Electricity Asset Management Plan

2023

POWERCO

FOREWORD FROM OUR CEO

Kia ora koutou

Our 2023 Asset Management Plan represents a well-prepared plan focused on our customers. It outlines the work we believe we need to carry out during the next decade to provide the reliable and resilient electricity networks our customers will increasingly rely on, both at home and at work, as our country decarbonises. This is fundamental in helping Aotearoa New Zealand meet its target of net-zero emissions by 2050.

The plan is a substantial review and reset of previous plans. It was, however, prepared before Cyclone Gabrielle. The work in this plan remains necessary and important. It must get done. The themes in the plan remain the right ones and they chart a path to a sustainable transition:

1. **Mitigate** harm from climate change – enable decarbonisation through electrification.
2. **Adapt** to climate change – adapt and harden the network as we rely on it more, and as it is exposed to the increasing effects of climate change.
3. Ensure it is **affordable** to Kiwis – invest intelligently to mitigate expenditure increases and, therefore, the costs to customers.

But there is much to learn from Cyclone Gabrielle and its terrible impact on communities. Its sheer intensity is challenging even our latest thinking. It is possible that some of the work outlined in the plan will need to be accelerated, and it is likely that additional work will be necessary to adapt and increase the resilience of our network.

An important national conversation is under way about what is the right level of resilience for our infrastructure – we will participate willingly and constructively. However, it is the work of months, not days, and so is not reflected in this plan.

In the meantime, pragmatic thinking is required to make ‘no regrets’ investments that will increase resilience. Our people are already working on this, driven by the desire to ensure the electricity is on when our customers need it and we’re here should they need us.

Much of this is captured in this plan, as it already recognises that the past is a poor guide to the future, and investment, coupled with really innovative thinking, is needed to mitigate, adapt, and enable an affordable energy transition.

I am very proud of how our Powerco whānau responded to Cyclone Gabrielle. More than 105,000 households and businesses on our network were without power for periods during and after the cyclone, but our people, our contractors and, indeed, our whole industry worked collectively and safely to restore power to customers as quickly as possible.

The major investment programme we have undertaken during the past five years ensured Powerco was geared up and had the muscle to respond quickly. Even so, some customers were without power for days.

As we decarbonise, more of what we do will rely on our clean green electricity system. One of the many questions we are contemplating is, setting aside the traditional engineering measures, just how long is it OK for someone to be without power?

As I have noted above, the work in the plan is all-important and must be delivered. But as we learn from Cyclone Gabrielle and its impact on people, increased and diverse investment will be needed in future plans. We will work with all stakeholders to understand what this may mean as we continue to focus on connecting communities now and in the future.

Our thoughts and best wishes to all whose lives have been so badly affected by Cyclone Gabrielle.

Kia kaha Aotearoa

James Kilty
Chief Executive Officer

CONTENTS

INTRODUCTION

This section introduces our 2023 Electricity AMP and provides an overview of the network.

1 EXECUTIVE SUMMARY

1.1 INTRODUCING OUR 2023 ASSET MANAGEMENT PLAN

Since we published our last comprehensive Asset Management Plan (AMP) in 2021, there have been considerable movements in New Zealand's energy environment. Key among these has been the firming up of New Zealand's decarbonisation goals and the plans to achieve these. There are major implications for the electricity sector as a result.

There is now an almost universal consensus that for New Zealand to meet its emissions reduction goals, electrification will play a central role. Indeed, this will be "the big game in town" for electricity distribution for the foreseeable future.

Electrification of the remaining energy-intensive areas of our society will require a major transformation of our industry. An intended 'just in time' approach to delivery will likely see us fail to keep pace with customer and electrification needs. Advance planning and investment will be essential, as will accelerating our ability to deliver major projects, to innovate and drive smart new solutions. In addition, we will have to work ever more closely with customers to ensure that, collectively, we come up with optimal energy solutions which deliver to their expectations in the most efficient manner.

If we should fail in this transformation and continue on a traditional network investment path, there are serious questions about the capacity of New Zealand – both in human and capital resources – to deliver to our decarbonisation goals.

The way in which our customers approach their energy use will also fundamentally change. This will be partly driven by developing technology and the new opportunities this offers, but also by our customers' attempts to reduce their own carbon footprint.

2022 has proved to be the year when the transformation of our industry finally seemed to become real, as witnessed by hugely accelerating uptake rates of distributed generation (large and small scale) and electric vehicles (EVs), and the greatly increased sense of urgency in the energy sector to come up with workable transition strategies, including planning major changes to the electricity market. These trends are expected to continue to accelerate for the foreseeable future.

To quote the Boston Consulting Group:

> ***The 2020s will be a critical decade for the electricity sector and New Zealand's transition to net zero carbon.***[1]

On top of the need to prepare for the electrification of our society, there is a heightened sense of urgency around rethinking and ensuring appropriate customers' energy resilience levels. Major climatic impacts, like those recently resulting from Cyclone Gabrielle, are anticipated to increase in frequency and severity, with major implications for all critical infrastructure providers. While our AMP focuses on electricity distribution, resilience is clearly a much wider societal issue that will demand extensive attention and resources.

All of this lies ahead during the planning period for this AMP, which outlines our plans for our electricity network and business improvements for the next 10 years[2]. Responding to the opportunities and challenges ahead will require a significant uplift in investment and this plan is, therefore, a material upgrade from earlier AMPs.

At the same time, we continue to recognise that, with electricity a key enabler for economic prosperity and a modern lifestyle, our prime responsibility remains to supply our customers safely, reliably, and efficiently. Our traditional network investments for growth, renewal, and reliability remain the bulk of what we do, and this is reflected in the AMP.

While future energy market arrangements are still being developed, we will ensure that the network remains safe and stable and provides sufficient capacity under any reasonable energy use scenario. The rate at which our network will transform will, ultimately, be dictated by our customers evolving needs, including their uptake of distributed energy generation or new devices connected to the network.

1.2 STEPPING OFF THE CPP PROGRAMME

Our Customised Price-quality Path (CPP) programme ends on 31 March 2023. At the time of finalising this AMP, there are still a few major projects to commission, but these and the rest of our planned works are well on track for on-time completion.

We intend to conduct a detailed look back on and review the efficacy of this programme and will publicly share our findings with interested parties later in 2023. We also published annual interim progress reports (Annual Delivery Reports[3]) on progress to date. It is already evident that this programme has been very successful in achieving its primary objectives of preventing the further deterioration of our asset base and providing sufficient capacity to cater for demand growth[4].

For FY24 and FY25 we will revert to a Default Price-quality Path (DPP) and have recently been informed of the Commerce Commission's determination of the revenue settings for this.

We are considering funding options for post the current DPP period. Our forecast is for significant expenditure increases as we develop the network for accelerated electrification. It is not yet clear whether or how such accelerated expenditure could be accommodated in the DPP4 setting. The Input Methodology rules that will determine this are under review and we expect these to be finalised by early 2024.

We consider it critically important that electricity distribution regulatory settings are evolved to reflect the realities of delivering to New Zealand's decarbonisation

1 Boston Consulting Group, "The Future is Electric: A decarbonisation roadmap for New Zealand's electricity sector", October 2022.

2 The AMP planning period runs from 1 April 2023 to 31 March 2033.

3 Copies of the ADR are available on https://www.powerco.co.nz/publications/disclosures/electricity/

4 Severe weather patterns have resulted in reliability issues in 2022, but the impact of this was muted by improved asset condition.

goals[5]. While there is still some timing uncertainty, it is by now abundantly clear that major electricity infrastructure development will be essential to achieve this. An inability to invest sufficiently in electricity infrastructure or the required enabling works will potentially seriously hamper our country's ability to meet its goals.

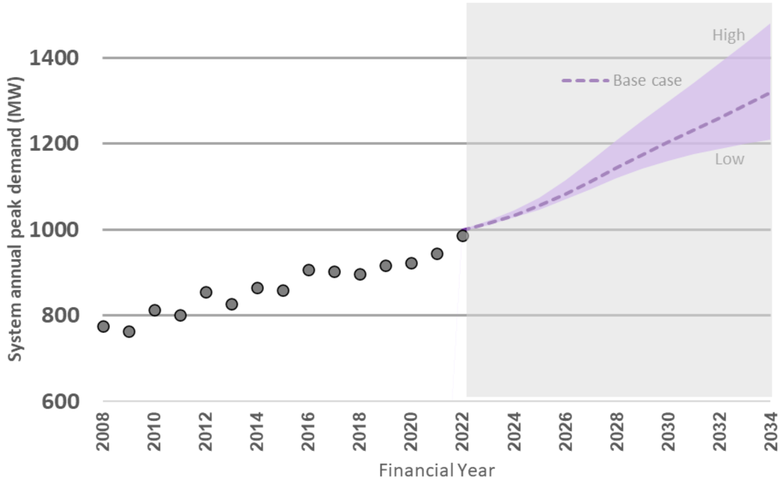
1.3 LOOKING AHEAD

We project a period of major network demand growth, primarily driven by:

- Organic growth on our network (growing populations and economic activity)[6].
- Increasing use of EVs.
- Conversion of large heat processes to electricity.
- (Potential) phasing out of gas distribution networks.
- Conversely, increasing the uptake of distributed energy resources (DER) will reduce peak demand.

Our current network-wide peak demand forecast is shown in Figure 1.1. Given the major uncertainty in the underpinning assumptions, we view this over a range, with detailed AMP planning conducted around the base case.

Figure 1.1: Powerco's forecast peak demand range during the AMP planning period



Despite the expected growing prevalence of DER, a large majority of our customers will continue to use centrally generated electricity as their key energy source. It is also important to note that our networks still provide the "last mile" connection to customers that is essential to support them to export excess generation or participate in flexibility or electricity markets.

As such, renewing and maintaining our networks to ensure the safety of the public and our service providers, as well as the reliability of our networks, remains paramount.

The scale of infrastructure required to keep servicing customers and meet the growing demand could be substantial. Therefore, it is essential that we consider all means possible to limit the required investment and the resulting cost impact on our customers.

Increasing the utilisation of our existing asset base will be a key factor in keeping costs down, as this will help limit or defer the need for reinforcement. To achieve this, we will have to enhance our ability to develop and implement smart, innovative solutions that can be used in conjunction with our existing assets to safely extend their lives and/or utilisation or can reduce the extent of new assets required to provide acceptable service levels.

Another key will be the deeper, earlier involvement of our customers in our decision-making. This will help us consider the dynamic nature of customer demand and available network capacity, and improve the match between these factors, resulting in potentially significant cost reductions.

We also intend to maximise the use of flexibility services procured from our customers (or other third-party providers), where these provide cost-effective network solutions.

However, even if we were highly successful at embedding the improvements noted above, we still expect a considerable increase in network expenditure during the AMP planning period. Most of our network expenditure will remain on conventional electricity network assets and practices. 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 existing customers. Investment in asset renewal, maintenance, and growth of conventional network assets will remain paramount.

We have ramped up the replacement rate for assets reaching the end of life during the CPP period, to a level where we are now essentially maintaining the average asset age and condition. Our data shows that for the foreseeable future, renewals will have to remain at current rates to maintain the stable health and reliability of our network.

5 This applies to commercial regulation (Commerce Commission) as well as market regulation (Electricity Authority).

6 Organic demand growth on the Powerco footprint has averaged 1.8% per year during the past decade compared with the country-wide average of 0.3% (as derived from "NZGP1 Scenarios Update", Transpower New Zealand Ltd, Dec 2021).

As an example, the age profiles for our wooden pole fleet are shown in Figure 1.2, and for our distribution conductors in Figure 1.3. With an average expected asset life of 45 years for wooden poles and 50-60 years for conductors, the extent of required future renewals is evident.

Figure 1.2: Wooden poles age profile

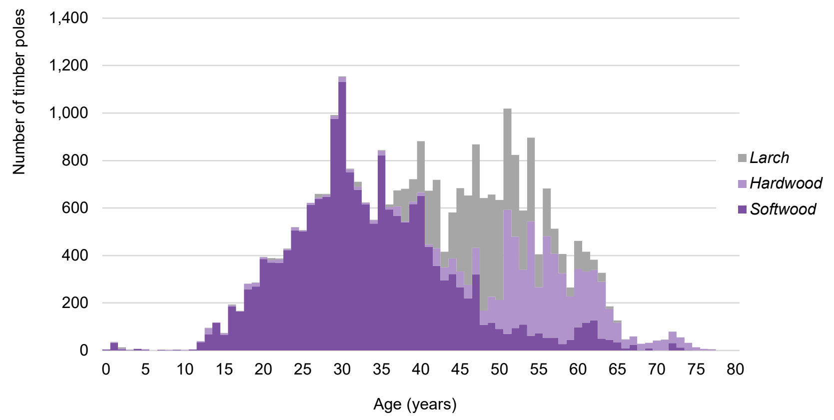
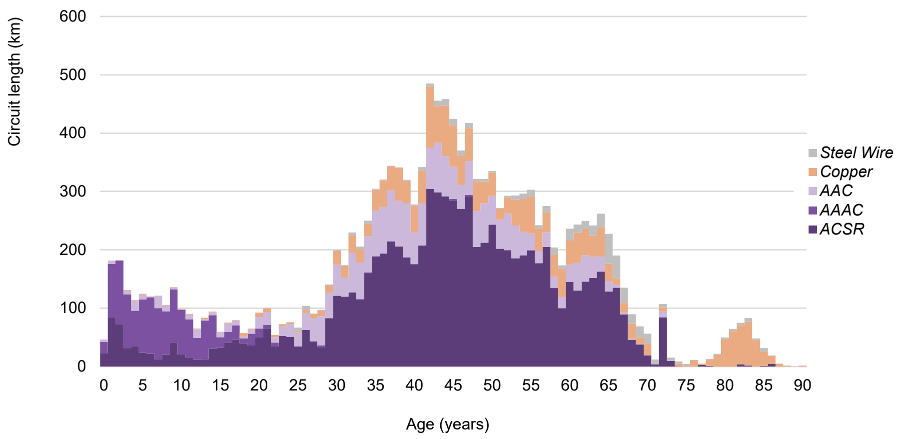


Figure 1.3: Distribution conductors age profile



Similarly, forecasts are for continued population and demand growth in large parts of our network. We will continue to expand and reinforce the network to cater for the needs of these new customers.

1.3.1 EXTERNAL FORCES SHAPING OUR NETWORK

In Chapter 3 we discuss some of the main external factors that we must consider in planning our network. These include:

- The urgency of electrification to help meet New Zealand's decarbonisation goals, with the resulting expectation for major electricity demand growth.
- Ongoing, organic network demand growth in populated areas.
- Network resilience and sustaining supply in the face of climate change impacts.
- The need to reduce our own environmental impact and to support our customers to do the same.
- Increasing applications for distributed generation connections, large and small.
- Changes in land use in rural areas, further reducing electricity demand, particularly in remote areas.
- Energy poverty is emerging as a major issue for a significant part of our customer base.
- The (slow) evolution towards a distribution system operator (DSO).
- Changes in customer technology and how they manage their energy use, including the impact of the so-called 3Ds – decarbonisation, digitalisation, and decentralisation.
- Changes in network technology and the opportunities this provides.

These factors have been driving changes to our Asset Management Strategies and are reflected in our network development and renewal plans.

1.4 OUR 10-YEAR EXPENDITURE FORECASTS

1.4.1 OVERVIEW

Our expenditure forecasts are based on our best current information regarding network use and performance trends, and a prudent allowance for readying the network for expected future changes.

1.4.2 CAPITAL EXPENDITURE

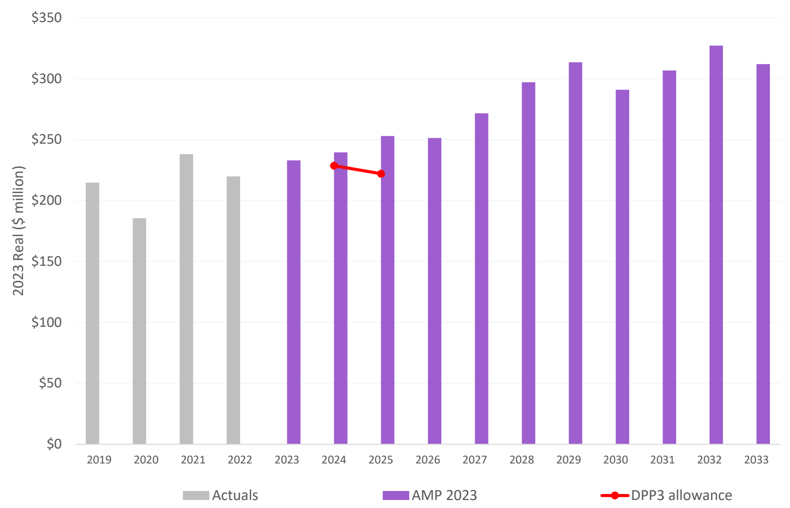
The forecast 10-year capital expenditure base case trend is shown in Figure 1.4. This forecast well exceeds current regulatory allowances, which are based on our most recent expenditure levels.

Our planned capital investments for the 2023-2033 period are further detailed in Chapter 24. The initial years reflect:

- 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.
- Modest expenditure on research and development, trials of emerging technology, and improving our low voltage network visibility and performance.
- Increasing investment in network enablement, including expanding visibility across our networks, particularly at lower voltage levels.
- Information and communications technology (ICT) and other non-network expenditure are set to remain roughly at current levels as we continue to invest in an Advanced Distribution Management System (ADMS), extend our enterprise resource planning (ERP) foundation, and complete a major upgrade to our Geographical Information System (GIS).

The forecasts for later in the planning period provide for a major uplift, reflecting the required network expenditure to keep pace with expected demand growth, including upgrading the bulk electricity supplies to parts of our network, most notably the eastern Bay of Plenty.

Figure 1.4: Forecast capital expenditure (AMP base case)

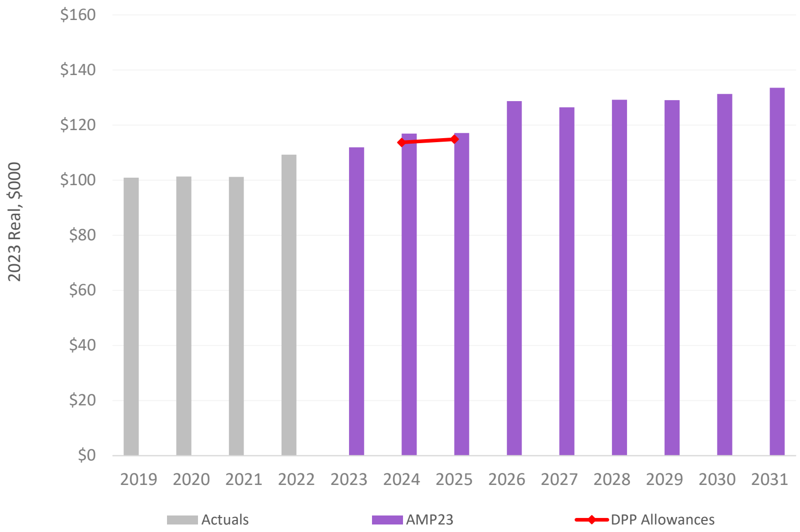


1.4.3 OPERATIONAL EXPENDITURE

The focus for operational expenditure during the planning period is set out in detail in Chapter 24. Our updated operational expenditure for the AMP planning period is shown in Figure 1.5 and displays a substantial increase from current levels. This reflects:

- Salary and wage growth, which is currently at exceptional levels and could increase even more as competition for skilled resources heats up.
- Increased contracting costs, again reflecting competition for scarce resources.
- The uptake of new digital solutions, including cloud services, with associated higher data network, software maintenance or subscription costs.
- An anticipated substantial increase in the use of flexibility services (Opex) as an alternative to (more costly) Capex alternatives.
- Increased maintenance as the electricity network grows.
- Increased communications costs as more intelligent devices are rolled out.

Figure 1.5: Forecast operating expenditure (AMP base case)



2 A DECADE OF CHANGE AHEAD

2.1 INTRODUCTION

The 2020s will be a critical decade for the electricity sector and New Zealand's transition to net zero carbon. With decisive, early action supported by the right policy, regulatory, and market settings, the electricity system can:

By 2030
Transition to 98% renewables and kick-start electrification, reducing New Zealand emissions by 8.7 Mt CO_2-e per year

By 2050
Enable rapid electrification of transport and heating, reducing New Zealand emissions by 22.2 Mt CO_2-e per year

Source: Boston Consulting Group[7]

Since we published our last comprehensive AMP in 2021, there have been considerable movements in New Zealand's energy environment. Key among these has been the firming up of New Zealand's decarbonisation goals and the plans to achieve these, with major implications for the electricity sector. There is now an almost universal consensus that for New Zealand to meet its emissions reduction goals, electrification will play a central role. Indeed, this will be "the big game in town" for electricity distribution for the foreseeable future.

This is captured in the recently released national Emissions Reduction Plan[8]. It explicitly sets out expectations for how the electricity sector will have to contribute, including requirements for ensuring the electricity system is ready to meet future needs:

- Investigating the need for electricity market measures to support the transition to a highly renewable electricity system.
- Reducing barriers to developing and efficiently using electricity infrastructure, including transmission and distribution networks.
- Supporting industry to improve energy efficiency, reduce costs and switch from fossil fuels to low-emissions alternatives.
- Setting a target of 50% of total final energy consumption to come from renewable sources by 2035.

Electrification is also seen as key to decarbonisation by industry observers. In its far-reaching report on the future use of electricity in New Zealand[9], the Boston Consulting Group sets out how New Zealand can not only achieve but even exceed, its carbon reduction goals through effective electrification while delivering more affordable household energy than today. Achieving this would, however, require a rapid transformation of the electricity system, starting in the 2020s.

Powerco is fully committed to New Zealand's decarbonisation goals, and we acknowledge our critical role in helping these be achieved.

For some years now there have been early signs of an energy transformation on the cards. 2022 has proved to be the year when the transformation finally seemed to become real. We have seen major step-ups in distributed energy activity, and the use of electric vehicles and we are increasingly in discussions with customers wanting to change carbon-fuelled processes to electricity – and perceive that this is just the start! Industry activity, planning, and discussions on how to meet decarbonisation goals have also greatly ramped up across all sectors and it is gratifying to see the high degree of collaboration on this. There is broad recognition that we have no time to waste and that we're all in this together.

This sense of urgency is heightened by the increasingly intense and damaging storm events affecting New Zealand. As our planet warms, we are likely to see more climate change-related events, with increasing severity. The impact on our network will be serious. Therefore, increased attention on network resilience is needed – avoiding or limiting outages from weather events, or allowing rapid, effective restoration and recovery after such events.

Looking at the next 10 years, we foresee a period of major change as we, along with the rest of the electricity supply industry, position ourselves to deliver to this two-pronged climate-driven requirement. Hardening our networks and delivering significantly increased electricity volumes will also require considerable capacity and investment.

This challenge could be so great that, unless our industry develops highly innovative, effective energy solutions in close collaboration with our customers and each other, there may not be sufficient resources – human, capital, or material – in New Zealand to successfully meet it. An intended 'just in time' approach to delivery will likely see us fail to keep pace with customer and electrification needs – Aotearoa does not have the capacity for reactive rapid build without a material adverse impact on other infrastructure classes in need of urgent investment.

Our AMP has been prepared with a focus on the urgent transformation of our industry and what we need to do to deliver this. To set the scene for the plan, below we give a high-level overview of its main themes and how we intend to respond.

- Electrification of our society will create significant demand for more electricity. This has major ramifications for how we must invest in and manage our networks to deliver to our customers' increasing needs while ensuring cost increases are kept to a minimum.

[7] Boston Consulting Group, "The Future is Electric: A decarbonisation roadmap for New Zealand's electricity sector", October 2022

[8] Te hau mārohi ki anamata. Towards a productive, sustainable, and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/)

[9] Supra note 7

- The opportunities and incentives associated with decarbonisation are having a significant impact on how our customers manage their energy use and how they expect us to support them. Energy consumption patterns will change, and we foresee much-increased activity in distributed generation and in customers' participation in distributed energy resources (DER) and flexibility markets.
- As noted, we will need to 'harden' the network to meet increasing climatic extremes. This is happening simultaneously with an increasing societal reliance on electricity as the dominant energy source for most needs. It will be essential to enhance reliability and resilience standards.
- Energy affordability is an increasing concern. It is of great importance to our society that the decarbonisation transition and network hardening is affordable. We have a critical role to play in helping ensure this through the efficient delivery of optimal, innovative energy solutions. We also have to provide targeted support for those groups of our customers that suffer energy hardship.
- We expect strong competition for skilled, capable staff as the industry (and the whole economy) transforms. It is essential that our working environment is attractive to the right people, as well as providing great training opportunities.
- There is a financial shift underway for electricity distribution businesses (EDBs) as operating expenditure becomes a larger proportion of their total expenditure. This is anticipated to accelerate as we increasingly use non-network solutions, such as flexibility services, and our operations rely more on cloud-based information technology.

Our plan for responding to these factors is built into this AMP and is set out at a high level in this chapter.

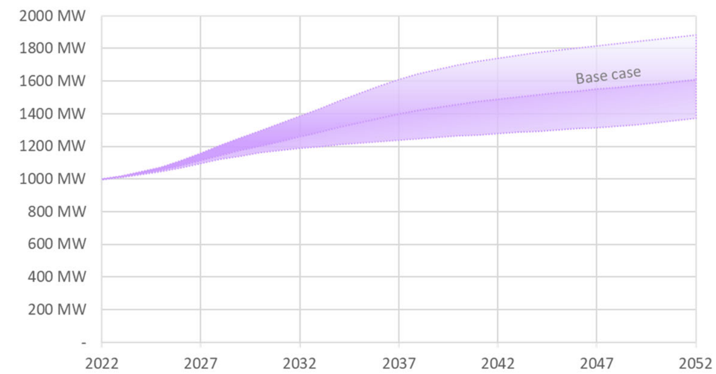
While this discussion focuses on the changes associated with the energy transformation, it is noted that the principles of our core business do not change. Our primary responsibility remains to deliver reliable electricity to our customers while ensuring their safety and the safety of our service providers. Sustainable asset management is essential for long-life assets that are to provide a stable, essential service to our community for an extended period (typically 45+ years). Ongoing investment in this network is essential and, as such, it represents the bulk of our planned investments and is, indeed, the focus of most of the latter chapters of this AMP.

2.2 MEETING THE FUTURE NEED FOR ELECTRICITY

The rapid electrification of our society will have a major impact on peak electricity demand and the infrastructure we will need to meet this demand. The rate of this increase is highly uncertain and, therefore, we plan within a likely demand range for the next three decades, as illustrated in Figure 2.1. Figure 2.2 also shows the extent of the accelerated growth forecast compared with historical trends[10].

Several key assumptions underpin these demand forecasts, which we will continue to refine over time. We are working with other EDBs and the ENA[11] to standardise some of these assumptions across the industry. In addition, we are also working with Transpower on aligning our forecasts with their countrywide analysis[12].

Figure 2.1: Powerco's long-term forecast peak demand range



The key factors that will drive demand growth are forecast to be:

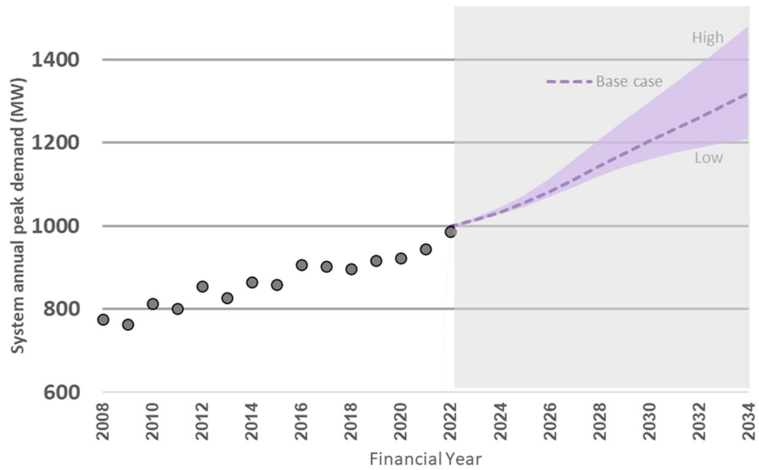
- Organic growth on our network (growing population and economic activity).
- Increasing use of electric vehicles (EVs).
- Conversion of large heat processes to electricity.
- (Potential) phasing out of gas distribution networks.
- Conversely, the increasing uptake of DER would reduce peak demand.

[10] As discussed in later chapters, our historic demand growth rate is by itself considerably higher than the country-wide average.

[11] Electricity Networks Association of New Zealand

[12] Recognising the differences in underlying organic growth rates between our networks.

Figure 2.2: Powerco's forecast peak demand range over the AMP planning period



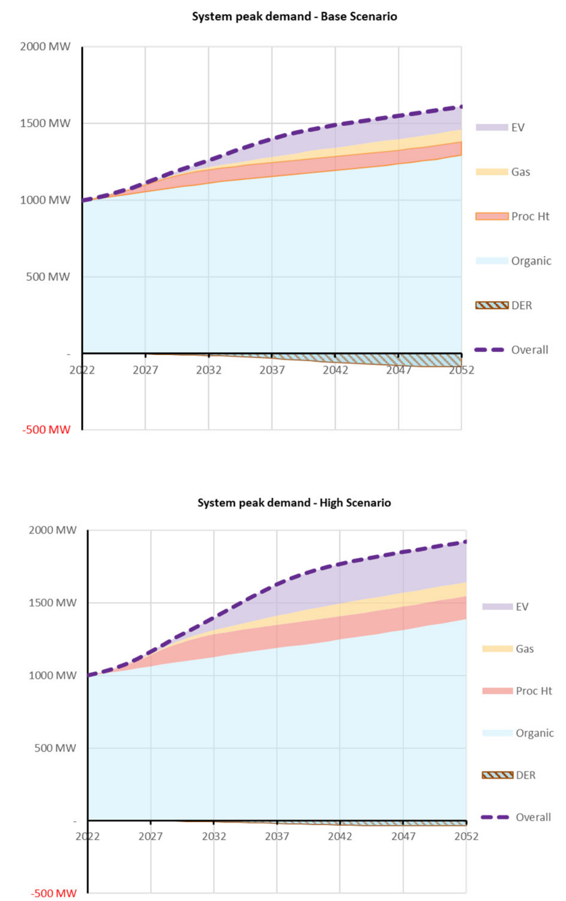
These peak demand forecasts are particularly sensitive to the following:

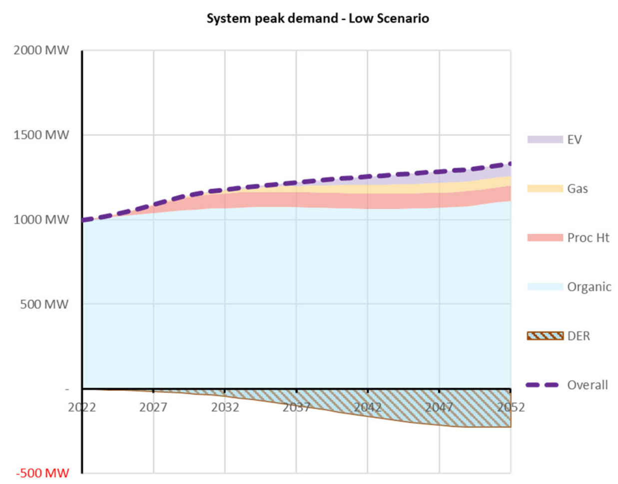
- Forecast population and economic growth rates, affecting organic growth.
- EV uptake rates.
- EV charging behaviour (particularly how much will happen during peak or off-peak times).
- Average distance travelled per day.
- Conversion rate to electricity for large heat processes.
- The future of gas distribution networks.
- Uptake rate and effectiveness of DER (and other flexibility services).

Based on scenario ranges for the above (and other) factors, our current view on how these could contribute to future demand is shown in

Figure 2.3.

Figure 2.3: Contribution of main factors to forecast demand – scenarios considered





Our AMP planning is built around the base case forecast scenario (shown in Figure 2.2). Providing capacity for this magnitude of load growth will place considerable demands on our resources and those of our service providers. We are also acutely aware that while time horizons and the main contributing drivers may vary between companies, all parts of the electricity supply chain will face material uplifts in demand during the coming decade. In their report, the Boston Consulting Group[13] estimates that during the remainder of the 2020s, expenditure from the various sectors could be:

Utility-scale generation	**$10.2Bn**
Flexible generation	**$1.9Bn**
Transmission	**$8.2Bn**
Distribution	**$22Bn**

Distribution utilities are forecast to increase their spend by about 30% in the second half of the decade if we pursue the most efficient pathway in their report ("Smart System Evolution").

[13] Supra note 7

It is unlikely that New Zealand as a whole will be able to achieve this order of infrastructure investment unless we make some fundamental changes in how we approach it. We are, therefore, strongly focused on how we can meet the growing decarbonisation needs as efficiently as possible while minimising expenditure. Key to this will be improving asset utilisation rates, both on our networks and in customers' installations, and eliminating energy waste.

We anticipate capturing the potential reductions in the required investment[14] by changing our approach to how we plan and operate our network. Accordingly, we are developing new investment solutions and will continue to improve and expand these to mitigate the required increase in expenditure. At the heart of this lies a drive to maximise the utilisation of existing assets (or minimising the need for new assets), while still providing the capacity and service quality our customers require. Important examples are:

- **Probabilistic design standards.** A more analytical, risk-based approach to security of supply (compared with traditional deterministic standards), is leading to better informed, economically sound decisions that often help avoid or defer reinforcement and renewal investments, while still accommodating the need to harden the network against climate change impacts.
- **Working closely with customers** to optimise their supply arrangements. Both customer demand and network capacity vary over time, even within a day. Peak demand or network capacity constraints often only occur for relatively short periods. By improved synchronising of customer peak demand with available network capacity, we are often able to significantly reduce the need for new connection infrastructure or network reinforcement. This requires a deep understanding of customers' process requirements and the flexibility or constraints they have in their energy use patterns and matching it with the capacity of our supply network. It could also involve measures to increase capacity for short periods of time.
- Closely linked with the above, we are working on **creating a dynamic view of available supply capacity** on various parts of our network. Just as customers' electricity demand often shifts between seasons, so does the capacity of our network. As noted, better supply and demand matching can often materially reduce required reinforcement investments.

  These benefits equally apply to distributed generation installations, which may be constrained by our network's hosting capacity. By collaborating on a more dynamic view, matching generation output and network capacity, significantly larger installations may be possible without costly capacity upgrades or only having to limit export for short periods of actual network congestion.
- Actively **encouraging the uptake of flexibility services,** such as DER or demand management. This will be procured from customers or third parties, or

[14] In comparison with counterfactual, which is reinforcing the network to meet notified peak demand by building more conventional network assets. See for example the 'Smart System Evolution Pathway' vs the "Business as Usual Pathway" in the Boston Consulting Group's report "The Future is Electric".

provided by ourselves if more economic to our customers. By better managing demand, asset utilisation can be improved, reducing the need for investment.

- **Real-time asset ratings**. By better understanding the condition and real-time operating environment of key network assets, we can make informed decisions about changing their utilisation. This often allows higher utilisation levels, enabling the deferment or avoidance of reinforcements.
- **Low voltage (LV) network monitoring**. The large majority of our customers connect to our LV networks, which traditionally have been largely out-of-sight, out-of-mind. As customers' energy needs and the use of DER increase, LV networks will likely become areas of major congestion and power quality problems. To avoid major investments to address this, we will need to start actively managing the LV networks. This will require visibility of power flows on all parts of the network and, increasingly, the ability for automation and remote operation.

These measures will allow us to reduce network reinforcement needs and will also guide our renewal decisions. However, even if fully adopted, meeting the expected magnitude of increasing energy needs and network hardening will still require considerable investment in traditional core infrastructure. This will be further compounded by ongoing growth in customer numbers and the widespread deployment of major utility-scale generation plants (solar photovoltaics or wind) connected to our networks.

In addition, a significant proportion of our forecast growth expenditure will be on reinforcing bulk electricity supply to parts of our network.

2.3 CHANGING CUSTOMER EXPECTATIONS

While the scale of the electricity demand increase, we face in coming years is exceptional, electricity networks have always had to deal with changing use patterns. Therefore, the basic frameworks for dealing with additional demand are largely in place[15].

However, what makes the upcoming transition more challenging is that the very nature of the energy market is changing. Over time, we foresee a shift away from being a monopoly service provider to a more competitive market, where our sustained success will depend on the value we deliver to customers.

Of particular interest to distribution utilities in the short to medium term will be the way in which our customers respond to reduce carbon emissions and the cost of energy. Some of the changes we see ahead are:

- Customer participation in flexibility markets, particularly around DER and demand management.
- Self-generation of all or part of customers' own energy requirements.

[15] Accepting that we'll need fresh thinking on the nature of the solutions, as discussed before.

- Exporting excess generation.
- Changing land-use patterns. As the physical and economic environment changes, our customers adapt their own activities. In rural areas, in particular, the use of land is changing over time. This has major implications for future energy use and the capacity and quality of service we have to provide.
- Microgrids, which are still grid-connected for occasional supply backup. This could be supported by energy aggregators.
- Competition between suppliers of stand-alone power generation and grid-supplied electricity.

Powerco supports customers' choice and has a stated objective of encouraging flexibility in energy use through developing an open-access network.[16]

Customer-provided energy services could greatly benefit supply networks, and we fully intend to procure these services where this is the case. We recognise that there are power capacity, quality and pricing implications associated with these applications, but rather than create restrictions, we see it as our role to develop the network to effectively manage these issues. In doing so, we will also ensure that there are no detrimental impacts on other consumers and that the cost implications are fairly reflected.

Powerco has several initiatives in place to accommodate customers' changing energy expectations. These include:

- Increasing our visibility of network utilisation, including on the LV networks. This is a prerequisite to facilitating the uptake of DER and for customers to export larger volumes of energy.
- We have already started to procure flexibility services from third-party providers and intend to greatly expand on this in the future.
- During 2023, we intend to expand our customer engagement to help us understand their intended future land and energy use, as well as provide better-informed calculations of the cost of un-served energy (or the value they place on electricity). These are fundamental inputs into improving our planning processes and ensuring we deliver what our customers seek and value.
- We are actively supporting a number of social groups in developing their own microgrids, with local generation and grid backup.

Other important changing aspects of customers' expectations include:

- Customer service. Modern customers expect excellent and flexible customer service, including quick response times. They also expect rapid, accurate information about aspects affecting them, such as outages.

[16] We particularly see that supporting customers' flexibility would materially benefit more widespread adoption of carbon emissions-reducing solutions.

- Focus on cost efficiency. Customers find it highly frustrating when they perceive an installation costing more than it should, with no recourse to challenge this.
- As we increasingly rely on electricity as our only energy source, the importance of reliability and resilience in supply also increases. The impact of electricity outages on customers will continue to grow.
- Social responsibility. Customers increasingly expect their suppliers to recognise and act on their environmental, social and governance (ESG) responsibility. It is now a basic expectation that we will demonstrate:
  - Our commitment to protecting the environment.
  - How we are reducing our carbon emissions.
  - No procurement of equipment from countries where modern-day slavery or child labour occur.
  - Our commitment to equitable employment practices, with no discrimination based on race, gender, sexual orientation, religion, or the like.

Powerco is acutely aware of these expectations. We recognise a need to improve our customer service and, as a key business objective for 2023, we plan to make a major improvement to all areas of our customer processes and interfaces. Likewise, improving our cost efficiency is another key objective for 2023.

In terms of ESG, we are proud of what we have achieved so far, but also realise this will need ongoing vigilance and commitment.

We also accept the increasing societal importance of the reliability and resilience of our network. Addressing this is woven throughout the Network Development and Fleet Management sections of this AMP, as well as in specific initiatives to improve network performance, such as automation, remote fault identifiers, and increased network monitoring.

2.4 RESPONDING TO CLIMATE CHANGE

Considering the impact of a changing climate on our operating environment is a very important aspect of planning the electricity network of the future. We continue to analyse and expand our understanding of the likely impact of climate change on our network footprint area.

Our rural, overhead networks are designed to withstand long-established, realistically expected patterns in climatic factors, such as wind intensity and direction, tree damage, land movements and snow loading. However, it is forecast that the severity and frequency of events exceeding design parameters will increase materially in the future, as the impact of climate change manifests. There is recent evidence of this, with our network having experienced an unusual number of major storm events in the past 12-18 months.

While our urban networks have traditionally been more protected against the climate, particularly the undergrounded sections, this is also changing. Recent incidences of major flooding and land movements are indicative of what we foresee for the future.

The impact of more severe operating conditions, for both rural and urban networks, is already reflected in our AMP planning. This relates to asset type selections, planning and design, monitoring and operation of the networks, and maintaining suitable sticks of critical spares. We also intend to roll out generation in remote areas that can provide back-up supply when long, exposed supply lines are damaged.

However, an in-depth review of network resilience to emerging climate extremes is planned for 2023. Following this, we will consider the architecture of our network and our design standards, to ensure appropriate resilience. Re-designing the network of the future to be resilient to climate change impacts will indeed be a core activity going forward.

Also of importance, is how we minimise our own carbon footprint at Powerco. To this end, we have developed a sustainability plan that sets out our commitment to reducing our emissions and the steps we plan to take to achieve this. This plan is also built into our AMP activities.

We recognise that there is somewhat of a contradiction between achieving network resilience and reducing our carbon footprint. Network resilience will likely require expanding our network footprint, with associated manufacturing and construction emissions. We are also looking into the more widespread use of remote generation (diesel or gas), which is a highly effective way of improving resilience but also has an increased emissions price.[17]

A careful balance will have to be struck to meet our objectives.

2.5 OTHER BIG CHANGES

While responding to climate change and forecast required network developments are our big focus for the next decade, there are also a number of other factors that require significant attention.

Access to skills

We foresee a major ramp-up in activity right across the electricity sector. This will require technical resources at all parts of the supply chain, from planners and engineers, project managers, and construction crews through to operators. Business support and information technology resources will also be needed to keep organisations and supply chains running smoothly.

[17] We also note that for the foreseeable future, we will still be employing SF_6-filled switchgear, particularly where we have space constraints. Our engineering team is looking into feasible alternatives.

In addition, as network technology changes to incorporate more and more "intelligent" devices, along with remote sensing and control, there will be a shift in the skillsets required for people working on these devices.

During 2022, there were already indications of a substantial shortage of staff, affecting both the labour and the professional markets. We do not see this situation easing. Powerco will, therefore, be in a market competing to attract skilled staff.

Our people policies are being revised with this in mind. We recognise that we will have to look beyond the traditional factors, such as competitive salaries, generous leave provisions and appealing, effective working conditions. In future, we will require a further focus on aspects such as:

- A highly flexible working environment that allows people to work from locations around the country (or potentially the world).
- Flexible working hours, while retaining strong contact with colleagues and the workplace.
- Excellent training programmes and opportunities for personal development.
- A strong sense of purpose and social commitment, with opportunities for staff to practically contribute to this.
- A workplace that celebrates and encourages diversity.
- Trust and responsibility.

Energy hardship

Energy hardship is a complex issue that requires a country-wide approach to resolve. We recognise that a significant proportion of our customers struggle to meet their basic energy needs. We also accept that we have a responsibility in this regard and that, while we cannot realistically solve the issue by ourselves, we should play an important role in addressing it.

Our most direct response is to minimise the cost to our customers by delivering the most efficient service possible. In addition, we will increasingly work with our customers to encourage improvements in energy use efficiency, and to seek opportunities to lower the cost of their supply. Emerging technology, with its associated opportunities, is likely to play a large part in this.

We are in the process of developing a formal policy and plan for helping to address energy hardship on our footprint – during 2023, this will be finalised, and the initial implementation will take place.

Powerco is a contributor to the Low-Fixed Charge Power Credits Scheme, which is targeted at helping struggling customers pay their energy bills.

Our Customer Engagement Strategy also outlines how we plan to involve our customers, retailers, iwi, third-party service providers and other interested stakeholders in our key decisions.

Shift to operating expenditure

We face a future where an increasing proportion of our expenditure will be operating, rather than capital. Primary reasons for this include:

- Increasing use of software as a service. Information technology makes up an increasing part of electricity network investment. Increasingly these services are cloud-based, provided by third parties rather than owned and hosted on our own premises. Procuring these services results in more operating expense, with an associated reduction in Capex.
- We see flexibility services providing a real alternative to many network investments in the future. Recently, we implemented our first major network solution using flexibility services procured from an independent third party. While still early in its use, this is promising for avoiding or deferring network reinforcement. Procuring flexibility services is an operating expense that generally directly offsets capital expenditure.
- As technology develops and we continue to look for more efficient network solutions, we foresee that we will be making more staff and funding available for research and development, or pilot programmes. These activities are generally heavier on operating expenditure and, if successful, often serve to reduce Capex.

The developments sketched above are all positive from a customer perspective, as they will reduce cost and/or improve service. We strongly support these.

However, current regulations mean that EDBs can only earn a return on capital investments (operating costs are at best a pass-through). This long-term shift, therefore, has the potential to eventually undermine the value of EDBs unless a regulatory alternative can be found.

We intend to cooperate with regulators and other EDBs and industry bodies to solve this issue.

2.6 GETTING READY FOR THE REST OF THE DECADE

The AMP sets out our investment plan for the next 10 years, based on our current analysis. Core to the plan is the delivery of our network development and fleet plans, which represent the bulk of our foreseen investment.

However, outside this core investment, Powerco has an active strategy to ready itself for the changes ahead. It broadly follows the three horizons model[18]. This model was developed for driving innovation and fits with the transformation work that lies ahead.

Horizon 1: We have delivered the first horizon (year 1). The focus is largely on immediate business-as-usual activities – completion of our

[18] Originally popularised by McKinsey.

Customised Price-quality Path (CPP) programme, delivering incremental improvements, and planning for electrification.

Horizon 2: The next two years. The focus is major improvements to our business – the steps that will help achieve Horizon 3.

Horizon 3: Year 3+ from now. The focus is on longer-term outcomes and innovations that will radically change the business.

As discussed in this chapter, during the latter half of this decade we expect to be entering a stage where the sheer volume of work required will force a very different approach to how we do business. This we view as horizon 3.

Most of our current transformation work we consider falling within the 2nd horizon, aimed at preparing for horizon 3, which aligns with the reset to DPP 4. We have agreed with the Powerco board that, outside delivering our core AMP investment programme (including meeting ever-increasing customer work requests), we will focus on using the next two years for readying ourselves for the growing customer needs foreseen in the second half of the decade.

We have discussed a number of the above improvement initiatives over a range of timeframes. Our particular focus areas for FY24 and FY25 are:

Rethinking supply resilience. To respond to the increasing frequency and severity of major events impacting our customers, we will undertake an in-depth review of how we approach and manage the supply of electricity to our customers, to ensure appropriate levels of resilience.

Improving customer application and delivery processes. We are very aware that Powerco needs to improve in this area. With the rising volumes of customer-requested works in recent years, our processes have struggled to keep up. We are also concerned about the rising cost of providing connections. In view of this, we have commenced a thorough review and redesign of our customer application processes and how we deliver to these.

Expanding our customer services. Linked to the previous, we plan to significantly improve the accuracy of the information we provide customers and the way in which we provide it. This includes improving the information on outages, distributed generation (DG) hosting, and the load capacity of the network. We have already made some improvements, but there is more work to do.

We will also improve our **engagement with iwi stakeholders** to understand how our plans may affect them and how we work together to improve our service. Our Te Raa Strategy set out our pathway to improving ourselves, and our engagement and relationships with iwi stakeholders.

Reviewing our network architecture. This will be an integral part of our resilience review. It also reflects that, as customer energy requirements and land use change, we must adapt the core architecture of our networks to make sure it remains fit for purpose. At present, we lean toward a one-size-fits-all approach, which will not enable the most efficient transition pathway.

Network and asset visibility. As noted earlier, the LV networks will be the crunch area as electrification accelerates. We will roll out monitors across this network, as well as limited increases in medium voltage (MV) monitoring, to help us deal with the upcoming demand growth and to optimise our investment and operational responses. It is also an important component in the overall resilience of the electricity supply chain.

This will begin during the next two years. In addition to LV monitoring, over time we plan to roll out an extensive network of asset condition or utilisation monitoring devices as we expand and renew our networks.

Managing the data from the field will also be a key component of these projects, with the systems having to be in place during Horizon 2.

Building a comprehensive LV network model. We will develop an LV network model to the same standard as our higher voltage models, which will allow accurate, fast network simulations and identification of potential problems.

Improved understanding of customers' electricity use patterns and the cost of unserved energy. This is the basic information required to make sure optimal future networks are designed that closely match our customers' needs. Historical assumed parameters for customer energy use do not hold anymore.

Enterprise architecture. We have started a comprehensive review of our enterprise architecture, which will involve core facets of our business, including our capability frameworks and data architecture models. We see this as fundamental to the required internal system and process improvements.

2.7 HOW MUCH SHOULD WE BE SPENDING?

While we are facing a future with much uncertainty, barring major economic disasters, decarbonising our economy will lead to substantial electricity demand growth. We also need to harden the network. This, we know, will require significant network investments. However, the ideal timing of these investments is an open question.

As discussed in the case study overleaf, during a period of rapid growth, especially with such major requirements attached, there is a strong argument that investment should actually be made slightly ahead of when absolutely required. This will have some customer cost, but the counterfactual – having to delay or block customers' decarbonisation initiatives because delivery can't be achieved on time – could cost New Zealand society much more.

In our AMP expenditure forecasts, we have allowed for the major uplift in demand growth rates discussed. In addition, there is provision for considerable work on improving our internal systems and processes and enabling investments to facilitate decarbonisation.

Case study: Investing ahead of need (or "at the optimally efficient time") – why?

For the foreseeable future, electricity networks in New Zealand are looking at rapid, but inherently uncertain demand growth, driven mainly by the electrification of our society, as well as the increasing need for network hardening to respond to a changing physical environment. To appropriately meet this, we will have to accelerate investment programmes, requiring us to invest somewhat in advance of the actual need arising.

The reason for this is primarily twofold:

A. Extending network capacity involves considerable lead times, especially if resource consents are required. Equipment delivery can also cause considerable delays. The lead time for a new feeder or large substation is often 4-5 years, assuming we already have access and resource consents.

For most customers, it is not tenable to wait that long before their requirements are addressed. They invest when a series of factors line up so as to make the investment economic. Our delivery constraints could cause them to delay or forego their decarbonisation plans, or drive them to other, potentially less efficient, non-electricity solutions.

In addition, given Powerco's commitment to New Zealand's decarbonisation, we plan to work with and encourage customers to maximise their use of (clean) electricity instead of other energy forms. We cannot realistically offer this as a solution if we are not in a position to provide the electrical capacity required to achieve it.

To avoid undue bottlenecks or exposure, we would typically build sufficient capacity for forecast load growth, with a 90% confidence margin to meet the potential variance around this. As shown below, when variability increases (even at the same base growth rate), to provide the same security means investment has to be brought forward. This is the economically prudent outcome.

B. The sheer magnitude of planning and building the network augmentations required in the foreseeable future, on top of the need for enhancing network resilience, could swamp the available resource capacity in New Zealand. This will particularly be the case if we were to merely add (conventionally) to network capacity to meet increased demand peaks or replace assets with like-for-like. This would also come at a greater cost and add an untenable burden on many of our customers.

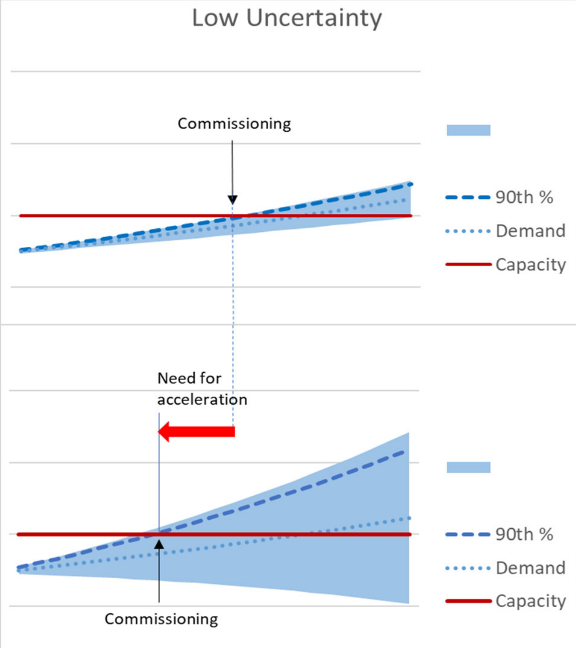
It is therefore imperative that a more intelligent augmentation and network hardening approach is adopted. Core to this would be maximising asset utilisation without unduly increasing risk exposure and working closely with customers to shape solutions that would achieve an optimal risk/cost trade-off.

(Case study continued)

This will require a major step up in how we manage the distribution network, requiring substantial enabling investments that include:

- Real-time visibility of power flows and quality, on all parts of the network, particularly LV, where we are mostly "blind" and where the initial constraints will likely arise.
- Automation and remote control.
- Enabling flexibility services and smart technology solutions.
- Enabling microgrids, partly or fully off-grid.
- Developing our internal capacity – people and systems.

