activity. We use the current in-year FY19 expenditure forecast as a baseline, as we have recently seen a rise in customer connection activity that is not reflected by historical expenditure levels. We then use forecast Installation Control Point (ICP) growth to modify the base into a final forecast.

Our ICP forecast is based on household growth data, derived from econometric parameters. ICP growth correlates well with historical consumer connection expenditure. Forecast ICP growth is also used to inform our demand forecast for growth and security investments.

Our forecast assumes continuing our current capital contributions policy.

Figure 24.1: Forecast consumer connection Capex (net of contributions)



Expenditure in this portfolio has been high in recent years because of strong growth on our network, particularly in the eastern region.

We expect to see a degree of variation year-on-year as major subdivision and upgrade works are completed. However, we have limited ability to forecast this as it is driven by third parties. We also have limited scope to reschedule this work year-to-year as we look to satisfy customer requirements as promptly as possible.

Step changes due to connection requests by major customers are included in the forecast period once their requirements are confirmed. The only known request at the time of publishing the AMP is the expansion of the Port of Tauranga wharfs at Sulphur Point ($3.3m FY20-22). A new zone substation with a new 33kV supply is proposed at Sulphur Point. This project will offload demand from the existing 11kV network and help maintain power quality standards across the network.

25 ASSET RELOCATIONS

25.1 CHAPTER OVERVIEW

This chapter explains our approach to relocating assets on behalf of customers and other stakeholders. It includes an overview of typical relocation works, our process for managing these works, and how they are funded. Our forecast Capex, net of capital contributions, during the planning period is also discussed.

Further detail on our stakeholders and how they affect our investment plans can be found in Appendix 3.

25.2 OVERVIEW OF ASSET RELOCATIONS

The assets that most often need to be relocated are poles, overhead conductors and underground cables. These are often located alongside other infrastructure, such as roads, water pipes, and telecommunications cables. A common example is moving poles and lines to accommodate the widening of a road.

Asset relocations Capex is driven by third party applications, which typically fall in one of the following four categories:

- **Roading projects** – road widening and realignment projects by the NZTA and councils require our assets to be relocated.
- **Infrastructure projects** – infrastructure owners may need us to relocate our assets as part of their developments eg storm water pipelines, electricity transmission lines or telecommunications assets.
- **Development** – councils, commercial organisations, farmers and residential land owners may require us to relocate our assets so they can redevelop sites or existing buildings.
- **Aesthetics** – customers ask that electricity lines disrupting their views be moved underground to improve aesthetics.

Expenditure is capitalised where assets, usually in poor condition, are replaced as part of the relocation. Relocating assets from one location to another, without increasing service potential, is treated as Opex.

25.3 OUR ASSET RELOCATION PROCESS

Our asset relocation process allows flexibility to facilitate development by other utilities, our customers and third parties.

The process for small relocation works is usually an externally managed design and build approach. We find this provides the most customer-centric service. When a customer seeks asset relocation we provide a list of approved service providers. During the design and pricing stage, the customer may choose to work with more than one contractor to create a competitive environment. The customer's contractor then works with us to deliver the relocation work. In this process, the contractor works for the customer to meet their needs, while we ensure the contractor complies with our technical, safety and commercial requirements. Typically, we undertake between 75 and 125 relocation projects each year.

In most circumstances we receive contributions from the third party requesting the relocation, reducing the amount of our investment in these projects. For roading and other infrastructure projects, the level of our investment is governed by legislation, which often requires us to fund the materials portion of the project.[110] For smaller projects, our level of investment is guided by our electricity capital contributions policy. The funding mix will vary based on the type of projects in any given year.

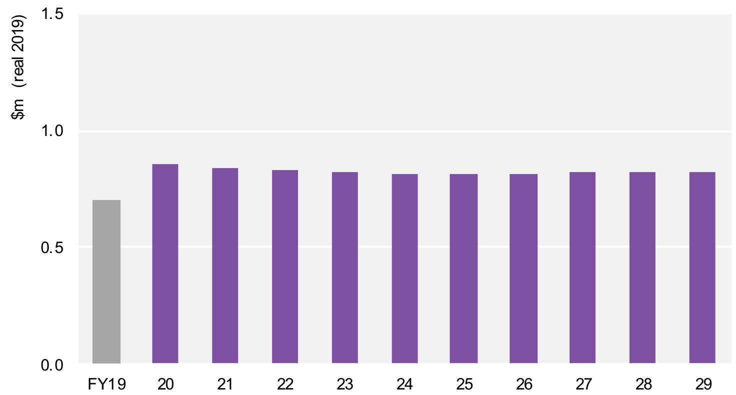
25.4 FORECAST EXPENDITURE

Because asset relocations are customer driven, often with short lead times, our ability to forecast this expenditure on a volume or project basis is limited and we also have limited ability to smooth the expenditure across years.

As such, our forecast is based on our FY18 asset relocations expenditure, which is our best indicator of future asset relocations Capex. This is modified by any significant project expenditure that we become aware of through consultation with councils and the New Zealand Transport Agency, internal cost assumptions and future efficiency targets.

The chart below shows our expected investment, net of contributions, in asset relocation works during the planning period. The FY19 expenditure is based on an in-year budget forecast and shows the lower-than-average works undertaken in the year.

Figure 25.1: Forecast asset relocation Capex (net of contributions)



110 Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act 1989

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Expenditure forecasts

This section provides an overview of our Capex and Opex forecasts for the planning period.

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26.1 CHAPTER OVERVIEW

This chapter provides a summary of our expenditure forecasts during the planning period. It is structured to align with our internal expenditure categories and forecasts provided in earlier chapters.

We supplement our expenditure forecasts by providing high level commentary and context for our forecasts, including key assumptions. We also discuss our cost estimation methodology and how this has been used to develop our forecasts for the planning period.

Note on expenditure charts and tables

The charts depict in-year forecasts (grey column) for our 2019 financial year (2018/19) and our forecasts (purple columns) for the remainder of the planning period.

Expenditure is presented according to our internal categories in this section. Expenditure is also provided in Information Disclosure categories, which differ in minor ways, in Schedules 11a and 11b in Appendix 2.

All dollars are denominated in constant price terms using FY19 dollars. The schedules in Appendix 2 also show expenditure in FY19 constant price terms.

26.2 FORECAST EXPENDITURE SUMMARY

Below we summarise our Capex and Opex forecasts for the planning period. To avoid duplication we have not restated discussions in previous chapters. Instead, we have focused on providing high level commentary and context for the overall forecasts, and have provided cross references to chapters with more detailed information.

26.2.1 CAPEX

Our forecast for total Capex increases slightly during the planning period. It represents our current best view, based on our asset management strategies and using available network information.

Total Capex includes the following four expenditure categories:

- **Growth and security Capex** – discussed in Chapters 11 and 12
- **Renewals Capex** – discussed in Chapters 15-21
- **Other network Capex** – discussed in Chapters 13, 24 and 25
- **Non-network Capex** – discussed in Chapter 22

The slight forecast increase during the later years of the planning period relates almost entirely to network expenditure. There is a decrease in non-network Capex following the completion of our investments in systems and capability. Below we set out our total forecast Capex for the planning period.

Figure 26.1: Total forecast Capex for the planning period

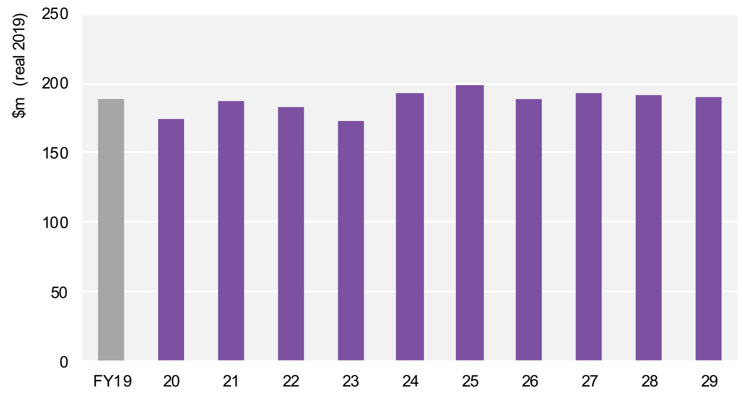

Table 26.1: Total forecast Capex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
189.3	174.1	187.8	183.7	172.7	193.5	198.9	189.4	192.5	191.4	190.7

Our Capex profile reflects the underlying network needs discussed in this AMP. The rate of increase in early years (from pre-FY19 levels) has been designed to balance a focus on ensuring network targets are achieved, along with the need to mobilise increased service provider resources and internal engineering capacity and capability.

26.2.1.1 GROWTH AND SECURITY CAPEX

As discussed in Chapters 11 and 12, our network development Capex is split into three portfolios. These are:

- Major projects
- Minor growth and security works
- Reliability

The combined expenditure in these portfolios is shown below.

Figure 26.2: Total growth and security Capex for the planning period

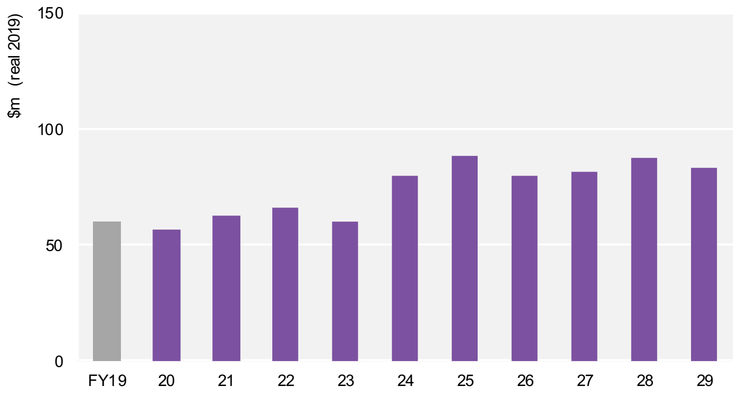

Table 26.2: Total growth and security Capex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
60.1	56.3	62.8	66.5	60.5	79.9	88.3	79.9	81.7	87.5	83.8

Growth and security forecast expenditure is higher than historical levels, reflecting, in part, constrained historical expenditure in line with regulatory settings. Increased levels of expenditure are required to address existing security exposures and ensure an appropriate and stable network security position in the longer term. The increase in the growth and security forecast from FY24 onwards is largely because of the expected rollout of network visibility initiatives, as forecast in Chapter 11.

26.2.1.2 RENEWALS CAPEX

As discussed in Chapters 15 to 21, our fleet management Capex is split into seven portfolios. These are:

- Overhead structures
- Overhead conductors
- Cables
- Zone substations
- Distribution transformers
- Distribution switchgear
- Secondary systems

The combined expenditure in these portfolios is shown below.

Figure 26.3: Total renewals Capex for the planning period

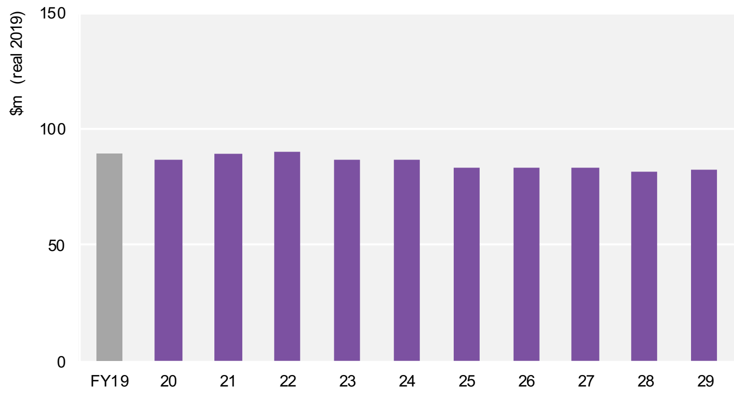

Table 26.3: Total renewals Capex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
89.8	87.1	89.8	90.1	87.0	86.9	83.4	83.5	83.2	82.1	82.4

Renewals expenditure during the planning period has increased from historical levels to address deteriorating condition and asset health trends, and to accommodate an increasing percentage of our assets reaching the end of their practical service life. Expenditure is forecast to reduce slightly during the planning period as we stabilise asset health, and because of expected efficiencies arising from improved asset management.

26.2.1.3 OTHER NETWORK CAPEX

As discussed in Chapters 13, 24 and 25, other network Capex is split into three portfolios. These are:

- Network evolution
- Customer connections
- Asset relocations

The combined expenditure in these portfolios is shown below.

Figure 26.4: Total other network Capex for the planning period

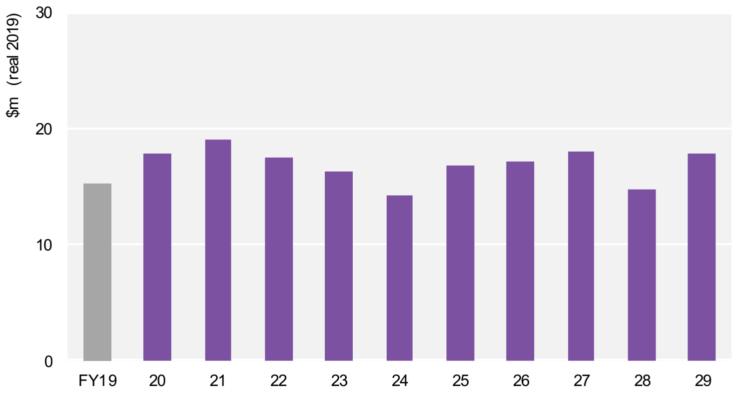

Table 26.4: Total other network Capex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
15.2	18.0	19.0	17.5	16.3	14.3	16.9	17.2	18.1	14.8	17.8

The profile for other network Capex is influenced by the variability in customer connections, large one-off customer projects, and an increase in network evolution expenditure.

26.2.1.4 NON-NETWORK CAPEX

As discussed in Chapter 22, our non-network Capex is split into two portfolios. These are:

- ICT Capex
- Facilities Capex

The combined expenditure in these portfolios is shown below.

Figure 26.5: Total non-network Capex for the planning period

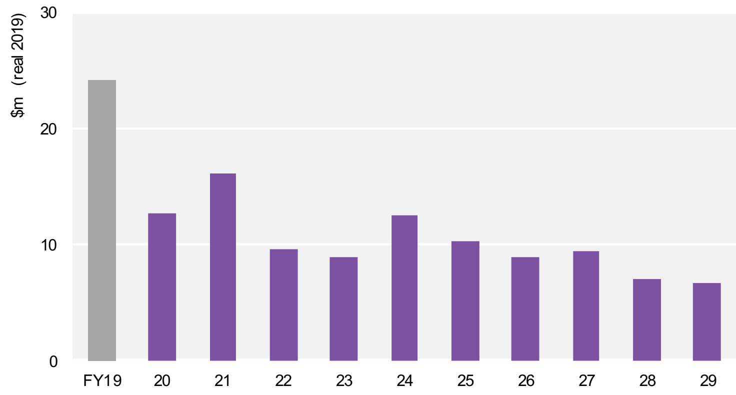

Table 26.5: Non-network Capex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
24.2	12.8	16.2	9.7	9.0	12.5	10.4	8.9	9.5	7.1	6.7

Our main non-network investments in the planning period include the continuation of the development of an Enterprise Resource Planning (ERP) system, new offices and office upgrades, and the rise in non-network Capex to reflect the capitalisation of leases. [111]

These investments are critical enablers of capacity and capability improvements needed to deliver increased work volumes and lift asset management capability.

26.2.2 OPEX

Our current Opex forecast is relatively stable during the planning period. These represent our best forecasts using available information.

Total Opex includes the following two expenditure categories:

- **Network Opex** – discussed in Chapter 23[112]
- **Non-network Opex**

[111] The new IASB standard, IFRS 16 Leases, requires leases to be recognised on the balance sheet. This came into effect on 1 January 2019.

[112] System Operations and Network Support (SONS) is part of our Network Opex category.

Appropriate Opex expenditure is a critical enabler of effective capital delivery, and increased capability will allow us to optimise total Capex during the period. Below we set out our forecast for total Opex during the planning period.

Figure 26.6: Total Opex for the planning period

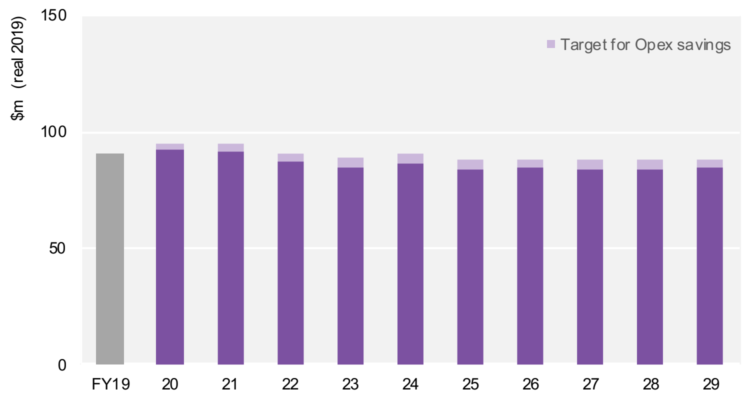

Table 26.6: Total forecast Opex for the planning period ($m real 2019)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPEX FORECAST	90.9	94.9	94.5	90.9	88.4	90.5	87.7	88.3	87.7	87.9	88.1
TARGET OPEX		92.0	91.1	87.3	84.7	86.7	83.9	84.5	83.9	84.1	84.3

Our Opex profile reflects the underlying network needs discussed in this AMP. The higher levels during the earlier years of the period will address our backlog in defects, allow more sophisticated condition assessment techniques, and allow us to reach sustainable levels of vegetation management. It includes investment in our people to ensure we can undertake our work programmes and lift asset management maturity.

The stretch targets for Opex savings indicated in Figure 26.6 are over and above the expected efficiencies from stabilised asset health, improved asset management capability, and process improvements already accounted for in the Opex forecast.

These stretch targets represent an additional challenge to deliver Opex savings for our customers. Significant analysis and improvements implementation are required to achieve these stretch targets. Given the high level of uncertainty, they have not been included in our Opex forecasts.

26.2.2.1 NETWORK OPEX

Our network Opex forecast includes our planned expenditure in the following portfolios[113]. Further information on the forecasts can be found in Chapter 23.

- Preventive maintenance and inspection
- Corrective maintenance
- Reactive maintenance
- Vegetation management
- System Operations and Network Support (SONS)

The combined expenditure in these portfolios is shown below.

Figure 26.7: Network Opex for the planning period

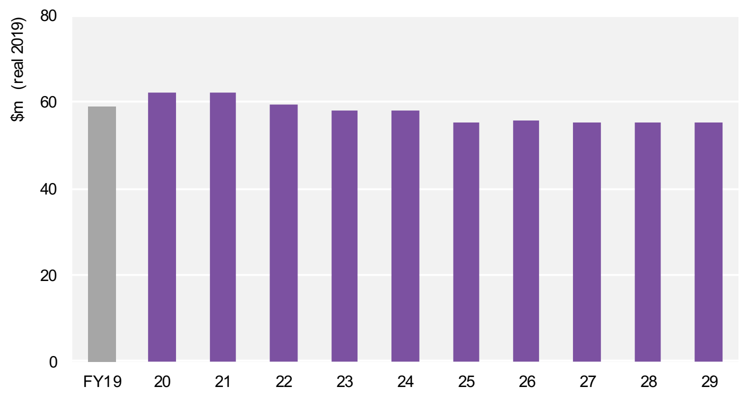

Table 26.7: Network Opex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
59.1	62.4	62.5	59.7	58.3	58.0	55.3	55.8	55.2	55.3	55.5

Opex levels are higher than historical levels because of increased expenditure in our corrective maintenance portfolio to address a high number of end-of-life component replacements (defects) and increases in our SONS portfolio to support increasing work volumes. Our SONS forecast also reflects the need to continue developing our people and their capabilities to support more advanced asset management maturity.

113 Ibid

Towards the end of the period we expect to reach a stable level of network Opex. This reflects the reduction of our defect backlog, expected benefits of increased renewals, our cyclical vegetation programme being embedded, and efficiencies in our asset management approach.

26.2.2.2 NON-NETWORK OPEX

Our non-network Opex forecast includes expenditure related to the divisions that support our electricity business. It includes direct staff costs and external specialist advice. The other material elements are office accommodation costs; legal, audit and governance fees; and insurance costs. A portion of our non-network Opex is allocated to our gas business, in accordance with our cost allocation policy, and is excluded from the forecasts in this AMP.

Figure 26.8: Non-network Opex for the planning period

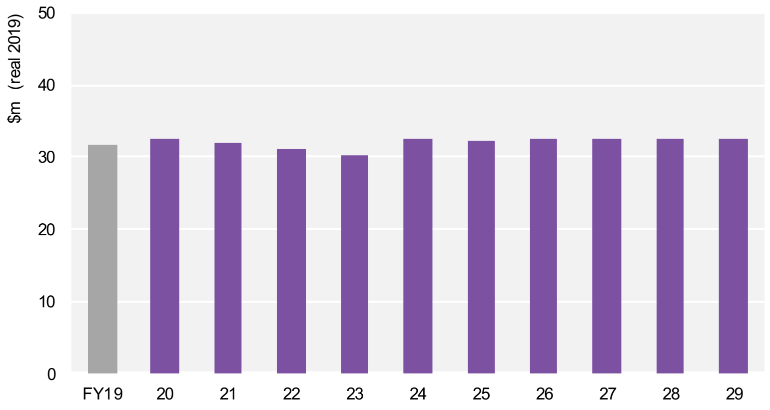

Table 26.8: Non-network Opex for the planning period ($m real 2019)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
31.8	32.5	31.9	31.2	30.2	32.5	32.4	32.5	32.5	32.6	32.6

Our forecast expenditure is consistent with historical costs during the planning period. Increases in Opex because of a transition to cloud-based services and increases to cyber security costs are partially offset by a reduction in Opex through capitalisation of leases.

26.3 INPUTS AND ASSUMPTIONS

This section sets out some of the key inputs and assumptions underpinning our forecasts for the planning period. We have set them out in the following two categories:

- Inputs and assumptions relating to our forecasts and underlying forecasting approaches.
- Our approach to escalating our forecasts to nominal dollars, including our estimates of capitalised interest and the timing of commissioning.

26.3.1 FORECASTING INPUTS AND ASSUMPTIONS

Table 26.9 sets out the main inputs and assumptions underpinning our forecasts for the planning period.

Table 26.9: Forecasting inputs and assumptions

INPUTS AND ASSUMPTIONS	DISCUSSION
Work volumes	
Historical asset failure rates provide an appropriate proxy for expected asset fleet deterioration (used in our survivorship analysis).	Except where specific type issues or localised accelerated deterioration have been identified, we have assumed that asset condition will degrade at similar rates to historical evidence when accounting for age and type. Through survivorship analysis, we can then use this information to estimate likely quantities of future asset replacements. In some cases, such as concrete poles, we have found we are able to operate assets well past industry design lives and our forecasts reflect this. We use this approach across a number of our volumetric asset fleets. Refer to Chapters 15-21.
Expected asset lives, based on experience operating our network, provide an appropriate proxy for longer term asset replacement forecasting.	For longer term forecasting we at times use expected asset lives to estimate future replacement needs. This assumption is appropriate for forecasting work on large asset populations. Actual replacement works are triggered by other factors, including condition and safety. This is only used on asset fleets of lower value, and where more detailed information is not available, such as asset condition or degradation data. Where we have applied this approach in the past we have found it to be a reasonable proxy for actual service life. Refer to Chapters 15-21.
Historical relationships between load growth and related drivers (local GDP, ICP growth etc) continue to apply in the short term.	Our demand forecasting approaches have performed well in recent years and we expect this to continue in the medium term. In the longer term, the increasing adoption of new technologies (see Chapter 13) may alter these relationships and we are monitoring these trends carefully. Our standard investment planning approach is designed to ensure that we do not invest in new capacity until we are sure it is required, which moderates the risk of over-investment.

INPUTS AND ASSUMPTIONS	DISCUSSION
An open-access network will be the new norm for network operations.	We forecast that distribution networks globally will commence the transition to an open-access platform. This is to ensure that our customers can maximise their energy options. The shift to open-access networks would require a deeper insight of the Low Voltage feeder on our networks, new analytical and operational capabilities and commercial arrangements.
Embedded generation will not have a material impact on network investment in the planning period.	We have assumed that the installation of photovoltaics (PV) and energy storage will not materially affect peak load growth and related investments during the planning period. The requirement for network reinforcement, which is largely driven by peak load or network stability requirements, is therefore not anticipated to change noticeably because of embedded generation. We note that industry studies, including Transform, which was carried out by the ENA Smart Grid Forum, suggest that high rates of embedded generation, such as PV, would be likely to increase capital requirements rather than reduce them. Therefore our assumption is conservative.
Brownfield asset replacement quantities are based on like-for-like replacement.	For volumetric fleets we assume that the quantity of assets forecast for replacement will be replaced with an equal number of assets, except where consolidation strategies are in place, such as with ground-mounted switchgear. Actual replacement may involve quantity variances, such as during line construction where the number of poles may increase or decrease. However, these variances are assumed to balance out resulting in an appropriate forecast.
Customers do not expect our network performance to degrade over the long term.	Customer surveys indicate they want us to at least maintain current performance levels (also considering price impacts). Our work volume models are therefore designed to ensure no reduction in performance during the planning period. In practice, there are parts of our network that will require more investment to ensure appropriate safety outcomes, or to reflect changing customer needs and demographics.
Unit rates (costs)	
Historical unit rates are appropriate for use in volumetric forecasts.	Historical unit rates for volumetric works reflect likely future scopes and risks, on an aggregate or portfolio level. While we continue to target efficiency in all aspects of our work delivery and have made some allowances for this later in the planning period, our experience has shown that increased efficiency tends to be offset by increased safety related costs, such as traffic management, and increased costs associated with accessing the road corridor and private land.
Current network Capex unit rates reflect likely costs during the planning period.	We expect historical unit rates for capital works to reflect costs during the planning period, with some capacity to reduce costs in the latter part of the planning period as efficiencies are identified. Some of these efficiencies are likely to be somewhat offset by factors such as requirements to manage network outages, for example using portable generators.

INPUTS AND ASSUMPTIONS	DISCUSSION
Current maintenance unit rates reflect likely costs during the planning period.	We expect historical unit rates for maintenance to reflect costs during the planning period. We may realise some efficiencies in future years because of increased maintenance volumes, although these may be somewhat offset by more stringent maintenance requirements reflecting improved asset management practices as well as the result of more sophisticated equipment rolled out across the network. We have allowed for some efficiencies in later years of our forecasts.
Materials and labour forecasts reflect likely future trends.	We assume that the independent cost escalation indices, as noted below, will appropriately reflect input price trends during the planning period.
Brownfield asset replacement costs are based on today's modern equivalent assets.	Unit costs used in brownfield asset replacements assume the continued use of today's modern equivalent costs, except where future technology changes are known, such as where sulphur hexafluoride (SF_6) switches will generally replace air break switches during the planning period (see Chapter 20).

26.3.2 ESCALATION OF FORECASTS

During the planning period we will face different input price pressures to those captured by a general measure of inflation, such as the consumers price index (CPI). We expect that the input price increases we face during the planning period will be greater than CPI because of factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.[114]

Our approach to developing cost escalators involves applying different cost escalators to our real price expenditure forecasts. Our escalators have been developed using:

- Independent forecasts of input price indices that reflect the various costs that we face, including material, labour and overhead components.
- CPI forecasts consistent with the Commission's input methodologies (used in limited circumstances).
- Weighting factors for cost categories, such as transformers, that are made up of a range of inputs.[115]

We have used the above inputs to develop tailored cost escalators for our cost categories. These are then applied to our real expenditure forecasts to produce the forecasts in nominal dollars for our Information Disclosure schedules in Appendix 2.

[114] The default price-quality path (DPP) also recognises that electricity distributors face different cost pressures from the economy overall by applying labour cost, producer price and capital goods price indices as appropriate.

[115] The weighting factors strike the right balance between appropriately reflecting the cost structure of the assets that make up our network and avoiding unnecessary complexity. Approaches that are more complex may reduce the transparency without necessarily better reflecting the cost pressures we expect to face.

26.4 COST ESTIMATION

In general, our AMP forecasts have been developed using forecasting techniques that estimate necessary work volumes. These will then have associated unit rates applied to them. This so-called 'bottom-up' approach has been developed alongside cost estimates that are:

- Transparent
- Repeatable
- Linked to out-turn costs
- Inclusive of appropriate allowances for forecasting uncertainty

Long-term cost estimates do carry estimation risk. We have not included any 'blanket' contingency in our estimates to account for uncertainty during the planning period. Instead, we have sought to develop forecasts to a confidence level of P50.[116] The use of P50 is considered appropriate as it equates to an equal allocation of estimation risk between us and our customers.

Our forecasts beyond two years use a combination of the following approaches:[117]

- **Customised estimates (Capex)** – used for large single projects (>$500,000) that require individual tailored investigation. Those above $5 million are also supported by independent external cost estimates.
- **Volumetric estimates (Capex and Opex)** – used for smaller, high-volume works that are reasonably routine and uniform. These are generally related to defect rectification, reactive works and scheduled maintenance.
- **Base-step-trend (Capex and Opex)** – is mainly used for forecasting network and non-network Opex. It is also used for certain trend-based Capex forecasts, such as asset relocations.

These estimate types are discussed below.

26.4.1 CUSTOMISED ESTIMATES

This approach involves developing cost estimates based on project scopes, with larger projects supplemented with cost estimates from external consultants. Project scopes are determined from desktop reviews of asset information, such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities.

Activity costs are based on historical costs, service provider rates, quotes, and external reviews. Material costs are determined with reference to supply contracts and historical installation costs contained in our price-book. Installation costs are informed by similar previous projects and updated with current prices from service providers.

There are risks associated with estimating projects up to 10 years in advance. The costs that are subject to material estimation risk will vary by project type. In general, the main cost items that lead to estimation risk include:

- Site location, eg remoteness of the site and likely impact on construction costs
- Cable or conductor lengths
- Building requirements
- Geotechnical/ground condition and the potential need for ground improvements
- Excavation requirements and the potential for contaminated soil to be present

For investment in large non-network systems or facilities works we have based our forecasts on a combination of tender responses and desktop estimates for later in the period. These desktop estimates are mainly informed by historical tenders and discussions with vendors.

26.4.2 VOLUMETRIC ESTIMATES

Programmes with relatively large volumes of similar works are categorised as volumetric works for estimation purposes. The key determinant of accurate cost estimates for volumetric works is the feedback of historical costs from completed equivalent projects. This feedback is used to derive average unit rates to be applied to future work volumes. These unit rates are often combined to form building block costs that include the main components of typical works.

Using this approach, we consider that our volumetric works will be based on P50 estimates, given the following assumptions:

- Project scope is reasonably consistent and well defined.
- Unit rates based on historical out-turns capture the impact of past risks. The aggregate impact of these risks across portfolios is unlikely to vary materially over time.
- To maintain a portfolio effect[118] a large number of future projects are likely to be undertaken.
- The volume of historical works is sufficiently large to provide a representative average cost.

For investment in non-network assets and systems, such as IT hardware, we have used expected volumes and unit rates informed by discussions with vendors and historical out-turns.

116 The P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.

117 Budgeting for the earlier part of the period is based on tendered work, detailed project-specific estimates, or maintenance delivery plans.

118 The net impact of cost variances will tend to diminish in a portfolio containing a large number of P50 estimates.

26.4.3 BASE-STEP-TREND

We have used a 'base-step-trend' approach to forecast part of our expenditure.[119] The approach is used by many utilities and economic regulators for forecasting expenditure that is recurring.[120] Figure 26.9 sets out the steps in developing base-step-trend forecasts.

Figure 26.9: Base-step-trend forecasting steps

Select base year

Adjust base year (if required)

Adjust for significant, non-recurring items

Adjust for step changes

Apply trends for ongoing drivers

Adjust for expected cost efficiencies

Expenditure forecast

The base-step-trend approach starts with selecting a representative base year. The aim is to identify a recent year that is representative of recurring expenditure that is expected in future years. If there are significant events, such as a major storm, an adjustment is made to remove its impact.

Expenditure in the base year is then projected forward. To produce our AMP forecasts, we adjusted the resulting series for anticipated significant, non-recurring expenditure, permanent step changes, trends because of ongoing drivers, and expected cost efficiencies.

[119] This includes reactive maintenance and SONS. It is also used to a lesser extent for non-network Opex and certain Capex forecasts, such as asset relocations and customer connections.

[120] The base-step-trend approach has been used by energy network businesses regulated by the Australian Energy Regulator. See its forecast assessment guidelines available at www.aer.gov.au/node/18864. The approach is also conceptually similar to the Commission's approach to Opex used in setting DPPs in 2012 and 2014.

26.4.4 COST ESTIMATION PRICE-BOOK

Our Capex cost estimation process is built around a cost estimation 'price-book'. Using this, we can develop robust cost estimates using a centrally managed dataset. We continue to improve our processes to capture actual project cost and feed it into relevant future cost estimates.

26.5 INFORMATION DISCLOSURE CATEGORIES

26.5.1 NETWORK CAPEX

For the purposes of Information Disclosure in Schedule 11a, we use the following network Capex categories. These differ somewhat from the categories we have used in our Capex expenditure forecasting, and which are discussed in this AMP. We use our categories as they better reflect the way we manage the associated assets, but we maintain mappings to allow us to meet our disclosure requirements[121].

- **System growth:** These investments are classified under our growth and security category, excluding reliability investments, and also includes our network evolution investments. The investment plans are described in detail in Chapters 11 and 13.
- **Asset replacement and renewal:** These investments are classified under our renewals category. The investment plans are described in detail in Chapters 15-21.
- **Reliability, safety and environment:** Safety and environment capital investments are generally managed as part of our renewals processes but are separately identified to reflect their particular drivers. The investment plans are described in detail in Chapters 15-21. Reliability investments include our automation programme (part of growth and security), discussed in Chapter 12.
- **Customer connections:** Our customer connections portfolio is consistent with the Information Disclosure definition. These investments are discussed in Chapter 24.
- **Asset relocations:** Our asset relocations portfolio is consistent with the Information Disclosure definition. These investments are discussed in Chapter 25.

[121] Our non-network Capex categories align with the disclosure requirements and are discussed in Chapter 22.

26.5.2 NETWORK OPEX

Like with network Capex, for the purposes of Information Disclosure in Schedule 11b, we use the following network Opex categories. These differ somewhat from the categories we have used in our Opex expenditure forecasting, and which are discussed in this AMP in Chapter 23.

- **Service interruptions and emergencies:** This category is consistent with our reactive maintenance portfolio.
- **Vegetation management:** Our vegetation management portfolio is consistent with the Information Disclosure definition.
- **Routine and corrective maintenance and inspections:** This category covers expenditure from our preventive maintenance and inspection portfolio, as well as the Commission's 'corrective' work within our corrective maintenance portfolio.
- **Asset replacement and renewal:** This category is generally consistent with our corrective maintenance portfolio, although our corrective maintenance portfolio also includes the corrective work from the Commission's routine and corrective maintenance and inspections category.
- **System operations and network support:** Our system operations and network support portfolio is consistent with the Information Disclosure definition, although we classify SONS as network Opex.

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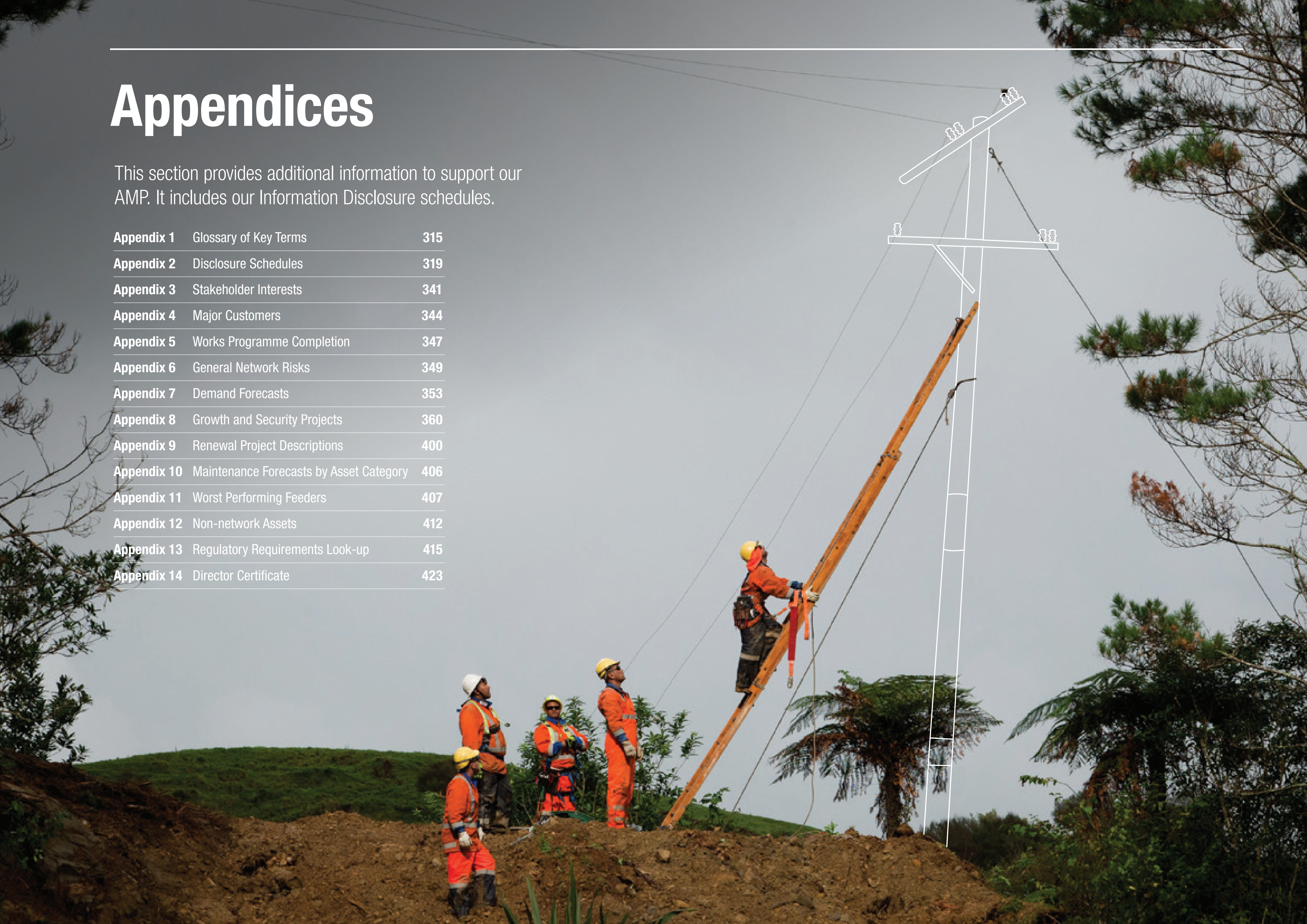

Appendices

This section provides additional information to support our AMP. It includes our Information Disclosure schedules.

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APPENDIX 1 GLOSSARY OF KEY TERMS

AAAC means All Aluminium Alloy Conductor, which is a commonly used type of overhead conductor.

AAC means All Aluminium Conductor, which is a commonly used type of overhead conductor.

ABS means Air Break Switch, which is a type of equipment used for isolating parts of a circuit.

ACSR means Aluminium Conductor Steel Reinforced, which is a commonly used type of overhead conductor.

Adequacy means the ability of the electrical power network to meet the load demands under varying steady state conditions while not exceeding component ratings and voltage limits.

ADMD means After Diversity Maximum Demand. This refers to the average maximum demand assigned to a customer or load for network dimensioning purposes during design. Typical domestic ADMDs are in the order of 4kVA at reticulation level and 2kVA at feeder level.

ADMS means Advanced Distribution Management System.

AHI means Asset Health Indices. These reflect the expected remaining life of an asset and act as a proxy for probability of failure. AHI is used to inform levels of investment within and between portfolios. AHI is calculated using a number of factors including asset condition, survivor curves, asset age relative to typical life expectancy, known defects or type issues and factors that affect degradation rates, such as geographical location.

ALARP means As Low As Reasonably Practical and is one of the principles of risk management.

AMI is Advance Metering Information, which includes meter information outside of that available through the registry.

AMMAT means Asset Management Maturity Assessment Tool.

Asset fleet describes a group of assets that share technical characteristics and investment drivers.

Availability means the fraction of time an asset is able to operate as intended, either expressed as a fraction, or as hours per year.

Backfeed is the ability for certain network circuits to be switched to supply part of another circuit during a planned or unplanned outage. This is usually done to minimise the impact of outages to customers.

BaU is Business as Usual.

Capex refers to capital expenditure, investments to create new assets or to increase the service performance or service potential of existing assets.

CAGR is Compound Annual Growth Rate.

CBD means the Central Business District.

CBRM means Condition-Based Risk Management.

CCA is Copper Chrome Arsenic, a treatment method for softwood poles.

CDEM is Civil Defence and Emergency Management.

Class Capacity means the capacity of the lowest-rated incoming supply to a substation, plus the capacity that can be transferred to alternative supplies on the distribution network within the timeframe required by the substation security classification.

Contingency means the state of a system in which one or more primary components are out of service. The contingency level is determined by the number of primary components out of service.

CPI means the Consumers Price Index.

CPP is Customised Price-quality Path.

Critical Spares are specialised parts that are stored to keep an existing asset in a serviceable condition. Critical spares may also include entire asset spares in case of serious failures.

CRM is the Customer Relationship Management system.

CWMS means Connections Works Management System, which is an online workflow management system that facilitates and tracks the processes associated with customer connection applications, approvals, and works completion.

DAS means Distribution Automated Switches, one of the many HV devices that can help us develop a network of the future.

Defect means that the condition of an asset has reached a state where the asset has an elevated risk of failure or reduced reliability. Defects are identified during asset inspections and condition assessments. There are three defect categories: Red, Amber and Green. These categories signify the risk of the defect. Defects may be Capex or Opex depending on the type of remediation action.

DER means Distributed Energy Resources, which are small scale power generation or storage technologies used to provide an alternative to, or an enhancement of, traditional electricity networks.

Development means activities to either create a new asset or to materially increase the service performance or potential of an existing asset.

DFA means Delegated Financial Authority.

DGA means Dissolved Gas Analysis, which is a type of oil test, typically carried out on transformers. It analyses the different gas traces found inside the oil. Different levels and combinations of gas traces provide an indication of the internal condition of the transformer.

DG/ESS is Distributed Generation/Energy Storage Systems.

DMS means Distribution Management System.

DNP3 is Distributed Network Protocol version 3, which is our standard communications protocol.

DP or Degree of Polymerisation is a type of test carried out on a transformer's paper insulation. This test provides an indication of insulation condition.

DPP means Default Price-quality Path.

DRAT is Powerco's Defect Risk Assessment Tool, a tool that is used to systematically analyse defects and the risks presented by them.

DSI is Distribution System Integrator. It is a utility that is able to utilise intelligent networks to enable widespread use of local generation sources connected to the network at multiple points and open-access to customers to allow them to transact over the network.

DSO is Distribution System Operator. It is a utility that has all the functionality of a DSI, but is also involved in managing all the transactions of energy and alternative services on the network.

EA is the Electricity Authority

Eastern region is the part of our electricity network supplying Tauranga, Western Bay of Plenty, Coromandel Peninsula and the area immediately to the west of the Kaimai and Mamaku ranges as far south as Kinleith.

ECP34 is the New Zealand Electrical Code of Practice for Electrical Safe Distances.

EDGS means the Electricity Demand and Generation Scenarios produced by MBIE.

EEA is the Electricity Engineers' Association, which aims to provide the New Zealand electricity supply industry with expertise, advice and information on technical, engineering and safety issues affecting the electricity industry.

EDB means Electricity Distribution Business.

EFSA is the Electricity Field Services Agreement, which is the agreement we have with our main field works service provider for undertaking routine capital works and maintenance work.

Emergency Spares means holdings of equipment to provide a level of protection against a catastrophic failure of assets.

EMS means Environmental Management System.

ENA is the Electricity Networks Association.

EPR means Earth Potential Rise (or Ground Potential Rise), which occurs when a large current flows to earth through an earth grid impedance and creates a change of voltage over distance from the point of injection. EPR can be hazardous to the public and field staff and is an ongoing safety concern.

ERP means Enterprise Resource Planning, which is a suite of applications that collect, store, manage and interpret data.

ESCP is Powerco's Electricity Supply Continuity Plan.

ETS is the Emissions Trading Scheme.

EV means Electric Vehicles.

EWP means Electricity Works Plan, which is our two-year rolling Electricity Works Plan scheduled works plan.

Failure means an event in which a component does not operate or ceases to operate as intended.

FIDI is Feeder Interruption Duration Index, which means the total duration of interruptions of supply that a customer experiences in the period under consideration on a distribution feeder. FIDI is measured in minutes per customer per year.

FIDIC is the International Federation of Consulting Engineers (its acronym is derived from its French name).

Firm Capacity means the capacity of the lowest-rated alternative incoming supply to a substation. In the case of a single supply substation, it is zero.

Forced Outage means the unplanned loss of electricity supply because of one or more network component failures.

GIP means Grid Injection Point.