To efficiently respond to the expected uplift in demand, these enablers will need to be ready in advance.



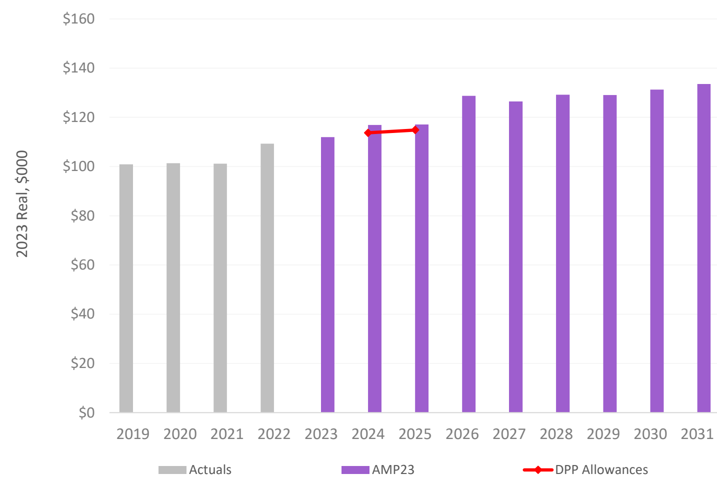
The AMP Capex base case forecast is shown in Figure 2.4. Also shown, for reference, are the historical expenditure levels and our DPP3 Capex allowance for FY24 and FY25.

Our latest Capex forecast well exceeds current regulatory allowances, which are based on our most recent expenditure levels. This uplift reflects already existing needs for material growth and renewal investment, and provision for major construction price increases as there is competition for access to New Zealand's limited infrastructure delivery resources, along with starting the required enabling projects. The future trend is for even more substantial increases, as network expenditure tracks the demand growth anticipated on our network.

Figure 2.4: Base case Capex forecast

The AMP Opex base case forecast is given in Figure 2.5, along with our DPP3 Opex revenue allowance.

Figure 2.5: Base case Opex forecast



Opex is also forecast at higher levels than the regulatory allowance for the next two years. This largely reflects current inflationary pressure on salary and wages and the difficulty in obtaining highly skilled staff. Future expenditure is expected to increase further, as we allow for more flexibility services to be procured and a higher proportion of research and development work to seek optimal, innovative network and non-network solutions.

The forecasts in Figure 2.4 and Figure 2.5 represent our current best view on how we could meet the investment challenges of the coming decade using our current assumed base case assumptions. However, there is a reasonable likelihood that these assumptions do not sufficiently cater for actual demand growth. We have, therefore, prepared a high scenario forecast that takes into account the following:

- Higher EV uptake rates, with more charging taking place at peak demand times. This situation could occur if major incentives are implemented to encourage EV use and EDBs are not allowed some form of effective control over charging times.
- More rapid decarbonisation of major heat processes, as consumers respond to national targets and incentives.
- Domestic gas networks are phased out more rapidly than assumed in our base case. This could come from major customers responding to incentives to replace gas processes, with remaining domestic gas use not being sufficient to justify ongoing operations of the gas bulk supply system.

- Somewhat lower uptake of DER and flexibility services, reducing the demand reduction assumed for the base case.
- More rapid rollout of LV network monitoring, to provide basic coverage of all LV feeders at the source, midpoint, and endpoint, by the end of the LV planning period. (The base case allows for monitoring at larger transformers and major LV feeders only.)
- Commencing preparations for a full-scale distribution system operator (DSO) deployment, over a 15-year period. This mainly provides for full installation control point (ICP) monitoring as would be required if there is a need for (semi) real-time demand and generation balancing across distribution networks.
- Accelerated research and development expenditure to grow by 2% of total expenditure by the end of the AMP period.

The high scenario Capex and Opex forecasts are shown in Figure 2.6 and Figure 2.7. While we currently do not intend to use these high scenario figures for our budgets, we will continue to monitor the situation. Should the higher case assumptions transpire, we will clearly need to adapt the position.

Figure 2.6: High scenario Capex forecast

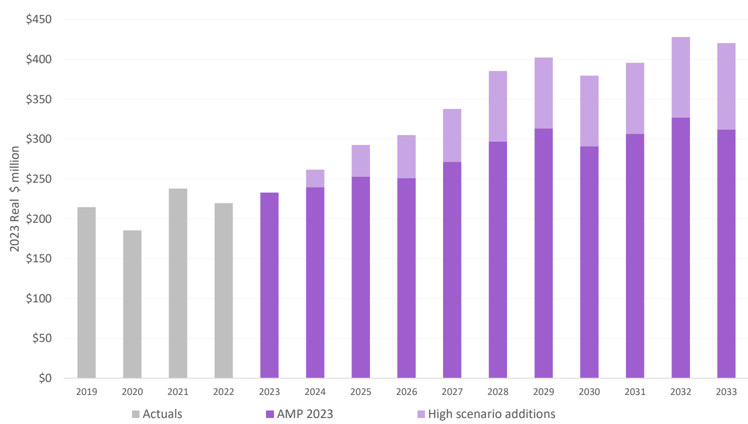
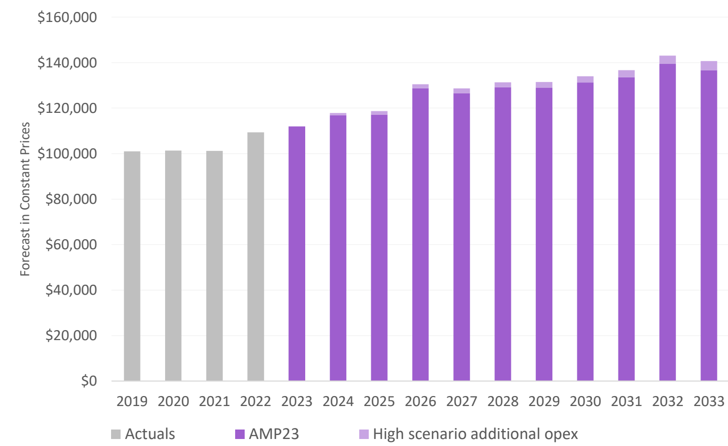


Figure 2.7: High scenario Opex forecast



3 AMP OVERVIEW

3.1 CHAPTER OVERVIEW

Powerco is a privately owned utility with two institutional shareholders[19]. We operate the largest network of electricity distribution lines in New Zealand by geographical area and network size, serving about 340,000 connections, or around 1 million customers.

This chapter provides the context for our 2023 Asset Management Plan (AMP). It outlines its purpose and objectives, whom it is written for, and how it is structured. It also introduces our network and provides an overview of the zones, network configurations and assets on our network.

3.2 PURPOSE STATEMENT

We recognise that our investment decisions impact homes and businesses throughout New Zealand, now and in the future. The purpose of our AMP is twofold:

- Provide our stakeholders with a view of our long-term plans to give them certainty and confidence in our network management and that we will meet their expectations. This transparency also supports customers' own longer-term energy planning.
- Document and communicate, for internal purposes, our Asset Management Strategies and Plans, including our detailed investment and operations plans, which inform our annual electricity network budgets.

During 2022, we undertook a detailed review of our future network strategies and plans, particularly with an eye on needs following the end of our current Customised Price-quality Path (CPP) period (2024 onwards). In the 2023 AMP, we discuss:

- Our view on the future architecture, function, and operation of the network.
- Operational and investment needs we foresee in the 10-year planning period to maintain a reliable and safe network.
- Our understanding of 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.
- Our response to potential changes in future energy policy and meeting our environmental obligations.

3.2.1 AMP OBJECTIVES

The objectives of our 2023 AMP are to:

- Help our stakeholders understand our asset management approach by clearly describing our assets, key strategies, and planned investments.
- Advise interested parties about major network investment plans and the potential opportunities to offer alternatives to these plans. We are committed to consider such offers where these are practical and would provide economically viable, equivalent customer service levels.
- 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.

3.2.2 CORPORATE OBJECTIVES

Powerco Ltd and its parent Powerco New Zealand Holdings Ltd are leading energy infrastructure asset managers. We operate on commercially sound and sustainable principles, which means we take responsibility towards our customers and our planet very seriously.

As part of a review of our longer-term strategy and an associated change in our company structure, we have completely refreshed our corporate purpose and values during 2022.

3.2.3 NGĀ TIKANGA – OUR WAY

Ngā Tikanga - Our Way, guides us as we work together to achieve our purpose of connecting communities.

It is our cultural framework, incorporating our purpose, values, and our ways of working, which govern how we show up each day. It best describes who we are and how we collaborate with each other, our partners and industry stakeholders to get the best outcomes for our communities. It is inspired by tikanga, a Māori concept that refers to the ethical framework of Māori society.

[19] Queensland Investment Corporation (58%) and AMP Capital (42%).

Figure 3.1: Ngā Tikanga - Our Way

3.2.4 OUR ANNUAL BUSINESS PLANNING PROCESS HELPS INFORM OUR AMP

The AMP incorporates plans and initiatives from Powerco's annual business planning process. The key corporate plans, policies, and standards used to guide our AMP are:

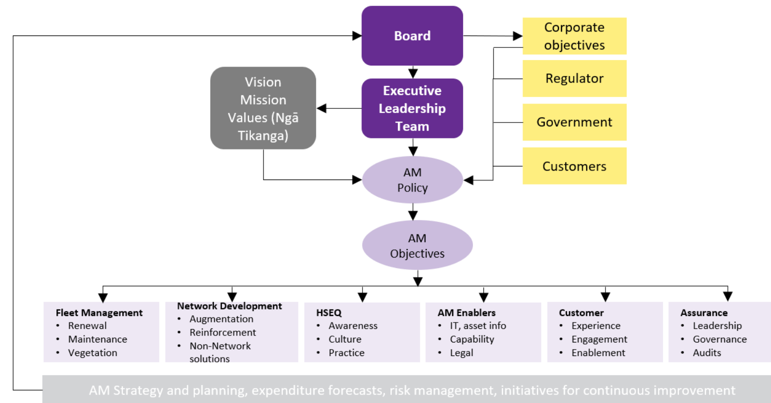
- Powerco Integrated Business Plan FY23-FY27
- Powerco Risk Appetite Statement
- Powerco FY21 Sustainability Reference Report
- Powerco Climate Change Policy
- Powerco Environmental Policy

3.2.5 ASSET MANAGEMENT OBJECTIVES

Five Asset Management Objectives are at the heart of how we manage our assets. They reflect our lifecycle asset management approach, which considers all aspects of asset decision-making and activities from inception to decommissioning. These Asset Management Objectives are illustrated in Figure 3.3 and described in more detail in Chapter 4.

[20] A brief overview of our longer-term, bulk supply planning is also given.

Figure 3.2: Line of sight from our corporate plans to our Asset Management Strategies



3.3 AMP PLANNING PERIOD

Our AMP covers a 10-year planning period, from 1 April 2023 to 31 March 2033[20]. Consistent with Information Disclosure requirements, greater detail is provided for the first five years of this period.

Our Board of Directors certified and approved this AMP on 23 March 2023.

3.4 OUR STAKEHOLDERS

A key objective of our AMP is to inform our stakeholders about how we manage our assets and where we intend to invest for future network growth or for maintaining the good health of our assets. This AMP explains how our plans and decisions are made and implemented. Our key stakeholders and their principal interests are summarised in Table 3.1.

Figure 3:3: Our Asset Management Objectives

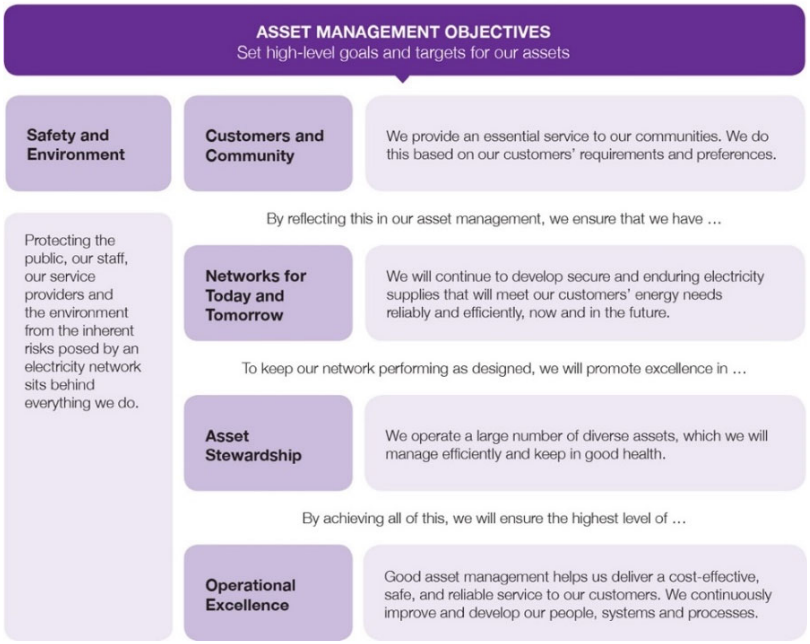


Table 3.1: Key stakeholders and their main interests

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, connection agreements.
Commerce Commission	Pricing levels, effective governance, quality standards, appropriate expenditure, effective asset management, Information Disclosure.
State bodies and other 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, planning documentation, security of employment, information and tools supporting effective work.
Service providers	Safe and productive work environment, consistent workflow, remuneration, training and development, planning documentation, security of employment, information and tools supporting effective work.
Transpower	Technical performance, technical compliance, bulk supply 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.

3.5 STRUCTURE OF THE AMP

The diagram below sets out the structure of the AMP, including the sections (purple boxes) and the chapters within these. Appendix 9 maps the chapters and appendices to relevant Information Disclosure requirements. Our Strategic Asset Management Plan is covered in Chapters 4 to 8.

Introduction

This section introduces our 2023 AMP, outlines the significant opportunities and challenges we foresee, and provides an overview of the network

1 Executive Summary

Provides context to our stakeholders on key factors that influence our investment over the planning period.

2 The decade of change ahead

Overviews the significant opportunities and challenges we foresee over the next ten years for electricity distribution and how Powerco intends to respond to these.

3 AMP Overview

This chapter describes the purpose and structure of the AMP and provides an overview of the network.

Strategic Asset Management Plan

The context, objectives and strategies driving our investment. Where we are heading in the future.

4 External forces shaping our network

Provides an overview of the externalities that we consider while developing our AMP.

5 Asset Management Objectives

Details Powerco's vision, mission and values and describes the interaction of these objectives with the Electricity Asset Management Strategy and Asset Management Policy.

6 Core Asset Management Strategies

Our core strategies for achieving our objectives and managing the network.

7 Evolving Asset Management Strategies

This chapter outlines "where we are", "where we are going", and "how we are going to get there".

8 Network Targets

Outlines our Network Targets for the planning period.

Asset Management System

How we organise ourselves to delivery our services

9 Asset Management System

This chapter discusses how we develop our investment plans, including the processes and analytical tools used to identify network needs and prioritise expenditure. It also covers our procurement processes, our interpretation of lifecycle asset management, our approach to risk management, and governance arrangements concerning asset management at Powerco.

Network Development

Our plans to develop and improve our network's response to customer change

10 Growth and Security Investment

This chapter outlines the impact of demand growth trends on our Growth and Security investment. It also discusses the assets and initiatives needed to enable better visibility of utilisation, power flows, and power quality, such as communication and open-access network investments.

11 Area Plans

Our network planning is based on 13 discrete areas. This chapter describes these areas and their significant planned investments related to growth and security.

12 Reliability and automation

This chapter discusses our automation strategy and its alignment with the asset management objectives.

13 Customer Connections

This chapter outlines our forecast customer connection expenditure.

Fleet Management

Our plans to manage our existing assets to deliver a safe and reliable service

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

For each portfolio we describe:

- High level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition, and risks
- Preventative maintenance tasks

22 Asset Relocations

This chapter explains our approach to relocating assets on behalf of customers and other stakeholders.

23 Non-network Assets

This chapter describes the investments required to enable the wider Asset Management Plan and Network Evolution. It discusses our data quality improvement programme and other non-network assets, such as office buildings and vehicles.

Forecast Expenditure

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

24 Expenditure Forecasts

Provides and overview of the Capex and Opex forecasts for the planning period. It also explains our inputs, assumptions, and cost estimation approach.

3.6 OUR NETWORK

3.6.1 NETWORK CONFIGURATION

The operation of the electricity network is comparable to roading. Road capacity ranges from high-volume national highways to small, access roads. Similarly, an electricity network uses High Voltage (HV) transmission lines to move large amounts of power over long 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 kilovolts (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.

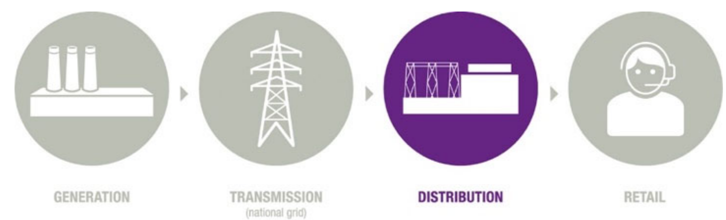
Changing electricity from one voltage to another requires the electricity to flow through a transformer.

We take bulk electricity supply from the Transpower network at several grid exit points (GXPs), generally converted to subtransmission voltage levels. For electricity flowing from a subtransmission circuit to a distribution circuit, it passes through a transformer housed in one of our zone substations. A smaller ground or pole-mounted distribution transformer is used when the electrical flow is from a distribution circuit into the LV network.

3.6.2 TRANSMISSION POINTS OF SUPPLY

Our place in New Zealand's electricity sector is illustrated in Figure 3.4.

Figure 3.4: Our place in the electricity sector



Electricity is generated across New Zealand using water (hydro), wind, geothermal, gas and coal stations.[21]

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 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.

[21] Distributed generation is a growing trend but still only a very small proportion of total generation.

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 supplies by duplicating incoming lines, transformers, and switchgear.

Detail on the GXPs in each zone and associated network maps can be found in Chapter 15.

3.6.3 REGIONAL NETWORKS

Our network includes two separate parts, referred to as our Eastern and Western regions. Both networks contain a range of urban and rural areas, although both are predominantly rural. Geographic, population, and load characteristics vary significantly across our supply area.

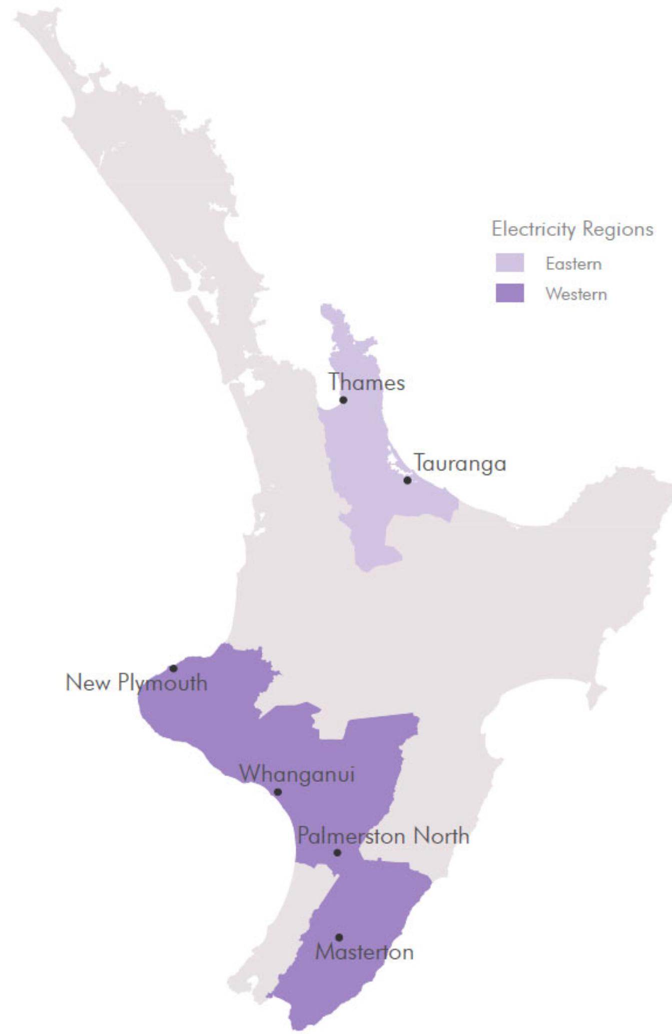
Our development as a utility included several mergers and acquisitions that have led to a wide range of legacy asset types and architecture. This requires an asset management approach that accounts for these differences while seeking to standardise network equipment over time.

Table 3.2 provides summary statistics relating to our assets in the Eastern and Western regions. Figure 3.5 provides a geographical overlay of these regions.

Table 3.2: Key regional statistics (2022)

MEASURE	EASTERN	WESTERN	COMBINED
Customer connections	167,436	184,748	352,563
Overhead circuit network length (km)	7,200	14,552	21,752
Underground circuit network length (km)	3,793	3,390	7,183
Zone substations	53	69	122
Peak demand (MW)	526	464	986
Energy throughput (GWh)	2,846	2,421	5,266

Figure 3.5: The regions we cover



3.6.4 EASTERN REGION

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

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

- **Valley** includes a diverse range of terrain, 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 zone have been associated with accommodating the rapid urban growth in Tauranga, maintaining safe and reliable supplies to the port, supplying new businesses, and supporting the horticultural industry.

The map in Figure 3.6 shows the Eastern region network footprint and planning areas.

Figure 3.6: Eastern network and planning areas

3.6.5 WESTERN REGION

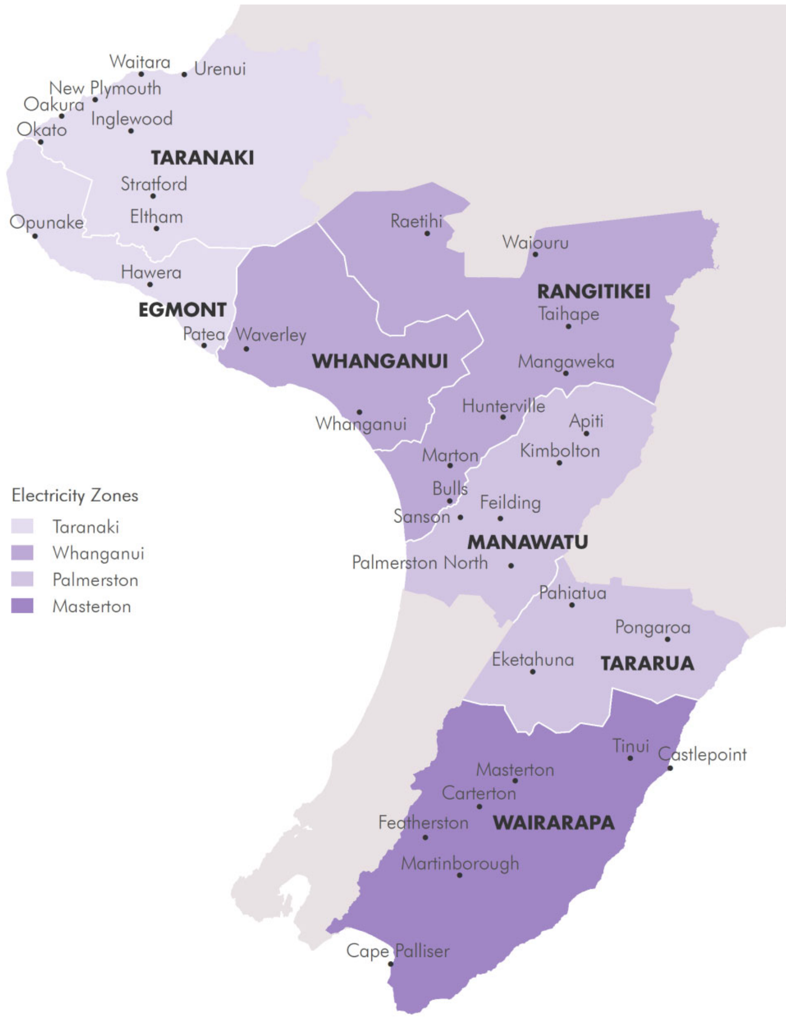
The Western region comprises the four network zones described below. Similar to the Eastern region, these zones have differing geographical and economic characteristics, presenting various asset management challenges. Because of the age of the network and, in particular, the declining asset health of some overhead lines, extensive asset renewal is required in this region. Renewal is about double the cost compared with that of 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, which includes the large regional centre of New Plymouth, has significant agricultural activity, oil and gas production, and some heavy industry.
- **Whanganui** includes the surrounding Rangitīkei and is a rural area exposed to westerly sea winds on the coast and snowstorms 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 in nature, but the large regional centre of Palmerston North has significant logistical industries, a university and associated research facilities.
- **Wairarapa** is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.

The investment priorities in these regions are largely to meet growth requirements – mainly around Whanganui, Palmerston North, Wairarapa and New Plymouth – and to renew assets at end-of-life or in poor condition.

The map in Figure 3.7 3.7 shows the Western region network footprint and planning areas.

Figure 3.7: Western network and planning areas



3.7 ASSET SUMMARY

3.7.1 OUR ASSET FLEETS

We use the term "asset fleet" to describe a group of assets that share technical characteristics and investment drivers. We categorise our electricity assets into 25 such fleets. These in turn are organised into the seven primary portfolios:

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

Our approach to managing our asset fleets is explained in Chapters 14 to 23.

3.7.2 ASSET POPULATIONS

Table 3.3 gives an overview of our asset populations across our full electricity network[22]. The large number of assets in certain fleets, such as 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 14 to 23.

Table 3.3: Asset populations summary (2022)

ASSET TYPE	POPULATION
Overhead network	
Subtransmission (km)	1,509
Distribution (km)	14,767
LV (km)	6,007
Underground cables	
Subtransmission (km)	287
Distribution (km)	2,305
LV (km)	6,870
Overhead structures	
Poles	264,341
Crossarms	428,027
Zone substations	
Power transformers	188
Indoor switchboards	142
Buildings	165
Distribution assets	
Transformers	35,572
Switchgear	45,135
Secondary systems	
Zone substation protection relays	2,019
Remote terminal units	313

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

This page intentionally left blank

STRATEGIC ASSET MANAGEMENT PLAN

The context, objectives and strategies driving our investment.
Where we are heading in the future.

4 EXTERNAL FORCES SHAPING OUR NETWORK

4.1 INTRODUCTION

We build electricity networks to serve our customers' needs. The energy sector sits at the cutting edge of several societal mega-trends, which will continue to accelerate change in how our customers use and produce electricity. We are also experiencing some more immediate issues that have a material impact on the use of energy and to which we have to respond. However, we have little to no control over these. Some of these longer-term changes include:

- **Changes to our customer base** – pertains to population movements, demographics, changing land-use patterns and increasing energy poverty.
- **Legislative and electricity market changes** – includes measures to reduce New Zealand's carbon footprint, the evolution of distribution networks to a distribution system operator (DSO) and other potential regulatory changes.
- **Technological changes** – includes changing customer energy technology or devices, new network technology, increasing cyber security risk, and a reduction in grid inertia with associated stability implications.
- **Managing business environmental footprint** – the increased incentives and pressure for businesses to better manage their environmental footprint. There is now wide consensus that broad electrification will be key to New Zealand meeting its carbon reduction targets.
- **Impact of climate change** – we are observing an increased frequency of major weather events, corresponding with the modelled longer-term impact of climate change. While we have little control over these events, improving the resilience of our network against these events is an important focus area.

Important immediate factors impacting current and near-term energy use and infrastructure provision include:

- In February 2021, **Russia invaded Ukraine** and there is not yet an end in sight to this conflict. While the direct ramifications on the local energy market are not nearly as severe as in Europe, this has had a material impact on the availability and cost of imported equipment.
- **Inflation** has spiked to the highest levels seen in several decades. The cost of delivering infrastructure has risen substantially during the past 18 months, with no sign of abatement.
- Since the second half of 2021, we have experienced a **major boom in requests for customer connections,** in all segments – residential, commercial, and industrial. In addition, requests for connecting distributed generation, particularly large and small-scale solar photovoltaics (PV), have grown exponentially.
- Linked to the above and also adding inflationary pressure, **capacity constraints** have become a major concern in most of our supply chain. This applies to the recruitment of skilled resources, availability of contracting and consulting resources, and material delivery.
- Conversely, **economic growth** has materially slowed during the past 12 months and there are indications of a looming recession in 2023. This is projected to have a dampening impact on construction activity that will, in turn, influence resource availability and potentially reduce inflationary pressure – the extent of which is as yet unknown.

To respond appropriately to these factors, we have to consider the immediate and potential longer-term impact on our business (our assets are typically expected to perform upwards of 45 years).

In this chapter, we explore some of the more important trends we observe that influence our strategies and our network. Our plans to respond to these, form the basis of our Asset Management Plan (AMP), as set out in the following chapters.

4.1.1 HISTORICAL ELECTRICITY DEMAND

From the early 1900s to 2007, national electricity consumption increased steadily, primarily driven by increased use in the commercial sector and a growing population base. Since then, national electricity use has remained relatively flat, despite continuing population and gross domestic product (GDP) growth, as shown in Figure 4.1. Most recently, between 2019 and 2021, there has been an uplift in residential consumption, while industrial use has declined.

MBIE[23] largely ascribes this to:

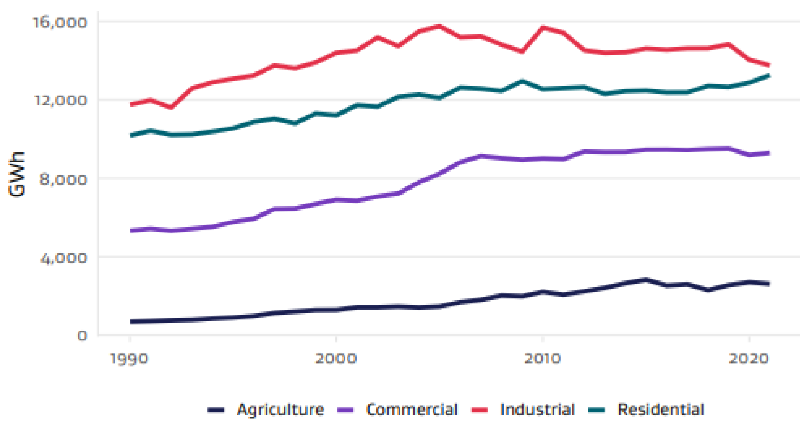
- More people working from home, particularly during COVID-19 lockdown periods.
- A major drop in consumption by the wood, pulp, and paper manufacturing sector, particularly influenced by the closure of Norske Skog's Tasman mill at Kawerau in June 2021.

Given the sustained annual increase in consumer numbers, the flat consumption levels imply a decline in average electricity use per installation control point (ICP). Increases in residential consumption from the 1970s to the 2000s were primarily attributed to the increase in the range and use of electric household appliances, including the increased use of electricity for heating and hot water. The subsequent decrease in consumption has been attributable to improvements in energy

[23] Source: Ministry of Business, Innovation & Employment: Energy in New Zealand 22 https://www.mbie.govt.nz/dmsdocument/23550-energy-in-new-zealand-2022-pdf

efficiency, e.g., the increased use of heat pumps instead of resistive heating, LED light bulbs, better home insulation etc.

Figure 4.1: Nationwide electricity consumption by sector[24]



On the other hand, peak demand for electricity has been rising in recent years, after a major drop-off post-2011. This is largely driven by increased demand during winter months (morning and early evening). Summer demand has been trending down but is anticipated to grow as warmer temperatures increase the need for cooling. Countrywide peak demand (half-hourly) is shown in Figure 4.2.

From a distribution network perspective, further changes in supplied energy levels (as opposed to consumed energy levels) are expected as the technologies for generating and storing electricity become more affordable and practical. As consumers take a greater part in generating and managing their own electricity, whether this is for environmental, economic or reliability reasons, we expect bigger changes in per capita energy consumption flowing over our network. This is, however, likely to be more than offset by increased use of our network as more customers switch to electric vehicles (EV) and there is more general electrification, particularly of heat processes.

Energy consumption and demand per connection point on the Powerco network in recent years has somewhat bucked the national trend, generally growing at a substantially faster rate than the national average. This is illustrated in Figure 4.3. Overall demand growth on the Powerco networks is shown in Figure 4.4.

Figure 4.2: Peak electricity demand for New Zealand[25]

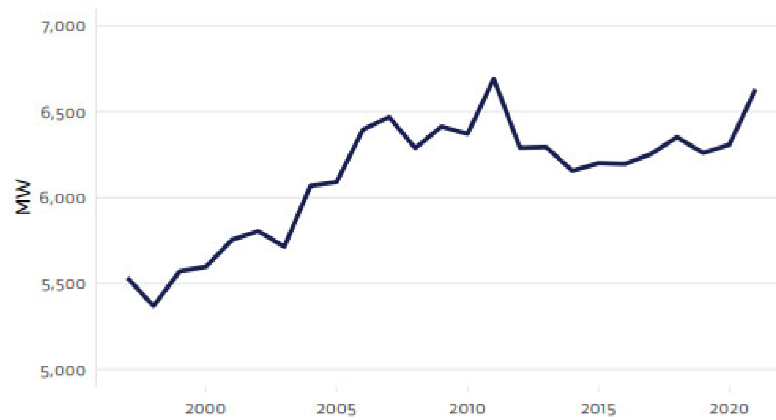
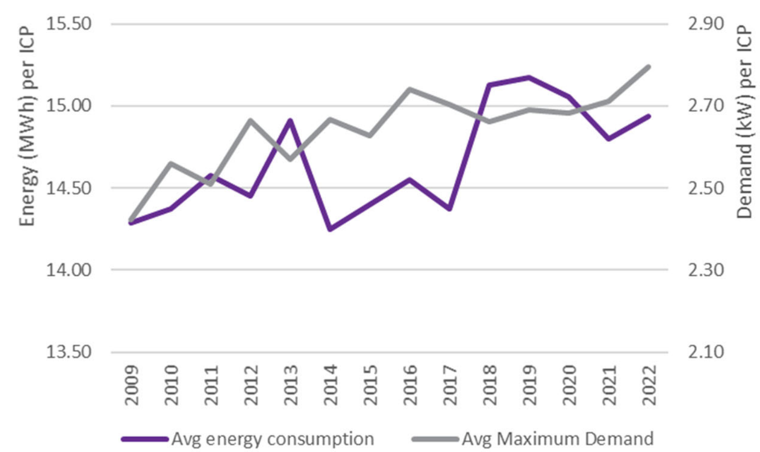


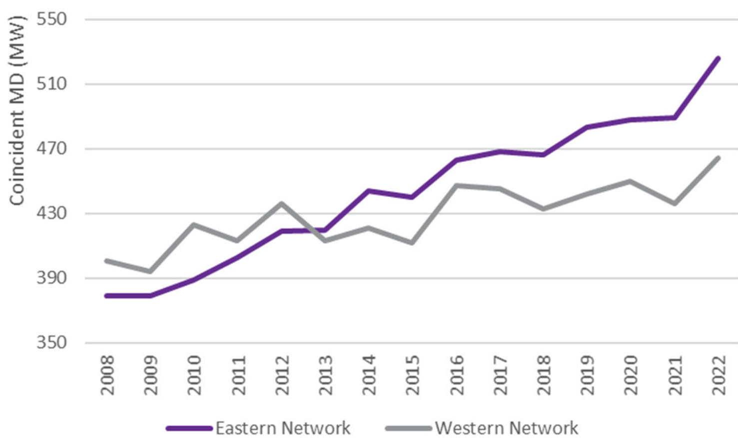
Figure 4.3: Energy consumption and demand per ICP on Powerco's network



[24] Ibid

[25] Ibid

Figure 4.4: Peak demand growth on the Powerco networks – Eastern v Western



4.2 CHANGES IN OUR CUSTOMER BASE

The size, demographics and primary activities of our customer base have a major influence on electricity consumption on our network. These factors have tended to follow relatively stable trends, which form key inputs in our network planning.

4.2.1 POPULATION MOVEMENTS

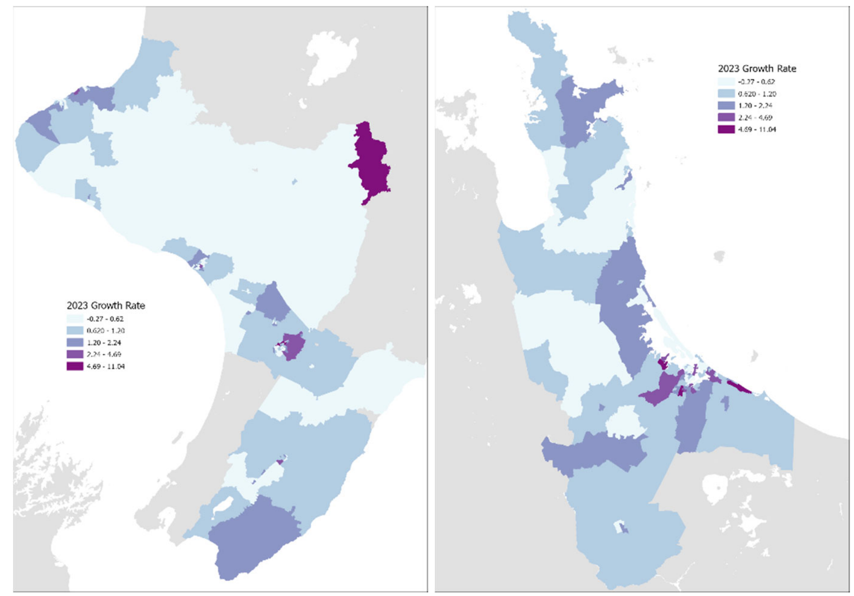
Our distribution networks cover a large part of the North Island, spanning areas with distinctly different population growth trends. While we have experienced overall population growth on the networks, the varying rates at which this is occurring across our regions are illustrated in Figure 4.5. The impact of current restrictions on immigration is uncertain, but we foresee these growth trends broadly persisting throughout the AMP planning period.

As shown in Figure 4.4, overall network demand is still growing at a constant rate, reflecting increasing customer numbers. But the growth is uneven across the network, with some areas showing materially higher growth than others.

The western Bay of Plenty region, in particular, is experiencing ongoing population growth from movement inside New Zealand, with an ongoing demand for new housing. To a somewhat lesser extent, population growth pressure is also being experienced in Whanganui, Wairarapa, and Palmerston North and surrounding areas.

Conversely, the longer-term population trend in Taranaki is still uncertain. At present, modest growth is persisting. In the Rangitīkei and Egmont areas, the population is decreasing.

Figure 4.5: Population growth rates in territorial authority areas 2023[26]



4.2.2 POPULATION DEMOGRAPHICS

The New Zealand population is ageing and there is a growing proportion of customers forecast to retire during the next decade, as shown in Figure 4.6. At present, the impact of this trend is not significant from a network development perspective. We will, however, continue to monitor the impact and adjust our future investment plans as necessary.

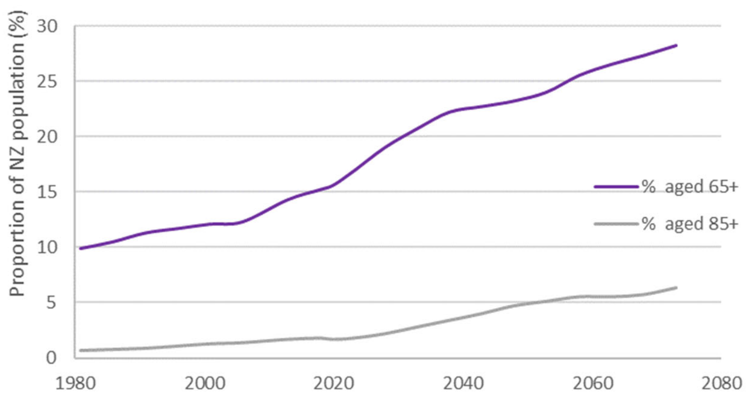
The ageing population does, however, have a direct impact on our business operations. As a large portion of the workforce retires, it takes with it a generation of acquired knowledge and know-how about our network. How we capture and

Stats NZ Census 2018 information. (Note: chart reflects relative change, not absolute numbers of population)

26

institutionalise this knowledge, and train the next generation of talent, will be a challenge that will be addressed by new information and knowledge management capabilities and resourcing strategies.

Figure 4.6: Population aged 65+ and 85+ (historical and forecast)[27]



4.2.3 CHANGING LAND-USE PATTERNS

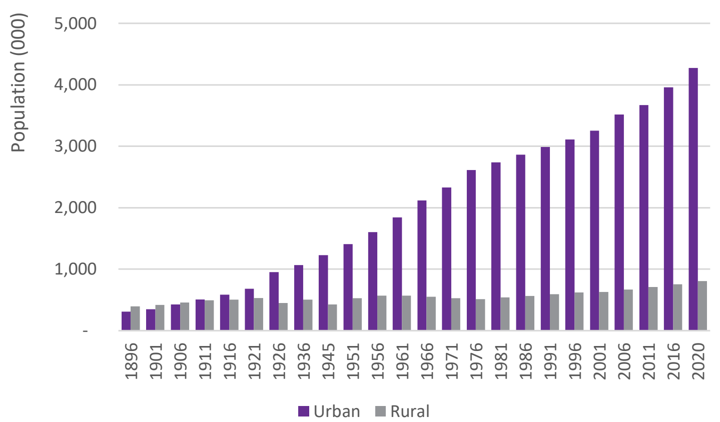
Most of our customers are urban-based, with a concentration in Tauranga, Palmerston North, New Plymouth, Whanganui, and several medium-sized regional centres. In our urban areas, energy demand growth is largely driven by population movements and associated commercial activities. However, given the large size of many industrial plants, the opening or closure of any of these can also have a material impact on regional electricity demand.

Outside the development of new residential areas to meet population growth requirements, the primary land-use trend we observe in urban areas is the increasing densification of residential areas. We have not reached a clear conclusion on material differences in individual household consumption patterns between traditional and denser urban areas.

While the volume of electricity consumption on our rural networks is generally much lower than suburban or urban, these make up the bulk of our assets. As the nature of farming changes, electricity consumption changes accordingly. Many of these trends are still developing, and we will continue to monitor long-term changes in land use and plan for the likely impact. Based on our observations to date, the following trends will likely have a material impact on our network and how we meet their demands.

- In recent decades, land conversion to dairy farming has caused additional energy demand on parts of our network. This trend now appears to have slowed down, with demand stabilising.

Figure 4.7: Urban v rural population growth 1896-2020[28]



- Over time, we have observed a decline in sheep farming in many parts of the network. This was partly driven by dairy conversions, but much of the land is also being repurposed for forestry. Energy consumption at sheep farms is generally low, but consumption in forestry-dominated areas is much lower still.
- More recently, there appears to be an increase in bee farming in rural parts of our network. There is increasing evidence of forestry areas and traditional farms being converted for this purpose. Energy consumption on bee farms is generally very low, especially if these are not permanently inhabited.
- On parts of our network, particularly in the Bay of Plenty, the horticultural industry is thriving, with associated growing energy demand. Kiwifruit farming, in particular, is adding additional load on these rural networks, such as for cold storage etc.

The historical trend of growing urbanisation and a relatively stagnant rural population is expected to continue into the future. As the network features and associated cost varies materially between urban and rural networks, this will have longer-term implications for the electricity quality/cost trade-off and economically

27 Source: Combined datasets from https://www.ehinz.ac.nz/indicators/population-vulnerability/age-profile/ (historic) & Stats NZ (forecast)

28 Source: Combined datasets from https://teara.govt.nz/en/graph/25294/urban-and-rural-populations-1891-1976 & Stats NZ

efficient electricity pricing. This will be reflected in varying service levels and pricing structures.

These trends will make it ever more important for us to segment our approach to network planning to meet our customers' needs.

4.2.4 ENERGY WELLBEING

As we strive to reach our goal of facilitating decarbonisation in New Zealand, it is important that we do so in an equitable manner. Enabling a just transition to a cleaner energy future means that our sector will need to focus as much on ensuring the wellbeing of our customers when planning ahead, as on the technical aspects of delivering electricity.

Energy wellbeing is defined by MBIE as *"When individuals, households and whānau are able to obtain and afford adequate energy services to support their wellbeing in their home or kāinga".* We recognise that achieving energy wellbeing is a challenge for many New Zealanders. The flip side, for those who are unable to maintain energy wellbeing, is energy hardship.

Energy wellbeing is a complex issue that requires a society-wide solution. We recognise that while we cannot realistically solve the issue by ourselves, we have an important role to play. A significant proportion of our customers struggle to meet their basic energy needs.

In addition to the impact of generally rising energy costs, energy poverty could be exacerbated by several other factors:

- Housing quality. A poorly insulated house requires more energy and is much harder to heat or keep dry than a house built to higher, modern specifications. However, often it is the sector of society that can least afford additional energy that lives in some of the poorer housing stock.
- Uneven access to customer-side energy technology. For example, parts of the population can afford electricity generation, such as solar PV, and storage, which may reduce the overall grid-sourced electricity they require. However, as most network costs are fixed and are generally recovered through overall energy sales, this may increase the network cost to customers without their own generation.
- There is a strong stream of current thinking, including from the Electricity Authority (EA)[29], that distribution pricing, in addition to allowing recovery of the fixed cost component of providing distribution services, should be based on sending congestion signals to consumers. The intent is that this would encourage consumers to take measures to reduce congestion (demand at peak consumption times), deferring as long as possible the need to upgrade network capacity.

  Effective management of energy use through the likes of more efficient housing insulation and implements, or controlling consumption during peak-demand periods, are useful ways of responding to price signals and reducing energy demand and cost. However, it is generally the higher socio-economic groups that are more able to achieve this.

  While the principle is economically sound, it raises a serious equity issue. Broadly speaking, customers in lower socio-economic groups have less ability to respond to energy pricing signals and would therefore be the hardest hit by such congestion pricing signals.

While Powerco has already taken steps to help address some of the issues noted here, we are in the process of expanding our activities and developing a formal energy wellbeing policy. Actions underway, or planned, include:

- The most obvious response for a distribution utility to help mitigate against energy poverty is to minimise its cost to customers by delivering as effective a service as possible. Within the bounds of practicality, we also have to ensure that we deliver to customers' price/quality trade-off preferences. These are also the underpinnings of good asset management, with its drivers of seeking optimal investment solutions, maximising the utilisation of assets (conversely, minimising the extent of assets required) and ongoing improvements in operational efficiency.
- Powerco is a contributor to the Low-Fixed Charge Power Credits Scheme, which is targeted at helping struggling customers pay their energy bills.[30]
- As we transition over time, to a more cost-reflective distribution pricing basis that is better tailored to customers' individual preferences and reflects actual network impacts, the impact on the customer will vary. To manage this impact, we will involve retailers and customer groups to ensure that change can be managed, and assistance can be effectively targeted. For example, Powerco is supporting the EnergyMate programme[31].
- We are increasingly working with our customers to encourage improvements in efficient energy use, and to seek opportunities to lower the cost of their supply. Emerging technology, with its associated opportunities, is likely to play a large part in this.
- We are working on projects to encourage more diverse customer groups to actively participate in the energy market or their own energy solutions. This includes supporting community microgrids that are considering distributed generation or storage solutions or facilitating peer-to-peer energy sharing.

[29] Distribution Pricing – Electricity Authority (ea.govt.nz)

[30] The Low-Fixed Charge Power Credits Scheme was established as part of the phase out of the low-fixed charge regulations. It is a 50:50 joint venture between retailers (Genesis, Nova, Meridian, Contact, Mercury including Trustpower) and distributors (ENA's 27 members), with ERANZ also involved. (https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price/phasing-out-low-fixed-charge-tariff-regulations/support-available/)

[31] https://www.powerco.co.nz/about-us/community-support/energymate/

Our customer engagement strategy also outlines how we plan to involve our customers, retailers, iwi, third-party service providers and other interested stakeholders in our key decisions.

4.3 REDUCING NEW ZEALAND'S CARBON FOOTPRINT

In May 2022, New Zealand's first Emissions Reduction Plan was published[32]. This plan was developed in response to recommendations from the Climate Change Commission, as well as building on several other reports prepared by various agencies.

The primary purpose of the plan is to contribute to the global effort to limit temperature rise to 1.5℃. This would be achieved through adopting a series of domestic emissions reduction targets, set in legislation, primarily requiring:

- All greenhouse gases, other than biogenic methane, to reach net-zero by 2050.
- A minimum 10% reduction in biogenic methane emissions by 2030, and a 24% to 47% reduction by 2050 (compared with 2017 levels).

A range of sector sub-targets to support this have also been set, including for the energy and industry sectors. A number of these actions will materially impact electricity distribution, including:

- Use energy efficiently, lower costs and manage demand for energy by improving business and consumer energy efficiency.
- Ensure the electricity system is ready to meet future needs by:
  - Investigating the need for electricity market measures to support the transition to a highly renewable electricity system and investigating options for electricity storage in dry years.
  - Reducing barriers to developing and efficiently using electricity infrastructure, including transmission and distribution networks.
  - Supporting renewable and affordable energy in communities through the Māori and Public Housing Renewable Energy Fund.
- Reduce our reliance on fossil fuels and exposure to volatile global fuel markets, and support the switch to low-emissions fuels by:
  - Setting a pathway to reduce reliance on fossil gas through a gas transition plan.
  - Increasing access to low-emissions fuels, including developing a hydrogen roadmap.
- Reduce emissions and energy use in the industry by:
  - Supporting industry to improve energy efficiency, reduce costs and switch from fossil fuels to low-emissions alternatives.
  - Banning new low- and medium-temperature coal boilers and phasing out existing ones by 2037.
- Set a strategy and targets to guide us to 2050 by:
  - Setting a target for 50% of total final energy consumption to come from renewable sources by 2035.
  - Developing an energy strategy to address strategic challenges in the energy sector and signal pathways away from fossil fuels.

Powerco supports these measures, which are for the greater good of our society. While there will be network implications, we are planning how to manage this effectively. Our planned response is set out in Chapter 7. In practical asset management terms, the major initial implications of working to achieve the decarbonisation targets will be:

- Increased use of EVs, while phasing out the fossil fuel vehicle fleet.
- Increased use of electricity for industrial processes as an alternative to energy sources with higher carbon emissions.
- Facilitating the uptake of large and small-scale solar PV generation (with or without associated energy storage).
- Increased support for energy efficiency measures in our own facilities as well as for our customers.
- Facilitating or incentivising customers' decarbonisation efforts through efficient, low-cost energy pricing and encouraging off-peak energy use.
- Understanding the likelihood that domestic customers may convert from natural gas use to electricity but also considering the increased focus on hydrogen or biogas as an alternative fuel source.

Another work area with potentially major ramifications for the electricity industry is the development by MBIE and the Gas Industry Company of the Gas Transition Plan, expected to be released by the end of 2023. The transition plan was highlighted in the Emissions Reduction Plan and is intended to set a long-term pathway for phasing out fossil gas in New Zealand.

Given the extent of gas use in New Zealand[33] and the relative inefficiency of converting some gas-fuelled processes to electricity, it is not realistic to expect electricity to easily or fully substitute for gas use in the short to medium term. However, there is an expectation that a considerable proportion of energy currently supplied by gas will convert to electricity. The manner and rate at which gas consumption is reduced or substituted by hydrogen or other alternatives will have a

[32] Te hau mārohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first Emissions Reduction Plan (https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/)

[33] There was 157.5PJ of natural gas produced in 2021, which is higher than the 144.2PJ (equivalent) of electricity generated in New Zealand during the same period. (Source: Energy in New Zealand 22, MBIE)

major impact on electricity consumption. This will impact generation, transmission and distribution sectors, and careful planning and coordination will be needed to ensure that sufficient resources, at all parts of the construction supply chain, are available to support an orderly transition. Therefore, we will closely follow the development of the Gas Transition Plan to ensure that the longer-term ramifications are reflected in our plans.

4.3.1 ELECTRIFICATION OF THE VEHICLE FLEET

Road transport accounts for about 17% of carbon emissions in New Zealand. The electrification of these fleets, starting with passenger vehicles, is key to reducing carbon emissions in New Zealand. The uptake rate of EVs, while still low across the country, has accelerated markedly in recent times, as illustrated in Figure 4.8.

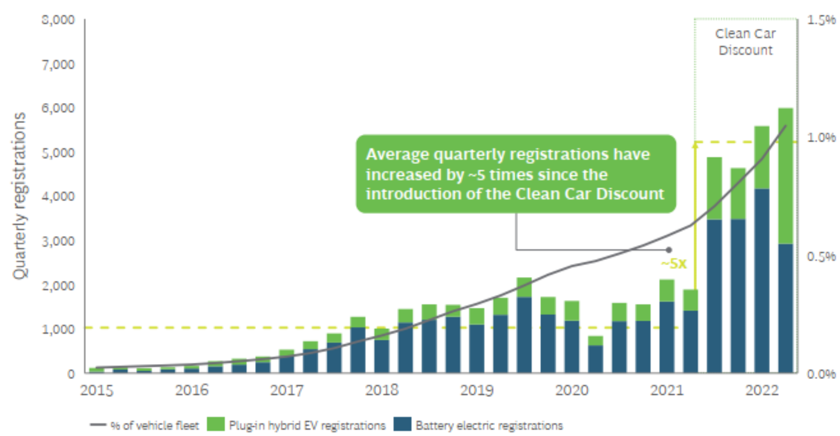
Electric vehicle usage increased by

60%

on our network last year

Looking forward, this uptake rate is set to exponentially accelerate, as shown in the projection adopted by the EA, taken in turn from the Energy Efficiency and Conservation Authority, shown in Figure 4.9.

Figure 4.8: Electric vehicle registrations in New Zealand[34]



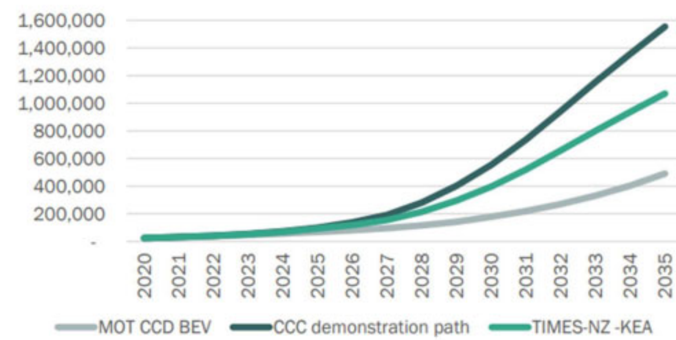
Source: Ministry of Transport

The impact of increasing numbers of EVs on electricity demand is still highly uncertain, as it is subject to multiple factors, particularly:

- Number of EVs in a network area.
- Average distance travelled per day and, hence, the energy required to recharge.
- Time of charging – off-peak charging will have relatively little impact in the near future, but should it coincide with the early evening demand peak, it will immediately add to total network demand.
- Use of charging infrastructure structure – public infrastructure v residential charging.

The time of charging is particularly pertinent to us as it is the only factor we can materially influence. Based on even a relatively benign assumption of a 28% EV uptake by the end of the AMP planning period (2033), we estimate that uncontrolled charging would add about 10% additional peak demand on our network. With relatively widespread smart control, shifting most charging to off-peak hours, this addition reduces to less than half that figure – about 4.5%. Various means of achieving and incentivising such smart charging are being investigated.

Figure 4.9: Battery EV uptake scenarios 2020-2035 (excluding plug-in hybrid vehicles)[35]



[34] Boston Consulting Group, "The Future is Electric," October 2022

[35] Energy Efficiency and Conservation Authority (2022) Improving the performance of electric vehicle chargers, Wellington, New Zealand, a green paper by the Energy Efficiency and Conservation Authority. https://www.eeca.govt.nz/assets/EECA-Resources/Consultation-Papers/EV-charging-Green-Paper-8-August2022.pdf

4.3.2 PROCESS HEAT ELECTRIFICATION

One of the main focus areas for reducing New Zealand's carbon footprint is the decarbonisation of process heat. Industrial processes and waste represent about 8% of New Zealand's carbon emissions[36].

Conversion of large industrial processes is unlikely to directly impact electricity distribution networks. Many of the major industries indicate that, in order to reduce carbon emissions, they are more likely to convert their plants to run on biomass than on electricity. This is partly driven by energy costs, but also by the limitations of using electricity to effectively drive high-temperature heat processes (as required, for example, for steam boilers). In addition, the sheer extent of the energy required for these large processes is mostly beyond the capacity of distribution networks to supply[37]. Where large processes are electrified, we foresee that these will be directly connected to the transmission grid.

However, there are still significant numbers of smaller industrial and commercial heat processes, such as heating for hospitals and schools or part-processes of major plants, operating at lower temperature levels, where converting to electricity from carbon-based heat sources is viable. At least part of the additional electricity capacity required to achieve this will be delivered via distribution networks.

As the pressure on businesses and other entities to reduce emissions increases, we see the potential for significantly higher electricity demand associated with process heat conversion.

During 2022, we kicked off an initial project with DETA Consulting, co-sponsored by Energy Efficiency and Conservation Authority (EECA) and Transpower, to determine the possible extent of process heat conversion on our network footprint. Most customers indicated that they were still in the process of developing their decarbonisation plans. We will continue engaging and collaborating with our customers to develop the most efficient decarbonisation outcomes, meeting their needs as well as optimising network utilisation. Our longer-term demand forecasts and investment plans will be updated as more information becomes available.

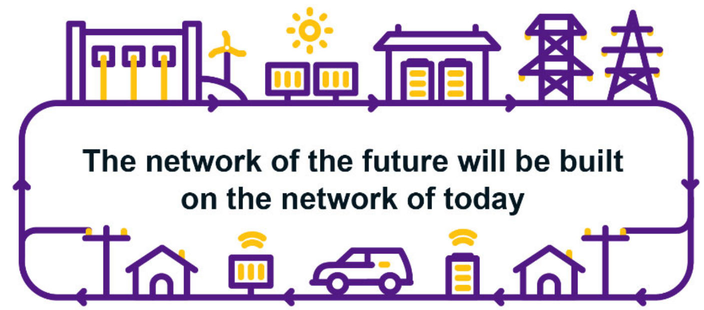
Based on our high-level assessment, we conservatively estimate that process heat electrification can increase peak loading by about 9% on our overall network by 2033 (or 16% under a more aggressive scenario). This impact can be even more substantial on those parts of our network where heat loads are concentrated.

Chapter 10 outlines our plan to meet this growing demand.

4.4 LEGISLATIVE AND ELECTRICITY MARKET CHANGES

The energy policy and market environment are adapting to improve the interface between technology, infrastructure, and sustainability drivers. Outcomes include relatively rapid shifts in electricity consumption and investment decisions, as well as the direct and indirect costs of providing services to customers. While the timing and extent are difficult to predict, we foresee several changes as a reasonably high likelihood during the AMP planning period.

4.4.1 DISTRIBUTION SYSTEM OPERATOR (DSO)



To encourage the uptake of local, particularly renewable generation, advanced economies are realising the importance of creating an electricity market at distribution network levels – the DSO.

The debate in New Zealand on what form such a DSO may take has not progressed significantly since we issued our 2021 AMP. However, based on observations of the United Kingdom and Australian electricity markets, we expect much more action on this during the AMP planning period. These decisions will likely have a major impact on our business.

Powerco is still committed to evolving from a distribution network operator to a DSO – to the extent the New Zealand electricity market will permit this. In anticipation of

[36] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/decarbonising-process-heat/#:~:text=In%20a%20New%20Zealand%20context,approximately%208%25%20of%20gross%20emissions

[37] When point demands start to exceed about 30MVA, it becomes increasingly impractical or uneconomic to connect to distribution networks, even at 33kV. Direct grid connections, or higher voltage subtransmission networks are generally necessary, which in some cases may still be provided by distribution utilities.

some form of DSO and distribution electricity market in New Zealand, we are looking to ensure that the essential (distribution network) enablers for this are being developed. These developments are largely agnostic to who will take on the role of the DSO, as the basic requirements will be similar for any party in this role. The developments are discussed in Chapter 7.

4.4.2 FLEXIBILITY SERVICES

An exciting international development, which has gained much prominence in recent years, is the increased provision of flexibility services to augment normal energy delivery.

Flexibility is defined as the ability to shift, in time or location, the generation or consumption of energy.

When combined with the ability to respond in real-time to a control signal, it creates a smart, flexible energy system.

The need for a flexibility service is normally triggered by a particular requirement or opportunity, such as a network constraint or financial incentive. It can take multiple shapes, but for distribution networks, it's particularly becoming assessable through the increased use of distributed energy resources (DERs), such as renewable generation, energy storage, electric vehicles, and the ability to control these in real-time. Broadly, the flexibility service will be triggered through an external signal, mostly digitally delivered.

Importantly, the distribution utility doesn't need to be the flexibility service provider for the network to reap the benefits from the service – the service can be procured from any number of parties, including end consumers, energy aggregators, DER, or consumer equipment providers. In future, we foresee that there will be an active flexibility market where flexibility services will be offered and procured, potentially by multiple parties.

Flexibility services offer a range of potential benefits to distribution utilities and the industry as a whole. These include, for distribution utilities:

- Deferring or reducing the need for network reinforcements, by shifting demand from congested to uncongested periods.
- Increasing the reliability of supply, by providing local energy storage.
- Improving power quality, by providing voltage and power factor support.
- Improved grid stability by better balancing supply and demand.

And for the wider industry:

- Reducing carbon footprint, by offsetting the need for generation through better utilising distributed renewable generation.
- Reducing the need for peaking generation, by shifting demand from peak to off-peak.
- Facilitating end-users' efforts to reduce their own carbon footprint.
- Providing potential revenue sources for end-users, through the flexibility market or by increasing the capacity for selling excess generation.
- Reducing line losses through supporting more generation close to the load.

Powerco's approach to procuring flexibility services will be to consider what is in the best interests of end customers, taking into account economics, operability, and quality of service. We foresee that, in the future, this will lead to a hybrid approach, where we provide conventional network services and DER/flexible services as part of our network, and also procure flexible services from third parties – the actual solution to be determined by the optimal customer outcome.

While there is not yet an operational flexibility services market in New Zealand, there are promising signs of this being developed. Powerco is a member of the FlexForum – a voluntary, cross-industry body that is working with interested parties to promote the use of flexibility services and the formation of a flexibility market. The EA and Commerce Commission have also both recognised the importance of flexibility services and are working on ways to facilitate this within the regulation of electricity lines companies.

We have also, on several occasions, issued requests for proposals from market participants for possible alternatives to major network reinforcement investments. While most of these have not yet resulted in economically viable propositions, we have had recent success with entering into a partnership with solarZero to provide a 1MW demand response scheme in Whitianga. This will utilise distributed home energy storage systems, supplied and coordinated by solarZero. Through this arrangement, we are able to defer network upgrades in Whitianga for several years[38], with a significant overall cost benefit to our customers.

In future, we intend to expand the procurement of flexibility services and include this as a standard solution in our network toolkit, evaluated alongside other options.

4.4.3 ELECTRICITY REGULATION

Electricity distribution in New Zealand is regulated by two entities:

- The Commerce Commission is the competition regulator. We are a monopoly, and the Commerce Commission determines the maximum revenue we are allowed to earn as well as the minimum quality of supply for the delivery of electricity. It also manages an Information Disclosure regime, requiring us to

[38] The initial contract, agreed in late 2022, is for a six-year period.

publish annually several key statistics about our business, asset, and network performance, as well as our plans for the network, changes to our pricing, and policies for sharing the costs of new connections.

- The EA is the market regulator, which sets and oversees the rules for participating in the New Zealand Electricity Market. Some of the key touchpoints for us are our commercial arrangements with other market participants (including data access), commercial and technical requirements for connecting new technologies to the network, and access and use of consumer data. The EA's powers also include guidelines, compliance, and reporting requirements relating to our pricing and equipment connected to the grid.

Any material change to electricity or market regulation could have a significant impact on our business, ranging from additional revenue or operational limitations to additional reporting requirements. Performance targets can also affect the way we have to run our operations.

Potentially, considerable changes are afoot in the following areas of regulation:

- The Information Disclosure regime was updated in November 2022, reflecting tranche one of the Commerce Commission's targeted Information Disclosure review. Additional information will, in future, have to be provided by electricity distribution businesses (EDBs) on a range of metrics, including:
  - Customers' quality of service, including connection times.
  - Plans for monitoring network voltage and ensuring compliance.
  - Network augmentation decision-making.
  - Innovation practices.
  - Vegetation management practices.
  - Capital investment forecasting.
  - Asset renewal planning.
  - Demand forecasting.
  - Cyber security expenditure.

  Updates were also made to better define and ensure consistency in interpretation and reporting between EDBs on various earlier metrics.

  A second tranche of Information Disclosure amendments have been identified for consideration under the next stage of review. These include additional information to be provided on:
  - Planned outages.
  - New connections processes and performance.
  - Commitments to improving customer service.
  - Additional and more disaggregated quality of supply measures.
  - Information on Low Voltage (LV) network performance and improvements.
  - Information on use of flexibility resources.
  - Network constraints.
  - Standardised pricing.
  - Asset information.
  - Unit cost information.
  - Resilience and climate change risk reporting.

  These are positive steps from a consumer and innovation perspective, and we support them, but they will likely bring about additional requirements for measurement, record-keeping, and reporting.
- The Commerce Commission has also kicked off a review of, and consultation on, the input methodologies (IMs) that will apply to the next Default Price-quality Path determination (DPP4) in FY26. The draft decisions on the IMs review are anticipated in April 2023. Following consultation, the final amendments to the IMs are anticipated to be published in December 2023.
- The EA is also working on improvements in the regulation of distribution networks. A discussion paper on this topic was released in July 2021, with follow-up information requests. This has culminated in an updated issues paper, released in late December 2022, in which the EA sets out its vision for distribution networks and further discusses how this may be achieved. Consultation on this paper is proceeding.

  In essence, the EA supports the implementation of open-access networks, which are an essential precursor to a DSO or distribution network electricity market, as well as the widespread use of flexibility services. The topics they cover in the issues paper include:
  - Equal access to data and information.
  - Market setting for equal access.
  - Capability and capacity (of skilled staff to integrate DER and non-network solutions).
  - Operating agreements for flexibility services.
  - DER standards.

  Again, we support this direction, which should greatly enhance efficient electricity delivery in New Zealand. However, as pointed out to the EA, its implementation will require additional, likely significant, investment in monitoring and metering equipment, information systems and reporting. Despite this additional cost, we believe that, overall, customers will still be economically far better off with these solutions than with the counterfactual – meeting capacity needs through conventional network solutions only[39].

- Pricing reform continues to evolve. The EA has approved a new transmission pricing regime to be applied by Transpower, coming into effect in 2023. These costs are a significant proportion of our network charges – equivalent to almost half of our distribution charges – so the impact of this implementation is being closely monitored.
- We anticipate the removal of the low-fixed charge regulations (by MBIE) will be complete during the AMP period, enabling significant improvement to the alignment of network costs and revenues.

4.5 TECHNOLOGICAL CHANGES

Energy technology, including communications networks and the ability to remotely monitor and control devices, is improving at a rapid rate. This brings about amazing opportunities for electricity customers and utilities to improve flexibility, reliability, efficiency and safety in the delivery and use of electricity, with associated cost benefits. However, along with this comes increased complexity of operations and the potential for network disturbances or instability, which we will have to manage to ensure the benefits from new technology can be fully realised.

4.5.1 CUSTOMER ENERGY TECHNOLOGY

Emerging technology is creating increased energy opportunities for customers. This includes possibilities for self-generation, participation in flexibility markets, energy storage, demand management, and improved energy efficiency etc. With a functional flexibility market or DSO, it will also become easier to sell excess generation directly to other consumers or aggregators (or back to suppliers) – using the distribution network as the platform for these transactions.

The number of customers with solar panels increased by

26%

on our network last year

However, the ability of distribution networks to integrate customer technology, especially local generation, or additional high-demand equipment, such as EVs, is finite. Should the network capacity be exceeded, this can not only cause the network to be overloaded but can also give rise to system instability resulting from voltage swings or reverse power flows. The latter can lead to signal distortion, equipment damage and, in serious cases, even the total collapse of a network requiring a shutdown and re-livening.

It is therefore essential that distribution businesses work closely with customers to ensure that the network has adequate capacity to manage new connected devices or to agree on mutually acceptable measures to reduce the impact of the new devices during periods of network constraint.

Managing the impact of new customer technology is discussed in Chapter 7.

4.5.2 NETWORK TECHNOLOGY

With emerging technology, distribution utilities also have an expanding scope to improve the service they provide or lower supply costs. Solutions include novel distributed generation solutions, demand management, remote monitoring and control, automated self-restoring networks, energy storage, real-time asset ratings and much more.

Our Network Evolution strategy, described in Chapter 7 is largely aimed at keeping abreast of emerging technology, testing promising ideas, and supporting the roll-out of new solutions where safe and technically and economically feasible.

As expressed elsewhere in this AMP, one of Powerco's key network planning and operational objectives is to operate an open-access network. This would encourage flexibility services and allow our customers maximum opportunities to manage their energy use or market participation, without compromising the stability and safety of the existing electricity supply. We see this as an essential enabler for an effective DSO, which in turn is a prerequisite for allowing customers to fully realise the benefits of emerging technology on their side.

Such an open network and distribution energy market will play an essential role in supporting customers to reduce carbon emissions, by facilitating and encouraging local, particularly renewable generation, with the associated ability to buy or sell excess local capacity with minimum constraints.

4.5.3 CYBER SECURITY

As our reliance on connected digital devices increases, so does our vulnerability to cyber attacks. This is true for our normal business operations, as well as for network operations – where devices are increasingly remotely monitored and controlled. Globally, the instances of electricity utilities being subject to cyber attacks are rapidly increasing, with New Zealand no exception.

To address this, we have a dedicated cyber security team and a well-established programme to continually upgrade our protection. Plans are also in place to react should our cyber defences be breached.

4.5.4 REDUCTION IN GRID INERTIA

[39] This conclusion is supported by multiple studies, including: "Sapere (Sep 2021), Cost benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority, Wellington New Zealand" and "Dept for Business, Energy & Industrial Strategy UK (July 2022), Low Voltage network capacity study – Phase 1 Report – Qualitative Assessment of Non-Conventional Solutions".

As technology changes from traditional large generators to smaller renewable sources, an inevitable loss in system inertia follows. Traditional spinning machines have considerable rotational momentum, with the associated ability to ride through short-term electricity system fluctuations and ensure stable system operation.

Most new renewable generation has little to no intrinsic inertia, particularly smaller-scale local generation. In addition, the devices are connected to the grid through electric inverters. In the absence of substantial permanently connected energy storage devices to create artificial inertia, the ability of the new generation to ride through system disturbances is limited. This holds the potential for system collapse following a significant event, which is exacerbated by the fact that individual equipment controllers often do not synchronise well, further contributing to instability.

Grid stability is currently mainly a System Operator function. However, as we move to more reliance on small-scale generation, connected to distribution networks, close coordination between distribution network operators and the System Operator will become more important than ever.

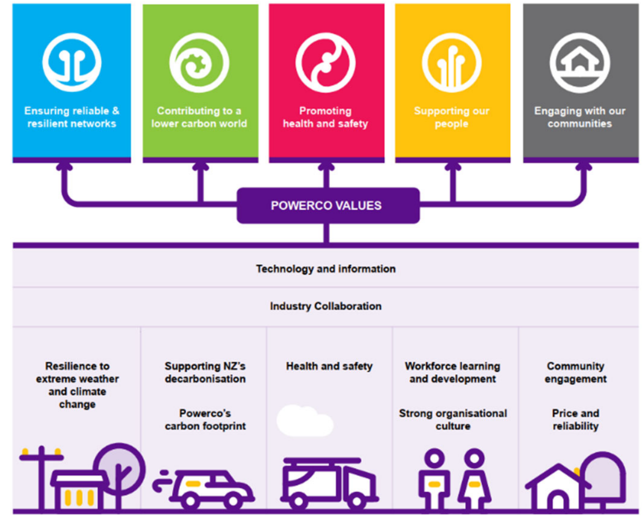
We continue to monitor the uptake of distributed generation on our network. Timely steps will be taken to ensure that we understand and manage the system impact of individual devices and work closely with the System Operator in this regard.

4.6 MANAGING OUR ENVIRONMENTAL IMPACT

As noted in section 4.3, New Zealand's first Emissions Reduction Plan was published in May 2022, with significant implications for how we will run our business in future. We are committed to the goals set out in the plan.

This is reflected in our annual Sustainability Reporting[40], which sets out our plans and goals for a sustainable business from an environment, social and governance perspective. Our five sustainability pillars (pou) are shown in Figure 4.10 and form the framework of our sustainability strategy. These were developed through a process of stakeholder engagement – known as a materiality assessment. During 2023, we will be reviewing our material issues with a deep dive into our initial materiality insights.

Figure 4.10: Powerco's pillars for a sustainable business



As an electricity distribution utility, we realise that electrification will be key to New Zealand's decarbonisation and that we have a major responsibility to help our society achieve this. This is the foundation of our strategy to building an open-access network and supporting flexibility markets, which we see as facilitating efficient energy use and carbon reduction initiatives for our end-users and electricity generators.

Our roadmap to achieve this, and its associated goals, is presented in Figure 4.11.

[40] FY22 Sustainability Reference Report – December 2022 https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/what-we-do/sustainability-doc-2022.pdf

Figure 4.11: Our roadmap to carbon reduction

Goals and targets FY23

Short term (1 April 2022 - 31 March 2023)

- Measure and reduce Scope 1 and 2 emissions (excluding line losses) and the most material Scope 3 emission activities
- Investigate emission reduction targets in line with science
- Understand and assess the financial impact of achieving science aligned emissions targets
- Publish low carbon transition strategy for gas network
- Complete the low carbon gas compatibility assessment for the network
- Build an automated application process for small-scale solar connections
- Develop and install three micro grids on our network to improve customer self-reliance, reduce grid demand and defer costly upgrades
- Complete North Island boiler review by partnering with EECA and DETA to identify large customers (or groups of customers) to quantify the scale of customer decarbonisation opportunities

Medium term (1 - 3 years)

- Implement emissions reduction strategies in line with our emissions reduction roadmap
- Trial diesel alternatives
- Set up streamlined process for large scale solar (1MW or more) and enable 200MW of connected capacity
- Work with stakeholders to evaluate decarbonisation pathways and ensure a policy environment that supports decarbonisation
- Produce a robust, decision-useful and authentic climate-related disclosure

Long term (3+ years)

- Offset any remaining emissions at 2030 from our reduction target for Scope 1 and 2 emissions, excluding electricity and gas line losses
- Facilitate and accelerate decarbonisation for our customers
- Continue to evolve the electricity network to support customer-driven renewable generation and energy trading
- Reduce volume of natural gas going through network by 20% (compared to FY20) by 2030

Our own greenhouse gas footprint is relatively small compared with that of the electricity we convey or the impact that this service could have. Powerco's Climate Change Policy commits to "applying a sustainability mindset to our investment decisions and operational practices to minimise their impacts on and from the climate", and our action on climate change and greenhouse gas (GHG) emissions is part of our contribution to this. We annually publish a GHG inventory report as part of our contribution to this commitment.[41]

Some of the direct improvements Powerco is working on to reduce its emissions include the following:

- Reducing electricity use at our substations and office facilities.
- Electrification of our vehicle fleet.
- Investigation and trialling of diesel generator alternatives.
- Ensuring we source our assets from responsible suppliers, using sustainably sourced materials.
- Improving our understanding of the embedded carbon in our network and maximising the knowledge gained. Carbon embedded in the materials used to build (e.g., concrete v wood poles) and operate (e.g., ester v mineral oils) our network has an impact on our footprint.
- Increasing automation and remote fault indication on our network, thereby reducing the travel required for switching, fault-finding and repairs.
- Development and implementation of our offsetting plan to offset Scope 1 and 2 emissions (excluding line losses by 2030).

Current New Zealand practice is to exclude line losses from distribution utilities' Scope 2[42] emissions reduction targets. This is to avoid the conflicting requirement to increase electricity use for decarbonisation purposes, but which results in an increase in line loss emissions. By ensuring that our networks operate within regulated voltage limits, we ensure that line losses do not exceed industry-acceptable levels. However, we appreciate that line losses can still be a major contributor to emissions and that this is a factor we can influence. Accordingly, we will be increasing our monitoring of losses (largely LV-related) and working on cost-effective means to reduce this.

[41] (refer "Greenhouse gas emissions inventory report - financial year ending 31 March 2022 (FY22): https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/what-we-do/final-ghg-report-with-assurance-report.pdf)

[42] We measure emissions in terms of the internationally accepted Greenhouse Gas Protocol. Scope 2 losses refer to indirect emissions.

5 ASSET MANAGEMENT OBJECTIVES

5.1 INTRODUCTION

Powerco's primary business is to deliver electricity to its customers safely, reliably, and efficiently while ensuring that its shareholders earn an acceptable return on their investment.

It is well understood that for modern society to thrive, it is essential communities have efficient and affordable electricity. We take our responsibility to deliver this seriously – it lies at the very heart of our business. The COVID-19 crisis has underscored the importance of electricity security, with a robust, reliable electricity supply a key precondition for the functioning of the healthcare system, maintenance of social welfare, and facilitation of online economic and social activity.

It is also abundantly clear that the electrification of energy consumption will be essential for New Zealand to achieve its carbon reduction goals. We have a major part to play in this.

Our Corporate Objectives and supporting Asset Management Objectives have been formulated to achieve the central business goal of delivering reliable, affordable, and safe electricity to our customers, along with providing a platform for a flexible market for multiple participants.

5.2 CORPORATE OBJECTIVES

Powerco Ltd and its parent Powerco New Zealand Holdings Ltd are leading energy infrastructure asset managers. We operate on commercially sound and sustainable principles, which means we also take our responsibility towards our customers and our planet very seriously.

As part of a review of our longer-term strategy and an associated change in our company structure, we completely refreshed our corporate purpose and values during 2022.

5.2.1 NGĀ TIKANGA – OUR WAY

Ngā Tikanga - Our Way, guides us as we work together to achieve our purpose of connecting communities.

It's our cultural framework, incorporating our purpose, values, and our ways of working. It best describes who we are and how we work with each other, our partners and industry stakeholders to get the best outcomes for our communities. It's inspired by tikanga, a Māori concept that refers to the ethical framework of Māori society.

Figure 5.1: Ngā Tikanga – our way

5.3 ASSET MANAGEMENT POLICY

All our policies and guidelines reflect Ngā Tikanga. This includes our Asset Management Policy, which is central to our Asset Management Plan. It highlights the expectations of our Board of Directors and management regarding how we will manage our assets and make decisions while reflecting Ngā Tikanga.

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

Asset Management Policy

Powerco's vision is to be a customer-focused infrastructure owner and operator. Our purpose is to connect communities by working better together, working smarter, being future-focused, and taking an integrated business-wide approach to our work.

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

We strive to achieve the following asset management outcomes:

- To protect the safety of the public, staff, and contractors.
- To meet all statutory and regulatory obligations.
- To be proactive, transparent, and authentic in our interactions with our customers and other stakeholders.
- To cater to the evolving needs of our customers.
- To cater for an evolving, net-zero energy future and low-emissions economy.
- To support sustainable environmental and governance practices.
- To recognise, prioritise, reduce, and monitor the physical and transitional climate change risks to Powerco's networks.
- To make prudent decisions that provide a sensible balance between asset cost, risk, and performance.

We will achieve these asset management outcomes by:

- Achieving the objectives and targets listed in our respective Electricity and Gas Asset Management Plans.
- Maintaining our Electricity ISO: 55001 certification and aligning the Gas business with ISO: 55001 principles through the implementation of cohesive, integrated Asset Management Systems.
- Recognising the importance of our people and their development.
- Treating data with the same importance as physical assets.
- Implementing information management tools and a governance framework that support asset management decisions.
- Continually enhancing our asset management capability and skills.

Members of the Executive Leadership Team are accountable for resourcing and delivering the outcomes of this policy by:

- Setting and regularly reviewing the Asset Management Policy.
- Monitoring and continually improving our Asset Management Systems.
- Monitoring and participating in the development and implementation of the country's energy transition plans

Specific roles and responsibilities are documented in the respective Asset Management Systems for our Electricity and Gas divisions.

We strive to be New Zealand's leading asset manager, enabling us to deliver a better energy future to our customers and a consistently safe, reliable, and cost-effective service.

James Kilty – Chief Executive

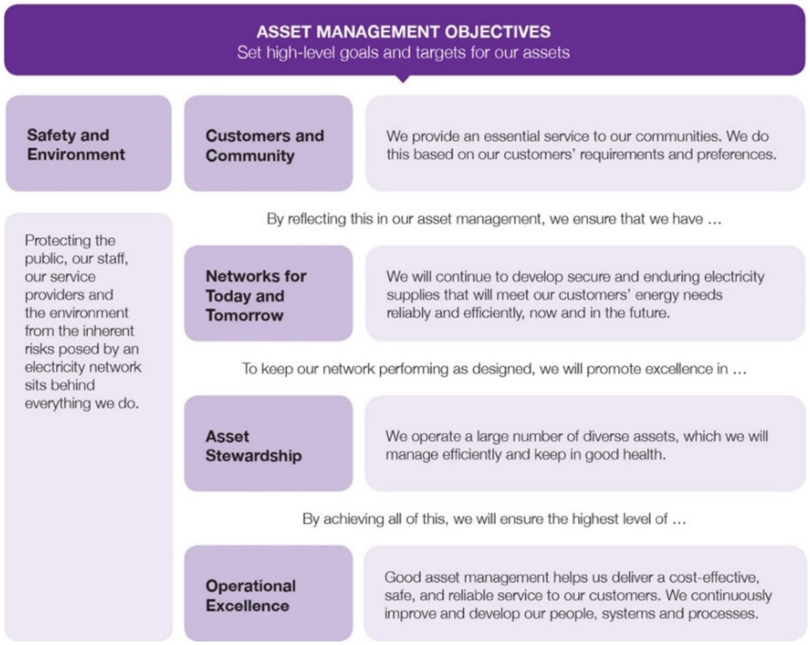
5.4 ASSET MANAGEMENT OBJECTIVES

Our Asset Management Objectives set the direction for managing our electricity network assets. They have been developed to achieve the following aims:

- Describe how our Asset Management Policy is used to develop Asset Management Objectives.
- Support the delivery of the 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 the Corporate Objectives.

Five Asset Management Objectives are at the heart of how we manage our assets. They reflect our lifecycle asset management approach, which considers all aspects of asset decision-making and activities from inception to decommissioning. These Asset Management Objectives are illustrated in Figure 5.2.

Figure 5.2: Our Asset Management Objectives



In the sections below, we discuss the five Asset Management Objectives in more detail and the goals and targets we have for each. We also illustrate key performance indicators for each objective to illustrate how we perform against them. More performance indicators are given in Chapter 8.

5.5 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 our drive to minimise harm.

We see ourselves as responsible custodians of our environment. To support this, we encourage the efficient use of energy, ensure sustainable business practices (also for our suppliers), strive to minimise our carbon footprint, and help our customers achieve the same. Our electricity assets and our operations are designed to minimise the potential for environmental damage.

Safety and Environment: Overall objectives

Our overall safety objectives are to safeguard the public from any harm from our assets and to ensure an injury-free workplace.

Our overall environmental objectives are to cause no lasting harm to the environment and to reduce our carbon footprint. We also have a commitment to offset our scope 1 and 2 emissions (excluding line losses) by 2030.

5.5.1 CONTEXT

The Safety and Environment context that our assets operate under can be broadly categorised into three parts:

- Public safety
- Lifecycle environmental stewardship
- Worker safety

It is also usually shaped by broader societal factors, such as legislation and public perception. Therefore, we must constantly monitor external factors to ensure the strategies for this objective are meeting their goals.

Public safety

On a societal level, electricity networks are inherently safe when compared to other societal risks e.g., transport, healthcare etc. But significant effort is required to keep it that way, which may only sometimes be apparent to the general public.

As society has grown around our assets, there is also a shift in expectations from managing these risks in absolute terms, such as Electrical Codes of Practice terms and conditions, to a more balanced assessment of risk to encompass more than physical harm but also other factors, such as ethical, economic, and social considerations – concepts including Tolerability of Risk (TOR).

When commissioning assets, work practices have also evolved to better manage public safety during construction and maintenance.

Lifecycle environmental stewardship

There was a significant lift in environmental awareness in the latter part of the 20th century. New networks are designed and built to minimise any potential environmental harm. However, as we have substantial legacy networks where the environment could have been more carefully considered, we must be extra vigilant about managing any potential impact of these older assets.

Organisations and asset owners worldwide also expect equipment suppliers and service providers be held to a higher standard. This has meant we have had to take a more active role in monitoring our key suppliers work practices and manufacturing practices of– ensuring that we obtain material from sustainable sources and from suppliers who are ethically and environmentally responsible in their manufacturing and workforce practices.

Worker safety

There has been substantial reform in health and safety in New Zealand, with the introduction of the Health and Safety Reform Bill enacted at the end of 2015. The Reform Bill put a strong emphasis on prevention and accountability. It followed on from other reforms in the health and safety area, such as the introduction of WorkSafe New Zealand, a health and safety regulator, and the adoption of a proactive approach to enforcement.

This has made it even more important for asset owners to have appropriate health and safety systems. It requires robust steps, including reviewing and updating existing internal policies and processes and considering whether the business is doing all it should concerning work travel.

5.5.2 SAFETY AND ENVIRONMENT GOALS

We have developed a set of goals to help us achieve our Safety and Environment objectives and to monitor our performance. These are set out in Table 5.1 and Table 5.2.

Table 5.1: 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 for their staff working on our assets.
	Enhance contractor approval and work monitoring 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	Ongoing development of safety culture maturity with our service providers, including recording, analysis, and reporting of safety-related issues.
10% year-on-year reduction in Lost Time Injury (LTI) frequency rate	Review the effectiveness of the contractor works manual to communicate critical information.
	Evolve contractor approval process to include design capability assessment.
	Develop leading and lagging performance metrics for 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	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.
Reducing public safety risks	Engaging the public about the dangers of copper theft.
	‘Look Up’: A comprehensive lines safety campaign across multiple digital, print and radio platforms.
	Raising awareness for tree management and safety through online and newspaper media.

Table 5.2: Environment goals

GOAL	SUPPORTING INITIATIVES
Reducing carbon emissions	One of our key environmental objectives is to reduce our carbon footprint. We are committed to offset our scope 1 and 2 emissions (excluding line losses) by 2030.
	Support distributed and renewable generation by enabling our customers’ use of solar panels, batteries, and electric vehicles.
	Collaborate with peers and customers on reducing line losses.
Zero significant, avoidable environmental incidents caused by our assets or work practices	Another key environmental objective is to cause no lasting harm to the environment
	Development and implementation of sustainable environmental management principles for employees and contractors.
	Identify critical environmental risks and associated mitigation measures for communication with all stakeholders.
	Environmental management planning is core to any project initiation process.
All environmental incidents reported in time	Continual improvement in measuring and reporting incidents that have a real or potential environmental impact.

GOAL	SUPPORTING INITIATIVES
	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 environmental impact.
	New materials approved for use on the network are subjected to rigorous MECO[43] 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 a 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 a certification.
	Continual self-assessment of systems and procedures, with ongoing improvements where the need is identified.

5.6 CUSTOMERS AND COMMUNITY

Our core business is to ensure that electricity is delivered to our customers safely, reliably, efficiently, and sustainably. Therefore, our customers' priorities guide our investments.

Achieving this requires balancing:

- Investment in the network to ensure it remains in an appropriate condition, has sufficient capacity and functionality to meet customers' current and future needs with
- Customers' individual experiences in the short-term as we deliver our investment programme and service their day-to-day needs.

Our Customers and Community objective is one of several objectives that set the direction for how we deliver our Customer Commitment, the policy detailing the high-level principles that reflect our vision, mission and Ngā Tikanga.

Customers and Community: Overall objective

Ensure customer and community preferences are reflected in the provision of a safe and reliable electricity network that meets their service level expectations, is future-ready, and cost-effective.

43 Materials, Energy, Chemicals, Other lifecycle considerations

5.6.1 CONTEXT

Evolving customer expectations

Customer expectations are increasing – people want to have instant information at their fingertips, a seamless customer service experience, and the ability to influence decision-making across all aspects of their life. For the electricity industry, this means we need to engage with customers and communities on topics ranging from how we design our networks to the individualised information customers can access about outages.

Our ability to understand changes in customer preferences and appropriately respond relies on comprehensive customer insights. We strive to generate quality insights through:

- Targeted engagement with individuals and communities on topics relevant to them in an appropriate manner and at the right time.
- Providing positive day-to-day experiences across all customer touchpoints.

Achieving this ensures our asset management decisions are based on the level of service customers desire at a cost they find appropriate, and we clearly understand the needs and timing of future network investments.

Effective customer engagement requires positive customer experiences. Customers' willingness to engage on matters beyond pricing, outages and land access is inherently difficult, even more so if a foundation of positive experiences has not been established.

Several indicators provide an outcome view of performance against our Customers and Community Asset Management Objective.

5.6.2 CUSTOMERS AND COMMUNITY GOALS

We have developed a set of goals and targets to help achieve our Customers and Community Asset Management Objectives and to monitor our performance. These are set out in Table 5.3.

Table 5.3: Customers and Community goals

GOAL	SUPPORTING INITIATIVES
Meaningful customer engagement on price and service quality levels	Maintain and implement an annual customer and community engagement research programme to deliver insights to support network planning and investment optimisation.
Improved satisfaction with network-related interactions	Understanding our customer journeys, touchpoints, and their specific pain points, and working in partnership with our delivery partners and the wider supply chain to improve their experience.
Major projects (>$5m) developed with customer/community consultation where appropriate	Community engagement and relationship management programme to ensure customer and community preferences and priorities are reflected in our investment decisions.
The network enables customers' future energy choices	Monitoring and analysis of local and international customer trends and preferences.
	Provide insights from our customers into changing usage patterns and trends related to future usage requirements.
	Provide dedicated energy consultancy service to support customers' decarbonisation decisions and journeys.
Investment programme enabled by the full community, landowner and other stakeholder support	Community engagement and relationship management programme to create partnerships that support the efficient delivery of our works programme.
Increase the community profile of Powerco	Provide better customer access to information, create personal connections with key community stakeholders and proactively develop and promote community and industry content.

5.7 ASSET STEWARDSHIP

Our electricity network is extensive and comprises assets of varying age and condition. Looking after these assets efficiently is essential to delivering a safe, reliable, cost-effective electricity supply.

Good stewardship 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 unsafe ways.

Maintaining stable asset health is a key focus. To stabilise and reverse deteriorating performance trends, we have accelerated investment in asset renewal and our maintenance programmes. We are also improving our asset management support systems and processes to ensure we get the benefits of modern information technology to optimise asset investments.

Asset Stewardship: Overall objective

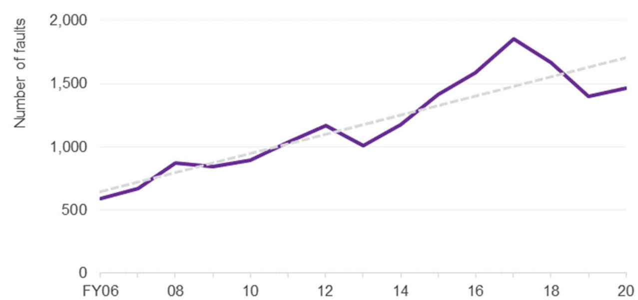
Through effective management and operation, our assets deliver a safe and reliable supply to customers cost-effectively over the full expected asset life.

5.7.1 CONTEXT

Defective equipment

Asset deterioration over time results in poor network performance and potentially puts the public and workers at risk. Therefore, maintaining stable asset performance is one of Powerco's main objectives. Arresting the declining asset performance trend associated with an aged asset fleet was a fundamental reason for our Customised Price-quality Path (CPP) application in 2018. A key indicator of the condition of our assets is the number of assets that fail in service, illustrated in Figure 5.3.

Figure 5.3: Defective equipment fault trend[44]



From this figure, our earlier concern about the long-term deterioration of our assets is clear. However, more recently, the trend appears to have stabilised – albeit based on limited observation data points. This coincides with the substantial uplift in our renewal programme since FY18.

[44] Equipment faults that led to outages longer than one minute are included in the trend. These are the outages that contribute to System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

5.7.2 ASSET STEWARDSHIP GOALS

Table 5.4: 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 Asset Health Indices (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 our network's cost-effective, safe, and reliable operation and maintain appropriate commercial tension between suppliers.
	Maintain a comprehensive set of high-quality asset standards and guidelines for all asset classes on the network.

5.8 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 according to their needs.
- Achieving internal cost efficiencies and ongoing improvements.
- 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.
- The efficiency of our service provider management.

Operational Excellence: Overall objective

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

5.8.1 CONTEXT

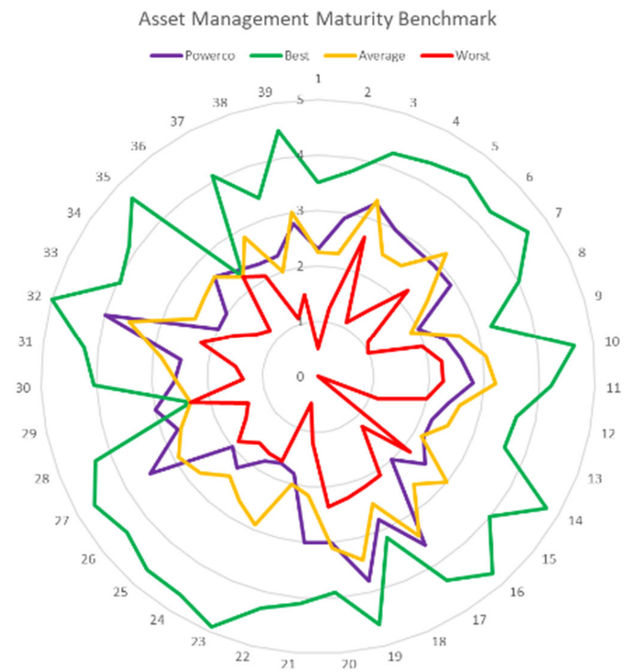
We have been assessing ourselves against the Asset Management Maturity Assessment Tool (AMMAT) structure since 2013. This is a self-assessment required by the regulator.[45]

To get a more in-depth understanding of our asset management maturity, we conducted independent assessments in 2018, This assessment allowed us to compare our practices to the requirements of the internationally recognised asset management standard, ISO: 55001, and Global Forum on Maintenance and Asset Management (GFMAM) and enabled us to benchmark ourselves against other utilities in Australia and New Zealand.

The assessment results led us to alter our AMMAT scores across various categories. In Figure 5.4, we show the scores grouped by assessment areas of GFMAM. We re-assessed ourselves as improving markedly in asset strategy and delivery, marginally declining in communication and participation.

[45] As it is a regulatory requirement, our AMMAT assessment for the 2023 AMP is provided, in Appendix 02

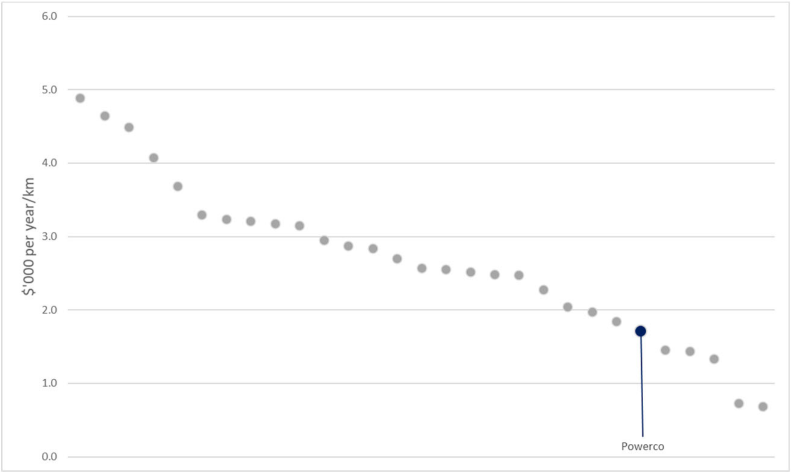
Figure 5.4: Benchmarking of asset management maturity against other utilities in Australia and NZ

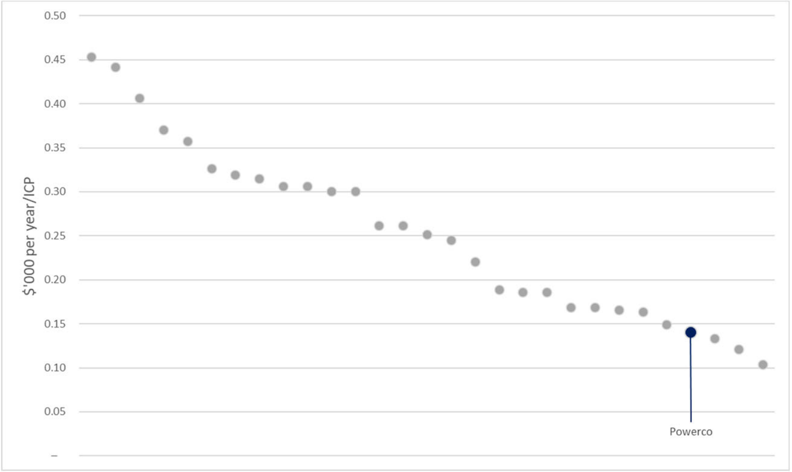


Further details about our improvements in our asset management maturity over the years can be found in Chapter 8.

Another important measure of Operational Excellence is the efficiency of our expenditure on internal support compared with the network we operate. Figure 5.5 compares our costs, normalised to network line length and the number of customers, with the rest of New Zealand's electricity distribution businesses (EDBs). Our non-network expenditure is low when compared with other EDBs in NZ.

Figure 5.5: System Operations and Network Support (SONS) and Business Support expenditure by network length (top) and per Installation Control Point (below) (Average FY19-21)





5.8.2 OPERATIONAL EXCELLENCE GOALS

We have developed a set of goals to help achieve our Operational Excellence objective and to monitor our performance. These are set out in Table 5.5.

Table 5.5: Operational Excellence goals

GOAL	SUPPORTING INITIATIVES
Implement leading asset management information practices	Improve data reliability by streamlining processes, providing new tools to report on the quality of data, and investing in new field mobility tools for asset data collection.
	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.
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.
	Automate manual processes to increase worker efficiency.
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.
ISO: 55001 certification	Continue improving on opportunities identified during our ISO 55001 audits.
	Develop skills for ISO: 55001 and evolve organisational structures to better align network development, fleet management, analytics, and future networks.

5.9 NETWORKS FOR TODAY AND TOMORROW

Our networks provide a lifeline service to communities. Safe, resilient, and reliable electricity is essential, and we will maintain this supply 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 for this.

Looking forward, it also means that our network should be capable of supporting customers' evolving energy requirements as well as providing a platform for flexible services and a potential distribution system operator (DSO). This means ensuring that we can support those customers who choose to utilise new energy solutions, such as rooftop photovoltaics (PV) and energy storage, those who wish to export energy or participate in a flexible market, as well as those who wish to continue just taking electricity supplies from our network.

In addition, overseas and local studies have shown that effective planning and application of appropriate emerging technologies are essential to realising 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 7**.**

Networks for Today and Tomorrow: Overall objective

We will continue to provide our customers with a safe, cost-effective, resilient, and reliable electricity service that will reflect their preferences and meet their needs today and, in the future, including the facilitation of flexibility services and allowing an electricity market to operate over our networks.

5.9.1 CONTEXT

The way electricity is delivered to customers is changing. 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 why electricity networks have evolved and been configured to meet peak demand, offering a one-size-fits-all approach to largely passive or disengaged customers.

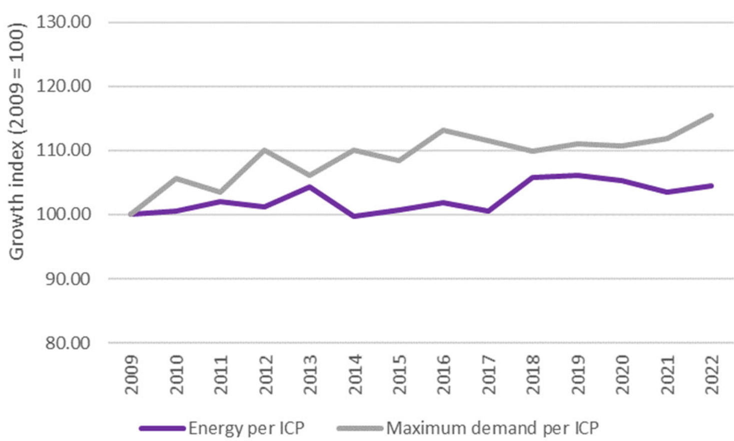
New technology in generation and consumption and the emergence of flexibility markets are starting to challenge this model. In future, we see customers taking a far more active part in the overall energy market, exporting excess energy, offering flexible services, and actively managing their consumption. With decarbonisation initiatives likely to lead to electricity becoming a far larger portion of the overall energy consumed, this increased customer activity is expected to coincide with a significant increase in electricity demand for the foreseeable future.

This increased demand, along with the technology that will enable increasing customer participation in energy markets, is anticipated to increase stress on the network during peak hours.

We are still experiencing a steady increase in demand on our network, as illustrated in Figure 5.6. This suggests that the average consumption pattern for our customers has not materially changed during the past decade – and we have no reason to expect this to change substantially during the AMP planning period. Accordingly, our primary asset management focus remains on conventional electricity networks – meeting the needs of today's customers.

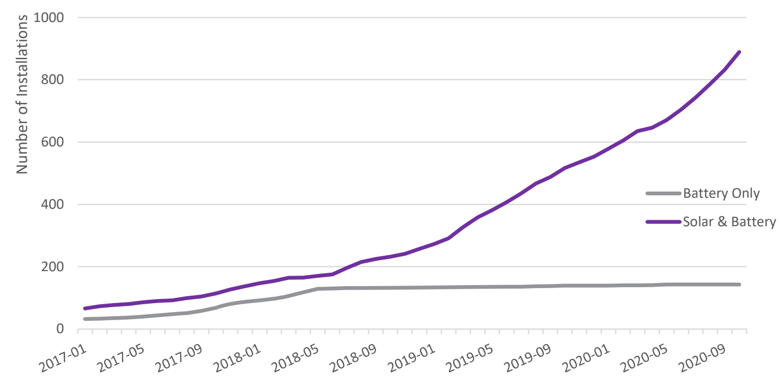
However, there is a slowly increasing uptake of solar PV generation and energy storage in our network area, as shown in. Over time, this number will increase, and as we plan networks with long-life assets, we must keep a close watch on the uptake and associated impact on network stability and act early when required.

Figure 5.6: Average electricity consumption and demand growth rate 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.

Figure 5.7: Increase in solar PV and battery storage on our network footprint



5.9.2 NETWORKS FOR TODAY AND TOMORROW GOALS

We have developed a set of goals to help achieve our Networks for Today and Tomorrow objective and to monitor our performance. These are set out in Table 5.6.

Table 5.6: Networks for Today and Tomorrow goals

GOAL	SUPPORTING INITIATIVES
At least maintain overall and disaggregated network reliability at historical levels[46] (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.
	Develop our networks to open-access principles that will allow our customers maximum flexibility to achieve their energy requirements.

46 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.

GOAL	SUPPORTING INITIATIVES
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 future 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.
Off-grid uneconomic supply areas	Identify parts of the network where it would be more cost-effective to provide off-grid electricity solutions, based on lifecycle considerations than maintain the grid. Work with customers on implementing such schemes.

6 CORE ASSET MANAGEMENT STRATEGIES

6.1 INTRODUCTION

In the previous chapters, we set out several external factors we have to consider when evolving our asset management approach. We also discussed our core corporate objectives and the supporting asset management objectives. In this chapter and Chapter 7, we describe our core and evolving Asset Management Strategies – our plans to continue a stable core business where appropriate, but also prepare for the changes in our environment and meet our objectives to support the long-term sustainability of our business.

Continually evolving Asset Management Strategies are important. However, these should be evaluated against the backdrop of our core business – electricity distribution – which remains predominantly stable and is unlikely to change dramatically in the near to medium future. Accordingly, our traditional, core Asset Management Strategies remain the most influential drivers for how we invest in and operate our networks.

As the bulk of the Asset Management Plan (AMP) is dedicated to the implementation of these core Asset Management Strategies, only a brief overview of these is provided below. In Chapter 7, more detail is provided about the areas where we intend to make material changes to our historical asset management practices.

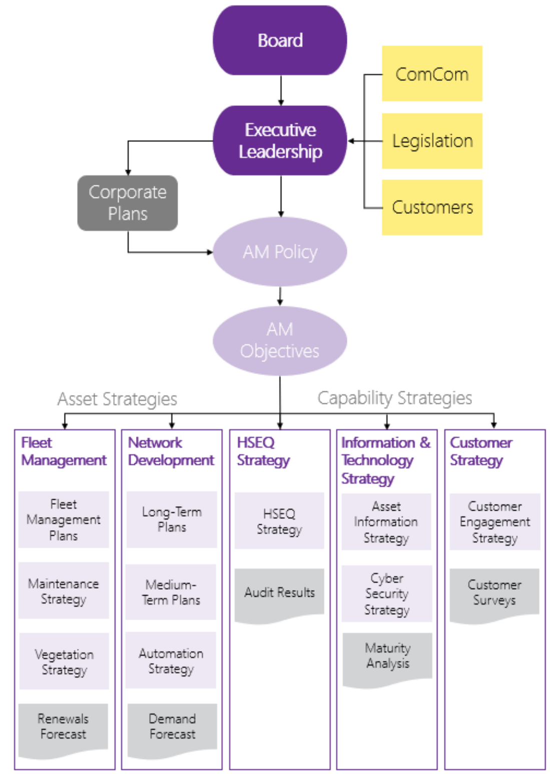
6.1.1 CORE ASSET MANAGEMENT STRATEGIES

Our core Asset Management Strategies have been developed to help deliver our Corporate Objectives and Asset Management Objectives. They form the basis of our long-term customer service plans and risk mitigation plans and provide direction for various parts of our organisation and our service providers. Our Asset Management Strategies can be broken into two broad categories:

- **Asset strategies:** These are broadly our Network Development and Fleet Management strategies.
- **Capability strategies:** These are our Customer, Information and Technology (I&T), and Health, Safety, Environment and Quality (HSEQ) strategies.