GIS means Geographical Information System, which is a system we use to capture, analyse, manage and present our assets in a spatial manner.

GEM means Gas and Electricity Maintenance Management System, which uses the asset register to create scheduled work.

GXP means transmission Grid Exit Point.

GWh means gigawatt hours.

HILP means High Impact Low Probability events.

HPI means High Potential Incidents.

HV refers to High Voltage, which is associated with assets on our network above 1,000 Volts.

iPaaS means integration Platform as a Service.

ICAM is Incident Cause Analysis Method, and is used in incident investigations.

ICP means Installation Control Point, which is the point of connection of a customer to our network.

ICT means Information and Communications Technology.

Incipient faults are faults that slowly develop and can result in catastrophic failure if not monitored and acted on appropriately.

ID means Information Disclosure, which suppliers of electricity lines services are subjected to under regulatory requirements by the Commerce Act.

IED means Intelligent Electronic Device.

Interruption means an unplanned loss of electricity supply of one minute or longer, affecting three or more ICPs, because of an outage on the network.

ION

IoT means Internet of Things.

ISO 55001 is an internationally recognised standard for asset management. It replaced PAS 55.

ISSP means Information Services Strategic Plan.

JDE means JD Edwards, which is our maintenance, work management and financial system.

kV refers to kilovolt – 1,000 volts.

LIDAR which stands for Light Detection and Ranging, is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances) to the Earth

LFI means Line Fault Indicator.

LoRaWAN is Long Range Wide Area Network, a long-range wireless communication protocol.

LTI means Lost Time Injury.

LTIFR means Lost Time Injury Frequency Rate, which is calculated as the 12-month rolling number of LTIs per 1,000,000 hours worked.

LV refers to Low Voltage, which is associated with parts of our network below 1,000 volts.

MBIE is the Ministry of Business, Innovation and Employment.

MECO is Materials, Energy, Chemicals, Other lifecycle considerations.

MfE is the Ministry for the Environment.

MPLS refers to Multi-Protocol Label Switching which is a routing technique in telecommunications networks that directs data from one node to the next based on short path labels rather than long network addresses, thus avoiding complex lookups in a routing table and speeding traffic flows.

MVA refers to mega volt amp.

MW is megawatt.

N-1 is an indication of power supply security and ‘N-1’ specifically means that in the event of one circuit failing, there will be another available to maintain the power supply, without interruption.

NER is a Neutral Earthing Resistor, which is attached to power transformers to reduce fault currents on the network.

NBS is New Building Standard. We use this seismic standard to determine which of our substation buildings require strengthening.

NOC is our Network Operations Centre, which is responsible for dispatch, coordinating/planning works, restoring supply and operating our network.

NZSEE is the New Zealand Society of Earthquake Engineering.

NZTA is the New Zealand Transport Agency.

OMS means Outage Management System, which is a system we use to capture, store, manage and estimate fault location, and control and resolve outages.

Opex means operational expenditure, which is an ongoing cost for running the business. It includes key network activities such as maintenance and fault response.

Outage means a loss of electricity supply.

P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.

PAS 55 is Publicly Available Specification 55, which is an asset management standard published by the British Standards Institution in 2004. While still in use, it has been superseded by ISO 55001.

PCB is Polychlorinated Biphenyls, a carcinogenic substance contained in the oil of pre-1970s transformers.

PD is Partial Discharge testing.

PHEV means Plug-in Hybrid Electric Vehicle.

PILC means Paper Insulated Lead Covered, which is a type of power cable.

PMI means Preventive Maintenance and Inspection.

PMO means Project Management Office.

PPE means Personal Protective Equipment.

Protection Discrimination is a coordinated electrical protection system that isolates part of the network circuit due to faults while keeping the remaining parts in service.

PTN means Packet Transport Network.

PV means Photovoltaics.

PVC means Poly Vinyl Chloride, which is a type of outer sheath on some of our cable and overhead conductor.

R – L1, L2, L3 is NOC’s storm response level, categorised in terms of an R – Readiness, L1 – Level 1, L2 – Level 2, or L3 – Level 3.

RAPS means Remote Area Power Supply, which provides a cost effective alternative for replacing long, end of line, remote rural distribution feeders.

RCM means Reliability Centred Maintenance.

Refurbishment means activities to rebuild or replace parts or components of an asset, to restore it to a required functional condition and extend its life beyond that originally expected. Refurbishment is a Capex activity.

REA means Remote Engineering Access. This is provided by the latest standard RTUs, and allows remote download of engineering information such as on faults.

R&D means Research and Development.

RMU means Ring Main Units, which is a collection of switchgear (load break switches, fused switches or circuit breakers) used to isolate parts of the underground network.

RTS means Real-Time Systems.

RTU means Remote Terminal Unit, which is a device that interfaces our network devices to our SCADA system.

SaaS means Software as a Service.

SAIDI means System Average Interruption Duration Index. This is the average length of time of interruptions of supply that a customer experiences in the period under consideration.

SAIFI means System Average Interruption Frequency Index. This is the average number of interruptions of supply that a customer experiences in the period under consideration.

SAP (Systeme, Anwendungen und Produkte in der Datenverarbeitung, "Systems, Applications & Products in Data Processing") is a German-based European multinational software corporation that makes enterprise software to manage business operations and customer relations.

SCADA means Supervisory Control And Data Acquisition. This is a system for remote monitoring and control that enables us to operate our network in a safe and reliable manner.

Scheduled Outage or Planned Outage means a planned loss of electricity supply.

Security means the ability of the network to meet the service performance demanded of it during and after a transient or dynamic disturbance of the network or an outage to a component of the network.

Service provider means a contractor or business that supplies a service to us.

SF_6 means sulphur hexafluoride.

SMC means the Service Management Centre operated by our service providers.

SONS means System Operations and Network Support.

SPS means Special Protection Scheme.

SSDG means Small Scale Distributed Generation.

STATCOM refers to a Static Synchronous Compensator. It is a shunt device of the that uses power electronics to control power flow and improve transient stability on power grids

Survivor Curve is a probabilistic survival likelihood curve for a given asset type, with associated rates of replacement at different ages. Survivor curves are derived from the analysis of historical replacements or defects. The replacement or defect likelihood can then be applied to an asset population to forecast required asset replacements.

SWER means Single Earth Wire Return, which supplies single phase electrical power to remote areas.

Switching Time means the time delay between a forced outage and restoration of power by switching on the network.

TCO is the Total Cost of Ownership when conducting lifecycle assessments for assets

VoENS is Value of Energy Not Served calculations for feeder capacity.

VRP refers to our Voice and Radio Platform

Western region is the part of our network supplying the Taranaki, Egmont, Manawatu, Tararua, Whanganui, Rangitikei and Wairarapa.

XLPE means Cross-Linked Poly Ethylene, which is a type of power cable.

3LoD is the Three Lines of Defence model to assist with the risk management decision-making process.

A2.1 SCHEDULE 11A

Included below is our Schedule 11A disclosure. Constant price figures in this schedule are in 2019 real dollars.

Company Name	Powerco
AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 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**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	42,063	44,334	46,524	42,331	42,303	36,055	44,195	48,588	53,332	40,995	55,000
11	System growth	59,776	56,387	66,411	72,758	67,233	90,817	103,941	96,073	100,794	111,091	109,290
12	Asset replacement and renewal	86,851	86,865	90,185	92,367	91,938	97,798	96,368	99,317	102,438	104,716	108,013
13	Asset relocations	2,275	2,779	2,814	2,845	2,875	2,930	2,998	3,067	3,148	3,219	3,292
14	Reliability, safety and environment:											
15	Quality of supply	2,517	3,967	3,841	3,760	3,671	3,755	3,853	3,953	4,063	4,159	4,258
16	Legislative and regulatory	-	789	1,330	1,332	666	-	-	-	-	-	-
17	Other reliability, safety and environment	2,902	2,367	3,259	3,847	3,755	1,156	1,373	1,268	738	-	-
18	**Total reliability, safety and environment**	5,419	7,123	8,430	8,939	8,092	4,911	5,226	5,221	4,801	4,159	4,258
19	**Expenditure on network assets**	196,384	197,488	214,364	219,240	212,441	232,511	252,728	252,266	264,513	264,180	279,853
20	Expenditure on non-network assets	24,208	13,001	16,859	10,273	9,745	13,900	11,850	10,395	11,379	8,635	8,340
21	**Expenditure on assets**	220,592	210,489	231,223	229,513	222,186	246,411	264,578	262,661	275,892	272,815	288,193
22												
23	*plus* Cost of financing	2,078	1,972	2,193	3,658	3,060	1,129	2,083	2,175	2,079	2,263	2,943
24	*less* Value of capital contributions	31,314	31,985	32,756	30,412	30,635	26,454	31,938	34,865	37,810	29,476	38,687
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	191,356	180,476	200,660	202,759	194,611	221,086	234,723	229,971	240,161	245,602	252,449
28												
29	Assets commissioned	191,127	191,513	163,654	220,235	230,286	198,400	232,377	231,077	236,566	236,387	255,005
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31	for year ended	**31 Mar 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**
32		**$000 (in constant prices)**										
33	Consumer connection	42,063	43,207	44,357	39,482	38,641	32,206	38,591	41,476	44,431	33,337	43,654
34	System growth	59,776	54,687	62,590	67,005	60,484	79,982	89,010	80,039	81,676	87,667	83,792
35	Asset replacement and renewal	86,851	84,045	85,456	85,358	83,039	85,927	82,234	82,419	82,658	82,077	82,433
36	Asset relocations	2,275	2,718	2,696	2,666	2,637	2,627	2,627	2,626	2,636	2,636	2,636
37	Reliability, safety and environment:											
38	Quality of supply	2,517	3,880	3,679	3,519	3,358	3,347	3,346	3,345	3,357	3,357	3,357
39	Legislative and regulatory	-	769	1,267	1,240	607	-	-	-	-	-	-
40	Other reliability, safety and environment	2,902	2,246	3,030	3,487	3,331	1,000	1,168	1,047	584	-	-
41	**Total reliability, safety and environment**	5,419	6,895	7,976	8,246	7,296	4,347	4,514	4,392	3,941	3,357	3,357
42	**Expenditure on network assets**	196,384	191,552	203,075	202,757	192,097	205,089	216,976	210,952	215,342	209,074	215,872
43	Expenditure on non-network assets	24,208	12,761	16,240	9,664	8,952	12,470	10,382	8,893	9,519	7,062	6,669
44	**Expenditure on assets**	220,592	204,313	219,315	212,421	201,049	217,559	227,358	219,845	224,861	216,136	222,541
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

	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 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
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	1,127	2,167	2,849	3,662	3,849	5,604	7,112	8,901	7,658	11,346
System growth	-	1,700	3,821	5,753	6,749	10,835	14,931	16,034	19,118	23,424	25,498
Asset replacement and renewal	-	2,820	4,729	7,009	8,899	11,871	14,134	16,898	19,780	22,639	25,580
Asset relocations	-	61	118	179	238	303	371	441	512	583	656
Reliability, safety and environment:											
Quality of supply	-	87	162	241	313	408	507	608	706	802	901
Legislative and regulatory	-	20	63	92	59	-	-	-	-	-	-
Other reliability, safety and environment	-	121	229	360	424	156	205	221	154	-	-
Total reliability, safety and environment	-	228	454	693	796	564	712	829	860	802	901
Expenditure on network assets	-	5,936	11,289	16,483	20,344	27,422	35,752	41,314	49,171	55,106	63,981
Expenditure on non-network assets	-	240	619	609	793	1,430	1,468	1,502	1,860	1,573	1,671
Expenditure on assets	-	6,176	11,908	17,092	21,137	28,852	37,220	42,816	51,031	56,679	65,652

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
*Consumer types defined by EDB**	**$000 (in constant prices)**					
All Consumers	42,063	43,207	44,357	39,482	38,641	32,206
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	42,063	43,207	44,357	39,482	38,641	32,206
less Capital contributions funding consumer connection	29,746	29,545	29,677	26,871	26,541	22,199
Consumer connection less capital contributions	12,317	13,662	14,680	12,611	12,100	10,007

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	16,380	23,797	19,804	26,561	21,471	18,333
Zone substations	9,760	12,227	22,314	21,606	22,135	20,669
Distribution and LV lines	6,236	2,653	3,958	3,496	3,344	3,186
Distribution and LV cables	7,209	2,512	3,568	3,258	3,686	4,041
Distribution substations and transformers	1,098	2,818	2,640	1,291	617	1,517
Distribution switchgear	6,251	2,659	3,968	3,534	3,510	7,512
Other network assets	12,842	8,021	6,338	7,259	5,721	24,724
System growth expenditure	59,776	54,687	62,590	67,005	60,484	79,982
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	59,776	54,687	62,590	67,005	60,484	79,982

11a(iv): Asset Replacement and Renewal

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
	$000 (in constant prices)						
	Subtransmission	5,172	6,565	5,054	4,060	2,740	2,240
	Zone substations	17,486	15,478	14,555	13,049	12,864	10,044
	Distribution and LV lines	35,700	37,830	43,925	47,036	48,188	50,377
	Distribution and LV cables	7,994	6,761	5,562	5,184	4,665	5,994
	Distribution substations and transformers	8,994	7,039	5,901	5,757	5,596	7,281
	Distribution switchgear	10,669	8,818	8,980	8,660	8,151	8,204
	Other network assets	836	1,554	1,479	1,612	835	1,787
	Asset replacement and renewal expenditure	86,851	84,045	85,456	85,358	83,039	85,927
less	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
	Asset replacement and renewal less capital contributions	86,851	84,045	85,456	85,358	83,039	85,927

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
	*Project or programme** / $000 (in constant prices)						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[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 project or programmes - asset relocations	2,275	2,718	2,696	2,666	2,637	2,627
	Asset relocations expenditure	2,275	2,718	2,696	2,666	2,637	2,627
less	Capital contributions funding asset relocations	1,568	1,857	1,857	1,834	1,811	1,811
	Asset relocations less capital contributions	707	861	839	832	826	816

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
	*Project or programme** / $000 (in constant prices)						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[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 - quality of supply	2,517	3,880	3,679	3,519	3,358	3,347
	Quality of supply expenditure	2,517	3,880	3,679	3,519	3,358	3,347
less	Capital contributions funding quality of supply	-	-	-	-	-	-
	Quality of supply less capital contributions	2,517	3,880	3,679	3,519	3,358	3,347

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
*Project or programme**		$000 (in constant prices)					
Secondary systems (relay replacement for extended reserves)		-	769	1,267	1,240	607	-
[Description of material project or programme]							
[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		-	769	1,267	1,240	607	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		-	769	1,267	1,240	607	-

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

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
*Project or programme**		$000 (in constant prices)					
Zone substations		1,630	628	1,567	2,080	1,981	1,000
Distribution transformers		844	1,059	872	839	805	-
Distribution switchgear		428	559	591	568	545	-
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - other reliability, safety and environment							
Other reliability, safety and environment expenditure		2,902	2,246	3,030	3,487	3,331	1,000
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		2,902	2,246	3,030	3,487	3,331	1,000

11a(ix): Non-Network Assets

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
Routine expenditure							
*Project or programme**		$000 (in constant prices)					
ICT capex		17,690	8,599	13,788	7,152	6,909	8,447
Facilities capex		2,115	1,813	1,581	1,469	1,477	1,843
[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 - routine expenditure							
Routine expenditure		19,805	10,412	15,369	8,621	8,386	10,290
Atypical expenditure							
*Project or programme**							
Facilities capex		4,403	2,349	871	1,043	566	2,180
[Description of material project or programme]							
[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 - atypical expenditure							
Atypical expenditure		4,403	2,349	871	1,043	566	2,180
Expenditure on non-network assets		24,208	12,761	16,240	9,664	8,952	12,470

A2.2 SCHEDULE 11B

Included below is our Schedule 11B disclosure. Constant price figures in this schedule are in 2019 real dollars.

Company Name	**Powerco**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7												
8	for year ended	**31 Mar 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**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	6,999	7,690	7,992	8,139	8,273	8,487	8,707	8,933	9,166	9,406	9,651
11	Vegetation management	10,102	9,923	9,871	10,441	10,054	9,994	9,044	9,225	9,411	9,390	9,579
12	Routine and corrective maintenance and inspection	15,374	16,940	17,694	17,033	17,363	17,781	17,670	18,805	18,446	19,290	19,821
13	Asset replacement and renewal	9,895	10,742	10,814	9,752	9,302	8,514	7,533	7,724	7,924	8,131	8,341
14	**Network Opex**	42,370	45,295	46,371	45,365	44,992	44,776	42,954	44,687	44,947	46,217	47,392
15	System operations and network support	16,686	18,858	19,531	19,261	19,580	20,780	20,783	20,975	21,210	21,448	21,863
16	Business support	31,813	33,478	33,758	33,819	33,560	36,860	37,507	38,318	39,206	40,094	40,944
17	**Non-network opex**	48,499	52,336	53,289	53,080	53,140	57,640	58,290	59,293	60,416	61,542	62,807
18	**Operational expenditure**	90,869	97,631	99,660	98,445	98,132	102,416	101,244	103,980	105,363	107,759	110,199

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
19												
20	for year ended	**31 Mar 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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	6,999	7,481	7,579	7,520	7,461	7,505	7,548	7,592	7,636	7,681	7,725
23	Vegetation management	10,102	9,654	9,361	9,647	9,068	8,836	7,840	7,840	7,840	7,668	7,668
24	Routine and corrective maintenance and inspection	15,374	16,451	16,737	15,693	15,611	15,673	15,270	15,932	15,313	15,691	15,798
25	Asset replacement and renewal	9,895	10,432	10,229	8,984	8,363	7,504	6,510	6,544	6,579	6,613	6,648
26	**Network Opex**	42,370	44,018	43,906	41,844	40,503	39,518	37,168	37,908	37,368	37,653	37,839
27	System operations and network support	16,686	18,412	18,617	17,898	17,770	18,490	18,130	17,939	17,795	17,652	17,652
28	Business support	31,813	32,512	31,932	31,158	30,173	32,491	32,412	32,464	32,547	32,613	32,633
29	**Non-network opex**	48,499	50,924	50,549	49,056	47,943	50,981	50,542	50,403	50,342	50,265	50,285
30	**Operational expenditure**	90,869	94,942	94,455	90,900	88,446	90,499	87,710	88,311	87,710	87,918	88,124
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
39												
40	for year ended	**31 Mar 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**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	209	413	619	812	982	1,159	1,341	1,530	1,725	1,926
43	Vegetation management	-	269	510	794	986	1,158	1,204	1,385	1,571	1,722	1,911
44	Routine and corrective maintenance and inspection	-	489	957	1,340	1,752	2,108	2,400	2,873	3,133	3,599	4,023
45	Asset replacement and renewal	-	310	585	768	939	1,010	1,023	1,180	1,345	1,518	1,693
46	**Network Opex**	-	1,277	2,465	3,521	4,489	5,258	5,786	6,779	7,579	8,564	9,553
47	System operations and network support	-	446	914	1,363	1,810	2,290	2,653	3,036	3,415	3,796	4,211
48	Business support	-	966	1,826	2,661	3,387	4,369	5,095	5,854	6,659	7,481	8,311
49	**Non-network opex**	-	1,412	2,740	4,024	5,197	6,659	7,748	8,890	10,074	11,277	12,522
50	**Operational expenditure**	-	2,689	5,205	7,545	9,686	11,917	13,534	15,669	17,653	19,841	22,075

A2.3 SCHEDULE 12A

Company Name	**Powerco**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	1.04%	1.69%	3.27%	5.48%	88.52%	-	4	2.67%
11	All	Overhead Line	Wood poles	No.	8.91%	13.81%	19.36%	20.03%	37.90%	-	4	20.72%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	15.20%	84.80%	1	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	2.24%	0.99%	5.20%	10.10%	81.48%	-	4	5.13%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	0.19%	8.31%	6.83%	84.67%	-	4	0.68%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	18.89%	81.11%	-	4	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	8.71%	91.29%	-	4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	8.75%	33.75%	5.63%	24.38%	4.38%	23.13%	3	15.63%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	8.20%	91.80%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	1.84%	40.49%	15.95%	41.72%	-	4	22.70%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	91.30%	8.70%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	22.57%	1.55%	15.82%	22.12%	37.94%	-	4	16.48%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-	-	4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	27.78%	11.11%	61.11%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	1.43%	32.30%	13.71%	52.56%	-	4	20.62%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	50.00%	50.00%	-	4	-
35												

Row	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2.03%	2.90%	5.40%	20.07%	69.61%	-	4	9.42%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	16.72%	1.10%	5.96%	13.83%	62.39%	-	3	8.88%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	0.00%	-	1.15%	21.56%	77.29%	-	3	4.09%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.86%	0.04%	1.94%	12.28%	84.89%	-	3	2.38%
44	HV	Distribution Cable	Distribution UG PILC	km	2.42%	-	1.03%	15.20%	81.35%	-	3	2.72%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	100.00%	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	1.02%	0.20%	1.02%	4.08%	93.68%	-	4	0.20%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	2.34%	48.65%	3.27%	4.67%	41.07%	-	4	57.09%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.56%	2.61%	10.24%	18.09%	67.50%	-	3	6.88%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	11.68%	4.26%	16.84%	22.38%	44.84%	-	4	13.37%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.91%	2.43%	10.19%	17.15%	68.33%	-	4	11.62%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.25%	2.08%	7.79%	12.19%	75.68%	-	3	5.02%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	2.03%	2.90%	5.40%	20.07%	69.61%	-	4	3.15%
53	HV	Distribution Transformer	Voltage regulators	No.	3.45%	-	1.72%	6.90%	87.93%	-	4	2.54%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.55%	1.35%	5.35%	9.13%	83.63%	-	3	3.80%
55	LV	LV Line	LV OH Conductor	km	0.89%	1.47%	7.63%	18.61%	71.40%	-	2	3.80%
56	LV	LV Cable	LV UG Cable	km	-	0.19%	2.43%	16.53%	80.85%	-	2	1.16%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.98%	0.99%	7.71%	23.60%	66.72%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	1.90%	11.50%	-	39.00%	47.60%	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	37.93%	1.98%	16.40%	43.69%	-	3	35.49%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	24.69%	-	15.43%	59.88%	-	3	13.01%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	8.11%	70.27%	21.62%	-	4	2.08%
62	All	Load Control	Centralised plant	Lot	-	27.78%	-	13.89%	58.33%	-	4	16.67%
63	All	Load Control	Relays	No.	8.18%	36.06%	0.58%	1.42%	53.77%	-	1	14.53%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Notes:

1. We interpret Grade 1 condition as assets requiring replacement within one year, based on our asset health models. This does not mean the assets are at imminent risk of failure, but rather have reached the end of their useful life. With appropriate risk mitigations (such as operating constraints for switchgear), these assets can safely continue in service for more than one year, though we do not consider this a sustainable practice over the longer term.
2. The ‘% of asset forecast to be replaced in next 5 years’ for Zone Substation Buildings is based on our seismic strengthening programme. The buildings will be strengthened via various means, but typically not replaced. This ensures consistency with our renewal Capex forecasts.
3. The ‘% of asset forecast to be replaced in next 5 years’ is based on a denominator of operational network sites, whereas disclosure schedules 9a and 9b additionally include spares.

A2.4 SCHEDULE 12B

Company Name	**Powerco**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Coromandel	5	1	N-1	1	927%	1	970%	Subtransmission circuit	Single 66kV circuit. Proposed generation support post 2026.
10	Kerepehi	10	-	N	2	-	7	163%	Transformer	Proposed alternate 33kV supply ~ 2022. Also Tx constraint
11	Matatoki	5	-	N	2	-	-	-	Transformer	Single Tx. 2nd transformer proposed 2027
12	Tairua	9	8	N	-	122%	8	126%	Transformer	Planned 66kV upgrades. Also a Tx firm capacity constraint.
13	Thames T1 & T2	12	-	N-1	2	-	19	63%	No constraint within +5 years	66kV upgrade removes binding constraint
14	Thames T3	2	7	N-1 SW	7	26%	7	26%	No constraint within +5 years	
15	Whitianga	17	-	N	-	-	16	115%	Transformer	66kV upgrades pre 2024. Post 2024 - new subs offload
16	Paeroa	9	6	N	2	153%	10	91%	No constraint within +5 years	Transfs upgraded
17	Waihi	18	16	N-1	-	110%	16	114%	No constraint within +5 years	Customer agreed security.
18	Waihi Beach	6	3	N	3	178%	3	190%	Subtransmission Circuit	Single 33kV cct. Plans post 2024 for local support.
19	Whangamata	10	-	N	1	-	-	-	Subtransmission circuit	Battery and generation support planned. Possible 2nd 33kV.
20	Aongatete	9	7	N-1 SW	1	121%	12	81%	No constraint within +5 years	Upgrades to 33kV system planned in post 5 year period
21	Bethlehem	10	8	N	8	125%	8	150%	Transformer	New single transf Sub - 2nd Tx planned late 2020s
22	Hamilton St	16	22	N-1	12	71%	22	76%	No constraint within +5 years	
23	Katikati	9	5	N	5	192%	11	87%	No constraint within +5 years	2nd circuit & 2nd Tx planned in next 5 years
24	Kauri Pt	3	2	N	2	209%	2	215%	Subtransmission Circuit	Single Tx and 33kV circuit limit security.
25	Matua	9	7	N-1	8	123%	7	125%	Subtransmission circuit	Circuit & Tx upgrades planned beyond 5 year period
26	Omokoroa	10	13	N-1	1	79%	13	84%	No constraint within +5 years	33kV upgrades & new substation planned in next 5 years
27	Otumoetai	15	14	N-1 SW	-	114%	14	125%	Transformer	Minor constraint - managed operationally.
28	Pyes Pa	9	12	N-1	8	75%	24	42%	No constraint within +5 years	New substation in high growth subdivision.
29	Waihi Rd	22	24	N-1	10	92%	24	93%	No constraint within +5 years	
30	Welcome Bay	24	21	N	4	111%	21	122%	Subtransmission circuit	Managed operationally. Upgrades and switchboard planned.
31	Matapihi	15	24	N-1	14	60%	24	63%	No constraint within +5 years	
32	Omanu	17	24	N-1	12	69%	24	71%	No constraint within +5 years	
33	Papamoa	15	21	N-1	10	73%	21	92%	No constraint within +5 years	Offload to new Subs maintains security at Papamoa.
34	Te Maunga	10	10	N	8	96%	10	104%	No constraint within +5 years	New single Tx Sub. Risk managed operationally via 11kV.
35	Triton	21	21	N-1	10	100%	23	97%	No constraint within +5 years	Transformers to be upgraded 2025.
36	Wairakei	7	6	N-1 SW	6	108%	24	35%	No constraint within +5 years	New Sub. 2nd transformer in ~ 5 years.
37	Atuaroa Ave	8	-	N	7	-	-	-	Subtransmission Circuit	33kV upgrades and 2nd transformer planned ~2026
38	Paengaroa	6	4	N	4	161%	4	162%	Subtransmission Circuit	New N security Sub with limited 11kV backfeed.
39	Pongakawa	5	1	N-1	1	401%	1	410%	Subtransmission Circuit	Single 33kV circuit. 11kV upgrades planned in longer term
40	Te Puke	20	23	N-1	11	88%	23	91%	No constraint within +5 years	Switchboard security upgrade planned
41	Farmer Rd	7	-	N-1	1	-	-	-	Subtransmission circuit	Switched backfeed. Constraint managed operationally.
42	Inghams	4	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security
43	Mikkelsen Rd	15	19	N-1	4	76%	19	77%	No constraint within +5 years	
44	Morrinsville	11	-	N	2	-	7	161%	Transformer	2nd 33kV circuit ~2023. Future Sub upgrade post 2023.
45	Piako	15	15	N-1	7	97%	15	102%	Transformer	Minor constraint - managed operationally.
46	Tahuna	6	1	N-1	1	850%	1	862%	Subtransmission Circuit	Single 33kV circuit. Risk mitigated operationally (via 11kV)
47	Tatua	5	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security
48	Waitoa	12	19	N-1	-	66%	19	66%	No constraint within +5 years	
49	Walton	6	-	N	2	-	-	-	Transformer	Single Transformer. Risk managed operationally
50	Browne St	10	11	N-1	6	94%	11	100%	Transformer	Very minor, low risk. Managed operationally

8	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
51	Lake Rd	7	2	N	2	390%	14	48%	No constraint within +5 years	2nd transformer planned in 2019
52	Tirau	10	-	N	-	-	-	-	Transformer	Single transformer. 2nd Tx planned post 2023
53	Putaruru	11	-	N	1	-	17	69%	No constraint within +5 years	New GXP, Subtrans. & transf. upgrades planned ~2022.
54	Tower Rd	9	-	N	5	-	17	55%	No constraint within +5 years	GXP and Subtrans upgraded, & 2nd Tx added ~ 2022
55	Waharoa T1	4	-	N-1 SW	-	-	9	40%	Subtransmission Circuit	Split sub restored to single sub again after 33kV upgrade
56	Waharoa T2	5	-	N-1 SW	-	-	-	-	No constraint within +5 years	Split sub restored to single sub again after 33kV upgrade
57	Baird Rd	11	-	N-1	7	-	11	97%	No constraint within +5 years	Switched 33kV ring. Switch timing nominally limits security
58	Midway / Lakeside	5	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security at both substations
59	Maraetai Rd	9	-	N-1	7	-	15	58%	No constraint within +5 years	Switched 33kV ring. Switch timing nominally limits security
60	Bell Block	19	25	N-1	9	77%	25	85%	Transformer	Load transfer planned post 2024
61	Brooklands	17	24	N-1	7	71%	24	79%	No constraint within +5 years	
62	Cardiff	2	6	N-1 SW	6	31%	6	31%	No constraint within +5 years	
63	City	19	20	N-1	12	93%	20	96%	Transformer	Capacity upgrade planned post 2027
64	Cloton Rd	11	13	N-1	1	86%	13	89%	No constraint within +5 years	
65	Douglas	2	2	N-1 SW	2	100%	2	100%	Subtransmission circuit	Single circuit. Very low risk. Most load can be backfed.
66	Eltham	10	11	N-1	3	92%	15	68%	No constraint within +5 years	Transformer upgrade ~2021
67	Inglewood	5	6	N-1	3	89%	6	93%	Transformer	Load transfer planned post 2025
68	Kaponga	4	3	N-1 SW	2	117%	3	118%	Transformer	Low risk of failure. Operationally managed.
69	Katere	15	21	N-1	11	74%	21	83%	No constraint within +5 years	
70	McKee	1	-	N-1 SW	-	-	-	-	No constraint within +5 years	
71	Motukawa	1	1	N	1	92%	1	95%	Transformer	Single transformer. Most load can be backfed.
72	Moturoa	23	21	N-1 SW	7	109%	30	75%	No constraint within +5 years	33kV circuits and transformers replaced ~2020
73	Oakura	4	4	N-1 SW	4	91%	4	103%	Subtransmission circuit	Single cct & Tx. 11kV backfed adequate till 2nd cct ~2025
74	Pohokura	5	9	N-1	-	59%	9	59%	No constraint within +5 years	
75	Waihapa	1	2	N-1	2	82%	2	82%	No constraint within +5 years	
76	Waitara East	6	10	N-1	4	55%	10	58%	No constraint within +5 years	
77	Waitara West	7	6	N-1 SW	8	109%	6	110%	Transformer	Risk of failure is low. Managed operationally.
78	Cambria	15	17	N-1	5	89%	17	99%	No constraint within +5 years	Transformer & Subtrans upgrade planned ~2026
79	Kapuni	8	7	N-1	4	108%	7	106%	No constraint within +5 years	
80	Livingstone	3	3	N	1	106%	5	64%	No constraint within +5 years	Transformers scheduled for replacement (higher cap)
81	Manaia	8	5	N	5	155%	5	155%	Transformer	33kV Tee resolved ~2022. Single Tx bank (after renewal)
82	Ngariki	4	4	N-1 SW	4	98%	4	99%	No constraint within +5 years	
83	Pungarehu	5	5	N-1 SW	2	100%	5	102%	Transformer	Low risk - operationally managed (e.g. backfeeds)
84	Tasman	7	6	N-1 SW	3	109%	6	110%	Transformer	Low risk - operationally managed (e.g. backfeeds)
85	Mokoia	4	3	N-1 SW	3	142%	3	-	Transformer	New Sub. Replaces Whareroa.
86	Whareroa	4	3	N-1 SW	3	142%	-	-	[Select one]	Sub decommissioned when new Mokoia built.
87	Beach Rd	11	16	N-1	3	68%	16	70%	No constraint within +5 years	Subtrans upgrades complete pre 2022.
88	Blink Bonnie	4	3	N	3	148%	3	151%	Transformer	Low risk of failure. Security upgrades planned post 2026
89	Castlecliff	12	9	N-1	5	133%	13	93%	Transformer	Post 2024 plan to upgrade transformers
90	Hatricks Wharf	11	-	N	6	-	10	111%	Transformer	Single transf, but 11kV bus tie (Taupo Quay) mitigates risk
91	Kai Iwi	2	1	N	1	237%	1	244%	Subtransmission Circuit	Single 33kV cct & single Tx. Also N security GXP.
92	Peat St	18	-	N-1	6	-	-	-	Transpower	2nd 33kV circuit ~2021, but N secure GXP limits security
93	Roberts Ave	8	6	N	6	138%	6	140%	Transpower	2nd 33kV circuit ~2021, but N secure GXP limits security
94	Taupo Quay	11	-	N	8	-	10	112%	Transformer	2nd 33kV circuit built. Single Tx with bus tie limits security.
95	Wanganui East	8	3	N	3	243%	3	244%	Subtransmission Circuit	Single 33kV cct and Tx. Post 2025 plan for 2nd cct and Tx.
96	Taihape	5	1	N	1	626%	1	624%	Transformer	Single transformer. 2nd Transformer post 2026
97	Waiouru	3	1	N	1	595%	1	589%	Subtransmission circuit	N secure GXP, 33kV & Tx. Post 2026 11kV upgrade.
98	Arahina	9	3	N	3	285%	3	288%	Subtransmission Circuit	N secure GXP, 33kV & Tx. Post 2026 2nd cct & Tx.
99	Bulls	6	2	N	2	282%	2	284%	Transformer	Post 2022 2nd 33kV. Post 2025 2nd transformer.
100	Pukepapa	5	2	N	2	239%	2	242%	Transformer	Single transformer. Limited backfeed. Post 2026 - 2nd Tx

8	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
101	Rata	3	1	N	1	402%	1	401%	Subtransmission circuit	Single 33kV cct and Tx. Post 2028 plan for 11kV Upgrade.
102	Feilding	22	24	N-1	2	95%	24	99%	No constraint within +5 years	Transformer upgrade 2021 and post 2023 33kV upgrade
103	Kairanga	19	19	N-1 SW	8	101%	24	83%	Subtransmission circuit	Transformer upgrade planned ~2023
104	Keith St	19	22	N-1	-	88%	22	90%	No constraint within +5 years	Upgrades offload 33kV circuits feeding Main and Keith St
105	Kelvin Grove	20	17	N-1 SW	5	114%	24	92%	No constraint within +5 years	Transformers upgraded in ~2021.
106	Kimbolton	3	1	N	1	208%	1	210%	Subtransmission Circuit	Single 33kV circuit & single transformer. Remote Sub.
107	Main St	27	17	N-1 SW	13	157%	25	92%	No constraint within +5 years	New Sub & 33kV cables address ex. high risk constraints.
108	Milson	19	18	N-1	5	103%	19	104%	Transformer	Posible TX and subtransmission upgrade post 2023
109	Pascal St	23	17	N-1	12	136%	25	66%	No constraint within +5 years	New Sub & 33kV cables address ex. high risk constraints.
110	Sanson	9	-	N-1	4	-	11	84%	No constraint within +5 years	33kV backfeed secures load. Tx upgrades post 2022
111	Turitea	16	-	N-1	5	-	-	-	Subtransmission Circuit	Switched 33kV security - Second 33kV circuit post 2023
112	Alfredton	0	1	N	0	33%	1	33%	No constraint within +5 years	Single Transf. but adequate backfeed.
113	Mangamutu	13	13	N-1	1	98%	13	99%	No constraint within +5 years	Major customer largely determines security requirements.
114	Parkville	2	-	N	-	-	-	-	Transformer	Single transformer
115	Pongaroa	1	3	N	1	27%	3	27%	No constraint within +5 years	Single transformer, but adequate backfeed
116	Akura	14	9	N-1 SW	7	150%	15	92%	No constraint within +5 years	Txs replaced & section of 33kV circuit upgraded, pre 2022
117	Awatoitoi	1	3	N	1	46%	3	47%	No constraint within +5 years	
118	Chapel	15	14	N-1	5	111%	23	68%	No constraint within +5 years	Upgrade short section of 33kV cable pre 2022.
119	Clareville	12	9	N	1	125%	9	134%	Transformer	Transformer and 33kV upgrade post 2024
120	Featherston	5	0	N	0	4,791%	0	4,982%	Transformer	Single transformer. 2nd bank proposed in longer term
121	Gladstone	1	1	N	0	71%	1	74%	No constraint within +5 years	
122	Hau Nui	2	-	N	-	-	-	-	No constraint within +5 years	Generation site. Not economic to provide higher security
123	Kempton	5	0	N	0	1,365%	0	1,440%	Subtransmission Circuit	Post 2024:- 2nd 33kV supply & upgraded 2nd transformer
124	Martinborough	5	0	N	0	5,147%	0	5,461%	Transformer	Single transformer. 2nd Tx planned post 2024
125	Norfolk	7	11	N-1 SW	3	69%	11	74%	Transformer	Risk is very low. Post 2024 upgrade planned.
126	Te Ore Ore	7	7	N	7	107%	7	109%	Transformer	Single transformer
127	Tinui	1	1	N	1	84%	1	85%	No constraint within +5 years	
128	Tuhitarata	3	-	N	-	-	1	337%	Subtransmission circuit	Single 33kV circuit & single transformer

[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation

A2.5 SCHEDULE 12C

Company Name	Powerco
AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*					Number of connections		
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**							
12	Small		4,909	4,909	4,909	4,909	4,909	4,909
13	Commercial		36	36	36	36	36	36
14	Industrial		6	6	6	6	6	6
15								
16								
17	**Connections total**		4,951	4,951	4,951	4,951	4,951	4,951
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		627	627	627	627	627	627
21	Capacity of distributed generation installed in year (MVA)		3	3	3	3	3	3
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25	GXP demand		808	815	823	830	838	845
26	*plus* Distributed generation output at HV and above		108	109	110	111	112	113
27	**Maximum coincident system demand**		916	924	933	941	950	958
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		916	924	933	941	950	958
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		4,498	4,511	4,558	4,606	4,653	4,701
32	*less* Electricity exports to GXPs		152	170	167	164	161	158
33	*plus* Electricity supplied from distributed generation		863	896	899	901	904	906
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		5,209	5,237	5,290	5,343	5,396	5,449
36	*less* Total energy delivered to ICPs		4,897	4,923	4,973	5,023	5,073	5,122
37	**Losses**		313	314	317	321	324	327
38								
39	**Load factor**		65%	65%	65%	65%	65%	65%
40	**Loss ratio**		6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

A2.6 SCHEDULE 12D

	Company Name	Powerco
	AMP Planning Period	1 April 2019 – 31 March 2029
	Network / Sub-network Name	Powerco - combined

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
10	**SAIDI**						
11	Class B (planned interruptions on the network)	84.2	86.6	93.2	98.4	99.4	94.1
12	Class C (unplanned interruptions on the network)	241.7	205.5	201.1	199.8	197.4	195.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.44	0.41	0.43	0.45	0.45	0.42
15	Class C (unplanned interruptions on the network)	2.28	2.29	2.28	2.28	2.27	2.25

	Company Name	Powerco
	AMP Planning Period	1 April 2019 – 31 March 2029
	Network / Sub-network Name	Powerco - Eastern Region

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
10	**SAIDI**						
11	Class B (planned interruptions on the network)	84.2	86.6	93.2	98.4	99.4	94.1
12	Class C (unplanned interruptions on the network)	241.7	205.5	201.1	199.8	197.4	195.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.44	0.41	0.43	0.45	0.45	0.42
15	Class C (unplanned interruptions on the network)	2.28	2.29	2.28	2.28	2.27	2.25

Company Name	**Powerco**
AMP Planning Period	**1 April 2019 – 31 March 2029**
Network / Sub-network Name	**Powerco - Western Region**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		84.2	86.6	93.2	98.4	99.4	94.1
12	Class C (unplanned interruptions on the network)		241.7	205.5	201.1	199.8	197.4	195.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.44	0.41	0.43	0.45	0.45	0.42
15	Class C (unplanned interruptions on the network)		2.28	2.29	2.28	2.28	2.27	2.25

A2.7 SCHEDULE 13

Company Name	**Powerco**
AMP Planning Period	**1 April 2019 - 31 Mar 2029**
Asset Management Standard Applied	**ISO 55001**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY 2018

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question	Function	Question	Score	Evidence—Summary
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.8	Our Asset Management Policy has been authorised by our CEO and circulated within Powerco. It is available on our document management system and referenced in our Asset Management Strategy and this AMP. Areas for improvement: a. The AM Policy does not contain guidance that identifies the requirements for the AM System framework and governance. b. The AM System and the roles and responsibilities have not been fully articulated
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2.5	Our Asset Management Strategy was created as part of a wider document review, so has a high degree of consistency with the new suite of documentation discussed in this AMP. The Strategy used our Business Plan and Asset Management Policy as a starting point, ensuring a line of sight. Areas for improvement: a. More clearly identify how the end to end processes integrate into the AM System. b. Make more evident in the strategies how they are prioritised or tracked.
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?	2.7	The Asset Strategy discusses the asset life cycle and its approach to this is summarised in this AMP. Specific asset life cycle strategies have been developed, and again, are summarised in this AMP.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2.4	We have continued to develop our suite of Fleet Management Plans that include work volumes across relevant time periods for all asset types, aligned to the asset information systems. The fleet plans identify inspection regimes and renewal programmes and future needs based on assessment of condition, age and trends in defects and failures. However we have reduced our score slightly compared to 2017 because the scope of the AMS is not explicitly defined.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2.5	We use the AMP as a key tool to communicate plans to our staff as well as external stakeholders The AMP provides a summary of a wide range of plans, and signposts staff to the source documentation of material. All our key standards are also communicated to people when the standards enter our Business Management System and Contractor Works Manual. However not all Powerco staff are aware of the AM Policy, with some communication ad-hoc at present
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.7	There is a range of documents that detail asset management responsibilities. These include Powerco's Business Plan, business unit tactical plans, position descriptions and employees' annual review and development forms. Powerco has detailed documents on responsibilities of service providers as well. Powerco has undertaken process mapping as part of continuous improvement to better align responsibilities. Areas for improvement: a. More clearly articulate the requirements for an AMS and define the roles and responsibilities for governance of the AMS. b. Further refinement needed with definition of roles and responsibilities, and how they are understood and communicated.
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)	2.6	Our field contract arrangements have been arranged to provide demonstrable cost efficiency. Deliverability is central to asset management, and our processes consider the skills and competencies needed to ensure cost effective delivery. Powerco has new field service contract arrangements and has reviewed the end to end processes of service provision and now implemented most of the process changes. However alignment with resourcing and shutdown planning needs improvement. Resource needs to meet reliability growth plans are not clearly articulated and better articulation of our supply chain management strategy is required.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2.8	Powerco has well developed and established procedures for dealing with emergencies and incidents that happen fairly regularly e.g. the process to manage storm response and incidents that have public risks, and adoption of a critical incident management system. We also have done a range of investigations on natural disasters, including the impact of earthquakes on key buildings, such as depots. However we tend to be better at response, rather than reduction and readiness.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	2.7	Powerco has a strong organisational structure, that clearly provides roles and responsibilities on assets, operations and commercial work. The responsibilities of ownership are described in Chapter 5 on Governance. Areas for improvement: a. More clearly articulate the roles and responsibilities for the governance of the Asset Management System. b. Existing governance committees do not cover the full scope of the AMS.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.8	The AMP provides an overview of delivability capability in the context of CP delivery requirements, and this is considered in the outsourcing arrangements through the EFSA refinements. Area for improvement: Prepare a clear overall resource strategy.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.4	As described in previous AMPs, we consider ourselves on a journey towards asset management excellence, and this has been driven from senior management. This includes emphasising the importance of meeting asset management requirements. Areas for improvement: a. The requirements of an AM System could be more fully articulated. b. Not all staff are aware of the AM Policy, and further training and communication will be needed to articulate individual staff contributions to the AM System.
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?	2.9	A refined outsourcing approach has been devised in the context of CPP delivery. Significant monitoring is undertaken to monitor the performance of service providers, supplied assets, services delivered, financial performance and process performance.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.4	Our Human Resources team has undertaken a range of analysis on training and competence needs and there is a structured approach to training in Powerco. As part of the process to retender service provider contracts, we have also undertaken a range of analysis on what training and competence is required in delivering field services. We have graduate and cadet programmes to bring in new engineering talent into the industry. However we need a clearer overall resourcing strategy and an overall asset management competence and training framework.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.2	We have documented our internal competence requirements for staff as well as for field staff. We are currently implementing these new competence requirements for all our contractors. Our HR team records training activity undertaken, oversees mentoring programmes and induction courses and has a dedicated learning and development role to support this. However an overall asset management competence and training framework, while being prepared, is still needed.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.2	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2.1	Powerco's Asset Management Policy is available to all employees. Powerco's progress on KPI's is reported on the intranet for all staff to view. Standards and notifications are made through the CWM portal. We also seek a range of ways for staff to feed back into the asset management process. In addition, there are also a range of systems that communicate asset information e.g. outages, customer initiated work etc. Our AMPs are widely circulated to our stakeholders, including plans to develop an AMP summary. Change mangement processes could be tightened up, such as with the technical standards where change requires communication, roll out training, business impact assessment, etc. This is why we have reduced our score in this area.
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?	2.0	Powerco has an extensive range of documentation to support its asset management process, such as standards, approval documentation and process mapping. The range of documents we use are described extensively throughout this AMP. However the scope of the AMS is not explicitly defined and this is why we have reduced our score in this area.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2.2	Information management is an area we have continued to work on over the last few years and is a strategic priority. However the scope of the asset information requirements in the AMS needs to be more clearly articulated.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2.3	Powerco has a range of controls to ensure data is accurate and there is an adequate process of quality review at input, and data cleansing plan, for example in the GIS system. We have an established internal assurance team, to provide increased checks on data accuracy. However there is no formal data and information management system in place that effectively manages, governs and assures that necessary asset information quality parameters are being met, and that data quality is continuously improved.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.2	Details or our ERP Project are provided in Chapter 22. There are plans for a better overall Asset Information strategy that defines and justifies the asset information requirements. It will include Asset Information Specifications or data standards showing the required information for AM decision making including accuracy and requirements. This is an area where we have reduced our score slightly compared to 2017 on account of there being no overall Asset Information strategy that defines and justifies the asset information requirements, and no Data standards showing the required information for AM decision making including accuracy and requirements. These are being prepared.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2.8	Chapter 5 details Powerco's processes for risk management and we have a structured approach across the business for identifying and mitigating risks. Areas for improvement: a. No AMS level risk assessment has been completed. Corporate risk registers and asset level risk assessments are relied upon. Need to demonstrate the risks and controls for the AMS to continue to achieve its objectives. b. There is no cross business Assurance Framework covering the 3 lines of defence, in particular the second line of defence. c. Management of Change is managed in an ad-hoc manner across a number of processes, tools and staff, and needs to be tightened up.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.7	Powerco has a structured approach to how risks are managed and actions are reported to the Board Risk and Assurance sub committee. However there is no cross business assurance framework covering the 3 lines of defence, particularly the 2nd line of defence.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2.5	Powerco has invested significant resource in the last few years in all aspects of legal and regulatory compliance. The Risk and Assurance and Regulatory teams monitor changes and update the business. A comprehensive compliance review is undertaken each year to ensure compliance with legislation and regulations. However we recognise that not all Powerco staff are aware of the AM Policy and that our AM System needs defining.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3.0	We have good documentation and contractual controls for maintenance activity. We have been continuously improving techniques for gathering asset inspection data. We have a high quality library of standards, with excellent coverage across planning, design, maintenance and safety. Defects are clearly classified and systematically assessed and prioritised. Areas for improvement: There are in excess of 36000 known backlog defects, with approximately 6000 of these duplicates. The CPP is targeting a catch up of 4000 backlog defect items pa making the catch up of 20000 over course of the CPP period. The find and fix methodology process can be improved.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3.1	
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.5	Condition assessment programmes are in place and the data collected from the field is building a solid asset condition history. We are primarily using lagging measures for scheduled work through worst performing feeders. We have implemented Asset Health Indicators and beginning to incorporate Asset Criticality, which will enable leading measures. Areas for improvement: Develop overarching performance management framework. Bridge gaps in the performance measures across some of the asset classes.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.9	Powerco has invested heavily in the last five years in health and safety and our Health, Safety, Environment and Quality Team. This has seen a marked level of improvement in our H&S maturity. The HSEQ team helps ensure that investigations occur, actions are taken and responsibilities are clear. We also have weekly incident meetings and Executive Health and Safety meetings to monitor our work in this area.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2.0	An assurance and audit framework exists and is mostly geared towards the third line of defence with the auditing approach capturing significant issues. There are deficiencies in the second line of defence that need development. There is no clear strategy for assurance of the Asset Management processes.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.9	We have a range of corrective action processes, for example, EFSA relationship meetings, HSEQ meetings and operational meetings all support these processes. The Incident Management System is generally well executed, with only a few examples of the end to end incident investigation and close out processes needing to be improved.
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?	2.3	Current asset management performance is assessed and findings used to drive improvement programmes. Formal monitoring and reporting on improvements is undertaken by the Executive. We have a continuous improvement programme to address process deficiencies. The Asset Management Improvement Plan has not been developed or approved.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.3	Powerco has good practices for seeking out new asset management technology and practices. We are active in the ENA and EEA, with employees on the Board of both organisations. Staff regularly attend and present at conferences and had discussions on practices with overseas EDBs. We have a Network Transformation team that leads research into this area. However an Asset Management Improvement plan has not been developed or approved.