Figure 6.1 illustrates how our Corporate Objectives, Asset Management Policy, and Asset Management Objectives feed into our various strategies. This AMP considers these strategies to develop our 10-year plan.

Figure 6.1: Line of sight from our objectives to individual strategies



6.2 ASSET STRATEGY: FLEET MANAGEMENT

The Fleet Management Strategy ensures that we deliver on our promise to act as good stewards of our assets throughout their lifecycle.

The Fleet Management Strategy includes our plans to replace and renew the existing network as it approaches the end of its functional life. Replacement and renewal are the largest components of our capital expenditure, and this strategy carefully considers how they should be best implemented. We base our renewal decisions on risk, considering asset condition and health, known type issues, asset criticality and obsolescence.

This strategy also includes our inspection and maintenance approaches for our asset fleets. The objective of these strategies is to ensure that our fleets reach the end of their expected asset life in a controlled manner. Maintenance, therefore, includes planning interventions on the physical assets to keep them serviceable, as well as management of hazards, such as vegetation, on the network. Key to this is the condition assessment data we collect during inspections, which informs our decision-making for asset replacement or repair.

To minimise the likelihood of failures, the fleet strategies also include our plans for managing failures caused by third-party interference and natural hazards.

6.2.1 FLEET MANAGEMENT PLANS

Renewing our asset fleets is essential to maintaining the overall health and condition of our network. Deteriorating condition increases safety and reliability risks because of the higher likelihood of asset failure. The primary purpose of our asset renewal strategies is to inform our approaches to replacing our existing assets to meet our Safety and Reliability objectives, while minimising costs.

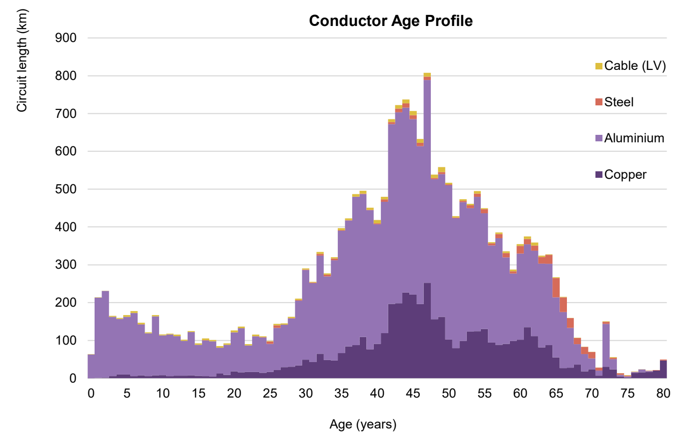
During the past five years, we have significantly increased our asset renewal investment. This was in response to asset renewal-related trends, such as:

- Increasing numbers of equipment failure-related network faults.
- Unsustainable levels of asset defects.
- Poor asset health.
- Increasing numbers of poor performing feeders.
- Poor unplanned System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) benchmarking (when considering customer density).

Most of our distribution network was constructed from the 1960s to the 1980s. Asset age is a useful indicator of asset replacement needs, although actual replacements are triggered by other factors. Asset service life varies by fleet, but distribution assets typically have a service life of 40 to 70 years. This means a large amount of our legacy network is becoming due for replacement.

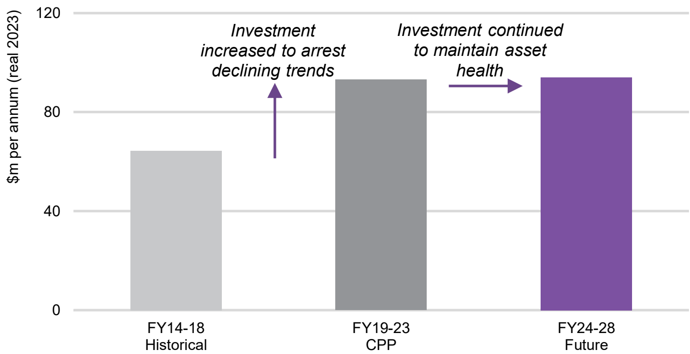
As an example, Figure 6.2 shows our overhead conductor age profile. Most of our overhead conductor fleet is 30 to 65 years of age, and large quantities of this will require replacement during the next several decades. We have now increased replacement to approximately 200-250km per year. During the upcoming planning period, we aim to further increase renewal rates of overhead conductor, with a particular emphasis on Low Voltage (LV) renewal. This work will require close coordination with our network development planning, which also has a focus on the LV network due to load growth from the increasing use of electric vehicles.

Figure 6.2: Overhead conductor age profile



Our increase in renewal investment during the past five years has bought us up to a sustainable level of asset replacement. We must continue this level of investment for the foreseeable future to manage the asset health and risk of our network. Figure 6.3 shows our historical, current (Customised Price-quality Path) and future levels of renewals investment. We increased our renewals investment by 45% in the CPP period to stabilise related safety and reliability trends. In order to stay on top of these risks, our future renewals investment level is broadly similar to that of today. Some portfolios will be allocated more or less funding, as required, to manage their specific risks, but overall investment remains the same.

Figure 6.3: Renewals Capex investment levels



Since establishing a new level of renewals investment, our focus has moved to how we best optimise our asset replacement programmes. We continue to improve our knowledge of asset condition and develop tools that use this knowledge to inform our short-term renewal priorities. We have:

- Embedded the use of Copperleaf C55, which allows for cross-portfolio optimisation of network investments.
- Transitioned our legacy Condition-Based Risk Management (CBRM) models to Copperleaf, based on the UK Common Network Asset Indices Methodology (CNAIM), while improving data calibration.
- Commenced a programme of zone substation building condition assessment, to target specific remedial works.
- Started developing improved cable condition assessment techniques, working cross-industry on standard methods.
- Developed a vehicle impact risk tool for our pole fleet, combining road traffic and vehicle accident data with network information, for the identification of poles at high risk of vehicle accidents.

Extending these capabilities will continue to be a focus. Our Maintenance Strategy (discussed in 6.2.3) will continue to expand our inspection processes and data collection, from which we will be able to improve our asset replacement decision-making.

We have also started work on updating the design and material specification of our modern equivalent assets we are currently installing. Our standards and specifications have a large bearing on our replacement costs, and making these decisions upfront has a critical impact on the overall lifecycle cost of the asset. Electricity networks are also faced with increased uncertainty about how they will be used and operated in the future, with disruptive technologies likely to impact how distribution networks are designed, and continued changes in rural land use e.g., increased forestry development. We will continue to improve our lifecycle cost analysis and use this to update our design and material specification standards. For example, we have reintroduced the use of wooden poles on our network, which although may have a shorter life than a modern concrete pole, they offer other advantages, such as being lighter in weight, more resilient and more sustainable. This work is part of our wider Network Architecture strategy, discussed in Chapter 7.

6.2.2 VEGETATION STRATEGY

Vegetation is a key risk to our overhead assets, with the potential for it to cause unplanned outages or fires. Although we do not own the vegetation, as a network operator we have obligations to manage vegetation near our powerlines, as prescribed in the Tree Regulations.

Known vegetation-related faults during the past eight years made up 16% of our total unplanned SAIDI. Therefore, our vegetation management approach can have a large bearing on the overall reliability of our network and impact customer experience.

From FY19, we approximately doubled our annual vegetation management Opex, bringing us to industry average levels per kilometre of line. Our cyclical strategy is consistent with good practice and aims to maximise the length of powerlines that are compliant with minimum clearance zone requirements. However, developments in Light Detection and Ranging (LiDAR) surveying, vegetation analytics, and risk-based planning have highlighted more investment is required in the short term to ensure the long-term sustainability of the Vegetation Strategy.

As we continue to leverage off our LiDAR surveys and analytical tool development, opportunities to improve the safety, performance and cost-effectiveness of our vegetation management activities will evolve.

This knowledge is being used to continually improve an updated Vegetation Strategy that is intended to move us to a more efficient management programme – one that achieves compliance while reducing long-term costs. It will also support improving reliability through the targeted removal of out-of-zone[30] vegetation in critical sections of the network. (The optimal long-term strategy will likely require a short-term increase in expenditure to realise the longer-term sustainable minimum.)

30 This relates to vegetation growing outside normal legislated cut zones around our assets.

6.2.3 MAINTENANCE STRATEGY

Maintenance and inspections

The objective of our fleet Maintenance Strategy is to minimise asset lifecycle costs while ensuring safe and reliable performance.

The current maintenance regimes are a combination of time-based asset inspections and time or operation-based preventive maintenance.
The time-based asset inspections identify any reactive maintenance requirements (i.e., defects) on the network. Routine preventive maintenance keeps assets operating optimally and reliably.

The next phase in our Maintenance Strategy is focused on transitioning to reliability-centred maintenance.

Currently, the maintenance regimes are applied uniformly across entire fleets. Reliability-centred maintenance will include optimising maintenance regimes and task intervals at individual asset levels. This is achieved by tailoring tasks for specific equipment types and scheduling maintenance based on the operating contexts and criticality of these assets. This includes adjusting maintenance frequencies for each asset based on their operation count, criticality, site-specific environmental factors, and rate of deterioration.

We are tailoring tasks for specific equipment types by introducing detailed maintenance procedures for use in the field and training field staff in their use. Initially, we are rolling out these maintenance procedures on our high-volume and high-risk assets, with the intent to eventually extend them to our entire fleet. As we roll out new sophisticated technology, with more complex maintenance requirements, on our network, this will become increasingly important.

Since 2019, we have introduced several new inspection and maintenance programmes. These programmes are intended to:

- Lead to an optimisation of expenditure and maintenance activities.
- Improve the performance of assets on our network in the medium to long term.
- Implement new maintenance, condition monitoring or test techniques to better understand asset condition and inform renewal plans.
- Extend the service life of assets.

Examples of these programmes include enhancing the performance of our overhead networks through rapid line inspections of the worst-performing feeders and undertaking periodic pole-top photography to better understand the condition of this fleet. We are also now undertaking major oil Ring Main Units (RMU) maintenance to ensure the assets can operate safely and reliably until the end of their planned life.

A shift to using specialist service providers will see us increase maintenance investment in critical assets, such as power transformer tap changers and partial discharge measurement on 33kV indoor switchboards. This shift is predominantly driven by the limited knowledge of older assets among service providers, and the ability to maintain working knowledge as new technology increases periods between maintenance.

Defects

The primary objective of the defects strategy is to manage and reduce the defect backlog to prudent levels. The defects strategy is closely aligned with the introduction of, and training for, the maintenance procedures, and the introduction of non-intrusive inspection techniques to drive consistency.

Our defects process can be broken into three main segments:

- Identification
- Prioritisation
- Remediation

The defects identification process can be subjective, resulting in inconsistencies in how defects are classified. This makes it difficult to efficiently prioritise defects. We are working on improving this capability by:

- Developing defect classification catalogues for our high-volume assets.
- Automating inspection processes through means such as our pole-top photography programme.

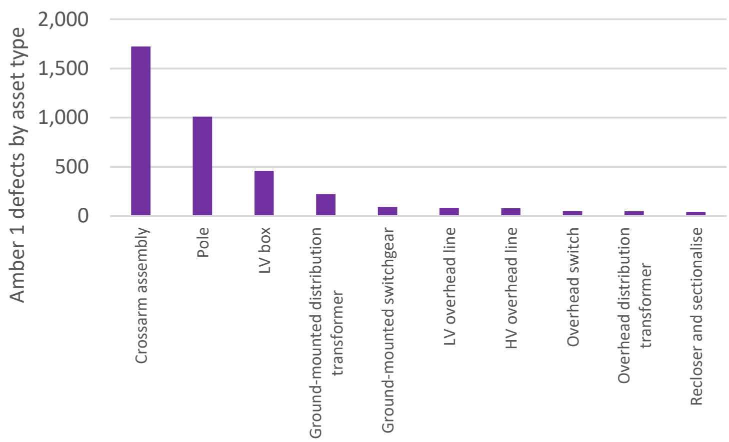
Better identification allows us to improve defect prioritisation by gathering consistent information to make decisions. We prioritise defects against time-mandated rectification intervals, such as hazardous (Red), unserviceable (Amber 1) and conditionally serviceable (Amber 2) categories, which have a strong focus on safety. Our next step will include developing risk-based failure trees for our most common defects. This will provide us with a better understanding of which defects in the backlog pose the highest risk and will allow us to prioritise works accordingly.

Lastly, we are focusing on improving our works packaging processes. The implementation of our Enterprise Resource Planning system SAP has enabled a step change in sharing information across all layers of our asset management. It allows everyone, from people in the field to planners forecasting long-term trends, to understand the defects logged against individual assets.

SAP creates opportunities for us to better package defects into the primary planned capital works programme, focusing remedial defects work on a smaller portion of the defects backlog, and allowing field staff to make decisions about what on-spot fixes they can carry out.

Figure 6.4 shows a breakdown of our current Amber 1 defects backlog and how the defects are distributed across different asset types. The top-ten fleets are shown with the overhead network fleet accounting for most of the defects pool as it is our biggest fleet.

Figure 6.4: Amber 1 defects backlog by asset type



The incremental improvements in defects identification, prioritisation and remediation will allow us to reign in and eventually reduce our defects backlog.

6.3 ASSET STRATEGY: NETWORK DEVELOPMENT

Our Network Development Strategy captures our plans for the capacity and functionality of our network.

Capacity of the network includes determining the number and types of subtransmission and distribution feeders and the size of the substations we install on the network. The capacity grows to meet customer demand. But as capacity grows, we also need to safeguard the network from the impact of any single failure. This includes ensuring adequate backup capacity to compensate for failures at critical nodes. It also includes ensuring that the segmentation of our network minimises the impact of outages on our feeders.

The functionality of the network is supported by non-network solutions and switching capability deployed on the network. Judiciously applying the appropriate mix of distributed generation and automation equipment on our network helps to defer expensive capacity development projects.

The Network Development Strategy also ensures that we maintain an appropriate quality of supply on the network. Going beyond managing fault statistics, it extends to voltage disturbances, brownouts, and the harmonics performance of our network. These qualities require us to carefully track and pre-empt the impact of customer demand.

6.3.1 SECURITY OF SUPPLY

We use security standards to define what level of redundancy our zone substations should have and the acceptable duration of outages. They include both the size and type of load, to reflect the consequence of an outage. These standards act as a ‘starting point’ for further investment analysis and are not used to mandate investments. They are discussed in more depth in Chapter 9.

Our security standards have traditionally been mainly deterministic in nature, but we are in the process of moving to a probabilistic approach (see Chapter 7). We are in the process of transitioning our planning standards to a more probabilistic approach, but we have retained elements of the deterministic standards in identifying investment needs.

After identifying non-conformances with our security standards, we undertake further analysis, including evaluating the economic cost of supply loss, and a full options analysis of potential supply solutions, or other means, to mitigate the downside of an asset-related failure while avoiding major investment. From here, we can develop a prioritised works plan that aims to reduce the load at risk while staying within our capital budgets.

We intentionally have not targeted full compliance with our security standards, as we have been willing to judiciously accept some risk to avoid potentially uneconomic investment. It is also a reflection that deterministic security criteria are comparatively simple, coarse, and conservative, and ignore important elements of Network Development planning, such as demand profiles, circuit failure rates, the value of lost load and mixed load types.

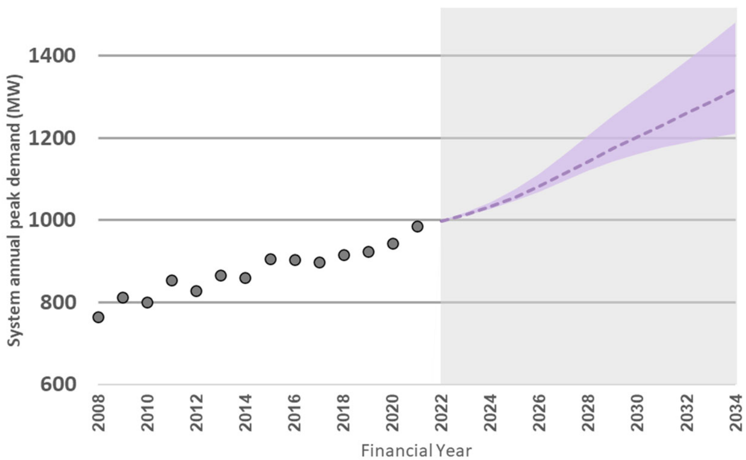
By using the security standards as a first past ‘trigger’, followed by economic analysis, we have already been moving away from the pure deterministic standards for some time. As we further develop our probabilistic approach this is intended to include elements such as different growth scenarios, failure rates reflecting specific asset performance and consideration of a wider set of options. The standards will use value of lost load (VoLL) inputs to calculate monetised risk and be compatible with our overall Value Framework.

6.3.2 DEMAND GROWTH

Electricity demand growth continues to be a main driver of investment in our network. New subdivisions and property developments because of population growth, or increasing economic activity, are the main factors contributing to the increase in electricity demand. To ensure our network can safely and reliably facilitate these growth factors we need to invest in more capacity or seek ways to reduce the impact of increased demand.

As discussed earlier, we have experienced continued growth on much of our network and expect this to continue. The figure below shows our overall system demand trend and forecast.

Figure 6.5: System demand trend and forecast



The increasing electrification of society will have a major impact on network peak demands. We have heavily revised our demand forecast assumptions for this AMP, reflecting our updated thinking on drivers such as electric vehicle uptake, conversion of process heat loads to electricity, and the potential phasing out of gas distribution networks. This is still underpinned by strong organic growth on our network through increased population and economic activity. There is uncertainty, however, regarding the size and timing of electrification, and our ability to manage peak demands through controllable distributed energy resources (DER). For our network development planning, we have used our base demand forecast. Further detail on our demand forecast scenarios is covered in Chapter 2.

At a subtransmission level, our demand forecasts are an input into our security analysis that will identify potential future areas requiring investment (as discussed above). Feeder level demand forecasts are used at the distribution level to identify future required reinforcements or greenfield installations. Over a shorter horizon, investments will often occur when we are aware of a specific customer need and have collaborated with them to ensure an appropriate solution is designed.

Our demand forecasts help inform our long-term plans but don't necessarily lead directly to committed works. For most of our investments, the demand requirements must be relatively certain before we commit to the investment.

We are also embarking on improvements in our demand forecasting approach, linked to our transition to probabilistic planning. This will involve forecasting at a much more disaggregated network level than what we do today and will require much-improved data on individual customer demand. Initially, we will use this for improved upper and lower demand scenarios but, ultimately, we will seek to transition to full probability distributions. Linked with our improved security standards, this will allow for a more refined approach to assessing load at risk and the optimal investments to manage this.

Overall, with demand forecast to dramatically increase during the next 10 years, significant investment in network upgrades and reinforcements will be required to support our customers' decarbonisation goals.

6.3.3 RELIABILITY

Powerco's overall network reliability objective is to ensure that we meet our customers' reasonable expectations regarding the quality at which we deliver their electricity, and the price they are willing to pay for this.

To achieve this, we focus on three key areas:

- At an aggregated network level, we aim to maintain the reliability of supply at historical performance levels. Regular customer feedback confirms that there is no general desire for improved reliability, particularly if that would affect the cost of electricity. While we will ensure that network and asset performance do not deteriorate, we will also not deliberately invest to improve overall performance.
- We may, however, decide to improve[31] the quality of supply to individual or smaller groups of customers. This decision will be driven by factors such as meeting customers' specific quality requirements, or where we assess that supply quality falls short of what customers should reasonably expect in terms of good industry practice.
- We will continuously improve the measurement of network performance to better inform our management and investment decisions. This includes greater disaggregation of reliability reporting, recording incidents on all parts of our network, and improving outage root cause analysis.

Our primary reliability measures are SAIDI and SAIFI, broken down into unplanned and planned outages. These measures are also what we report to the Commerce

[31] In rare cases, we may also decide to allow quality of supply to deteriorate if our customers indicate their preference for this, or supply quality is inappropriately high.

Commission to meet the quality of supply regulation obligations. However, these are aggregate network measures only, and therefore we also track performance at the feeder and distribution transformer level to identify poor performing parts of our network.

Many investments contribute to the reliability of our networks. Asset renewal, maintenance, and defect work address reliability concerns of our older assets, while Network Development projects help enhance reliability by providing alternative options for supply. Vegetation management is also a key tool in keeping our network reliable. Our operations have a key role in managing the reliability impacts of outages, such as through outage response times, contingency planning, and spares management.

Specific reliability-focused investments have traditionally been centred on the deployment of automated distribution switches and fault indicators. For our radial feeders, we typically use reclosers and sectionalisers. These devices enable the faulted section of the circuit to be isolated while maintaining supply to the customers upstream of the fault. We will continue to seek out further opportunities to install these devices during the planning period.

We are now beginning to expand our automation strategy beyond this legacy approach. With an increased likelihood of two-way power flows and considerable DER on our network, the ability to monitor the network and react to the changes becomes essential. This will mean a greater focus on measuring and monitoring the state of the network and adding increased remote-control capability. This new automation strategy is discussed in Chapter 7.

Resilience planning also forms a part of our overall reliability approach. Customers are increasingly wanting a highly resilient supply, and these expectations are only expected to increase as people become more dependent on electricity and as climate change storm events become larger and more frequent. Resilience planning covers many facets including:

- Equipment selection and design, to ensure appropriate resilience to storms.
- Increasing network redundancy, through additional backfeeds.
- Undergrounding of overhead lines.
- Use of remote generation and/or energy storage.

6.3.4 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

Operating the distribution network is becoming more complex and dynamic, with growing numbers of backfeeds, switching points and automation devices. This is leading to a major increase in the volume of information that operators contend with, and the complexity of switching plans. The anticipated future growth of DER technology will add to the complexity of operations.

We intend to address this growing complexity by improving the capability of our operations centre through the application of an Advanced Distribution Management System (ADMS). Our ADMS strategy is to simplify and streamline control room operations by using platform-based software solutions to support operational decisions – leading to increased operational efficiency, service provider safety, and network reliability. These platforms will allow us to integrate data between asset management, control room and field staff by using historical, real-time, and forecast data for real-time operations. Examples of such applications to support decisions in the operation room include:

- Fault Location, Isolation, and Service Restoration (FLISR)
- Real-time Distribution Power Flow analysis (DPF)
- Switch Order Management (SOM)

We see this as one of our key initiatives for improving customer service and the effectiveness and safety of our operation. While the focus will initially be on our subtransmission and distribution networks, it is intended that, over time, the LV network will be introduced into the system as well, while we roll out more monitoring, automation and switching capability on this part of the network.

6.4 CAPABILITY STRATEGY: CUSTOMER

We know New Zealand's electricity networks will change because of customer needs and demands. However, the 'when' and 'how' is uncertain. Our Customer Strategy supports the delivery of our Customer Commitment to provide a safe and reliable electricity network that meets their service level expectations, is future ready and cost-effective. Successfully delivering on our Customer Strategy lays the platform for achieving our Customer and Community Asset Management Objective.

We have focused on improving the experience of customers and communities when they interact with us. This provides the foundation for meaningful and constructive community discussions and is achieved in partnership with the wider supply chain.

We operate an interposed contractual model with retailers. As a result, customers interact with us directly, through their retailer or other delivery partners, such as service providers and electricians. In either case, we know the customer's experience is heavily dictated by the information they receive, the ease of communication, and the interactions they have. For us, this means that regardless of whom the customer is engaged with, they should experience seamless access to consistent, accurate information and service. This is a core principle of our Customer Commitment.

Our Customer Strategy sets a path to ensure we have the processes, systems, and people to deliver this experience. In recent years, this has included evolving our customer-facing digital platforms to provide individualised access to information on planned outages, and the ability to directly log network faults with Powerco. Additionally, we now have greater capability to engage with customers and communities on work that could or does affect them at a more individual level and/or on a specific topic.

6.4.1 WHERE WE ARE HEADING

Our Customer Strategy is broadly focused on delivering outcomes driven by our Customer Commitment principles. These include:

- Minimising the disruption caused by our work programme or loss of supply.
- Growing a customer-centric mindset across the entire business that delivers a seamless customer experience.
- Building relationships with our customer base so that engagement delivers the information and intelligence required to ensure optimal network investment decisions.
- Providing public-facing digital platforms that support engagement through access to information and two-way communication.
- Providing access to energy professionals to support customer decision-making, and leading industry discussion by encouraging constructive debate on energy topics.

Our Customer Strategy primarily focuses on five key service dimensions developed through engagement with customers, our delivery partners, and the wider industry. The five dimensions drive initiatives that support our Customer Commitment and associated objectives.

6.4.1.1 CUSTOMER SERVICE DIMENSIONS

Customer service (information and works delivery): Our customers value timely and accurate information about their electricity supply and information to mitigate the impact of a loss of supply or the impact of physical work carried out in their communities. Advances in mobile technology and social media have created an expectation that information should be readily available through several communication channels. The most important information for residential customers is communication about power cuts, why they are occurring, changes to planned outages and other disruptions, such as traffic movement restrictions or access to private land.

For customers who proactively have a need to engage with us and our partners to achieve a specific network outcome, a seamless experience is a goal. Our processes, systems and culture are essential factors in meeting the standards we set, and we are continuing to review and improve where we can.

Responsiveness to unplanned loss of supply: Unplanned outages occur for a variety of reasons. Some of these are within our control, such as equipment failures. Others are beyond our control, such as lightning strikes or vehicles hitting poles. The 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 to reduce the impact and potential safety risks.

Reliability and continuity of supply: Customers generally place a high value on reducing or avoiding outages. But this varies for different groups, and our approach to asset management is to better understand these differences so we can align our investment plans. 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. This will become a growing challenge as climate change impacts our largely rural and often remote network.

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. Delivering value and having control over our costs is important at Powerco.

Choice of energy options: Increasingly, customers are wanting more flexibility and choice in the way they interact with the network. New technology offerings, combined with an increasing customer willingness to take more control of their energy options, are leading to a change in the way energy markets operate. This 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. We also have a role in supporting customers to achieve their decarbonisation goals by providing expert advice to ensure they can make informed decisions.

6.4.2 HOW WE WILL GET THERE

Delivering our investment programme on time and within budget, while minimising the disruption to our customers and communities, creates the need for trade-offs. Our Customer Strategy endeavours to achieve the optimal balance between delivering our works programme and meeting the customer expectations. We continue to review and prioritise Customer Strategy initiatives to ensure they are supporting customer preferences and expectations. The key short-to-medium term initiatives of the Customer Strategy are detailed in the following sections.

6.4.2.1 CUSTOMER RESEARCH AND INSIGHT PROGRAMME

The Customer Research and Insight Programme ensures the customer intelligence needs of the business are met. This programme will develop digital communication tools to collect data that we will use to inform long-term asset management decisions.

6.4.2.2 COMMUNITY ENGAGEMENT AND RELATIONSHIP MANAGEMENT PROGRAMME

The Community Engagement and Relationship Management Programme provides a framework to support the efficient delivery of our works programme by creating partnerships that support meaningful connections in communities.

6.4.2.3 CUSTOMER SERVICE DEVELOPMENT

Continued development of our customer service experience is important to meet our customers' expectations. We will use our customers' insights and priorities to improve processes, optimise network design, and minimise the disruption caused by our work.

This initiative focuses on understanding our customers' journeys, touchpoints, and their specific pain points, and working in partnership with our delivery partners and the wider supply chain to improve customer experience.

6.4.2.4 CUSTOMER EXPERIENCE TECHNOLOGY ROAD MAP

Meeting customer expectations around ease of doing business, contact channels, and service levels drives continued innovation in the development of new digital capabilities for our customers. The Customer Experience Technology Road Map comprises a programme of investments focused on delivering significant customer experience improvements through the development of new customer self-service tools and customer relationship management systems.

6.4.2.5 CUSTOMER SOLUTION SUPPORT

We have a key goal to increase our ability to provide focused support to commercial and industrial customers, looking at energy solutions to support decarbonisation and their future energy needs.

We will support our customers' decarbonisation by providing more detailed network capacity information and online tools, and by collaborating directly with them to understand their business and energy needs, and exploring options to optimise their emissions reduction, cost, and security needs.

6.5 CAPABILITY STRATEGY: INFORMATION AND TECHNOLOGY

Our Information and Communications Technology (ICT) capabilities underpin Powerco's operations and play a central role in enabling both ongoing improvement and the evolution of our business. These capabilities are embedded across all elements of our organisation, supporting, and enabling strategic, tactical, and operational activities.

6.5.1 WHERE WE ARE NOW

Over the preceding period, we undertook the largest programme of ICT investment in Powerco's history, resulting in the establishment of strategic technology platforms aligned to key business capabilities; these include network investment, plant maintenance, asset and financial management, information security, data and analytics, cloud, and digital workplace.

Powerco's approach to Information and Technology Strategy can be summarised as:

- **Operate:** Support what we currently have in place to keep existing information technology capabilities secure and resilient.
- **Improve:** Enhance our existing ICT capabilities to optimise our business operations.
- **Exploit:** Adopt and embed new ICT capabilities aligned with our business and customer priorities to enable the achievement of Powerco's strategy.

6.5.2 WHERE WE ARE HEADING

The high-level goals for our Information and Technology capability remain unchanged:

- Our customers get the information they need, wherever they are, whenever they want it.
- Our people (employees, service providers and contractors) have the right tools and processes to do their jobs efficiently, anywhere, anytime.
- Our people can make insightful, informed, and fact-based decisions with confidence.

To achieve these goals, we need to maintain focus on three areas:

- Reducing information security and technology risk, and increasing business resilience.
- Increasing business efficiency through the delivery of foundational business practices and technology.
- Developing new skills and adopting new ways of working to be successful with technology.

Our previous strategic programmes identified the requirement for business process change and the importance of reliable, high-quality data. This need has not been fully resolved, so these areas remain ongoing areas of challenge requiring further focus and investment. Our ability to service the needs of our customers and key stakeholders has increased in both urgency and impact during the past 12 months. Technology will play a central role in developing and refining our customer experience offerings.

6.5.3 HOW WE WILL GET THERE

We will take a less prescriptive approach to technology investment during the AMP planning period because we need to be responsive to changing customer and industry requirements and since we established our foundational ICT platforms during the Customised Price-quality Path (CPP) period.

With the recent establishment of an Enterprise Architecture team, we intend to undertake a reset of our Information and Technology Strategy during FY24 to better reflect our current context and future ICT needs.

Rather than our previous approach of solely delivering ICT investments via strategic programmes, we are also implementing a value, stream-based model. This operating model is being established within our Business Transformation team and can be summarised as:

- Cross-functional teams aligned to Powerco's core end-to-end business processes.
- Tasked with the achievement of key business outcomes detailed within Powerco's Business Plan.
- Utilising agile work practices, such as rapid delivery cycles, to achieve early and regular delivery of value.
- Focused on ensuring change is embedded by integrating culture change with digital capabilities.
- Empowered through simplified governance and distributed decision-making.

Alongside the value streams, we will continue to invest in the development of our information security capabilities and progress the implementation of an ADMS that is designed to enable the operation of an intelligent, open-access grid.

6.6 6.3.4HEALTH, SAFETY, ENVIRONMENT AND QUALITY

Powerco is committed to keeping people safe – the public, our staff, and our service providers. The Health, Safety, Environment and Quality (HSEQ) Strategy enables us to deliver on our HSEQ Objectives, business commitments and to improve our systems. Initiatives in this strategy are broadly categorised into public safety and worker safety, with an underlying focus on critical risks.

Driving simplicity and proportional risk management is at the core of our systems and our strategy. This includes defining, monitoring, and improving the processes used to manage risks that are presented during the delivery of our network and fleet strategies. It also builds on our advisory capability for our staff and contractors.

The use of our assets improves the lives of our customers, but also presents risks that need to be managed. The strategy outlines the way we manage those asset-related risks and our role as a person conducting a business or undertaking (PCBU).

The HSEQ Strategy also helps ensure that we have appropriate resources to monitor the quality of works on our network. This provides for good oversight throughout our supply chain, from equipment suppliers to internal staff and contractors in the field. The strategy is built around three pillars:

- Critical risks
- Public safety
- Safety as usual

Each of Powerco's health and safety initiatives are targeted towards supporting at least one of the three strategic pillars.

6.6.1 KEY CRITICAL RISK INITIATIVES

6.6.1.1 TRAFFIC MANAGEMENT

One of the main health and safety risks involves working in local council and Waka Kotahi New Zealand Transport Agency (NZTA) roading corridors, which expose workers to traffic. There have been several traffic management incidents in the wider construction and roading industry, as well as during work carried out by Powerco.

We are engaging with contractors and encouraging them to implement more robust traffic management controls focused on worker safety. Powerco, along with the Electricity Engineers' Association (EEA), has representation on the NZTA's Road Work Site Health and Safety Improvement Programme (stakeholder group meeting).

NZTA is undertaking a review of the Code of Practice for Temporary Traffic Management (CoPTTM). It is expected this will lead to an increased focus on the hierarchy of controls and greater use of road closures and technology solutions. It will mean an increase in traffic management training requirements for our service providers working on the NZTA roading corridor.

WorkSafe has released its Good Practice Guide for Road Worksite Safety in 2021. This introduced additional legal requirements that Powerco and our service providers must meet.

The effectiveness of traffic management is included in our Field Auditing Programme. This helps ensure that all work carried out in the roading corridor has an approved traffic management plan in place to keep workers and the public safe and that the traffic management on site is in compliance with this plan.

6.6.1.2 HIGH VOLTAGE LIVE LINE WORKING

Live line working has long been an important part of how we minimise customer disruption when we build or maintain assets. While there have been very few safety incidents related to this practice, it has become somewhat controversial, with questions asked about whether the intrinsic risks, it may pose warrant its use.

We believe that live line working can be safe in many situations, provided it is appropriately managed. Accordingly, we have been working with our live line service providers to develop a common industry set of procedures for (safe) live line glove and barrier working.

We have also developed and are implementing a decision-making tool to assist with an understanding of where live line work can be safely undertaken. The purpose of developing this tool is to carry out realistic assessments of where live work on our network can be completed safely, thereby reducing the impact of outages on our customers.

Critical risk controls to manage live line working were identified as part of the assessment process. An assurance programme for live line working risk controls will be included in future wider audit and assurance programmes.

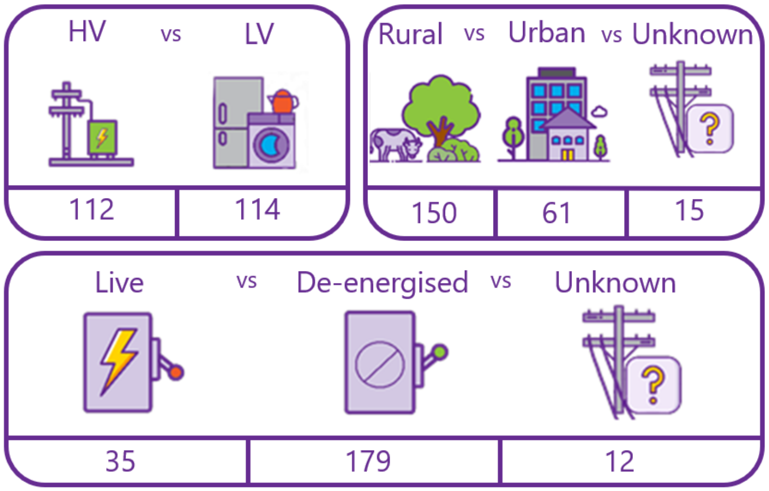
6.6.1.3 COMPETENCY DATABASE UPGRADE

The Powerco Contractor Competency Database will be transitioned from a Microsoft Access platform and incorporated into ISNetworld's wider contractor management offering. This will align the Powerco Contractor Approval process and the Powerco Contractor Management process and allow service providers to manage their own employee competencies.

6.6.2 KEY PUBLIC SAFETY INITIATIVE

Downed power lines that remain live present a significant risk to the public, as shown in statistics in Figure 6.6. Lines are brought down for several reasons, including falling vegetation, wind, asset failure and car v pole incidents. We track and report monthly to our Board the number of lines that remain live when downed.

Figure 6.6: Lines down data across the Powerco network



To reduce the risk of downed power lines to the public, our current standard is for all new LV conductors to be covered with insulating material. This safety mechanism is necessary as it is impossible, with existing protection devices and low levels of LV network monitoring, to ensure that all downed conductors will be de-energised. Given the large volume of legacy assets on our networks, a substantial portion of LV conductors are bare. Chapter 15 contains further details on the LV bare conductor renewal programme.

We have a Learning Team that examines live lines down incidents to improve understanding of root causes and the actions that we can take to reduce the number and impact.

Projects are underway to increase the sensitivity of sensitive earth fault protection schemes in 32 substations. This will increase detection rates of downed lines. We are also conducting trials on using LV monitoring devices to detect lines down on the distribution network. Should this live up to the initial promise, we will extend this approach across the network during the AMP planning period.

Powerco runs several public safety campaigns each year to educate our communities on how to keep themselves safe around our network assets. Information on how to stay safe in the event of a line coming down is included in these campaigns.

6.6.3 KEY SAFETY AS USUAL INITIATIVE

Our safety as usual initiative has the goal of building closer collaboration and understanding between us and our service providers. The planned outcome is to achieve a broad understanding across the wider business of how each role contributes to the safety of staff, contractors, and the public.

6.6.3.1 LEARNING TEAMS

An initiative involving Powerco, and service providers is underway to encourage the sharing of knowledge on safety-related events and asset performance. This allows improvements to be identified and for us to build on what is already going well.

Learning Teams have been implemented to better understand:

- Rotten wooden assets.
- Live lines down.
- Worksite safety interactions.

The outcome of the Learning Teams work will be an improved understanding of what is really happening out in the field. Based on this knowledge, improvement options can be identified and implemented.

6.6.4 AUDIT AND ASSURANCE PROGRAMME

Our Audit and Assurance Programme is delivered by an external provider. It covers:

- Worker safety in the field.
- Quality of workmanship.

- Work planning.
- Documentation and record keeping.
- Assurance of critical work and public safety controls.

The audit programme provides our managers and senior leadership with oversight of the performance of service providers completing our work, as well as the quality of work carried out for customers who engage Powerco-approved contractors.

The audit programme will continue to grow to include further aspects of our operations, including auditing of:

- Our capital works projects process.
- Traffic management for our works.
- Assurance of internal and service provider critical risk controls.

We utilise the data gathered through the Audit and Assurance Programme to identify safety and quality trends. Positive trends are reinforced, while improvement action may be indicated by negative trends.

7 EVOLVING ASSET MANAGEMENT STRATEGIES

7.1 INTRODUCTION

In Chapter 6 we described the core Asset Management Strategies that help us deliver our Corporate Objectives and Asset Management Objectives. While the way we build and operate our electricity network is generally very stable, we also continually look for ways to improve and adapt to material changes in our operating environment. In this chapter, we describe the significant changes planned in our asset management during the AMP planning period.

Our evolving strategies are mainly centred on three overlapping aspects:

- Adapting to changes in network and customer technology.
- Adapting to a changing operating environment, driven by changing customer needs as well as environmental and legislative changes.
- New ways of thinking about traditional asset management approaches.

Developing and implementing the emerging strategies discussed below have been factored into our AMP expenditure forecasts. Our general intent is to embed successful outcomes from new strategies into our core business-as-usual practices. Where appropriate, our network development and fleet management plans have already been expanded to reflect some of this.

7.1.1 DRIVERS FOR CHANGING ASSET MANAGEMENT STRATEGIES

The overall drivers for the continuous evolution of our asset management are to ensure that our services remain relevant to our customers and represent the best value when customers make energy choices. This, in turn, will also support our business's long-term profitability and sustainability. Several factors require us to review our practices, chief among which are:

Cost efficiency of electricity distribution

We have a responsibility to our customers to distribute electricity at the lowest reasonable cost while ensuring they receive a safe, reliable service that reflects their preferences and requirements. The importance of keeping distribution services affordable is further underlined by the very real pressures many of our customers face in meeting their basic energy needs.

Optimal lifecycle investment decisions have always been a core foundation of our asset management. However, we continually look for further improvement opportunities, particularly in ways that we can enhance network performance or improve asset utilisation at the lowest cost, without taking on unacceptable risk.

Network resilience

A combination of increasingly unstable environmental conditions, from climate change or other factors, and customers' increasing reliance on electricity to sustain their lifestyles, has brought network resilience into strong focus. Accordingly, we are developing strategies to ensure the appropriate resilience of our networks.

We are looking at how we can reduce the impact of major events; this includes avoiding outages from major events, restoring supply quickly, and efficiently recovering following major events.

Environmental change

Protecting the environment from any adverse impact of our assets underpins our asset management decisions. In support of New Zealand's carbon emissions reduction targets[32], we have adopted stringent emissions reduction goals of our own, which are considered in our investment and operating decisions.

We also have a major role to play to ensure that our electricity network will be an efficient, easy-to-access platform in supporting the flexibility of customers' and other stakeholders' energy use and generation, or energy market transactions. This will be central to the broad electrification of energy use, which in turn will be critical to New Zealand's decarbonisation.

Emerging technology

Emerging technology is a huge opportunity that can benefit customers as well as network and support New Zealand's decarbonisation. From a network perspective, we are researching and conducting trials, and implementing new technology that is found to be practicable and cost-effective.

Increased customer-side use of edge devices can, however, have a destabilising impact on network operations. Since we do not want to inhibit customers from seeking out new applications, we see it as our responsibility to manage network stability (within practical bounds). This requires us to evolve the network alongside customers' changing requirements.

Improving customer understanding

It is fundamental to good asset management that we develop solutions that optimally meet our customers' needs. Traditionally, customer requirements have remained relatively static and predictable. However, this is changing at an increasing rate. Therefore, understanding existing and evolving customer requirements is an essential pillar of network planning and investment.

Network reliability

Customer reliability requirements change over time. This has to be reflected in changing network architecture, security standards and designs.

[32] See discussion in Chapter 4

In addition, we have to continually upgrade our network to ensure acceptable supply quality to all our customers. Finding cost-effective ways to achieve this is imperative if we are to avoid potentially substantial associated price increases.

7.2 NETWORK EVOLUTION: EMERGING TECHNOLOGY

Our Network Evolution strategy maps out how we intend to benefit from, or will manage the potential adverse impact of, emerging technology.

Understanding and responding in good time to emerging customer energy trends is a key part of our Network Evolution strategy, as is the research into and testing of the impact of new customer or network technology. This allows us to not only understand the technical features and how to integrate new equipment but also the behavioural aspects of how this influences customers' energy use patterns and overall network performance.

7.2.1 NETWORK EVOLUTION: WHERE WE ARE NOW

In our previous AMPs, we described how three mega-trends in the energy industry drove the evolution of our network – the so-called 3Ds of decarbonisation, decentralisation, and digitalisation. These are still the key drivers.

7.2.1.1 DECARBONISATION

Decarbonisation is the challenge to reduce carbon dioxide (CO_2) emissions.

As discussed in Chapter 4, in accordance with the Emissions Reduction Plan, national targets have been set to limit temperature rise. This includes a range of sub-targets, aimed specifically at the energy sector. Our general strategy for adapting to climate change and meeting these targets is set out in section 7.6 of this chapter. Our Climate Change strategy recognises technology-driven solutions as an important feature. This integrates with our Network Evolution strategy.

Most electricity distribution utilities do not generate significant electricity and are not themselves large electricity users. Therefore, our direct impact on carbon emissions is relatively minor. However, we believe we can make a major contribution to encouraging and accommodating carbon reduction initiatives for our end-users and generators. We will provide the enabling network solutions and services to achieve this. 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. They will be able to conduct largely unconstrained flexibility service and energy transactions over our network, while we continue to ensure a stable and safe electricity supply.

7.2.1.2 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.

This could be a challenge for us in terms of both policy and technical aspects.

Customers reasonably expect the unfettered ability to use distributed generation or energy storage devices to offset or manage their electricity consumption, to sell surplus electricity, or to participate in flexibility markets. The large majority wants to maintain a connection to our network to cover the times that their devices cannot generate sufficient electricity for their own use, such as at night. The network also provides a connection to others, to allow the trading of energy or flexibility services.

This requires us to maintain electricity connections at full peak demand capacity, even if average consumption levels reduce. Since the bulk of our revenue is traditionally derived from the quantum of electricity delivered, this makes network capital cost recovery increasingly difficult. It will require us to consider alternative pricing structures in the future, particularly if we are to avoid charging other, non-generating, customers more.

Concentrated clusters of new distribution edge devices33, such as solar photovoltaic (PV) generators or electric vehicles (EV), can 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. However, such limits would be a last resort and an undesirable situation, as it would not only inhibit customer flexibility but would also run counter to achieving carbon reduction targets.

7.2.1.3 DIGITALISATION

Digitalisation is the substantial and sustained increase in the amount of digitally enabled and connected equipment available to customers, market participants and asset owners, along with data, analysis, monitoring and control applications.

It is a key part of future automation and distributed network control systems. In addition, it will be essential to help ourselves and our stakeholders to understand and manage energy demand and generation profiles, allowing energy transactions over our network.

The cost of data capture, storage and communication continues to decrease. Low-cost sensors and communication mediums, for example, Long Range Wide Area Network (LoRaWAN), are becoming mainstream.

[33] 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.

For asset managers, this trend offers major opportunities to efficiently expand the visibility of network use and condition, increase asset utilisation and better manage operations. It allows 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 – in the long run reducing customer cost and enhancing their services.

7.2.2 OUR CURRENT OBSERVATIONS OF ENERGY TRENDS ON OUR NETWORK

7.2.2.1 BASE CONSUMPTION TRENDS

As shown in Figure 7.1 and Figure 7.2, peak demand on Powerco's network (per connection point and in total) has continued to increase substantially in recent times, with energy use showing a somewhat more subdued increase. Overall demand has grown at a compound rate of 1.8% per year during the past decade, which is considerably higher than the country-wide average (of 0.3% per year[34]).

The growth in energy use on our network, particularly since 2017, has been underpinned by considerable customer connection activity, demonstrated in Figure 7.3. This reached an all-time peak during 2020 and 2021, before softening somewhat in recent months.

Figure 7.1: Growth trend on the Powerco network – average use per consumer

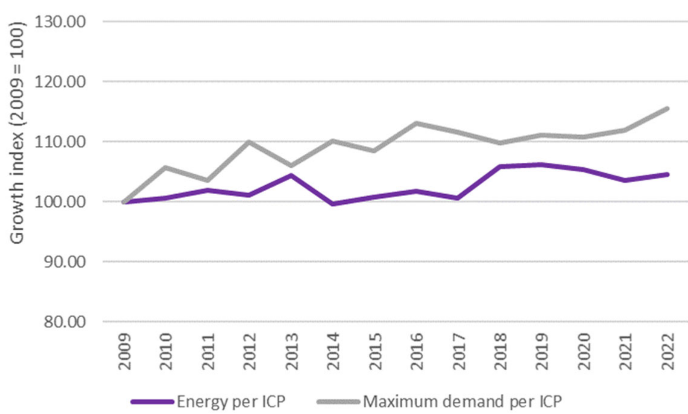
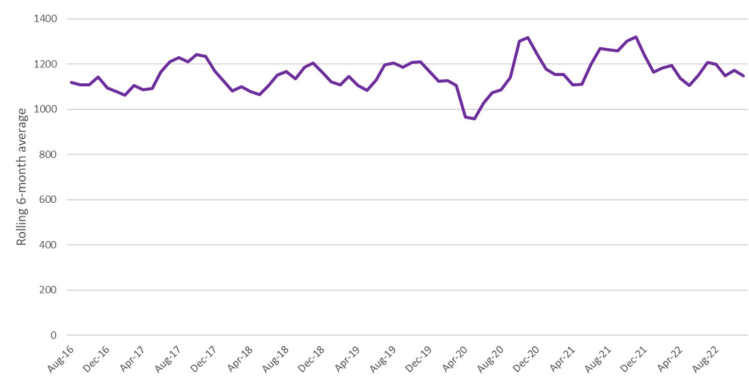


Figure 7.2: Growth trend on the Powerco network – total network use

Figure 7.3: Monthly customer connection applications (six-month rolling average)



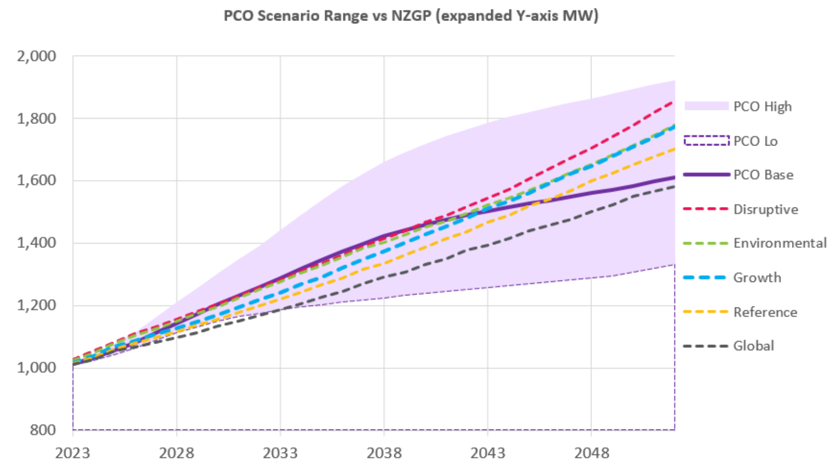
[34] Derived from "NZGP1 Scenarios Update", Transpower New Zealand Ltd, December 2021

Current projections are for organic growth to broadly continue at historical rates, with overall growth weighted towards our Eastern network. A temporary easing in new connection applications and economic activity is likely, given the widely signalled economic downturn forecast in 2023. However, the underlying drivers remain strong, and we forecast substantial growth during the next decade (and longer).

Powerco has undertaken considerable work during FY21 and FY22 to refine its longer-term electricity demand forecasts. Our updated, network-wide view is shown in Figure 7.10. These forecasts are very sensitive to the future trends noted above, which are by themselves uncertain. To accommodate this, we have adopted a forecast range, based on a base case, high and low scenarios.

By way of comparison, we also illustrate Transpower's Net Zero Grid Pathways 1 (NZGP1) grid planning scenario update, published in December 2021, using its forecast growth rates applied to Powerco's 2022 peak demand. The NZGP1 scenarios are a variation on the Ministry of Business, Innovation, and the Environment (MBIE) Electricity Demand and Generation Scenarios (EDGS 2019).

Figure 7.4: Powerco demand forecast range compared with NZGP1



Note: In this forecast, the forecast base growth rate has been adapted from the Transpower figure to reflect Powerco's anticipated base growth rate

Five key factors are driving the variances in our demand forecast range. Assumptions related to these are also behind the differences between Transpower's and our own forecast growth rates.

Adding to electricity demand:

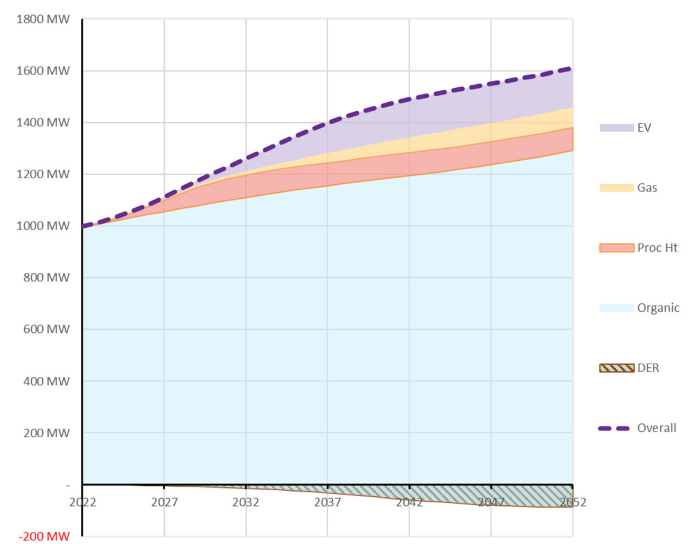
- Organic growth in electricity demand.
- Uptake and use of EVs.
- Decarbonisation of carbon-based industrial processes, particularly lower temperature heat processes.
- Potential phasing out of natural gas reticulation.

Subtracting from electricity demand:

- Increased uptake of distributed energy resources (DER), such as local generation or energy storage, demand management or flexibility services.

The forecast impact of these factors on our base case demand forecast scenario is shown in Figure 7.5.

Figure 7.5: Components of Powerco's base case demand forecast



Based on this forecast, our base case scenario shows an increase in peak demand from 2022 until the end of the AMP planning period (31 March 2033) of 262MW, or 26%. (Growth until 2050 is foreseen at 586MW or 59%)

The long-term demand scenarios are highly sensitive to several assumptions for each major growth component. We will continue to refine these based on improved information and ongoing review of emerging international and local trends.