A2.8 SCHEDULE 14A – NOTES ON FORECAST INFORMATION

Below we comment on differences between our forecast capital expenditure (schedule 11a) and operational expenditure (schedule 11b) in nominal and constant prices:

- We explain our approach to forecast escalation in Chapter 26.
- We are required to identify any material changes to our network development plan disclosed in our previous AMP. We discuss our current plans in Chapter 11 and changes from our previous AMP in Appendix 5.
- We are required to identify any material changes to forecast Capex (Schedule 11a) and Opex (Schedule 11b). We explain both these forecasts and their basis throughout the AMP.
- We state our expenditure in constant prices in 2019 real dollars in the body of this AMP. Schedules 11a and 11b uses constant prices in 2019 real dollars, as per the Commerce Commission's information disclosure requirements for a 2019 AMP and for consistency with other electricity distributors' disclosures.

A2.9 MATERIAL CHANGES

This section discusses any material changes in the approach to the population of information disclosure schedules shown in the previous sections.

A2.9.1 MATERIAL CHANGES TO SCHEDULE 12A

The method for calculating our internal asset health indices (AHI), scored H1-H5, is consistent with the 2017 AMP for most fleets. This aligns with the EEA AHI 1-5 grades.

Since the 2017 AMP, we have created CBRM models for - Distribution Switchgear, Ground Mount Distribution Transformers, Zone substation switchgear and Zone substation transformers – which has improved the evaluation of AHI for these fleets. These are also scored H1-H5.

Disclosure Schedule 12A template has also changed since 2017 to better align with the EEA AHI methodology. This allows us to map the asset condition in the schedule directly to our internal AHI calculations.

Asset health is discussed in more detail in Chapter 7, and is used extensively throughout our fleet management chapters of this AMP.

A2.9.2 MATERIAL CHANGES TO SCHEDULE 12B

Installed firm capacities and transfer capacities have been fully reviewed, and a more consistent interpretation of our security standards has been applied.[122] Any changes to the metrics reported in 12b are due to adjustment made to the underlying parameters for a site.

A2.9.3 MATERIAL CHANGES TO SCHEDULE 12C

Our forecasts of demand growth rates were developed at feeder level, and these then determine zone substation and GXP growth rates. This is consistent with the previous forecast methodology and as a result there are no significant adjustment in this schedule.

A2.9.4 MATERIAL CHANGES TO SCHEDULE 12D

We have updated our modelling assumptions for populating the planned SAIDI and SAIFI forecasts of schedule 12d since our last AMP. We use separate models to forecast unplanned and planned SAIDI and SAIFI. The forecasts are based on modelling historical fault data, and our planned work. The planned SAIDI and SAIFI model has updated assumptions regarding live-line work, which indicates an increased need for outages to deliver our works plan. The unplanned SAIDI and SAIFI forecasts are not normalised.

[122] See Chapter 7 for a description of our security standards.

APPENDIX 3 STAKEHOLDER INTERESTS

A3.1 APPENDIX OVERVIEW

The main objective of our AMP is effective consultation with our stakeholders. In Chapter 2 we provide an overview of our main stakeholders and their interests. Given how important our stakeholders are to us, this appendix gives more details about each stakeholder and insights into what they tell us they want from our asset management.

A3.2 OUR CUSTOMERS

We exist to serve the needs of our customers. More than 800,000 New Zealanders rely on us for a safe, reliable and high-quality supply of electricity at a reasonable price.

We serve a diversified group of households, businesses and communities. These customers include:

- 337,137 homes and businesses comprising:
  - Residential consumers and small businesses (“Mass Market”)
  - Medium sized commercial businesses
  - Large commercial or industrial businesses
- 21 directly-contracted industrial businesses, including large distributed generators

Electricity is an indispensable part of modern economic and social life. As use and dependence on electricity has grown, so too has customers expectation of the availability and quality of supply. In addition to excellent customer service, customers increasingly expect good, timely information on their service.

A3.2.1 STAKEHOLDER INTEREST

The interests of each of our main customer groups are described in Chapter 4. These are as identified through consumer surveys, meetings with customers and consumer groups, and feedback from our hotlines. Customer’s interest can be summarised as:

- Reliability – our customers want us to minimise the frequency and duration of supply interruptions, as well as ensuring quality of supply and network capacity.
- Responsiveness – our customers expect us to respond quickly to issues on the network and reduce potential safety and reliability risks.
- Cost effectiveness – our customers expect our investments are appropriate to meet their expectations and that we are constantly evaluating our approach to optimise these investments and their underlying costs.
- Customer service and information quality – our customers value timely and accurate information about their supply, especially during supply interruptions. They want more real time information available through digital channels.

A3.3 COMMUNITIES, IWI AND LANDOWNERS

With almost 28,000km of network circuits, we interact with a range of communities, iwi and landowners. We are also an active corporate citizen and involved in a range of community projects and activities.

We recognise the importance of consulting with iwi and communities on significant new projects, particularly development of new subtransmission line routes. We regularly meet with landowners, iwi and local community groups to ensure their views, requirements, values, significant sites and special relationship with the land are taken into account early in the project development phase.

- Affected landowners wish to be advised when maintenance crews enter their property and wish to be assured their property will not be damaged or put at risk.
- Communities expect us to be an active and responsible corporate citizen, supporting the areas where our staff live and our network operates.

A3.4 RETAILERS

We currently have 23 electricity retailers operating 32 brands on our network. Of these, three serve 70% of our customers.

Like most EDBs we operate an interposed model. This means retailers purchase our services, bundle them with energy supply and the cost of accessing the transmission grid, and provide a bundled price for delivered energy to their customers. Working with retailers to ensure a simple and effective energy supply for customers is a key part of what we do.

Retailer interest follows customer interest, as described above. In addition, retailers have an interest in:

- How we work with them to provide customers with information about outages and other information customers may require
- Our pricing structure and pricing changes
- How we resolve customer complaints (that may have been directed to the retailer)
- How we operate under the Consumer Guarantees Act
- Our use of system agreement

A3.5 THE COMMERCE COMMISSION

The Commerce Commission is the main agency that regulates us. It aims to ensure that regulated industries, such as electricity lines businesses, are constrained from earning excessive profits, and are given incentives to invest appropriately and share efficiency gains with consumers.

The Commerce Commission has responsibilities under Part 4 of the Commerce Act 1986, where it:

- Sets default or customised price/quality paths that lines businesses must follow
- Administers the information disclosure regime for lines businesses
- Develops input methodologies

Part 4 of the Commerce Act requires the Commission to implement an information disclosure regime for EDBs. The regime places a requirement on businesses to provide enough information publicly, such as via regulatory accounts and various performance indicators, to ensure interested parties are able to assess whether or not the regulatory objectives are being met.

We meet regularly with Commissioners and staff to compare notes.

A3.6 STATE BODIES AND REGULATORS

The state bodies and regulators that have jurisdiction over our activities include the Ministry of Business, Innovation and Employment, WorkSafe, and the Electricity Authority.

The Ministry of Business, Innovation and Employment administers the Health and Safety at Work Act 2015 and the Electricity (Safety) Regulations.

The new Health and Safety at Work Act comes into force on 1 April 2016 and we are confident our existing processes and systems meet all the new Act's requirements.

The Electricity (Safety) Regulations came into effect in April 2011 and set out the underlying requirements the electricity industry must meet. In particular, lines companies must set up and maintain a Safety Management System that requires all practicable steps to be taken to prevent the electricity supply system from presenting a significant risk of (a) serious harm to any member of the public, or (b) significant damage to property.

There are several codes of practice that apply to line companies. The most important of these are:

- ECP34 - Electrical Safe Distances
- ECP46 - HV Live Line Work

WorkSafe is the regulator for ensuring safe supply and use of electricity and gas. It conducts audits from time to time to ensure compliance with safety standards as well as accident investigations following serious harm or property loss incidents.

Radio Spectrum Management administers the radio licences needed for the operation of the SCADA and field communication systems.

The Electricity Authority regulates the operation of the electricity industry and has jurisdiction over our activities as they relate to the electricity industry structure. These include terms of access to the grid, use of system agreements with retailers, as well as metering, load control, electricity losses and distribution pricing methodologies.

We are committed to supplying electricity in a safe and environmentally sustainable manner and in a way that complies with statutes, regulations and industry standards. In the electricity distribution network context, the most noteworthy legislation to comply with is:

- Electricity Act 1992 (and subsequent amendments)
- Electricity Industry Act 2010
- Electricity (Hazards from Trees) Regulations 2003
- Electricity (Safety) Regulations 2010 (and pursuant Codes of Practice)
- Resource Management Act 1992
- Health and Safety in Employment Act 1992
- Electricity Industry Participation Code 2010
- Hazardous Substances and New Organisms Act 1996

A3.7 TERRITORIAL LOCAL AUTHORITIES

As the largest electricity distributor by geographical size, we cross a large number |of local and regional councils.

These organisations are valued customers and have an interest in how electricity supports economic growth and how our activities interact with the Resource Management Act.

- Implementation of the Resource Management Act – local councils have a role in promoting the sustainable management of natural and physical resources. This includes how our network interacts with its environment. We consider ourselves a long-term and responsible corporate citizen. We aim to be actively involved in district and regional plan changes debates and take part in hearings and submissions on local issues.
- Economic growth – authorities have an interest in promoting economic growth in their communities, and we work with them to understand where investment may be needed by us to support this.
- A valued customer – local councils are also often our customers, supplying lifeline utility services, such as water and sewage. We work closely with councils to understand their supply needs and co-ordinate any outages.

A3.8 OUR EMPLOYEES

We have around 450 staff, based in offices in New Plymouth, Tauranga, Whanganui, Palmerston North and Wellington. The level of engagement with our teams and the strength of our culture is important to us. We regularly undertake engagement surveys to make sure we continually improve what we do.

Our employees wish to have interesting and varied careers, with the ability for career development. Safety, job satisfaction, working environment and staff wellbeing are key employee tenets.

Our teams have an interest in managing the network competently and doing the 'right thing', therefore the effective communication of our Asset Management Plan to them is of great importance.

Employees need to have a safe environment to work in and we also need to ensure our assets are safe for contractors and the public. Safety in design principles are a key part of our design and construction standards.

These principles are discussed in more detail in Chapters 5, 6 and 10.

A3.9 OUR SERVICE PROVIDERS

We operate an Electricity Field Services Agreement with Downer Limited, and have expanded the capital works contractor panel to include Northpower and Electrix. We also have a range of approved service providers who work on our network.

Our service providers require a sustainable and long-term relationship with us. As part of this relationship we expect our service providers will be profitable, but efficient. This means having a foreseeable and constant stream of work to keep their workforces productively employed. Focus areas, from our perspective as an asset owner, are safety, competency, crew leadership and alignment of business models.

Given the anticipated increase in expenditure over the AMP planning period, we will work closely with our service providers to ensure we are able to deliver the higher volume of work in the most efficient manner.

Workflow certainty allows our service providers to confidently build up the right level of resources to achieve efficient resource utilisation. It also allows service providers to achieve benefits of scale from their material purchases resulting in efficient pricing and a stable industry environment.

Electrical equipment is capable of causing serious harm and we take measures to ensure service provider employees work in a safe environment. This is accomplished through a competency certification framework, procedures and through audit processes.

These principles are discussed in more detail in Chapters 7 and 10.

A3.10 OUR INVESTORS

We are a privately-owned utility with two institutional shareholders: Queensland Investment Corporation (58%) and AMP Capital (42%).

As the electricity distribution sector is regulated, regulatory certainty is a key issue that affects our owners' investment decisions. Our investment plans are subject to certain aspects of the regulatory regime being changed and clarified through the Commission's formal review of the Input Methodology rules. These cover:

- Productivity and commercial efficiency: Delivery of asset management in a productive, efficient and commercially prudent manner.
- Optimal utilisation of assets represents the best trade-off between capital expended on the assets and network risk.
- Risk management processes seek to identify, recognise, communicate and accept or control risks that arise in the asset management process.

We have also just lodged a formal application for a Customised Price Path which will also have a material effect on our investment planning.

Owners (as represented by the directors) have overall responsibility for Powerco and expect our management team to address this wide range of business drivers.

A3.11 OTHER STAKEHOLDERS

Other stakeholders with an interest in our asset management process include Transpower, the media and groups representing the industry such as the Electricity Networks Association and the Electricity Engineers Association.

Transpower supplies bulk electricity through their grid. Operational plans (like outages and contingency planning) and long-term development plans need to be coordinated well in advance to ensure seamless supply.

The Electricity Engineers Association provides industry guidelines, training and a point of focus for inter-industry working groups. The Electricity Networks Association represents the interests of the distribution lines companies in New Zealand.

APPENDIX 4 MAJOR CUSTOMERS

A4.1 APPENDIX OVERVIEW

As explained in Chapter 4, we have 627 customers with demand greater than 300kVA, whom we class as large commercial or industrial customers. These customers account for 0.2% of our ICP numbers but consume 28% of the electricity we deliver.

Given the size and complexity of their operations, our large customers have more specific service requirements than the mass market. It's important that we understand the unique characteristics and requirements of these organisations and develop strong working relationship with a long-term view.

This appendix provides more details on our largest customers (defined as having installed capacity greater than 1.5MVA). These organisations have a significant impact on our network operations and asset management priorities, and it's very important that we provide the highest levels of service.

A4.2 DAIRY SECTOR

Dairy farms are spread across our footprint, and are particularly dominant in the Taranaki and Waikato regions..

At an individual farm level, recent years have seen operations increasing network uptake due to increasing cooling and holding standards. While this drives need for effective network planning and operations, it is anticipated that further volume growth in this sector will be subdued while commodity prices remain soft.

Off-farm processing loads remain strong across footprint.

The industry requires a reliable supply, so shutdowns for maintenance or network upgrade activities have to be planned for the dairy low season, especially in South Waikato and South Taranaki.

Major Dairy Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Fonterra – Mainland Products	Fonterra – Morrinsville
Fonterra – Pahiatua	Fonterra – Tirau
Fonterra – Longburn	Fonterra – Waitoa
Open Country Dairy Ltd - Whanganui	Open Country Cheese
	Tatua Dairy

A4.3 TIMBER PROCESSING SECTOR

Forestry is a significant industry in New Zealand, and we have a number of commercial forests and timber processing operations across our footprint.

These timber processing facilities are often located away from other users, in remote areas with low network security. This means that outage planning may involve customer consultation and that voltage fluctuations may occur.

Major Timber Processing Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Kiwi Lumber - Sawmill	Oji Fibre Solutions Ltd
Juken Nissho	Kiwi Lumber
Waverley Sawmill	Pacific Pine
Taranaki Pine	PukePine Sawmills
	Thames Timber
	Fletcher Challenge Forests
	Claymark Katikati

A4.4 FOOD PROCESSING SECTOR

Many of our larger customers are involved in food and beverage processing. As demonstrated by the table below, we have a significant number of meat cool stores and processing plants, as well products such as bakeries and pet food.

The Kiwifruit industry which includes cool stores and post-harvest facilities is expected to grow significantly. This is primarily due to the increase in demand for the Sun Gold Variety. These cool stores can have heavy, peaky loads on outer edges of the supply network. Careful planning is needed to ensure adequate capability is allowed for these loads. Cost effective redundancy for full site capacities are becoming more difficult to provide due to the size of the loads.

Major Food Processing Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Affco NZ Feilding	Apata Coolstores
Affco NZ Whanganui	Affco Rangiuru
ANZCO Foods	Baypac
Aotearoa Coolstores	Champion Flour
Canterbury Meat Packers	Eastpac Coolstores
Cold Storage - Nelson	Greenlea Meats
DB Breweries	Huka Pak Totara
Ernest Adams	Hume Pack N Cool
Foodstuffs	Inghams Enterprises Mt Maunganui
Foodstuffs Coolstores	Inghams Enterprises Waitoa
Goodman Fielder Meats	Cold Storage Tauranga
International Malting Company	Silver Fern Farms Te Aroha
Lowe Walker	Sanford
Mars Pet Foods	Seeka
Riverlands Eltham	Trevalyan Coolstore
Riverlands Manawatu	Wallace Corporation
Tegel Foods	Jace Investments
Yarrows Bakery	
Silver Fern Farms Hawera	

A4.5 TRANSPORTATION SECTOR

We have two major ports on our network – the Port of Tauranga and Port Taranaki. The Port of Tauranga is aggressively pursuing market share, and is already the largest port in the country in terms of total cargo volume. For Port Taranaki, volume is largely oil and gas condensates.

Port operations are based around shipping movements and the quick turnaround of ships is important. When ships are in port, the facilities make heavy demands on the electricity distribution network and at these times a highly reliable supply is needed to ensure a fast turnaround.

A secure supply (N-1) is therefore needed by ports. The continued drive for efficiency and increasing demands in this sector has been squeezing the windows available for maintenance.

Major Transportation Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Port Taranaki	Port of Tauranga

A4.6 INDUSTRIAL SECTOR

We have a variety of large manufacturers and extractive companies connected to our network.

The manufacturing sector is dependent on prevailing economic conditions, particularly the conditions within the industry's niche. The requirements on the distribution network can therefore vary accordingly. The strong New Zealand dollar has put pressure on this sector, however, the large companies we serve are well established.

Major Manufacturing Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
MCK Metals Pacific	A & G Price
Ballance Agri-Nutrients	Fulton Hogan
Olex Cables NZ	Thames Vehicle Operations
Iplex Pipelines NZ	Katikati Quarries 2001
Waters & Farr	Waihi Gold

A4.7 CHEMICALS SECTOR

The companies we serve in the chemicals sector are dominated by the oil and gas industry in Taranaki and the agri-nutrient industry in the Eastern region.

The chemical sector is heavily reliant on a reliable supply of electricity with few voltage disturbances. Some of the machines in this industry can create large voltage dips on the network when they start. This needs ongoing coordination with the customers on installation of variable speed drives or alternative options.

Major Chemicals Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Shell Exploration NZ – Pohokura	Ballance (Mt Maunganui)
Methanex NZ – Waitara Valley	Evonik
Shell Todd Oil Services – Oaonui	Ballance (Morrinsville)
Methanex NZ – Waitara Pumps	
Origin Energy – Waihapa TAG Balance Kapuni	

A4.8 GOVERNMENT SECTOR, EDUCATION AND RESEARCH FACILITIES

We serve a range of public sector organisations, including hospitals, sewage and water plants, army and air force bases, universities, polytechnics and research facilities.

We recognise the impact a supply outage can have on these facilities and work carefully with district health boards, local councils and the New Zealand Defence Force to ensure our service meets their needs.

Given the critical nature of their activities, some of the government sector organisations have on-site generation. This needs to be coordinated with our network operations.

Government, Research and Education Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
AgResearch	Chapel St Sewage Plant
Dow AgroSciences NZ	Tauranga Hospital
Taranaki Healthcare	Bay of Plenty Polytech
Whanganui DC – Waste Water Treatment	Matamata Piako DC Waste Water Treatment Plant
NZDF – Army Training Waiouru	
TEI Works	
Fonterra Research Centre	
NZDF – Linton Military Camp	
MidCentral Health	
NZDF – RNZAF Base Ohakea	
Massey University – Turitea Campus	

APPENDIX 5 WORKS PROGRAMME COMPLETION

A5.1 APPENDIX OVERVIEW

This appendix provides information on our progress against physical and financial plans set out in our 2019 AMP.

In summary, we completed 97% of our scheduled capital works programme for FY18, and overall completed 106% of our scheduled maintenance programme. Any incomplete capital and maintenance work was carried over to the FY19 programme.

A5.2 DEVELOPMENT PROJECT COMPLETION

During FY18 we undertook a series of network development projects. The table below provides a summary of key projects, their progress, and discussion of material variances against plan.

PROJECT	DESCRIPTION	PHYSICAL PROGRESS AT END FY18	REASONS FOR SUBSTANTIAL VARIANCES
Wairarapa			
Akura Sub to Te Ore Ore Sub line	33kV line capacity upgrade	Construction started	No major variances
Taranaki			
Moturoa 33kV	33kV cable Moturoa to Carrington GXP	Construction started	No major variances
Mokoia Sub	New Zone substation near Hawera	Construction started	No major variances
Whanganui			
Westmere Peat St feeder upgrades	Kai Iwi sub security 11kV feeder upgrade	Construction Complete	Access issues and SAIDI management
Western PTN Communications	Communications for voice and data	Construction 50% complete	No major variances
Palmerston North			
Pascal-Main St cable	33kV cable capacity upgrade for security	Construction Complete	No major variances
Gillespies 33kV cable	33kV cable capacity upgrade for security	Construction Complete	No major variances
Ferguson zone substation	New sub to improve security to CBD	Construction started	No major variances

PROJECT	DESCRIPTION	PHYSICAL PROGRESS AT END FY18	REASONS FOR SUBSTANTIAL VARIANCES
Pongaroa substation	Sub rebuild due to age and condition	Construction Complete	Civils and site shift. Remote site
Tauranga			
Te Matai Wairakei 33kV cabling	New 33kV cable Te Matai GXP to new Wairakei substation	Construction near complete	Underbudget due to coordination with TEL
Pyes Pa zone substation	New Zone substation to supply development	Construction near complete	No major variances
Wairakei Zone Substation	New Wairakei substation	Construction near complete	No major variances
Otumoetai 33kV cabling and switchboard	Bethlehem / Matua / Otumoetai security	Construction complete	No major variances
Valley			
Baird – Maraetai cable	New link between substations to improve security	Construction Complete	No major variances
Waihi sub switchboard	Replace 11kV switchboard	Construction Complete	Project completed on budget
Kinleith Ripple plant	Replace aged ripple plant due to reliability	Construction Complete	Project completed on budget
Minden Rd upgrade	11kV feeder capacity upgrade	Construction Complete	Access and site geography
Mikkelsen Rd Feeder	11kV Distribution conductor upgrade	Construction Complete	Under budget. Good project management

The majority of project actual costs are in-line with project budgets. Increased project costs have mainly been influenced by land access and consenting resulting in time delays and construction route constraints. Additional costs associated with SAIDI management are having increasing impact on direct costs and time to manage works. Coordination of works with other parties, like Tauranga Eastern Link, have resulted in cost reductions on some projects.

A5.3 MAINTENANCE PROGRAMME DELIVERY

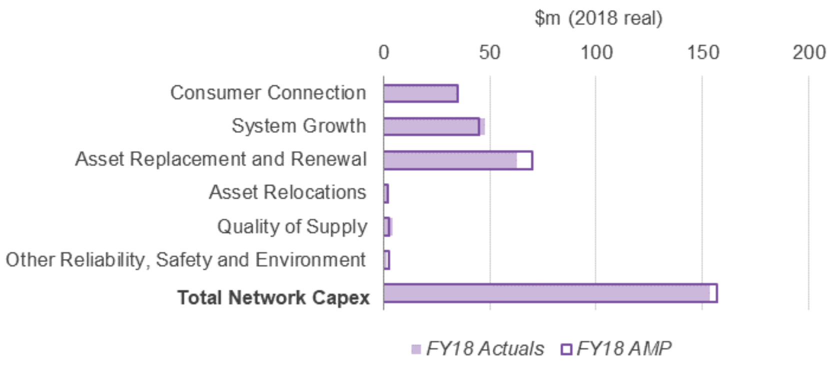
The FY18 maintenance programme was completed, with all scheduled activities completed by year end. Over-delivery of the vegetation management programme occurred because of increased focused on improving performance of the network.

A5.4 FINANCIAL PROGRESS AGAINST PLAN

A5.4.1 NETWORK CAPEX

Total network Capex for FY18 was slightly below the 2018 AMP forecast by $3.2M (-2%). The primary driver behind this was in the asset replacement and renewals expenditure as shown in the figure below.

Figure A5.1: Network Capex variance FY18



In the 2017 AMP we outlined our change in approach to Capex categorisation, when compared to the information disclosure categories. We are doing this to better support our expenditure tracking and justification by providing more consistency in expenditure categorisation, and removing unnecessary variability between years.

This recategorisation included adding System Growth and Quality of Supply together to form ‘Growth and Security’, and to add Asset Replacement and Renewal and Other Reliability, Safety and Environment together to form ‘Renewals’.

This approach aligns better with how the expenditure is forecast within the AMP.

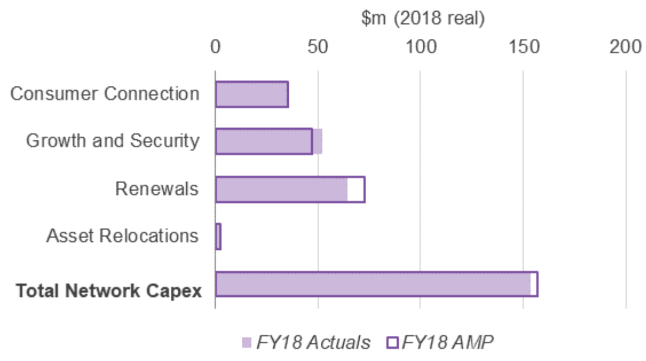
Consumer connection expenditure was close to target, under by $0.3m (-1%).

Growth and security expenditure was higher than forecast by $4.8m (10%). Increased expenditure in this area reflects progress on projects that experienced practical delays due to land access constraints in FY17. There was also some adjustments to recategorise specific projects from Renewals to Growth and Security.

Renewals expenditure was $8.1m or (11%) lower than forecast. This is primarily due to $5m reallocation of the Palmerston North cable replacement project from Renewals to System Growth.

Demand for asset relocations from third parties was over forecast by $0.4M, resulting in capital expenditure of $2.7M.

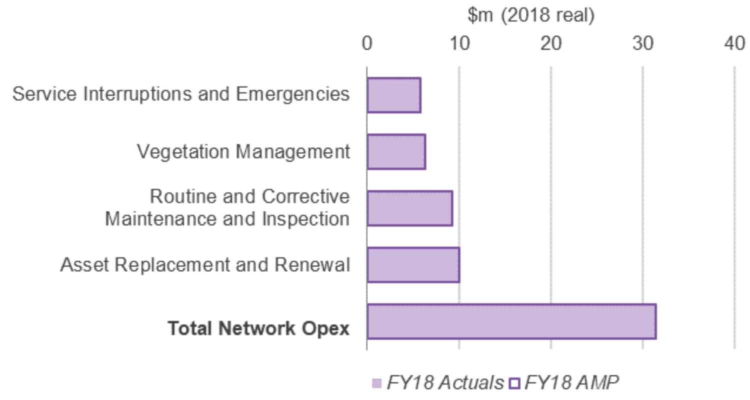
Figure A5.2: Network Capex variance FY18, adjusted categories



A5.4.2 NETWORK OPEX

The figure below shows our FY18 Opex actuals were on target against our AMP18 operational expenditure levels. Total Network Opex was on target.

Figure A5.3: Network Opex variance FY18



APPENDIX 6 GENERAL NETWORK RISKS

A6.1 APPENDIX OVERVIEW

This appendix provides summaries of key network risks from our corporate risk register. It also details the main controls we have in place and the expected likelihood and consequence of the risk under current controls. As described in this AMP, safety of our staff, service providers and the public is our most important priority. We have an extensive range of measures in place to reduce the likelihood of a serious incident occurring. We will continue to evaluate our practices to ensure these controls remain appropriate. We also have a variety of controls to minimise the risk of a loss of supply to many customers.

In other cases, we have less influence on an event occurring, such as a major earthquake or significant storm. In these situations, our controls focus on reducing the consequence of the risk. For example, we have duplicate control centre facilities in different geographical locations to ensure we will always be able to operate our control centre.

Our assessment of risks also recognises the impact that technology may have on our business, such as an increased uptake of distributed generation. As described in our customer strategy in Chapter 4 and our future networks strategy in Chapter 13, we are creating a strong platform to be ready for these changes when they occur.

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
1. Health and safety – approved contractor	Fatality or serious harm to approved contractors working on Powerco network. Could result from: – Motor vehicle or road traffic incidents – Negligence and human error – Equipment failure – Asset failure eg pole – Lack of, or incorrect mix of competence Lack of effective supervision of inexperienced crews or subcontractors	– Contractor works manual includes network asset, procedural, HSE and quality requirements – Contractor approval system – only Powerco approved contractors permitted to work on our networks – Contractor competency system – named persons allowed to carry out specific tasks based on competency and training records – Safety-in-design considerations are further defined and integrated into the asset planning processes – HSE risk management framework hazard management including performance monitoring; ongoing hazard identification and review process – Asset strategy and planning processes including defect management process to manage end-of-life assets – Increased focus on risk-based assessment on potential of asset failure and carrying out increased numbers of preventative renewals on assets to improve safety around our assets – Field audits of approved contractors – technical, compliance and HSE requirements	Unlikely	Major	Medium
2. Health & safety – member of the public	Fatality or serious harm to member of the public on Powerco's network. This can result from the following: – Negligence or human error – Equipment failure, eg LV line down – Weather event, eg LV line down – Incorrect or inadequate information issued by Powerco – Public not aware of potential hazards, eg underground assets – Unauthorised access to the Powerco network – Vandalism This risk excludes car / pole fatalities.	– Cable and gas pipe location and stand-over service – Active public awareness programmes aimed at specific target audience, eg field days, seminars, art promoting safety in public places and Powerco website, videos, bus adverts – Signage and security around high risk assets – Compliance with NZS7901 including effective management of network defects and red tagged pole structures – external certification – Asset strategy and planning processes including defect management process to manage end of life assets – Increased focus on risk-based assessment on potential asset failure and carrying out increased numbers of preventative renewals on assets to improve safety around our assets – Safety-in-design considerations are further defined and integrated into the asset planning processes	Unlikely	Major	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
3. Technological change	Technology risk has a material impact on revenues. Notes: – Population growth predicted to be the biggest driver of demand for the foreseeable future – Complete off-grid consumer solutions remain uneconomical for the foreseeable future until battery technology is more developed and economic Lack of government subsidies, increased electrification, increased reliance on internet, and winter evening peak limit impact by off-setting any reduction in output and increasing the demand for a reliable power supply	– We are moving to a more cost reflective pricing to improve appropriate signals for usage which should help support improved utilisation / increased delivery efficiency for grid connected supply over time.	Unlikely	Major	Medium
4. Loss or disruption to critical business information and operational control systems	– Loss of SCADA network system – Malicious or targeted attacks on IT systems (cyber and physical) Failure of key operational and business systems (SCADA, OMS, Junifer, etc)	– The 2 main NZ providers are used to ensure redundancy – One SCADA system has redundancy options in place – Malicious – antivirus, firewalls, mail marshal, etc. – Targeted – education of users & physical access controls – Rebuildable systems	Possible	Moderate	Medium
5. Health & safety – Powerco employees	Fatality or serious harm to Powerco employee. This can result from: – Motor vehicle or road incidents – Stress – Negligence or human error – Equipment failure – Lack of competence Unawareness of potential hazards	– Hazard registers, HSEQ committee information, Health and safety management system, policies and procedures are widely available on the Intranet – Wellness and occupational health service provision – Powerco staff cannot access network assets without the competencies required of field staff - typically Powerco staff role is supervisory only – Staff induction procedure includes hazard and HSE information and information on HSE representative and health monitoring – HSEQ training matrix is documented and competency is monitored for staff, manager and HSE / warden / First aider roles – Employees are offered interactive on-line driver training and a practical driving assessment. In addition, there are advanced sessions for employees who drive more than 10,000 km a year as well as 4WD and quad bike training for employees who require this	Rare	Major	Medium
6. Business continuity	– Earthquake of similar magnitude to the Christchurch event or major eruption which severely impacts the network. Consequence is based on an earthquake impacting the Palmerston North region which has Powerco's greatest exposure (refer to 2011 Update of Marsh & McLennan Uninsured Assets - Catastrophe Risk /Loss report) – Eruption of Mt Taranaki which impacts the Taranaki region only – Major pandemic impacting Powerco and NZ in general rather than just one region Note: ENA and EEA facilitate service provider arrangements in event of a national disaster, eg Christchurch earthquake)	– Business continuity framework, plans (BMS documents) and regular desktop exercises are reviewed / scheduled for improvement and training purposes – Backup NOC facilities are available at Bell Block in the event of a loss of the Junction Street site, and network oversight and control can be assumed from the Tauranga office (for network triage purposes) in the event that both New Plymouth facilities become inoperable – Materials damages and business interruption insurances are held for depots / offices and contents, zone substations and SCADA; special earthquake insurance cover is held for GMS, DRS, ground mounted transformers and ground mounted substations – $70m revolving cash loan maintained for an event where the network fails and it is not covered by insurance, eg lines and pipes	Rare	Major	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
7. Regulatory impacts – Price / Quality threshold and / or Information Disclosure breach	Breach of the Commerce Act Electricity and Gas DPP (price and/or quality), CPP price setting and associated information disclosure requirements resulting in pecuniary penalties and reputation damage. The reducing quality targets imposed on Powerco over the CPP period are not considered by Management to be achievable, and pose a potential breach risk over the CPP period. The key risk remains as being a breach of unplanned SAIDI and SAIFI breach caps due to adverse weather. Without this the Controlled Risk level for this risk would be rated lower.	– Regulatory presence in Wellington ensures a continued focus on maintaining relationships with the Commerce Commission – Active monitoring is in place to ensure that Powerco's position with respect to the CPP new quality-price incentives is tracked on a routine basis – The risk of inadvertent breach of annual information disclosure requirements is reduced through having tight controls on underlying processes and systems to ensure information quality; this is an area of ongoing management focus and is subject to regular internal audit and oversight by Regulatory – The CPP decision should enable Powerco to progress investments necessary to ensure stable long-term network performance – Our CPP application proposed variations to quality targets to allow us to achieve the network work without potential to be penalised due to increased planned interruptions; we also proposed an annual delivery report against which investment progress and other factors are made public; assessment against these requirements will occur in 2019	Possible	Moderate	Medium
8. Operational continuity	Severe weather event which adversely affects Powerco's ability to respond to network and customer issues in the timeframes required as well as: – Increased propensity towards storm damage as assets age, particularly in the lead into a CPP application – Cost of replacing uninsured assets requires funding by Powerco as no cost-effective insurance facility exists for overhead assets – Increased risk of fatigue-induced accidents and incidents due to abnormally long hours being worked by Control Centre, Dispatch and Service Delivery resources during extended storm events – The wide geographical spread of Powerco assets can result in widespread storm damage for some scenarios, resulting in extended loss of supply (2+ days) to customers Centralisation of operational control makes Powerco vulnerable in some scenarios where the core operating centre at Junction Street is damaged or unable to be accessed	– The scale of Powerco's capital programme means that we typically have high levels of staff and plant to respond to storms and other events – Practice of splitting to local 'hubs' for power rectification in major events reduces dependence on central control room co-ordination in peak events – Resource rotation and maximum hours worked policies (both Powerco and its service providers) are adhered to – Training of Powerco and Downer employees in the CIMS process for improved responsiveness under a severe weather event. – Backup NOC facilities are available at Bell Block in the event of a loss of the Junction Street site, and network oversight and control can be assumed from the Tauranga office (for network triage purposes) in the event that both New Plymouth facilities become inoperable – Levels and locations of emergency and critical spares holdings are documented, also levels of general materials eg poles, cable and where these are located. There are contracts with some suppliers to hold contingency stock levels	Possible	Moderate	Medium
9. Health & Safety – External third parties	Fatality or Serious Harm to external third parties working near the network. This can result from: – Negligence, human error or equipment failure or – Incorrect or inadequate information given by Powerco – Unawareness of potential hazards Lack of competence	– Free cable and gas pipe location and stand-over service, also close approach permits – Compliance with industry best practice in close approach excavation – Accurate GIS location data – Public awareness programmes in conjunction with local authorities – Compliance with NZS7901 – external certification – Asset strategy and planning processes including defect management process to manage end of life assets	Unlikely	Major	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
10. Resourcing – capability and capacity to deliver increased work volumes	Lack of skills to deliver the business plan due to: – Inability to recruit necessary skills – Loss of key staff – Employees not sufficiently competent – Age profile of employees. The inherent risk is currently higher than usual due to impending new and increased programmes of works and disruptive technology changes in operations impacting personnel resources company-wide	– Powerco has a good reputation in the industry and is considered a good place to work – Good recruitment agency networks are in place to support skills searches – Succession planning being implemented across company to identify and plan for high risk / critical roles – Ready access to professionals and experts in consultancy network – RnD/Rem review processes linked to both employee and company performance; encouraging and incentivising skill increase and performance; with due regard for critical roles and specialist skills – Competence levels assessed individually and companywide on an annual basis as part of rem review – Formal recruitment process in place which is applied to each appointment; focus on competency and behaviour outcomes – Organisational structuring designed to alleviate key person dependencies and with continuity in mind	Possible	Moderate	Medium
11. Political subsidies for micro generation	Subsidies for micro-generation promote uneconomic uptake of disruptive technology which has an impact on Powerco's operation and utilisation. Notes: – The risk of new policies in these areas being introduced is considered low over the short term. Neither main political party – Labour or National support the introduction of feed in tariffs, although there is indirect support through EECA funding for innovative projects. With respect to consequence, this would be muted in first instance. This is because Powerco's will operate under a revenue cap until 2023, and likely past then. Plus, the winter evening peaking nature of the NZ system more than halves the value of PV when compared to Australia making subsidies less commercially attractive and the uptake of technologies less disruptive	– Active monitoring of: ▪ the rate of new technology uptake (PV, EV) ▪ Smart grid technology developments ▪ Other related technology developments and political intention to subsidise DG – Pricing considers marginal impact on consumers if they install new technologies such as PV and EV	Unlikely	Moderate	Low

APPENDIX 7 DEMAND FORECASTS

A7.1 APPENDIX OVERVIEW

This appendix sets out our 15-year demand forecasts for our zone substations.

As discussed in Chapter 8, we are reviewing our demand forecast methodology which will further improve the robustness of our demand forecasts.

A7.2 DEMAND FORECAST FOR COROMANDEL AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coromandel	0.5	1.0%	4.6	4.7	4.7	4.8	4.8	4.8	4.9	4.9	5.0	5.0	5.1	5.1	5.1	5.2	5.2
Kerepehi	0.0	0.7%	10.2	10.3	10.4	10.4	10.5	10.6	10.7	10.7	10.8	10.9	10.9	11.0	11.1	11.2	11.2
Matatoki	0.0	0.9%	4.9	5.0	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.3	5.4	5.4	5.5	5.5
Tairua	7.5	0.7%	9.1	9.2	9.2	9.3	9.4	9.4	9.5	9.5	9.6	9.7	9.7	9.8	9.8	9.9	10.0
Thames T1 & T2	0.0	0.3%	12.0	12.0	12.1	12.1	12.1	12.2	12.2	12.2	12.3	12.3	12.4	12.4	12.4	12.5	12.5
Thames T3	6.9	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Whitianga	0.0	1.7%	17.4	17.6	17.9	18.2	18.4	18.7	18.9	19.2	19.5	19.7	20.0	20.2	20.5	20.8	21.0

A7.3 DEMAND FORECAST FOR WAIKINO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Paeroa	6.0	0.4%	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4	9.4	9.5	9.5	9.6	9.6	9.6
Waihi	16.0	0.7%	17.6	17.8	17.9	18.0	18.1	18.2	18.3	18.4	18.6	18.7	18.8	18.9	19.0	19.1	19.3
Waihi Beach	3.3	1.4%	5.9	5.9	6.0	6.1	6.2	6.3	6.3	6.4	6.5	6.6	6.7	6.7	6.8	6.9	7.0
Whangamata	0.0	0.4%	9.8	9.8	9.8	9.9	9.9	10.0	10.0	10.0	10.1	10.1	10.2	10.2	10.2	10.3	10.3

A7.4 DEMAND FORECAST FOR TAURANGA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Aongatete	7.2	2.7%	8.7	8.9	9.1	9.3	9.5	9.7	9.9	10.1	10.3	10.5	10.7	10.9	11.1	11.3	11.5
Bethlehem	8.0	4.4%	10.0	10.4	10.8	11.2	11.6	12.0	12.4	12.8	13.2	13.6	14.0	14.4	14.8	15.2	15.6
Hamilton St	22.4	1.3%	15.9	16.1	16.3	16.5	16.7	16.9	17.1	17.3	17.5	17.7	17.9	18.1	18.3	18.5	18.7
Katikati	4.6	1.6%	8.9	9.0	9.1	9.3	9.4	9.5	9.7	9.8	10.0	10.1	10.2	10.4	10.5	10.6	10.8
Kauri Pt	1.6	0.6%	3.3	3.4	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.6
Matua	7.4	0.3%	9.1	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.3	9.4	9.4	9.4	9.4	9.5
Omokoroa	13.2	1.5%	10.4	10.5	10.7	10.8	11.0	11.1	11.3	11.4	11.6	11.7	11.9	12.0	12.2	12.3	12.5
Otumoetai	13.6	2.1%	15.4	15.8	16.1	16.4	16.7	17.0	17.3	17.6	17.9	18.3	18.6	18.9	19.2	19.5	19.8
TAURANGA 11kV	11.7	3.2%	8.7	9.0	9.3	9.6	9.8	10.1	10.4	10.6	10.9	11.2	11.5	11.7	12.0	12.3	12.5
Pyes pa	30.0	3.2%	23.2	23.9	24.5	25.2	25.8	26.5	27.1	27.8	28.4	29.1	29.7	30.4	31.0	31.7	32.3
Waihi Rd	24.1	0.4%	22.1	22.2	22.2	22.3	22.4	22.5	22.6	22.6	22.7	22.8	22.9	22.9	23.0	23.1	23.2
Welcome Bay	21.4	2.0%	23.8	24.2	24.7	25.2	25.6	26.1	26.5	27.0	27.4	27.9	28.3	28.8	29.3	29.7	30.2

A7.5 DEMAND FORECAST FOR MOUNT MAUNGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Atuaroa Ave	0.0	0.8%	8.4	8.5	8.6	8.6	8.7	8.8	8.9	8.9	9.0	9.1	9.1	9.2	9.3	9.3	9.4
Matapihi	24.1	1.0%	14.6	14.7	14.8	15.0	15.1	15.2	15.4	15.5	15.7	15.8	15.9	16.1	16.2	16.3	16.5
Omanu	24.3	0.6%	16.7	16.8	16.9	17.0	17.0	17.1	17.2	17.3	17.4	17.5	17.6	17.7	17.8	17.9	18.0
Paengaroa	3.6	0.6%	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Papamoa	21.3	6.3%	15.5	16.3	17.1	18.0	18.8	19.7	20.5	21.3	22.2	23.0	23.9	24.7	25.5	26.4	27.2
Pongakawa	1.3	0.5%	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.6
Te Maunga	10.3	1.6%	9.9	10.1	10.2	10.4	10.5	10.7	10.8	11.0	11.2	11.3	11.5	11.6	11.8	11.9	12.1
Te Puke	22.9	0.6%	20.3	20.4	20.5	20.6	20.8	20.9	21.0	21.1	21.3	21.4	21.5	21.7	21.8	21.9	22.0
Triton	21.3	0.8%	21.3	21.4	21.6	21.8	22.0	22.1	22.3	22.5	22.7	22.8	23.0	23.2	23.3	23.5	23.7
Wairakei	6.0	6.3%	6.5	6.9	7.3	7.7	8.0	8.4	8.8	9.2	9.6	10.0	10.3	10.7	11.1	11.5	11.9

A7.6 DEMAND FORECAST FOR WAIKATO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Browne St	10.6	1.3%	9.9	10.1	10.2	10.3	10.4	10.6	10.7	10.8	10.9	11.0	11.2	11.3	11.4	11.5	11.7
Farmer Rd	0.0	0.2%	7.0	7.0	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.2	7.2
Inghams	0.0	-	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Lake Rd	1.7	0.4%	6.6	6.7	6.7	6.7	6.7	6.8	6.8	6.8	6.9	6.9	6.9	6.9	7.0	7.0	7.0
Mikkelsen Rd	19.2	0.3%	14.5	14.5	14.6	14.6	14.6	14.7	14.7	14.8	14.8	14.8	14.9	14.9	14.9	15.0	15.0
Morrinsville	0.0	0.5%	10.7	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4
Piako	15.2	1.0%	14.8	14.9	15.1	15.2	15.4	15.5	15.6	15.8	15.9	16.1	16.2	16.3	16.5	16.6	16.8
Putaruru	0.0	0.5%	11.5	11.5	11.6	11.7	11.7	11.8	11.8	11.9	12.0	12.0	12.1	12.1	12.2	12.3	12.3
Tahuna	0.7	0.3%	5.9	6.0	6.0	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.2	6.2	6.2
Tatua	0.0	-	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Tirau	0.0	0.5%	9.9	10.0	10.0	10.1	10.1	10.2	10.2	10.2	10.3	10.3	10.4	10.4	10.5	10.5	10.6
Tower Rd	0.0	1.6%	8.7	8.9	9.0	9.1	9.3	9.4	9.6	9.7	9.8	10.0	10.1	10.2	10.4	10.5	10.6
Waharoa T1	N/A	0.8%	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Waharoa T2	N/A	0.8%	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Waitoa	18.8	-	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Walton	0.0	0.1%	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.2	6.2	6.2

A7.7 DEMAND FORECAST FOR KINLEITH AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Baird Rd	0.0	0.6%	10.7	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.3	11.4	11.4	11.5	11.6
Maraetai Rd	0.0	0.3%	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.8	8.8	8.8	8.8	8.9	8.9	8.9
Midway / Lakeside	0.0	-	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8

A7.8 DEMAND FORECAST FOR TARANAKI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Bell Block	24.5	2.3%	18.8	19.2	19.6	20.0	20.4	20.7	21.1	21.5	21.9	22.3	22.7	23.0	23.4	23.8	24.2
Brooklands	24.0	0.9%	17.0	18.3	18.5	18.7	18.8	19.0	19.1	19.3	19.4	19.6	19.8	19.9	20.1	20.2	20.4
Cardiff	5.5	0.6%	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
City	20.1	0.6%	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.2
Cloton Rd	13.0	0.6%	11.2	11.3	11.3	11.4	11.5	11.5	11.6	11.6	11.7	11.8	11.8	11.9	11.9	12.0	12.1
Douglas	1.7	-0.0%	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Eltham	11.3	0.1%	10.4	10.4	10.4	10.4	10.4	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Inglewood	6.2	1.1%	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2	6.2	6.3
Kaponga	3.0	0.2%	3.5	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Katere	20.6	3.0%	15.2	15.6	16.0	16.4	16.8	17.2	17.6	18.0	18.4	18.8	19.2	19.6	20.0	20.4	20.8
McKee	0.0	1.6%	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.8
Motukawa	1.3	0.5%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Moturoa	20.7	1.2%	22.6	21.6	21.8	22.1	22.3	22.6	22.8	23.1	23.3	23.6	23.8	24.0	24.3	24.5	24.8
Oakura	0.0	2.9%	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2
Pohokura	9.2	-	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Waihapa	1.5	-	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Waitara East	10.1	1.3%	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4	6.4	6.5
Waitara West	6.4	0.3%	7.0	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.2

A7.9 DEMAND FORECAST FOR EGMONT AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Cambria	17.0	0.5%	15.1	16.5	16.5	16.6	16.7	16.8	16.9	16.9	17.0	17.1	17.2	17.2	17.3	17.4	17.5
Kapuni	7.0	-0.2%	7.5	7.5	7.5	7.5	7.5	7.4	7.4	7.4	7.4	7.4	7.3	7.3	7.3	7.3	7.3
Livingstone	3.0	0.0%	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Manaia	5.0	0.1%	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.8	7.8	7.8
Mokoia	3.1	0.6%	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8
Ngariki	3.9	0.3%	3.8	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Pungarehu	4.5	0.4%	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7
Tasman	6.4	0.2%	7.0	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.2
Whareroa	3.1	0.6%	4.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-

A7.10 DEMAND FORECAST FOR WHANGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Beach Rd	16.2	0.5%	11.0	11.1	11.1	11.2	11.3	11.3	11.4	11.4	11.5	11.5	11.6	11.6	11.7	11.7	11.8
Blink Bonnie	3.0	0.4%	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7
Castlecliff	8.7	0.5%	11.6	11.6	11.7	11.7	11.8	11.9	11.9	12.0	12.0	12.1	12.1	12.2	12.3	12.3	12.4
Hatricks Wharf	0.0	0.1%	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.2
Kai Iwi	1.0	0.6%	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Peat St	0.0	0.6%	18.0	18.1	18.2	18.3	18.4	18.5	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5
Roberts Ave	5.8	0.3%	8.0	8.0	8.0	8.1	8.1	8.1	8.1	8.2	8.2	8.2	8.3	8.3	8.3	8.3	8.4
Taupo Quay	0.0	0.1%	11.1	11.1	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.3	11.3	11.3	11.3
Wanganui East	3.4	0.1%	8.2	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4	8.4

A7.11 DEMAND FORECAST FOR RANGITIKEI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arahina	3.1	0.2%	8.8	8.8	8.9	8.9	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1
Bulls	2.0	0.1%	5.6	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Pukepapa	1.9	0.2%	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7
Rata	0.7	0.3%	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Taihape	0.8	-0.1%	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Waiouru	0.5	-0.1%	3.0	3.0	3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9

A7.12 DEMAND FORECAST FOR MANAWATU AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Feilding	23.7	1.0%	22.7	22.9	23.1	23.3	23.5	23.7	24.0	24.2	24.4	24.6	24.8	25.0	25.2	25.5	22.5
Ferguson	N/A	0.4%	-	11.7	11.7	11.7	11.8	11.8	11.9	11.9	12.0	12.0	12.0	12.1	12.1	12.2	-
Kairanga	19.1	0.5%	19.3	19.4	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6	19.2
Keith St	21.9	0.5%	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9	19.9	20.0	20.1	20.2	20.3	20.4	19.2
Kelvin Grove	17.2	2.4%	20.1	20.5	20.9	21.3	21.7	22.1	22.6	23.0	23.4	23.8	24.2	24.6	25.0	25.5	19.6
Kimbolton	1.4	0.2%	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.9
Main St	17.0	0.5%	26.9	27.0	22.7	22.8	22.9	23.1	23.2	23.3	23.5	23.6	23.7	23.8	24.0	24.1	26.8
Milson	18.1	1.6%	18.9	19.1	19.4	19.7	20.0	20.2	20.5	20.8	21.1	21.3	21.6	21.9	22.2	22.5	18.6
Pascal St	17.0	0.3%	23.2	23.2	16.2	16.2	16.3	16.4	16.4	16.5	16.6	16.6	16.7	16.8	16.8	16.9	23.1
Sanson	0.0	1.1%	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.2	10.3	9.1
Turitea	0.0	1.5%	16.3	16.6	16.8	17.0	17.2	17.4	17.6	17.9	18.1	18.3	18.5	18.7	18.9	19.2	16.1

A7.13 DEMAND FORECAST FOR TARARUA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Alfredton	1.4	-0.0%	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Mangamutu	12.8	0.1%	12.5	12.5	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Parkville	0.0	-0.1%	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Pongaroa	2.9	-0.2%	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

A7.14 DEMAND FORECAST FOR WAIRARAPA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Akura	9.0	0.5%	13.5	13.6	13.6	13.7	13.8	13.8	13.9	13.9	14.0	14.1	14.1	14.2	14.3	14.3	14.4
Awatoitoi	3.0	0.5%	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5
Chapel	13.8	0.5%	15.3	15.3	15.4	15.5	15.6	15.6	15.7	15.8	15.9	15.9	16.0	16.1	16.2	16.2	16.3
Clareville	9.4	1.5%	11.8	11.9	12.1	12.2	12.4	12.6	12.7	12.9	13.0	13.2	13.3	13.5	13.6	13.8	14.0
Featherston	0.1	0.9%	4.8	4.8	4.9	4.9	4.9	5.0	5.0	5.1	5.1	5.1	5.2	5.2	5.2	5.3	5.3
Gladstone	1.4	1.0%	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hau Nui	0.0	0.5%	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Kempton	0.4	1.2%	5.5	5.5	5.6	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2	6.2	6.3
Martinborough	0.1	1.3%	5.1	5.2	5.3	5.3	5.4	5.5	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.0	6.0
Norfolk	10.6	1.9%	7.3	7.4	7.5	7.6	7.8	7.9	8.0	8.1	8.2	8.4	8.5	8.6	8.7	8.8	9.0
Te Ore Ore	6.8	0.4%	7.3	7.3	7.3	7.4	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6	7.7	7.7	7.7
Tinui	1.3	0.4%	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2
Tuhitarata	0.0	0.7%	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.5	3.6	3.6

A8.1 APPENDIX OVERVIEW

This appendix provides additional details of the constraints, analysis options and preferred solution for the growth and security projects outlined in Chapter 11.

Major growth and security projects are those which are expected to cost more than $5M. Minor growth and security projects estimated to cost between $1M and $5M. Only projects scheduled to commence in the next five years are listed.

Towards the later part of the planning period, project needs and solutions are less certain. This is due to the volatility of the growth forecasts and impact of future technologies on demand. The listed ‘future projects' are continuously reviewed against future demand forecasting. Available options, cost estimates and preferred solutions are expected to change and refine over time and become firmer as the projects move closer to commencement.

A8.2 COROMANDEL AREA

A8.1.1 MAJOR PROJECTS

NEW KAIMARAMA 66KV SWITCHING STATION

Constraint

The combined 2017 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage of the 66kV line between Kopu and Tairua, the section of 66kV line between Kaimarama and Whitianga would be overloaded during peak conditions. During an outage of either 66kV circuit from Kopu, the remaining network is voltage constrained at peak demand. These three substations therefore do not meet our Security of Supply Standard, which requires a no break N-1 supply (security class AAA).

In addition to the above constraints, the subtransmission network supplying the Coromandel, Whitianga and Tairua substations has a history of poor reliability due to the long overhead lines that cross rugged and exposed terrain, coupled with the existing meshed configuration and tee connections. More specifically, the Coromandel area's subtransmission network is our worst performing area in terms of SAIDI.

There is a particular issue with the Coromandel substation which is supplied via a 66kV line that tees off the Tairua-Whitianga 66kV line. The implementation of a robust electrical protection system on this three-terminal network has been found to be difficult. Protection systems have been upgraded on the subtransmission circuits to allow the 66kV ring to be operated permanently closed. Future upgrades will involve high speed communication systems to enable fast inter-trip schemes to operate on the subtransmission network.

Options

Both non-network and network solutions have been considered to address the existing constraints. Network options involved a range of upgrades or new overhead or underground circuits, and also a new switching station option. Non-network options such as demand-side resources or widely distributed small scale renewable generation (including with energy storage) did not offer sufficient capacity and availability. Large scale thermal generation could address the underlying security driver, but there are no acceptable fuel sources available in the region.

The following network solutions were shortlisted

1. Re-conductor existing Kaimarama-Whitianga 66kV lines.
2. New Kaimarama-Whitianga 66kV overhead line.
3. New Kaimarama-Whitianga 66kV underground cable.
4. New Kaimarama-Whitianga 110kV overhead line (initially operated at 66kV).
5. New Kaimarama-Whitianga 110kV underground cable (initially operated at 66kV).
6. Kaimarama 66kV Switching Station

Preferred Options

The currently preferred option is the installation of Kaimarama 66kV switching station (Option 6 above) based on the use of indoor GIS (gas insulated switchgear) equipment enclosed in a switch room designed to blend in with the environment.

Early investigations on the land such as to determine requirements for geotechnical and civil works is being carried out to provide a solid, suitable foundation for the GIS (gas insulated switchgear) yard and assess flood risks from the nearby stream to explore the GIS switching station option. Ongoing negotiations with the landowner is on track and an outcome will be determined once the la nd investigations are completed. Discussions with affected landowners are currently ongoing.

KOPU – TAIRUA 66KV LINE UPGRADE

Constraint

The combined 2017 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage anywhere on the long 66kV line from Kopu GXP right through to Whitianga, the line between Kopu and Tairua does not have sufficient capacity to supply all three substations during peak loading conditions. The 66kV network would also experience voltage constraints at its extremities (ie Coromandel substation). These three substations therefore do not meet our Security of Supply Standard, which requires a no-break N-1 supply (security class AAA) in regard to the subtransmission network.

Options

Both non-network and network solutions have been considered to manage or remove the existing constraint. Of the non-network options, only large scale thermal generation resolves the underlying capacity and security issues adequately, and this is largely precluded on the grounds of fuel availability and environmental concerns. This meant only options involving investment in network infrastructure upgrades could adequately address the needs.

The following network solutions were shortlisted:

1. Re-conductor existing Kopu-Tairua 66kV line.
2. Duplex the existing Kopu-Tairua 66kV line.
3. Build a second Kopu-Tairua 66kV line.

To manage the post-contingency voltage step change when the 66kV network is operated in a closed ring, dynamic reactive support will eventually be required at Whitianga and Whenuakite to meet voltage quality standards.

Preferred Option

Option 1, to re-conductor the existing Kopu-Tairua 66kV line, is preferred. This is more cost effective than either alternative network option. The consenting and property issues of a new line are considered to be prohibitive through this area of sensitive landscapes and difficult physical access. Moving to a non-standard (for the distribution industry) duplex construction represents high risk – conductor fittings are scarce and the technology largely unproven in post or pin type construction.

In addition to the line upgrade, 66kV reactive support will be needed to address the voltage constraints eventually. This will occur as a separate project following the line upgrade.

NEW KOPU – KAUAERANGA 66KV LINE

Constraint

During 2015 the total load on the Thames substation was ≈15MVA. The substation supplies a number of relatively large consumers including A and G Price and Thames Toyota. Under normal operating conditions the supply to Thames is via a single 66kV circuit. If there is a fault on the normal Thames supply a second overhead 66kV supply line can be switched in. However, the second circuit is shared with the Coromandel/Whitianga/Tairua substations and the shared section (≈5 km of Raccoon conductor between Kopu and Parawai) would be overloaded during peak loading conditions. The existing supply network to Thames does not meet the requirements of our Security of Supply Standard, which recommends a (N-1), no break supply network with a security class of AAA.

The section of overhead line between Parawai and Kauaeranga is overloaded when supplying Whitianga, Coromandel and Tairua in the event of a Kopu-Tairua outage.

In addition, the subtransmission network in the Coromandel Area has a long history of poor performance due to the long overhead lines that cross rugged terrain. This is compounded by the meshed configuration that involves a number of 66kV tee connections. The simplification of the existing network is expected to deliver significant benefits to the consumers in the Coromandel Area.

Options

Both non-network and network options were considered during the long list evaluation. As for associated projects on the Coromandel 66kV subtransmission, the magnitude of the required step change in capacity/security, together with environmental concerns and energy source availability, meant there were no feasible non-network options to resolve the constraints.

The following network solutions were shortlisted:

1. New 66kV/110kV line from Kopu GXP to Kauaeranga.
2. Thermal upgrade of the existing Kopu-Kauaeranga 66kV line.
3. Re-conductor the existing Kopu-Kauaeranga 66kV line.

Preferred Option

The preferred option is to construct a new ≈8km, 110kV capable, overhead line from Kopu GXP to Kauaeranga (Option 1 above). This is the only option that addresses the performance issues related to the meshed configuration and manually switched backup circuits, by separating the subtransmission for Thames from that for the peninsula (Coromandel, Whitianga and Tairua). The new line would initially be operated at 66kV but be 110kV-capable to align with our future plans to supply the proposed Kaimarama switching station, from Kopu, via an 110kV supply line.

The proposed line route has been designated, and agreements are in place with most landowners. However one block of land is subject to Treaty settlement claims and is likely to delay the project by up to five years. To temporarily alleviate the existing constraint, it is proposed to reconductor the section of Mink conductor between Parawai and Kauaeranga and thermally upgrade the Kopu-Parawai section of Racoon as an interim measure to enable the deferral of the new line.

WHENUAKITE 66/11KV SUBSTATION

Constraint

From 2007- 2013 the Whitianga substation experienced ≈3% growth per annum. This growth is generally supported by the published census information of the township's population growth. Whitianga already exceeds its secure capacity and in the future peak demand is forecast to grow by 1.6% per annum.

The 11 kV network supplied by the Whitianga substation is presently facing an issue with respect to ICP growth. A number of 11kV feeders well exceed our recommended ICP numbers. As a result the SAIDI levels on these 11kV feeders tend to be relatively high (ie customers are exposed to more network outages). The coastal townships to the south of Whitianga (including Hahei and Hot Water Beach) are supplied by two 11kV feeders as follows:

- **Coroglen Feeder:** A rural overhead line feeder that follows a path south from the Whitianga substation to Coroglen and then heads east towards Hahei and Hot Water Beach, a distance of ≈25km. During peak network loading periods (≈3MVA in 2017) a significant portion of the electrical load is at the end of this feeder and it is equipped with a voltage regulator and two pole mounted capacitor banks to elevate delivery voltages. Backfeed capability is now very limited.
- **Purangi Feeder:** Passes through the Whitianga township (via cable and overhead line), crosses the Whitianga harbour (via submarine cable) to supply the Cooks Beach area before heading south-east (via overhead line) to Hahei. The 2017 peak load on the feeder was ≈2.1MVA. Insufficient capacity is available for backfeed.

The loads on the above two, long 11kV feeders are projected to continue to increase.

Options

Options considered were:

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Whenuakite substation (in and out 66kV configuration).
3. New Whenuakite substation (66kV tee connection).
4. New Whenuakite Substation (66kV switching station)

No feasible non-network options were shortlisted. The underlying issues of high customer count, high growth and feeders with poor reliability cannot be addressed by demand modifying (DG or DSR) non-network approaches. This is evident in the network options also, which propose significant network architecture changes, rather than incremental capacity upgrades.

Preferred Option

The currently preferred option is to build a new Whenuakite substation, supplied via a new 66kV double circuit line that connects into the Tairua – Whitianga circuit using an in-and-out configuration (option 2 above). Installing additional 11kV feeders from Whitianga substation, instead of a new Whenuakite substation, would face considerable consenting and construction challenges and would not address load constraints at Whitianga itself. A tee connection for the proposed Whenuakite substation (Option 3) would exacerbate the existing protection and operational constraints on the 66kV. Obtaining property and consents for both a substation and a switching station (Option 4) would considerably add to costs and project complexity.

MATARANGI 66/11KV SUBSTATION

Constraint

As noted for the Whenuakite constraints above, the 11kV feeders from Whitianga substation are long and heavily loaded, with ICP counts and feeder lengths exceeding our recommended standards. This impacts on reliability as more customers are affected and for a greater number of outages per year. Strong growth has been sustained in the last decade and is predicted to continue due to the area's continued popularity for holiday accommodation. Backfeed capacity on the 11kV is particularly constrained and secure capacity at Whitianga substation is exceeded.

The coastal townships to the north of Whitianga (including Matarangi and Kuaotunu) are supplied by two 11kV feeders as follows:

- **Owera Rd Feeder:** A rural overhead line feeder that follows a path north-east from the Whitianga substation to Matarangi, a distance of ≈15km. During peak network loading periods (≈3MVA in 2017) a significant portion of the electrical load is at the end of this feeder and it is equipped with a voltage regulator and two pole mounted capacitor banks to elevate delivery voltages.
- **Kuaotunu Feeder:** Passes through the Whitianga township supplying some urban consumer load before heading north-west to Kuaotunu. The 2017 peak load on the feeder was ≈2.MVA.

The loads on the above two, long 11kV feeders are projected to continue to increase. The combined peak load of ≈5MVA on the two feeders cannot be supplied by a single feeder (ie during an outage of the other feeder).

Options

Options considered were:

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Matarangi substation supplied via a 66kV spur line.
3. Install an 11/22kV transformer and upgrade the existing 11kV network to 22kV.

In similar manner to Whenuakite substation, the nature of the underlying issues necessitated options providing a substantial change in network configuration, as opposed to incremental demand adjustments (most non-network options) or capacity upgrades to existing circuits.

Preferred Option

The preferred solution is a new Matarangi substation supplied from a new 66kV line from Whitianga substation (Option 2 above). This option also provides for a staged implementation where the new 66kV line could initially be operated at 11kV and upgraded later when the substation was needed. Upgrading feeders from 11kV to 22kV (Option 3) has been looked at as a coordinated strategy for the Coromandel, but costs remain too high considering the infrastructure (distribution transformers, insulators, lines, cables, tap-changers) that would need to be upgraded or replaced. As for the Whenuakite project, constructing additional 11kV feeders out of Whitianga substation ultimately do not address the constraints on Whitianga substation itself.

BACKUP SUPPLY TO KEREPEHI SUBSTATION

Constraint

The Kerepehi substation is supplied via a single 66kV circuit from Kopu GXP. During an outage of this circuit, there is limited 11kV backfeed from nearby substations to provide backup. This backfeed is not sufficient to provide the required security to Kerepehi substation.

Options

The following options were considered:

1. Reinstate an old 50kV line between Kerepehi and Paeroa energising it at 33kV, and install a 33/11kV transformer at Kerepehi to back-up the substation;
2. Construct a second 66kV circuit from Kopu; or
3. Improve the distribution network and increase the 11kV backfeed capability.

Preferred Option

The preferred option is to refurbish and reinstate the old 50kV line for use at 33kV and install a back-up 33/11kV transformer at Kerepehi substation. This will provide the substation with the appropriate level of security, even though both supply lines cannot be used at the same time. The backup supply is effectively on hot stand-by. Investigations is currently underway to assess the viability of reinstating the line in service. As the results of the line/route investigations and inspections/design reviews become more evident, we will then be able to re-evaluate the solution.

Constructing a second line at 66kV from Kopu (Option 2) is considered too expensive and would also pose considerable access and consenting issues. Reconfiguration work on the 66kV buswork is required at Kopu GXP in order to allow the 66kV bus to be extended. The option of improving the distribution network to increase the 11kV backfeed capability (Option 3) is limited by distance and line capacities, and unlikely to provide an effective long term solution.

TAIRUA-COROGLEN CONDUCTOR UPGRADE

Constraint

The combined 2017 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage anywhere on the long 66kV line from Kopu GXP to Kauaeranga right through to Whitianga, the line between Tairua and Coroglen does not have sufficient capacity to supply all five substations; Coromandel, Whitianga, Tairua, Whenuakite & Matarangi.

Following completion of the proposed subtransmission upgrade projects in the area over the next five years, this section of line remains as the constrained element that limits capacity.

During peak loading conditions the 66kV network would also experience voltage constraints at all five substations. These substations therefore do not meet our Security of Supply Standard, which requires a no-break N-1 supply (security class AAA) regarding the sub transmission network.

Options

Both non-network and network solutions have been considered to manage or remove the existing constraint. Of the non-network options, only large scale thermal generation resolves the underlying capacity and security issues adequately, and this is largely precluded on the grounds of fuel availability and environmental concerns. This meant only options involving investment in network infrastructure upgrades could adequately address the needs.

The following network solutions were shortlisted:

1. Re-conductor existing Tairua-Coroglen 66kV line.
2. Duplex the existing Tairua-Coroglen 66kV line.
3. Build a second Tairua-Coroglen 66kV line.

To manage the post-contingency voltage step change when the 66kV network is operated in a closed ring, dynamic reactive support will eventually be required at Whitianga and Whenuakite to meet voltage quality standards.

Preferred Option

Option 1, to re-conductor the existing Tairua-Coroglen 66kV line, is preferred. This is more cost effective than either alternative network option. The consenting and property issues of a new line are prohibitive through this area of sensitive landscapes and difficult physical access. Moving to a non-standard (for the distribution industry) duplex construction represents high risk – conductor fittings are scarce and the technology largely unproven in post or pin type construction. In addition to the line upgrade, reactive support in the form of STATCOM or capacitor banks will be needed to address the voltage constraints. This will occur as a separate project prior to the line upgrade. Refer to Coromandel area voltage support project.

COROMANDEL AREA VOLTAGE SUPPORT

Constraint

During a subtransmission outage on either Kopu-Whitianga 66kV or Kopu-Tairua 66kV circuits, low voltage levels can appear at these substations during high load periods; Coromandel, Whitianga, Tairua, Whenuakite and Matarangi. This voltage constraint means Powerco cannot meet voltage regulation requirements.

The anticipated post-contingent voltage step change will be excessive and result in voltage quality issues.

Options

1. The following options are currently under consideration:
2. Install an outdoor 66kV switched shunt capacitor bank at Whenuakite substation and a dynamic reactive compensation system (STATCOM) at Whitianga substation; or
3. Install more 11kV capacitors spread across the distribution network.

Preferred Option

Both option 1 and option 2 are considered.

Option 2 to install more 11kV capacitors is not preferred as the existing power factor at Kopu GXP is already leading. Adding more capacitors will exacerbate the leading power factor issue and cause distribution lines to overload in some places.

Option 1 to install a STATCOM compensation range sized for ± 5MVAR (dual stage) with each stage installed at both sides of the Whitianga 66kV bus, operated normally in-service.

Paired with the combined ± 10MVAR STATCOM is a 6MVAR shunt capacitor bank installed at the Whenuakite 66kV bus, controlled by the STATCOM to offer slow response reactive compensation to provide additional voltage support if required. The resultant compensation scheme will have a reactive range of 0 to 16MVAR capacitive, and 0 to 10MVAR inductive.

Due to the large dynamic voltage step change following a contingency event when the network is operated as a closed 66kV ring, the STATCOM—operated in voltage control mode—will provide dynamic reactive support to arrest the voltage step. This ensures that Powerco can meet power quality standards related to voltage regulation.

MANGATARATA 66/11KV SUBSTATION

Constraint

Two 7.5/9.4 MVA 66/11kV transformers supply Kerepehi substation and the transformer firm capacity is anticipated to exceed later in the planning period. This means that the substation does not meet Powerco's security class of supply standards.

Some of the 11kV feeders supplied from Kerepehi zone substation are also voltage constrained during high load times and would be even more constrained when providing back feed during an outage because of their long lengthy feeders. The reliability on these feeders is historically poor due to their long lengths.

Options

The following options are currently under consideration:

1. Install a third 7.5/9.4 MVA transformer at Kerepehi substation; or
2. Replace the existing transformers with higher capacity units; or
3. Increase 11kV backfeed capacity to Kerepehi.
4. New substation at Mangatarata.

Preferred option

The preferred solution is option 4 to build a new substation at Mangatarata, supplied via the existing 50kV-capable circuit line from Kerepehi (currently running at 11kV) with a single bank transformer 7.5MVA 66/11kV. Existing feeders from Kerepehi can be converted into new feeders that will come out from the new Mangatarata substation. The 50kV line will be upgraded to 66kV capability in order to supply the new substation.

Replacing the existing transformers with higher capacity units (option 2) will mean there will be spare transformers that are left unused and this solution gives no benefit to improvement of feeder reliability and performance. Increasing the 11kV backfeed capacity will require substantial work on the existing network and there is a possibility voltage could be constrained which would limit the 11kV back up supply.

Option 1 to install a third transformer will increase the fault level at the 11kV and will not resolve 11kV feeder reliability issues either. Therefore, it is not a preferred option.

A8.1.2 MINOR PROJECTS

COROMANDEL SUBSTATION ALTERNATE SUPPLY

Constraint

Coromandel substation is supplied via a single 66kV circuit and an outage on this circuit results in the loss of supply to Coromandel substation. 11kV back feed from Thames is limited. In recent years there have been number of sub transmission outages resulting in loss of supply at Coromandel substation. Some of these outages have been longer than 30 minutes in duration.

Options

1. Second 66kV circuit to the Coromandel substation; or
2. Install feeder-based distributed generation (DG) equipment spread across the distribution network supplemented by 11kV backfeed from Thames.

Preferred Option

The preferred solution is to install a distributed generation system for standby emergency use. Each unit is sized sufficiently with enough capacity to support the corresponding feeder load in islanded operation until normal 66kV supply is restored to the substation. We intend to learn as much as we can from the DG/ESS project in Whangamata to see if the learnings can be applied here as it shares similar characteristics with Coromandel. Option 2 to build a second circuit to Coromandel is unlikely going to be economical.

MATATOKI SUBSTATION TRANSFORMER CAPACITY UPGRADE

Constraint

Matatoki is supplied from a single 7.5 MVA 66/11kV transformer. An outage on this transformer causes loss of supply to the substation. Existing 11kV backfeed capacity is insufficient to support the load. This means that the substation does not meet Powerco's security of supply standards.

Options

The following options are currently under consideration:

1. Install a second transformer at Matatoki substation; or
2. Increase 11kV backfeed capacity to Matatoki.

Preferred option

The preferred solution is Option 1, which is to install a second 7.5 MVA 66/11kV transformer at Matatoki substation which will provide backup to the existing unit.

Option 2 to further increase 11kV backfeed capacity will involve substantial 11kV infrastructure investment and is unlikely to be economical.

WHENUAKITE 2ND TRANSFORMER

Constraint

The proposed substation at Whenuakite will initially have a single 7.5 MVA 66/11kV transformer. An outage on this transformer causes loss of supply to the substation. Existing 11kV backfeed capacity is sufficient to support the load but with load growth in future, this capacity will be eroded. This means that the substation does not meet Powerco's security of supply standards.

Options

The following options are currently under consideration:

1. Install a second transformer at Whenuakite substation; or
2. Increase 11kV backfeed capacity.

Preferred Option

The preferred solution is Option 1, which is to install a second 7.5 MVA 66/11kV transformer at Whenuakite substation, which will provide backup to the existing unit.

Option 2 to further increase 11kV backfeed capacity will involve substantial 11kV infrastructure investment to lift transfer capacity and is unlikely to be economical.

A8.3 WAIKINO AREA

A8.1.3 MAJOR PROJECTS

WHANGAMATA BACKUP POWER SUPPLY

Constraint

The existing 33kV network supplying the Whangamata substation has a number of constraints/issues as follows:

1. Whangamata substation is supplied via a single lengthy 33kV overhead line from the Waihi substation. During **last three years the peak demand has been ≈10MVA with load controlled.** The 11kV backup is ≈2MVA and in the event of a 33kV line outage most customers cannot be supplied. This falls well short of our security of supply standards, which recommends a security class of AA+ (full restoration in 15 seconds or less).
2. The 11kV backfeed which serves Whangamata is via an 11kV feeder located under the 33kV circuit. Certain contingencies (eg car vs pole) can render both circuits out of service, meaning no 11kV backup is then available.
3. A significant portion of the existing 22km Waihi-Whangamata overhead 33kV line is equipped with small conductor and built to operate at a 50°C conductor temperature (ie summer rating of ≈11MVA). The Whangamata load is summer peaking and during holiday periods the line is both voltage and thermally constrained. 11kV capacitor banks have been installed to manage voltage problems but the substation now operates at a leading power factor worsening line thermal loadings.
4. To avoid outages, maintenance work requires either live line working, or expensive and logistically challenging temporary generation. The restricted outage windows have placed pressure on our ability to keep up with maintenance.
5. The Waihi-Whangamata 33kV line has a history of relatively poor reliability. Between 2002 and 2009 Whangamata experienced 10 line outages greater than 30 minutes, and five of these exceeded four hours. Outages often coincide with peak holiday periods, exacerbating the impact on our customers. Whangamata has a permanent population of ≈4,500 but during holidays this swells to more than 10,000.

Options

Both non-network and network options are being considered to manage or resolve the existing constraint(s).

The following non-network options were considered:

1. Fossil fuelled generation (ie diesel generation), in conjunction with targeted energy storage (eg for critical feeders or loads).
2. Renewable generation: No viable grid scale (~10MW) option has been identified yet that would provide a secure supply. Widely distributed PV

is conceptually possible, but would be challenging to coordinate operationally. Renewable sources would need to be combined with energy storage to provide the required availability and address the reliability issues.

3. Fuel switching and demand-side response (DSR): There are no immediate options for large scale fuel switching. Demand-side response approaches can moderate the existing demand peak, but cannot on their own address the intrinsic reliability issues of the N security 33kV supply. Some DSR options may be possible as part of the interim solution to mitigate outage impacts in the short term.

The following solutions were shortlisted:

1. Construct a second 33kV line from Waikino GXP, via Golden Cross mine and DOC reserve.
2. Install a new 33kV, underground cable from Waihi substation to Whangamata substation predominantly via legal road.
3. Install a new 66kV overhead line that is connected onto the existing Kopu-Tairua 66kV line and supplies a new 66/11kV transformer bank at the Whangamata substation.
4. Re-conductor the existing Waihi-Whangamata 33kV line and install permanent backup diesel generation.
5. Upgrade the 11kV network to provide sufficient backfeed capability.
6. Install a limited quantity of Energy Storage and Diesel generation, targeted at critical commercial loads.

Preferred Option

Option 6 is the preferred option and, at the time of writing this option is being implemented. We will monitor performance of the facility and evaluate the need to consider any other additional or alternative in due course if required. A second line may be one alternative.

Option 6 is the preferred option and, at the time of writing this option is being implemented. We will monitor performance of the facility and evaluate the need to consider any other additional or alternative in due course if required. A second line may be one alternative.

A8.1.4 MINOR PROJECTS

WAIHI BEACH SUPPLY TRANSFORMERS

Constraint

The Waihi Beach substation contains a single transformer. The peak demand has exceeded the transformer's capacity. There is limited 11kV back-feed, and the substation does not meet our security requirements.

Options

Options considered include:

1. **Increased 11kV back-feed:** This would be costly as Waihi Beach is a considerable distance from other substations and is interconnected by a weak 11kV rural distribution network. The manual 11kV switching time would also be too great to allow offload of the transformer in time.
2. **Upgrade existing single transformer: A**ddresses the capacity constraint but does not address the lack of security exposed by having a single transformer.
3. **Upgrade substation to two transformers:** Addresses both capacity and security issues but at additional cost. The substation has adequate space for a second unit.

Preferred Option

The proposed solution is to upgrade to a two-transformer substation ensuring the capacity and security will provide for the future demand.

WAIHI BEACH 33KV TEE SUPPLY

Constraint

The Waihi Beach supply is via a spur teed off one of the Waikino GXP-Waihi 33kV overhead circuits.

Supply for Waihi Beach is lost if a fault anywhere on the overhead Waikino-Waihi Beach-Waihi 33kV circuit occurs. Conversely, a fault on the 33kV spur line to Waihi Beach will result in Waihi substation running on N (single redundancy) security.

Furthermore, the loss of the Waihi Beach spur may cause the parallel Waikino-Waihi 33kV circuit to overload at high loads, resulting in the need to shed Waihi Gold Mine load at Waihi to resolve the overloading

Options

The following shortlisted solutions were considered:

1. Extend 33 kV outdoor bus to accommodate new bay for the Waihi Beach circuit. Install new 33 kV cable from Waihi to the Waihi Beach tee-off to create dedicated Waihi-Waihi Beach circuit. Install a sectionaliser (normally open) at the tee to allow remote reconfiguration of the network in the event of a cable fault or cable maintenance. This option requires an extension to the site.
2. Install a new 33 kV indoor switchboard in a separate switchroom located next to the existing 11 kV switchroom. Remove existing outdoor 33 kV buswork. Install a new 33 kV cable from Waihi to the Waihi Beach tee-off to create a dedicated Waihi-Waihi Beach circuit. Install a sectionaliser (normally open) at the tee to allow remote reconfiguration of the network in the event of a cable fault or cable maintenance.

Preferred Option

The preferred solution is to build a new 33kV indoor switchroom at Waihi. This will consolidate all existing outdoor switchgear into a modern indoor equivalent which will free up space on the existing site and enhance safety. To give Waihi Beach a dedicated supply, a new 33kV cable will be laid from the new switchboard to the existing tee-off to create a new Waihi-Waihi Beach 33kV circuit. This option is the lowest cost option and has considerable safety and operational benefits compared to the option of extending the outdoor bus work.

WAIHI BEACH ALTERNATIVE SUPPLY

Constraint

Waihi Beach substation is currently supplied via single sub transmission circuit and an outage on this circuit does not meet our security class supply standards.

One of the key 11kV backfeed supplies to Waihi Beach substation is underbuilt the subtransmission circuit. This results in a high risk of failure that causes an outage to both circuits.

Options

1. New 33kV circuit from Waihi substation to Waihi Beach substation.
2. Standby Diesel Generation at Waihi Beach substation.

Preferred Option

The probable solution is Option 2 which is to install a back-up Diesel Generator that is remote operable to support the load during an outage. It is not economical for an alternative second 33kV circuit due to the load at risk.

PAEROA 33KV BUS SECURITY

Constraint

The Waikino GXP supplies the Paeroa substation via dual 33kV circuits. The existing 11kV switchboard and 33kV assets will be renewed due to age.

An outage on any one of the Waikino GXP-Paeroa 33kV circuits will also cause an outage for its associated supply transformer.

As there is no 33kV switchboard at Paeroa, the proposed Paeroa-Kerepehi 33kV circuit (refer to backup supply to Kerepehi project) will be temporarily connected to a line circuit breaker at Paeroa substation.

The circuit breaker is teed off one of the existing Waikino GXP-Paeroa circuits. This means that the ability to support Kerepehi during a contingency becomes constrained by the capacity of the existing Waikino GXP-Paeroa circuit that it is teed off.

Options

1. 33kV Indoor switchboard.
2. 33kV Outdoor bus extension.
3. Extend 33kV Paeroa-Kerepehi circuit back to Waikino GXP.

Preferred Option

Option 1 is preferred to install an indoor switchroom at Paeroa substation. The existing Waikino GXP-Paeroa transformer feeders will be terminated into circuit breakers in the new switchboard. The risk of a transformer outage caused by a subtransmission circuit outage will be removed as a result.

The teed arrangement of the new Paeroa-Kerepehi circuit will be removed at Paeroa and directly connected to the new switchboard.

The switchboard will be fitted with fast bus protection schemes to provide fast inter-trip schemes.

Option 2 although similar in scope to Option 1 will require site expansion in order to accommodate the required number of 33kV outdoor assets. We will continue to explore this option further as we get closer to time.

Option 3 is not preferred as it will be costly to build new 33kV subtransmission through difficult terrain back to the GXP. Consenting is expected to be challenging resulting in long lead times.

WAIHI VOLTAGE SUPPORT

Constraint

An outage on either of the Waikino-Waihi circuits can cause low voltage levels at Waihi, Whangamata and Waihi Beach during high load periods. The post-contingent voltage step change is excessive.

This voltage constraint means Powerco cannot meet voltage regulation and voltage quality requirements.

Options

The following options are currently under consideration:

1. Install an outdoor 33kV shunt capacitor bank at Waihi substation.
2. Install dynamic reactive support (STATCOM) at Waihi substation.
3. Install 11kV capacitors across the distribution network.

Preferred Option

The probable solution is Option 1, which is to install a 12MVAR switched multi-staged capacitor bank at Waihi 33kV bus to provide voltage support in the area.

Option 2 to install a STATCOM will be much more expensive although it will offer faster response compared to the capacitors.

Option 3 to install more 11kV capacitors across our distribution network will not be as economical compared to Option 1. It also introduces a higher risk of network overloads particularly in areas where the fault level is weak. There will also be increased risk of amplifying harmonic distortions across the network due to resonance.

A8.4 TAURANGA AREA

A8.1.5 MAJOR PROJECTS

NORTHERN TAURANGA (OMOKOROA)

Constraint

The region to the northwest of Tauranga is supplied by a relatively long 33kV subtransmission network, called the Omokoroa Spur. This connects the Omokoroa, Aongatete, Katikati and Kauri Point substations. The spur emanates from the Greerton switchyard, and initially comprises two predominantly overhead circuits, ≈12km long, that run northwest to Omokoroa. The 2015 peak load on these lines was ≈26MVA. There is some network interconnection at 11kV but the transfer capacities are relatively small. The Greerton to Omokoroa 33kV lines have already been thermally uprated to operate at 70°C to address a past constraint.

The four substations supply a mix of both urban and rural land. The rural areas include small-holdings, market gardens, lifestyle blocks and kiwifruit orchards, which are expected to experience significant growth. Residential subdivision expansion has also been identified in the Bay of Plenty's Smart-Growth strategy.

The following constraints/issues exist:

1. The combined peak demand of all four substations is projected to exceed the N-1 ratings of the uprated 33kV overhead lines between Greerton and Omokoroa, again breaching our security standards.
2. During outages of one of the Greerton-Omokoroa circuits the 33kV voltages at Katikati and Kauri Pt substations are low with the result the 33/11kV zone transformer tap-changers exceed their tap range.
3. For the first ≈4km of lines from Greerton, the Omokoroa circuits share poles with the Otumoetai-Bethlehem circuits. Both circuits are configured as rings in normal operation. The circuits are therefore prone to sympathy tripping ie a fault on one of the rings induces a current in the adjacent one causing a false trip in this also.

Options

Both non-network and network options have been considered to manage or resolve the existing constraints. Generation options are conceptually feasible, but can only address the security issues if implemented at a large scale and use non-renewable energy sources, which is largely inappropriate in this context. Renewable generation, if combined with energy storage, could also address the N-1 capacity limitations, but would be unlikely to keep pace with the high growth which is anticipated. Similarly, demand side responses, already a component of our network strategies, would not provide the magnitude of “capacity” necessary. As such, the following shortlisted options all contemplate major infrastructure upgrade. This included a review of our regional development path, and the consideration of transmission and GXP options.

The following network solutions were shortlisted:

1. Construction of a third Greerton to Omokoroa 33kV overhead line.
2. Construction of a new Greerton to Omokoroa 33kV underground cable circuit.
3. Upgrade of the existing Greerton to Omokoroa 33kV overhead line circuits.
4. Construction of a new 110kV overhead line spur from the Tauranga GXP to Omokoroa, coupled with 110/33kV substation. This option could be staged with the 110kV line operating at 33kV initially.