We are planning several initiatives for implementation during 2023 and 2024 to enhance our ability to do detailed network modelling based on substantially improved customer intelligence. While uncertainty around longer-term forecasts will always exist, these initiatives will significantly improve the accuracy of our forecasts and allow us to apply them on a much more granular level around the network[35].

We are strongly of the view that, in a growth scenario, it is important to make infrastructure available potentially slightly ahead of actual need, rather than run the risk of delays in meeting customer requirements.

- There is a significant asymmetry in the economic impact to society between (small) over- and under-investment in infrastructure, and electricity, in particular. Over-investment has additional customer cost associated with recovering the investment on assets built some time before they're fully utilised. Conversely, not having capacity available when required could have economic and societal impacts of a much larger magnitude. For example, there may be enforced delays in commercial, industrial, or residential developments, or customers may suffer the consequences of poor supply reliability when sufficient redundancy cannot be maintained.
- In addition, New Zealand's pathway to carbon neutrality will depend, to a substantial degree, on electrification – for industrial processes, transport and residential or commercial use. The inability of the electricity system to deliver the capacity for this will significantly impede or delay decarbonisation.

Our base case scenario, therefore, reflects a slight bias towards higher future demand expectations, which we believe is appropriate to address this asymmetry risk. (See the case study in Chapter 2 for an explanation of this.)

We review our forecasting assumptions on a regular basis and will continue to adapt our longer-term investment plans as new information about actual growth patterns come to light.

It should be noted that when it becomes apparent that customer growth needs on any part of our network are likely to exceed capacity within the planning window, our first response is always to test whether sufficient capacity can be securely made available through minor tweaks to existing infrastructure or changing operating practices. Following that, we consider whether feasible options exist to defer major investment, typically through applying non-network solutions, incremental network investments, or seeking alternative capacity proposals on the wider market. Only if these options are not economical or practical, do we proceed to plan major network investments.

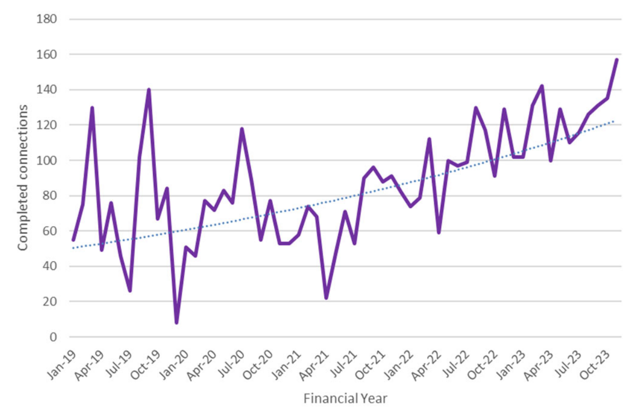
7.2.2.2 DISTRIBUTED GENERATION

In 2022 we started to see significant activity in the large-scale solar PV market. After commissioning what is still the largest solar farm in New Zealand (the 2MW site at Kāpuni) during FY21, we have now received distributed generation (DG) connection inquiries and applications that would total more than 1000MW. Application numbers for large DG installations have risen from 17 in FY22 to 42 in the first eight months of FY23.

While we are also fielding increasing inquiries regarding large-scale wind generation, including potentially major offshore windfarms, PV activity still makes up the bulk of what is being implemented.

The growth rate of residential (typically <=10kW) PV applications on the Powerco network is continuing to grow, demonstrating an exponential trend, as shown in Figure 7.6.[36]

Figure 7.6: DG applications on Powerco's network



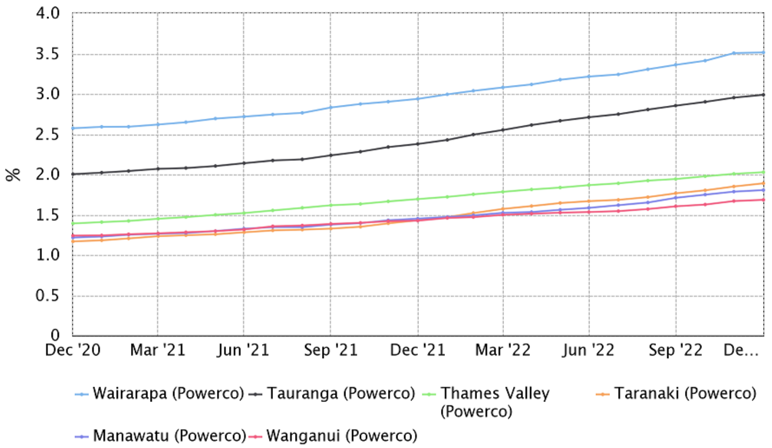
Small-scale PV uptake on our network is shown in Figure 7.7. At the end of December 2022, the total PV connection proportion on our network was 2.3%

[35] The current scenario forecasts are network wide, based on average assumed figures. In reality, the growth rates will vary greatly across our network.

[36] While this data shows all DG applications, the vast majority is for solar PV installations (with or without energy storage).

(7,962 Installation Control Points – ICPs). The total number of PV connections on our network has grown by 25% in the year to December 2022.

Figure 7.7: PV uptake on our network (percentage of ICPs)

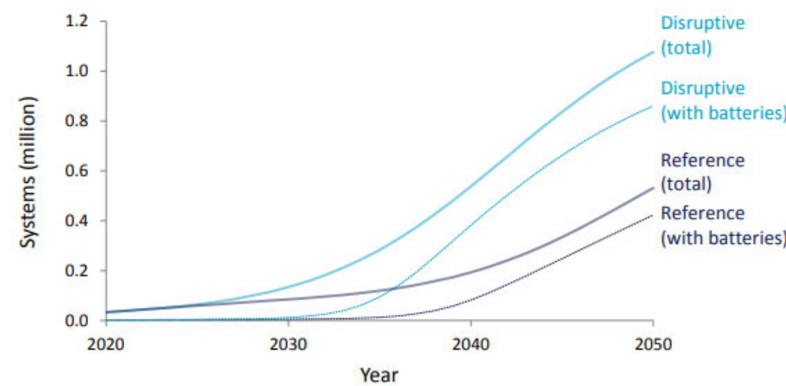


While growing steadily in New Zealand, overall solar PV uptake is still much lower than in countries where strong incentives exist (or existed) for such installations, including Germany, parts of Australia, the United Kingdom, Denmark, and some United States states, such as California. Our view is that, given New Zealand's high proportion of renewable grid energy, it is unlikely that material incentives for solar PV installations will be applied locally. Uptake rates are therefore not expected to reach the higher international levels.

International literature suggests that when PV penetration exceeds about 10% on a network, issues associated with the variability of its output could become material, requiring some form of network investment[37]. 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 July 2019, the latest updated Electricity Demand and Supply Generation Scenarios (EDGS) model was produced by the Ministry of Business, Innovation and Employment (MBIE), which included forecasts for the anticipated growth of solar PV generation in New Zealand under various scenarios. In Figure 7.8, the 'disruptive' scenario suggests that residential PV generation could approach 37% of total residential energy demand by 2050 (or 10% of current residential demand by about the early 2030s).

Figure 7.8: Forecast growth of residential PV installations in New Zealand[38]



7.2.2.3 ELECTRIC VEHICLES

The use of EVs (full electric or plug-in hybrid) in New Zealand is starting to pick up pace, with a total of 68,562[39] electric motor vehicles (all light fleet types) registered by mid-January 2023. This is an increase of about 78% on the previous year. The increased rate of electric vehicle registrations is illustrated in Figure 7.9.

There is wide acceptance 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. A number of incentives exist in this regard, most notably the clean car discount announced by the government in April 2022.

Current national targets are for 30% of the light vehicle fleet to be zero-emissions by 2035. Further plans are expected that will ban high-emitting vehicles.

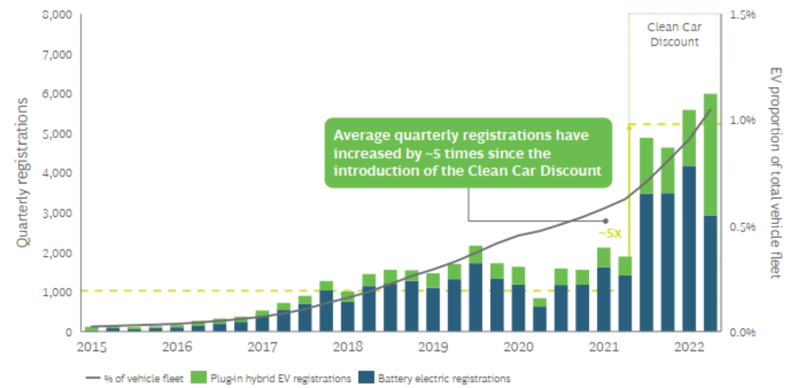
Pure electric and hybrid electric vehicle uptake on Powerco's footprint increased by 59.5% over the period 2021 to 2022, now standing at a total of 3,920 registrations.

37 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.

38 Source: MBIE, "Electricity Demand and Supply Generation Scenarios 2019", https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios

39 The Ministry of Transport, https://www.transport.govt.nz/statistics-and-insights/

Figure 7.9: Electric vehicle registrations in New Zealand[40]



Source: Ministry of Transport

The total number of EVs on our footprint is still relatively small and we do not yet see a material network impact on electricity demand. However, as penetration rises, we expect that vehicle charging will become one of the major contributors to increased electricity use and demand. If not managed effectively, this could have serious implications on available network capacity and potentially lead to localised power quality issues, initially, particularly on the LV network, but eventually extending to all parts of the network.

To facilitate EV charging, particularly 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. It showed that, without any form of control, the demand could increase significantly, as shown in Figure 7.10.

The study also showed that this increase in demand can be mitigated by the introduction of smart charging. Figure 7.11 shows how smart EV charging can influence the demand profile – shifting consumption away from current network peak demand times. Similarly, Transpower reports that for every MW of peak demand avoided, about $1.5m investment cost can be saved across the electricity supply chain. Based on forecast EV uptake rates, smart charging could lead to a saving of about $3 billion for the New Zealand economy[41].

Figure 7.10: Impact of EV charging on an average household demand profile

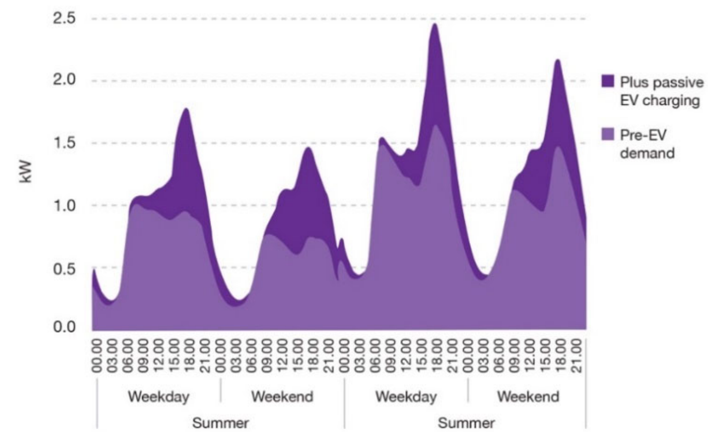
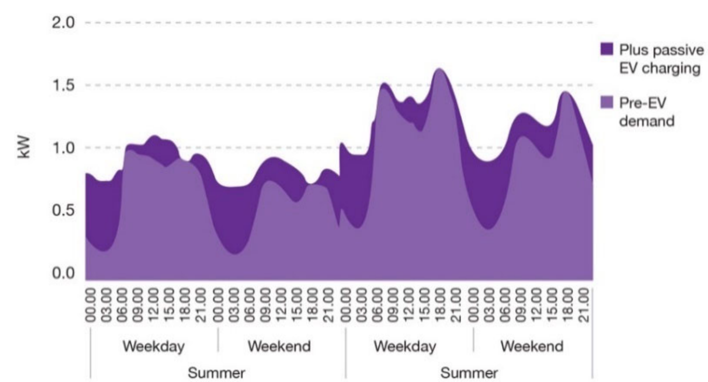


Figure 7.11: Impact of smart EV charging on an average household demand profile



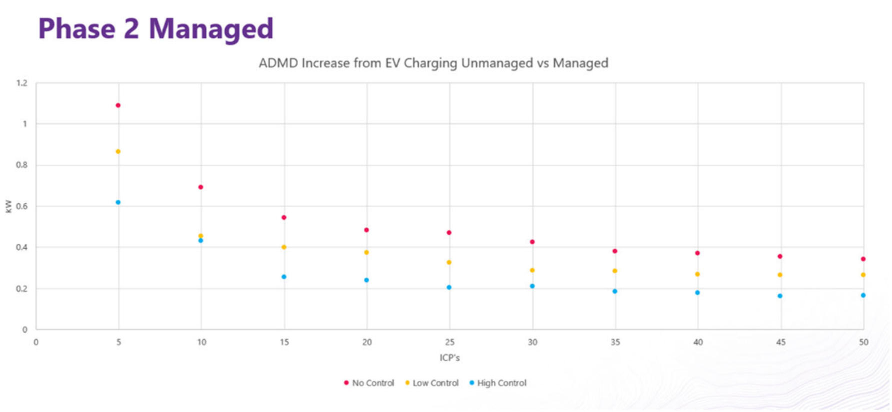
Initial results from our EV charger study, however, suggests a somewhat lower individual demand impact, as shown in Figure 7.12. It is however too early, with a

40 Boston Consulting Group, "The Future is Electric", October 2022

41 Transpower, Distributed Energy Resources and Flexibility Services, 2020

too selective (early adopter) participant range, to draw firm conclusions from this data.

Figure 7.12: EV charging demand results from the Powerco Evnex trial



Given the potential extent and impact of electric vehicles on network demand, we continue to monitor these developments very closely. We also have an ongoing pilot project whereby we issued medium rate chargers to EV owners and monitor their use – this is providing valuable customer behaviour and network impact insights.

7.2.2.4 ENERGY STORAGE

Energy storage continues to be a major topic of discussion in the industry, with a rapidly escalating range of market offerings at both the domestic and utility-scale. The numbers on our network have increased at a steady rate, but ICPs with battery storage remains a small percentage of our overall customer base.

While internationally the focus of energy storage 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. Grid-scale energy storage systems usually only impact the distribution network in certain specific circumstances.

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, with several installations around the world now exceeding 100MW peak capacity. These are mainly installed for participation in the electricity market, peak demand management, network stability, standby capacity, or ancillary services. 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. In addition to 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. Residential-scale battery installations are, however, in the longer term likely to have a greater impact on distribution networks than grid-scale battery installations.

In New Zealand, the uptake of battery storage and other new forms of energy storage is still relatively slow, with only a small number of major installations in place (including the 2MW, 2MWh unit that Powerco has installed to provide backup supply to the Whangamata CBD).

Residential storage uptake is steadily increasing, with the vast majority of this being installed directly by customers for their own use or by suppliers for the benefit of customers. At this stage, we are not aware of significant interest from end-use customers in participating directly in the energy market or providing flexibility services, but fully anticipate – and will support – this to increase within the AMP planning period.

An exciting recent development is two instances of larger-scale aggregation projects, where multiple privately located batteries are being collectively managed by a third party, solarZero, to provide demand response. Aurora Energy has entered into a 0.5MW scheme in the Upper Clutha Valley, and Powerco a 1MW scheme in Whitianga in the Coromandel Peninsula. Again, we see multiple applications for these types of flexibility service arrangements and will actively seek them out in the future.

Although the cost of battery storage systems has reduced substantially in recent years, at present, it seems to have plateaued. This is partly driven by increasing international demand and the difficulty in sourcing sufficient raw materials for battery manufacturing. For the large majority of individual customers, an off-grid battery/solar PV (or other generation) installation is still significantly more expensive than retaining a level of grid-supplied electricity (by comparable capacity). Being connected to the grid also retains opportunities for participating in the electricity market. 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.

In some instances, mainly in the more remote rural areas, the installation of combined generation and battery storage units is economically feasible, and off-gridding rates in these cases may accelerate. Where this is appropriate, Powerco will encourage such conversions.

Overall, we do not believe that battery storage will lead to material levels of grid defection. 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, in addition to their customer benefits. They offer significant potential for increased reliability and resilience of supply, the potential for deferring network reinforcements and lifting network utilisation, improving network stability, and maximising the value from distributed generation sources. Therefore, it is an area in which we intend to increase our focus, increasingly incorporating storage solutions where these provide economic or reliability benefits.

The benefits should be achievable regardless of the ownership model. While there will be instances where it makes more sense for us to own the infrastructure, we will also encourage agreements with customer or third-party providers. The decision will ultimately be driven by what would benefit customers most.

7.2.2.5 DEMAND MANAGEMENT AND FLEXIBILITY SERVICES

For years, New Zealand has been a world leader in applying demand management systems, particularly in its use of water heaters as controllable load. Many of these control systems are now reaching end-of-life and there is considerable debate as to whether upgraded systems should be provided by network companies or third-party providers, including retailers. Powerco is relatively agnostic to the ownership model, as long as access to the controllable load can be commercially secured. Hot water control systems will continue to play an important, even increasing, part in managing peak demand on our network.

With improving communications systems and more intelligent home devices, new opportunities are also opening up for demand management on the customer side of the electricity meter, or for providing further flexibility services.

While it is not our intent to become involved in supplying or operating customer products, such as home area networks or household devices, we will continue to pursue demand management solutions or flexibility services and offer incentives to customers to provide this where it is economically preferable to network reinforcement. This will be an important part of our focus on increasing the utilisation of our existing asset base (in preference to reinforcing).

With the arrival of large-scale energy storage on our network in future, opportunities will also arise for demand management on the network side. There is an increasing opportunity to roll out ‘intelligent’ devices on the network. These allow more visibility, remote communication, and the 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 the 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.

7.2.3 POWERCO’S CURRENT INITIATIVES TO ADAPT TO THE NEW ENERGY FUTURE

While we have always been a leader in developing and adopting conventional network solutions and assets, in recent years, we have stepped up our focus on non-network solutions and emerging technology. A dedicated Network Transformation team is in place to coordinate Powerco’s other teams, monitor energy trends, research and test new technology and the customer impact of these, and to develop new solutions to meet network requirements. Current and recent activities include:

- Monitoring and analysing trends on our network, as well as nationally and internationally, of customers’ technology changes, focusing on EVs, PV panels and domestic batteries. Providing insights to the rest of the business, based on this analysis.

  This activity is further supported by projects to work with customers to install new edge devices, particularly rapid EV chargers, on parts of our network and use the information gained to better inform our strategy.
- Testing and enabling our network to incorporate the future widespread implementation of flexibility markets.
- Deploying various types of monitoring and communication devices across our network to ascertain performance and ease of integration, thereby laying the foundations for more automation and asset utilisation optimisation.
- Developing an Internet of Things (IoT) across our network – integrating various sources of information from multiple “intelligent” devices and using this information for operational, fault-response, planning and maintenance purposes.
- Enabling new and existing market participants to develop new services on our network.
- Testing various forms of LV network monitoring devices, to inform our future investment in this important area. This is essential to ensure that we can optimise utilisation and defer investment of this part of the network, where most of the initial potential capacity and supply quality problems associated with the rapid future electrification of energy use will be seen.
- Continuously use the learnings from these activities to define our Network Evolution strategy.

7.2.4 WORK WITH OTHER EDBS AND PROVIDERS OF NON-NETWORK SOLUTIONS

Recent innovation collaborations with other EDBs and third parties include the following:

- In 2018, we commissioned a study in collaboration with Unison and Orion to model the impact of EV charging on residential ICP demand.

- In 2022, Powerco partnered with solarZero to establish a community-led solution to help keep the lights on across the Coromandel Peninsula. The system is a virtual power plant made up of a network of hundreds of community-based smart energy storage and solar generation systems on homes across the region. Using this system, solarZero will provide 1MW of network support to Powerco to help maintain its electricity supply to customers in the north Coromandel during peak consumption times.
- We're in the early stages of working with Australia-based Future Grid after the company was named one of the winners in Ara Ake's electricity distribution Decarbonisation Challenge. Future Grid uses data from smart meters, IoT (internet of things) and increasing DER (distributed energy resources) inverters to create real-time power quality visibility to understand the behaviour and impacts of DER on the low-voltage (LV) distribution grid.

We are also increasingly seeking potential third-party solutions to address major network requirements. These will be adopted where they are more cost-effective than our network or non-network solutions.

7.2.5 NETWORK EVOLUTION: WHERE ARE WE GOING?

While we know that fundamental changes lie ahead in the electricity industry, the speed of the change in New Zealand's energy use patterns is still uncertain. It is noted, however, that current uptake rates of edge technology, while still low by world standards, have been accelerating significantly during the past 12-18 months.

7.2.5.1 DEALING WITH AN UNCERTAIN FUTURE

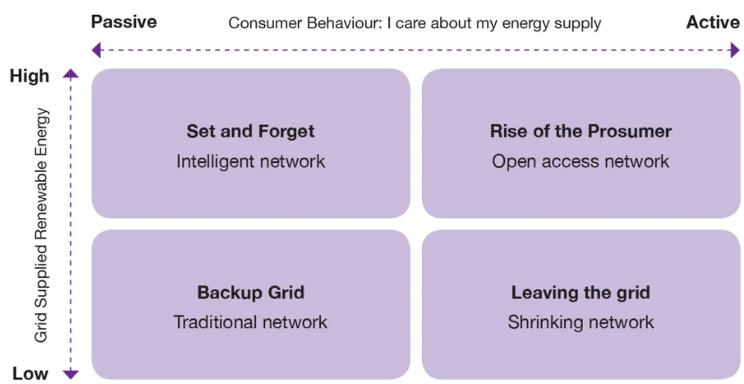
The future nature of electricity distribution networks is being widely debated around the world. We subscribe to the New Zealand-specific Network Transformation Roadmap developed by the Electricity Network Association (ENA)[42]. It is backed up by international research in similar jurisdictions, particularly 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, are connected to the grid?

Using these primary dimensions, four future scenarios were created, shown in Figure 7.13. These purposely extreme scenarios are intended to support clarity in thinking and assessment – it is unlikely that any of these will arise by themselves. A more feasible outcome 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.

Figure 7.13: Network transformation scenarios adapted from ENA with evolution pathways



A. Backup grid scenario: Traditional network

This is largely the distribution network that we are accustomed to:

- It relies on physical assets to convey electricity from bulk electricity supply points[43] 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 provided – price and reliability are their major considerations.
- Other than electricity conveyance, distribution utilities do not participate in energy markets and limit their activities to 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.

42 Source: ENA, "Network Transformation Roadmap", https://www.ena.org.nz/resources/publications/document/483

43 These are generally points of connection to the transmission grid but can be direct connections to generators.

- 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.
- Localised concentrations of customers wanting to connect EV and PV can compromise system stability.

B. Set and forget scenario: Intelligent network

This is the often-touted 'smart grid', which is based on the traditional network with extended capabilities for monitoring, measurement, control, reconfiguration 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 largely on physical assets to convey electricity from bulk electricity supply points to customers, although local generation and energy storage can be encouraged.
- The large majority of customers remain generally passive, not taking much interest in changing their behaviour or in their energy supply or how this is provided – 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 do not participate in energy markets, other than providing electricity conveyance. They are compensated for the assets they provide and operate as well as for, in many instances, the reliability of service and for energy efficiency improvements[44].
- 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 allow a significant reduction in the degree of asset redundancy required (to achieve the same or improved network outcomes).
- Traditional deterministic planning and operational approaches are increasingly substituted with a probabilistic approach – this allows distributed energy devices to be appropriately considered in reliability planning, as well as supporting better informed risk/cost trade-off decisions.
- Customers can generally connect their EV and PV; however, technical network limitations may restrict their ability to fully utilise them.

C. Rise of the prosumer scenario: 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.

[44] This is to ensure that incentives exist to find optimally efficient solutions, rather than stick to traditional network investment solutions.

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.

D. Leaving the grid scenario: Shrinking network

The shrinking network describes a situation where it makes economic 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 core network would then likely 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.

We are not aware of examples in New Zealand of large-scale grid defection. However, it may become increasingly feasible in remote areas, where grid supply is expensive, eventually spreading to larger parts of networks. For example, we already facilitate the decommissioning of long rural feeders supplying isolated loads through the use of the Base Power alternative, albeit only for individual or very small groups of customers.

7.2.5.2 DEVELOPING THE OPEN-ACCESS NETWORK

Internationally, there is much activity on the development of open-access networks. This is done in conjunction with the development of the distribution system operator (DSO) concept – open-access networks are an essential enabler. In New Zealand, the Electricity Authority (EA) is supporting this concept, but as reported in previous AMPs, there has been little progress on discussing how it may be achieved. This may change in the near future, with the EA now taking an active interest in the regulation of distribution utilities[45].

7.2.6 NETWORK EVOLUTION: HOW WILL WE GET THERE?

7.2.6.1 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. These include:

- 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 (OMS).
- Extensive automation devices spread across the network.
- Increasing communications networks, including a network-wide roll-out of a LoRaWAN network to connect multiple sensors and other IoT devices.

Our network is not homogeneous. It covers large areas of rural land, coastal townships, dense cities, Department of Conservation-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, especially between the higher-density, more urban network areas, and the low-density rural network areas.

Therefore, we expect the four scenarios described above will have different likelihoods and outcomes 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 AMP21, 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.

Therefore, our Network Evolution strategy 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 into a particular scenario or network configuration.

[45] For example: Electricity Authority, "Updating the regulatory settings for distribution networks (December 2022)"

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 network visibility.
- Future energy consumers.
- Modernising the grid edge.
- Enhanced network response.

Each theme and its 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 rollout. If a 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 decision processes and tests.

In parallel, we continue to develop non-network solutions, such as the 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 renewing uneconomic and unreliable existing (pre-1992) overhead lines. (Refer to Section 7.3.3.1.)

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 maximise energy options for our customers and facilitate energy markets and flexibility services trading is by operating an open-access distribution network. This will be supported by:

– Applying suitable technology to ensure network capacity and stability.
– Much improved visibility of power flows, network utilisation, status, and condition.
– Increased network automation and self-healing capability.
– Improved data and analytics.

Essentially, this future network would allow customers or flexibility service providers to be largely unconstrained in what they can connect to the network and how they 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.

7.2.6.2 IMPROVED NETWORKK VISIBILITY

A high level 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 and enable flexibility services trading. At present, this visibility is patchy across the HV networks and largely lacking on our LV networks. We, therefore, need to increase monitoring across our network and customers' installations.

This programme, which commenced in 2021, is intended to materially pick up the pace from FY24 on and involves:

- Greatly increase monitoring throughout the network, down to LV level.
- 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.

Intended stakeholder benefits from this programme are:

- Enabling the open-access network, which in turn will allow an effective DSO.
- Enabling flexibility markets to operate effectively on our electricity network.
- Improved real-time understanding of asset condition and loading will allow higher utilisation rates. This will materially defer the need for network reinforcement, without having to take on undue risks.
- Reducing the time to locate and respond to network faults, thereby improving general network reliability. This will include LV outages, where our fault response now largely relies on being notified about outages by the customers.
- Safety enhancements – being able to recognise potential issues more accurately and more effectively.
- Improved ability to predict and prepare for network congestion because of changes in customer energy profiles and distributed energy resources (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.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to support improved network visibility.

- **LV network monitoring** – a tiered approach to monitoring the utilisation of LV feeders, transformers, switches, and other LV assets throughout the Powerco network. This essential programme will inform future investment plans, provide inputs for automation schemes, and help ensure network stability in the face of increased use of distribution edge devices. The initial focus is on monitoring LV feeders at the distribution transformers. Over time, we intend to expand visibility further down into the networks – typically to include feeder endpoints, midpoints, and tee-offs.

  The programme will also look at the integration of other available monitoring devices on the network, for example, customers' inverters (for PV), smart meters, battery control devices etc.
- **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 section 7.8.4.3

Note, that as part of our network development expenditure forecast, described in Chapter 10, we make provision for the early stages of a systematic rollout of network monitoring devices across the whole network. The learning from early years will inform the technology choices and business case for the eventual proposed comprehensive rollout. 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 remove the need for our own investment.

7.2.6.3 FUTURE ENERGY CONSUMERS

The future energy consumers programme centres on 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.
- Building a detailed understanding of customers' intended decarbonisation plans and collaborating closely with them to ensure the optimal win-win outcome – minimising the need for additional investment, while still meeting the energy needs.
- Detailed study into customer cluster groups and understanding the impact of electricity not being served to these groups, including at different times. This will form the basis for revising our security of supply standards in future.
- Testing beyond-the-meter assets to understand how these interact with network operations and changes in customer preference[46].
- Exploring the potential to obtain and integrate external sources of data that help us improve demand and customer profiling.

Our stakeholders will benefit from this programme through:

- Optimised support and cost minimisation as they decarbonise their processes and activities.
- Enhanced ability to accommodate increasing use of distribution edge devices.
- Facilitation of flexibility markets.
- Improved ability to respond 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 on customers' actual consumption patterns and expressed quality preference (probabilistically based) rather than generic designs and deterministic security of supply standards.
- Sufficient lead time to prepare our network and services to meet changing market environments.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to develop our understanding of future energy consumers.

- **Decarbonisation surveys and customer engagement** – collaborating with customers to understand their future decarbonisation plans and to develop options and optimal outcomes.

[46] Note, we have little appetite to own beyond-the-meter assets – instead preferring to work with customers or suppliers who own these to better understand the network implications. We also wish to understand how we may develop incentives to obtain network benefits or avoid negative impact on our operations. To aid our research projects we will look at ways to encourage accelerated take-up of customer devices, in limited areas.

- **Customer and retailer collaboration** – actively seek opportunities to collaborate with customers or 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, to test the impact of these on the network.
- **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. By doping real-world trials and pilots with our customers and communities, we start to understand what they might want in the future, as well as demonstrate what is possible in the future.
- **Value study and surveys on customer clusters and value of lost load surveys** – greatly improving our customer understanding and associated planning and operational standards and practices.

7.2.6.4 MODERNISING THE GRID EDGE

We define modernising the grid edge 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 standby capability.
- Expanding the 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.
- Improved power quality.
- Reduced callouts for investigations on fault causes.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to enhance our grid edge modernisation programme.

- **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 operating condition, it is often possible to increase asset utilisation over pre-defined limits, while still running assets safely. (For passive networks, we have to build in conservative safety factors in operating allowances, to avoid asset damage under worst-case operating scenarios.) 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** – quicker fault response and location times are achievable by automatically providing information to the Network Operations Centre (NOC) on the occurrence and location of an outage.
- **Energy storage** – effective energy storage can have multiple network benefits, ranging from the ability to reduce peak demands and provide standby capacity, 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[47].

7.2.6.5 ENHANCED NETWORK RESPONSE

The enhanced network response programme relates to our ability to maintain stable network operation in the face of increased use of distribution edge devices that can interfere with power quality. In particular, we have to ensure voltage levels, frequency and signal distortion can be maintained within prescribed regulatory limits. This can be challenging when distributed generation, non-linear devices or equipment with large, rapidly changing load profiles become abundant on the network.

This programme extends to:

[47] We are also looking into strategically situated generators on the network – refer to Section 7.7. This will complement energy storage.

- 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, off-grid solutions.

Our stakeholders will benefit from this programme through:

- Facilitation of the open-access network, which in turn will allow an effective DSO.
- 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 regarding demand response incentives for future DSO markets.

The limits of today's networks

The design of traditional electricity networks 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 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.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to support our enhanced network response programme.

- **Energy communities** – testing new forms of network architecture designs, for example, microgrids and LV meshing, which 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. Examples include variable tap changing transformers and taking customers off grid at times.
- **Innovative network design** – develop new methods of designing networks to improve quality of supply potential during planned and unplanned outage events, for example, 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.

7.3 NETWORK ARCHITECTURE

Network architecture largely sets out the blueprint for how we plan, build, and operate our networks. Architecture decisions have a major bearing on the cost of distribution, network utilisation, and the resilience and reliability of electricity supply.

While legacy networks have a major influence on our network architecture, new installations and replacements are built to standards that have not been materially reviewed in the past 15 years. By reviewing the network architecture, we see an opportunity for cost reduction without sacrificing safety or quality of supply.

7.3.1 NETWORK ARCHITECTURE: WHERE ARE WE NOW

Traditional network architecture

Network architecture generally refers to the fundamental design elements of a network. These include:

- Feeder configuration and interconnection of feeders, substations etc.
- Standard sizes/capacities for backbone, spur lines etc.
- Allowed nominal lengths and connection numbers on feeders or circuit sections.
- Size and configuration of substation bays and buses.
- Protection and communication design.
- Type and density of switching devices.

Drivers of architecture are:

- Required service and capacity levels.
- Load and, in future, DER density.
- Network location.
- Asset costs, particularly as a function of size.
- Reliability and security requirements.
- Operational requirements.
- Technology developments and costs.

Design and asset standards generally follows architecture, which sets the all-encompassing framework for the network.

Powerco is an amalgamation of many historical networks and, as such, has inherited some significant variation in architectural elements across its footprint. Notwithstanding this, the New Zealand industry has traditionally adopted some very similar architectural features. It is particularly common to have a quite different architecture for urban networks and rural networks.

This difference between urban and rural networks sits at the heart of our network architecture review. We refer to our situation as a "tale of two networks" – with the major differences detailed in Table 7.1.

Table 7.1: Comparison of rural and urban network features

	URBAN	RURAL
Load density	High	Low (except for some primary industry)
Topology	Predominantly underground, some overhead. Moderate length HV circuits.	Almost exclusively overhead. Long lines, low capacity.
Interconnection	Large capacity backbone feeders, some sub-rings. High degree of interconnectivity and backfeed capability.	Medium capacity backbones, large number of long spurs with minimal interconnection.
Capacity constraints	Mainly thermal, and generally only under contingent events.	Mainly voltage, sometimes even in normal configuration.
Protection	Substation circuit breakers and fused distribution transformers.	Substation CB, some line, spur and group fuses.
Automation	Minimal or no automatic reclosing.	Line reclosers and sectionalisers widely used.
Isolation	Feeders regularly segmented by ring main units or air-break switches (ABSs).	Widely spaced ABSs.
LV	Large capacity. Multiple connections per feeder. High diversity of load.	Low capacity and often long. Single or few connections.
Switching	Increasing levels of automation, including loop.	Some automation, mostly sectionalisation.
Fault finding	High degree of isolation points. Some fault passage indicators.	Minimal fault indicators. Reliance on line surveys.

The above also leads to two contrasting price/quality outcomes:

1. The cost per connection for rural customers is generally substantially higher than urban.
2. Long exposed rural lines are more exposed to interference from vegetation and weather and environmental factors than urban feeders. Therefore, they do not perform as well, and it takes longer to find and repair faults. Rural supply quality is generally intrinsically lower than in urban areas.

7.3.1.1 URBAN NETWORK ARCHITECTURE

By virtue of the network density and resulting architecture, our urban networks are generally better utilised and more reliable than rural networks. The average cost per connection is substantially lower. They are also generally better suited to accommodate technology improvements, such as automation, fault restoration or load shifting.

Most of the potential gains from reviewing our architecture will, therefore, come from the rural areas. However, it is recognised that the urban networks, particularly the LV side, also need review.

At the distribution voltage level, capacity is generally sufficient to absorb a substantial volume of new customer devices, such as solar PV, batteries and EVs, before capacity or stability issues, may pose a challenge.

This will likely be different on the LV side, where the immediate impact of new consumer devices will be directly experienced, and where there is generally less capacity and load diversity to accommodate the associated load increases or fluctuations.

We have several programmes of work under our Network Evolution strategy to understand and respond to the impact of new technologies on urban networks – refer to section 7.2. A review of our LV networks and increased levels of monitoring and automation is also beginning, see section 7.8.

7.3.1.2 RURAL NETWORK ARCHITECTURE

Note: We are generalising "rural" networks for the following discussion. While the assumptions hold true on average, there are a number of rural areas with considerable economic or high-density farming activity and associated high energy use. The supply economics for these areas is markedly different from the low-consumption rural areas. Reflecting customer requirements, the supply quality in these areas is, mostly, much better than in the general rural areas.

As noted above, the cost to supply rural connections is generally substantially higher than in urban areas, even if supply reliability is generally lower – and this differential is likely to increase as urban customers have more opportunities to adopt technology and change their energy use patterns. Pricing differentials for distribution services cannot realistically reflect these urban/rural cost differences unless we are prepared to entertain significant price-shocks with associated upheaval in rural areas, which is unlikely to be politically palatable (or to us) and might not ultimately be beneficial to any part of our customer base.

This requires us to look more deeply into rural architecture and the ensuing price/quality implications. At the same time, there are a number of changing dynamics that also necessitate a re-think about the makeup of rural networks:

- Continued urban drift and changing land use, leading to flat or negative demand growth[48]. This means low and reducing asset utilisation.
- Ageing rural infrastructure, commonly built from the late 1950s to early 1970s.
- The move towards more cost-reflective pricing and open-access networks where tailored energy solutions and applications will be supported.
- Reducing costs of off-grid and network alternatives and, therefore, more opportunity for beyond-the-meter services and solutions.
- The need to use more sustainable construction materials and techniques, with less impact on the environment.
- A challenging framework for effectively managing vegetation issues.
- The need for networks to be more resilient and designed to more onerous criteria in the future.
- Sustained pressure on costs from the need to keep electricity affordable.
- Safety issues, especially around downed conductors.
- Potential for large-scale renewable generation located in rural areas.
- The increased availability of remote monitoring and communications, plus improved protection and switching capability.

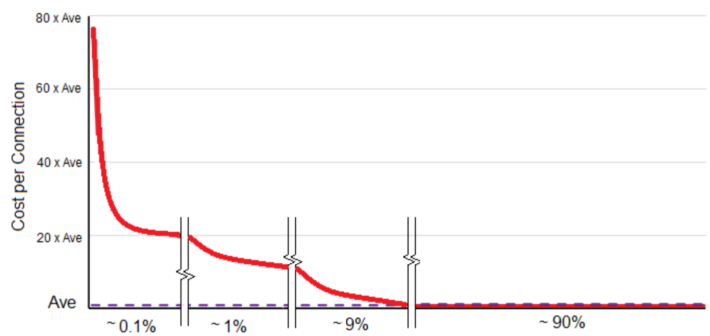
The combination of these factors poses some serious challenges. On the one hand, lower consumption and network utilisation makes it imperative to reduce the cost for providing rural supplies – or accept an even greater wealth transfer from urban to rural customers. Conversely, rural networks are facing a pending tsunami of renewal needs (the “wall of wire”) in the next decade or so. Much of the rural network will need to be totally rebuilt. At the same time, rural customers still rely on reliable electricity to support their lifestyle and economic activity.

Emerging technology will likely provide part of the solution. Opportunity now exists for much greater customer participation in providing their own energy, in full or in part. We also have an increasing ability to use technology to reduce the operating cost of networks, through improved automation and remote fault-finding.

Before any large-scale rebuilds, we will have to resolve the ideal network architecture and engage with rural customers on possible alternative electricity supply arrangements. This engagement has to be transparent, particularly in presenting the price/quality options that exist, and the extent of cross-subsidisation already in place.

Figure 7. shows the extent of the cost imbalance for different parts of our customer base – this is directly correlated to the degree of remoteness from our core network. While this presentation is stylised (of necessity to visualise the sharply hyperbolic nature of the relationship), the underlying numbers are based on real network data.

Figure 7.14: Comparison of connection costs for different customer proportions



- Network supply to a very small (~0.1%) portion of the most remote customers costs up to 80 times the average cost per connection; the supply economics of which should pose very obvious questions about remaining on-grid.
- Approximately 1% of customers cost up to 20 times the average to service. The economics of remaining on-grid is still questionable but will be a function of costs (driven by network architecture) and the alternatives (new technology).
- A further 9% of customers could still be classified as semi-remote, in that service costs can be up to 10 times the average. Network connections are

[48] For example, a general shift from sheep farming to forestry on large parts of our footprint led to substantial load reductions. This trend now appears to be continuing with conversions from forestry to bee farming.

likely to remain more economical than alternatives, but we need to consider supply quality trade-offs.

- For the remaining 90% of mass market customers, mostly urban, network supply remains the obvious most economical choice.

7.3.2 NETWORK ARCHITECTURE: WHERE ARE WE GOING?

We are continuing with our programme to review and modernise our overall network architecture. This is being informed by our technology trials, customer surveys and discussions with suppliers and other industry participants.

Our approach to re-architecting the rural network starts with better understanding the different nature, needs and costs of our customers on the various parts of the network. The biggest cost differentiator is remoteness, which could be measured by the allocated share of supply, assets to serve a customer.

Our rural architecture review is initially focusing on three tactics.

- **Off-gridding of remote connections – remote area power supplies (RAPS)** – this is already the economical supply solution for the most remote connections (~0.1% of our customers). Should we be able to obtain lower cost RAPS units, the number of viable off-grid supplies could increase to about 1% of our connections.
- **Alternative build/design for overhead line assets** – we are working on lower-cost designs for rural lines with low demand. These serve about ~10% of our network connections.
- **Use of generation to improve reliability (and resilience) on remote feeders** – by judicious use of remote generation, we foresee that we will be able to defer major line rebuilds on a substantial portion of our rural network.

Our ultimate vision is for a rural network architecture that is more cost-effective, tailored to customers' land-use and associated price/quality trade-off preferences, and to ultimately strive to reflect this in appropriate pricing schemes.

A cost-effective network will mean capacity and quality of supply are finely tuned to the future needs of customers. As this is uncertain, there is value in deferring major rebuilding of existing network assets until there is greater certainty about future consumption patterns or to allow for more cost-effective solutions to emerge.

Accepting the uncertainty, our view of the future rural network is that it will comprise the following:

- The most remote customers will be supplied by off-grid systems.
- Pockets of clustered remote customers will be operated on an off-grid microgrid.
- Remote customers still connected to the network should be able to cost effectively deploy DER, both supplemented by and supporting the network.
- Network lines will be built small, light and at low cost – sufficient for the expected load, but with a shortened life expectancy. The network may be supported by distributed DER, including stand-alone generators.
- More use is made of single phase and single wire earth return lines (SWER).
- Applying real-time monitoring, asset ratings, and smart protection systems will allow lines to operate beyond traditional capacity or performance limits. Downed lines will be quickly detected, remotely isolated, and made safe.
- Monitoring and fault indicators will provide rapid isolation and fault location.
- Networks will be constructed using sustainable materials and construction techniques that are also resilient to changing climate effects.
- An appropriate mix of underground cable covered aerial conductor and improved vegetation management will be applied in critical areas to minimise tree interference. New protection systems could detect tree contact before faults become permanent.
- EVs or farm implements in rural areas will be accommodated. Local storage and smart charging regimes will be applied to overcome capacity and voltage constraints.
- Over time, we may switch to higher distribution voltages to provide additional capacity with smaller-sized assets.

7.3.3 NETWORK ARCHITECTURE: HOW WILL WE GET THERE?

Our implementation of the three core architecture change strategies is discussed below. A key goal is also to defer major network reconstruction as long as possible, to allow more certainty before committing to specific fixed solutions.

7.3.3.1 OFF-GRIDDING

The most remote and costly connections will be considered for off-gridding when local spur lines become due for renewal. For some of these, off-gridding is already an economical option with lower lifecycle cost than rebuilding the lines. This is essentially a continuation of our current Base Power RAPS deployment programme.

We are investigating ways to reduce RAPS costs and extend the range of options in terms of capacity and reliability. In particular, a lower-cost, simpler unit may be appropriate for very low-energy users. Ideally, a contestable market will develop that will allow customers a choice of supplier and products, and therefore let them refine their price/quality options to individual preferences.

With lower off-gridding costs, more remote connections will become viable to off-grid. Our financial forecasts for the AMP period make some modest assumptions around these cost reductions. Timing may become critical, as renewal of poor-quality lines cannot be deferred indefinitely.

Off-gridding requires the agreement of the affected customer (or a small cluster of customers). This often involves lengthy negotiations and measures to put customers at ease so that the reliability of their electricity supply will not deteriorate[49].

Microgrids are a potential solution for a cluster of customers situated relatively close to each other at the end of a long rural line. Aged and poorly performing sections of line would be removed, and facilities installed so that downstream customers could operate within an isolated network of their own. While this appears to be an economical solution, implementation faces considerable operational, legal (electricity market) and logistic obstacles.

7.3.3.2 ALTERNATIVE LINE BUILD

Alternative line build essentially involves a strategy to trade off initial construction cost against service capability, and to some extent asset life. During the past 18 months, we have reviewed our line design standards and have now approved, where appropriate, the use of smaller, lighter lines utilising softwood poles that will still serve current needs and meet safety requirements but should materially reduce immediate costs. From a lifecycle perspective, our calculations show that such an approach will still be the most cost-effective, even if assets reach end-of-life at an earlier point. This is especially true in highly exposed (to wind, landslips, storms, snow etc) areas where significant portions of lines have to be replaced well before end-of-life because of damage from these factors.

In addition, lower upfront cost solutions can defer major investment until there is greater surety about long-term electricity needs.

Softwood poles are lower cost, locally sourced, environmentally beneficial and, above all, are lightweight, which materially reduces transport and construction costs for lines that are commonly built in hard-to-access backcountry areas. While the softwood poles have lower crossline strength than pre-stressed I-section poles, their superior downline strength is more important to long-span rural construction, especially in backcountry areas with significant snow loading.

These poles are complemented with smaller conductors, which could constrain future capacity, but the risk is low with most rural lines very lightly loaded and demand growth being negligible. Possible future thermal capacity constraints may be manageable through DER or demand side response (DSR) alternatives. New technologies are allowing more dynamic rating of lines, leveraging additional latent capacity.

Given modern treatment standards, the durability of softwood poles has improved markedly. Notwithstanding this, the economic life of these poles may be restricted by standards of safety related to the surety of pole integrity before climbing. We are conducting tests to ascertain the pole strength and will continue this over time to ensure full understanding of the lifecycle performance of poles. Even if pole integrity cannot be guaranteed for the whole expected lifetime (45 years), replacing poles after 30 years is still economical given the early installation savings.

As part of the alternative build, we are also investigating expanded use of SWER lines or single-phase lines. These are very cost-effective for backcountry areas with long spans across deep valleys. There may be some capacity constraints, and options for more than single-phase supply will need to be investigated.

7.3.3.3 RELIABILITY OPTIONS

Off-grid and alternative build options are only useful as a counter-factual to the default choice of replacing lines with like-for-like at the end of their life. The timing of a line renewal is never a clear binary decision; instead, it is a risk trade-off balancing declining asset and network performance against investment timing.

Therefore, strategies to defer major line renewal are valuable to allow greater certainty of future requirements before investing.

Strategies to manage declining network performance or extend capacity includes the use of DERs on the customer and network side. There are options for generation solutions, potentially supplemented by energy storage. Located near the end of long lines, these can drastically improve overall power quality, both in terms of reduced outages and providing voltage support. Refer to section 7.7 on our generation and storage strategy for more details.

7.4 PROBABILISTIC PLANNING

We have started to adopt probabilistic planning standards for most of our forward planning – systematically rolling this out to all network categories. Over time, this is expected to lead to material cost-savings in new network investments (growth and renewal), as the approach intrinsically leads to optimally efficient solutions, while being very transparent about the risk involved.

In addition, this planning approach will become essential as we see more renewable generation on the network or intermittent demand. Current planning methods cannot effectively accommodate these factors so cannot reflect any network benefit from, for example, wind generation connected to the network.

7.4.1 PROBABILISTIC PLANNING: WHERE ARE WE NOW?

Traditionally, the electricity distribution industry has used deterministic approaches to plan network investment, particularly in regard to security of supply or network reliability. This was a pragmatic approach, which was appropriate given limited past

49 Given the relatively poor performance of many long rural feeders, supply reliability actually improves materially with a RAPS unit.

data and analytic capabilities and was well suited to less volatile and more predictable growth trends, particularly in high-growth scenarios.

Analysis and network modelling capabilities have greatly increased, allowing disaggregation of data to low levels, potentially even individual customers. Multiple uncertain planning dimensions can also be analysed simultaneously using a risk-based or probabilistic approach to better understand the economic and risk trade-offs for network solutions.

The following drivers necessitate a different approach to network planning:

- Changing patterns of electricity use, particularly where these are more variable.
- Emerging technology, particularly where these represent intermittent generation and/or demand features, such as energy storage, solar PV, and EVs.
- Customer participation in providing network services or selling excess energy.
- More volatile economic, demographic and industry factors.
- Smart grid solutions – variable asset ratings, automation and network reconfiguration, Advanced Distribution Management Systems (ADMS).
- Pressure on affordability of utility services.
- Risk-based and value-based investment frameworks.

Faced with these drivers and changes, retaining a planning deterministic approach limits our ability to optimise network investment decisions. Problems with a deterministic approach include it:

- Considers only the maximum demand, not the demand profiles, or the potential future changes to these profiles.
- Does not reflect circuit failure rates, asset age/condition or circuit length.
- Assigns a single capacity to assets, despite the fact that this changes with time or seasons.
- Cannot reflect the reliability benefits from intermittent connected generation, e.g., wind generation.
- Is biased towards traditional supply side (poles and wires) solutions.
- Uses a very subjective and generic (class-based) approach to risk management and customer criticality.
- Does not support value-based investment frameworks or ensuing pricing signals.
- Does not reflect the actual cost of an outage to customers, which is much higher for some than others. Optimal cost-reflective solutions are therefore not possible.

Deterministic approaches set security criteria to cater for the lowest common denominator in the security class, assuming the worst-case peak demand. This leads to conservative planning decisions, particularly where network redundancy or alternative supply arrangements exist – as is often the case in urban networks.

The main dimension in which our current deterministic standards vary across classes is in terms of the switching response speed – the time taken to reconfigure the network and establish alternative feeds where possible. This was appropriate given the traditional and stable network architecture in the past but will struggle to cope with a future where network configuration is more varied, operations more automated, and customer-side solutions more common.

The existing deterministic approach does not support monetised risk, which is foundational to our recently introduced value framework for investment decisions.

Finally, the move from deterministic to probabilistic is predicated on the increased future uncertainty that impacts so many investment drivers. As its name implies, a probabilistic approach is required to assess and manage uncertainty. The deterministic approach cannot assess the impact of alternative demand scenarios such as can arise from electrification, customer technology uptake etc. The future open-access network will be a platform for trading energy transport, meaning network export capability may be just as important as serving loads. A new approach is needed that can assess the value an investment returns in regard to any network service.

7.4.2 PROBABILISTIC PLANNING: WHERE ARE WE GOING?

In principle, a probabilistic approach analyses the uncertainty or variation in any input driver/parameter of a planning decision and produces a statistical distribution of out-turn costs, risks, or benefits. This is in contrast to a deterministic approach that takes a single representative value for each input variable, which may be a percentile or mean, and produces a single output value.

The term “probabilistic approach” is often more simply interpreted as the application of:

- Generic circuit failure rates.
- Value of lost load (VoLL), associated with likely customer outages.

This is largely the extent of “probabilistic planning” as defined in the “EEA Guide to Security of Supply”. These two aspects have already been introduced to our network planning process.

A full probabilistic approach should also contain the following elements:

- Load profiles and different future growth scenarios.
- Forecast changes because of technology uptake and changing customer use patterns, or political drivers e.g., electrification.
- Failure rates reflecting specific asset performance, and future interventions.

- Consideration of smart grid solutions – automation, dynamic rating, intermittent generation.
- Consistent comparison of non-network solutions alongside network solutions.
- A monetised risk approach supporting future value-based investment frameworks and pricing regimes.
- An assessment of variance (risk) in regard to the out-turn variables, such as costs, benefits, value, and pricing.

Ultimately, a Monte Carlo-type analysis is envisaged to assess the complex interactions of multiple random distributed variables. The analytic platforms, data integration and user applications required to support this will need significant work, but the rapidly changing world of digital technology makes this possible.

Security criteria

The broad security classes within which the deterministic approach groups assets and loads often lead to sub-optimal investment decisions. The probabilistic approach eliminates the need to use prescribed security classes or criteria, as the analysis takes place at a very granular level. Needs, options, and solutions are tailored to the specifics of each case.

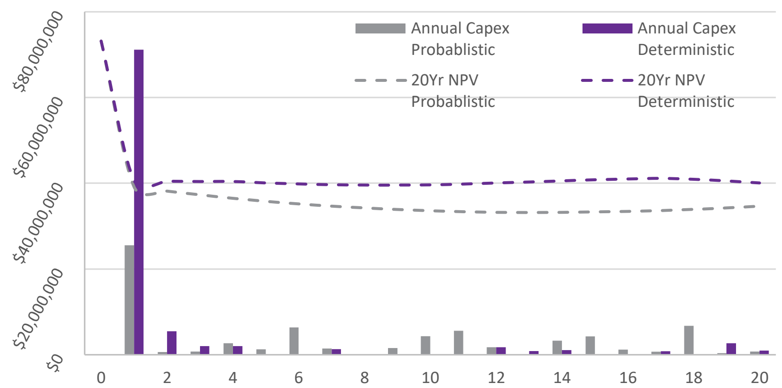
This was already reflected in a new approach introduced for our Customised Price-quality Path (CPP) application. The entire network was analysed against a single contingent event criterion, with the resulting constraint costs ranked by order of risk exposure. This allowed planning to focus on high-risk areas. The planning process then considered options, evaluating the final costs and benefits of the optimum solution, which can be "do nothing" if the value of the problem being resolved exceeds the cost to do so.