Preferred Option

Option 2, being a 3rd circuit using underground cable, is preferred because:

- Acquiring and consenting a new overhead line route (option 1) via either public road (including state highway) or private land (intensive horticulture or lifestyle) would be very challenging.
- Further upgrade of the existing lines (Option 3) would require substantially larger conductor, invoking considerable design, property and consenting costs.
- The concept of extending the footprint of the 110kV grid (option 4) was examined in the wider context of possible links right through to the Waikino. The costs for such transmission options, even in the long-term and in addressing a far wider range of constraints, could not ultimately be justified for the relatively small loads at risk.

We will continue to review the possibility of using overhead line construction along sections of the proposed new circuit to reduce the project costs. The project scope already makes use of existing overhead crossings of the Wairoa River.

APATA / PAHOIA CAPACITY REINFORCEMENT (OMOKOROA)

Constraint

The existing 11kV supplying the area north of Omokoroa is capacity constrained. Growth at the Apata coolstore and recent devlopments on the Omokoroa Peninsula have eroded the 11kV capacity to the point where there is no spare capacity to pick up new load.

Load on the existing feeder supply this area exceeds thermal limits over the peak periods. This also constrains the backfeed capability.

Growth in the Omokoroa peninsula will continue to increase as indicated in the recent Western Bay of Plenty district plan. Load at the Apata Coolstores is likely to increase especially with the new varities of Kiwifruit coming on line which are heavy fruit producers.

In summary, the following constraints/issues exist:

1. The existing feeder supplying this area is overloaded with high ICPs on each feeder.
2. Limited backfeed capacity which means there is a high SAIDI risk.
3. Customer numbers are continuing to grow in this area.
4. Supply to a major Coolstore site is limited by the capacity of the network.

Options

The following network solutions were considered:

1. Installation of additional 11kV feeders from Omokoroa substation; or
2. Supplying the area from Aongatete substation; or
3. Commissioning a new substation near the Apata Coolstore or Pahoia area.

Preferred Options

The preferred option at this stage is Option 3 which is to commission a new substation near Apata Coolstore or Pahoia region with its supply coming off one of the Greerton-Omokoroa-Aongatete 33kV circuits.

The new zone substation will offload Omokoroa zone substation. This will provide the capacity to support future load growth in the Omokoroa Peninsula and for any possible load increase at Apata Coolstore.

WELCOME BAY REINFORCEMENT

Constraint

Welcome Bay zone substation is supplied from Kaitimako GXP via two 33kV overhead circuits. One of these circuits has a teed connection that supplies Atuaroa zone substation used only during a contingent event of a loss of supply at Atuaroa.

An outage on either of these 33kV circuits is anticipated to cause the parallel circuit to overload around 2027 based on growth forecasts for the area.

At present, the existing 11kV backfeed has enough capacity to support the load during an outage of one Welcome Bay supply transformer or an outage of one of the 33kV circuits. However, this will be difficult further in the planning horizon with backfeed capacity eroded due to load growth.

Options

The following network solutions were considered:

1. Increase 11kV backfeed capacity from adjacent substations; or
2. Upgrade the existing subtransmission capacity supplying Welcome Bay substation; or
3. Construct a new third 33kV circuit from Kaitimako GXP and improve security at Welcome Bay substation by installing a 33kV solid bus.

Preferred Option

Option 1 to increase 11kV backfeed capacity from adjacent substations will be costly, ineffective and uneconomical in the long run so is not preferred.

Option 2 to upgrade the existing subtransmission capacity of the Kaitimako GXP-Welcome Bay circuits although a viable option, it will not facilitate a secure supply for the future second substation in Welcome Bay. Therefore, it is not preferred.

The preferred option at this stage is Option 3 which is to construct a third circuit from Kaitimako GXP to Welcome Bay substation. To accommodate the third circuit as well as improve security for Welcome Bay, a 33kV solid bus will be implemented at Welcome Bay substation. The third Kaitimako GXP-Welcome Bay circuit will resolve the N-1 capacity issue going beyond the planning horizon.

In the long term we propose to install a new 33kV switchboard at Welcome Bay and to construct a new zone substation in the area to the east of the current substation. This will cater for ongoing residential development and to reduce overall customer numbers per feeder.

The existing tee connection off the 33kV circuit to Atuaroa will be removed and a 33kV circuit extended to Welcome Bay substation to enable a dedicated circuit to supply the proposed second substation in the Welcome Bay area out of the existing Welcome Bay substation.

WELCOME BAY SECOND SUBSTATION

Constraint

The existing 11kV feeders supplied by the Welcome Bay zone substation are highly loaded with high ICPs. Loop automation has already been implemented on many feeders to help minimise SAIDI risk. Additional feeders are currently being installed to address the growing demand in the area.

Residential growth continues to be strong with minimal direction outlined in Council district plans as the area lies between the jurisdiction of two local Council authorities. This makes it hard for forecasting and targeting future requirements accurately.

The continuing load increase will add more ICPs to the existing feeders, which will deteriorate the backfeed capability going into the future.

Transformer firm capacity at the Welcome Bay substation is exceeded today.

Options

The following network solutions were considered:

1. Increase 11kV backfeed capacity from adjacent substations; or
2. Construct a new second substation at Welcome Bay.

Preferred Option

The preferred option at this stage is Option 2 which is to construct a new second substation on the eastern side of Welcome Bay suburb with its 33kV supply coming off the existing Welcome Bay-Atuaroa circuit.

The new substation will offload the existing Welcome Bay substation which will resolve the transformer firm capacity issue there.

With the new substation in place, the existing 11kV network will be carved up resulting in shorter feeder lengths and reduced ICPs on each feeder. This helps to reduce the SAIDI risk.

Option 1 to increase 11kV backfeed capability from adjacent substations will be a costly exercise as significant upgrades will be required on existing infrastructure as well as extra 11kV feeders from adjacent substations will be required to increase transfer capacity. Therefore, this option is not preferred.

GATE PA / HOSPITAL SUBSTATION

Constraint

The urban intensification proposed in the Te Papa Peninsula as indicated in Tauranga City Council district plans will drive ICP numbers up on the existing 11kV feeders.

The high ICP count relates to an increased risk exposure for high SAIDI during outage events across the distribution network.

With future growth eroding the capacity of the existing feeders, backfeed capability will reduce as a consequence, which means that we will not be able to meet our security of supply standards.

The 11kV feeders in this area of the network are supplied from Waihi Rd and Tauranga GXP substations. These feeders are already heavily loaded.

The existing Hospital supply has a switched 11kV backup from Tauranga 11kV GXP – used only during emergencies when normal 11kV supply is unavailable. Future expansion of the hospital will exceed the capacity of the existing 11kV infrastructure to support the load after an outage of the primary supply.

In summary, the following constraints/issues exist:

1. The existing feeders supplying this area is highly loaded.
2. Growth from future Urban intensification will drive ICP numbers up resulting in high SAIDI impact.
3. Security of supply for the Tauranga Hospital
4. Both Tauranga 11kV and Waihi Rd substations are highly loaded and difficult to get additional feeders out of due to restricted space for expansion of the switchboards.

Options

The following network solutions were considered:

1. Installation of additional 11kV feeders from Waihi Rd or Tauranga 11kV; or
2. Commission a new substation in the Tauranga South, Gate Pa or Hospital area.

Preferred Option

The preferred option is Option 2 which is the installation of a new substation in the Gate Pa / Hospital area is the preferred solution. It provides an increase in capacity for the area off loading both the Tauranga 11kV and Waihi Rd substations. It provides a more robust and secure supply for the Tauranga Hospital. The new zone substation will carve up the distribution network supplied by the existing substations, reducing the length of each feeder, and in turn reducing the SAIDI risk allowing for the prospect of urban intensification to take place.

Option 1 to create new 11kV feeders out of the existing substations will be an expensive option due to the lack of room to support expansion of the 11kV switchboards at these sites. Hence, it is not deemed to be economic and therefore is not preferred.

WAIHI RD 33KV BUS SECURITY PROJECT

Constraint

Te Papa Peninsula is forecast to grow rapidly in future years. District Council structure plans discuss plans for potential urban intensification taking place in the area over the next decade. The anticipated load increase will put more pressure on our existing infrastructure serving the zone substations in the city.

In the later part of the planning horizon, it is expected that the following constraints will appear:

An outage on one of the two Tauranga GXP-Waihi Rd 33kV transformer feeder circuits will overload the parallel circuit and the associated supply transformer at Waihi Rd zone substation.

An outage on one of the two Tauranga GXP-Hamilton St 33kV circuits will overload the parallel circuit.

Options

Both non-network and network options have been considered to manage or resolve the existing constraints. Renewable generation, if combined with energy storage, could also address the N-1 capacity limitations, but would be unlikely to keep pace with the high growth which is anticipated. Available space to site the non-network solutions and to allow for future expansion to keep pace with growth would come at a premium given its close proximity to the city centre. The options listed below are based on our current thinking at this stage but we will continue to explore other options in the coming years.

The following network solutions were shortlisted:

1. Upgrade the constrained sections of the Tauranga GXP-Hamilton St and Tauranga GXP-Waihi Rd 33kV circuits; or
2. Construct a third circuit from Tauranga GXP to Hamilton St and a third circuit from Tauranga GXP to Waihi Rd substations; or
3. Construct a 33kV bus at Waihi Rd substation and terminate the Tauranga GXP-Hamilton St and Tauranga GXP-Waihi Rd circuits at this new bus. This also creates two Waihi Rd-Hamilton St 33kV circuits.

Preferred Option

Option 3, to construct a 33kV bus at Waihi Rd for termination of the existing circuits is preferred because:

- The 33kV bus significantly enhances security of supply for Waihi Rd substation as it will be supplied from four 33kV circuits out of Tauranga GXP.
- With four circuits supplying the combined load of Waihi Rd, Hamilton St and possible future Sulphur Point substations, an N-1 event of one of the circuits will no longer breach the firm capacity of the subtransmission circuits.
- Existing Tauranga GXP-Hamilton St circuits run past the Waihi Rd substation so terminating these circuits at the Waihi Rd 33kV bus will be straightforward.
- The future Sulphur Point substation will cause the Waihi Rd-Hamilton St circuits to exceed N-1 capacity if it is supplied off Hamilton St substation. New 33kV circuits supplying Sulphur Point from this new 33kV bus is one possible solution that will resolve the N-1 capacity issue.

Option 1 is not preferred because the increased capacity of the circuits will offer only short-term relief before additional augmentations are required again.

Option 2 to construct additional third circuits from Tauranga GXP to both substations would be costly and involve significant traffic management. Obtaining suitable route corridors between Tauranga GXP and the two zone substations at Hamilton St and Waihi Rd would not be a simple exercise.

A8.1.6 MINOR PROJECTS

KATIKATI SUBSTATION SECOND SUBTRANSMISSION CIRCUIT

Constraint

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings.

The substation is supplied via a single 33kV overhead line from Aongatete substation. The size and nature of the load connected to the Katikati substation at risk from non-supply in the event of a 33kV line outage is significant. Some load can be back fed from neighbouring substations, such as Aongatete and Kauri Point substations, but it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance is limited to low load times.

Options

The following shortlisted options were considered:

1. Increase the 11kV back-feed capability to Katikati substation.
2. Install a second 33kV circuit to Katikati substation.

Preferred Option

The preferred solution is to install a second 33kV circuit to the Katikati substation by laying a cable from the Katikati substation and connecting onto the Aongatete – Kauri Point overhead line, creating a hard tee to Kauri Point. This means that for an outage on one subtransmission circuit, supply can be maintained at the Katikati substation (n-1 security). With this solution, the Katikati substation will meet our required security level.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required back-feeding capacity are not favoured due to the higher overall cost and the complexity of upgrading the mix of conductors on some of the lines. The switching required on the 11kV network can also take a considerable amount of time for a substation outage.

KATIKATI SUBSTATION SECOND TRANSFORMER

Constraint

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings. The substation is a single supply transformer bank substation.

The size and nature of the load connected to the Katikati substation, at risk from non-supply in the event of a transformer outage, is significant. Some load can be back-fed from neighbouring substations, such as Aongatete and Kauri Point substations. But it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance has to be limited to low load times, for which appropriate windows are increasingly difficult to achieve.

Options

The following shortlisted options were considered:

1. Increase the 11kV back-feed capability to Katikati substation.
2. Install a second transformer at Katikati substation.

Preferred Option

The preferred solution is to install a matching second 33/11kV supply transformer (Option 2). This option will provide full (no break) N-1 security to the Katikati substation (together with the Katikati second circuit, refer to Katikati Substation second subtransmission circuit project). This option will cater for future growth and development without introducing unusual operating configurations.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required back-feeding capacity are not favoured due to the complexity of upgrading the mix of conductors on some of the lines. The switching required on the 11kV network can also take a considerable amount of time to restore supply after a substation outage.

A8.5 MOUNT MAUNGANUI AREA

A8.1.7 MAJOR PROJECTS

TE MATAI SUBTRANSMISSION VOLTAGE SUPPORT

Constraint

The subtransmission region east of Papamoa is supplied from the Te Matai GXP substation. The GXP is supplied at 110kV and interconnected to the Transpower substations at Kaitemako and Okere.

An outage on the Kaitemako-Te Matai 110kV circuit has the potential to cause post-contingent low voltages to appear across the entire Te Matai subtransmission network. According to Transpower's 2017 Transmission Planning Report, there is a planned risk-based replacement of the smaller capacity 110/33kV transformer at Te Matai GXP scheduled for 2019 although this timing is likely to slip. A new transformer fitted with on-load tap changers will improve the post-contingent steady state voltage levels. However, it does not resolve the dynamic voltage step change. Future load growth in the area as identified in the Bay of Plenty Smart-Growth strategy will worsen the voltage step, which impacts on the quality of supply (voltage quality) to customers.

Options

Both non-network and network options have been considered to manage or resolve the existing constraints.

Generation options are conceptually feasible but can only address the quality of supply issues if they are operated continuously to offset the voltage dip. Demand side responses, already a component of our network strategies, would not provide the magnitude of load shed and fast response necessary to resolve the issue.

We work closely with Transpower to identify possible transmission network options as well. As such, the following shortlisted options have been put together forming a list of solutions we are currently considering:

1. 110kV reactive support system – capacitors at Te Matai GXP (Transpower owned); or
2. 33kV switched capacitors at Te Matai GXP; or
3. STATCOM (2x 5 MVAR) connected to the 33kV network at Wairakei substation.

Preferred Option

The preferred solution at this stage is Option 3 because:

- There is enough land at Wairakei substation to accommodate the STATCOM and its associated equipment.
- Dynamic reactive support – faster response compared to switched capacitors which mitigates the voltage step change magnitude.

STATCOM reactive power output is more stable across a wider voltage range compared to Static Var Compensator (SVC) or capacitors.

- Reactive support situated close to the main load centres (Papamoa, Wairakei, Rangiuru Business Park) provides for improved voltage quality to customers locally.
- Reactive support at high load centres frees up capacity on the existing Te Matai-Wairakei 33kV subtransmission circuits.
- Voltage support across the subtransmission network during contingencies when either Te Matai GXP or Mt Maunganui GXP must provide backfeed support to each other.

ATUAROA PROJECT

Constraint

At the Atuaroa zone substation, there is a single 12.5/17 MVA supply transformer. An outage of the transformer at high load times makes it difficult to backfeed due to limited capacity from adjacent substations.

Further load growth will worsen the situation and result in voltage constraints across the 11kV network.

The existing 33kV subtransmission circuit supplying Atuaroa terminates directly to the transformer. Atuaroa does not have a 33kV bus. This limits options to improve subtransmission security of supply to the substation. This means that Atuaroa substation does not meet Powerco's security of supply standards.

Options

The following network reinforcement options are currently under consideration as part of the development plans:

1. Build new 33kV switchboard at Atuaroa substation and install a second 12.5/17 MVA transformer; or
2. Increase 11kV backfeed capacity into Atuaroa; or
3. Install standby diesel generators within the substation site

Preferred Option

The preferred option is presently Option 1 which involves the construction of a new 33kV indoor switchboard and installing a second 33/11kV 12.5/17 MVA transformer to parallel the existing transformer at Atuaroa zone substation.

The new 33kV switchboard will facilitate the connection of a future 33kV circuit from Te Puke, refer to Atuaroa sub-transmission reinforcement project.

Option 2 to increase 11kV backfeed capacity from the adjacent substations (Papamoa, Te Puke and Welcome Bay) is not preferred as it is expected to be more expensive compared to Option 1.

Option 3 to install and run diesel generators on site in the event of an outage to supplement the existing 11kV backfeed is feasible but not preferred as the substation site is next to a residential zone due to pollution and noise.

RANGIURU BUSINESS PARK PROJECT

Constraint

A proposed 148ha industrial park located at Rangiuru is in council district plans for the area and is promoted by the Western Bay of Plenty District Council's development arm. Powerco are already conducting preliminary assessments for a new customer connection in the area.
Buoyed by strong growth in the local economy, confidence in the development is high. The area is presently supplied via 11kV feeders from Te Puke substation. Future load growth in the area will place pressure on the ability of the existing 11kV network to support the expected load increase at the business park.

Options

The following network reinforcement options are currently under consideration as part of the development plans:

1. Build new 11kV feeders from Te Puke substation and Paengaroa substation; or
2. Construct two new 33kV circuits from Te Matai GXP to a new Rangiuru Business Park zone substation; or
3. Construct a new Rangiuru Business Park zone substation via an in-and-out arrangement from one of the Te Matai-Wairakei 33kV circuits.

Preferred Option

The preferred option is presently Option 3 which involves the construction of a new zone substation at Rangiuru Business Park with its 33kV supply taken from one of the two nearby Te Matai GXP-Wairakei 33kV circuits.

Two new 33kV underground circuits cut into the Te Matai-Wairakei 33kV circuit will supply the new substation through an in-and-out arrangement.

There is a planned 33kV-capable underground cable to be installed from Paengaroa to a location close to the proposed substation. The cable is initially going to be operated at 11kV until Rangiuru Business Park substation is commissioned.

When the new zone substation is commissioned, the cable will be converted to 33kV operation and terminated into the substation, thereby creating a 33kV closed ring arrangement between Te Matai GXP, Wairakei, Rangiuru Business Park and Paengaroa zone substations.

Option 2 to build two new 33kV circuits from Te Matai GXP to the new Rangiuru Business Park zone substation is not preferred as it is expected to be costlier compared to Option 3.

Option 1 to build new 11kV feeders will only provide limited short-term capacity and will not sustain the expected growth in the region going into the future.

Timing of the project is customer driven. We will continue to monitor the situation closely.

A8.1.8 MINOR PROJECTS

TE PUKE 33KV BUS SECURITY UPGRADE

Constraint

The Te Puke substation is supplied via two 33kV radial circuits from Te Matai GXP. It has a switched alternative supply from the Te Matai GXP-Atuaroa 33kV circuit.

An outage of a Te Matai GXP-Te Puke 33kV circuit also results in an outage of a supply transformer at Te Puke substation due to the 33kV bus normally operated as a split bus arrangement.

From 2026 onwards, an outage of a Te Matai GXP-Te Puke 33kV circuit will cause the parallel circuit to overload.

Existing 11kV backfeed capacity is insufficient to support the load. This means that the substation does not meet Powerco's security of supply standards.

Options

The following options are currently under consideration:

1. Construct a third Te Matai GXP-Te Puke 33kV circuit; or
2. Implement a secure 33kV bus at Te Puke substation complete with bus zone protection; or
3. Increase 11kV backfeed capacity to Te Puke substation.

Preferred Option

The cost-effective solution is Option 2, which is to improve security at Te Puke substation by having a solid 33kV bus. Additional line circuit breakers are required including a new bus coupler and a fast bus differential protection scheme.

The existing Te Matai GXP-Atuaroa 33kV circuit will be terminated to this solid bus, creating three 33kV circuits between Te Matai GXP and Te Puke substation.

This project will then facilitate the connection of the proposed Atuaroa second 33kV circuit, refer to Atuaroa subtransmission reinforcement project.

Option 1 to construct a third Te Matai GXP-Te Puke 33kV circuit would be uneconomical and expensive to construct due to difficult terrain and suitable line route.

Option 3 to further increase 11kV backfeed capacity will involve substantial 11kV infrastructure investment and is unlikely to be economical

ATUAROA SUBTRANSMISSION REINFORCEMENT

Constraint

The Atuaroa substation is currently supplied by a single 33kV subtransmission circuit from the Te Matai GXP in normal configuration. It has a switched 33kV supply from the Kaitimako GXP, used if there is a fault on the overhead line section between Te Matai GXP and the tee-off to Kaitimako GXP.

However, if the fault is on the cable from the tee to Atuaroa substation, there will be total loss of supply to Atuaroa. For this reason, Atuaroa does not meet Powerco's security of supply criteria.

Options

The following options are currently under consideration:

1. Increase 11kV backfeed capacity into Atuaroa substation;
2. Construct a new 33kV circuit from Te Puke to Atuaroa
3. Construct a new 33kV circuit from Te Matai GXP to Atuaroa

Preferred Option

The preferred solution is Option 2, which is to install a new underground 33kV circuit from Te Puke substation to Atuaroa substation. This will give Atuaroa a dual 33kV supply and resolve its security of supply issue.

Option 3 to build a new 33kV circuit from Te Matai GXP to Atuaroa substation is not preferred as it will be much costlier compared to Option 2.

Option 1 to increase 11kV inter-tie capacity is not preferred because doing so would require new 11kV feeders to be built out from Te Puke substation. This will ultimately prove not as cost-effective as Option 2.

TRITON SUBSTATION TRANSFORMER CAPACITY UPGRADE

Constraint

Two 11.5/23 MVA 33/11kV transformers supply Triton substation and firm capacity of the transformers is exceeded. When one transformer is out of service, overheating of the other transformer may occur especially during high load times. This means that the substation does not meet Powerco's security of supply standards.

The substation supplies the port and surrounding industrial sector, as well as the residential and urban centre of Mount Maunganui. There is also a renewal driver to replace the aging 33kV assets on site.

Options

The following options are currently under consideration:

1. Replace the existing transformers with higher capacity units; or
2. Install a third 11.5/23 MVA transformer at Triton substation; or
3. Build a new substation near Mt Maunganui urban central district and partially offload Triton load.

Preferred Option

The current preferred solution is Option 1, which is to replace the existing transformers with higher capacity units. This will resolve the transformer firm capacity at Triton.

Option 2 will involve site expansion due to a lack of space to accommodate a third transformer. Land purchase will be required and as the adjacent sites next to the substation are established industrial sites, so the costs will certainly be significant. As a result, this option is not likely to be economical and is therefore not preferred.

Option 3 to build a new substation in the central district of Mt Maunganui will allow Triton to transfer some load over to the new substation and enable Triton to resolve its firm capacity issue. Land purchase will be required for the new substation. Ultimately, this will not be the preferred option as obtaining suitable land will be significantly expensive. Also, the costs associated with constructing underground 33kV circuits to supply the new substation will involve significant traffic management which will further increase the costs. For these reasons, this option is not ideal.

A8.6 WAIKATO AREA

A8.1.9 MAJOR PROJECTS

PUTARURU GXP

Constraint

Six zone substations with a combined demand of 53.2MW are supplied from Hinuera GXP, which is supplied by a single 20km long 110kV circuit from Karapiro.

The 33kV network from Hinuera supplies south to Tirau and then Putaruru substations. There is no backfeed, and only a single circuit between Tirau and Putaruru. To the north of Hinuera, a 33kV network serving two substations in Matamata and one in Waharoa, have limited backfeed at 33kV from Piako GXP.

The network supplies a number of industrial consumers which include Fonterra (Waharoa), Fonterra (Tirau), Open Country Cheese (Waharoa), Buttermilk (Putaruru), Icepak (Waharoa), Kiwi Lumber (Putaruru) and Pacific Pine (Putaruru). Over the last decade the Hinuera GXP has experienced steady growth. A significant portion of the load relates to the dairy industry, which means that the electrical demand peaks in spring/summer. Sustained outages, as have occurred too often in the past, have substantial economic impacts on our customers.

A number of constraints therefore apply to this and associated projects:

1. The single 110kV overhead line to Hinuera provides only N security.
2. The peak demand on the Hinuera GXP is 52.7MW, which exceeds the N-1 capacity of the existing transformers.
3. The load to the north of Hinuera (Waharoa, Walton and Browne St substations), has limited back-feed from Piako, and this does not meet our security criteria.

   Putaruru substation is supplied via a ≈10km, single circuit, 33kV line. There is limited 11kV backup from the adjacent Tirau substation, which falls well short of that required by our security standard.
4. Maintenance on the 110kV line has been restricted due to constraints on outage windows.
5. Customer feedback in regard to the outages has been understandably strong. The South Waikato District Council has expressed concern over the security of supply to Putaruru and Tirau on a number of occasions.

Options

With only N security provided by the single 110kV line to Hinuera, alternate transmission circuits or GXPs are the obvious options, and earlier analysis concluded that a new Putaruru GXP was the preferred solution. Constructing a new Putaruru GXP remains our strategic objective, but insurmountable property issues and grid reconfiguration have both prompted reviews of available options. These reviews have modified the scope of the Putaruru GXP proposal, both in terms of grid interconnection, and in terms of considering high capacity underground circuits to obviate property issues. The only non-network option that could address the scale of the security issue at Hinuera would be a centralised thermal generation unit. Because of its unique commercial and operating characteristics, this option is not included in the shortlist below, but we will continue to investigate its viability and see if any commercial possibilities become evident.

The following grid / network options were shortlisted:

1. Construct a new Putaruru GXP, connected to an existing Arapuni – Kinleith 110kV line.
2. Construct a new Putaruru GXP, connected to the Arapuni power station at 110kV.
3. Construct a new 110kV circuit from Arapuni power station to Hinuera GXP.
4. Construct a second 110kV circuit from Karapiro power station to the Hinuera GXP.
5. Construct a new GXP at Arapuni power station, and supply Putaruru via dual 33kV circuits.

Preferred Option

Option 2 is preferred and involves constructing a new 110kV circuit from Arapuni power station to a new GXP located at Putaruru.

This outcome was confirmed through a collaborative study involving both Powerco and Transpower. This review of options was driven by unexpected changes to the grid configuration, which substantially reduced the benefits of the previously preferred option 1, by introducing constraints on the available offtake capacity from the Arapuni-Kinleith 110kV lines.

Option 2 is now preferred because, in conjunction with upgrades to the 33kV network (refer sections **B** and **C**), it provides appropriate security to all customers currently supplied from the N security Hinuera GXP. This option also has the lowest estimated cost and is less likely than other options to incur delays or cost escalation due to property or consenting difficulties. Option 2 resolves the limitations on grid offtake capacity imposed by Option 1, and also adopts established grid and network architectures, protection and operating standards, including the ability to parallel both GXPs.

The estimated cost of Option 4 is high, and it also exposes risks of delay or cost escalation by virtue of challenging property and consenting issues. It would also be necessary to upgrade the Karapiro 110kV bus.

Options 3 and 5 had similar order of cost to the preferred Option 2. Option 3 exposes considerable risk around securing property rights and consents for a long overhead line. Option 5 has very similar cost/benefit outcomes to Option 2, but does require voltage management under some contingencies, and has lower limits on the capacity when feeding right through to Hinuera from the new Arapuni GXP.

It is intended to carry out further investigative work in the next 12 months to refine cost estimates and confirm the optimum solution among these remaining options with similar indicative cost / benefit. During this timeframe we can also further investigate the possibilities of possible gas generation options. This will likely be a function of what commercial partnerships are available. This work can be undertaken in parallel with preliminary design/planning for the preferred solution, particularly in regard to aspects of securing access to Arapuni switchyard and crossing the Waikato river.

KEREONE – WALTON 33KV SUBTRANSMISSION ENHANCEMENT

Constraint

None of the zone substations supplied from Hinuera GXP meet our security standards. This results from a number of constraints, the most serious of which is the single 110kV line from Karapiro to Hinuera, which only provides N security to ~53.2MVA of demand.

The option to build a new Putaruru GXP, as proposed in section 0, resolves the constraints in as much as they affect the substations south of Hinuera (Putaruru, Tirau and Lake Rd substations). However, the capacity of the 33kV network is not sufficient to secure the substations north of Hinuera (Browne St and Tower Rd in

Matamata and Waharoa). Backfeed to Waharoa and Browne St from Piako GXP is limited by a low capacity 33kV line between Kereone and Walton substation.

Waharoa supplies a number of important industrial customers including Fonterra, Open Country Cheese and Icepak. The peak load at Walton, Waharoa and Browne St substations has been growing recently by over 3%. Waharoa alone has seen rapid expansion and growth is forecast to continue at over 2.1% pa and this does not include an anticipated growth on an existing upgrade to accommodate expansion for Open Country Dairy Ltd.

Due to the speed of recent developments at Waharoa, it has been necessary to temporarily split the substation bus and feed half the load from each direction. This means different parts of the load are supplied from different GXPs and subtransmission networks which is operationally undesirable and further degrades reliability.

The aging infrastructure and condition of the assets between Piako and Kereone, is undesirable in terms of reliability. This section will be upgraded through planned renewal work to improve the reliability.

Options

Non-network options were considered, but only larger scale non-renewable generation could provide the required no break security/availability to the industrial load base and flat demand profile. A Cogen arrangement would be the most likely scenario where this might be viable, but no synergistic commercial opportunities to implement a Cogen solution have yet been identified.

The following network solutions have therefore been considered:

1. Re-conductor the Kereone-Walton 33kV line and thermal upgrade Piako-Kereone 33kV line.
2. Thermally upgrade the Piako-Walton 33kV line only.
3. Replace the Kereone-Walton 33kV line with a 33kV cable and re-conductor Piako-Kereone 33kV line.
4. Install a new Kereone-Walton 33kV cable and supply Walton permanently from Waihou GXP.
5. All of the above options include the addition of a 33kV capacitor bank to support network voltages during network contingencies.

Preferred Option

Option 4 is our preferred option. This makes use of the existing low capacity line to carry the small Walton substation, switching it onto Waihou GXP. The new high capacity cable then feeds Waharoa from Piako GXP, and has sufficient capacity to back-feed Browne St in Matamata, when supply from Hinuera is unavailable. This also allows us to remove the split at Waharoa bus so that all load is sourced from one GXP.

Alternative Options 1 and 2 require costly upgrade work to the existing Kereone-Walton line, and still impose severe capacity limitations on back-feed. Option 3 provides no greater capacity increase than Option 4, but also requires uprating of the existing line. Option 3 is constrained by needing to operate the very low impedance new cable in parallel with the high impedance overhead line. Option 4 circumvents this problem by a reconfiguration, switching Walton substation onto Waihou GXP.

Walton substation has aging 33kV and 11kV assets. The existing switchroom housing the old 11kV switchboard is seismically unsafe and traces of asbestos is suspected in the building. Planned renewals of the assets on site will be coordinated with this project.

PUTARURU – TIRAU UNDERGROUND CIRCUIT

Constraint

We recently installed a new 33kV underground cable from the Hinuera GXP to the Tirau substation to address an overload on the existing overhead line. However, this was also part of a long-term plan to improve support for Tower Rd substation from the new Putaruru GXP. While Tower Rd can be partially back-fed from Putaruru GXP (once constructed) the limited capacity of the overhead line between Putaruru and Tirau will still restrict this to light loads. Voltage constraints would also apply.

Options

Both non-network and network options have been considered to manage or remove the existing constraint(s). The non-network considerations are discussed in Section 0.

The following options have been considered as part of the development plans:

1. Re-conductor the existing Putaruru-Tirau 33kV line.
2. Install a new 33kV underground cable between the Putaruru and Tirau substations.

Preferred Option

The preferred option is presently (Option 2 above) which involves the installation of a 13km long, 33kV underground cable from Putaruru to Tirau. The new cable would significantly increase the 33kV network capacity between the proposed Putaruru GXP and the existing Hinuera GXP and provide adequate security to the load at Tower Rd substation.

MORRINSVILLE SUBSTATION TRANSFORMERS UPGRADE

Constraint

Morrinsville substation supplies the township, commercial, residential and the surrounding rural area. Major industrial customers include Greenlea Meat Processing Plant and Fonterra. Fonterra alone consumes 2.7MVA of it present demand. The Morrinsville area has experienced rapid residential and industrial growth. This is expected to continue.

The firm capacity of the transformers is already exceeded. Although some back-feed from Piako and Tahuna is available, this is insufficient to meet the growing demand.

The existing site of the substation is space-constrained to accommodate higher rated transformers.

Options

1. Upgrade substation transformers to 16/24MVA with new 33/11kV indoor switchroom and switchboard
2. Increase 11kV inter-tie capacity; – This would need at least one high capacity bus tie circuit and substation upgrades

Preferred Option

The preferred solution is to construct a new switchroom for the new 33kV and 11kV switchboards as well as installing higher rated transformers.

Option 2 to install additional 11kV inter-tie capacity is limited as backfeed capability of existing donor feeders will continue to deteriorate due to load growth, which effectively means that new feeders will need to be constructed out of Piako and possibly Tahuna zone substations. This is unlikely to be economic.

A8.1.10 MINOR PROJECTS

HINUERA OUTDOOR INDOOR (ODID) CONVERSION

Constraint

The Hinuera GXP supplies the area around Matamata, Tirau and Putaruru. The network comprises three single radial feeds:

- Hinuera-Lake Rd-Browne St supplies Browne St, half of Waharoa substations
- Hinuera-Lake Rd-Tower Rd supplies Lake Rd, and Tower Rd substations
- Hinuera-Tirau supplies Tirau and Putaruru substations.

Constraints in the area include a single circuit breaker supplying both Lake Rd and Tower Rd substations; a single circuit breaker supplying both circuits to Tirau substation (one cable and one overhead line), and that the existing protection system is designed to operate with Hinuera GXP as a source.

Following the commissioning of the Putaruru GXP, and with the scenario of an outage of Hinuera GXP, the Hinuera area sub-transmission network including Tirau, Lake Rd and Tower Rd substations will have slower tripping times due to the lower fault levels when Putaruru becomes a fault source. Due to these constraints, the required security levels at Lake Rd, Tower Rd, Tirau and Putaruru substations are not met.

Options

The following options were considered:

1. Extend the existing outdoor 33kV bus at Transpower's site; or
2. Construct an indoor switchboard at Hinuera GXP capable of fast bus protection to facilitate the connection of the new Hinuera-Tirau underground cable and other circuits.

Preferred Option

The preferred option is Option 2 to install an indoor 33kV switchboard at Hinuera.

Powerco's original scope is to partially indoor the 33kV outdoor yard in order to facilitate the connection of the recently installed Hinuera-Tirau 33kV circuit and the additional circuit to Lake Rd. It is also a pre-requisite for the Putaruru GXP project. This approach was based on the original assumption that Transpower has no plans to renew the outdoor 33kV assets within the planning period.

Transpower has since advised that they have scheduled replacement of the outdoor 33kV assets in 2022. As a result, it would be more cost-effective if Powerco carries out the full outdoor-to-indoor conversion and build a new switchroom.

This in turn allows the accommodation of the recently installed Hinuera to Tirau cable and separate out the Lake Rd and Tower Rd circuits.

MATAMATA (TOWER – BROWNE 33KV CABLE)

Constraint

The Browne St and Tower Rd substations are each supplied via a single 33kV line from Hinuera GXP. Together these two substations supply the entire Matamata township, including the CBD. Outages on either of the 33kV lines will cause an immediate loss of supply to the respective substation. The 11kV inter-tie capacity between the substations is not sufficient or sufficiently switchable to meet our security requirements

Options

Options considered include:

1. **11kV back-feed upgrades:** Increased 11kV back-feed capacity and automated switching could reduce outages. Against this, the more obvious 11kV back-feeds have already been upgraded and multiple automation schemes violates our automation strategy and the principle of simple/safe operational configurations.

2. **2nd 33kV circuit to each substation:** This would involve two new circuits from Hinuera GXP, one to each substation. While this would provide a desirable architecture with ample capacity and security and even support initiatives to backstop Hinuera GXP (refer section A8.1.11), it ultimately proved too expensive.

Preferred Option

The proposed solution is to construct a 33kV underground cable circuit between Tower Rd and Browne St substations. This will create a secure 33kV subtransmission ring serving Matamata, without excessive costs and without undesirable operating configurations.

HINUERA – TOWER ROAD 33KV LINE UPGRADE

Constraint

The project detailed in section 0 completes a proposed 33kV ring from Hinuera GXP to Browne St and Tower Rd substations. Both substations will then be afforded N-1 security on the subtransmission, but the combined load will exceed the capacity of the Hinuera to Tower Rd 33kV line.

Options

Alternate options and reasoning considered were:

1. **Second circuit from Hinuera to Tower Rd:** Excessive cost, plus it would require additional switchgear and added complexity of the protection.
2. **Additional 11kV back-feed:** Cannot meet the no-break N-1 requirement required for appropriate security and rejected for the same reasons as detailed in section 0.
3. **SPS to transfer Browne St to Piako:** Operationally complex with automated switching across GXPs required.

Preferred Option

The solution is to thermal upgrade the conductor on the Hinuera – Tower Road 33kV line. Once this project is complete along with the Tower Road to Browne Street tie, both Tower Road and Browne Street substations will meet our required security levels.

This solution is much cheaper than an additional circuit to Matamata. There are no further practical 11kV back-feed options and the option does not align with our preferred network architecture and security standards. Non-network solutions such as demand side response, load shedding may be possible but only as a risk management strategy to defer the proposed line upgrade.

MORRINSVILLE SECOND CIRCUIT

Constraint

The Morrinsville substation is fed by a single 33kV circuit from the Piako GXP and only provides N-security. If there is a fault on this circuit, there will be an immediate loss of supply to all of Morrinsville, including the Fonterra factory adjacent to the substation. Some back-feed from Piako and Tahuna is available, but this does not meet our security criteria.

Options

Options considered include:

1. **Second 33kV circuit Piako to Morrinsville:** A second circuit (mostly underground cable via road reserves) would be constructed from Piako GXP to Morrinsville substation.
2. **33kV ring with Tahuna:** A new 33kV circuit from Morrinsville to Tahuna would allow a 33kV ring to be established.
3. **Increase 11kV backfeed or inter-tie:** This would need at least one high capacity bus tie circuit, and potentially substation upgrades.
4. **Non-network options:** Particularly diesel generation or Cogen.

Options to create a 33kV ring between Morrinsville and Tahuna (also supplied by a single circuit) would provide benefits to both substations, but ultimately proved too expensive considering the long distance to Tahuna substation. Increased 11kV capacity is viable, but is operationally more complex for minimal saving in cost. Non-network options are not well suited to N-security issues. Backup generation could conceivably be deployed under contingencies, but no opportunities have been identified

Preferred Option

The proposed solution is therefore to construct a second 33kV circuit from Piako GXP to Morrinsville substation (Option 1). This is both cost effective and provides adequate capacity and security for Morrinsville now and in the future.

PIAKO SUBSTATION NEW 11KV FEEDER

Constraint

The Piako substation supplies the rural area surrounding Morrinsville, some of the outlying suburban areas of Morrinsville and one major industrial load. The substation contains two supply transformers.

There are a total of seven 11kV feeders supplied from the Piako zone substation. The Kereone 11kV feeder is 114km in length with three other rural 11kV feeders over 40km in length. During peak periods, the loads at the end of the feeders can experience low voltages. These feeders experience voltages outside the regulatory requirements that Powerco must comply to.

Moreover, the Kereone area is experiencing steady growth, so the voltage performance of these feeders will deteriorate over time.

Options

1. Upgrading conductor
2. Voltage support
3. Feeder rearrangement

Preferred Option

The proposed solution is to split the existing Kereone feeder into two feeders; one of the new feeders will be created to serve the area to the south including Te Miro, and the other feeder will essentially be the remaining section of the existing Kereone feeder, which will serve the Kereone area only. The southern section of the existing Kereone feeder will be offloaded to the neighbouring Lake Rd feeder.

This solution will also provide sufficient capacity for future growth in this area.

Alternative solutions such as voltage support and upgrading the conductor are not favoured as they will only provide limited improvements in capacity and short-term benefits and will not improve reliability due to the long feeder lengths.

TOWER RD 2ND TRANSFORMER

Constraint

Tower Rd substation currently has just one 33/11kV transformer. The 11kV back-feed from Browne St is not sufficient to meet our security standards.

Options

Options considered include:

1. **Install a second transformer:** A matching 33/11kV transformer provides full N-1 security. Tower Rd substation has a programme of upgrades to improve performance and security. The substation has been designed to accommodate a second transformer.
2. **Increased 11kV backfeed:** More complex operationally and potentially higher cost.

Preferred Option

Option 1 (a second transformer) is preferred. This provides no break N-1 security appropriate to this urban substation and caters for future growth and development, without introducing unusual operating configurations. Costs are comparable for both options.

TIRAU SUBSTATION SECOND TRANSFORMER

Constraint

A single 7.5 MVA 33/11kV transformer supplies the Tirau substation including a large dairy factory. An outage of this transformer causes loss of supply to the load. Existing 11kV backfeed capacity is insufficient to support the load. This means that the substation does not meet Powerco's security of supply standards.

Options

The following options are currently under consideration:

1. Install a second transformer at Tirau substation and upgrade the existing transformer to a higher capacity unit; or
2. Increase 11kV inter-tie capacity

Preferred Option

The preferred solution is Option 1, which is to install a new 12.5/17 MVA 33/11kV transformer at Tirau substation, and upgrade the existing 7.5 MVA unit to a matching 12.5/17 MVA transformer so that Tirau becomes a two-bank substation.

Option 2 to further increase 11kV backfeed capacity will involve substantial 11kV infrastructure upgrade, and is unlikely to be economical.

Timing of the project correlates to how quickly demand grows in the region.

PUTARURU SUBSTATION TRANSFORMERS CAPACITY

Constraint

Putaruru is presently supplied from two 7.5/10 MVA 33/11kV transformers. The maximum demand exceeds the transformers firm capacity. Existing 11kV backfeed capacity is minimal from Tirau and Baird Rd substations as they are voltage-constrained. This means that the substation does not meet Powerco's security of supply standards.

Options

The following options are currently under consideration:

1. Upgrade to higher capacity transformers; or
2. Increase 11kV inter-tie capacity; or
3. Build a new substation at Waotu to offload some Putaruru load.

Preferred Option

The preferred solution is Option 1, which is to upgrade the transformers with 17/24 MVA units.

Option 2 to further increase 11kV backfeed capacity will involve substantial 11kV infrastructure upgrade and is unlikely to be economical.

Option 3 to build a new substation at Waotu will also address the capacity issue by allowing some Putaruru load to be transferred over to the new substation. However, this does not address the need to renew the existing transformers at Putaruru due to age.

We will continue to assess the situation to determine the best overall solution.

WAHAROA SUBSTATION TRANSFORMER CAPACITY

Constraint

Waharoa is presently supplied from two different GXPs – Hinuera and Piako. Due to the mismatched transformers on site, the substation itself is effectively operated as two separate substations on the same site with a split bus configuration. An older 7.5 MVA unit supplies the Waharoa township loads and is fed from Piako GXP. The second unit with a 12.5/17 MVA capacity was recently installed and supplies only the dairy factory load at present from Hinuera GXP.

Due to the mismatched transformer sizes, the transformers are not paralleled. The other reason for keeping the split is due to the lack of sub-transmission capacity to supply the entire Waharoa load from either GXP.

Later in the planning horizon following the completion of the Hinuera-Browne St-Tower Rd closed 33kV ring, the loss of the Hinuera-Browne St circuit will overload the Hinuera-Tower Rd circuit at high load times. Conversely, an outage of the Hinuera-Tower Rd circuit will overload the Hinuera-Browne St circuit.

Options

The following options are currently under consideration:

1. upgrade the 7.5 MVA transformer, install a new 33kV indoor switchboard and supply the whole Waharoa load from Piako GXP; or
2. install REG-DA relays on both transformers configured for circulating current operation mode.

Preferred Option

The preferred solution is Option 1, which is to upgrade the older 7.5 MVA transformer to a 12.5/17 MVA unit. The existing 33kV overhead strung bus will be replaced with an indoor 33kV switchboard at the same time due to space constraints on site.

Together with the completion of the upstream 33kV sub-transmission (refer to the Kereone-Walton 33kV Subtransmission Enhancement project), the Waharoa transformers can be paralleled and the substation supplied from Piako GXP in normal operation. The transfer of the dairy factory load over to Piako GXP will help address the N-1 thermal overload of the Hinuera-Browne St and Hinuera-Tower Rd circuits.

Option 2 to enable circulating mode of operation for the transformers' on-load tap changers will not resolve the substation's firm capacity issue and will mean that network upgrades are required also for the Hinuera-Browne St and Hinuera-Tower Rd circuits. Hence this is not the preferred solution.

LAKE RD SECOND TRANSFORMER

Constraint

Lake Rd substation currently has just one 33/11kV transformer. Substations which could provide back-feed are quite remote and existing 11kV capacity is not sufficient to meet our security standards.

Options

Options considered include:

1. **Install a second transformer:** A matching 33/11kV transformer provides full N-1 security in a standard substation configuration.
2. **Increased 11kV backfeed:** More complex operationally. Expected to be higher cost in light of the large distance to the next nearest substations.

Preferred Option

The proposed solution is therefore to install a second transformer.

MAUNGATAUTARI AREA REINFORCEMENT

Constraint

Maungatautari and Karapiro are areas on the edge of Powerco's network. Supply to the area is from Tirau substation. The ability to provide a secure supply to the area is set back by distance and terrain. A total of 746 ICPs is supplied by Cambridge Rd feeder and 11kV back-feed capacity from Lake Rd substation is minimal due to the great distance

Historically, the time taken to restore supply in this area is longer after an outage. Due to the terrain involved and accessing to site for fault-finding and repair is more difficult.

Options

The following options are under consideration:

1. Increase the 11kV back feed from neighbouring Lake Rd substation feeder by installing a 5km underground link, voltage regulator and significant network enhancement.
2. Install new 33/11kV substation with new 33kV circuit.
3. Install distributed generation equipment for islanded operation.

Preferred Option

The likely solution is Option 3 which is to install distributed generation equipment capable of islanding operation to support the load in the Maungatautari region.

Two diesel generation units sized at 1 MW each will be installed – one for each spur serving the Maungatautari and Horahora local areas.

Enough fuel storage will be required to provide backup power for up to two hours duration during an outage situation. Combined with selective automation of switchgear at strategic places on the network, the distributed generation facilities should minimise time to restore supply to our customers.

With Powerco's Maungatautari repeater in close proximity, communication is expected to be low latency and with a high signal-to-noise ratio content, the diesel generators would be fitted with remote operation capability.

A8.7 KINLEITH AREA

A8.1.11 MAJOR PROJECTS

There are no major growth and security projects planned for Kinleith. There are however significant fleet upgrade plans. These are outlined in Chapters 15-21.

A8.1.12 MINOR PROJECTS

There are no minor growth and security projects planned for Kinleith following the completion of the Baird Rd-Maraetai Rd 33kV cable project. However, step load changes from industrial development can change this. We will continue to monitor the situation.

A8.8 TARANAKI AREA

A8.1.13 MAJOR PROJECTS

SECURITY OF SUPPLY TO MOTUROA SUBSTATION

Constraint

The Taranaki regional loads connect to the 110kV system, with the 220kV being predominantly for through transmission and bulk generation. There are two 220/110kV interconnector transformers, one at Stratford, one at New Plymouth. Transpower's long-term plans identify some constraints on the 110kV capacity.

The New Plymouth substation was primarily built to accommodate the power station, which has now been permanently decommissioned. Alternative uses for the land have been proposed. Transpower is considering options to partially or fully exit the site. This includes upgraded 220/110kV interconnectors at Stratford, and rationalising the northern Taranaki grid configuration at 110kV only. This would then leave New Plymouth as a small capacity GXP, serving just 20MW of load at our Moturoa substation. The scale of switchgear and plant at the site would vastly exceed that which is optimal for such a small load, and the already disproportionately high maintenance and operating costs are exacerbated by the corrosive coastal environment. Transpower are therefore investigating the economics of disestablishing the whole site, and supplying Moturoa by some alternative means. If this proceeds, it will therefore be necessary to make alternative arrangements to supply Moturoa substation.

Option

The magnitude of the existing load and the security required for this largely preclude non-network options, particularly those such as renewable generation, energy storage or demand side response, which offer only incremental demand adjustments. Only grid scale generation would provide secure supply to Moturoa, but the removal of such generation is the driver behind the need to exit New Plymouth and hence find an alternate supply for Moturoa substation.

The following network solutions have been considered:

- 2 x 33kV underground cables from Carrington GXP to Moturoa.
- 1 x 33kV underground cable ring connecting Carrington GXP, Moturoa and City substations.
- A new 110/33kV GXP at Omata coupled with a 33/11kV substation. Decommission the existing Moturoa substation.
- A new zone substation in the Spotswood area replacing Moturoa. Supply the new substation via 2 x 33kV circuits from Carrington GXP.

Preferred Option

Option 1 appears the most cost effective, while maintaining the required level of security to the Moturoa substation. This option would involve two new dedicated 33kV cables from Carrington St GXP to our existing Moturoa substation.

INGLEWOOD 6.6KV TO 11KV CONVERSION PROJECT

Constraint

The Inglewood zone substation supplies power to Inglewood township and the surrounding rural areas at 6.6kV. The substation contains two 33/6.6kV supply transformers. Only two substations in Powerco's Western network – Inglewood and Motukawa, operate at 6.6kV.

Disadvantages with operating a 6.6kV network include:

- Voltage drop at the ends of the feeders becomes excessive as the load increases resulting in poor quality supply to customers
- The network is isolated from neighbouring zone substations which all operate at 11kV. This limits the back-feed capacity available to Inglewood substation during a contingent event.
- The 6.6kV voltage is a non-standard Powerco's distribution voltage.
- Due to these issues, the Inglewood substation does not presently meet our required security and performance quality levels.

Options

The nature of this project is unique in contemplating a strategic decision to upgrade a small section of 6.6kV distribution to standard 11kV voltage. Typical development options contemplating new circuits, substations or network architecture are not appropriate in this context, and neither are non-network options.

The following network solutions have been considered:

- Continue to operate the Inglewood network at 6.6kV by upgrading conductors
  to meet voltage and capacity demands. Over time, all the 115km of feeders would need to be replaced.
- Install 6.6/11kV step up transformers midway on the feeders, converting the ends of the feeders to 11kV and progressively moving the step up transformers back toward the start of the feeder, eventually carrying out a full conversion to 11kV.
- Replace the remaining 6.6kV/400V transformers with dual wound transformers and then converting all feeders to 11kV within a 2-3 year timeframe. Changeover would be done on each feeder as a whole, beginning with the one having the worst voltage drop. Once all feeders were changed over the substation would be reconfigured to supply at 11kV.

Preferred Option

The preferred solution is Option 3 which involves replacing all of the remaining 6.6kV/0.4kV distribution transformers in the Inglewood area with dual winding transformers (11/6.6kV-0.4kV) over a 2-3 year period.

Option 1 is not favoured due to the long length of feeder upgrade required, and consequently high cost.

Option 2, which involves using 6.6/11kV step up transformers, is not favoured due to higher capital cost needed for the installation of a voltage regulator and 6.6kV/11kV step up transformer on each feeder

OAKURA 2ND 33KV LINE & 2ND TRANSFORMER

Constraint

The Oakura substation supplies Oakura township (population 1400), 12km southward Okato township (population 530) and surrounding rural customers – mainly dairy & farming.

Oakura 2018 demand was 3.5 MVA (1830 ICPs) and expected demand in 2030 is 5.3 MVA

The substation presently contains one 7.5/10MVA 33/11kV transformer supplied by one 14km long 33kV line (mostly overhead). The substation's security class is AA, which requires restoration of supply within 45 minutes.

Present 11kV backup supply is from neighbouring Moturoa substation, which would be inadequate by 2027 and beyond. A large subdivision (around 300 lots), next to Oakura substation, could also take place in next 5 to 10 years' timeframe.

Preferred option

The only feasible solution is to construct a second 33kV line (approx. 16km) from Carrington St GXP along with the installation of a second transformer at Oakura.

EGMONT VILLAGE NEW ZONE SUBSTATION

Constraint

Mangorei 11kV voltage regulating station supplies three distribution feeders (1218 ICPs) at 11kV. Mangorei takes its 11kV supply from Brooklands substation by a dedicated 11kV feeder Brooklands-5, which consists of 1.73km underground cable & 3 km overhead line. This dedicated feeder is rated for 33kV operation.

The underground section of Brooklands-5 feeder would reach to its capacity by 2030 (expected demand load 4.5MVA). In addition, Mangorei's voltage regulator (manufactured in 1982) would reach close to its capacity of 5 MVA.

Furthermore, the Mangorei regulating station is not at the centre of the load, it supplies and voltage quality of its two feeders is approaching to acceptable limit (95%).

Preferred Option

The only feasible solution is to construct a new zone substation (10MVA capacity) at Egmont Village on a land to be purchased along with the extension (around 6km) of Mangorei 33kV line to this new substation. Brooklands-5 feeder cable will be shifted to Carrington St GXP by installing a new 33kV CB. In the future this 33kV line could be extended (around 7km) to join with Inglewood substation 33kV line, which would then provide n-1 supply.

NEW WHALERS GATE ZONE SUBSTATION

Constraint

The Moturoa substation supplies the western side of New Plymouth city including the Taranaki Port, the Moturoa industrial area, the Taranaki Base Hospital and the rural load westward to Oakura. Its security level is AAA. The demand growth is high due to new subdivisions and developments in certain areas of New Plymouth, such as Whalers Gate. In addition to the risk of exceeding substations N-1 capacity, the high feeder demand growth can cause security of supply issues to critical urban, commercial and industrial loads in future.

Preferred Option

The only feasible solution is to establish a new zone substation to offload the existing Moturoa substation. This will reduce the lengths and loads of the feeders and consequently reduces the risk of feeder outages.

Alternatives such as increased offload to existing zone substations are considered to be impractical and limited.

A8.1.14 MINOR PROJECTS

WAITARA – MCKEE 33KV

Constraint

During peak demand periods, if the Waitara West line is not available, the single 33kV Waitara East circuit from Huirangi GXP has insufficient capacity to supply all four substations- Waitara East and West, Pohokura and McKee substations. The tee configuration of the Waitara East/McKee lines also causes protection issues and limits generation injection levels

Options

Options considered include:

1. **Second circuit from Huirangi to McKee/Waitara Tee:** This allows the tee to be removed and a dedicated circuit provided for each of the McKee circuit and the Waitara East circuit. The new circuit will provide sufficient capacity to resolve the existing constraints for contingencies on the Waitara West circuit.
2. **Upgrade existing 33kV circuit:** This can resolve the capacity issue, but not the protection and architecture issues presented by the tee configuration. Upgrade could still incur costs associated with acquisition of property rights.
3. **Secure generation availability:** No commercially acceptable options are available, and this option does not resolve the protection and configuration issues.

Preferred Option

The preferred solution is presently Option 1 – construct a second 33kV circuit from Huirangi GXP to the McKee/Waitara East tee. The cost is slightly higher than other options, but it provides a highly secure standard network configuration that resolves all existing operational and protection issues.

ELTHAM TRANSFORMERS

Constraint

The Eltham substation supplies Eltham town, the surrounding rural areas, and two significant industrial loads. The substation contains two transformers. The demand has exceeded the secure capacity of the transformers, ie the capacity that can be supplied by one transformer plus available 11kV back-feed.

Options

Options considered include:

1. **Upgrade transformers:** Install two units that will ensure N-1 secure supply meeting the security standards for the future projected load.
2. **Increase 11kV back-feed:** The nearest substations are some distance and their capacity is quite limited, meaning this option is not very effective. Manual switching is still required in this option.

Preferred Option

The preferred solution is to replace the existing transformers with two larger units. The Eltham 33kV substation is operated with a split bus and hence the transformers are exposed to higher duty more often, ie whenever there is a subtransmission fault.

BELL BLOCK SUBSTATION 11KV OFFLOAD

Constraint

The Bell Block substation supplies the Bell Block industrial area and the nearby residential and rural areas. The area offers flat industrial zoned sites, conveniently sited for access to the highway, port and rail at reasonable cost, so further industrial load growth is considered likely. Its security class is AAA, which requires uninterrupted supply in n-1 situation.

Bell Block 2030 demand, as forecasted, is 24.6 MVA. At such demand Bell Block would exceed its firm capacity of 24 MVA.

Preferred Option

The most feasible solution is to offload Bell Block onto neighbouring Katere Rd substation by constructing a new 11kV feeder (4km long) from Katere substation..

CITY SUBSTATION SUPPLY TRANSFORMER

Constraint

The City substation supplies New Plymouth CBD and the surrounding urban area consumers – mostly commercial and some residential. The substation contains two transformers, manufactured in 1977. Each has a continuous rating of 20.1 MVA. Its security class is AAA, which requires uninterrupted supply in n-1 situation.

City substation would exceed its firm capacity by 2030.

Preferred Option

The most feasible solution is to replace the existing transformers with two larger units. This will secure the load at City and provide adequate capacity for future demand.

INGLEWOOD SUBSTATION SUPPLY TRANSFORMER

Constraint

The Inglewood substation supplies power to Inglewood Township and the surrounding rural areas. The substation contains two 5 MVA transformers.

Inglewood security class is AA, which requires restoration of supply within 45 minutes in n-1 situation.

Inglewood would exceed the secure capacity of the transformers (i.e. the capacity that can be supplied by one transformer plus available back-feed) by 2025.

Preferred Option

The most feasible solution is to replace the existing transformers with two larger units. This will secure the load at City and provide adequate capacity for future demand.

CLOTON RD SUBSTATION SECOND DEDICATED 33KV LINE

Constraint

The Cloton Rd substation supplies power to Stratford CBD and the surrounding urban and rural areas. There are 4260 ICPs supplied by this substation and its 2018 demand was 11.2 MVA.

Cloton Rd takes its 33kV supply from Stratford GXP by two overhead lines – one is dedicated (4.14km long) and the other shares partly (3.87km) with one 33kV line, that also supplies Eltham substation.

This shared part of 33kV line would reach to its limit (16.5 MVA) by 2025 for an outage on Cloton Rd dedicated 33kV line or Eltham other 33kV line.

Both Cloton Rd and Eltham substations' security class is AA+, which requires restoration of supply within 15 seconds in n-1 situation.

Preferred Option

The most feasible solution is to remove the shared part by installing 4km of new 800mm^2 AL 33kV cable from Stratford GXP along with a new 33kV CB at Stratford GXP.

CLOTON RD SUBSTATION SUPPLY TRANSFORMER

Constraint

The Cloton Rd substation supplies power to Stratford CBD and the surrounding urban and rural areas. The substation contains two 10/13 MVA transformers. Its security class is AA+, which requires restoration of supply within 15 seconds in n-1 situation.

Cloton Rd 2030 expected demand of 12.1 MVA would be close to its firm capacity of 13 MVA. At times Cloton Rd supports Motukawa, a single transformer's substation, which has a demand of 1.3 MVA.

Preferred Option

The most feasible solution is to replace the existing transformers with two larger units. This will secure the load at Cloton and provide adequate capacity for anticipated future demand.

MOTUKAWA 6.6KV TO 11KV CONVERSION

Constraint

The Motukawa substation supplies Tarata and Ratapiko townships along with surrounding rural areas at 6.6kV. There are 420 ICPs supplied by this substation and its 2018 demand was 1.2MVA. The substation contains one 5MVA 33/11-6.6kV transformer.

As 6.6kV draws more current, Motukawa's two feeders' (Ratapiko and Tarata) voltage quality is approaching to acceptable limit (95%). The 6.6kV voltage is also a non-standard Powerco's distribution voltage.

Neighbouring Inglewood and Midhurst 6.6kV network is being converted into 11kV during CPP1 period. Then Motukawa would be the only substation operating at 6.6kV.

Motukawa's present distribution network is rated for 11kV operation.

Preferred Option

The most feasible solution is to replace remaining (130 out of 163) 6.6/0.415kV transformers with dual wound (11-6.6/0.415kV) transformers and then switching the network for 11kV operation.

A8.9 EGMONT AREA

A8.1.15 MAJOR PROJECTS

CAMBRIA SUBSTATION 33KV LINE & TRANSFORMER

Constraint

The Cambria substation supplies the Hawera CBD and the surrounding urban and rural areas. One major industrial consumer, Lowe Walker Freezing Plant, consumes a significant part (4MVA) of its demand.

Cambria takes its 33kV supply from Hawera GXP by two (each 3km) pressurised oil cables (installed in 1968). Each cable is 3-core Aluminium with a cross sectional area of 0.43inch2, nominally 277mm^2 and has no manufacturer's rating, but are believed to be good for 17 MVA.

The substation contains two 12.5/17 MVA transformers. Its security class is AAA, which requires uninterrupted supply in n-1 situation.

Cambria Substation 2030 expected demand of 17.6 MVA would exceed its single 33kV line and transformer's capacity.

Preferred Option

The most feasible option is to replace the existing transformers with two larger units and present two 33kV cables (each 3km) with larger capacity cables. This will secure the load at Cambria and provide adequate capacity for anticipated future demand.

A8.1.16 MINOR PROJECTS

MANAIA SUBTRANSMISSION

Constraint

Manaia substation is supplied by a short section of single circuit 33kV line. This tees off the Hawera GXP-Manaia-Kapuni 33kV ring. The tee connection and single circuit expose Manaia to reduced N-security and has higher risk of outages. This means the security does not meet our standards.

The capacity of the Hawera-Manaia circuit is also constrained under future peak loading for contingencies where the Hawera-Kapuni line is out of service.

Options

Options considered include:

1. **Change tee to 'In and Out':** This requires a short section of new line from the tee into Manaia substation, and additional switchgear at Manaia.
2. **Increase 11kV backfeed:** While reducing risk of extended non-supply, this cannot meet the security class requirements due to the switched back-feed.
3. **Second circuit from Hawera to Manaia:** A second line from Hawera GXP to Manaia, plus appropriate switchgear and protection would resolve the N security section of line, plus the pending capacity constraint when back-feeding Kapuni.

Preferred Option

The preferred solution is Option 1 – to construct a second section of line from the tee into Manaia substation and reconfigure as an in-and out connection. This would allow Hawera-Manaia-Kapuni to operate as a fully secure, closed ring. Option 3 would also resolve the pending capacity constraints but the cost is prohibitive. Relatively low cost thermal upgrades of the existing line may be instead be sufficient, and will be considered when required as part of routine project planning.

KAPUNI & MANAIA SUBSTATION THIRD 33KV LINE

Constraint

The Kapuni and Manaia substation takes 33kV supply from a ring network, that consists of Hawera GXP to Kapuni (16.4 km long), Kapuni to Manaia tee-off (6.9 km) and Manaia tee-off to Hawera (13 km). The Manaia 33 kV line is 3.5 km long from this tee-off. The Manaia Subtransmission project, as mentioned above, will construct a second 33kV line from this tee-off point.

The security class of Kapuni and Manaia is AA+ and AA respectively.

The 33kV ring has a capacity of 15 MVA in n-1 situation. This capacity is inadequate for the load growth of Kapuni and Manaia substation, 7.2 MVA and 7.8 MVA respectively in 2030. In addition, Manaia 33kV bus voltage would drop to 89% in N-1 situation and Manaia transformer tap position would be just one tap above its limit

Preferred Option

The most feasible option is to replace present Hawera to Manaia tee single overhead 33kV line (13 km) with two circuits overhead 33kV line and to install Manaia Subtransmission project 33kV switchboard at Manaia tee-off location instead of Manaia substation.

MANAIA SUBSTATION SECOND TRANSFORMER

Constraint

The Manaia substation supplies Manaia township, as well as surrounding rural areas. One industrial consumer, Yarrows Bread, takes a significant part (1.7 MVA) of its load (7.7MVA). The substation contains one 10/12.5MVA transformer.

The size and nature of the load connected to the Manaia is at risk from non-supply in the event of the transformer outage. Two-third of its load can be back-fed from neighbouring substations such as Kapuni (mostly) and Tasman 11kV network. But requires the installation of a mobile regulator which is not readily available, as most of the time they (presently two) are being used in another site.

Preferred Option

The most feasible option is to install a matching second 10/12.5MVA 33/11kV transformer together with new transformer pad and bunding.

A8.10 WHANGANUI AREA

A8.1.17 MAJOR PROJECTS

There are no major projects planned for the Whanganui area in the near future.

A8.1.18 MINOR PROJECTS

ROBERTS AVE TO PEAT ST 33KV CIRCUIT

Constraint

The existing 33kV subtransmission network in Whanganui uses a meshed architecture that relies on switched, cross GXP back-feeds to provide security. This results in numerous issues where the subtransmission or substations do not strictly meet our security standards. The issues related to this project can be summarised as follows:

1. Peat St is our most important substation in Whanganui, but only has a single (N-security) 33kV circuit from Brunswick GXP. This cannot provide the no-=break N-1 security (class AAA) which our standards require for a substation serving a load in excess of 20MVA, including parts of the city's CBD.
2. Switched backup 33kV supply is available from substations fed from Whanganui GXP, but the capacity of this is also constrained.
3. Roberts Ave substation is also served by a single N secure 33kV line from Brunswick GXP. It has no alternate 33kV supply, switched or otherwise, and relies heavily on 11kV back-feed from Peat St substation.
4. Kai Iwi substation is fed from Peat St and suffers from the same security issues.
5. Substations fed from Whanganui GXP (Hatricks Wharf, Taupo Quay and Beach Rd) all rely to some degree on capacity from Brunswick GXP to Peat St for certain contingencies on the Whanganui GXP side. Increased capacity into Peat St is required to secure these substations at peak loading.

Note – While the single, hence N security, 220/33kV transformer at Brunswick is a security issue directly impacting Peat St load, the project scope and analysis of options did not consider this issue. It is common to all options and cannot be resolved by subtransmission upgrades on the Brunswick side of the city. The GXP single transformer issue can be, and is in part, addressed by proposals for subtransmission upgrades on the Whanganui side. This is a strategy adopted following earlier higher level (ie GXP and transmission) consideration of regional options, in consultation with Transpower.

Options

The following network options have been considered:

1. Second 33kV circuit from Brunswick GXP to Peat St.
2. Construct a new 33kV circuit between Roberts Ave and Peat St substations and upgrading the existing 33kV circuit between Brunswick GXP and Roberts Ave substation
3. Additional 11kV back-feeds from neighbouring substations.
4. Additional 33kV circuit(s) from Brunswick GXP into Castlecliff substation.

Preferred Option

The preferred project is option 2, which involves the construction of a new 33kV circuit between Roberts Ave and Peat St substations and upgrading the existing 33kV circuit between Brunswick GXP and Roberts Ave substation. This option will enable a secure supply to Peat St and Roberts Ave substations, enabling them to meet our security levels.

In conjunction with the Whanganui GXP to Taupo Quay new circuit project (Taupo Quay Second Circuit), Option 2 will ensure all of the key Whanganui city substations, including Taupo Quay, Hatricks Wharf, Peat St as well as Beach Rd, Castlecliff and Roberts Ave substations, will meet our required security levels.

Option 1, which involves the construction of a new circuit between Brunswick GXP and Peat St substation while providing a secure supply to Peat St substation, will not resolve the security of supply issue at Roberts Ave substation. Hence this option was not favoured.

Increased 11kV back-feed (Option 3) would not have addressed the systemic network architecture issues, and would have been unlikely to provide sufficient capacity either. The Castlecliff alternative (Option 4) looked promising in light of urban growth in this area, but ultimately the length of new circuit proved too costly.

TAUPO QUAY SECOND CIRCUIT

Constraint

This project addresses a number of network constraints, but most particularly:

1. Taupo Quay and Hatricks Wharf are each fed by single 33kV circuits, but the substations are paralleled at the 11kV bus. There is insufficient capacity in either circuit to carry the total peak load following a fault on the other circuit.

2. The 33kV to Taupo Quay also supplies rapidly growing industrial demand at Beach Rd. This 33kV also needs to supply Castlecliff when the normal supply via Brunswick & Peat St is interrupted. The capacity is not sufficient at peak loadings.
3. There are multiple constraints if trying to backfeed Taupo Quay via Brunswick, Peat St, Castlecliff and Beach Rd. If Taupo Quay had full N-1 security from Whanganui GXP, this contingency would not be considered.
4. Peat St is the most critical substation in Whanganui, but if the single 220/33kV GXP transformer at Brunswick is unavailable, Peat St, and all other Brunswick load, must be supplied from Whanganui GXP. Significantly greater capacity is required, especially into Taupo Quay or Hatricks Wharf, to secure all substations under such contingencies.

Options

Due to the highly inter-meshed nature of the network in Whanganui, analysis needs to consider multiple substations, constraints and the matrix of options which can address these. Proposed options below are a result of this wider analysis but are options (or component projects of overall development path options) which are particularly pertinent to the Taupo Quay constraints identified above.

1. **Second Circuit from Whanganui GXP to Taupo Quay:** A second dedicated circuit for Taupo Quay would provide full N-1 security from Whanganui GXP into Taupo Quay. Additional switchgear and protection would also be required. Subject to property negotiations, much of the circuit might need to be underground.
2. **New (second) circuit from Whanganui GXP to Hatricks Wharf:** This would require extensive property and consenting cost, which could necessitate an underground cable via the existing road reserve, similar to options 1 for most of the route. Additional 33kV switchgear and protection would be needed at Hatricks Wharf, which is highly space-constrained.

Preferred Option

The preferred project is Option 1, which involves the construction of a new 33kV circuit between Whanganui GXP and Taupo Quay substation. This option will relieve the capacity constraints between Whanganui GXP and Taupo Quay/ Hatricks Wharf substations, including enabling the backup of Castlecliff and Peat St substations during contingencies.

Option 1 will ensure that our required security levels are met at Taupo Quay, Hatricks Wharf, Castlecliff and Peat St substations.

Option 2 involves the construction of a new 33kV circuit between Whanganui GXP and Hatricks Wharf substation. Space limitations at Hatricks Wharf substation mean terminating an additional 33kV circuit there will be difficult. While this option will provide our required security level at Peat St substation, it will not provide the capacity to ensure the required security levels to the Taupo Quay, Beach Rd and Castlecliff substations. Hence this option was not favoured.

WHANGANUI GXP BUS B TO HATRICKS WHARF

Constraint

During a Brunswick GXP outage at year 2029 demand forecast, supply between Whanganui GXP and Hatricks Wharf sees insufficient capacity on both direct buried cables and conductor portion. This line parallels with the WGN GXP Bus A supply to Hatricks Wharf.

Preferred Option

The most feasible option would be to upgrade capacity to above 23MVA, removing the Brunswick GXP outage scenario constraint.

An interim year commitment to dual transformers at Brunswick GXP, might reduce the risk associated with this forecast constraint.

WHANGANUI GXP BUS A TO HATRICKS WHARF

Constraint

During a Brunswick GXP outage at year 2029 demand forecast, supply between Whanganui GXP and Hatricks Wharf sees insufficient capacity on conductor line. This line parallels with the WGN GXP Bus B supply to Hatricks Wharf.

Preferred Option

The most feasible option would be to upgrade capacity to above 23MVA, removing the Brunswick GXP outage scenario constraint.

Solution would be in addition to IR2922, a river crossing cable project underway in 2019 with a $750k budget.

An interim year commitment to dual transformers at Brunswick GXP, might reduce the risk associated with this forecast constraint.

HATRICKS WHARF TO PEAT ST

Constraint

Hatricks Wharf is centrally located on the sub transmission ring between Brunswick and Whanganui GXP stations. This centrality requires Hatricks to provide bi-directional high capacity lines to Peat St, Whanganui and Taupo Quay.

Under a Brunswick GXP outage at year 2029 demand forecast, supply between Hatricks Wharf and Peat St becomes over loaded on both 630mm cable and conductor portion.

Preferred Option

The most feasible option would be to upgrade cable and conductor capacity to minimum 32MVA, providing sufficient contingent capacity to the steadily growing Peat St Sub demand.

An interim year commitment to dual transformers at Brunswick GXP would not impact this project, since a commensurate demand reverse supply from Peat Street to Hatricks Wharf is also required during a Whanganui GXP constraint.

PEAT ST TO CASTLECLIFF

Constraint

Taupo Quay sub transmission forms part of the Peat St, Beach Rd, Castlecliff and Hatricks Wharf ring. At year 2029, forecast demand outage modelling of a malfunction of the Taupo to Beach conductor, shows the alternate Peat St to Castlecliff ring loading above rating on both cable and conductor.

Preferred Option

The most feasible option would be to upgrade both cable and conductor to minimum 24MVA, allowing supply of Castlecliff and Beach Road Subs at forecast demand levels.

WHANGANUI GXP TO WHANGANUI EAST

Constraint

The Whanganui East substation supplies the residential area on the eastern side of the Whanganui River and rural area to the east of Whanganui City. A security level of AA is intended due to the type of load the substation supplies.

The substation is supplied by one single 33kV circuit from Whanganui GXP (N security) and contains one supply transformer. There is potential for loss of supply at the substation for a transformer or sub transmission fault, with limited back feed capability from distribution network.

Preferred Option

The most feasible option would be to install a second sub transmission circuit and a second 17MVA transformer at the substation, improving the substation’s security. The supply point of a second circuit would be determined during the concept design stage, with two options visible at present.

Alternatives such as increased 11kV back feed capability would be costly, due available transfer capacity, even with substantial distribution upgrade.

PEAT STREET TRANSFORMER UPGRADE

Constraint

Peat St modelled past year 2029 forecast demand, shows a potential for an outage of one transformer to place the other transformer at 100% loading, if forecast growth increases.

10/12.5/20 MVA Tx loaded to 20.1MVA during a single transformer outage event. There exists a requirement to maintain AAA security class.

Preferred Option

The most feasible option would be to upgrade both Peat St transformers to a capacity that allows Sub demand growth beyond 20MVA and firm capacity well beyond 20MVA. Preliminary suggestion is 2x 30MVA transformers, noting this capacity is beyond the normal Powerco materials range. This project is presently considered a contingency, requiring further analysis ongoing.

TAUPO QUAY TRANSFORMER OUTAGE / HATRICKS WHARF TRANSFORMER UPGRADE

Constraint

Under a Taupo Quay transformer outage at year 2029 demand forecast, supply must be sourced through a Hatricks Wharf distribution interconnect. Under this scenario, line loading of the distribution cable is nearing maximum capacity rating and the single Hatricks Wharf transformer exceeds capacity.

Additionally, the conductor portion of converged Whanganui cables, before the river crossing portion, sees demand well above rating. This is to be upgraded under a separate listed project, or supply could be via Brunswick GXP.

Preferred Option

The most feasible option would be to upgrade interconnecting distribution cable, supply side conductor and perhaps Hatricks Wharf transformer capacity to well above 26MVA, to allow for growth. Upgrade fo the transformer would prompt a similar project at Taupo Quay, so further analysis and planning is required to determine full scope.

The above-mentioned solutions would be in addition to IR2922, a 2019 bride crossing cable project currently underway with a $750k budget.

CASTLECLIFF TRANSFORMER UPGRADE

Constraint

Castlecliff Sub modelled at year 2029 forecast demand shows an outage of one transformer will overload the other under normal configuration. The 10MVA transformer would be loaded to above 12MVA during a single outage event. There exists a requirement to maintain AA+ security class.

Preferred Option

The most feasible option is to upgrade both transformers to provide firm capacity well above 10MVA, factoring for future growth. Present time suggestion would 2x 17MVA transformers, though exact rating will be decided during the conceptual design phase.

There might exist an opportunity to re-use 15MVA transformers from the Kelvin Grove upgrade, condition assessment pending, introducing cost control.

BRUNSWICK GXP TO ROBERTS AVENUE CABLE

Constraint

Supply to Peat St from Brunswick GXP is constrained upon an outage of the 5.49km direct path conductor.

There is a 2019 project delivering a new large capacity cable between Roberts Avenue and Peat St Subs, which will provide an alternate supply path in the event of malfunction of the main direct conductor.

As demand grows at each of the substations on the Brunswick and Whanganui GXP sub transmission ring, there becomes the requirement to increase capacity between Brunswick GXP and Roberts Avenue Sub. This would ensure adequate alternate path capacity between Brunswick GXP and Peat St, and Subs beyond.

Preferred Option

The most feasible option is a cable upgrade for the 3.55km conductor between Brunswick GXP and Roberts Avenue Sub, ensuring adequate contingent supply through Roberts Avenue.

ROBERTS AVENUE UPGRADE AND SECOND TRANSFORMER

Constraint

The Roberts Avenue substation is situated in Aramoho, supplying the Aramoho industrial area and surrounding residential and rural areas.

The substation is supplied by one single 33kV circuit from the Brunswick GXP (N security) and contains one supply transformer.

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or sub transmission fault. There is also limited back feed capability from the distribution network. The Roberts Avenue substation does not presently meet our required security level.

Preferred Option

The most feasible option would be to install larger transformers in the substation, improving the substation's security level.

Alternatives such as increased 11kV back feed would be costly as there is not adequate transfer capacity.

BLINK BONNIE SECOND SUPPLY AND TRANSFORMER

Constraint

The Blink Bonnie substation is situated to the east of Whanganui city, adjacent to Transpower's Whanganui GXP. It supplies the rural loads to the south of Whanganui.

This project addresses particular development constraints:

- The substation contains a single supply transformer and is has N-1 sub transmission switching capability. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited back feed capability from distribution network.
- Due to these constraints, the Blink Bonnie substation does not presently meet our required security level.

Preferred Option

The most feasible option would be to install a second supply transformer at the substation. This will improve the security level at the substation.

Alternatives such as increased 11kV back feed would be costly as there is not adequate transfer capacity

KAI IWI 11KV UPGRADE

Constraint

This project addresses particular development constraints:

- The Kai Iwi substation is situated northwest of Whanganui and supplies the Whanganui city water pumping station and the residential area on the east side of the Whanganui River and rural area to the east of Whanganui. Kai Iwi's security level is A2. Its 11 kV backup supply is not adequate for the supply of the substation load, in particular for starting the pumps at city water supply.
- The substation is supplied by one single 33kV circuit from the Peat Street substation (N security) and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or sub transmission fault.

Due to these constraints, the Kai Iwi substation does not presently meet our required security level.

Preferred Option

The most feasible option would be to increase 11kV back feed through distribution. Due to the long length and high impedance of the conductors, upgrade to 22kV could be cost effective so remains an option. Alternatively, installing the second sub transmission supply and transformer for the substation would be costly as the substation location is quite remote.

HATRICKS WHARF TO BEACH ROAD NEW LINE

Constraint

The existing ring from WGN to BRK encompasses Taupo Quay, Beach Road, Castlecliff and Peat St Subs. This leaves two options for supplying Castlecliff and Beach Road, one of which heavily loads the main supply lines out of WGN GXP. Supply from Brunswick GXP to Beach Road, under select scenarios, must pass through Roberts Avenue, Peat St, then Castlecliff or Hatricks Wharf and Taupo Quay.

Preferred Option

A most feasible option is a new line between Beach Rd and Hatricks Wharf, which would provide a more direct route supply option via advancement toward a meshed configuration.

The solution for the conductor portion would upgrade to a large capacity underground cable, allowing full utilisation of the parallel Bus A and Bus B lines, all the way to Hatricks Wharf Sub

A8.11 RANGITIKEI AREA

A8.1.19 MAJOR PROJECTS

Although there are several issues affecting the security of the substations in the area, most of these are low risk and major upgrades to the subtransmission 33 kV circuits or the substations themselves are not cost effective or feasible.

Replacement of the Bulls and Arahina transformers is planned, but this will not address security issues. Switchgear replacement at Arahina, Pukepapa and Rata may also be considered under the renewal program.

A project affecting an identified issue at the Bulls substation is covered in the Manawatu Area. The Sanson substation is currently supplied by a single circuit from the Bunnythorpe GXP. Resolution of this issue will likely also provide additional 33 kV security for Bulls.

A8.1.20 MINOR PROJECTS

BULLS SECOND TRANSFORMER

Constraint

The Bulls substation supplies Bulls Township, some large industrial customers and its surrounding rural areas.

The substation is supplied by one single 33kV circuit from the Marton GXP (N security) and contains one supply transformer.

This project addresses particular development constraints:

- The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or sub transmission fault.
- Bulls is presently supplied by a 10/12.5MVA transformer. Security class is AA. This Sub has difficulty back feeding across the 11kV for a sub transmission outage.

At year 2029, forecast modelling shows the single transformer at only 47% loading.

Preferred Option

The most feasible option is to install a second-hand WGN East transformer, after refurbishment, which will be available late FY19. The addition of this second transformer would ensure full AA security across incomers and transformers.

This project initiative is intended to improve operational flexibility and security, with resultant improved access for any future maintenance and feeder reliability works.

NEW SUBSTATION LAKE ALICE

Constraint

Bulls and Pukepapa Subs supply both residential and commercial customers, via Parewanui and Lake Alice feeders respectively.

Demand is approaching voltage support limits on these feeders, but there are still customer load increase requests being submitted for approval.

Significant backbone conductor upgrades would have an impact on SAIDI targets and would likely not provide the step change required.

Discussions have been ongoing for some time with local large irrigators, regarding the prospect of transferring their generator loads onto the main network. Successful conversion would mean a MW scale step change of demand on both feeders.

Some sub transmission extension preparatory work has already been completed along the Lake Alice feeder, in the form of overbuilt line, though has not been extended back to a Sub yet.

Preferred Option

The most feasible option is for a new Substation at the end of Lake Alice Feeder, to supply potential irrigation conversions from gensets. Since Bulls has more Sub Trans spare incomer capacity than Pukepapa, the 33kV supply for the new Sub would come from Bulls Sub, although it technically could be either Bulls or Pukepapa.

An accompanying project is IR3544, which is an interim of cable intertie between feeders, plus some hardware installed for future operational segregations.

ARAHINA SECOND SUPPLY AND TRANSFORMER

Constraint

The Arahina substation supplies urban and rural loads. It has a security class of A1 but AA is intended.

The substation is supplied by one single 33kV circuit from Marton GXP (N security) and contains one supply transformer.

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or sub transmission fault. A fault on Arahina sub transmission supply will result in an outage on Rata substation as well. There is also limited back feed capability from distribution network.

Due to these constraints, the Arahina substation does not presently meet our required security level.

Preferred Option

The most feasible option is to install a second sub transmission supply and transformer at the substation. This will improve the security level.

Alternatives such as increased back feed would be costly as there is no adequate transfer capacity, even with substantial distribution upgrade

PUKEPAPA SECOND TRANSFORMER

Constraint

The Pukepapa substation is adjacent to Transpower's Marton GXP and supplies Marton's surrounding rural residential and irrigational loads. It is the main backup supply for the Arahina substation and to a lesser extent to the Bulls substation. Its security level is A1, though demand is forecast to approach 5MW after 2030.

The substation contains a single supply transformer and is has N-1 subtransmission switching capability. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from distribution network.

Due to these constraints, the Pukepapa substation does not meet our required security level.

Preferred Option

The most feasible option would be to install a second transformer to the substation. This will improve the security level.

Alternatives such as increased 11kV backfeed would be costly as there is no adequate transfer capacity.

RATA 11KV UPGRADE

Constraint

The Rata substation supplies Hunterville town and the surrounding rural areas. Most of Its distribution network is at 22kV.

The substation is supplied by one single 33kV circuit from the Arahina substation (N security) and contains one supply transformer.

The demand has exceeded class capacity, sustained at nearly 3MVA and there is potential for loss of supply at the substation for a transformer or sub transmission fault.

Due to these constraints, the Rata substation does not presently meet our required security level.

Preferred Option

The most feasible option is to increase back feed through distribution. This will improve the security level.

Alternatively installing the second sub transmission supply and transformer for the substation would be costly as the substation location is quite remote.

TAIHAPE SECOND TRANSFORMER

Constraint

The Taihape substation supplies Taihape Township's urban and rural load.

The substation contains a single supply transformer and has N-1 sub transmission switching capability.

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited back feed capability from distribution network.

Due to these constraints, the Taihape substation does not presently meet our required security level.

Preferred Option

The most feasible option would be to install a second transformer at the substation. This will improve the security level.

Alternatives such as increased 11kV back feed would be costly as there is no adequate transfer capacity.

WAIOURU 11KV UPGRADE

Constraint

The Waiouru substation is situated just south of Waiouru. It supplies the Waiouru Army camp and the surrounding rural areas.

The substation is supplied by one single 33kV circuit from Mataroa GXP (N security) and contains one supply transformer.

The demand has exceeded the class capacity, sustaining around 2.9MVA and there is potential for loss of supply at the substation for a transformer or sub transmission fault.

Due to these constraints, the Waiouru substation does not presently meet our required security level.

Preferred Option

The most feasible option is to increase the 11kV distribution back feed capability. Due to the long lengths and high impedances of the conductors, upgrades to 22kV could also be a cost-effective option.

Installing a second sub transmission supply and transformer for the substation would be too costly.

A8.12 MANAWATU AREA

A8.1.21 MAJOR PROJECTS

PALMERSTON NORTH (FERGUSON SUB)

Constraint

The Palmerston North CBD and commercial / industrial areas are mainly supplied by three zone substations (Pascal St, Main St and Keith St). A number of constraints/issues impact the supply to these important substations:

1. Four 33kV oil filled cables form part of the interconnected network serving these inner-city substations. The condition of the cables is difficult to assess, and the incidence of cable leaks is increasing. They have been de-rated to reduce the thermal cycling stress on the cable joints. It also recognises past exposure to thermal cycling and to potentially large circulating currents when paralleling across GXPs. These factors make the continued operation of these cables a very high risk. Maintenance and repair costs are also very high since they are located in dense urban road networks and not easily accessible.
2. During 2015 the Main St substation peak load was ≈28MVA. The two oil filled 33kV cables supplying Main St have a de-rated capacity of ~17MVA, meaning Main St is well below the required no break N-1 (AAA class) security required.
3. During 2014 the peak loads on the Main St and Pascal substations exceeded their respective N-1 firm transformer capacities. Again this means the security to these critical inner city substations is below that required.
4. During 2015 the Main St, Keith St and Kelvin Grove substation load was ≈55MVA and is supplied via a meshed set of three overhead circuits connected to the Transpower Bunnythorpe GXP. The N-1 capacity is exceeded at peak loads. The northern arm of the Tararua Wind Farm can inject up to 34MW, but this does not provide additional security.
5. During 2015 the combined peak load on the Pascal and Kairanga substations was ≈40MVA and has exceeded the N-1 firm capacity of the 33kV network.
6. During 2015 the peak load on the Kairanga substation was ≈17MVA. The substation is supplied via two circuits. One of the circuits includes an oil filled cable that has been de-rated to 12.7MVA. Kairanga substation (also requiring no break class AAA security) does not meet our standards.
7. During 2015 the peak load supplied by the Transpower Bunnythorpe GXP marginally breached the substation's 100MVA transformer firm capacity. Upgrading Bunnythorpe would be difficult and expensive. By contrast the Transpower Linton GXP is moderately loaded.

Options

Analysis of strategic options for the wider region, considering GXP and subtransmission architecture, concluded that reinforcement of the city's supply, particularly for the CBD, should concentrate on utilising the available capacity from Linton GXP. This strategy would necessitate a step change in subtransmission investment to provide new circuits from Linton GXP right into the city. This would be a long term investment, facilitating growth for some time, but would also address the immediate and severe risks exposed by the existing under-rated and poorly performing oil filled cables interconnecting the inner city substations.

Furthermore, in considering the growing risks associated with the exceedance of firm capacity at both Pascal St and Main St substations, together with limitations on the 11kV network from these substations feeding the CBD, the long term development strategy for the city proposed to construct a new zone substation on the south side of the city, with a future northern side equivalent substation constructed in future as and when load growth determined this was necessary.

In this context, the following options were shortlisted:

1. Construct a new substation at Ferguson, install two new 33kV circuits from the Linton GXP to Ferguson substation and two new 33kV circuits from Linton GXP to the Main Street substation.
2. Construct a new substation at Ferguson, install a new 33kV circuit between the Linton GXP and the Ferguson substation, install a new 33kV circuit between Linton GXP and the Main Street substation, install a new 33kV circuit between Main St and Ferguson and divert the second Linton GXP to Pascal Street 33kV circuit to connect to Ferguson substation.
3. Construct a new substation at Ferguson, install two new 33kV circuits between the Linton GXP and the Ferguson substation. Install two new

33kV circuits between Main St and Ferguson, and install a new 33kV circuit between Pascal St and Ferguson.

The deployment of non-network strategies has also been considered in the context of this project:

- Fossil fuelled generation or alternate energy sources: Gas is available and feasibility has been investigated, particularly in regard to Cogen. No viable opportunities have yet been identified and environment/consenting would be challenging, especially within the CBD.
- Renewable generation: No viable options have been identified at the scale required, especially within the CBD. The 33kV network already has wind generation injected from the northern arm of the Tararua Wind Farm. However, the intermittent availability of this, without storage, precludes any benefit to security.
- Storage, efficiency and demand side responses: Widely distributed storage and solar PV, or efficiency programmes could have offered possible demand side resources but the flat daytime load profile of the commercial loads render these less effective. The capacity needed already and the time frame also preclude such options which require complex coordination across multiple parties. In all instances, these options would only serve to mitigate risk until network solutions could be deployed.

Preferred Option

Option 3 will deliver the highest reliability benefits to the Palmerston North CBD. It will alleviate all the existing subtransmission constraints and, with the construction of a new substation at Ferguson, relieve the capacity issues at Main St and Pascal St substations. With this option, all three existing CBD substations will meet our required security levels.

The transfer of Main St onto Linton GXP and the new Ferguson substation being connected to Linton offloads Bunnythorpe and also restores security to the 33kV circuits from Bunnythorpe into Keith St. The oil filled cables are no longer critical to CBD security and can be retired or deployed as emergency backup as appropriate.