While this detailed bespoke method to find solutions was practical for large investments and high-risk situations, it has not, to date, been implementable at lower investment levels.

Investment and risk impacts

Our preliminary analysis suggests that the shift from deterministic to probabilistic planning will see a significant reduction in investment, or investment deferral, for a similar or even improved level of risk. Figure 7.14 demonstrates the outcome of a theoretical application of strict deterministic versus probabilistic approaches to the zone substation power transformers.

Figure 7.14: Potential investment savings from adopting a probabilistic planning approach



Both the approaches reduce risk to a sustainable level with modest subsequent investment to counter growth beyond Year 1. More detailed analysis revealed there were two aspects to the reduced investment under the probabilistic approach:

- Drastically reduced (or deferred) upgrades for "N-1 secured" substations (those previously requiring full redundant backup under the deterministic criteria).
- Increased investment for "N secured" substations (i.e., those with nominally one primary circuit, and limited backup), which previously would not have attracted any consideration as they nominally complied with the deterministic criteria.

Value and risk basis

The probabilistic planning strategy is required to support our investment value framework and our strategy to apply more risk-based asset management. It is also a necessary step on the way to DSO capability.

Our new investment optimisation system requires that the benefits of any investment, on multiple dimensions, are evaluated in equivalent dollar terms for optimisation purposes. For network security investments, VoLL benefits from reduced outages are generally the dominant project benefit. A deterministic approach could not evaluate monetised value.

A further example of better risk-based outcomes is where a high criticality load might be more cost-effectively secured through a targeted smart grid or customer-side solution than a network investment. The value of this can be readily assessed under a probabilistic approach, but not under a deterministic approach.

The capabilities required by a DSO are still being defined, but the monetised constraint costs directly support a marginal pricing system, which is not achievable under the deterministic approach.

7.4.3 PROBABILISTIC PLANNING: HOW WILL WE GET THERE?

7.4.3.1 ANALYSIS AND DECISION-MAKING

We have already introduced the “probability of failure” and “value of lost load” concepts into our planning approach. These are foundational to the value framework now being introduced for investment optimisation.

The longer-term analytic platform and user interfaces (tools, visualisations) we intend to use for our probabilistic modelling and planning are still being evaluated. No single off-the-shelf software platform satisfies all the requirements (power flow analysis, statistical forecasting, and Monte Carlo analysis). We, therefore, plan to develop our own prototypes but will continue to monitor the software landscape and adopt good products as these become available.

Prototype tools have already been developed to jointly consider asset lifecycle renewal alongside network augmentation. The goal is to develop an integrated modelling platform for asset fleet management and network development.

7.4.3.2 DATA MODELS

A probabilistic approach requires considerably greater volumes of data and analysis than our current needs. In future, network performance will need to be modelled over a range of possible demand scenarios and profiles (a time series of demand), to be assessed for every circuit section in a feeder. Modelling the frequency and location of outages needs to be expanded. In addition, the models must reflect the operational response to events (protection systems and operator driven), and the customers’ sensitivity to outages, requiring VoLL or value of customer reliability (VCR) data and load profiles specific to each customer type.

Our plan is to progressively improve the underlying data driving the models. In the interim, we will use generalised assumptions, based on our best knowledge to date.

7.4.4 DEMAND FORECAST METHODOLOGY

We intend to transition our demand forecasting to a probabilistic basis in the near future, as well as forecasting at a much more disaggregated network level (both in time and spatially). To fully implement this will necessitate historical customer demand data, reconciled against normalised network historical load data. These forecast profiles will also be needed for our ADMS system.

We will initially simplify our assumptions, using scenarios to set realistic demand limits at load points. Ultimately, we will seek to transition to full demand probability distributions at these points. We will also seek to integrate the expected changing future demand trends and profiles into our models.

7.4.4.1 VALUE OF CUSTOMER RELIABILITY (VCR)

VCR or VoLL is one of the most important variables used in probabilistic planning. It is dynamic in nature, changing with the time of day, load type, and outage duration. As it is a somewhat abstract concept, it is also one of the hardest parameters to quantify – requiring extensive customer intelligence.

Obtaining quantified data for VoLL/VCR rates should ideally be a cross-industry initiative. We continue to monitor international and national research in this regard but will append surveys of our customers to this research.

Depending on how the DSO concept and distribution pricing models evolve, there may ultimately be a market to directly inform VoLL rates, but this will likely be some time away.

In the meantime, we plan to develop our own customer surveys and commence implementing these during FY24. This is part of our preparations to ensure optimal investment outcomes that will be essential if we are to realistically meet New Zealand’s upcoming decarbonisation needs.

7.4.4.2 NEW CUSTOMER TECHNOLOGY UPTAKE AND DISTRIBUTED ENERGY RESOURCES

Understanding the nature and impact of new technology uptake or customer-side investment on demand profiles is important for probabilistic network planning. We will continue our research into this – it is also a key part of our Network Evolution strategy, described in section 7.2.

This understanding has become particularly critical given the potentially major impact that decarbonising large heat processes will have on electricity demand. As discussed before, it will be imperative that we work closely with customers to achieve optimal energy-efficient and asset-efficient outcomes to achieve the required customer targets at a minimum realistic cost.

Having access to good information on the cost of implementing non-traditional network solutions on the network and customer side is also essential to informing the assessment of investment solutions. Research on this is also ongoing.

7.4.4.3 MODEL AND BUSINESS INTEGRATION

An early required initiative will be to align and integrate our asset and network models.

Asset lifecycle models are effectively probabilistic in nature, using condition and health data to forecast the probability of failure. As networks are made up of individual assets, these forecasts ultimately determine the likely availability of supply.

We have already started to build out a full suite of asset renewal models and plan to integrate these with our enterprise data systems and investment optimisation platform. As we do this, we will look to expand this into our network, vegetation management, and operational models. Effective integration of our models will allow information sharing and support more comprehensive assessments to inform our probabilistic network planning.

Finally, implementing a probabilistic approach will require coordination with a number of other strategic developments across the business:

- Automation, generation, and energy storage.
- Network Evolution strategy.
- Network visibility (i.e., data and monitoring, IoT), especially at LV.
- Open-access networks and cost-reflective pricing.
- Regulatory and political initiatives (electrification, affordability).
- IS, data governance and digital strategies.
- ADMS programme.
- Investment value framework and optimisation platform.
- Criticality framework and asset model development.

7.5 NETWORK AUTOMATION

One of the major benefits associated with developing technology is our increased ability to automate the network. The scope for real-time monitoring and the ability to remotely control “intelligent” network devices is rapidly expanding – facilitated by ever-improving communication networks, metering, and monitoring devices, and the capability of the network assets themselves.

With distributed intelligence and local control, it is also increasingly possible to build autonomous applications on the network – allowing, for example, automatic fault isolation, network islanding, self-restoration, or synchronising adjacent devices to minimise the extent of outages.

All of this can contribute greatly to improved reliability of supply, the effective integration of distributed generation, and improved network and asset utilisation – often in more cost-effective ways than building conventional network extensions.

7.5.1 NETWORK AUTOMATION: WHERE ARE WE NOW?

7.5.1.1 OUR CURRENT NETWORK AUTOMATION STATUS

Automation schemes on our network have been a major contributor to keeping network reliability under control in recent years, in spite of increasing asset failure rates. System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) trends are, therefore, better than what asset performance trends by themselves would suggest. It is one of the most cost-effective ways to manage network reliability.

To date, our automation programme has focused mainly on deploying automated distribution switches and fault indicators. For our radial feeders, which are the bulk of our network, we typically use automatic reclosers and sectionalisers that can isolate a faulted circuit section while maintaining supply to upstream customers. Reclosers briefly interrupt supply to enable downstream sectionalisers to open and isolate a faulted line section, before restoring upstream supply.

Once the protection devices have isolated a faulted area, service crews will typically manually operate switches in the field to restore supply to as many customers as possible, switching around faulted sections, where possible.

These devices have been complemented with fault passage indication, to reduce service providers’ time to locate network faults. Devices placed at nodal points (from which more than one line radiate) on the network visual indicate which spur experienced a fault. For longer circuits, we use fault indicators along the circuit to help pinpoint fault location. Increasingly, we use fault passage indicators that provide remote indication – allowing our controllers to advise service providers more accurately of the fault location as they are dispatched.

In our network's more interconnected (meshed) areas, we have applied a small number of automated restoration schemes (loop automation schemes). This is to provide rapid reconfiguration of the network around faulted sections, maximising the use of available backfeeds. Typically, these schemes consist of a remote-operated switch at the interconnection point and reclosers at feeder mid-points. If a fault is detected in a portion of a feeder, the schemes isolate that section and backfeed the remainder of the feeder. These schemes use a mix of centralised SCADA control and distributed intelligence, using the onboard functionality of the switching devices themselves. To date, the performance of these schemes has been somewhat problematic, as the additional complexity can result in maloperation and misunderstanding of the reasons for operations. This has resulted in trust issues for our NOC staff.

Another focus has been on improving the visibility and operation of expulsion drop out (EDO) fuse operation by the application of ‘fuse saver’ devices designed to clear transient faults. These have proven difficult to deploy in remote rural areas, where fault levels often tend to be too low for the devices to operate effectively.

7.5.1.2 LIMITATIONS AND DRAWBACKS OF OUR CURRENT AUTOMATION

There are a number of areas where we need to improve network automation:

- A major shortfall of our current automation is that it is essentially static. It cannot adequately deal with changing network needs and the challenge of future emerging technologies, such as distributed generation and storage, PV and EV uptake, and the possibility of two-way power flows.
- Opportunities for further deployment of reclosers and sectionalisers on our network is limited. As we attempt to split feeders into even smaller sections, using the protection functions associated with these devices, we encounter

issues with protection grading on circuits. On many feeders, we have effectively reached a limit to the effective number of these devices.

- In evaluating the cost-benefit of automation schemes, we traditionally take a pure SAIDI approach to determining the benefits, based on our deterministic performance targets for various customer groups. This does not accurately reflect the real value of load at risk and, therefore, compromises investment decisions. In addition, faults on LV networks are not factored in at all.
- Manual field-switching exposes our service crews to risks arising from human error, equipment failure during operation, and general environmental impact associated with working during poor weather.

We have been updating our automation strategy to address these shortcomings. In addition, anticipating a changing future, we have undertaken several trials, covering distribution transformer monitoring, power quality monitoring, remote fault locators, communications, and equipment trials. These studies have helped shape our thinking on our future automation plans.

7.5.2 NETWORK AUTOMATION: WHERE ARE WE GOING?

Our Network Evolution roadmap suggests that we will ultimately move to a DSO future, where two-way power flows and the extensive deployment of DER will be the norm. Under these conditions, to keep network operation stable while avoiding excessive reinforcement costs, the ability to closely monitor power flows and performance and to react effectively to rapid changes in demand and generation will be essential. This reaction can include automatic voltage and reactive power management, constraining or enabling energy sources and load, demand management, and the dynamic reconfiguration of the network through remote control.

To meet these challenges, we have taken a wider view of automation, to consider the elements it will take to efficiently and safely manage the network of the future. Generally, it means a greater focus on measuring and monitoring the state of the network and adding increased remote-control capability – centrally controlled or through distributed automation. The main directions we will pursue are summarised below.

- We still have opportunities to expand our current approach to keep improving network reliability and will continue seeking opportunities for further sectionalisers and reclosers. However, we intend to continually increase our ability to remotely operate isolation points, moving away from field-staff intensive operations, initially to a centralised network configuration management. In future, we see increased uptake of distributed automation schemes, requiring no operator intervention.
- An interesting avenue we are pursuing is detecting pre-fault conditions using sensors on our network to pre-empt outages. This development is another key component in addressing network performance.
- With increased network operations visibility and remote operability, our ADMS system will be crucial to our ability to manage our network effectively. As network complexity increases, response requirements will be well beyond the capability of human intervention. Our automation rollout, therefore, aligns closely with our ADMS pathway.
- In addition to the ongoing focus on reliability, we need to consider power quality. As the number of distributed generation sites increases, we expect to see more reactive power flows and excessive voltage excursions on our network. While it is expected that in the main, at least initially, this will impact the LV networks in urban areas, there will likely be larger installations on our rural networks that could also impact our medium voltage (MV) network.
- We intend to increasingly use our LV network for outage support and to reduce loading constraints – this will reduce the need for augmentation on MV networks. Ultimately, we will require control of voltages and reactive power flow on the LV network. That may be through reactive power (Volt/VAR) support, directly or through the control of third-party inverters. Where loading constraints begin to surface through the increased use of, for example, EV charging, demand side management may be required to ensure peaks are effectively minimised. Monitoring, communication systems, data processing and remote controllable device systems on the LV networks will be essential to achieve this.
- To better serve our customers and optimise our investment benefits, a shift from our current pure deterministic-based assessment to a VoLL-based (probabilistic) approach is underway. To inform and prioritise our automation investments, we intend to look more closely at the risk associated with various segments in the network, determining the probability and consequence of failure, and also considering the availability of alternative feeds, distributed generation, energy storage and the like.

7.5.3 NETWORK AUTOMATION: HOW WILL WE GET THERE?

The creation of an open-access network is an essential enabler of a DSO future. To provide customers as much flexibility as possible to manage their energy use or to trade energy over the network, we will have to ensure that network capacity and stability is well managed. This will require increased visibility and operability, particularly on the LV networks.

To make the desired improvements, we initially intend to focus more on remote control operation and monitoring, developing tools to determine the optimal network segregation, understand the real-time state of the network, and remotely reconfigure it. Over the longer term, we will move to increased use of decentralised control systems, truly automating the network.

7.5.3.1 REMOTE CONTROL

Initially targeting existing network intertie points, we propose to significantly increase the number of remote operable switches on the network – overhead and underground. We will initially focus on locations where the value of the load at risk is high and traditional response times are lengthy. Over time we will expand on this by creating additional remote-control points across the network – where cost-benefit analysis supports this.

We intend to continue developing assessment tools that support improved understanding of the reach, benefit, and cost of interventions.

7.5.3.2 URBAN NETWORKS

For our denser urban and suburban networks, we are adding sectionalisation through retrofits to our existing distribution overhead and ground-mounted switchgear. This allows for both remote operation and increased fault passage indication, with the goal to restore supply around a faulted section within one minute. We will continue to target existing tie points and strategic nodes in the network, before moving to increased sectionalisation through additional control points over time.

For our urban LV networks, we will initially continue to focus on monitoring as a means to understand the impact of emerging energy use patterns. Over time we will expand our automation portfolio to include automated Volt/VAR control and remote switching capability. The intent is to be able to manage quality and performance on our LV network as we would for our MV network.

7.5.3.3 RURAL NETWORKS

Our rural networks are a mixture of mesh and, mostly, radial configurations. For these feeders, we will prioritise automation of locations that deliver the highest value outcomes based on the value of the load at risk and the probability of faults occurring. For the meshed sections, we will supplement the remote control with voltage and current monitoring, allowing us to safely maximise backfeed potential. For radial feeders, we will look to increase the visibility of the operation of protective devices, using a combination of end-of-line voltage monitoring and fault passage indication, and replacing fuses with electronic equivalents where practical.

7.5.3.4 REMOTE RURAL NETWORKS

For our more remote fringe networks, which tend to consist almost completely of radial feeders, monitoring and fault location are the main automation focus. For these areas, we will continue to roll out remote-readable fault passage indication and end-of-line monitoring, along with additional protection devices to better detect high-impedance faults. For isolated communities, we plan to improve resilience and reliability through remote generation and storage options – refer to the Generation and Energy Storage strategy discussed in Section 7.7.

7.5.3.5 DYNAMIC ASSET RATINGS

In areas of our networks where load growth is uncertain or very low, or where network capacity is generally sufficient other than during relatively short peak demand times, network upgrades are difficult to economically justify. In these situations, it is valuable to extract as much capacity from existing assets as possible – balancing this with the risk implications. An often-effective means to increase available asset capacity is by using dynamic asset ratings. This generally means that actual operating and asset status conditions are considered to determine the actual asset capacity in real-time, as opposed to creating static operating limits based on capacity determined for generalised, worst-case assumed operating conditions.

To apply dynamic ratings, we need to be able to monitor real-time conditions, such as temperature, windspeed, voltages and currents. To achieve this, we intend installing additional remote monitors and weather stations, integrating these with our remote-control switching devices where possible.

7.5.3.6 FAULT ANTICIPATION

Preventing faults from occurring in the first place is the key to long-term reliability and customer satisfaction. Many faults, such as failed insulators or vegetation faults, tend to manifest over time, starting out as a power quality issue before developing into a hard fault that activates protection devices and results in an outage. By analysing the voltage and current waveforms, it is often possible to detect fault signatures and address the issue ahead of a loss of supply. Part of our strategy is to implement pre-fault monitoring at our substations.

We are trialling both generic power quality monitoring as well as AI-based (artificial intelligence) systems that utilise a multi-user database to match waveform abnormalities to known fault causes and indicate probable fault types and probable location. We also want to leverage the pre-fault information collected from our existing protection relays to detect issues worthy of further investigation.

7.5.3.7 DEMAND SIDE MANAGEMENT

As we see increased uptake of distributed generation and EV charging, we expect to see an increase in network constraints. Although our initial focus will be on monitoring power quality, augmenting network capacity or curtailing load or generation will likely become ultimately necessary. Managed curtailment[50] can be

50 Network capacity is often only insufficient for a small proportion of the time, so the need for curtailment is often very limited.

the most economical solution, as long as the probability and extent of this is transparent and pre-agreed with customers, who can then choose to accept this or contribute to the cost of augmenting the network.

Besides working with customers on optimal solutions, we intend to work with the industry to ensure that new energy resources can react to constraint signals issued by networks.

7.5.3.8 DATA SUPPORT AND ANALYSIS

Our future automation approach will require intensive data analysis, based on a comprehensive network model.

We intend to apply solutions based on feeder topography, tailoring solutions to match the interconnectivity of the feeders and the value of load at risk. We will use a common criticality framework to enable us to consistently evaluate automation responses in comparison with other capital works solutions. This will be integrated with our Copperleaf investment optimisation tool, to direct our spend to the optimal projects and enable us to more accurately predict the benefits of an individual automation project.

Over time, we will continue to improve our network model and asset information. An important part of this will be to compare the actual out-turn results of investments with the initial planning assumptions and using this feedback to tune our approach.

We also intend to integrate all the available information from around the network to present a more holistic view of what is happening and improve our modelling with this information.

7.6 ADAPTING THE NETWORK FOR CLIMATE CHANGE

7.6.1 OVERVIEW

As a critical infrastructure owner, Powerco needs to ensure that it has the capability to meet its customers' needs now and in the future. During the next 12 months, we will update our initial climate hazards assessment conducted in 2020 and further embed this in our operational planning. This will involve a process of developing plausible scenarios to test Powerco's strategy against short, medium, and long-term transitional and physical drivers. These scenarios will then be used as a basis for further testing of the specific risks and opportunities for our future investment and operations plans. In addition, we will be completing a resilience maturity assessment to better understand areas of resilience planning that can be improved.

New Zealand is already feeling the impacts of climate change and the effects of climate change can already be seen globally through:

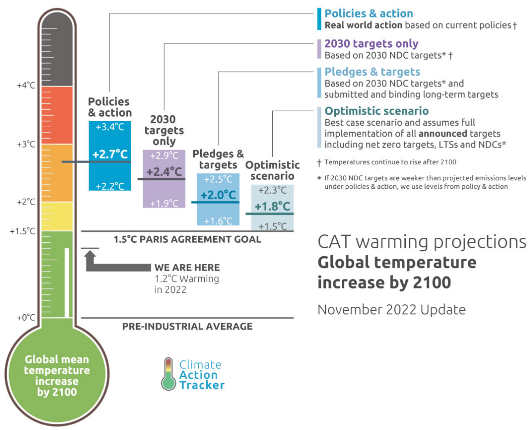
- Sea level rise.
- Increased wind velocity and frequency.
- Extreme weather magnitude and frequency.
- Seasonal changes – fewer frost and snow days.
- Drought events – increased severity and frequency.
- Wildfire events – increased severity and frequency.

Planning for physical climate change risk is different to traditional risk management in that the planning horizons are typically longer term and there are currently significant uncertainties regarding the impact and timing of climate change. In addition, the impacts extend beyond the immediate physical risk to assets and spread organisation wide. Therefore, we need to understand our exposure and vulnerability to transitional risks, as we aspire to transition to a lower-carbon world.

Several representative concentration pathways (RCP) forecasts have been adopted by the Intergovernmental Panel on Climate Change (IPCC) that consider a range of possible greenhouse gas concentration trajectories (pathways). The impacts from climate change will most likely be dependent on which RCP eventuates. By understanding the impact across several pathways, Powerco can then identify which areas or activities need to be prioritised.

Because of the long service life of some of our assets, consideration needs to be given now to the future risk posed by climate change. By having a thorough understanding of the exposure and vulnerability of the respective risks, better outcomes can be planned for. Including climate resilience planning in our business processes will help us incorporate a more proactive, efficient, and considered approach in our asset management framework.

Figure 7.15: Climate Action Tracker indicating global temperature increase by 2100[51]



7.6.2 NETWORK CLIMATE CHANGE RESPONSE: WHERE ARE WE NOW?

In 2020, Powerco engaged specialist climate change consultant Tonkin and Taylor to conduct a climate change vulnerability assessment. High-level maps of projected climate change hazards, such as coastal inundation and coastal erosion, caused by sea level rise were overlaid on maps of Powerco assets to determine the type and number of assets exposed to each hazard. This initial assessment provided the foundation for the subsequent work that has gone on to further develop our Geographical Information System (GIS) to understand our risk exposure to flooding and coastal inundation.

Our asset and design standards are based on our historical experience of climatic events on the various parts of our network. While these include significant safety margins, they assume that climate patterns will remain constant. The scenarios we are conducting will provide Powerco with a common narrative across the business that can be used to set the context for understanding the risk to our assets under the different RCPs. This in turn will enable us to understand the possible future operating environment for our assets and determine what changes need to be made to our design and planning standards.

7.6.3 NETWORK CLIMATE CHANGE RESPONSE: WHERE ARE WE GOING?

The most efficient way to incorporate climate adaption or resilience is to include it into our design standards, so that resilience and climate adaption planning is “baked in” to our asset management approach and is not a separate undertaking or consideration. The initial work completed in 2020 provided a high-level overview of where our assets may be exposed. The next tranche of work will be to better understand the risks, and what the best approach is to mitigate these risks.

To determine this approach, we need to understand not just our exposure, but also how vulnerable we are to climate change risks. Once this has been established our standards can be reviewed to ensure that our network meets our needs now and in the future.

Having the capability to present climate risk information spatially will be essential to enable effective resilience management and we will be investigating what platform will be best suited to present the information that will add value to the organisation.

An example is shown in Figure 7.16.

Figure 7.16: Visualisation of Powerco asset exposure to flooding hazard extent in Taranaki

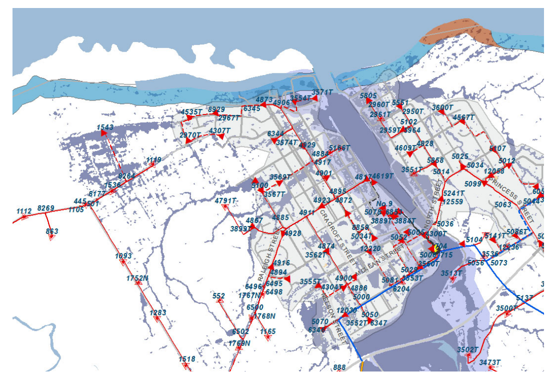


Table 7.2 shows the current adaptation strategies considered by Powerco. These range from ‘do nothing’ for assets that are not materially affected by climate change, to proactive intervention where action is required now. By and large, the most

[51] Source: New Zealand Sea Rise https://climateactiontracker.org/global/cat-thermometer/

applicable adaptation strategy is organic adaptation, where assets are replaced at the end of their current useful life with alternatives that have designs and specifications adapted to cater for changing climate and environment.

Table 7.2: Powerco's climate change adaptation strategies

STRATEGY	DESCRIPTION
Do nothing	Climate change is not considered a threat to this asset class.
Organic	The rate of renewal through age or condition is sufficient to allow adaptation with minor evolutionary changes to asset specifications that marginally affect costs.
Proactive	Climate change-related threats require proactive action in the near-term future.
Remediation	The asset is at risk. Improvements can be justified against current climate conditions.
Redevelopment	While climate change drivers may not render the asset unsuitable, land use or other public infrastructure changes may drive the need to replace the asset. For example, road raising, or relocation works to allow for adaptation to sea level rise.

Our assessment is that organic adaptation strategies will, in general, require some changes in equipment specifications – see Figure 7.17 as an example. This could result in a modest increase in asset replacement costs (<10%). In some cases, new assets may need to be relocated, resulting in significantly higher renewal costs. We will continue to liaise with other infrastructure providers to ensure that our work is coordinated with other climate-related infrastructure investments.

Figure 7.17: Example of organic adaptation. Standard LV pillars (left) are vulnerable to coastal inundation as they are not waterproof. A newer submersible design (shown right).

7.6.4 NETWORK CLIMATE CHANGE RESPONSE: HOW WE WILL GET THERE?

As noted above, we prefer to incorporate climate adaptation needs into our business-as-usual processes and not be a separate undertaking. By being proactive and understanding the risk exposure to our assets we can optimise the mitigation. During this period, we plan to undertake the following actions:

- Further develop our climate change hazard maps based on projections of climate change variables. This will be used to identify potential asset exposure as part of the asset planning process. Exposure maps will also identify exposed and vulnerable assets for interventions.
- Progressively review and, where necessary, revise equipment specifications, standards, and designs to accommodate projected climate change impacts.
- Utilise new equipment specifications, standards and designs in capital and maintenance works processes.
- Develop a spatial platform to visually present climate risk exposure to facilitate risk mitigation.

7.7 GENERATION AND ENERGY STORAGE

7.7.1 WHERE ARE WE NOW?

Our traditional deterministic planning approach tends to result in black-and-white outcomes – we either meet our deterministic threshold or we don't. If it is the latter, we look at long-term solutions to achieve the threshold and rank those based on the benefits they deliver for the cost incurred. Partial solutions or solutions that target high-value load over low-value are not effectively considered.

Traditionally, we build and upgrade lines or substations to meet growth and security requirements. Where capacity is constrained, we revert to bigger or more wires and cables. This is a long-term, costly solution with a risk of at least initial under-utilisation, which in situations with peaky loads may persist into the future. Assets could become stranded when demand growth does not eventuate or reduces, or where energy use patterns change.

In addition, land/route acquisition and consenting can take several years, which does not support meeting more rapidly changing customer needs.

While conventional network solutions are still appropriate for most required network augmentations or renewals, particularly on the more energy-dense part of our networks, there are many cases where the construction of new circuits is prohibitively expensive and not economically viable based on lifecycle considerations, or where there is too much uncertainty to support major long-term investments. This is especially true for remote communities, supplied by single circuits over long distances in often rugged terrain or ecologically sensitive areas. Areas with highly peaky loads, where we have to provide capacity that may be required only for short periods during the year, also pose economic challenges.

For these areas, generation and energy storage can provide viable alternatives – not only being more cost-effective but also providing options for future redeployment or scaling. This allows (expensive) permanent solutions to be deferred until we have more certainty that energy demand would justify these.

We have trialled this approach in areas such as Whangamatā, focusing on maintaining supply to the town's commercial hub through a hybrid Battery Energy Storage System (BESS) and traditional generation.

7.7.2 GENERATION AND ENERGY STORAGE: WHERE ARE WE GOING?

Those parts of our network where upgrades by conventional network means are uneconomical, or where we have significant uncertainty of future energy demand, often lend themselves to generation and storage options. The ability for periodical peak lopping is often sufficient to avoid other upgrades or to defer these for extended periods[52].

We propose to apply more non-network solutions, particularly large generation – with or without storage – to these areas. Benefits include:

- **Modular rollout** – the solution can be sized to match the immediate problem.
- **Faster response** – reduced property and consenting delays compared with new line and substation builds.
- **Relocatable** – we are able to uplift and redeploy assets if demand patterns change again.
- **Economical** – these solutions generally provide a lower up-front cost option.
- **Scalable** – we can add or subtract generation and storage to match changes in loads, resulting in minimal stranded assets.

Short-term solutions provide future option values, allowing us more time to better understand and influence longer-term customer behaviour before committing to major investments. This will support initiatives such as demand side management, incentivising beyond-the-meter energy storage or generation, and energy efficiency drives etc to offset demand growth.

Storage and generation can be applied modularly to match the ongoing shortfall increases. Where growth continues, this allows time to implement more traditional network enhancement and to redeploy generators/storage elsewhere.

We expect that some demand management will occur naturally on the customer side, as battery and PV costs decline, and energy efficiency is better managed. We could support or accelerate this through cost-reflective pricing signals, or through directly supporting demand side management solutions.

Ultimately, as large-scale energy storage costs reduce, the focus could be on replacing generation with storage.

7.7.3 GENERATION AND ENERGY STORAGE: HOW WILL WE GET THERE?

We intend to increase the application of generation and storage solutions, making this part of our inventory of network solutions. With the intended introduction of probabilistic planning assessments in future, using VoLL as the key measure of consequence, such non-conventional solutions can be appropriately evaluated alongside our more traditional approaches.

These solutions will be especially targeted at areas of our network where an alternative supply either cannot be economically justified or where unserved demand peaks only persist for short periods. We will also target areas where longer-term future growth is uncertain, and peak loads cannot be met without costly

52 Note that generation or storage solutions are generally not well suited to applications with extended peak demand periods.

upgrades. In these cases, we will use generation and storage as a deferral to traditional upgrades, providing time to gain certainty of growth or to give us time to plan our traditional upgrades. This will include areas where we have previously considered traditional solutions to be uneconomical and not worthy of further investigation, such as remote rural and beachside communities at the end of lengthy subtransmission and distribution lines.

Generation is initially likely predominantly diesel-based – this is by far the most reliable and cheapest option available. However, as renewable energy technology improves and battery storage costs decline, we will progressively work to replace diesel generation with greener alternatives. In the interim, to mitigate the environmental impact of diesel generation, we are investigating options for biofuel. We also note that the intended use of these devices is for short periods only – often as a stand-in in case of primary network outages. This means that overall emissions will mostly be very low, especially when compared with that manufacturing and building lines and substations.

In the longer term, we will look to encourage load management schemes and beyond-the-meter (customer-owned) energy solutions to reduce demand within current network capabilities, ultimately negating the need for generation altogether.

To assist us in choosing the appropriate areas to target, we are developing spatial analytics tools to help bring those opportunities to the fore.

Table 7.3: Generation and storage use cases

USE CASE	CUSTOMER/NETWORK BENEFIT	APPLICABLE SITUATIONS
Peak lopping	Reduce peaks to remove thermal capacity constraints on existing network assets; avoid or defer expensive network asset upgrades. Immediate reliability and resilience benefits.	Infrequent short-duration peak loads exceed network capability. Could be on subtransmission or the distribution networks.
Peak lopping (abnormal state)	Reducing peaks to remove thermal capacity constraints when the network is reconfigured following a fault. Avoids expensive network upgrades.	Where subtransmission and/or zone substation security of supply criteria is exceeded or where distribution backfeed is insufficient.
Voltage support (steady state)	Reduce peaks to ensure regulatory voltage levels are met. Avoid expensive network upgrades.	Infrequent short-duration peak loads exceed network capability. Could be on subtransmission or the distribution networks.
Voltage support (abnormal state)	Providing voltage support when the network is reconfigured to support a faulted section. Avoids expensive network asset upgrades.	Infrequent short-duration peak loads exceed network capability. Could be on subtransmission or the distribution networks.
Islanding	Creating an independent island supplied from distributed generation enables the restoration of supply to remote parts of the network while the upstream fault is repaired. Also enables upstream assets to be isolated for renewals or maintenance with minimal interruption.	Areas where the ICP clusters are reasonably condensed, at the ends of long overhead lines, vulnerable to outages with little or no alternative supply.
Maintenance support	Enabling the connection of generation to support the network while undertaking maintenance activities reduces the impact of planned outages on our customers.	Locations where regular out-of-service maintenance is required on assets where alternative supply is unavailable or limited. For example, single bank substations.

7.8 LV TRANSFORMATION OVERVIEW

7.8.1 OVERVIEW

Our LV network (<= 400V) is where the large majority of our customers connect to the electricity network. Traditionally, this network has been somewhat out of sight, as it was built robustly, in a set-and-forget manner with substantial capacity, and purely intended to deliver electricity to the end-user. Reliability measures also ignore outages on the LV networks, so there was limited incentive to focus on its performance[53]. This simple, economic approach has generally served New Zealand well.

This is now changing. As we move to a future of increasing DER, active customer participation in energy markets and an expected major rise in electricity use, we expect to see LV networks pushed well beyond operating design limits. If not addressed, this will lead to major power quality problems and, increasingly, an inability to meet customers' peak load.

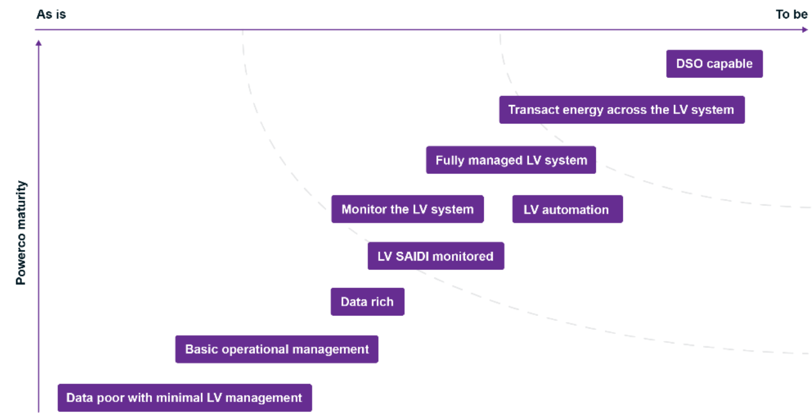
The LV network is therefore set to be a key component for meeting the needs of the changing energy environment and our aim of achieving an open-access network and supporting flexibility services. If we are to realise our goal, we must be able to administer, monitor and operate in real-time, the entire distribution network, including the LV system.

Our vision to get the best out of the LV distribution network will require us to move to a fully administered LV system. We see this happening over at least a 10-year period, with the initial focus on areas with likely early congestion or power quality issues, then expanding to the higher energy usage or energy value parts of the network, and eventually covering the remainder as well.

A synopsis of LV change for the next 10 years can be seen in Figure 7.18.

[53] This is despite the fact that from a customer's perspective, there is no discernible difference in outages arising from faults on the LV network or the higher voltage networks.

Figure 7.18: 10-year LV network evolution roadmap



7.8.2 LV NETWORKS: WHERE ARE WE NOW?

Background

Given the set-and-forget nature of LV network design and build, and the relative limited attention to its performance, there has been a deterioration of LV asset information over time. This contributes to an even more reactive management approach to the LV system.

The lack of LV performance monitoring also impacts negatively on using the LV network to improve network operations. Parts of our LV networks were initially constructed with interconnectivity to enable isolation and backfeeding around faulted sections. More modern LV networks broadly do not have these features. However, even where some flexibility was designed into networks, this was not done with rapid response or safe operation in mind. Many areas were simple bolted connections, which are unsafe to operate by today's standards. This has reduced our reliance on using these interconnections, leading to a deterioration in the condition, operational capability and network knowledge of these connection and isolation points.

LV records have further deteriorated, as we have lost the direct interface with our customers after the Electricity Industry Reforms Act of 1998. Our lack of a perceived need for the information meant a steady decline of accurate records and knowledge.

Operations

The LV network comprises about 38% of the entire electricity network – a complex interconnected component of the distribution system that is designed to provide high levels of supply security to commercial and residential areas under traditional consumption conditions.

The LV system was designed with consideration of known appliances for the time before DER were practical options. High-capacity EV chargers, solar PV or energy storage was not envisaged and high uptake rates of these will often lead to load constraints or power quality issues.

From an information system perspective, our ICP connectivity diagrams broadly stop at the distribution transformer. Actual connectivity to LV feeders, particularly the phase connections, is not captured. This poses a significant limitation to facilitating customer management for outages or for detailed power system analysis. Management of LV networks also does not employ a systematic criticality approach, largely because of incomplete connection data.

Monitoring

Based on forecast uptake rates of EVs and DER, we expect some early signs of stress within parts of the LV network to occur in the second half of this decade. However, at present, we can only surmise transformer loads based on thermal maximum demand indicator (MDI) readings where available or loading calculations around the number of connected ICPs. This has occasionally led to solar (voltage) or loading violation, which we have had to manage reactively.

The LV system has little or no real-time monitoring. Network operations and investment planning are both blind to possible latent voltage and capacity issues in the LV system, being only able to reactively respond to customer complaints.

The lack of monitoring means it is suspected there are occasions when LV voltage limits are being exceeded which, while not causing issues for customers, is outside legislative voltage criteria.

7.8.3 LV NETWORKS: WHERE ARE WE GOING?

The industry and regulator are both working towards including LV reliability in the compliance framework. This reflects a growing awareness that the LV system is the essential interface with the customer, and also that customers do not differentiate between outages arising from higher or lower voltage networks.

A fully transparent and managed LV system is a key requirement for our transition to a DSO future. The LV network will take on increased importance as our customers connect new devices and interact with a more open energy market future.

We anticipate EV or solar growth will occur in urban clusters and require attention within a few years, followed by an uptake across most of the urban network. Monitoring will be a key capability if we are to actively manage PV/EV issues.

However, it will take several years to prepare the network to be fully monitored and capable of managing load and quality to the ICP level. We are expecting to target investment to enable monitoring of the highest-risk parts of the network first.

We want to ensure that our operations and planning align with our customer needs. This means taking account of outages and performance on our LV network in the same way we would our HV networks. This would also require a better understanding of our LV system to proactively plan and invest in the LV network.

In short, we want to get back to operating our LV as a network.

As a principle, Powerco is seeking to make the best use of LV assets through the operation and monitoring of the LV network. This can be interpreted as:

- Making use of LV distribution to provide continuity of supply for customers during planned or unplanned outages.
- Configuring the LV distribution system to maintain supply quality.
- Facilitating PV owner connection and EV connection without undue cost, yet allowing customers to reach the potential of their connected assets.
- Enabling the distribution system for future evolution by installing end-of-line LV monitoring to fully administer the last mile of LV distribution.
- Real-time management of power flow through the LV system.
- Optimised, both in scale and timing, LV network investment, balancing costs against future service level expectations.
- Identifying high-value distribution transformer assets that supply dense ICP locations or high-value CBD load.
- Measuring each LV circuit load, power quality and voltages at chosen transformer locations.
- Measuring mid and end-point circuit load, power quality and voltages for each LV (monitored) circuit.
- Working to obtain customer metering (AMI) data.
- Developing an analytics capability that can identify LV network congestion, imbalance, and power quality violations.
- Real-time management of power quality.
- Enhancing our customer provision by maximising asset utilisation.
- Preparing for active load and DER management.
- Monitoring LV SAIDI.

7.8.4 LV NETWORKS: HOW WILL WE GET THERE?

7.8.4.1 BETTER MONITORING

We have installed about 65 monitoring devices to a broad cross-section of overhead and ground-mounted distribution transformers, monitoring the transformer LV terminals only.

We are planning to deploy a further 430 multi-channel monitors to the LV distribution frames of our larger residential or commercial transformers in the New Plymouth, Tauranga, and Palmerston North CBDs. This will provide us with a good sample understanding of what load and power quality we have at an individual LV feeder level.

Monitoring devices will help us understand load density, congestion, and imbalance to the lowest level of our network. Deployment of monitoring will be prioritised by ICP density and commercial loading. In general, we will build out monitoring capability as follows:

Urban network

- We will monitor all LV circuits at transformer sites of 200kVA and above.
- In future phases, we will deploy monitoring at mid and end points of each major LV circuit and at smaller transformers.
- We will seek to obtain customer metering data, or data from other intelligent devices connected to the network, for example, inverters from battery storage or solar PV units. This data will be integrated into our monitoring system and will, ideally, reduce the extent of our required roll-out.

Rural network

- We will deploy monitoring along the main HV lines at periodic transformers, monitoring the transformer bushings only.
- We will deploy monitoring at the end transformer of extended HV spur lines, monitoring the transformer bushings only.

Further out, we intend to expand the programme to about 3,000 monitoring units per year. By the end of the AMP period (2033), we will have coverage of all our major transformers and partial coverage of all major LV feeders.

7.8.4.2 BETTER INFORMATION MANAGEMENT

We are well advanced on a programme of data gathering and labelling of LV assets. To date, about 75% of all LV assets have been surveyed and labelled. We anticipate the remaining programme of work to take a further two years which will provide us with an improved LV connectivity model. Further work is required during this programme to assign ICPs to the lowest labelled LV asset that allows tracing from any ICP through the connected assets.

It is also our intent to develop a detailed electrical model of our LV network during the next two years. This, combined with increased information on LV network use from the LV monitoring roll-out, is required to allow us to accurately analyse the network and detect where congestion or power quality issues are likely to emerge. In turn, that will enhance our ability to plan for LV reinforcements, to accurately budget for these, or to identify where we need to focus on non-network alternatives to avoid congestion.

To properly administer the LV network, we must develop new tools and systems to support field staff and engineering staff to get the best out of the LV distribution system. This means:

- Accelerating the existing programme of LV asset labelling and circuit tracing to update our GIS records and provide a reference and connectivity view of the LV reticulation system.
- We will need to develop modelling and analytical capability to analyse the large amounts of information that monitoring and AMI sources will produce. This will be an essential tool for the management of congestion.
- We will develop our SCADA and connectivity models that identify each component of the LV distribution system. This will be an essential tool for field and engineering staff to plan and manage the LV asset.
- In developing our SCADA system, it is also essential that we create a mobility function so that field staff can utilise the information in real-time. This will be a component part of our ADMS project.
- Our current plan is for data for these devices to be replicated within our historian systems for analysis. However, this will be reviewed to make sure we adopt the most efficient, lowest-cost solution that can effectively accommodate and manage the vastly increasing volumes of network data anticipated in the future.
- We will automate analytics to review LV data and alert us of any quality of supply issues. Currently, this can only be done manually.

7.8.4.3 BETTER COMMUNICATION SYSTEMS

Monitoring has been achieved by utilising cellular communication systems to recover information. This limits monitoring of the LV distribution system to where there is reasonable cellular coverage. This is appropriate for higher-population areas or CBD locations.

However, as part of extending monitoring of the LV system, we are rolling out LoRaWAN technology for communications – a network of LoRaWAN gateways around our Packet Transfer Network system. This network is intended to provide ubiquitous coverage on all parts of our network and is currently about 50% rolled out.

A secondary benefit being explored is whether we are able to use the same LV monitoring technology to detect HV lines down. Moving to a long-range communication system will enable more rural deployment of sensors and thereby increase our capability to detect lines down across the network.

7.8.4.4 BETTER ASSET PLANNING

Increased visibility will enable us to see where LV networks may be inadequate in future, help us get ahead of problems as they manifest and, ultimately, provide a basis for accurate forward planning.

It will improve the quality of service and safety of our customers, supporting this with new procedures and improved records to ensure we can operate safely and efficiently. Over time, we will add more operable connection points to facilitate more granular sectionalising and load transfer, ultimately automating these points and integrating them into an ADMS system.

We will carry out LV upgrades, initially to ensure we meet appropriate quality thresholds, but over time upgrades will be needed to cope with the additional impacts of distributed generation and EVs on the network. This will include upgrading cables and adding new technology, such as voltage and reactive power control to address the additional issues arising from distributed generation and storage.

We are establishing an investment strategy that accelerates key LV investment to facilitate increased operation of the LV distribution network. Such as:

- A programme of replacing underground link box equipment.
- A programme of replacing J-type fuse installations.
- A programme of replacing older street link/switch equipment.
- A programme of adding operable link and switch equipment to the overhead LV network.

Some preliminary analysis of LV monitoring data and circuit connectivity indicates that a targeted approach of investment is required where high impact, lost load and high ICP density can benefit from LV investment strategies.

A shift in focus of our network development expenditure allowance from HV to LV assets will be reactive initially but will be informed by detailed forecasting and analysis in the future.

8.1 CHAPTER OVERVIEW

This chapter sets out our Network Targets for the planning period, as well as our historical performance against these targets. We use these to gauge our performance 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. It also serves to provide an early indication of areas requiring intervention.

Our plans and strategies outlined in this Asset Management Plan (AMP) are focused to help deliver and achieve these targets.

8.2 SAFETY AND ENVIRONMENT

8.2.1 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.

8.2.2 TARGETS

Table 8.1 lists the targets we have set ourselves to monitor performance for Safety and Environment objectives. Table 8.2 outlines the rationale behind the targets.

Table 8.1: Safety and Environment targets

INDICATOR	FY21		FY22		FY23		FY24
Safety	**Target**	**Actual**	**Target**	**Actual**	**Target**	**Actual**	**Target**
Total Recordable Incident Frequency Rate (TRIFR) per million hours worked	12.33	9.01	12.33	11.24	8.06	TBA	TBA
High Potential Incidents (HPI) containment actions completed in seven days	100%	100%	100%	100%	100%	TBA	TBA
Response time to emergency electrical calls – arrive on site within 60 minutes	90%	91.3%	90%	87.0%	90%	TBA	TBA
Learning teams initiated	3	3	3	3	N/A[71]		N/A

ENVIRONMENT	FY19 ACTUAL	FY20 ACTUAL	TARGET	FY22
Major or higher consequence environmental incidents investigated using Incident Cause Analysis Method (ICAM)	No major or higher consequence incidents occurred in period	No major or higher consequence incidents occurred in period	100%	No major or higher consequence incidents occurred in period.
IS0 14001:2015	Certified	Certification withdrawn	Certification by FY22	Certified in FY21 and maintained in FY22.
Environmental improvements	86% achieved	82% achieved		64% achieved. Good progress was made in the areas of compliance management and valuable insights into the effectiveness of our environmental management system gained. Increasing environmental awareness and responsibilities is currently a focus.
SF_6 (sulphur hexafluoride) leak rate (% of stock)	0.13%	0.01%	<2%	0.18%
Offsetting target carbon emissions at 2030 (Scope 1 and 2 excluding line losses)	886.83tCO_{2e}	855.09tCO_{2e}	Reduce and offset target emissions by 2030	1,293.7 tCO_{2e}

LEGISLATIVE COMPLIANCE	FY19 ACTUAL	FY20 ACTUAL	TARGET	FY22
Legislative non-conformances	n/a	n/a	0	0

[71] Learning teams did not have a target for the Board in FY23, but one was set up in compliance with the HSEQ tactical plan.

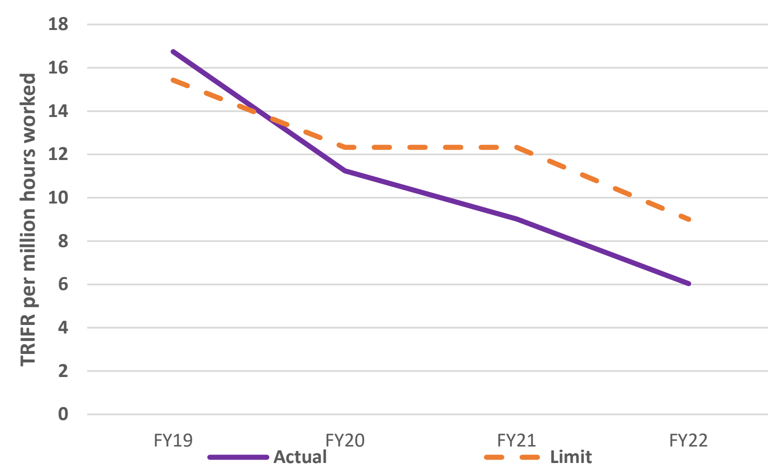
Table 8.2: Safety and Environment target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
SAFETY	
Our targets have been set to reflect progressive reduction of harm over time and to measure the processes that drive harm reduction. We aim to create an environment where we learn from our success in order to replicate it, and act quickly to prevent incidents from occurring or reoccurring to protect workers and the public. Swift completion of incident actions and consistent emergency response time allow Powerco to ensure we create a safe operating environment.	TRIFR is our primary lagging indicator. Section 8.2.3 outlines our improving trend in this area. We are also measuring a series of leading indicators (i.e., HPI, response times and learning teams), and are making ongoing improvements to our safety processes.
ENVIRONMENT	
We have set targets that seek to decrease our environmental footprint and that align with the material sustainability issues identified by our stakeholders. We have publicly reported on our greenhouse gas emissions for the first time in FY20 and this is available on our website[72]. We have set a net-zero at 2030 emissions target for scope one and two emission sources[73]. Our net-zero road map is under development.	In FY20, a small number of issues relating to compliance obligations and document management were identified during an ISO: 14001 audit. We were, therefore, unable to maintain certification in FY20 and this is reflected in our environmental programme delivery being below 90% for FY19 and FY20. We were recertified in FY22. Our SF_6 losses remain well below 1% of total holdings.
LEGISLATIVE COMPLIANCE	
We undertake a legal compliance programme to assure we are meeting our legal obligations. We are committed to: – Identifying our legal obligations and risks. – Ensuring our people are clear about what the law requires. – Tracking compliance against obligations and resolving outstanding risks.	Regular surveys help us better understand, monitor, and report on our legal compliance obligations and risks, and track the resolution of those risks. There have been no breaches to date that we are aware of.

8.2.3 HISTORICAL TRENDS

The TRIFR per million hours worked is a standardised measure of the rate of health and safety incidents occurring during work completed on the Powerco network. The initiatives implemented during the past five years have resulted in a steady rate of decline from FY18 to FY22.

Figure 8.1: Total Recordable Incident Frequency Rate (TRIFR) trend



8.3 CUSTOMERS AND COMMUNITY

8.3.1 OVERVIEW

The Customers and Community targets are measures aligned with our Customers and Community Asset Management Objective outlined in Chapter 5. They demonstrate our focus on customer service and ensuring the customer voice is heard in our planning and delivery processes.

The Default Price-quality Path (DPP) imposes separate planned and unplanned quality standards (System Average Interruption Duration Index – SAIDI and System Average Interruption Frequency Index – SAIFI). This section sets out the specific targets we have set ourselves for customers and communities during the planning

72 Sustainability at Powerco – https://indd.adobe.com/view/6b1d988f-ddc6-4e53-83cf-5a25a1bb1ae3

73 Excluding emissions associated with network line and pipe losses.

period, and the DPP targets set by the Commerce Commission. We also consider the basis for these targets and our historical performance against these targets.

8.3.2 TARGETS

Table 8.3 lists the targets we monitor when assessing how well we are serving our customers and communities. (Note that the SAIDI/SAIFI targets are as set by the Commission in their DPP decision.) Table 8.4 outlines the rationale behind the targets.

Table 8.3: Customers and Community targets

INDICATOR	FY21		FY22		FY23	FY24	FY25
	Target	Actual result	Target	Actual result	Target	Target	Target
UNPLANNED SAIDI							
Cap/Limit	183.5		179.7		175.9	180.25	180.25
Target	162.5	168.9	159.1	201.1	155.8	151.96	151.96
Collar	141.6		138.6		135.7	NA	NA
UNPLANNED SAIFI							
Cap/Limit	2.24		2.22		2.19	2.26	2.26
Target	2.07	1.83	2.05	2.025	2.03	NA	NA
Collar	1.91		1.89		1.87	NA	NA

INDICATOR		FY20		FY21		FY22	FY23	FY24
Customer engagement		**Target**	**Actual**	**Target**	**Actual**	**Actual**	**Actual**	**Target**
Percentage of customers satisfied or very satisfied:								
I.	**Overall satisfaction**	N/A	N/A	N/A	N/A	43%	48%	53%
II.	**Reliability of service**	N/A	N/A	N/A	N/A	60%	62%	64%
III.	**Customer service**	N/A	N/A	N/A	N/A	57%	65%	70%
IV.	**Brand and reputation**	N/A	N/A	N/A	N/A	31%	36%	45%
Percentage of major projects ($5m>) where community consultation is undertaken		N/A	55%	N/A	60%	80%	100%	100%

Table 8.4: Customers and Community target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
CUSTOMER ENGAGEMENT	
Network-related customer-initiated complaints help us to understand customer satisfaction of network performance beyond the duration frequency of outages. Community engagement for major projects has planning and implementation benefits for both communities and Powerco. Understanding the needs and expectations of communities is an essential input for network planning and the delivery of our work.	Despite annually increasing Installation Control Point (ICP) numbers and improved complaint capture channels, complaints have decreased. Engagement was targeted at projects identified as having high implementation impacts on communities. Seeking broader input on project planning and delivery is driving an increase in engagement. Engagement that influences network decision-making has not been previously tracked as a subset of our overall engagement.
UNPLANNED RELIABILITY	
Our unplanned SAIDI and SAIFI performance metrics help ensure that the works we undertake provide a better outcome for our customers.	Details of our unplanned reliability performance are outlined in Section 8.3.3

8.3.3 HISTORICAL TRENDS

Our Customised Price-quality Path (CPP) unplanned reliability targets for the five-year period are shown in Table 8.3 and Figure 8.2, alongside our actual results. The targets were set based on a 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. Major event day normalisation using a boundary value is included.