Option 1 is not favoured as it is less cost effective, and has less flexibility to staged development. As there are four cables running along the same route, there is an increased risk of the combined failure of the four cables due to a contingent event. A wider corridor required for the four cables will likely result in increased consenting and easement acquisition risks.

Option 2 is not favoured as it will have greater interconnection of the CBD substations, which will require more complex protection coordination systems, and hence a potentially lower reliability.

Due to recent failures and reliability issues with the oil filled cables, it has been necessary to undertake urgent work to restore security to the city's commercial district. This resulted in construction of a temporary overhead line which will later be removed. It was also necessary to bring forward work to effectively retire all four oil filled cable circuits 5-10 years earlier than previously planned. While the urgent work has been necessary to address the immediate and critical supply security risks, it may now be necessary to review the overall long term development strategy for the city, to confirm whether the remaining works and timing are still appropriate given the greater capacity of the replacement circuits and the altered network configuration.

SANSON – BULLS 33KV LINE

Constraint

The northern region of our Manawatu Area is supplied from Bunnythorpe GXP via two 33kV circuits to Feilding substation. From Feilding there is a single 33kV overhead line to Sanson substation, and another long 33kV circuit to Kimbolton substation.

Sanson substation supplies Sanson township, surrounding rural properties and also the Royal New Zealand Air Force (RNZAF) Ohakea air base. Past long-term plans have proposed a 33kV link between Sanson and Bulls (one of the options below) and a 33kV cable operated at 11kV was installed some years ago to supply Ohakea directly from Sanson substation at 11kV. The intention is to upgrade this to 33kV and install a small switching station at Ohakea when the 33kV is extended through to Bulls.

The following constraints presently exist:

1. Sanson is supplied by a single 15km long 33kV overhead line, affording only N security.
2. The 2015 peak demand on the Sanson substation was ≈9MVA. The 11kV back-feed is well below this and maintenance or faults on the 33kV line result in prolonged or widespread outages. This provides security well below the AA+ class prescribed by our standards.
3. The 2015 peak demand on the Bulls substation was ≈6MVA. Bulls is also supplied from a single 33kV line, from Marton GXP. Bulls load can be partially restored (≈3MVA) via switching on the 11kV network, but this also does not meet the required AA security class.
4. The Ohakea base security is sub-optimal considering the critical load supported.
5. The total demand (of Feilding, Sanson and Kimbolton substations) on the Bunnythorpe- Feilding circuits is approaching their N-1 capacity.

Options

The N security resulting from the single Feilding-Sanson 33kV line, means alternate 33kV circuits are the most effective solutions. Similarly, non-network options could not address the intrinsic need for secure subtransmission.

The following network solutions were shortlisted:

1. A new Feilding-Sanson 33kV line.

2. Complete the Sanson-Bulls 33kV link, coupled with a new 33/11kV substation to supply the Ohakea air base, installing an automatic load transfer facility at Sanson substation and thermally upgrading the Bunnythorpe to Feilding 33kV lines.

Preferred Option

Option 2 is currently preferred as it will resolve the security of supply issues at the Sanson and Bulls substations as well as the Ohakea air base. The new 33kV link would involve the use of an existing ≈3.5km 33kV cable (presently operating at 11kV) from Sanson to Ohakea. There would also be the construction of a new 2km overhead line along SH1, followed by ≈2.5km new underground cable across the Rangitikei River and through the Bulls township to the Bulls substation. A new 33/11kV substation would also need to be constructed at Ohakea to supply the existing (and future) air base load.

In Option 2, the Sanson substation can be normally supplied from Bulls via the new 33kV Bull-Ohakea-Sanson line. An automatic load transfer can switch supply back to Feilding when necessary. This would help reduce loading on the Bunnythorpe GXP to Feilding 33kV circuits, and the Bunnythorpe GXP.

The cost of the Sanson-Bulls link (Option 2) is estimated to be lower than a 2nd dedicated circuit from Feilding (Option 1). Option 1 also would not improve security at Bulls, nor assist to offload Feilding circuits or Bunnythorpe GXP.

SECOND FEILDING ZONE SUB AND SUBTRANSMISSION

Constraint

The Feilding substation supplies Feilding Township and the surrounding commercial, industrial, residential and rural load. Its security level is AAA. The demand growth is high in areas covered by Feilding substation. In addition to the risk of exceeding substations N-1 capacity, the high feeder demand growth can cause supply security issues to critical loads in future.

Preferred Option

The most feasible option is to establish a new zone substation to offload Feilding substation. This will reduce the length and demand of the feeders and consequently, reduces the risk of feeder outages.

Alternatives such as increased offload to existing zone substations would be impractical and limited.

NEW ASHHURST ZONE SUBSTATION AND SUBTRANSMISSION

Constraint

The Kelvin Grove substation supplies the commercial, industrial and residential load in Palmerston North city and the rural load to the north of the city. Its security level is AAA. The demand growth is high in areas covered by the Kelvin Grove substation. In addition to the risk of exceeding substations N-1 capacity, the high feeder demand growth can cause supply security issues to critical loads in future.

Preferred Option

The best long-term solution is to establish a new zone substation, named Ashhurst, to offload the existing Kelvin Grove substation. This will reduce the lengths and demand of the feeders and consequently reduces the risk of feeder outages.

Alternatives such as increased offload to existing zone substations would be impractical and limited.

A8.1.22 MINOR PROJECTS

KAIRANGA TRANSFORMERS

Constraint

The Kairanga substation supplies residential, rural and industrial loads in the southern parts of the Palmerston North area. The substation contains two 15MVA rated transformers. The demand has exceeded the transformer firm capacity. High growth is expected on this substation due to both residential and agricultural developments.

Options

Options considered include:

1. **Increased 11kV back-feed:** This is conceptually possible, but the development of the 11kV network presupposes security standards at the zone substation. A variation to these recognised architectures would not meet our standards and create operational anomalies due to the 11kV automated switching schemes needed. Ultimately, the substantial growth signalled by council planning in and around Kairanga would negate this as a practical long-term solution.
2. **Upgrade transformers:** We have adopted a standard 16/24MVA transformer for large capacity urban substations. Upgrading to this capacity at Kairanga would provide for the immediate demand and growth in the next decade, beyond which an additional substation would be appropriate.
3. **Install a 3rd transformer:** This would be a non-standard substation configuration and quite costly considering expansion of switchyards, transformer bays and the whole substation site.

Preferred Option

The proposed solution is to replace the existing transformers with two new 24MVA units. This will provide adequate capacity for future demand with appropriate security, and standard operational and substation configurations.

SANSON TRANSFORMERS

Constraint

The Sanson substation supplies Sanson township, Rongotea and Himatangi areas, and the Ohakea Air Base. The substation contains two 7.5MVA rated transformers. Demand has exceeded the firm capacity of the transformers. There is also limited back-feed capability from the 11kV distribution network.

Options

Options considered include:

Increased 11kV back-feed: Sanson is quite remote from other substations, and due to the N security 33kV subtransmission, most practical 11kV back-feed upgrades have already been exploited.

Upgrade transformers: Upgrading both transformers would provide adequate security for the substation loads.

Preferred Option

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate security for future demand. Options to utilise the existing transformers at another site, or make use of larger ones from another site at Sanson will be considered at the time

KELVIN GROVE TRANSFORMERS

Constraint

The Kelvin Grove substation supplies commercial, industrial and residential loads in Palmerston North and the rural load to the north of Palmerston North city. The substation contains two transformers rated 15MVA. The demand has exceeded the firm capacity of the transformers.

Options

Options considered include:

1. **Increased 11kV back-feed:** This is conceptually possible, but the development of the 11kV network presupposes security standards at the zone substation. A variation to these recognised architectures would not meet our standards and create operational anomalies due to the 11kV automated switching schemes needed. Ultimately, the strong growth at Kelvin Grove would negate this as a practical long-term solution.
2. **Upgrade transformers:** We have adopted a standard 16/24MVA transformer for large capacity urban substations. Upgrading to this capacity at Kelvin Grove would secure the substation and provide for the anticipated growth.

Install a third transformer: This would be a non-standard substation configuration and quite costly considering additional switchgear, transformer bays and the necessary space at the substation site

Preferred Option

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate capacity for the future demand with appropriate security.

FEILDING TRANSFORMERS

Constraint

The Feilding substation supplies Feilding and the associated commercial, industrial, residential and rural loads in the area. The substation contains two transformers nominally rated at 21MVA each. The demand has exceeded the firm capacity of the transformers. Due to limitations in back-feed capability, the security of supply will not be adequate as load grows.

Options

Options considered include:

1. **Increased 11kV backfeed:** The distance to Feilding from comparably sized secure substations largely precludes this option.
2. **Upgrade transformers:** We have adopted a standard 16/24MVA transformer for large capacity urban substations. Upgrading to this capacity at Kelvin Grove is viable, but notably does not provide a particularly large increase in firm capacity. Growth would erode this relatively quickly. 30MVA units are also feasible but will again create a non-standard configuration and mean that fault levels can be hard to manage.
3. **Install a third transformer:** This would be a non-standard substation configuration, which we would prefer to avoid because of the additional protection complexity.
4. **New Zone Substation:** A new zone substation for Feilding is a viable long-term strategy but incurs a very high cost (>$10m compared with $2m for the transformer upgrade only). Consideration of such a high cost major project is more in the scope of high-level analysis associated with the Feilding subtransmission (also close to N-1 capacity), and the long-term growth patterns in the region and Feilding itself.

Preferred Option

The proposed solution is to replace the existing transformers with two larger units. This solution is likely to be reviewed closer to the expected upgrade date. In particular, we will attempt to firm up the longer-term development path and determine whether another zone substation in Feilding is a more appropriate long-term strategy.

FEILDING-SANSON SUBTRANSMISSION UPGRADE

Constraint

Sanson Sub takes its subtransmission supply by one 14.5km long line from Feilding Sub. A Sanson-Bulls 33kV interlink project coupled with a new substation to supply Ohakea Air Base is on the works plan linking Sanson and Bulls substations at 33kV providing the required security of supply to Sanson and Bulls as well as Ohakea Air Base. However, the addition of Bulls and Ohakea Subs substation loads has put constraints to the Sanson 33kV supply.

Preferred Option

The most feasible solution is to increase the thermal capacity of Feilding-Sanson subtransmission line. This will provide capacity for the future demand.

Alternatively installing the second subtransmission supply would be costly due to the long distance to the substation.

TURITEA NEW 33KV LINE

Constraint

The Turitea substation supplies Massey University, Linton Army Camp, NZ Pharmaceuticals, residential and rural load to the south east of Palmerston North. Its security level is AA but AAA is intended.

The substation has switched N-1 subtransmission switching capability26 from Bunnythorpe and Linton GXPs. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for subtransmission fault.

There is also limited backfeed capability from distribution network.

Due to these constraints, the Turitea substation does not presently meet our required security level.

Preferred Option

The most feasible option is to install the second subtransmission supply for the substation. This will improve the security level.

Alternatives such as increased backfeed would be costly as there is no adequate transfer capacity.

MILSON-2 33KV LINE UPGRADE

Constraint

The Milson substation supplies the industrial, commercial and residential load in western Palmerston North, including the airport and industrial park. Milson Sub takes its 33kV supply from Bunnythorpe GXP by two dedicated 33kV lines, Milson-1 (7.1km long) and Milson-2 (13.7km long). For an outage on Milson-1 line, Milson-2 line could not supply the substation due to thermal capacity constraint.

Due to this constraint, the Milson-2 33kV line needs upgrading.

Preferred Option

The only feasible option is to upgrade 13km OH section of Milson-2 33kV line to improve its capacity and the security of supply.

Alternatives such as offloading the 11kV feeders are not favoured due to the complexity of switching and can take a considerable amount of time.

NEW (3RD) 33KV LINE BUNNYTHORPE - FEILDING

Constraint

Feilding Sub takes its 33kV supply from Bunnythorpe GXP by two lines, one is 8.6km long (FEI East) and the other is 9.1km long (FEI West). Each 33kV line has a conservative rating of 415A (23.7MVA, Butterfly). Feilding's 33kV bus supplies Sanson substation by one 14.5km long line and Kimbolton substation by another 26.5km long line. Also, Feilding will supply Bulls and Ohakea Subs for the upcoming Sanson-Bulls 33kV interlink and future second Feilding zone substation.

The total demand (of Feilding, Sanson, Bulls, Ohakea, Kimbolton and Feilding 2 substations) on the Bunnythorpe- Feilding circuits will exceed their N-1 capacity.

Preferred Option

The most feasible option is to install a third subtransmission line to Feilding sub from Bunnythorpe GXP. This will provide adequate capacity for the future demand with appropriate security.

Alternatives such as increasing the thermal capacity of the two 33kV lines will not provide the appropriate security of supply for the substations involved.

A8.13 TARARUA AREA

A8.1.23 MAJOR PROJECTS

PONGAROA 33KV UPGRADE

Constraint

The Parkville-Alfredton-Pongaroa ring is very lightly loaded in terms of thermal loading because of the low aggregate demand at the three substations supplied by this ring.

However, this ring comprises 89km of line length in total. The large distance between substations supplied by this ring means that in N-1 conditions the voltage drop can be high.

Preferred Option

The most feasible option would be to upgrade the 33kV supply line from Lamprey to Coyote.

A8.1.24 MINOR PROJECTS

There are no minor investments in security or capacity planned in the area.

There will be continued investment in small scale development projects. This is mainly represented by 11kV distribution feeder upgrades, some of which will provide improved back feed between substations, and hence improve the security of those substations.

A8.14 WAIRARAPA AREA

A8.1.25 MAJOR PROJECTS

NEW BIDWELLS-CUTTING SUBSTATION AND DUAL SUPPLY

Constraint

Tuhitarata substation is supplied by one single 33kV circuit from Greytown and has limited back feed capability. As the demand increases, the class capacity is exceeded.

Preferred Option

The most feasible option is to increase back feed through the distribution network. Due to the long lengths and high impedance of the conductors, upgrading to 22kV could be cost effective.

However, utilising an existing but out of service 33kV feeder to supply a small new sub could be still more cost effective. Re-livening this feeder has the additional benefit of increasing security to Featherston and Martinborough substations.

NEW PIRINOA SUBSTATION AND DUAL SUPPLY

Constraint

As demand increases, voltage quality issues during normal state and ability for restoration of supply through distribution back-feed will be progressively worse for southern most loads presently supplied by Tuhitarata substation feeders Pirioa and Burnside.

Options

Option 1:

Distribution upgrades

- Revan St conductor upgrade (16 km)
- Burnside feeder conductor upgrade (50 km)

Sub-transmission upgrades

- Build new 33kV feeder to Tuhitarata
- Build new 33kV feeder to Hau Nui

Option 2: New Substation

Preferred Option

A new substation and dual sub transmission supply.

A8.1.26 MINOR PROJECTS

MASTERTON-AKURA 33KV FEEDER UPGRADE

Constraint

Security is not adequate and during peak load periods back feeding capability is limited.

Options

Option 1: Underground 1.9 km on Norfolk Road, re-tension 5 km OH

Option 2: Underground 1.9 km on Norfolk Road, conductor upgrade 5 km OH

Option 3: Underground 1.9 km on Norfolk Road, build new 33kV line

Preferred Option

Upgrades to most of the Masterton-Norfolk-Chapel 33kV ring circuit (option 2) are planned. This will provide the substations with adequate security and also allow some excess capacity for 11kV back-feeds, the latter being a serious operational issue at present.

MASTERTON – TE ORE ORE 33KV FEEDER UPGRADE

Constraint

Security is not adequate and during peak load periods.

Options

Option 1: Upgrade 10.6 km of OH

Option 2: Re-tension 10.6 km of OH and install series capacitor on line

Option 3: Build new 33kV line

Preferred Option

Option 1 is the preferred option. The Akura-Te Ore Ore 33kV feeder is being upgraded at present and has improved security on the Masterton-Akura-Te Ore Ore 33kV ring circuit. A further upgrade to the Te Ore Ore 33kV feeder is planned.

MASTERTON – CLAREVILLE 33KV RE-TENSIONING

Constraint

Growth of Clareville-1 and Clareville-2 33kV feeders has been steady.

Options

Option 1: Re-tension 15.8 km of 33kV OH line

Option 2: Conductor upgrade 15.8 km of 33kV OH line

Option 3: New line between GLA and CLV

Preferred Option

A re-tensioning of Masterton-Clareville-1 and Clareville-2 33kV feeders (option 1) is planned.

NORFOLK SUBSTATION SUPPLY TRANSFORMERS

Constraint

The Norfolk substation is situated a few kilometres south of Masterton and supplies a large sawmill, as well as other small industrial and rural loads. The substation contains two transformers. The demand has exceeded the transformers' capacity, and there is potential for loss of supply at the substation for a transformer fault.

There is also limited backfeed capability from the 11kV distribution network.

Due to these constraints, the Norfolk substation does not presently meet our required security level.

Preferred Option

The only feasible solution is to replace the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required backfeeding capacity are not favoured due to the complexity and cost.

KEMPTON SUBSTATION SECOND TRANSFORMER AND SUBTRANSMISSION SUPPLY

Constraint

The Kempton substation supplies Greytown and the surrounding rural area. The substation security level is A1.

The substation is supplied by one single 33kV circuit from the Greytown GXP (N security) and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. There is also limited backfeed capability from distribution network.

Due to these constraints, the Kempton substation does not meet our required security level.

Options

Option 1: Second transformer at Kempton substation

Option 2: New substation between Kempton and Clareville substations

Preferred Option

The solution is to install the second subtransmission supply and transformer for the substation. This will improve the security level.

Alternatives such as increased backfeed would be costly as there is no adequate transfer capacity.

CLAREVILLE SUBSTATION SUPPLY TRANSFORMERS

Constraint

The Clareville substation supplies Carterton township and the surrounding rural load. The substation contains two transformers.

The demand has exceeded the transformers' capacity, and there is potential for loss of supply at the substation during a transformer fault.

There is also limited backfeed capability from the 11kV distribution network. The Norfolk substation does not meet our required security level.

Options

Option 1: Upgrade transformers at Clareville Substation

Option 2: New substation between Kempton and Clareville substations

Preferred Option

The only feasible solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand. This will also improve the security level.

MARTINBOROUGH SUBSTATION SECOND TRANSFORMER

Constraint

The Martinborough substation supplies the urban and rural loads around Martinborough. Its security level is A2, but A1 is intended.

The substation contains a single supply transformer and is has N-1 subtransmission switching capability26. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from distribution network.

Due to these constraints, the Martinborough substation does not presently meet our required security level.

Preferred Option

The solution is to install the second transformer for the substation. This will improve the security level. Alternatives such as increased backfeed would be costly as there is no adequate transfer capacity.

APPENDIX 9 RENEWAL PROJECT DESCRIPTIONS

A9.1 APPENDIX OVERVIEW

This appendix details upcoming or in progress significant renewal projects. Only zone substation and subtransmission projects are included, that also have costs expected to exceed $500k.

Section A9.2 below outlines projects that are in progress during our FY20 financial year. Section A9.3 provides a summary of projects planned for execution during FY21-24.

A9.2 SIGNIFICANT RENEWAL PROJECTS

A9.2.1 2020CHAPEL SUBSTATION 33 KV SWITCHGEAR REPLACEMENT

Chapel substation is located in the Masterton CBD. The three 33 kV outdoor circuit breakers and buswork are aging (45-50 years old). Spare parts are not available for the circuit breakers, and the equipment is difficult to maintain. In addition there are safety concerns in relation to operating an exposed 33 kV bus in a CBD area with significant foot and vehicle traffic. An adjacent block wall in close proximity to the buswork is a further risk, as it could collapse into live equipment during a seismic event.

The project will involve replacing the three outdoor 33 kV CBs with a five panel indoor switchboard in a new building. The building will be located on the Western side of the site, removing any risk of collapse of existing buildings onto the new switchroom.

CHAPEL SUBSTATION 33 KV SWITCHGEAR REPLACEMENT ($000, 2019 REAL)

Estimated Total Project Cost	$1,400
Expected Project Timing	2019-2020

A9.2.2 GREERTON SUBSTATION INDOOR 33 KV SWITCHBOARD

Greerton switching station is located in the Tauranga region and is critical to the supply of the Tauranga region.

The site contains a large number of outdoor 33 kV oil circuit breakers which are aged and in poor condition. In addition, the site is at risk of damage from a slip from a nearby hill which would likely damage a large portion of the outdoor switchyard.

We are currently undertaking a major project to replace the outdoor 33 kV switchgear with a pair of indoor switchboards, and have undertaken civil works to level the land and reduce the risk of slips. The conversion will also improve the reliability of the site and provide switchgear that is far safer to work on. While conversion to an indoor switchboard has a higher capital cost, it is cost effective over the lifetime of the assets due to the associated reliability, maintenance and safety benefits, particularly for a site of this criticality.

This project is progressing as scheduled through construction, and is expected to be fully commissioned within the 2020 FY.

GREERTON INDOOR 33 KV SWITCHBOARD ($000, 2019 REAL)

Estimated Total Project Cost	$2,930
Expected Project Timing	2019-2020

A9.2.3 MOBILE SUBSTATION

Many of our rural zone substations have only a single power transformer supply (ie N security), typically rated between 5 and 10 MVA. Any maintenance or planned replacement work at these substations often requires an outage and recently it has become increasingly difficult to arrange the required shutdowns due to diminishing backfeed capability. A mobile substation will be used as a temporary bypass and eliminate the need for extended outages to carry out scheduled maintenance or replacement work.

Procurement of all major components of the mobile substation, such as the 8MVA transformer and 11kV and 33kV switchrooms is currently underway, and installation of permanent connection points at key sites to allow straightforward connection. The switchboard will likely include three outgoing 11 kV feeders, and the unit will be self-contained for communications and SCADA.

The total project costs include an allowance for preparing up to 7 single transformer zone substation sites for connection to the mobile substation.

MOBILE SUBSTATION ($000, 2019 REAL)

Estimated Total Project Cost	$2,450
Expected Project Timing	2018-2021

A9.2.4 LIVINGSTONE SUBSTATION 33 KV SWITCHYARD REBUILD

The 33 kV outdoor structure at Livingstone is in poor condition and represents a safety risk. Concrete structure poles have spalled and the connecting steel is beyond remedial work. A severe corrosion problem with externally mounted CTs and VTs means that parts of these are in imminent risk of failure, with some CTs having already failed due to corrosion causing oil leaks.

The project is to rebuild the outdoor 33 kV switchyard at Livingstone zone substation, replacing the 33 kV circuit breakers, CTs, VTs and line isolators. The project also includes replacing the last remaining oil 11 kV circuit breaker with an equivalent vacuum circuit breaker.

LIVINGSTONE SUBSTATION 33 KV SWITCHYARD REBUILD ($000, 2019 REAL)	
Estimated Total Project Cost	$630
Expected Project Timing	2020

A9.2.5 PAEROA SUBSTATION REBUILD, TRANSFORMER, 11 KV AND 33 KV SWITCHGEAR

The Paeroa substation supplies the Paeroa township & surrounding farming area. The transformers at Paeroa substation are the oldest in service in the Eastern region. Obtaining spares is difficult and the transformer foundations have been found to be inadequate and do not comply with current seismic codes. There is no bunding or oil containment.

We plan to replace the transformers at Paeroa substation with refurbished units in order to improve substation capacity and backfeed capability. We also have projects planned to upgrade other equipment at Paeroa including the 11kV switchboard and building (discussed below), 33 kV circuit breakers and feeder cables.

The project also involves replacing the 11 kV switchboard and a new switchroom. The new switchboard will be fitted with modern arc flash protection. This project is currently being tendered and is expected to be completed in FY 2020.

PAEROA SUBSTATION – TRANSFORMER REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$2,280
Expected Project Timing	2019-2020

A9.2.6 MOTUROA SUBSTATION BUILDING, TRANSFORMER, 11 KV AND 33 KV SWITCHGEAR

Moturoa substation supplies several important loads including Taranaki Port, Base Hospital, the Moturoa commercial hub and a large number of urban residential consumers. It supplies approximately 8,881 ICPs.

We acquired Moturoa Substation from Transpower in 2010. It was constructed in 1971 and none of its equipment has been renewed since then. The coastal environment has badly impacted its building, 11 kV switchboard, two power transformers and other equipment. The transformers have no bunding or oil containment. The 11 kV switchboard and related equipment are old and obsolete and the switchboard has no arc flash containment. The seismic strength of the building housing the 11 kV switchboard is well below our current standard.

This project is to renovate Moturoa Zone Substation by constructing a new building to house a 13-panel 11 kV switchboard and to replace the existing transformers with two new higher rated 33/11 kV transformers. This was found to be the least cost, long term economically sustainable solution to bring the aging assets up to standard and achieve Moturoa's required security of supply criteria.

The new substation is on track, with construction well underway and equipment expected to be fully installed and commissioned within the 2020 FY.

MOTUROA SUBSTATION BUILDING, TRANSFORMER, 11 KV AND 33 KV SWITCHGEAR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$5,000
Expected Project Timing	2017-2020

A9.2.7 PUTARURU 11KV SWITCHGEAR REPLACEMENT

Putaruru substation supplies Putaruru and the surrounding townships, including the large industrial timber customers Kiwi Lumber, Pacific Pine and Buttermilk.

The 11kV switchboard and switchroom was constructed by the Thames Valley Electric Power Board back in 1962, making it the oldest Reyrolle LMT switchboard on the network - being 58 years old in 2019. CBRM modelling has shown that this site is at an increased risk of disruptive failure due to the age and condition of the circuit breakers. Breakers are showing signs of sluggish operation which may result in protection misgrading, and as such this site has been identified for renewal.

This project will replace the existing switchgear and construct a modern seismically rated building and install new power cable tails. Arc flash levels will also be reduced. Project timing and overall site layout will be coordinated with the larger Putaruru GXP major growth project.

PUTARURU 11KV SWITCHGEAR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$1,500
Expected Project Timing	2019-2020

A9.2.8 AKURA SUBSTATION T1 AND T2 POWER TRANSFORMER REPLACEMENT

Akura supplies industrial, commercial, residential and rural load to the north west of Masterton.

The two transformers were installed in 1965, making them 55 years old in 2020. and are in poor asset health, with inadequate oil bunding and oil containment, which could cause significant contamination of the nearby creek. In addition, Akura has now reached firm capacity in FY19 and this has driven a need for a size increase. This project includes the replacement of two transformers, installing oil containment, bunding, firewalls and new power cable tails

AKURA T1 AND T2 POWER TRANSFORMER REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$2,680
Expected Project Timing	2020-2021

A9.2.9 FIELDING SUBSTATION OUTDOOR TO INDOOR CONVERSION, 33KV SWITCHGEAR

Feilding substation supplies Feilding town and the surrounding commercial, industrial, residential and rural load. The outdoors 33kV switching structure is low and has been constructed with minimum electrical clearances with several low level underhung isolators adjacent to the ground mounted oil circuit breakers.

The 33kV circuit breakers are AEI JB424 bulk oil and English Electric minimum oil circuit breakers; these are all approaching the end of their expected service lives.

The original Reyrolle switchgear was installed circa 1964. Several newer panels and circuit breakers have been added to the switchboard in order to meet increased load requirements.

This project will convert the existing outdoor switchgear and associated structures into an indoor 33kV switchboard including a new building, power cables and associated secondary system.

FIELDING OUTDOOR TO INDOOR CONVERSION, 33KV SWITCHGEAR ($000, 2019 REAL)	
Estimated Total Project Cost	$2,820
Expected Project Timing	2020-2022

A9.2.10 KAPONGA SUBSTATION TRANSFORMER TR8 AND TR26 REPLACEMENT

Kaponga substation supplies Kaponga and the surrounding rural area. Both existing transformers will be 49 years old in 2020 and are in poor condition with paint deteriorated down to primer and poor oil condition. This project will replace the existing two transformers with a single standard 7.5/10 MVA unit, with cabled connections. The new transformer pad will be built in a position away from the existing transformer pads. New support frames will be required for cable termination onto both the 33kV and 11kV termination points.

The transformer is to be installed on the new pad along with all cable terminations. A new 11kV CB or Recloser and isolator will be installed as a means of isolation from the transformer to the 11kV bus.

KAPONGA, TRANSFORMERS AND 11 KV SWITCHGEAR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$1,240
Expected Project Timing	2020-2021

A9.2.11 MILSON SUBSTATION 11KV SWITCHGEAR REPLACEMENT

Milson is a critical substation supplying the industrial, commercial and residential load in western Palmerston North, including the airport and industrial park. The original Reyrolle LMT oil switchgear was installed circa 1978, and has one of the highest arc flash incident energies on our network. This project will replace the existing switchgear, replace existing incomers and install new cable tails.

MILSON 11KV SWITCHGEAR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$920
Expected Project Timing	2020-2021

A9.2.12 TRITON SUBSTATION BUILDING, TRANSFORMERS, 11KV AND 33KV SWITCHGEAR

The existing outdoor 33kV and indoor 11kV switchgear is in poor condition. The existing outdoor switchyard is currently constrained in terms of space. This project will convert the existing outdoor switchgear to indoors as well as replacing the existing 11 kV switchgear, new building and install the associated power cables and secondary systems. The existing two transformers are in poor condition and will be replaced.

TRITON SUBSTATION BUILDING, TRANSFORMERS, 11KV AND 33KV SWITCHGEAR ($000, 2019 REAL)	
Estimated Total Project Cost	$4,860
Expected Project Timing	2020-2022

A9.2.13 WAIHAPA POWER TRANSFORMER, 33KV AND 11KV SWITCHGEAR REPLACEMENT

Waihapa Substation supplies mostly Origin Energy's Waihapa Petroleum Production Station and several nearby well pumps. Presently it has one 1.25 MVA & one 2.5 MVA transformer. The 1.25 MVA Transformer was manufactured in 1957, and its tank has serious corrosion. The 2.5MVA transformer was manufactured in 1968. Present demand is around 1.2 MVA. This project will convert this sub into one transformer substation with a spare 5 MVA transformer along with a new transformer foundation. The outdoor 33kV and 11kV switchgear will also be replaced.

WAIHAPA POWER TRANSFORMER, 33KV AND SWITCHGEAR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$1,350
Expected Project Timing	2020

A9.2.14 WALTON SUBSTATION 33KV AND 11 KV SWITCHGEAR REPLACEMENT

The existing 11kV switchroom building does not meet seismic code requirements. The switchroom must allow for a future indoor 33kV switchboard and 11kV switchboard upgrade/replacement.

The 11kV switchboard is old and requires upgrading/replacement. The existing 11kV switchboard also requires extending for future load increase. The new 11kV switchroom building will also allow for the installation of 8 panels of 33kV indoor switchgear. This will replace the existing 33kV outdoors structure and switchgear.

The 33kV component of this project will funded as a growth project, rather than a renewal project.

WALTON SUBSTATION 33KV AND 11KV SWITCHGEAR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$510
Expected Project Timing	2020-2021

A9.2.15 REPLACEMENT OF KIDNEY STRAIN INSULATORS

The old kidney strain insulators installed in the 1960's are prone to cracking. This causes moisture and dust to build up and provides a path for faults, resulting in a loss of supply. We are in the process of replacing the old kidney strain insulators with replacement cross arms as required. Key projects in the programme include the following:

- Blitz 20 Replace 11 kV Kidney Mangorie CB6
- Blitz 20 Replace Kidney Strain Insulators Eltham
- Blitz 20 Replace kidney strain insulators NP
- Blitz 20 Replace 11kV Kidney Mangorie CB5
- Blitz 20 Replace11 kV Kidney Strain BBK8

KIDNEY STRAIN INSULATTOR REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$1,392
Expected Project Timing	2020

A9.2.16 16MM CU CONDUCTOR REPLACEMENT

Aged 16mm Cu conductor has been a poor performing conductor and has been identified as a type issue conductor and is targeted for replacement. Key projects in this programme include:

- Blitz 20 Tatuanui Re Conductor Stg 2
- Blitz 20 Taihoa Nth Rd Reconductor
- Blitz 20 Cape Rd Reconstruction

16MM CU REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$1,115
Expected Project Timing	2020

A9.2.17 HAWERA TO LIVINGSTONE 33KV FEEDER UPGRADE

The driver of this project is the poor condition poles on the 33kV line from the Hawera GXP to the new Mokoia Substation and onto Livingstone substation. Network development is requesting that the existing Dingo conductor be replaced with Neon.

There is also a type issue with the Egmont Electricity Board reinforced concrete poles where spalling of the poles reduces the service life and causes structural degradation.

The upgrade has been divided into the following projects:

- Blitz 20 HWA-MOK 33kV Reconductor
- Blitz 20 MOK-LIV 33kV Repole and Thermal Upgrade

16MM CU REPLACEMENT ($000, 2019 REAL)	
Estimated Total Project Cost	$1,100
Expected Project Timing	2020

A9.3 SIGNIFICANT RENEWAL PROJECTS 2021-2024 ($000, 2019 REAL)

PROJECT NAME	DESCRIPTION	PLANNING AREA	2021	2022	2023	2024
Akura – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear, protection and install new power cable tails. Arc flash levels will also be reduced.	Wairarapa	140	790	-	-
Aongatete – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Tauranga	-	100	560	-
Arahina – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Rangitikei	-	120	650	-
Baird Rd – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Kinleith	-	110	620	-
Bunnythorpe – Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Manawatu	-	780	-	-
Cardiff – 4700T Power Transformer Replacement	Poor asset health. This project includes the replacement of the power transformer and upgrading the foundation and oil bunding.	Taranaki	-	-	-	570
Chapel – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Wairarapa	140	800		
City – 11kV Switchboard Replacement	Oil type switchgear with high arc flash incident energy. This project will replace the existing switchgear and install new power cable tails.	Taranaki	160	900	-	-
Clareville – 11kV Switchboard Replacement	Oil type switchgear with high arc flash incident energy. This project will replace the existing switchgear and install new power cable tails.	Wairarapa	-	110	630	-
Feilding – 11kV Switchboard Replacement	Poor asset health, oil type switchgear and high arc flash incident energy. This project will replace the existing switchgear.	Manawatu	140	810	-	-
Greytown – Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Wairarapa	-	-	-	780
Kai Iwi – W27 Power Transformer Replacement	Poor asset health. This project includes the replacement of the power transformer and upgrading the foundation and oil bunding.	Whanganui		590	290	-
Kaponga – Outdoor to Indoor 11kV Switchgear Conversion	Existing outdoor Nulec reclosers used as breakers. This project will convert the existing outdoor switchgear and associated structures into an indoor 11kV switchboard including a new building, power cables and associated secondary systems.	Taranaki	-	-	300	1,700
Kapuni – 11kV Switchboard Replacement	The11kV switchboard is a known type issue, is no longer supported and has high arc flash incident energy. This project will replace the existing switchgear and install new power cable tails.	Egmont	-	110	630	-
Kimbolton – T1 Power Transformer Replacement	Poor asset health. This project includes the replacement of the power transformer and upgrading the foundation and oil bunding.	Manawatu	-	830	410	
Linton – Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Manawatu	780	-	-	-
Livingstone – T1 and T2 Power Transformer Replacement	Poor asset health. This project will replace the existing transformers, install new firewall and reuse existing feeder cables.	Egmont	-	1,100	540	-
Main Street – T1 and T2 Power Transformer Replacement	Poor asset health. This project will replace the existing transformers, install new firewall and reuse existing feeder cables.	Manawatu	-	-	1,800	890

PROJECT NAME	DESCRIPTION	PLANNING AREA	2021	2022	2023	2024
Matapihi – Arc Flash Retrofits	The existing 11kV and 33kV boards at Mataphi will be retrofitted with arc flash protection, including bus and cable termination arc flash protection..	Mt Maunganui	570	-	-	-
Milson – Outdoor to Indoor Conversion	Outdoor 33kV circuit breakers are bulk oil (with associated risks of explosive failure), and their condition is beginning to degrade. As the zone substation is in a residential area, the project will replace the outdoor switchgear with a modern indoor 33kV switchboard, reducing public safety risks and visual impact.	Manawatu	-	230	1290	-
Motukawa – Outdoor to indoor 11kV Switchgear Conversion	Existing outdoor 11kV Kyle reclosers used as breakers. This project will convert the existing outdoor switchgear and associated structures into an indoor 11kV switchboard including a new building, power cables and associated secondary systems	Taranaki	-	-	200	1,150
Pongakawa – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Mt Maunganui	540	-	-	-
Pungarehu – 13E Power Transformer Replacement	Poor asset health. This project will replace the existing transformer, transformer foundation, bund and install transformer feeder cables.	Taranaki	-	-	-	710
Rata – W36 Power Transformer Replacement	Poor asset health. This project will replace the existing transformer, transformer foundation, bund and install transformer feeder cables.	Rangitikei	-	-	-	670
Roberts Ave – W23 Power Transformer Replacement	Poor asset health. This project will replace the existing transformer, transformer foundation, bund, earthing upgrade and install transformer feeder cables.	Whanganui	-	780	330	-
Sanson – 11kV Switchboard Replacement	Existing switchgear is an oil type switchgear and has high arc flash incident energy. This project will replace the existing switchgear, replace existing incomers and install new cable tails.	Manawatu	120	700	-	-
Stratford – 33kV Aged Copper Renewal	The subtransmission network in Stratford is a mixture of 16mm2 and 40mm2 copper, which is heavily aged and in poor condition – in recent years there have been a significant number of conductor failures. This project is a continuation of the renewal projects in this area .	Taranaki	-	411	445	632
Thames – 11kV Switchboard Replacement	The existing switchgear is old and has high arc flash incident energy. The project will replace the existing switchboard including installing new power cable tails.	Coromandel	130	830	-	-
Welcome Bay – 11kV Switchboard Replacement	The existing switchgear is old and is an oil type switchgear. This project will replace the existing switchboard as well as install new power cable tails.	Waikato	120	660	-	-

APPENDIX 10 MAINTENANCE FORECASTS BY ASSET CATEGORY

A10.1 APPENDIX OVERVIEW

This appendix sets out forecast scheduled maintenance expenditure ($000, real 2019) by asset category over the planning period.

ASSET CATEGORY	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Zone Substations											
Routine scheduled maintenance and inspection	3,794	4,104	3,812	4,229	4,491	4,046	3,944	4,102	3,168	3,222	3,587
Subtransmission Lines and Cables											
Routine scheduled maintenance and inspection	808	859	879	301	316	318	302	329	304	319	323
Distribution and LV Lines											
Routine scheduled maintenance and inspection	3,438	3,533	3,726	3,403	3,261	3,636	3,480	3,462	3,730	3,702	3,605
Distribution Transformers											
Routine scheduled maintenance and inspection	816	901	977	859	808	938	889	923	971	1,018	989
Distribution Switchgear											
Routine scheduled maintenance and inspection	2,013	2,546	2,808	2,335	2,175	2,171	2,112	2,541	2,594	2,866	2,725
Other Network Assets											
Routine scheduled maintenance and inspection	761	765	791	823	816	819	800	832	802	820	825
General Maintenance											
Other corrective work	7,402	6,685	6,482	5,757	5,136	5,845	5,881	5,915	5,950	5,984	6,019
Defects	5,305	6,559	6,559	6,039	6,039	4,471	3,442	3,442	3,442	3,442	3,442
Third party damage repair	931	931	931	931	931	931	931	931	931	931	931
Reactive maintenance	6,999	7,481	7,579	7,520	7,461	7,505	7,548	7,592	7,636	7,681	7,725
Total Maintenance Expenditure	**32,268**	**34,364**	**34,545**	**32,197**	**31,435**	**30,682**	**29,328**	**30,068**	**29,528**	**29,985**	**30,171**

A11.1 APPENDIX OVERVIEW

This appendix discusses the performance of our poorer performing feeders. For the worst few of these feeders we explain the reasons and any planned remedial works.

The analysis uses FIDI, which is the average number of minutes that a customer on a feeder experiences without supply. The analysis period is the 2019 calendar year.

The analysis is broken down by feeder class[123]. Each distribution feeder is assigned a class that best encompasses the types of consumers connected to the feeder.

A11.2 FEEDER CLASS F1

Mangatoki, Taranaki – A total 13 outages, nine being unplanned and four planned. 89% of the total FIDI minutes is attributed to one unplanned outage during cyclone Gita. The remaining unplanned outages were caused by vegetation, foreign interference and defected equipment. The feeder is a F1/F4 security rating.

Rangiunu, Tauranga – A total of five outages, four planned works and one unplanned outage during a storm event. 64% of the FIDI minutes were from planned capital works.

Origin 2, Taranaki – One unplanned outage account for the full FIDI minutes listed. This was due to defected equipment namely a failed Jumper.

Mccabe Road, Valley – A total of 15 outages, six unplanned and nine planned works. 39% of the FIDI minutes listed were due to unplanned outages caused by defected equipment. Six of the planned outages were pole and hardware replacement projects and overall the planned works accounted for 61% of the FIDI minutes listed. The feeder is a F1/F4 security rating.

Te Puke Quarry Rd, Tauranga – A total of seven outages occurring with four planned shutdowns accounting for 80% FIDI minutes listed for projects of reconductoring the 33kV line. Three unplanned outages, two with unknown causes. The feeder is a F1/F4 security rating.

Dairyfact, Manawatu – A total of seven outages with 92% of the overall FIDI minutes being from planned works. The works were from a mix of pole and crossarm replacement projects.

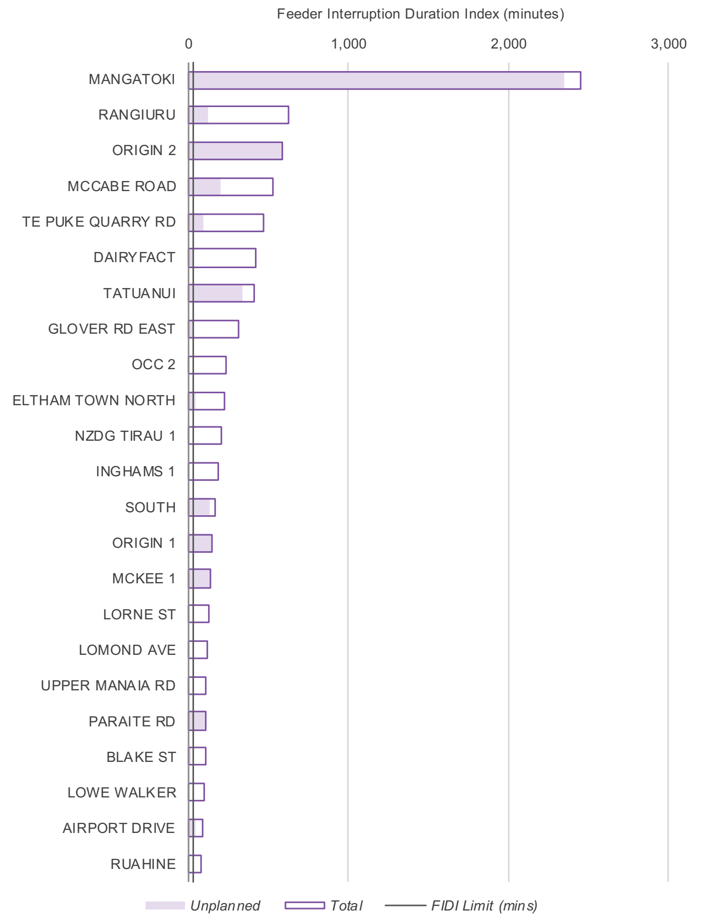
Tatuanui, Valley – A total of 15 outages, three planned and 12 unplanned. 50% of the total FIDI minutes is from unplanned outages caused by defected equipment and 29% had unknown causes of the unplanned outages.

Glover Rd East, Taranaki – A total of eight outages, three unplanned and five planned that accounted for 90% of the total FIDI minutes listed. The planned works were capital projects of pole and conductor replacements.

OCC 2, Valley – One planned outage accounts for 100% of the FIDI minutes listed which was due to maintenance within the Substation.

Eltham Town North, Taranaki – A total of nine outages, three planned and six unplanned. 67% of the total FIDI minutes listed is due to planned works, replacement of hardware primarily around ABS's. Unplanned outages accounted for 17% being from Foreign Interference and the remainder defected equipment and adverse weather.

Feeder Class F1 FIDI



[123] We note that some of the feeders may contain multiple feeder classes and in this analysis the total FIDI contribution from all the feeder classes will be compared against the highest class target. Please refer to Chapter 7 for more details.

A11.3 FEEDER CLASS F2

Waterworks Rd, Wanganui – A total of 17 outages, three planned and 14 unplanned that account for 95% FIDI minutes listed. 70% of the overall total were a result of vegetation, with 41% of those occurring during storm events. Vegetation defects are being managed and a full feeder vegetation project is planned for FY21.

Pahoia, Tauranga – A total of 16 outages, four planned and 12 unplanned that account for 62% of the total FIDI minutes listed. 41% have unknown causes and 11% have been attributed to vegetation. This feeder is scheduled for vegetation inspection during FY19 and has had hardware replaced and bird spikes added in various locations. This feeder has a F2/F4 security rating.

Linton, Manawatu – A total of 21 outages all unplanned. 87% of the total FIDI minutes listed have been caused by defected equipment with the remainder being caused by vegetation, adverse weather, human element and 7% have an unknown cause. There has been work completed in FY19 for pole and hardware replacement.

Aokautere, Manawatu – A total of 22 outages, four planned and 18 unplanned that account for 79% of the FIDI minutes listed. Of the unplanned, 54% were caused by defected equipment, 16% vegetation, 9% unknown cause. The planned works, 21% of the FIDI total, were replacing pole, cross arm's and installing a new recloser device.

Ridgeway St, Wanganui – One unplanned outage caused by a defected cable makes up 100% of the FIDI minutes listed on this feeder.

Ngaumutawa Rd, Wairarapa – A total of 11 outages, one unplanned caused by foreign interference and ten planned works that attribute to 87% of the overall FIDI minutes listed. The planned works were pole and hardware replacement projects.

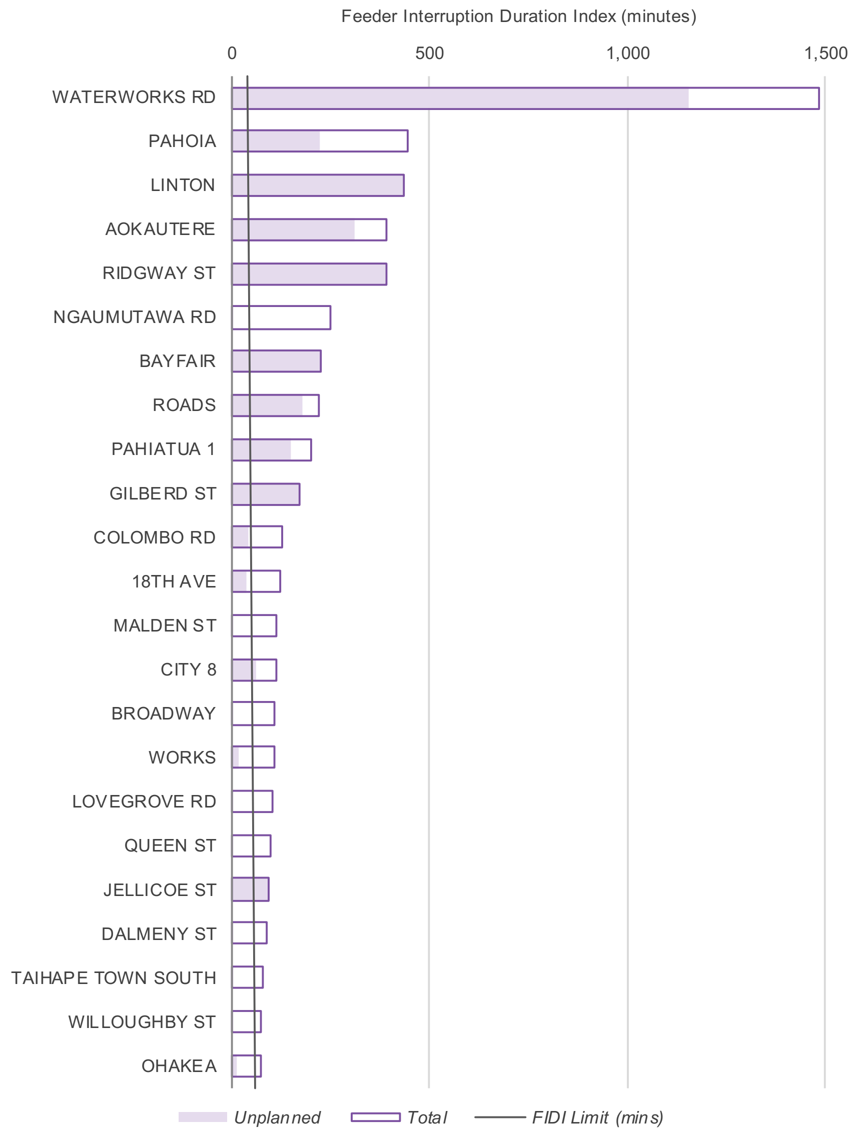
Bayfair, Tauranga – A total of two unplanned outages due to foreign interference has attributed to 100% of the FIDI minutes listed.

Roads, Tauranga – A total of 11 outages, four planned and seven unplanned that accounts for 81% of the FIDI minutes listed. 61% has been attributed to foreign interference and 18% vegetation. The planned outages were mainly new pole and hardware projects.

Pahiatua 1, Manawatu – A total of 12 outages, five planned and seven unplanned. The unplanned account for 75% of the FIDI minutes listed with 40% of the overall FIDI were from defected equipment and 31% from adverse weather. The planed outages attributed to 25% of the FIDI and were replacement of Low Voltage assets pole replacement projects.

Gilberd St, Wanganui – One unplanned outage caused by a defected cable makes up 100% of the FIDI minutes listed on this feeder.

Feeder Class F2 FIDI



A11.4 FEEDER CLASS F3

Tarata, Taranaki – A total of 20 outages, one planned and 19 unplanned with 89% of the total FIDI minutes attributed to defected equipment. The planned work was for a crossarm replacement project. Project works of reconductoring and pole replacement are set to be completed by early 2019.

Hunterville 22kV, Wanganui – A total of 55 outages, one planned for a pole replacement and 54 unplanned. Of the overall FIDI total 44% were unplanned due to adverse weather, primely from a snow storm event. 30% from defected equipment and 21% was attributed to outages caused by vegetation. A full feeder vegetation project is planned for this feeder. And during FY19 pole and hardware replacement projects have occurred.

Brooklands 13, Taranaki – One unplanned outages caused by vegetation accounts for 100% of the FIDI minutes listed. A full feeder vegetation inspection has been undertaken and work will be completed by end of FY19.

Westmere Peat St, Wanganui – A total of 39 outages, six unplanned attributed to 6% of FIDI minutes listed. 94% was due to planned capital works with 61% from pole, reconductoring and hardware replacement projects.

Athenree, Valley – A total of nine outages, six planned and three unplanned. 44% of the total FIDI minutes listed was due to foreign interference and 10% to defected equipment. 45% of the total FIDI was attributed to planned outages primarily for pole replacement and reconductoring projects.

Belvedere, Wairarapa – A total of 13 outages, eight planned and five unplanned. The planned account for 91% of the FIDI minutes listed which were made up of pole replacement and projects to rectify identified defects.

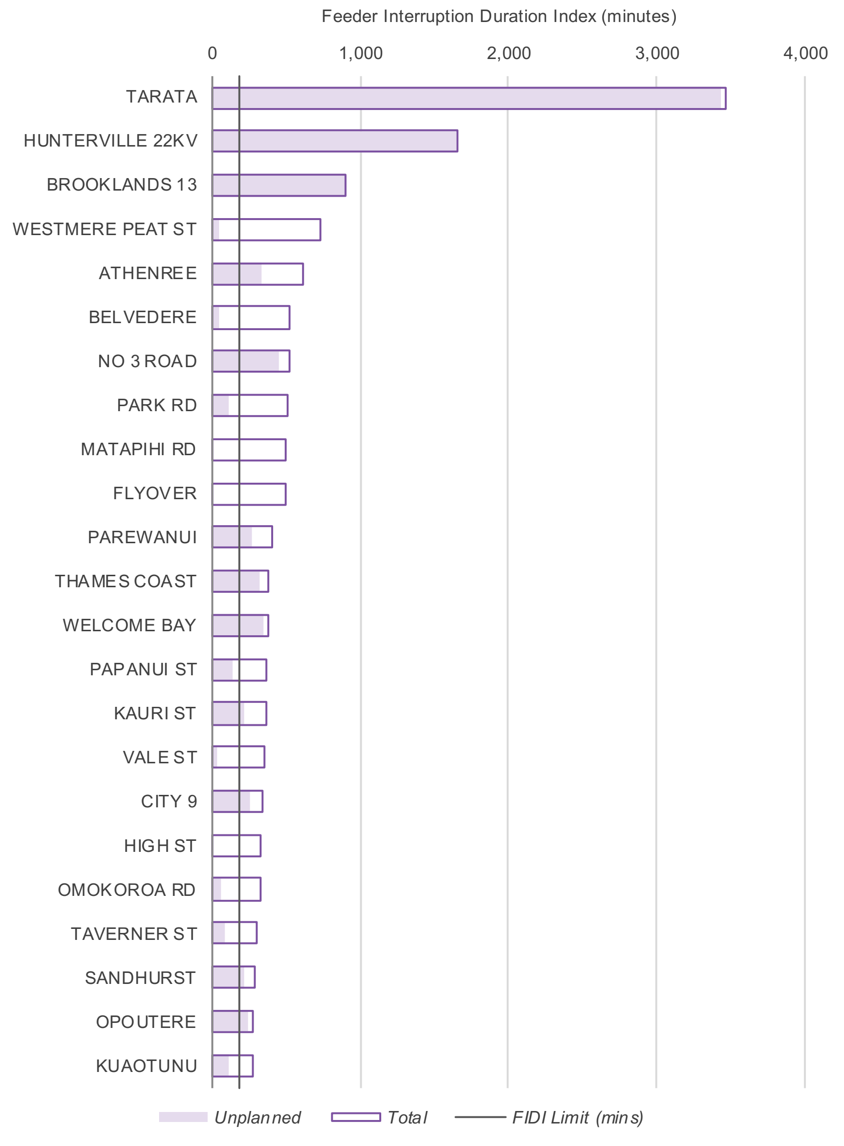
NO 3 Road, Tauranga – A total of 19 outages, ten planned and nine unplanned. Unplanned account for 88% of the FIDI minutes listed with 52% had unknown causes, 16% foreign interference and 15% vegetation. Planned projects of pole and hardware replacements made up 10% of the total FIDI minutes.

Park Rd, Wairarapa – A total of 25 outages, ten planned and 15 unplanned. The ten planned outages accounted for 77% of the total FIDI minutes listed and were made up of pole and hardware replacement projects. 23% of FIDI minutes listed were unplanned outages with 13% for Defected equipment, unknown cause equates to 5% and vegetation 4%. During FY19 reconductoring and pole replacement projects have occurred.

Matapihi Rd, Tauranga – A total of six outages, five planned and one unplanned which accounted for 2% and caused by adverse weather. The five planned outages were due to pole and hardware replacement projects.

Flyover, Tauranga – A total of five outages, 99% of the total FIDI was due to four planned outages for pole and hardware replacement projects. One unplanned with an unknown cause.

Feeder Class F3 FIDI



A11.5 FEEDER CLASS F4

Strathmore, Taranaki - A total of 49 outages, four planned and 45 unplanned which account for 98% of the total FIDI minutes listed. Defected equipment has been attributed as the cause for 63% of the FIDI total with 20% vegetation with the reminder attributed to a mix of causes. Vegetation defects are being managed. Works are planned to redesign and underground near forestry locations and two projects of replacing or reconditioning pole and hardware.

Huiroa, Taranaki – A total of 17 outages, two planned and 15 unplanned. The unplanned account for 98% of the total FIDI minutes listed. 54% caused by vegetation, 41% unknown causes and 3% from defected equipment.

Matakana Rd, Tauranga – A total of 15 outages all unplanned. FIDI minutes have been attributed to the following causes; 55% adverse weather, 35% foreign interference, 5% defected equipment, 5% vegetation and the remainder from unknown causes.

Waituna, Manawatu – A total of 44 outages, six planned and 38 unplanned. Unplanned account for 99% of the overall FIDI minutes listed of which 71% caused by adverse weather during the July 2017 snow storm event and 12% caused by vegetation. During FY19 works have occurred replacing hardware and a vegetation inspection and cut project is planned for FY20.

Otakeho, Taranaki – A total of 9 outages all unplanned. 97% of the overall FIDI minutes listed have been caused by defected equipment with the remainder caused by foreign interference. During FY19 a pole replacement project has occurred.

Whakamara, Taranaki – A total of 18 outages all unplanned. 88% of the overall FIDI minutes listed have been caused by defected equipment with the remainder being a mix of causes.

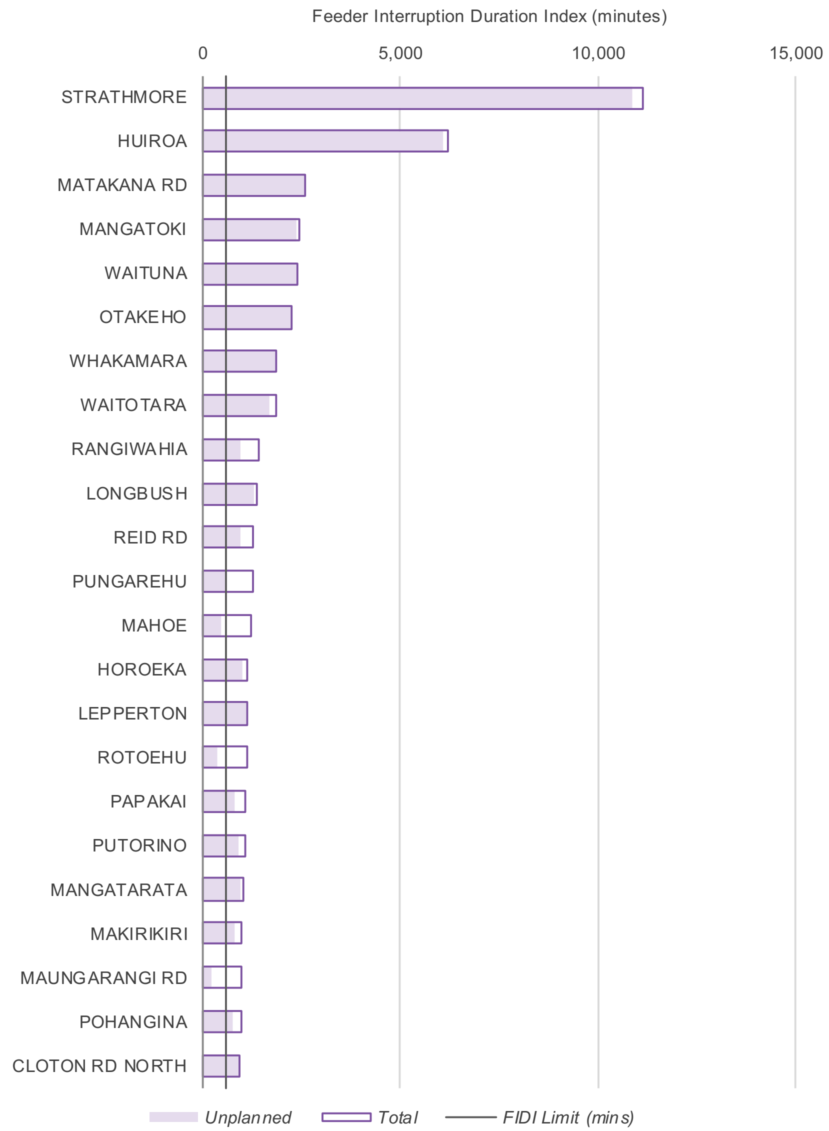
Waitotara, Wanganui – A total of 37 outages, four planned and 33 unplanned. The unplanned made up 93% of the overall FIDI minutes listed. 84% caused by defected equipment with the remainder being a mix of causes.

Rangiwahia, Manawatu – A total of thirty outages, 13 planned accounting for 32% and 17 unplanned account for 68% of the FIDI minutes listed. 22% of the FIDI minutes were from planned pole and crossarm replacement projects, 41% of the total FIDI attributed unplanned caused by foreign interference. During FY19 pole replacement and reconductoring projects have occurred.

Longbush, Wairarapa – A total of 12 outages, one planned and 11 unplanned outages. The planned was a pole and hardware replacement project. The unplanned were caused by adverse weather 48%, unknown 24% and defected equipment 12% of the total FIDI minutes listed.

Reid Rd, Tauranga – A total of 34 outages, 11 planned and 23 unplanned. The planned account for 27% of the FIDI minutes listed due to pole, crossarm and conductor replacement projects. The unplanned has been caused by adverse weather of 40%, defected equipment of 26% of the overall FIDI minutes listed with the remainder being from a mix of causes.

Feeder Class F4 FIDI



A11.6 FEEDER CLASS F5

Irirangi, Wanganui – A total of 20 outages, one planned and 19 unplanned. The unplanned account for 99% with 85% being attributed to adverse weather during the snow storm in July 2017 and 15% caused by defected equipment.

Rawhitiroa, Taranaki – A total of 31 outages, 11 unplanned and 22 planned. 33% of the overall FIDI minutes listed were unplanned caused by defected equipment and 10% caused by, outside of zone, vegetation. Pole and reconductoring projects have occurred on this feeder during FY2018 and account for 56% of the FIDI total.

Main Rd Motonui, Taranaki – A total of 47 outages, five planned with the remainder being unplanned accounting for 98% of the FIDI minutes listed. One outage due to cyclone Gita accounts for 66% of the overall FIDI total. 16% were caused by, outside of zone, vegetation and 8% foreign interference. During FY19 hardware replacement works have occurred.

Cloton Rd South, Taranaki – A total of 16 outages, two planned and 14 unplanned. 86% of the FIDI minutes listed has been attributed to defected equipment causing unplanned outages.

Annedale, Wairarapa – A total of five unplanned outages account for the FIDI minutes listed on this feeder, 65% is attributed to defected equipment and 35% caused by, outside of zone, vegetation. Pole replacements and reconductoring work is planned for 2019.

Waione, Manawatu – A total of 12 outages, four planned and eight unplanned. 73% of the total FIDI minutes were unplanned and caused by defected equipment. 22% from planned works, primarily tree removal and transformer replacement.

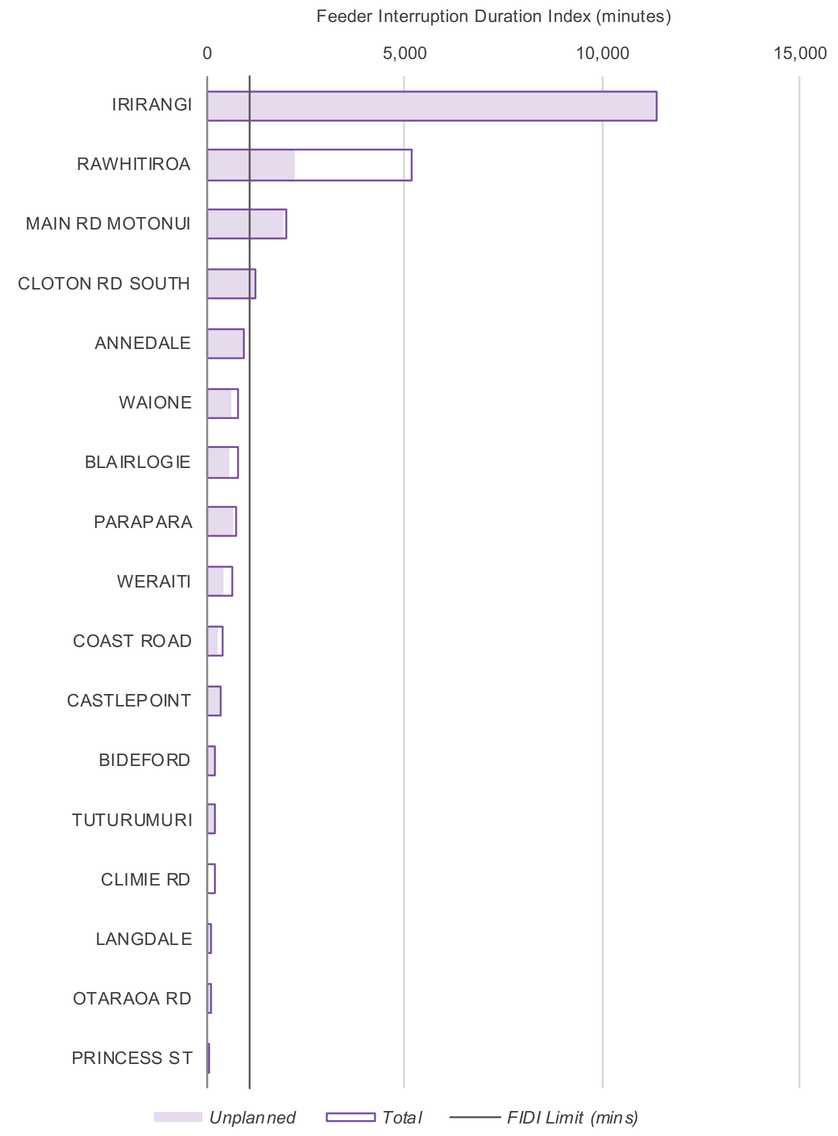
Blairlogie, Wairarapa – A total of 11 outages, one planned and ten unplanned. 60% of the total FIDI minutes were due to adverse weather during the July 2017 snow storm event, 40% defected equipment, 6% from vegetation and 5% from unknown causes of the unplanned. Pole replacements and reconductoring projects are planned for 2019.

Parapara, Wanganui – A total of 25 outages, seven from planned works and 18 unplanned. 70% of the total FIDI minutes listed was caused by, outside of zone, vegetation during the Gita storm event. The remainder of the outages were due to a mix of causes. A vegetation project is scheduled for FY20.

Weraiti, Wairarapa – A total of 18 outages, 10 planned, making up of 34% FIDI primarily pole replacement projects. Eight unplanned outages with 24% of the FIDI total caused by defected equipment and 41% from, outside of zone, vegetation. During FY19 pole and hardware replacement has occurred and a vegetation project is scheduled for FY21.

Coast Road, Manawatu – A total of 11 outages, two planned and nine unplanned. The unplanned equated to 67% of the total FIDI minutes listed. 40% of the total has been attributed to unknown causes, 21% from defected equipment. Of the planned works 32% was due to replacing defected equipment.

Feeder Class F5 FIDI



A12.1 APPENDIX OVERVIEW

This appendix provides further information on the non-network assets that support our electricity business.

A12.2 PLANNED CHANGES TO ASSET MANAGEMENT SYSTEMS

We are currently undertaking a work programme to modernise our asset management systems. This appendix describes our current state systems, however the following changes are planned to occur during 2019:

- Replace JD Edwards with SAP S/4HANA ERP system
- Replace Service Provider Application (SPA) field mobility solution with MyPM

A12.3 SYSTEMS USED TO MANAGE ASSET DATA

We use the following information systems when managing our assets:

- Geographical Information System (GIS)
- Maintenance, Work Management and Financial System
- Field Mobility solution
- SCADA master stations, SCADA corporate viewer and PI system
- Outage Management System (OMS)
- Customer Works Management System (CWMS) electricity
- Improvement Register database and Coin optimisation tool
- Engineering Drawing Management System (EDMS)
- Protection Settings Management System
- Customer Complaints Management System (CCMS)
- Safety Manager
- Billing System
- Vegetation Management System
- Other Record Systems

These systems are described in the following sections.

A12.3.1 GEOGRAPHICAL INFORMATION SYSTEM (GIS)

We use a GIS to capture, store, manage and visualise our network assets. The GIS is built on top of a set of ESRI and Telvent applications (ArcGIS, ArcFM) that deliver data in web, desktop and service-based solutions. The system contains data about the lines, cables, devices, structures and installations of our electricity distribution network. Work includes identifying key connections between our electricity and gas network and mapping them on the GIS.

GIS is the master system for current assets in the network, but it also distributes and informs other systems about the current assets via a middleware system interface (Biztalk server).

The primary consumer of this data is the enterprise system (JDE), which acts as the works management and financial system that operates as a slave system off the GIS data. The asset spatial information is also a key input into maintenance scheduling where geographical and network hierarchy factors are considered in the planning, monitoring and improvement of the asset base.

A12.3.2 MAINTENANCE, WORKS MANAGEMENT AND FINANCIAL SYSTEM

We operate a JD Edwards (JDE) system, which provides asset management and reporting capability, including financial tracking, works management, procurement and maintenance management. We have centralised asset condition and maintenance programming in JDE. As the master for all maintenance and condition information, JDE drives asset renewal programmes centrally. Within JDE, we have implemented system and process improvements for defects management.

A12.3.3 FIELD MOBILITY SOLUTION

We have a mobile platform that delivers applications to field services PCs and mobile devices. This application enables field capture of asset condition, maintenance activity results and defects. Reporting on the data generated by the Service Provider Application (SPA) is delivered via a suite of reports out of both JDE and Business Objects. The defect and condition data can also be viewed spatially from the GIS.

SPA helps ensure that asset management data provided by service providers is complete and to standard. This is key if we are to retain core asset knowledge in-house.

A12.3.4 SCADA MASTER STATIONS, SCADA CORPORATE VIEWER, AND PI SYSTEM

We operate OSI Monarch SCADA in both our regions. The master stations to control and monitor our network are highly available and are located in each of our datacentres. In the event of a failure the SCADA support team is able to fail over the system from one location to another.

Monarch Lite provides real-time access to users outside of our Network Operations Centre (NOC). This application provides users with access to real-time network information for use in planning and network management.

The OSIsoft PI system specialises in the collection, processing, storage and display of time-series data.

A12.3.5 OUTAGE MANAGEMENT SYSTEM (OMS)

The OMS is a business-critical application designed for 24/7 operations within our business. OMS is used as a Fault Management System for all faults reported by consumers and retailers. Our OMS uses information provided by the OSI SCADA system from customers who inform their retailer of faults, and who enter the information directly into the OMS system or via a B2B interface. Complex algorithms are used within the OMS system to calculate the possible fault location on the network and the affected number of ICPs. This information is then provided to service providers so they can dispatch a service provider to resolve the fault.

OMS is also used as the fault database to produce external reports for the Commerce Commission and Ministry of Economic Development, and internal reports for our management and engineers to improve network performance. It is an ongoing record of electrical interruptions in our network, with data collected by fault staff in the field and control room.

Daily automated interruption reports from OMS are circulated internally. Key outages and SAIDI and SAIFI totals are reported monthly. An annual network reliability report is prepared for information disclosure purposes.

A12.3.6 CUSTOMER WORKS MANAGEMENT SYSTEM (CWMS) ELECTRICITY

This is an online workflow management system, which facilitates and tracks the processes associated with connection applications, approvals, and works completion. Application, review and input work steps are available to our approved contractors via the internet. The primary function of the system is to manage the flow of customer-initiated work requests through our formal process, from initial request through to establishment of the ICP in billing and reference systems. The workflow ensures that the latest business rules are applied to all categories of connection work.

Work requests from new or existing customers are covered by our Customer Initiated Works process. This process places importance on providing new and existing consumers with a choice of prequalified contractors that they can engage to carry out work at their connection point(s). The business rules of the process ensure that the integrity of the overall local network and the quality of supply to adjacent consumers is retained, while making the customer-initiated work contestable.

A12.3.7 ENGINEERING DRAWING MANAGEMENT SYSTEM

The drawing management system is based on BlueCielo Meridian, and works in conjunction with AutoCAD drawing software. It is a database of all engineering drawings, including substation schematics, structure drawings, wiring diagrams, regulator stations, and metering stations. In addition, there is a separate vault that contains legal documents relating primarily to line routes over private property.

A12.3.8 PROTECTION SETTINGS MANAGEMENT SYSTEM

This application provides us with a protection database to manage settings in our protection relays.

A12.3.9 CUSTOMER COMPLAINTS MANAGEMENT SYSTEM

This is a workflow management system that maintains an auditable record of the life cycle of a customer complaint. The application is designed to work within the Utilities Disputes rules regarding complaints, and automatically generates the key reports required.

Another feature of the application is the integration with the GIS and ICP data sources, to provide spatial representation and network connectivity details of complaints and power quality issues. This provides valuable information to the planning teams.

A12.3.10 SAFETY MANAGER

Safety Manager is one of the systems that support our operational risk model and workflow. As the central repository for incidents, hazards and identified risks, it acts as a platform to manage these across internal and external stakeholders at both an operational and strategic level. In addition, it supports the Health, Safety Environment and Quality team in supporting the management of PPE and H&S competencies for all our employees.

A12.3.11 BILLING SYSTEM

Powerco receives consumption data from retailers and customers. Bills are calculated using the Junifer billing engine and invoiced from JDE.

A12.3.12 VEGETATION MANAGEMENT SYSTEM

We use Clearion's Vegetation Management solution to identify, track and manage vegetation encroachment within our electricity networks.

A12.3.13 OTHER RECORD SYSTEMS

In addition to the electronic systems, several other recording systems are maintained, including:

- Standard construction drawings
- Equipment operating and service manuals
- Manual maintenance records
- Network operating information (system capacity information and operating policy)
- Policy documentation
- HV and LV schematic drawings

A12.4 CONTROLS OF SYSTEMS AND LEVEL OF INTEGRATION

A12.4.1 CONTROLS

Extensive effort is made to protect the integrity of asset information held in our information systems. The system architecture deployed by us has security controls in place to restrict access, a change management process to control system changes, and is fully backed up on and off-site. Process and controls to limit human error are applied to user interfaces to reduce inputting error and reconciliation of data occurs, where possible, to identify cases of potential data error.

A12.4.2 INTEGRATION

Asset management information systems support us in our asset management processes. Over the past seven years we have implemented new enterprise systems and are working through a replacement programme for our ageing systems.

We strive to implement open platform, fit-for-purpose systems that allow us to manage our asset management information so that data and information is readily accessible to internal and external parties.

A12.4.3 LIMITATIONS OF DATA AND INITIATIVES TO IMPROVE DATA

Obtaining high-quality information to support asset management carries an expense. We are continually assessing where new investments should be made to improve the data available. We have a wide range of projects that focus on making better use of data we already collect.

We are continually working to improve the asset data we maintain in our enterprise systems.

Planned IT asset management business improvement programmes to address data and information are listed in Chapter 10.4.

APPENDIX 13 REGULATORY REQUIREMENTS LOOK-UP

This table provides a look-up reference for each of the Commerce Commission's information disclosure requirements. The reference numbers are consistent with the clause numbers in the electricity distribution information disclosure determination (2012).

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
Contents of the AMP	
3. The AMP must include the following:	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Chapter 1 is an Executive Summary and provides a brief overview and the key messages and themes in the AMP. Chapter 2.5 provides information on the structure of the AMP
3.2 Details of the background and objectives of the EDB's asset management and planning processes	The background to our asset management and planning process is provided in Chapters 2 to 6. This describes the context in which we operate. The objectives of our asset management and planning process are provided in Chapter 5.
3.3 A purpose statement which: 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 3.3.2 States the corporate mission or vision as it relates to asset management 3.3.3 Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB 3.3.4 States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management 3.3.5 Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest	3.3.1: The purpose statement is in Chapter 2.2. 3.3.2: Our corporate vision, mission and values and their relationship with the AM process is discussed in Chapter 5.2. 3.3.3: See Chapters 6.5 3.3.4: See Chapters 5 and 6.5. 3.3.5: This is described in Chapters 5 and 6.5.
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	Our AMP planning period is from 1 April 2019 to 31 March 2029, as described in Chapter 2.2.2.
3.5 The date that it was approved by the directors	The AMP was approved on 14 March 2019 (refer to Appendix 14).
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates: 3.6.1 How the interests of stakeholders are identified 3.6.2 What these interests are 3.6.3 How these interests are accommodated in asset management practices 3.6.4 How conflicting interests are managed	An overview of our stakeholders is in Chapters 2.4 and 4. A more detailed description of each main stakeholder's interests, how these are identified and accommodated in the asset management plan is in Appendix 3.
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including: 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 3.7.2 Executive – an indication of how the in-house asset management and planning organisation is structured 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	3.7.1: Refer to Chapter 6.2.. 3.7.2: Refer to Chapter 6.3. 3.7.2: Chapters 7.5 and 8.4 discuss field operations in detail.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
3.8 All significant assumptions: 3.8.1 Quantified where possible 3.8.2 Clearly identified in a manner that makes their significance understandable to interested persons, including 3.8.3 A description of changes proposed where the information is not based on the EDB's existing business 3.8.4 The sources of uncertainty and the potential effect of the uncertainty on the prospective information 3.8.5 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	3.8.1, 3.8.2, 3,8.4: Chapter 26 provides key assumptions and uncertainty in the development of the AMP. 3.8.3: Chapter 13 3.8.5: Chapter 26.3.2 describes how we developed the escalators we used to inflate our forecasts into nominal New Zealand dollars in schedules 11a and 11b (refer to Appendix 2).
3.9 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.	This is discussed in Chapter 26.4.
3.10 An overview of asset management strategy and delivery To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify: • How the asset management strategy is consistent with the EDB's other strategy and policies • How the asset strategy takes into account the life cycle of the assets • The link between the asset management strategy and the AMP • Processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented	Chapter 5 explains how corporate vision is translated into Asset Management investment and operational decisions. Chapter 6 explains our approach to asset management decision-making. It discusses the asset management governance structures and responsibilities. It introduces our approach to life cycle asset management. An explanation of how we plan, deliver and monitor investments is detailed in Chapters 7, 8 and 9.
3.11 An overview of systems and information management data To support the AMMAT disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe: • The processes used to identify asset management data requirements that cover the whole of life cycle of the assets • The systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets • The systems and controls to ensure the quality and accuracy of asset management information • The extent to which these systems, processes and controls are integrated	The processes used to identify data requirements are discussed in Chapter 10.4 whereas the systems used to manage asset information and how they are integrated are detailed in Chapter 22.4 and Appendix 12.
3.12 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.	Asset data and system limitations and improvement initiatives are detailed in Chapters 10.4 (refer to Tables 10.3 and 10.4), 22.4 a, 22.5 and Appendix 12.
3.13 A description of the processes used within the EDB for: 3.13.1 Managing routine asset inspections and network maintenance 3.13.2 Planning and implementing network development projects 3.13.3 Measuring network performance.	3.13.1: Refer Chapters 8 and 23. 3.13.2: Refer Chapter 7.2 3.13.3: Refer Chapter 9.5.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
3.14 An overview of asset management documentation, controls and review processes. To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should: (i) Identify the documentation that describes the key components of the asset management system and the links between the key components (ii) Describe the processes developed around documentation, control and review of key components of the asset management system (iii) Where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy (iv) Where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house (v) Audit or review procedures undertaken in respect of the asset management system	Chapter 6 provides commentary on documentation, process and systems.
3.15 An overview of communication and participation processes To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should - (i) Communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants (ii) Demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements	This is discussed in Chapters 2.4, 5 and 10.
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	Figures are reported in constant FY19 dollars. Refer to each chart axis throughout the AMP and Chapter 26.1
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. The purposes of AMP disclosure referred to in clause 2.6.1(2) are that the AMP: (1) Must provide sufficient information for an interested person to assess whether (a) Assets are being managed for the long-term (b) The required level of performance is being delivered (c) Costs are efficient and performance efficiencies are being achieved (2) Must be capable of being understood by an interested person with a reasonable understanding of the management of infrastructure assets (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks	We have refined this AMP to be easier to follow and for an interested person to understand. This includes a flow which better covers the dynamic long-term management of assets, efficient delivery of services and reaching an appropriate performance level. (1) & (2): An overview of the AMP is provided in Chapter 2.5. Chapters 5 to 9 describe how we manage our assets. A glossary is provided in Appendix 1 to assist understanding; and (3): Risk is discussed in Chapter 6.7 and Appendix 6. High Impact Low Probability (HILP) events are specifically addressed in Chapter 6.7.2.
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 4.1.1 The region(s) covered 4.1.2 Identification of large consumers that have a significant impact on network operations or asset management priorities. 4.1.3 Description of the load characteristics for different parts of the network 4.1.4 Peak demand and total energy delivered in the previous year, broken down by sub-network, if any	4.1.1: A high level description of sub-regions is in Chapters 3.2 to 3.4. The extent to which these are interlinked is in Chapter 3.2. 4.1.2: Large consumers are described in Appendix 4. 4.1.3: Load characteristics for our two network regions are described in Chapter 3, and for each of our planning areas throughout Chapter 11. Detailed demand forecasts are included in Appendix 7. 4.1.4: This is provided in Table 3.1 (Chapter 3).

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
4.2 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 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 4.2.3 A description of the distribution system, including the extent to which it is underground 4.2.4 A brief description of the network's distribution substation arrangements 4.2.5 A description of the low voltage network including the extent to which it is underground 4.2.6 An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	4.2.1: Bulk supply points are described in Chapters 3.2.2 and 11, specifically 11.4 and the maps throughout, and Tables 11.28 and 11.29. 4.2.2: The subtransmission system is referred to in Chapters 3.2 to 3.4 and maps and tables are provided throughout Chapter 11. The information required on zone substation capacity is provided in Schedule 12b of Appendix 2. 4.2.3: The distribution system is described at a high level in Chapter 3, along with the extent to which it is underground. Chapters 11 and 15 to 21 describe the distribution system in more detail. 4.2.4: Refer Chapter 19. 4.2.5: The low voltage system is described at a high level in Chapter 3, along with the extent to which it is underground. Chapters 15 to 20 describe the low voltage system in more detail. 4.2.6: Refer Chapter 21. Single line diagrams of the subtransmission network are available to interested parties on request.
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network.	We have two sub-networks: the Eastern and Western regions. The maps in Chapter 3 denote if a GXP is in the Eastern or Western region (Figures 3.3 and 3.4).
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category: 4.4.1 Voltage levels 4.4.2 Description and quantity of assets 4.4.3 Age profiles 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.	An asset summary is provided in Chapter 3.5. The fleet categories and a Portfolio to Asset Fleet mapping are provided in Chapter 7.4.2 . Chapter 14 provides an introduction to our fleet management plans which are provided by each asset category (7 broad portfolios) in Chapters 15 to 21.
4.5 The asset categories discussed in subclause 4.4 above should include at least the following: 4.5.1 Sub transmission 4.5.2 Zone substations 4.5.3 Distribution and LV lines 4.5.4 Distribution and LV cables 4.5.5 Distribution substations and transformers 4.5.6 Distribution switchgear 4.5.7 Other system fixed assets 4.5.8 Other assets 4.5.9 assets owned by the EDB but installed at bulk electricity supply points owned by others 4.5.10 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand 4.5.11 Other generation plant owned by the EDB.	4.5.1- 4.5.8: Refer to Chapters 15 to 21 4.5.9: GXP meters are discussed in Chapters 11.5 and 21.6 4.5.10: Refer to Chapter 18.3 4.5.11: The only generation plants owned by us are a small number of BasePower units on the network. These are modular combinations of micro-hydro, solar PV and diesel generation as a stand-alone power supply to replicate grid supply, along with conversion of heating to LPG. For further information see Chapter 16.4.6
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.	Chapter 9 details the AMP performance objectives and how they are consistent with the business strategies and asset management objectives. This includes targets over the planning period (refer to figures).

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6.	Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next five disclosure years.	Chapter 9.5 and Schedule 12d in Appendix 2 provides this information.
7.	Performance indicators for which targets have been defined in clause 5 above should also include: 7.1 Consumer orientated indicators that preferably differentiate between different consumer types 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	This is discussed in Chapter 9. 7.1: Chapter 9.4 provides customer-orientated indicators. The consumer types that we service are listed in Table 9.10. 7.2: Chapter 9 discusses our network targets, including a summary of the basis of our targets in each Asset Management objective area.
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.	This is discussed in Chapter 9.
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	The figures throughout Chapter 9 provide historical performance for new targets.
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.	This is discussed in Chapters 9.2 and 26.
Network Development Planning		
11.	AMPs must provide a detailed description of network development plans, including:	Network development planning is discussed in Chapter 11.
	11.1 A description of the planning criteria and assumptions for network development	The criteria are discussed in Chapters 7.3.
	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	This is discussed in Chapter 7.3.
	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	The use of standard designs and standardised assets is discussed throughout Chapters 15 to 21. Materials and equipment standards are specifically covered in Chapter 7.5.4
	11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss: 11.4.1 The categories of assets and designs that are standardised 11.4.2 The approach used to identify standard designs	Detailed in Chapters 15 to 21 which are disaggregated to individual asset categorises. The approach used for standard designs is in Chapter 7.5.3, including standardised assets to address obsolescence
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network. The energy efficient operation of the network could be promoted, for example, though network design strategies, demand-side management strategies and asset purchasing strategies.	Our strategy for future electricity network is discussed in Chapter 13.5 and our current initiatives are in Chapter 13.6.
	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. The criteria described should relate to the EDB's philosophy in managing planning risks.	This is discussed in Chapter 7.3.5
	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.	Chapters 6.5, 7.2, 7.3 and 7.4 provide detail on how network development is prioritised, and Chapter 5 provides alignment with corporate visions and goals.

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11.8 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: 11.8.1 Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates 11.8.2 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 11.8.3 Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period 11.8.4 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	Demand forecasts and network constraints are in Chapters 7.3.5, 11.4 and Appendix 7. 11.8.1: The methodology is provided in Chapter 7.3.2. 11.8.2: Forecasts at zone substation level, constraints and the impact of distributed generation are provided in Chapter 11.4 (refer to Tables) and Appendix 7.
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including: 11.9.1 The reasons for choosing a selected option for projects where decisions have been made 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 11.9.3 Consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment	Chapter 11.4 summarises our Area Plans and describes all significant network developments. Appendix 8 discusses all network and non-network options considered for major projects. 11.9.3: Chapters 10, 11.4 and 13.6 describe our current innovation program and strategies.
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: 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 11.10.2 A summary description of the programmes and projects planned for the following four years (where known) 11.10.3 An overview of the material projects being considered for the remainder of the AMP planning period	Chapter 11.4 summarises our Area Plans and describes all significant network developments. Chapter 7.3.8 describes how non-network options are explored to allow deferment of certain network investments. Appendix 8 discusses all network and non-network options considered for major projects.
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.	Chapter 7.3.2 describes how we treat distributed generation in our demand forecasts which informs network development plans. Our policies for connecting distributed generation are available on our website www.powerco.co.nz
11.12 A description of the EDB’s policies on non-network solutions, including: 11.12.1 Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation 11.12.2 The potential for non-network solutions to address network problems or constraints	Refer to Chapters 7.3.8, Chapter 13 and Appendix 8
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12. The AMP must provide a detailed description of the lifecycle asset management processes, including:	
12.1 The key drivers for maintenance planning and assumptions	The drivers and key challenges are in Chapter 8.2.
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 12.2.1 The approach to inspecting and 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 12.2.2 Any systemic problems identified with any particular asset types and the proposed actions to address these problems 12.2.3 Budgets for maintenance activities broken down by asset category for the AMP planning period	Our maintenance strategy is discussed in Chapters 23.2 to 23.4 and forecasts in Appendix 9. 12.2.1 & 12.2.2: Each asset class fleet plan in Chapters 15 to 21 contains known issues and programmes of replacement. 12.2.3: Described in Appendix 10.

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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: 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 12.3.2 A description of innovations made that have deferred asset replacement 12.3.3 A description of the projects currently underway or planned for the next 12 months 12.3.4 A summary of the projects planned for the following four years (where known) 12.3.5 An overview of other work being considered for the remainder of the AMP planning period	12.3.1-12.3.5 (excluding 12.3.2): Chapters 15 to 21 and Appendix 9 covers our renewal strategy which documents all asset replacement and renewal policies and programmes. 12.3.2: Examples are documented in Chapters 11,13, 23.3.3, 23.4.3, 23.5.3, and 23.7.4.
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.	The fleet categories and a Portfolio to Asset Fleet mapping are provided in Chapter 7.4.2. Chapter 14 provides an introduction to our fleet management plans which are provided by each asset category (seven broad portfolios) in Chapters 15 to 21.
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	Chapter 22 and Appendix 12 describe non-network assets.
13.2 Development, maintenance and renewal policies that cover them	Maintenance and renewal strategy are discussed in Chapter 22.
13.3 A description of material capital expenditure projects (where known) planned for the next five years	Refer to Chapter 22.5 and 22.7.
13.4 A description of material maintenance and renewal projects (where known) planned for the next five years	The major projects are described in Chapter 22, with expenditure forecasts included in Chapter 26.
Risk management	
14. AMPs must provide details of risk policies, assessment, and mitigation, including:	Chapters 6.6 and 6.7 provides an overview of risk management, including details of our policies and processes for assessment and mitigation.
14.1 Methods, details and conclusions of risk analysis	14.1: Methods are discussed in Chapter 6.7. The details of risks are provided in Appendix 8.
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.	14.2: This is discussed in Chapter 6.7.2.
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 16.2.	14.3: This is discussed in Chapter 6.6
14.4 Details of emergency response and contingency plans.	14.4: This is discussed in Chapter 6.7 and Appendix 6 (risks 7 and 11)
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. i) Referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances ii) Commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced iii) Commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted	This AMP contains objectives, targets, and the rationale for these targets is in Chapter 9. 15.1: Project and expenditures variances are described in Appendix 5. Additional material is provided throughout Chapters 15 to 21.

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15.2 An evaluation and comparison of actual service level performance against targeted performance: (1) In particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances	Chapter 9 provides an evaluation of performance against historic targets.
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.	15.3: Refer to Chapters 10.5 and Schedule 13 of Appendix 2.
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.	Chapter 9 describes our initiatives for each category of network targets and Chapter 10 for delivery initiatives.
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.	Chapters 5 and 6 describe how we ensure the AMP is realistic and objectives can be achieved.
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Chapter 6 describes the processes and organisational structure we use for implementing the AMP.

APPENDIX 14 DIRECTOR CERTIFICATE

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

~~Pursuant to clause 2.9.1 of Section 2.9~~

We, John Loughlin Director and Paul Callow being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Powerco Limited prepared for the purposes of clauses 2.6.1, 2.6.6, and 2.7.2 of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which with align with Powerco's corporate vision and strategy and are documented in retained records.

Director

Director

14/3/19

Date

14/3/19

Date

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