As seen in Figure 8.2, we exceeded our regulatory limit for unplanned SAIDI in FY19 and FY22 and are likely to exceed it by a smaller margin in FY23 because of abnormal storm activity. We aim to remain within regulatory quality limits and closely monitor our unplanned SAIDI performance. We have strong governance in place and are progressing multiple work programmes in order to manage performance (through our asset renewal, defect, vegetation, and automation programmes).

Although our performance is judged on the normalised SAIDI/SAIFI values, the un-normalised SAIDI/SAIFI provides a better reflection of our customers' experience.

Figure 8.2: Unplanned SAIDI and SAIFI performance

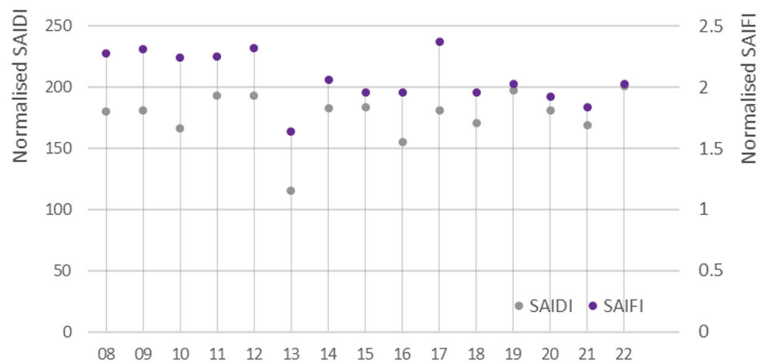
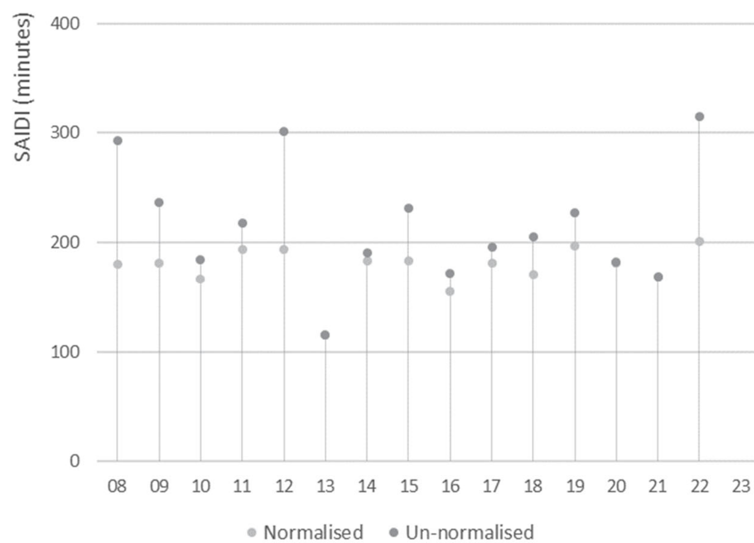


Figure 8.3: SAIDI performance, normalised v un-normalised



Schedule 12D in Appendix 2 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 shown above.

Our longer-term unplanned SAIDI and SAIFI forecast reflects our focus on arresting deterioration and maintaining network reliability at target levels.

8.4 NETWORKS FOR TODAY AND TOMORROW

8.4.1 OVERVIEW

This section outlines the specific targets we have set to demonstrate that our networks are suitable for today's needs while being ready to meet the requirements 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.

Our feeder performance metrics help us identify parts of the network that may not be performing to their expected service levels. This allows us to better plan for future improvements.

To prepare our network for tomorrow, we have outlined our new Network Evolution strategy in Chapter 7. The strategy focuses on four principal themes:

- **Improved network 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.
- **Enhanced network response** – improving our network's ability to deal with emerging customer applications, changing consumption and generation patterns, and two-way power flows.

8.4.2 TARGETS

The tables below set out our targets for Networks for Today and Tomorrow and the rationale behind them.

[74] The reliability performance in the table is for distribution feeders only and excludes the performance of the network upstream of the feeder.

Table 8.5: Networks for Today and Tomorrow targets[74]

INDICATOR	TARGET			FY19	FY20	FY21	FY22
Feeder performance							
	FEEDER CLASS	TARGET	CONSUMER TYPE	NUMBER OF FEEDERS EXCEEDING TARGET			
Feeder Interruption Duration Index (FIDI) targets	F1	30	Large industrial	41	33	34	40
	F2	60	Commercial	57	54	47	56
	F3	180	Urban	82	69	79	81
	F4	600	Rural	73	69	52	93
	F5	1080	Remote rural	10	10	5	11
Feeder Interruption Frequency Index (FIFI) targets	F1	0.5	Large industrial	44	36	35	40
	F2	1.0	Commercial	51	48	42	44
	F3	1.5	Urban	99	89	92	89
	F4	4.0	Rural	100	88	67	87
	F5	6.0	Remote rural	14	16	8	13

Table 8.6: Networks for Today and Tomorrow target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Feeder performance	
We analyse our feeder performance using FIDI and FIFI targets. FIDI represents the average number of minutes per year that a customer on a particular feeder is without supply. FIFI represents the average number of times per year that a customer is without supply on a particular feeder.	Other than for FIFI targets in urban areas, feeder performance has deteriorated or stayed much the same during the past two years, at least in part because of the preponderance of storm activity during that period. The completion of multiple work programmes targeted at underperforming feeders is expected to help.

8.5 ASSET STEWARDSHIP

8.5.1 OVERVIEW

This section outlines 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.

8.5.2 TARGETS

Table 8.7 lists our Asset Stewardship targets and performance, while Table 8.8 explains the rationale behind them.

Table 8.7: Asset Stewardship targets

INDICATOR	TARGET	FY19	FY20	FY21	FY22
Asset failure rates (Faults/interruptions per 100km)					
6.6, 11, 22kV overhead lines	<16 faults	30.30	28.17	25.96	29.69
	<10 interruptions	21.61	18.97		
6.6, 11, 22kV underground cables	<4 faults	4.35	5.62	6.00	5.49
	<4 interruptions	4.35	5.53		
33, 66kV overhead lines	<9 faults	14.2	10.8	10.7	12.4
	<5 interruptions	6.68	5.43		
33, 66kV underground cables	<1.7 faults	0.00	0.82	0.00	0.00
	<1.5 interruptions	0.00	0.82		
Asset utilisation (%)					
Distribution transformer utilisation	30%	28.6	28.7	29.0	28.8
Network energy losses versus energy entering network	6%	5.0	5.3	5.3	5.2
Vegetation management					
Cyclical trimming programme (cumulative)	Trimming of trees to regulatory limits complete once for 100% of the network during the CPP period.	22%	45%	65%	82%

[75] Faults refer to all asset failures, even where these do not result in supply interruptions. Interruptions refer to instances where customers lose supply for 1 minute or longer.

Table 8.8: Asset Stewardship target commentary

FOCUS AREA	INITIATIVE
Asset failure rates	
Fault and interruption[75] 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 New Zealand.	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. Section 8.5.3.1 discusses our failure rates and benchmarks our performance against other utilities.
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 28.8% against a target of 30%. Figure 8.11 shows how this compares with the industry averages. Our energy loss has been measured at 5.2%, near our target of 6%.
Vegetation management	
Tree regulations require us to ensure appropriate vegetation clearances from lines. Our target of moving to a full cycle across our network is based on a cyclical trimming regime, which is designed to ensure full compliance.	The first cycle to bring back the vegetation corridors to regulatory limits requires additional resources. Subsequent cycles will require fewer resources to help maintain the clearances along the corridor.

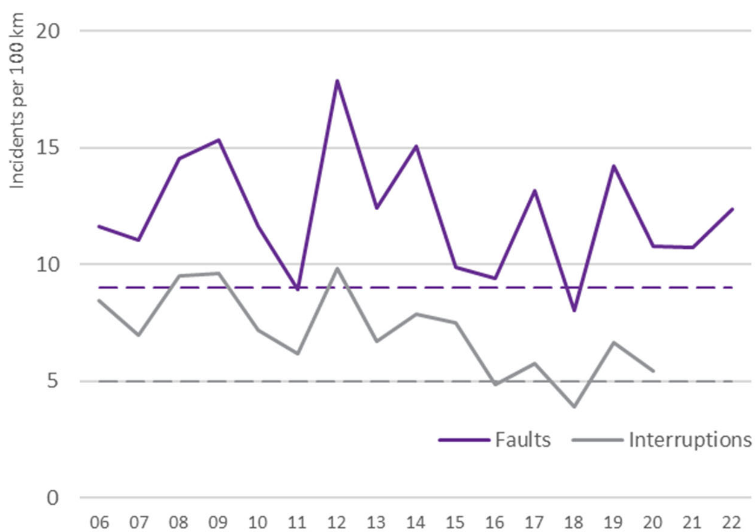
8.5.3 HISTORICAL TRENDS AND BENCHMARKS

8.5.3.1 ASSET FAILURE RATES

Failure trends

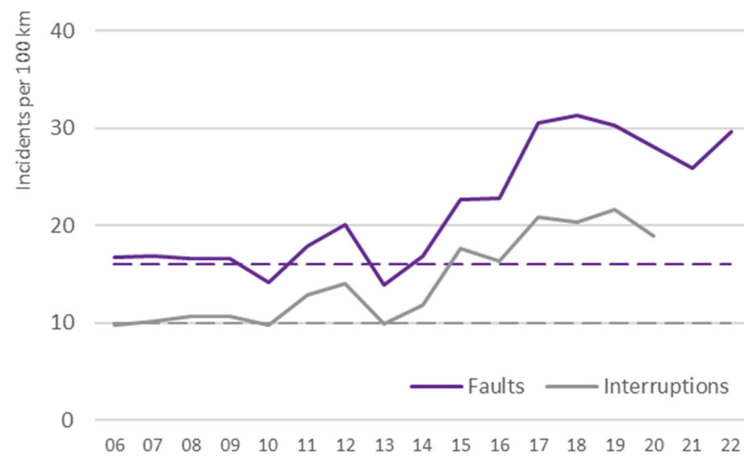
The figures below show our historical fault and interruption performance on our subtransmission and distribution system asset fleets.

Figure 8.4: Subtransmission overhead faults and interruptions per 100km



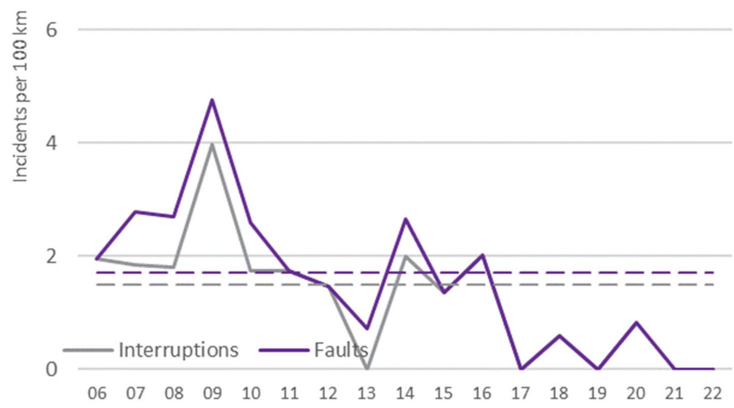
As shown in Figure 8.4, subtransmission overhead faults and interruptions have consistently been above target during the past decade. The irregular shape of the trend line reflects inclement weather conditions from year to year. Our targets are designed to improve asset health and decrease the number of subtransmission overhead faults we are experiencing.

Figure 8.5: Distribution overhead faults and interruptions per 100km



As shown in Figure 8.5, 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 CPP programme has targets designed to improve health, reduce the number of defects and reduce failure rates. Notwithstanding the blip in FY22, caused by exceptional storm activity, this has started to show gradual long-term improvements in the performance of our network.

Figure 8.6: Subtransmission underground faults and interruptions per 100km



As indicated in Figure 8.6, the performance of our underground subtransmission circuits has improved.

Figure 8.7: Distribution underground faults and interruptions per 100km

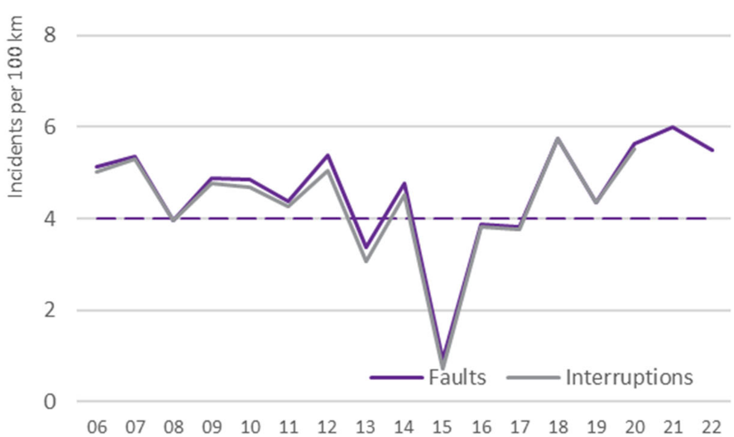
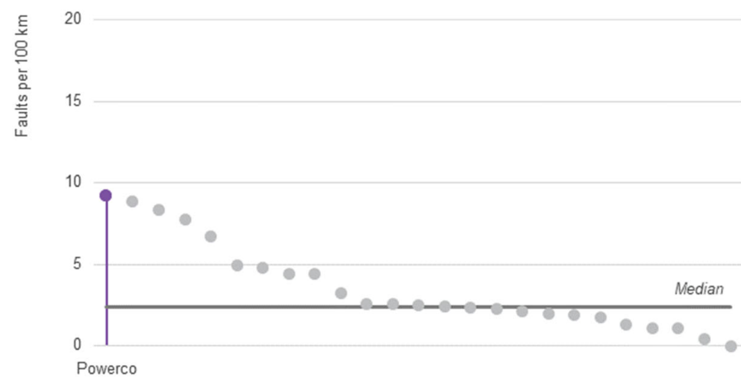


Figure 8.7 shows that we experienced a higher-than-average number of distribution cable failures.

Benchmarking

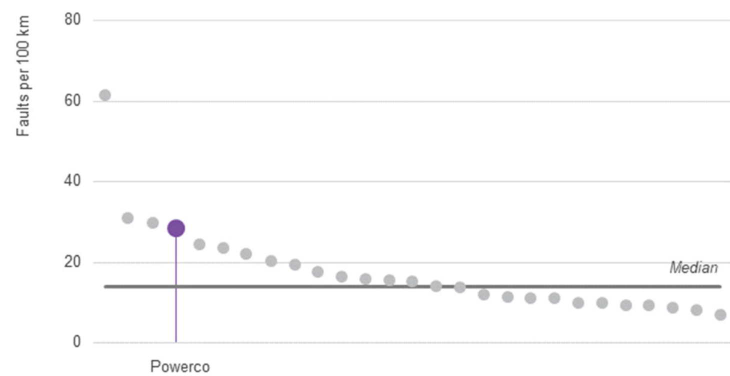
The following graphs show where we sit among our peers in terms of faults per unit length of circuit.

Figure 8.8: Subtransmission overhead line benchmarking (FY19-22)



As shown in Figure 8.8, 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.

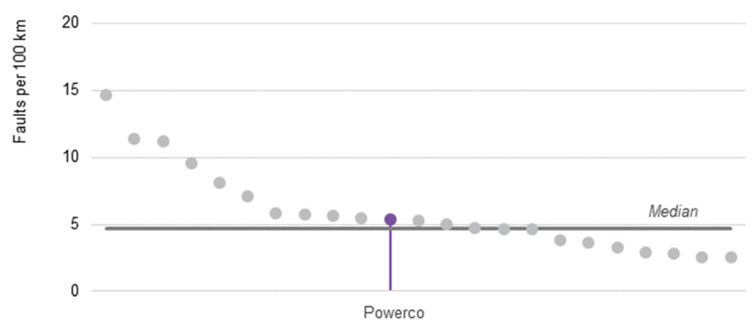
Figure 8.9: Distribution overhead line benchmarking (FY19-22)



As shown in Figure 8.9, the frequency of faults on our distribution overhead lines is higher than the industry median. Our targets are designed to reduce the number and duration of these types of faults.

As shown in Figure 8.10, we sit close to industry median with respect to faults on distribution cable networks.

Figure 8.10: Distribution cable benchmarking (FY19-22)

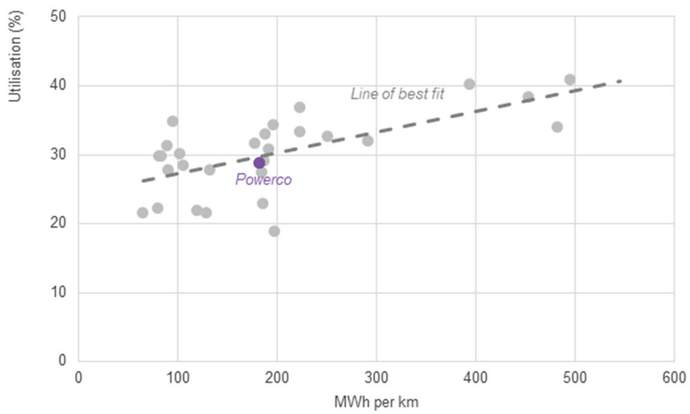


8.5.3.2 ASSET UTILISATION

Distribution transformer utilisation

Figure 8.11 shows our distribution transformer utilisation against network load density.

Figure 8.11: Comparison of NZ EDB distribution transformer utilisation and network load density

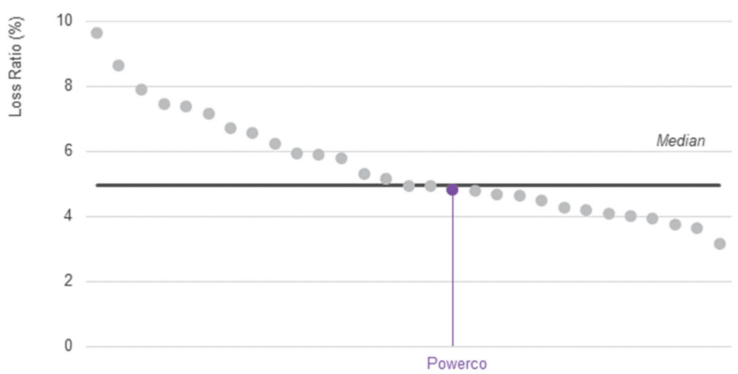


We sit close to the line of best fit for us. We use this relationship to inform our distribution transformer utilisation target of 30%.

Network losses

Figure 8.12 shows our network loss ratio compared with that of other EDBs.

Figure 8.12: Benchmarking of average network loss ratio (FY19-22)



Our network losses are at industry median level and considered satisfactory and appropriate for our network.

8.6 OPERATIONAL EXCELLENCE

8.6.1 OVERVIEW

This section outlines 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.

8.6.2 TARGETS

Table 8.9 lists our Operational Excellence targets, while Table 8.10 explains the rationale behind them.

Table 8.9: Operational Excellence targets

SAIDI / SAIFI

INDICATOR	FY23	FY24	FY25	FY26	FY27	FY28
PLANNED RELIABILITY	**TARGET**	**TARGET**	**TARGET**	**TARGET**	**TARGET**	**TARGET**
Planned SAIDI	92.8	94.1	90.2	91.3	90.0	88.4
Planned SAIFI	0.39	0.42	0.41	0.41	0.40	0.39

The planned SAIDI and SAIFI targets for FY23 to FY28 in Table 8.9 are taken from our forecasts in Schedule 12d - Report forecast interruptions and duration.

Asset Management Maturity

INDICATOR	FY23	FY24	FY25	FY26	FY27	FY28
ASSET MANAGEMENT MATURITY	**TARGET**	**TARGET**	**TARGET**	**TARGET**	**TARGET**	**TARGET**
AMMAT self-assessment average	3.0	3.2	3.2	3.2	3.2	3.2

Table 8.10: Operational Excellence target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
PLANNED RELIABILITY	
The planned reliability metrics (SAIDI/SAIFI) provide an insight into the impact our works programme has on our customers.	Our planned SAIDI performance has increased in line with our larger works programme. Refer to section 8.6.3.1 for more details.
ASSET MANAGEMENT MATURITY	
We have proven ourselves as capable asset managers. In 2022 we achieved certification with ISO: 55001. However, we recognise there is more to do as our asset management approaches mature.	Our approach has matured progressively, as evidenced by the gradual increase in our AMMAT from 2013-2021 and ISO: 55001 certification in 2022. Details and associated 'spider' diagrams are included in section 8.6.3.2.

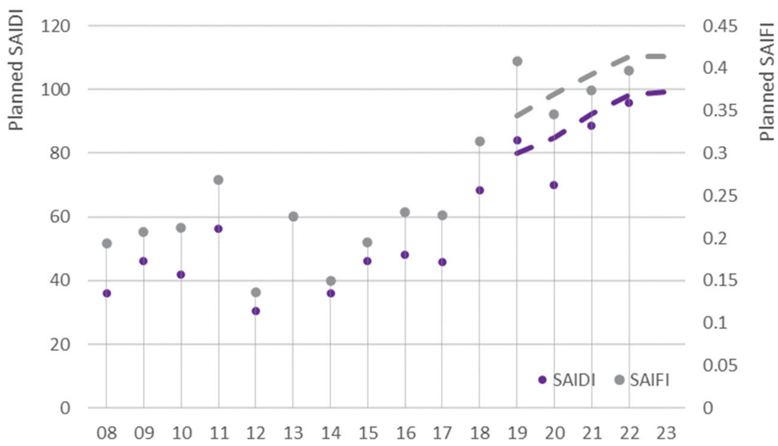
8.6.3 HISTORICAL TRENDS AND BENCHMARKS

8.6.3.1 PLANNED RELIABILITY

Our CPP planned reliability targets was based on our modelling of expected planned SAIDI and SAIFI to provide the increased work volumes of our CPP delivery programme.

Since these CPP planned outage limits were set, we have found it difficult to fully deliver our works programme while staying within these limits.

Figure 8.13: Planned SAIDI/SAIFI



Since FY18, we have had higher planned SAIDI, and especially SAIFI, than what we had modelled for our CPP application. Since developing the CPP forecasts, unforeseen (at the time) changes in live-line work practices[76], in particular, have led to major increases in the outages required for planned works.

We have put significant focus on improving our planned outage processes to minimise customer disruption while ensuring we complete our work. We have increased the use of other forms of SAIDI mitigation, such as generation, and the use of multiple crews. We have also materially improved the efficiency at which we plan and deliver our works.

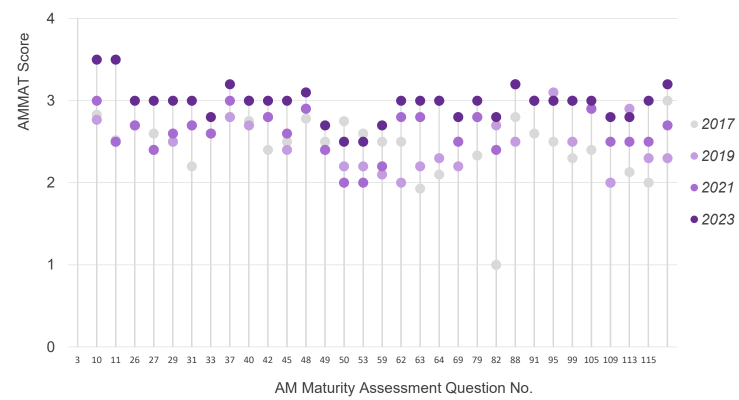
Increased planned SAIDI and SAIFI compliance limits in the upcoming default price-quality path period (DPP3) will improve our ability to deliver our works and maintenance plans[77]. Whilst the compliance limit is increasing, a new additional notice incentive for planned interruptions in DPP3 incentivises us to limit the disruption to customers from planned outages.

8.6.3.2 ASSET MANAGEMENT MATURITY

We published our first AMMAT assessment in the 2013 AMP and repeated the assessment in subsequent AMPs[78]. Figure 8.14 shows the AMMAT results from this year's assessment and compares them with previous scores. Scores range from 0 ('innocent' maturity level) to 4 (excellent maturity level).

The increased scores reflect Powerco achieving ISO:55001 certification in 2022, following focused attention on bringing our Asset Management System and assurance processes into line with ISO:55001 principles.

Figure 8.14: Asset maturity self-assessment scores 2013-21



The scores shown in Figure 8.14 reflect an honest reappraisal of our asset management maturity, while also taking into account the ISO: 55001 assessor's feedback.

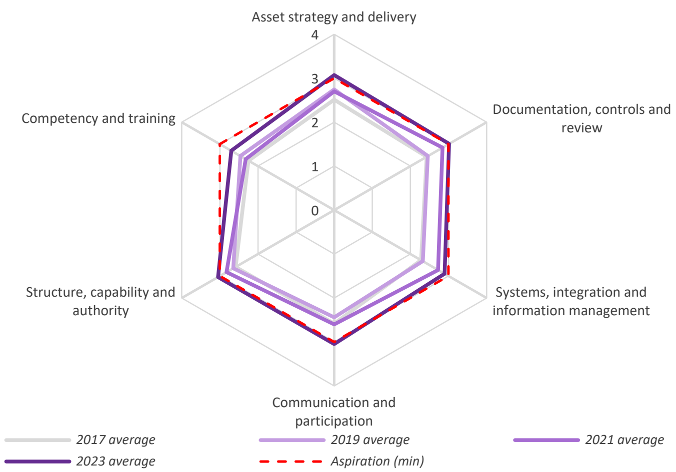
In Figure 8.15 we show the scores grouped by assessment areas. We re-assessed ourselves as improving markedly in many areas, with modest improvements in others.

[76] 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-line permits.

[77] Powerco was on its customised price-quality path for the first three years of DPP3 but will transition to DPP3 for FY24 and FY25.

[78] As an electricity distributor we are required to undertake and publicly disclose the AMMAT self-assessment results.

Figure 8.15: Summary of asset maturity self-assessment scores by assessment area



This page intentionally left blank

ASSET MANAGEMENT SYSTEM

How we do asset management at Powerco.

9 ASSET MANAGEMENT SYSTEM

9.1 CHAPTER OVERVIEW

This chapter discusses how we develop our investment plans, including the processes and analytical tools used to identify network needs and prioritise expenditure. It also covers our procurement processes, our interpretation of lifecycle asset management, our approach to risk management, and governance arrangements concerning asset management at Powerco.

Our Asset Management System aligns with the principles of internationally recognised asset management standard ISO: 55001 – we were certified in 2022. Investment decision-making is a crucial aspect of a competent asset management system.

9.2 LINE OF SIGHT BETWEEN OUR CORPORATE VISION AND ASSET MANAGEMENT DECISIONS

The Powerco Board and Executive Leadership Team (ELT) formulate policies and business objectives, aligning our Asset Management Strategies with the Corporate Objectives and the company's vision, mission, and values.

The interrelated functions of the business that are needed to manage a suite of assets effectively, constantly balancing asset performance, cost, and risk, are called an Asset Management System (AMS). An effective AMS maintains a line of sight between Corporate Objectives and asset management practice. Our AMS and the implicit line of sight between Corporate Objectives and our asset management decisions are illustrated in Figure 9.1.

The AMS diagram also illustrates how all the interrelated parts of the business work together. This provides context for our decisions and shows how each function influences our overall performance.

Powerco was recently certified to ISO: 55001 in recognition of our effective AMS.

9.3 DEVELOPING OUR INVESTMENT PLANS

In this section, we describe how we develop our:

- Renewal and Maintenance Plans
- Network Development Strategy
- Vegetation Management Strategy
- Information & Technology Strategy

9.3.1 DEVELOPING OUR FLEET MANAGEMENT PLANS

Renewal investment and maintenance of our asset fleets are integral to achieving our Asset Management Objectives and targets.

Our goal is to manage asset performance within acceptable bounds, ensure assets are safe and in a suitable condition to remain in service and minimise the total lifecycle cost of ownership.

9.3.1.1 RENEWALS FORECAST

A significant portion of our asset management resources is consumed by asset renewal and maintenance activities. These are major components in forecasting our network's financial and resource requirements. We use various methods to develop these forecasts. These methods vary from fleet to fleet, with our fleet breakdown summarised in Table 9.1 and the renewal drivers shown in Table 9.2.

Figure 9.1: Powerco's Asset Management System

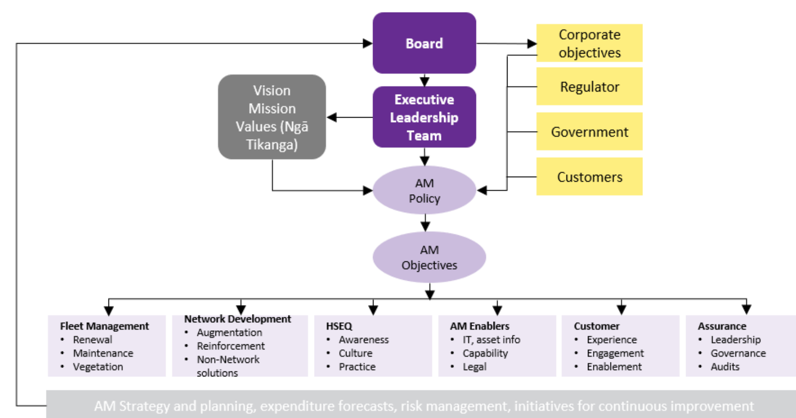


Table 9.1: Portfolio and asset fleet mapping

PORTFOLIO	ASSET FLEET
Overhead structures	Poles, crossarms.
Overhead conductors	Subtransmission overhead conductors, distribution overhead conductors, Low Voltage (LV) overhead conductors.
Cables	Subtransmission cables, distribution cables, LV cables.
Zone substations	Power transformers, indoor switchgear, outdoor switchgear, buildings, load control injection, other zone substation assets.
Distribution transformers	Pole-mounted distribution transformers, ground-mounted distribution transformers, other distribution transformers.

PORTFOLIO	ASSET FLEET
Distribution switchgear	Ground-mounted switchgear, pole-mounted fuses, pole-mounted switches, circuit breakers, reclosers and sectionalisers.
Secondary systems	Supervisory Control and Data Acquisition (SCADA) and communications, protection, Direct Current (DC) supplies, metering.
Non-network assets	Information and communications technology (ICT), buildings, office fittings, vehicles.

Table 9.2: Asset fleet renewal drivers and forecasting methods

PORTFOLIO	FLEET	RENEWAL DRIVER	PRIMARY FORECASTING METHODS
Overhead structures	Poles	Reliability, resilience (storm), condition.	Survivor curves.
	Crossarms	Safety, reliability.	Survivor curves.
Overhead conductors	Subtransmission conductors	Resilience (storm), safety.	Type and age.
	Distribution conductors	Resilience (storm), safety.	Type and age.
	LV conductors	Safety.	Age.
Cables	Subtransmission cables	Condition, environment, reliability.	Type and age.
	Distribution cables	Condition, reliability.	Type and age.
	LV cables	Reliability (cable) and safety (pillar boxes).	Historical trend (cable) and defect rates (pillar boxes).

9.3.2 RENEWAL ANALYSIS

9.3.2.1 ASSET HEALTH

We routinely inspect and test our assets in the field to understand their condition. Given that this includes a mixture of non-intrusive observational and tested results, and more intrusive electrical and mechanical tests requiring outages, gathering this information represents a significant portion of our operational expenditure.

Asset health reflects an asset's expected remaining life and is a proxy for the probability of failure. Factors such as age, environmental location, operating duty, observed condition, measured, or tested condition, and known reliability are combined to produce the health index (H1-H5), described in Table 9.3.

Table 99.3: Asset Health Indices (AHI) scale

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.

9.3.2.2 COMMON NETWORK ASSET INDICES METHODOLOGY

In 2016 we developed Condition-Based Risk Management (CBRM) models for our substation primary assets – power transformers, circuit breakers, ring main units and ground-mounted distribution transformer fleets. This modelling uses a combination of asset condition and risk to predict failure cost, helping to prioritise renewal expenditure. These were based on the Distribution Network Operators (DNO) Common Network Asset Indices Methodology (CNAIM).

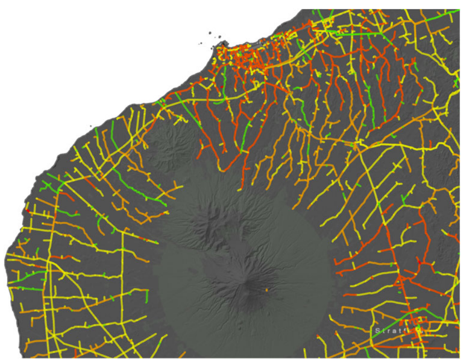
We have integrated these models into our new Copperleaf C55 system - in total, Copperleaf has integrated nine asset models covering 50 different asset types. This integration greatly refines our modelling approach for these asset categories.

This methodology differs from other forecasting methods in that it develops a bottom-up estimate of current and future asset health, probability of failure, and risk for each asset in the fleet. Information used to produce these estimates includes the asset's physical characteristics, the asset's physical condition and the operational context – how failure could affect safety, network performance, and operational and environmental objectives.

The assets and project integration in Copperleaf C55 allow us to directly view the risk reduction benefits of renewals on a project via the assets impacted, as well as incorporating other non-CNAIM benefits an investment may provide.

This modelling also allows us to consistently view the impact of different renewal profiles and the impact this has on our current and forecast health and risk profiles.

9.3.2.3 OVERHEAD RENEWAL PLANNING TOOL



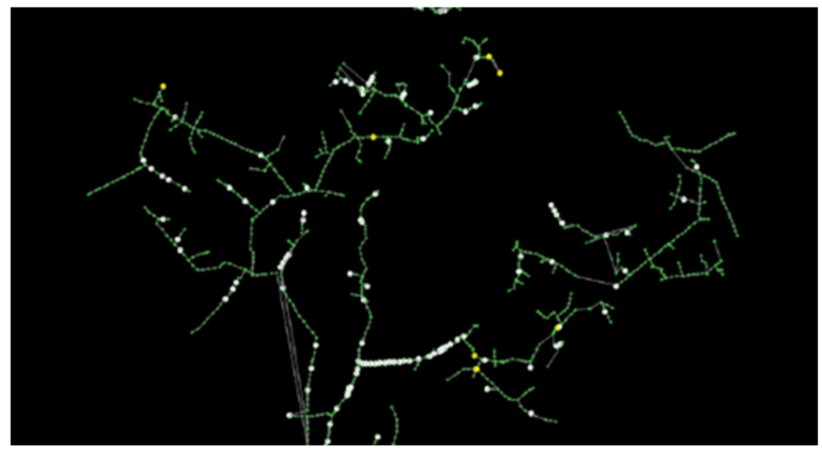
To understand our asset health across all overhead fleets, we have built a model using the CNAIM as a base. The model uses standard CNAIM inputs, such as the asset's expected life, location, duty, type, and age. We also use additional health score modifiers where we have further information, such as known defects, visual assessments, manufacturing faults and test results. The combination of these inputs calculates an asset health score for each asset.

The output from this modelling is displayed geospatially and allows for effective project identification to feed out works plans. The spatial analysis results are also verified through field inspections before the renewal investment is committed.

The Overhead Renewal Planning Tool (OHRPT) is under constant development and improvement.

9.3.2.4 OVERHEAD STRUCTURE LOAD ANALYSIS

The resilience of our overhead network, in terms of strength and loads on poles, is not always known. One reason for this is that the network has been erected through rule-of-thumb techniques, using the knowledge and best practices at the time of construction.



Some key elements in the design of the overhead network are wind, snow, and ice loads. For many areas, appropriate values would not have been known because weather records were available for a limited time.

We undertake load analysis on our network when designing new lines but also when renewing large segments of a feeder.

9.3.2.5 FEEDER PERFORMANCE

In addition to predicting how much power a feeder will need in the future, and what level of reliability and power quality is required, we regularly check which of our feeders are performing at substandard levels of reliability, and why.

The analysis uses the Feeder Interruption Duration Index (FIDI), which is the average number of minutes without supply experienced by connected customers. The analysis is broken down by feeder class, reflecting the class of connected load.

Remedial options include a renewal blitz on overhead line hardware, installation of automation technology, improvements in protection systems or capacity enhancements.

9.3.2.6 DEVELOPING OUR MAINTENANCE STRATEGY

Our maintenance activities are categorised as follows:

- **Preventive maintenance and inspection** – this portfolio deal 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 the replacement of defective 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.

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

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 manage risk and improve overall network performance.

9.3.3 DEVELOPING OUR VEGETATION MANAGEMENT STRATEGY

Vegetation in contact with our assets can lead to safety and reliability issues, such as asset failures, outages, and fires. This must be managed to ensure the security of supply and the safety of the public. It is also a legislative requirement to maintain mandated clearance distances between vegetation and our lines.

In line with our Vegetation Management Strategy, we are transitioning 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 are inspected at pre-determined intervals, typically three years. We are adopting a risk-based approach to vegetation outside statutory clearance zones – where this will likely 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.

9.3.4 DEVELOPING OUR NETWORK DEVELOPMENT STRATEGIES

9.3.4.1 DEMAND FORECASTS

Our current “organic demand forecasting approach” leverages the historically strong correlation between population, residences, commerce, and ensuing electricity demand. Two key assumptions have been significant to date: the constancy of population per household; and the constancy of demand profile per consumer type.

The pending uptake in electrification and distributed energy resources (DER), among other changes, will invalidate these assumptions in future. Integrated models are under development to factor in these new societal and technology drivers. As an interim measure, an assessment of the growth impact resulting from each electrification driver is made in a high-level scenario model, and this is then superimposed on the organic growth, being weighted by customer mix.

The existing organic growth methodology uses a bottom-up approach to estimate a linear growth rate applicable to each load block – feeder, substation, and grid exit point (GXP). Multiple growth drivers (predictors) are used – historical new connection trend, forecast population by census area, forecast industry indexes, and in some cases the historical maximum demand trend. The weighting of these drivers is dependent on the mix of customer types in each load block reflecting the applicability of the driver to that customer type.

The resultant forecast growth rate is then applied to the existing peak demand for each load block – feeder, substation or GXP. The existing peak demand is determined from our historian database of network loading. Because these measurements can be distorted by network reconfiguration, the raw results must be filtered and reviewed to establish a true annual peak demand.

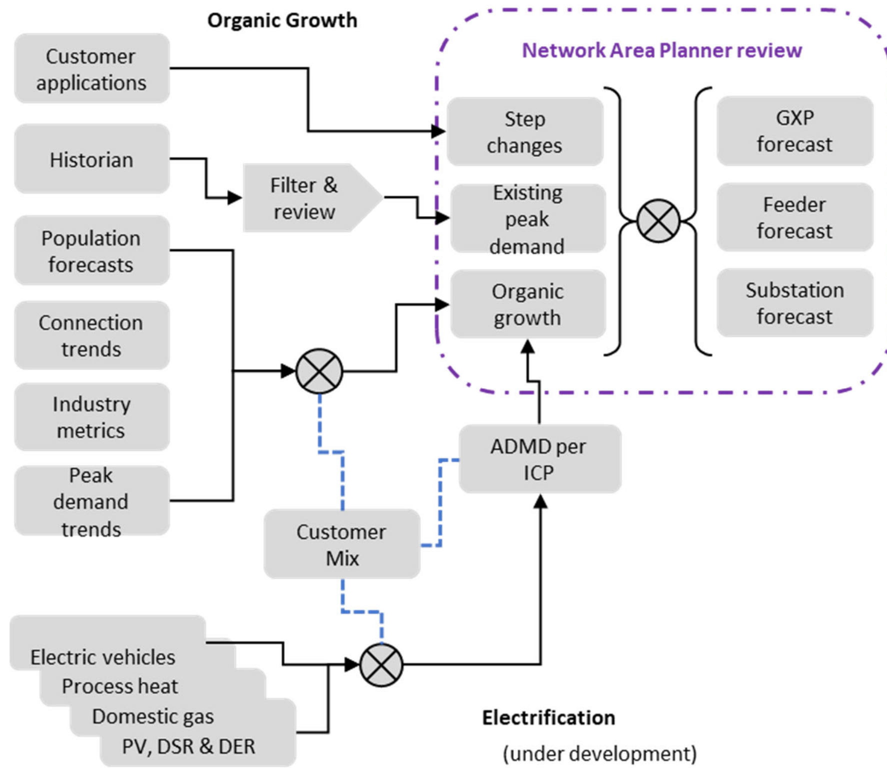
Lastly, committed or confirmed step changes in customer requirements are added, provided the load increase is not already reflected in the organic growth. These step changes generally relate to industrial or commercial load increases.

Governance of the forecasting involves network planning oversight and review of all forecasts produced by the analytic models. Planners leverage their knowledge of activity around customer load increases, historical network loading, and network reconfiguration to sense check and challenge any abnormalities or discrepancies. At higher network levels, especially the total system demand, the forecast is further reviewed by senior asset and business management.

As noted, before, with the pending impact of electrification and flexibility, the demand forecast methodology will be significantly improved in the next two years, with the objective of systematically forecasting all drivers in a fully disaggregated manner. Scenarios, being variants on a base forecast, will also be introduced. In support of probabilistic planning, peak annual demands will also be replaced with demand profiles. Given the "demand forecast' then becomes a very large dataset (disaggregated, multiple scenarios and full profiles), this is a major business transformation, as all the processes and tools/systems consuming the forecast need to be migrated onto data and analytic platforms that are suitable for the volume of data and processing.

Figure 9.2 shows the key elements of our demand forecasting approach.

Figure 9.2: Demand forecasting approach



9.3.4.2 NETWORK DEVELOPMENT PLANS

Justification for network upgrades is generally based on the need to meet demand increases or to achieve specified network security standards. Such upgrades increase the capacity, functionality, and size of our network.

We conduct a detailed options analysis for individual network projects before deciding on the final details, which includes consideration of realistic network alternatives and non-network alternatives, such as generation, energy storage or demand management.

Network projects are generally prioritised based on the expected reduction in unserved energy they would achieve.

The highest priority projects that fit into available budgets make up our Area Development Plans. These plans are subject to approval by the General Manager Electricity and, ultimately, by the Powerco Board.

Our Area Development Plans for this reporting period are described in detail in Chapter 11.

The key drivers for Growth and Security planning are as follows.

9.3.4.3 SECURITY OF SUPPLY

Our zone substation security classifications start with the 11kV feeder type (F1, F2, etc) at each substation. The feeder types are determined by the predominant type of customer on each 11kV feeder. The zone substation security classes are then determined from Table 9.4, which is a function of both 11kV feeder type, and the amount of load involved. These classes are shown in demand forecast tables throughout this AMP.

Table 9.4: 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 9.5.

Table 9.5: Substation security class restoration targets

SECURITY CLASS	TARGETED RESTORATION CAPABILITY FOR	
	FIRST EVENT	SECOND 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, where 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 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 an alternative supply cannot be economically justified.

9.3.4.4 DISTRIBUTION PLANNING

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

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

Table 9.6: 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. Some elements of reliability are considered, but the focus of analysis for distribution planning is predominantly the capacity and performance of the network under normal configuration.

Feeders are also assessed regarding 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.

9.3.4.5 THERMAL CONSTRAINTS

Electric current passing through our assets causes heating which, if excessive, can result in damage. The current-carrying capacity, or ampacity, of our assets, is important to determine how much electricity we can distribute on our network.

Alleviating thermal bottlenecks in our networks can act as a trigger for projects, such as conductor or transformer upgrades.

9.3.4.6 POWER QUALITY

We must maintain the power quality within statutory limits. The key elements that we monitor to ensure supply quality are:

Voltage: The maintenance of the voltage at the customer's point of connection.

Table 9.7: Targeted voltage variance

ASSET TYPE	TARGETED VOLTAGE VARIANCE FROM NORMAL	
	MAX	MIN
33kV transmission circuit	+5%	-5%
11kV distribution circuit	+3%	-3%
Distribution transformer	-	-2%
LV distribution circuit	+6%	-6%

Harmonics: The distortion of the voltage waveform. Harmonic voltages and currents passed on to consumers should conform with the Electrical Code of Practice for Harmonic Levels 36.

Maintenance of frequency is not in our quality metrics as it is not presently under Powerco's control, except for installing under-frequency load shedding relays at zone substations.

9.3.5 NETWORK DEVELOPMENT ANALYSIS

9.3.5.1 DEMAND FORECASTS

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 the aggregate demand forecast at the zone substation, GXP and subtransmission level. We estimate existing peak demand based on 90th percentile of filtered and trended historical peaks. The starting point for our demand forecasts is the distribution (11kV) feeder level forecasts. Our modelling combines NZ Statistics census area population forecasts mapped to each feeder and historical trends in new customer connections. 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.

9.3.5.2 LOAD FLOW STUDIES

The network planning team conducts load flow studies for each region. These studies allow us to understand the performance of our network under different demand and network configuration scenarios.

Load flow studies are among the most important tools for investigating problems in our network operating and planning. They allow us to conduct studies on load flow, short circuit analysis, dynamic analysis, optimal capacitor placement, Volt/VAR optimisation, harmonics, ripple control, protection coordination, and power quality.

Asset thermal ratings

While all assets are assigned a specific standard or nominal rating, actual capacities vary in real-time, depending on environmental conditions. The approach to asset ratings is tailored 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, i.e., 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 – we recently reviewed ratings and issued a new standard that assigns consistent, systematic standard ratings for planning analysis, and will also set a framework for dynamic or monitored rating schemes using distributed fibre temperature sensing.

9.3.6 INFORMATION & TECHNOLOGY STRATEGY DEVELOPMENT

The Information & Technology Strategy (I&T) is designed to reduce technology risk and increase business resilience and efficiency by delivering foundational business practices and technology.

The highest priority projects that fit into the available non-network budget make up our Information Services Tactical Plan.

All I&T 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:

- What is the risk of not doing this initiative?
- Which initiatives enable our business plan?
- Which initiatives are the most beneficial?
- How much change can the organisation absorb?
- What can the organisation resource?
- What can we afford?
- What are the implementation risks and impacts?

Additionally, network cyber security and communications projects are prioritised via the electricity asset investment process as either renewal or growth projects.

9.4 PROJECT PRIORITISATION

In August 2020, we commissioned Copperleaf C55, a class-leading asset management application to support the prioritisation of our investments. In essence, it applies a value framework to our proposed projects (other than reactive, defect or customer-initiated works), quantifying the expected benefit from each, and producing an overall ranking.

Developing the value framework was a critical part of the implementation, and involved our Board, the executive, and many teams across the business. The value measures that we adopted are shown in Figure 9.3.

Figure 9.3: Optimisation value framework

Value Measures

Network performance	Maintaining or improving reliability of service to customers.
Financial	Direct financial impacts (e.g. Opex impact, efficiencies, additional revenue).
Future enabling	Investing to better position the network for the future.
Health and safety	Health and safety of employees, contractors, customers and the public.
Customer and reputation	Any impact on our reputation, including with our customers, stakeholders and media.
Legal and compliance	Compliance with legal or regulatory obligations.
Environment	Risk of environmental incidents or reducing our environmental footprint.

Another important aspect was the quantification of the value measures by using value models. The models can draw on information from diverse sources, including defined system parameters, asset attributes, and information provided by project planners. The sum of these quantified benefits can then be compared with the lifecycle cost to implement a project, and so derive the net value of a proposed investment.

The optimisation tool is used to inform when projects progress into our works plan – picking the most valuable portfolio that fits within our financial and delivery constraints. Its use will expand in future to also inform our five-year investment plan.

9.5 SOLUTION DEVELOPMENT

9.5.1 OPTIONS ANALYSIS

The complexity of any options analysis is commensurate with the associated level of risk and cost. For example, the upgrade of overhead lines needs to consider thermal re-tensioning, reconductoring, or the installation of new lines or circuits, i.e., dual circuits. 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, indicating the cost of possible unserved energy to customers. Based on these factors, we identify the most cost-effective, long-term solution.

We have developed formal tools and guidelines for undertaking options analysis. This helps ensure that the assumptions and approach remain consistent between options, traceable and documented. It also provides built-in unit rates and helps estimate the cost of different options.

9.5.2 NON-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 practicable and cost-effective in the future. Examples that are likely to become more prevalent include:

Embedded renewable generation

- Photovoltaics (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

Large-scale or small-scale batteries are currently the most practical energy storage options for distribution networks. However, other options, such as heat, water, or flywheel energy storage systems, are also being considered. Storage offers several potential benefits, especially related to shaving daily peaks, reducing the network's effective peak demand, and increasing utilisation.

Demand-side management

Emerging possibilities range from simple variable thermostats to smart appliances and home energy management systems. Small-scale distributed energy storage, e.g., home batteries, can effectively be treated as a demand-side resource.

Power flow

Management/automation involves techniques to improve utilisation and use of 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 large projects includes a formal review of non-network solutions.

Third-party provision of network alternatives – Northern Coromandel

We are increasingly seeking out potential third-party solutions to address major network requirements. These will be adopted where they are more cost-effective than our own network or non-network solutions.

For example, in March 2021 we went to the market with a Registration of Interest (ROI) for network support services in the northern Coromandel. The ROI process gained interest from several parties offering a variety of network alternative technologies, such as demand response, generation, and energy storage.

A subsequent Request for Proposal (RFP) process was run with selected parties where their proposed solution was technically feasible. These proposals were compared to traditional network solutions (such as subtransmission upgrades or dedicated generation plant) to determine the best overall solution for Powerco's customers.

In December 2022, we reached an agreement with SolarZero. SolarZero will support customers in the northern Coromandel with a virtual power plant solution that utilises residential solar and battery systems. This agreement helps us to defer significant network upgrades.

We continue to explore other network alternative agreements in this area where they can provide cost-effective network support.

9.5.3 INVESTIGATIVE STUDIES

Investigative studies may be conducted to assist with finalising the scope of a project. These studies are usually conducted for complex projects. Uncomplicated, routine projects can be delivered without requiring an investigative study.

9.5.3.1 FEASIBILITY STUDIES

Feasibility studies are used to check whether the project is technically possible and economically viable. This is to make a 'go/no go' decision on a proposed project. It is not used to validate the condition assessment data gained from a desktop study, or for checks on individual assets.

Depending on the context, feasibility studies could be used to help narrow down options, understand the viability of a concept, or try to understand the size of the problem being considered.

9.5.3.2 CONCEPT DESIGNS

If the project is complex or very large, an early design can be requested. It is generally used to help in effective decision-making or to clarify the scope of the detailed design. The designer gets involved early in the project delivery process to investigate how the project is best implemented.

9.5.4 PROJECT STAGES

A project goes through various stages as it evolves from an idea to a full detailed design. These stages are captured in our Project Portfolio Planning system.

9.5.4.1 PROJECT SUMMARIES

A project summary is the very initial stage of a project. This stage captures basic, high-level details about what a project may look like.

Project summaries are used to help the resourcing teams gain insight into the type and quantity of work so that they can start organising resources for timely delivery when required.

9.5.4.2 PROJECT BRIEFS

Project briefs are used to help finalise the detailed requirements for a project. The briefs also ensure that the needs of multiple stakeholders within the organisation are captured in the project.

During the development stage of Capex projects, asset and planning engineers gather the information required to be able to describe what is needed to deliver the project. The key elements of a robust scope are a high-level design and accurate time and cost estimates. That information is built up and added to until it culminates in a completed 'project brief.'

9.5.5 PROJECT APPROVAL

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

- **Growth and security** – the Network Development Manager generally reviews solutions. 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.
- **Renewal and refurbishment** – solutions are generally tested by the Asset Fleet Manager. This review assesses whether renewing the asset(s) and the timing will support our overall Asset Management Objectives. Cost-effectiveness and deliverability are essential considerations. This review may also include testing against non-network and Opex solutions.
- **Consumer connections and asset relocations** – the Commercial Manager generally review solutions. However, less rigour is applied to assessing options as the customer often dictates what is required.
- **Network evolution** – the Energy Futures Manager generally reviews proposals. Research-based investments are tested to assess the expected learning, potential network benefits, cost and practicality of the activity proposed.

Depending on the size of a project, further approval may be required to ensure we meet our delegated financial authority rules.

9.6 CUSTOMER CONSULTATION

9.6.1 COMMUNITY CONSULTATION

Customer consultation and engagement are a consideration for all network changes – particularly major and minor projects in the Works Delivery Programme. Powerco has a Community Engagement Advisor whose role is to assess the requirements for customer consultation and engagement and prepare an engagement plan.

Even if an engagement plan is not required, it may still be necessary to inform the local community of the work that will take place. If the community needs to be informed about the work because of disruption from outages or works in the road corridor, the Marketing and Communications team will take the lead and prepare a communications plan for the project. The process that Powerco follows for making an assessment for customer consultation and engagement is shown in Figure 9.4.

Powerco's customer and community engagement aligns with IAP2's (International Association for Public Participation) spectrum of engagement.

Figure 9.4: Community consultation process

INCREASING IMPACT ON THE DECISION

	Inform	Consult	Involve	Collaborate	Empower
Public participation goal	To provide the public with balanced and objective information to assist them in understanding the problem, alternatives, opportunities and/or solutions.	To obtain public feedback on analysis, alternatives and/or decisions.	To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	To partner with the public in each aspect of the decision including the development of alternatives and the identification of the preferred solution.	To place final decision-making in the hands of the public.
Promise to the public	We will keep you informed.	We will keep you informed, listen to and acknowledge concerns and aspirations, and provide feedback on how public input influenced the decision.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how public input influenced the decision.	We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.	We will implement what you decide.

9.6.2 CUSTOMER ENGAGEMENT

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 consultations we complete provide us with appropriate insight into the areas of service that our customers value and their evolving expectations.

9.7 WORKS PROGRAMME DEVELOPMENT

9.7.1 CAPITAL WORKS PROGRAMME

Our Capital Works Plan is approved by the Board on an annual basis. It is generally a compilation of the highest priority projects identified at the time but also includes the rolled-over portions of larger, multi-year projects.

Planning on a purely annual basis is counterproductive to effective service provider works planning, as it would involve waiting for annual project approval before works can commence. Accordingly, we also prepare a rolling two-year works plan, which is regularly updated with the next highest priority projects. We also have the approval to commit up to 30% of the following year's work programme in advance to smooth the service providers' workload.

In addition, we often commission the detailed design well before final project approval. This early design, in turn, allows us to procure long lead-time equipment, acquire the necessary land, and get consent for lines and substations.

From our network needs analysis, we generally develop, at a high level, a long-term 10-plus year view of required works. The work for the earliest five years is developed in more detail, and the work of the immediate two years is developed to a full concept design stage. The rolling Electricity Works Plan (EWP) draws on this collection of identified projects. It follows a prioritisation process by the Planning team and accounts for the availability of design and contracting resources. The Project Management team determines other possible delivery constraints, such as the available planned System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) to undertake works.

Within reasonable limits, there is usually flexibility to move the timing of projects to reflect resource or outage availability, or factors such as preferred construction seasons.

The actual planned construction programme is continually updated, and progress is regularly reported.

9.7.1.1 MAINTENANCE

The Maintenance Work Programme is sourced from:

- The Systems, Applications & Products in Data Processing (SAP) 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 Network Operations Centre (NOC), which issues urgent Reactive Maintenance fault work on an individual job basis to our Service Management Centre (SMC).

Our 10-year portfolio maintenance and vegetation forecasts are updated as part of our AMP process. This reflects updated information on asset condition, criticality, our current maintenance standards, changes in maintenance strategies, and known type or other identified one-off issues that need to be addressed.

Annual maintenance budgets are set as follows:

- Preventive maintenance budgets are set to allow the effective execution of our scheduled maintenance work and inspections for the year. These schedules are determined per our maintenance standards, using our SAP scheduling tool.
- Corrective maintenance budgets are generally informed by the volume of defects to address, which in turn is informed by asset condition and criticality factors.
- Reactive maintenance budgets are set to historical expenditure run-rates.

The budgets are compiled by the maintenance management teams, reviewed by the General Manager Electricity, and presented to the Board for approval.

The bulk of our network maintenance activities are completed by our service provider Downer – as part of an Electricity Field Services Agreement (EFSA) – and our approved vegetation contractors. In addition, some specialist contractors are used for non-standard tasks.

9.7.1.2 VEGETATION

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 to 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.

Vegetation management budgets are set to ensure that we can cycle through the whole network on a three-yearly basis and make an allowance for some risk-based interventions.

9.8 WORKS MANAGEMENT

9.8.1 CAPITAL WORKS TYPES

The acquisition of assets arises out of two principal necessities:

- Network requirements for growth, security, renewals, reliability, or proof-of-concept needs.
- Customer-initiated works (CIW).

The need for Growth and Security projects is identified by Powerco's Network Development team, the need for asset renewals by Powerco's Fleet Management team, and for proof-of-concept projects (generally) by Powerco's Energy Futures team. Investments are prioritised using the principles, processes and tools described in 9.3 to 9.6 above.

CIW generally comprise new connections, connection upgrades or asset relocation requests. Our Customer Works team handles these.

We have a list of approved contractors for customer subdivisions or other customer-managed works. These contractors work directly with the customer to arrange for the required works. The contractor will obtain approval from us for their proposed design concept and notify the customer of any special requirements, such as easements.

Larger customer projects are often managed by Powerco or under our supervision.

Our customer connection process is set out on our website. 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.

9.8.2 DESIGN MANAGEMENT

The Planning teams generally manage concept designs and work scopes for network enhancement or renewal projects. For customer requests, we have a dedicated Customer Connection team. Following project approval, the project is then passed to Powerco's Design team to either:

- Prepare in-house the design drawings, material and equipment specifications, and the installation specifications required for construction.
- Prepare briefs for external consultants to undertake this work, and to subsequently manage the delivery of drawings and specifications.

The availability of internal resources and the complexity of the work governs the choice. For example, Powerco is not equipped to undertake geotechnical surveys or civil design in-house.

9.8.3 CONSTRUCTION MANAGEMENT

The delivery of construction services is managed by our Works Delivery teams using a combination of internal and external resources.

Project managers manage contractor performance, focusing on safe construction, delivery on time, within scope, and on or under budget. Contractor supervision extends to commissioning new assets, handover to operations, and project closeout.

9.8.4 HANDOVER TO OPERATIONS

When projects have reached the practical completion stage, i.e., the equipment and all necessary SCADA interfaces have been proven safe and ready for operation, Powerco's operations group is requested to take over the works. The process may involve training and will require an assurance that all as-built and commissioning documentation is uploaded within the timeframe agreed to in the installation contract.

9.9 PROCUREMENT PROCESS

9.9.1 TESTING THE MARKET

The procurement process can consist of informal or formal testing of the market. Informal processes can range from web searches to cold calls and verbal references. Informal testing of the market is appropriate when making minor purchases.

For more substantial items, more formal testing is undertaken. Formal testing of the market includes Request for Information (RFI), Request for Proposals (RFP) and Request for Tenders (RFT), as discussed in the section below.

9.9.2 REQUEST FOR INFORMATION

An RFI is used in instances when the cost, risk and performance requirements are uncertain. It is a useful method for us to test the markets and better understand the various options available and their implications.

An RFI does not create a binding commitment on Powerco – responses from the RFI can be used to enter negotiations with a preferred party, re-evaluate the options, or not proceed at all.

9.9.3 REQUEST FOR PROPOSALS

As our understanding of what we need increases, we may issue an RFP.

RFPs are more prescriptive than RFIs because they contain a clearer scope of what is required. RFPs are often used for procuring design services, special one-off equipment, software, technology solutions and plant.

An RFP suggests a higher level of commitment than an RFI, and although Powerco is not bound to proceed with any of the proposals it receives, the general expectation is that we will engage a provider at the end of the process.

9.9.4 REQUEST FOR TENDERS

RFTs are used when we clearly understand our needs and the key risks. A detailed scope or specification accompanies them.

This method for testing the market is generally used for construction contracts or procurement of equipment that has been approved by Network Approval Test (NAT).

Tenders are the highest level of commitment of all three methods and constitute an offer to contract, subject to the price (and any other outstanding details) being accepted by Powerco.

9.9.5 OFFER ASSESSMENT

RFI/RFP/RFT responses should be formally assessed, ideally using a multi-criteria analysis framework. This ensures we consider factors beyond just price in assessing the best offer.

The ratio of price to non-price factors used to award a contract will depend on the level of uncertainty within the works. Broadly speaking, RFI assessment will have the most focus on the qualitative aspects of the assessment, followed by RFP, and finally, the RFT, which is usually the most price-focused assessment.

9.9.6 CONTRACT PROCESS

Upon selecting a successful supplier, contract process steps are completed using terms most appropriate for the transaction’s nature, value, and risk.

The appointed design coordinator for each project will manage the design contract negotiation, award, and execution. The Service Delivery Project Manager for the project will manage the contract negotiation, award, and execution of installation contracts.

9.9.7 VENDOR MANAGEMENT

This involves ensuring our contractors have adequate systems in place before we award a new contract. Powerco utilises ISNetworld to authorise prospective contractors via a desktop audit, and verification of their health, safety, environmental and quality management systems.

The project completion process and requirements are detailed within the Powerco standard and contracts. For all projects, the works will not be taken as complete until the requirements have been met and a certificate of practical completion is issued.

The audit programme under our assurance framework ensures that service providers work safely on our network and that assets are built to an acceptable standard. The programme is used to identify systemic issues with the services provided by the contractor. The relationship manager or the contract owner addresses opportunities for improvements identified under the audit programme.

9.10 LIFECYCLE MANAGEMENT

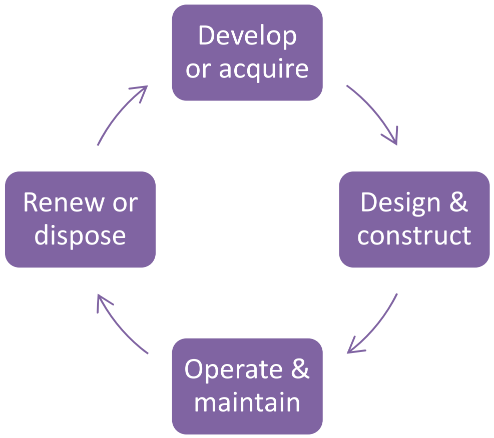
Holistic asset management considers every stage of an asset’s lifecycle, including inception and definition, design and construction, operation, and disposal. Our Asset Management Framework and Fleet Management Plans consider:

- 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.

9.10.1 OUR ASSET LIFECYCLE

Our interpretation of the lifecycle is shown in Figure 9.5.

Figure 9.5: 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 Chapters 10 and 11)
- Network reliability enhancements (discussed in Chapter 12)
- New customer connections and relocations of existing assets (addressed in Chapters 13 and 22, respectively)
- Future network needs (discussed in Chapter 7)

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 14-23.

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 14- 23.

Renew or dispose

These covers deciding 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 14-23.

9.11 RISK MANAGEMENT AND ASSURANCE

To ensure that we create value and enable New Zealand’s energy transition, effective risk management practices are a core component of good asset management.

In this section, we describe how we approach risk management in relation to asset management at Powerco.

9.12 RISK SCOPE AND CONTEXT

Asset health, criticality and risk-based decision-making are well-developed practice areas within asset management. Our risk management framework, aligned to AS/NZS ISO: 31000:2018, provides guidance for prudent decision-making within our strategic priority and risk appetite boundaries.

Our risk culture promotes flexibility and accountability across the organisation, and ensures the sustainable utilisation of resources and a common understanding of our risk systems. The environmental, social, and corporate governance alignment drives sustainable choices that will help our communities now and into the future.

9.13 RISK REPORTING

9.13.1 RISK MANAGEMENT FRAMEWORK

The Powerco Board establishes risk policy (including degree of risk appetite) and enforces compliance. It is kept informed by the ELT with respect to priority risk profiles. It uses an Audit and Risk Committee to monitor and report on how well risk management practices are applied.

The ELT has oversight of risk management practice, using the Risk Committee to promote its use across the business. It reviews risk and audit issues regularly to implement changes in response to the strategic and operational environment.

9.13.2 RISK REVIEW AND SIGN-OFF

Risk review, undertaken at both ELT and line manager level, considers the following questions:

- **Risk identification** – are risks being identified from a range of sources that reflect the organisation's core activities?
- **Controlled risk** – what is the level of risk that the organisation is exposed to once the design and effective operation of processes and controls have been considered?
- **Risk management plans** – what further risk mitigations are required to reduce risk levels to within acceptable risk appetite boundaries?
- **Future risk** – if mitigating actions are effective, what is the remaining level of risk?
- **Emerging risk** – are there new or unforeseen risks that have not yet been contemplated?
- **Risk monitoring** – are risks being viewed dynamically to ensure timely risk-based decisions are being made?

Priority-based risk registers capture all risks that are relevant to each strategic priority, grouped around our three core areas of focus:

1. **Customers and communities**
2. **Core delivery**
3. **Future readiness**

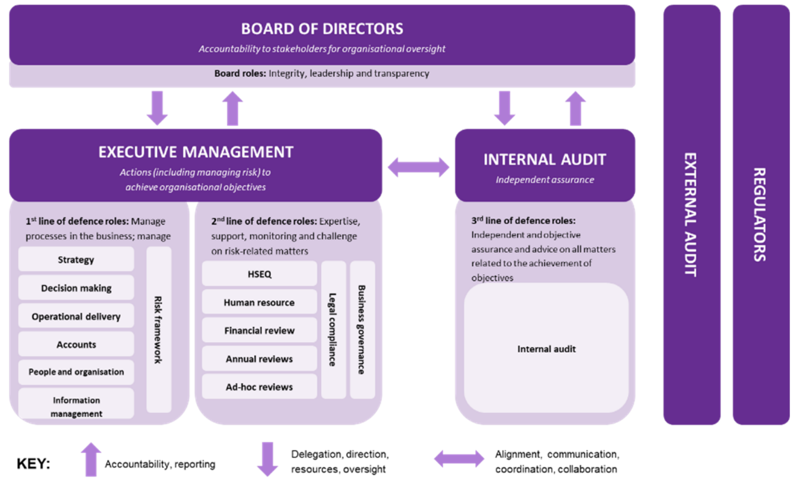
All risks are ultimately measured as a function of the impact they have on achieving our business objectives and are evaluated on common criteria.

9.14 RISK MONITORING AND ASSURANCE

9.14.1 THREE LINES OF DEFENCE

'Assurance' refers to the activities we undertake to ensure that the systems we have in place are being used consistently and that they are working. The Assurance Framework is built around the three 'lines of defence' illustrated in Figure 9.6.

Figure 9.6: Assurance Framework



1st line of defence

This is the principal area where we focus our risk management efforts. A significant portion of business-as-usual practices, e.g., standard operating procedures, permit control, and confined space entry, reside in this layer. This layer includes line supervisors and frontline staff who conduct work on the network. A significant portion of the effort spent by the ELT, 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. 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 human resources.
- Risk management team that provides risk consulting and other business support services consistent with 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 consists of qualified internal auditing staff being supported by independent external assurance providers.

9.15 RISK ASSESSMENT

Some of the primary techniques we use for assessing and managing network risk are summarised in the section below.

9.15.1 NETWORK DEVELOPMENT – VOLL

Network development planning processes address the risk of customers not being served because of network capacity or security constraints – a functional failure of assets or groups of assets. The impact of customers not being served is often quantified in terms of Value of Lost Load (VoLL).

The risk is managed through demand forecasting, maintaining knowledge of major customer investment plans, and responding to identified risks by increasing capacity, providing system redundancy, or instituting load management measures.

Powerco's Network Development approach is discussed in more detail in Chapter 10.

9.15.2 NETWORK DEVELOPMENT – RELIABILITY

Reliability engineering refers specifically to network automation projects designed to minimise the duration of supply outages, thus reducing SAIDI risk.

Powerco's automation plans are based on analysis of historical network SAIDI profiles to identify where the most significant SAIDI risks exist, and, therefore where the best gains can be made. We then devise automation strategies to minimise outages and their impact.

9.15.3 RENEWAL AND MAINTENANCE PLANNING – CBRM, RCM

Fleet planning involves consideration of historical failure trends, asset health, asset criticality (i.e., the relative service level consequences of asset failure), and asset survivor curves. We then derive a measure of service level risk.

CBRM is a tool that is increasingly being used to quantify fleet risk and to prioritise renewal expenditure. Copperleaf C55 is another recently introduced tool to help rank the importance of proposed projects.

Reliability-Centred Maintenance (RCM) is used to determine the most appropriate maintenance approach for each asset fleet. The RCM approach uses a combination of preventive maintenance, predictive maintenance, real-time monitoring, and run-to-failure (also called reactive maintenance) techniques to reduce the probability of failure.

9.15.4 DEFECTS MANAGEMENT – DEFECT RISK ASSESSMENT TOOL (DRAT)

Defects are mostly identified through inspections, which are either scheduled or undertaken on an ad hoc basis following a triggering event (e.g., a SCADA system alarm) or the identification of an asset type issue. Inspections can be visual but also include acoustic or thermographic diagnostic techniques.

Powerco uses a colour-coded grading system for identified defects that reflects the priority for repair. The grading is derived from criticality analysis that considers public and personnel safety and customer service level risks.

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	RESOLVED BY
Find-and-fix	Any job identified by a service provider onsite, which can be fixed on the spot for under $800 and will not require an outage.	Field service provider
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.	NOC
Amber defect	Condition not otherwise classified as a red defect that requires permanent repair or renewal of an asset that will likely fail within 12 months.	Service delivery
Green defect	Condition that requires permanent repair or renewal of an asset that will likely fail in a period greater than 12 months but less than 36 months.	Fleet team

While the 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.

9.15.5 CONTINGENCY PLANNING AND RESILIENCE ANALYSIS

High Impact Low Probability (HILP) events are rare, but when they do occur, they have a more significant impact than that usually catered for in our system planning criteria. They include extended outages (e.g., snow loading causing multiple pole failures), major common mode failure events (e.g., a control centre fire), and domino effect failures (i.e., failures causing related systems to fail).

Such events are hard to predict because there are multiple failure modes. Well-known examples include:

- The Penrose cable trench fire in Auckland.
- The 220kV earth shackle failure at Ōtāhuhu.
- The Christchurch earthquake.
- Powerco cascading pole failures near Taihape because of unexpected snow loading.

HILP events generally have a return period 10 times greater than the life of the asset for common mode and domino effect failures, and/or a return period of more than 500 years for extended outage events.

Generally, our mitigation of HILP events focuses on making the network as resilient as possible to reduce the probability of asset failure during contingent events, to reduce the impact of failure, and facilitate easier restoration.

Resilience measures employed by Powerco include:

- Building diversity into our network, not only from an electric circuit perspective (the focus of our planning criteria) but also from a geographic and natural disaster perspective.
- Maintaining our assets to updated codes, e.g., 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 outage scenarios.
- Taking an active role in Civil Defence and Emergency Management (CDEM) activities associated with any failure to reduce vulnerability, e.g., establishing contingency plans to deal with the consequences of unknown modes of failure.
- Considering diversity in our designs to improve resilience to type issues and single event failures, i.e., having a mix of cables and overhead lines as they have different failure modes.
- Geographically diverse and multiple supply points on the network mean that natural disasters will impact only part of our network. This includes considerations such as creating independent physical routes for redundant circuits feeding important load, or multiple GXPs 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.
- Holding appropriate critical spares to support easier repair and restoration.
- Multiple control options mean 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 against 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 participants in a regional Lifelines group, which considers disaster scenarios and tests (virtually) the responses of the various councils, utilities, and emergency services involved. Lessons learned and agreed actions are disseminated to relevant groups within Powerco.

9.16 ORGANISATION AND PEOPLE

In this section, we discuss our organisational structure and responsibilities, particularly in relation to electricity asset management.

9.16.1 CORPORATE RESPONSIBILITIES

9.16.1.1 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, approving the strategies needed to achieve those objectives, and monitoring our delivery to this.

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

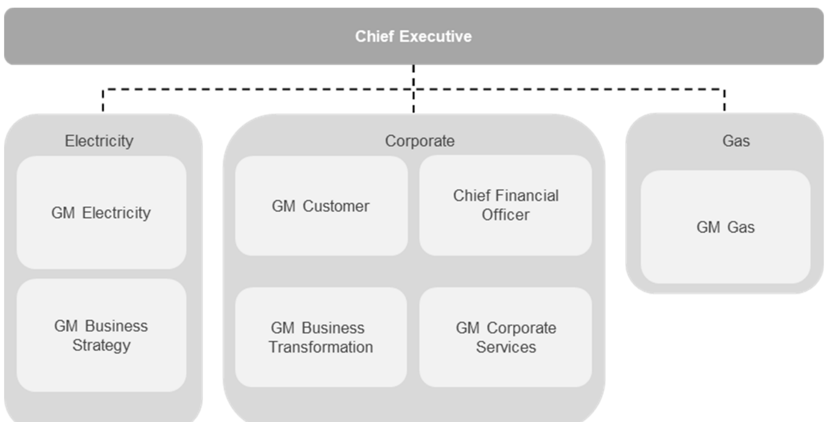
- The Board has overall accountability for maintaining a safe working environment and ensuring public safety is not compromised by our assets and operations.
- The Board reviews and approves our AMP, including our medium-term (10-year) investment forecasts and shorter-term expenditure plans.
- Based on the AMP forecasts, the Board approves our annual electricity Capex and Opex budgets. This includes our prioritised Capital Works Plan, the allowance for reactive works, maintenance and vegetation management programmes, System Operations and Network Support (SONS), and Business Support.
- The Board sanctions individual operational or capital projects involving expenditure greater than $2 million, and the divestment of assets with a value greater than $250,000. Again, 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 guide management on improvements required, or changes in strategic direction.
- The Board's Audit and Risk Committee oversees risk management practices and reviews audit findings.

9.16.1.2 THE EXECUTIVE LEADERSHIP TEAM

Our organisational structure is based on two asset management-focused units – the Electricity and Gas divisions – with the support of four functional units. The makeup of our ELT, which reflects this organisational structure, is illustrated in Figure 9.7. This structure allows the Electricity division to focus on core activities and decisions and access specialist skills and advice as required.

Figure 9.7: Executive Leadership Team structure

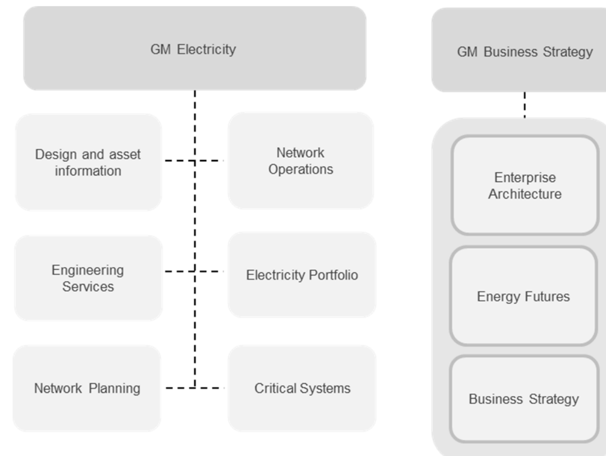


The Electricity and Gas divisions are responsible for asset investment, operational management, and commercial management of each business line.

9.16.2 CORE ELECTRICITY ORGANISATION STRUCTURE

The Electricity division has specialised teams reporting to two general managers, as depicted in Figure 9.8.

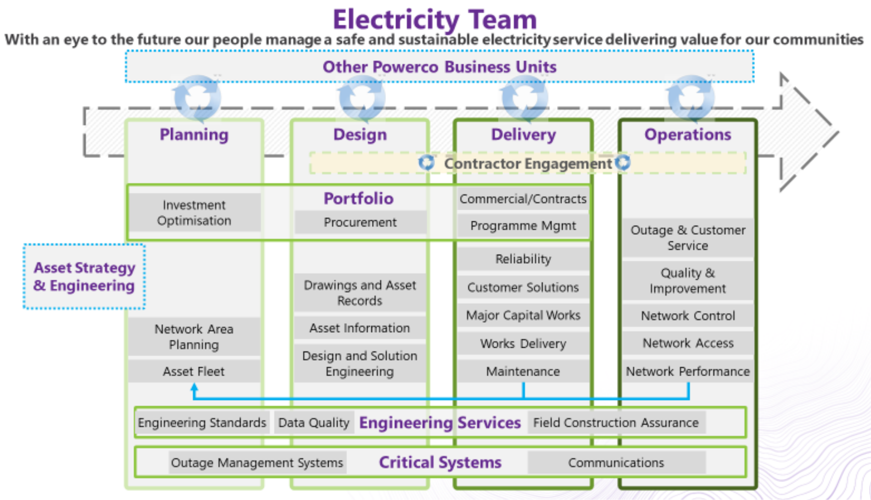
Figure 9.8: Electricity division structure



9.16.2.1 ELECTRICITY DIVISION

The key responsibilities of the Electricity team are illustrated in Figure 9.9.

Figure 9.9: Electricity team structure and functions



9.16.3 BUSINESS STRATEGY

The Business Strategy team is responsible for:

- **Enterprise architecture** – business capability framework, system, and data architecture.
- **Energy futures** – network transformation and advanced analytics.
- **Business strategy** – setting business strategic direction.

9.16.4 OUTSOURCING MODEL

External contractors provide the bulk of our field services. We have developed a close working relationship with these contractors to provide essential services on our network. These services are managed under a series of foundational agreements. Table 9.8: summarises our contract arrangements with our major service providers.

Table 9.8: Summary of our major contracts

CHARACTERISTICS	NAME	KEY CONTRACTS
Electricity Field Services – minimum spend	Electricity Field Services Agreement	1 x contractors
Electricity Field Services – no minimum spend	Electricity Field Services Agreement Master Field Services Agreements	11 x contractors (variable)
Vegetation Management	Vegetation Management Services Agreements	9 x contractors (variable)
Equipment supply	Framework Agreements for Supply of Equipment	8 x contractors (variable)
Use of Network	Default Transmission Agreement Default Distributor Agreements Carrier Access Agreements Electricity Network Connection Agreements	Variable
Design & engineering services	Master Agreements for Design and Engineering Services	7 (variable)

9.17 ASSET MANAGEMENT GOVERNANCE

We have established several internal asset management governance groups to ensure a prudent delivery of our objectives.

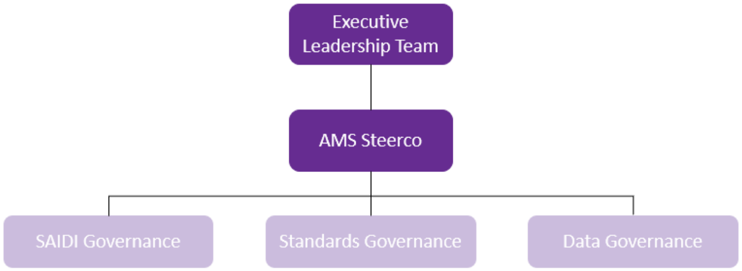
Internal governance bodies are at the management (not Board) level. They are cross-functional and often cross-disciplinary teams with a targeted mandate to lead, review, and report in particular areas.

Our Asset Management Governance Framework defines the committees, steering groups, and boards. This structure provides a single point of control and governance for specific activities. It also outlines procedures to formalise the key interactions and responsibilities across our business.

9.17.1 NETWORK GOVERNANCE GROUPS

In Figure 9.10, our network governance groups are illustrated.

Figure 9.10: Overview of network governance groups



Asset Management System Steering Committee

The Asset Management System Steering Committee is an executive-level committee responsible for our electricity operations. It is accountable for and provides strategic guidance and oversight on the development and implementation of our AMS.

SAIDI/SAIFI Governance Group

The SAIDI/SAIFI Governance Group provides the structure, develops strategies, and coordinates the activities of our business to ensure that our planned and unplanned reliability quality targets are met.

Standards Governance Group

This committee includes appropriate managers or engineers across Asset Strategy and Service Delivery with an in-depth technical appreciation of the standards applicable to the network. Its primary role is to review and approve new or changes to Network Standards.

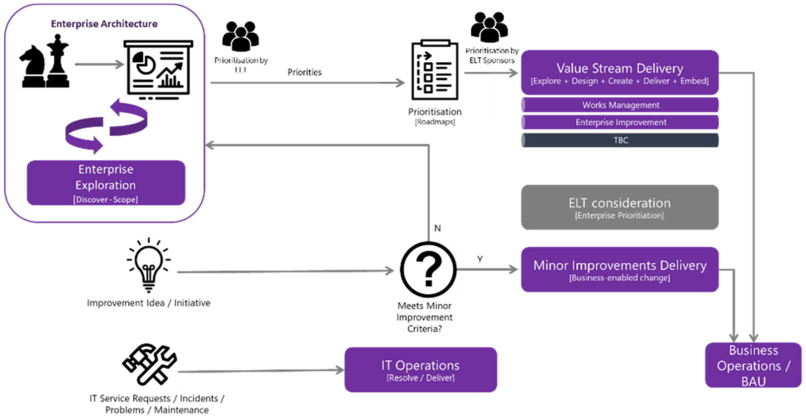
Data Governance Group

This committee is accountable for the governance of all Powerco business data. It oversees and coordinates several data communities from various parts of the business. The intent is to maintain a culture of ongoing data improvement through policies, procedures, standards, ownership, accountability, communication, and teamwork.

9.17.2 NON-NETWORK GOVERNANCE GROUPS

The interactions between the Business Strategy, Business Plan and value streams are depicted in Figure 9.11. The interactions and prioritisations between each stage are the effective governance groups.

Figure 9.11: Overview of non-network governance groups



Enterprise Exploration, Strategy and Business Plan

Powerco has a newly formed Enterprise Architecture team that governs the architecture across Powerco, including non-network (ICT Investments). The team is working with wider Powerco leaders to set the Business Plan for FY24, which is aligned to the objectives set out in the Business Strategy. Any work outside this will run through the Enterprise Exploration phase to discover and scope the work.

Once the Business Plan has been developed, the ELT will be passed a set of outcomes or capabilities to prioritise. The ELT will be the first level of governance carrying out this prioritisation exercise.

Once the outcomes or capabilities have been prioritised, these are passed to our ELT Sponsors for each value stream to prioritise the activities that will take place within each stream.

ASSET MANAGEMENT PLANNING RESPONSIBILITIES

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

Table 9.9 provides an overview of these expenditure planning governance levels.

Table 9.9: 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 Business Strategy	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 Business Strategy	Asset Management Plan
Long-term planning	The plan for development of the network and its bulk supply points to meet customers' needs in the long term – up to 20 years.	Network Development Manager, GM Business Strategy	Long-term Network Development Plan
Medium-term planning	Fleet, Network Development and Operating Activity plans, covering the next 10 years, including expenditure forecasts.	GM Business Strategy, 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 Business Strategy, 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

9.18 INFORMATION MANAGEMENT

This section gives a brief overview of the information systems (IS) at the core of asset management at Powerco. This relates primarily to information we use to plan, design, operate, monitor, and maintain the electricity network and its performance. However, it also extends to our activities for Information Disclosure, regulatory and statutory reporting, customer management and billing management.

Easy access to accurate and useful information is essential for an effective electricity utility. Therefore, information is considered a valuable company asset that sits alongside our physical assets and demands the same level of protection and management throughout its lifecycle.

Asset management information systems are predominantly software-based applications, ranging from extensive, integrated, enterprise-wide systems to stand-alone processes or spreadsheets. They also include paper-based and photographic records, maps, and drawings.

The ultimate objective of these systems is to enable an organisation to provide comprehensive, easy-to-access asset information, and to ensure that this is accurate and consistent.

9.18.1 INFORMATION TECHNOLOGY ARCHITECTURE

We have adopted a platform approach where all the information and technology capabilities 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 9.12, and will see the addition of three new platforms: Customer Experience, Business Ecosystem, and Internet of Things.

It is important to note that we have not specified a separate cyber security platform as this is a component of each platform.

Figure 9.12: Technology infrastructure platform architecture (future state)

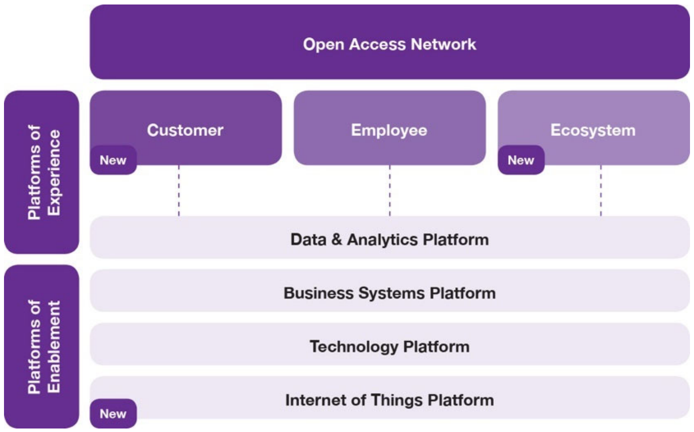


Table 9.10: IS architecture

TERM	DESCRIPTION	KEY SYSTEMS
Customer Experience platform	Contains the main customer-facing elements, such as customer portals, multichannel commerce, and customer apps.	Salesforce Customer Relationship Management (CRM), SiteCore Experience Platform
Employee Experience platform	Consumerised tools and services to aid employee engagement, collaboration, and productivity. This includes managing unstructured information, such as designs, standards, and procedures.	Microsoft Office 365 email, Teams, SharePoint, Meridian, 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.	Dell Boomi, SAP PO/PI, Microsoft Azure API Gateway
Data & Analytics platform	Contains data management, business analytics and advanced analytics capabilities. Data management programs and analytical applications fuel data-driven decision-making, and algorithms automate discovery and action.	SAP Business Objects, Data Services, and Information Steward, Tableau Online, SQL Server Datawarehouse, Google Cloud Platform, Alation Data Catalogue
Business Systems platform	Supports the back office and operations, such as ERP, ADMS and information management. For Powerco these include:	SAP S/4 HANA, ESRI GIS, Clearion vegetation management, Junifer Billing, Customer Works management system, OSII SCADA & OMS, Safety Manager, AutoCAD, OSI PI
Technology Infrastructure 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 platform	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

9.19 BUSINESS SYSTEMS USED TO MANAGE ASSET DATA

The main applications comprising the Business Systems platforms used to manage asset data are described in more detail below.

9.19.1 ENTERPRISE RESOURCE PLANNING (ERP) SYSTEM

We have recently implemented a new ERP using SAP.

It provides a single, integrated software system that connects our financial and works management (projects, maintenance etc) systems, and is the master of non-spatial asset and financial data.

SAP also provides financial tracking, works and maintenance programming, works and maintenance management, procurement, asset information database, asset condition database, and defect and rotable asset management.

9.19.2 MOBILE WORKFORCE MANAGEMENT

We have also integrated a mobile workforce management solution (Blueworx) to provide field staff real-time access to SAP. All these capabilities are interconnected, which will lead to operational efficiency gains, the primary benefit of an ERP. This application enables field capture of asset condition, maintenance activity results and defects. Data entered in Blueworx and synchronised with SAP, allows us to generate key reports.

Blueworx helps ensure that service providers' asset management data is complete and standard. This is key if we are to retain core asset knowledge in-house.

9.19.3 GEOGRAPHICAL INFORMATION SYSTEM (GIS)

We use a GIS to capture, store, manage and visualise our network assets. The system contains data about the lines, cables, devices, structures, and installations of our electricity distribution network. Importantly, it is also where we maintain information about the interconnectivity of our assets – essentially the master model of our network.

It also distributes and informs other systems about our current assets.

The asset spatial information is also a key input into maintenance scheduling, where geographical and network hierarchy factors are considered in the asset base planning, monitoring and improvement.

9.19.4 ASSET INVESTMENT PLANNING AND MANAGEMENT (AIPM)

Our AIPM tool is a software package that allows us to optimise investment for our portfolios. We use Copperleaf's C55 product (known internally as Copperleaf), to help with our portfolio optimisation process. Utility companies globally use Copperleaf to identify annual programmes of works, based on asset condition information.

The aim of utilising Copperleaf is to use our understanding of our asset risk position to identify and validate investment solutions efficiently. The program also allows us to quickly explore multiple varied scenarios to make optimal use of our resources.

The implementation of Copperleaf represents a significant step change in our portfolio optimisation capabilities.

9.19.5 SCADA MASTER STATIONS, SCADA CORPORATE VIEWER, AND PI SYSTEM

We operate OSI Monarch Supervisory Control and Data Acquisition (SCADA) in both our regions. The master stations to control and monitor our network are highly available and are located in each of our data centres. In the event of a failure, the SCADA support team can safely de-energise parts of the network from another location.

Monarch Lite provides real-time access to users outside of our NOC. This application provides users with access to real-time network information for planning and network management.

The OSIsoft PI system specialises in collecting, processing, storing, and displaying time-series data.

9.19.6 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 customers 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 number of affected ICPs. This information is then given to service providers so they can dispatch a resource to resolve the fault.

OMS is also used as the fault database to produce external reports for the Commerce Commission and Ministry of Business, Innovation and Employment, and internal reports for our management and engineers to improve network performance. It is an ongoing record of electrical interruptions on 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.

9.19.7 CUSTOMER WORKS MANAGEMENT SYSTEM (CWMS) ELECTRICITY

This online workflow management system 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 system's primary function is to manage the flow of customer-initiated work requests through our formal process, from the initial request to the 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 CIW process. This process places importance on providing new and existing customers with a choice of prequalified contractors 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.

9.19.8 ENGINEERING DRAWING MANAGEMENT SYSTEM

The engineering 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, a separate vault contains legal documents relating primarily to line routes over private property.

9.19.9 PROTECTION SETTINGS MANAGEMENT SYSTEM

This application provides a protection database to manage settings in our protection relays.

9.19.10 CUSTOMER COMPLAINTS MANAGEMENT SYSTEM (CCMS)

This is a workflow management system that maintains an auditable record of the lifecycle of a customer complaint. The application (Salesforce) 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.

9.19.11 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 an operational and strategic level. In addition, it assists the Health, Safety, Environment and Quality (HSEQ) team in supporting the management of personal protective equipment (PPE) and Health and Safety competencies for all our employees.

9.19.12 BILLING SYSTEM

Powerco receives consumption data from retailers and customers. Bills are calculated using the Junifer billing engine and invoiced from SAP.

9.19.13 VEGETATION MANAGEMENT SYSTEM

We use Clearion's Vegetation Management solution to identify, track and manage vegetation encroachment within our electricity networks.

9.19.14 OTHER SYSTEMS OF RECORD

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
- High Voltage (HV) drawings

9.20 INFORMATION SECURITY

Cyber risk management is a core component of our business. It is essential in the face of an ever-evolving threat landscape and an increasingly interconnected IT ecosystem. Powerco's strategy for managing information (cyber) security risk is continuous improvement, simplifying our approach to risk quantification, and finding the right balance between security, maintainability, and agility.

Information security involves protecting our organisation's information systems (including the data they contain) from unauthorised use that could jeopardise the confidentiality of our employees, customers, and partners, negatively impact the availability of our core operational systems, or corrupt the integrity of the data we need to deliver our services effectively.

A dedicated Information Security team, the Privacy Officer, and the broader Risk team manage Information Security at Powerco. Our works programme not only aims to manage those risks faced by our core energy distribution networks and customer-facing IT systems but to ensure we remain resilient in the face of new and emerging threats.

Data privacy is essential. Using third-party software services to host and process sensitive data increases the risk of data compromise, breach of privacy laws, and reputational damage. In addition, legal and regulatory changes place more emphasis on the privacy and security of personal data. In addressing these concerns, we will maintain our ISO: 27001 certification for managing sensitive customer information and take a risk-based approach to strengthen our cyber security controls.

9.21 IT SYSTEMS IMPLEMENTATION AND CONTINUOUS IMPROVEMENT

Powerco's strategy for ICT is 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 we support.

We have 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. Cloud services will help drive standardisation, reduce implementation time, and bring operational benefits important for a midsize organisation such as Powerco.

NETWORK DEVELOPMENT

Our plans to develop and improve our network's response to customer change.

10 GROWTH AND SECURITY INVESTMENT

10.1 CHAPTER OVERVIEW

Most of our network continues to experience sustained demand growth. This growth is mainly driven by residential development in areas including Tauranga, and dairy and industrial growth in Waikato and Taranaki. We also anticipate an increase in demand because of the increased use of electric vehicles and the conversion of smaller-scale industrial processes to electricity. These trends will continue to drive sustained Growth and Security investments.

The pace of demand growth on our network will be highly influenced by factors such as the uptake of electric vehicles, local generation, energy storage, electrification from process heat conversion, and the potential for customer energy trading over our network.

In the long term, these factors will likely cause increased investment in our Growth and Security portfolios, which is discussed later in this chapter. However, we will moderate this investment by introducing probabilistic planning standards, allowing us to understand our reliability risks better and plan more efficient investments to manage these risks.

The impact of the above demand trend factors is uncertain and could lead to various future scenarios. 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.

10.2 GROWTH AND SECURITY PRINCIPLES

10.2.1 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 eight main types of investments.

Customer reliability and security investments:

- **Major projects** – more than $5m that involves zone substation works and subtransmission projects. These are discussed in our area plans in Chapter 11.
- **Minor projects** – less than $5m that involves zone substation works and subtransmission projects. These are discussed in our area plans in Chapter 11.
- **Routine projects** – Growth and Security-driven investments on our distribution and LV network.
- **Reliability** – includes network automation projects to help manage the reliability performance of our network. These are discussed in Chapter 12.

Network-enabling investments:

- **Open-access network investments** – investments in network monitoring, communications, and power quality management to support our transition to an open-access network.
- **DSO** – investments to enable a DSO future, primarily focused on improving the operation of our LV network.
- **Communications projects** – to support improved control and automation of the network and provide voice communications to our field staff.
- **Network evolution** – includes investments in network trials to understand our long-term network response to the 3Ds – decarbonisation, decentralisation, and digitalisation.

10.2.2 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 4.

Table 00.1: Growth and Security objectives

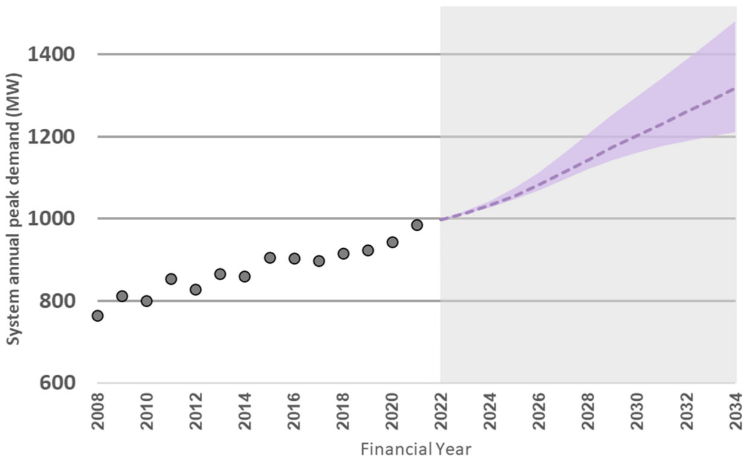
ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Use safety-in-design to ensure appropriate design of the network to provide for alternative supply during maintenance, and help ensure the intrinsic safety, ease of maintenance, operations, and accessibility of our assets.
	Consider 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 closely with landowners during our access and consent process.
	Ensure our customer contribution policies are fair, in that they reflect the unrecovered cost of progressing a connection.
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 in delivering reliable energy more effectively.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
	Use appropriate levels of network automation and remote control to reduce outage times following faults, as well as the number of Installation Control Points (ICPs) affected.
	Refine our demand forecasting and security criteria using probabilistic methods 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 make future planning more systematic and thorough.
Operational Excellence	Obtain more comprehensive, accurate data to aid high-quality options analysis, so that the most cost-effective, long-term solutions can be consistently identified.
	Develop our area plans to holistically consider all network priorities – renewal, development, customer needs and reliability.

10.3 DEMAND TRENDS

Our network has continued to experience steady and sustained growth during the past 10-15 years. Figure 00.1 shows the historical trend and our forecast of total system demand for the whole network.

Figure 00.1: 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 in the dairy industry, and the oil and gas industry in Taranaki.
- Smaller contributions from irrigation developments, cool stores, and other agricultural loads.

The demand forecast has been heavily updated for the 2023 Asset Management Plan to reflect updated decarbonisation drivers, such as electric vehicles and process heat conversion. These updates have resulted in a significant increase in our demand forecast compared with the 2021 Asset Management Plan, particularly in the latter part of the planning period. This increased demand results in an increase in our Growth and Security expenditure. Our demand forecast is explained further in Chapter 2.

Growth in each area of our network varies according to demographic changes and economic activity. Figure 10.2 and Figure 00.3 indicate annual forecast growth rates by planning area for the Western and Eastern regions.

Figure 10.2: Forecast demand growth in Western planning areas

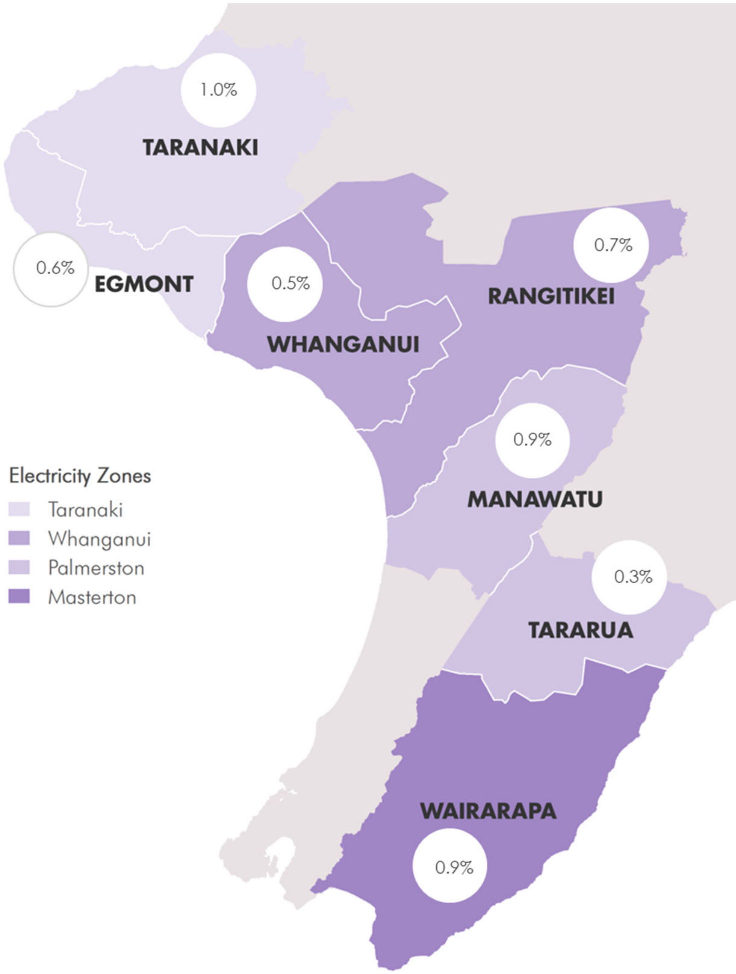
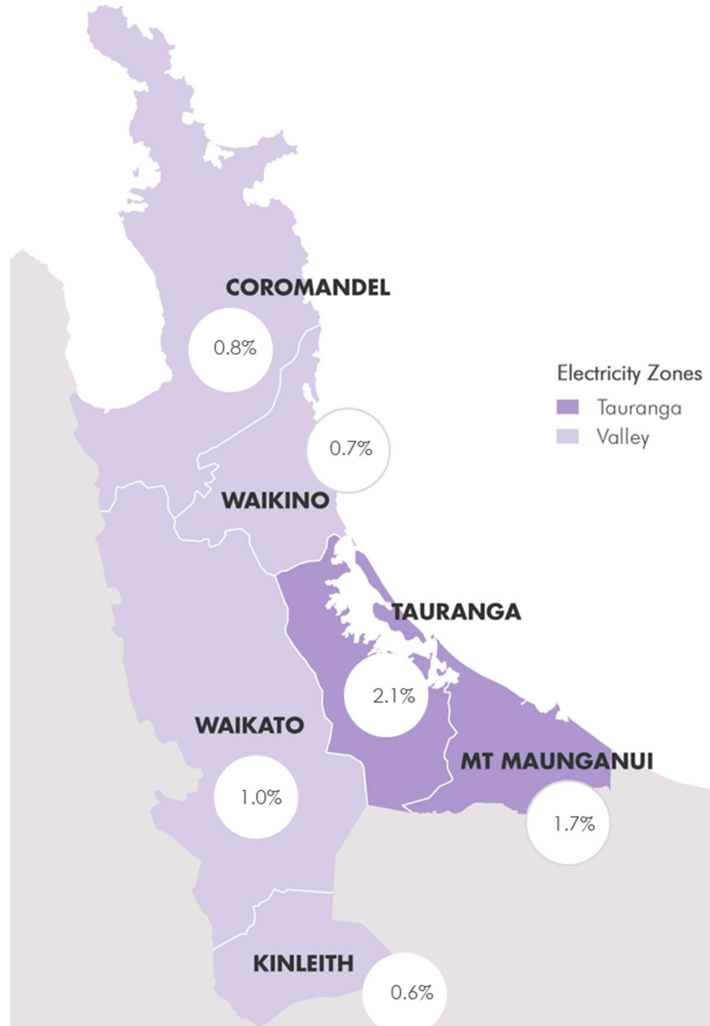


Figure 00.3: Forecast demand growth in Eastern planning areas



Higher growth is evident in areas such as:

- Tauranga and Mt Maunganui – population increase driving residential subdivisions and commercial/industrial developments.
- Waikato – industrial developments, with early signs of decarbonisation, supported by population growth.
- Taranaki – industrial, often associated with oil and gas.

Compared to our 2021 AMP, nearly all planning areas are forecasting higher growth. In recent years there has been an increase in general growth underlined by strong economic activity.

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 Chapter 11.

For more detailed descriptions of the options considered for our large Growth and Security projects, refer to Appendix 7.

10.4 ROUTINE PROJECTS

10.4.1 OVERVIEW OF ROUTINE CAPEX

We define routine Capex as a Growth and Security-driven investment in our distribution and LV network. Unlike our major and minor projects, routine growth projects incorporate the lower cost, usually repetitive projects that address capacity and security. This typically includes distribution capacity and voltage upgrades, distribution backfeed reinforcements, distribution transformer upgrades, and LV reinforcement.

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 and, currently, we typically don't identify individual projects more than two to three years before implementation.

As such, to understand our longer-term investment requirements, we need to consider the type of work, why it needs to be done, and the general trends in these activities.

Historically, these investments mainly occur at the High Voltage (HV) distribution level. However, we are now turning more attention to our LV network to understand and then manage the impact of new technology, such as increased distributed generation, energy storage, and electric vehicle charging, particularly from residential customers. We aim to ensure that the network is an enabler for our customers to invest in these technologies.

While it is not practical to identify specific projects in the routine class, some trends and patterns influence each planning area. These trends are discussed in the Area Plans Chapter 11.

10.4.2 ROUTINE PROJECTS INVESTMENT DRIVERS

Historical expenditure trends on routine Growth and Security projects have been used to inform appropriate expenditure levels.

Types of projects include those that come from distribution planning analysis (refer to Chapter 9). These projects typically add capacity to existing parts of the feeder network or create additional feeders or backfeed ties.

Traditionally, such expenditure was strongly linked to underlying growth, which is still true for some project types, such as capacity upgrades, voltage regulators and new feeders.

However, in areas with less growth, upgrades to distribution feeder links are often focused on providing additional backfeed capability. These upgrades include new feeder interconnections (or ties) and larger conductors or cables to allow a better voltage or thermal capability under backfeed conditions.

Our automation plan (refer to Chapter 12) includes investment to ensure our automated or remote-controlled switching schemes do not overload existing circuits or result in unacceptable voltages. This investment has brought forward several feeder tie and backfeed upgrades.

Other drivers for routine project Growth and Security expenditure include:

- Increased use of 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.

With increasing electricity demand, we expect our routine Capex to increase during this planning period. The expenditure forecast is based on our demand forecasts, and our historical expenditure to support our prior growth. With the rate of demand growth increasing, investment is expected to more than double by the end of the planning period, compared with today's investment levels. The future investment will also include upgrades to the LV network driven by growth, whereas today most routine investment is on the distribution network.

10.5 OPEN-ACCESS NETWORK

10.5.1 OVERVIEW

Internationally, there is much activity on the development of open-access networks. This is done in conjunction with the development of the distribution system operator (DSO) concept, of which open-access networks are an essential enabler.

In New Zealand, the Electricity Authority (EA) is supporting this concept but as also reported in previous AMPs, there has still been little progress in discussing how it may be achieved. This may change in the near future, with the EA now taking an active interest in the regulation of distribution utilities.[79]

There is much discussion within 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, as is discussed further in Chapter 7. But looking later into the AMP planning period, we anticipate their impact on the network will become noticeable and continue to accelerate.

As stated in our strategy, we want to support these changes – helping our customers in their drive for energy efficiency, and providing them with an easily accessible, stable, and economical platform over which to conduct energy transactions. This is the essence of the open-access network.

While an open-access network promises significant opportunities, it will also pose substantial challenges to ensure our network remains secure, safe, and stable under the anticipated highly variable load and two-way power-flow conditions. It will therefore require substantial changes to the way we plan, construct, and operate the network. This includes:

- Adapting probabilistic planning standards for most of our forward planning, and systematically rolling this out to all network categories.
- Increasing asset and network utilisation.
- Network energy storage solutions, for demand management and standby capability.
- Expanding the use of demand-side participation, such as load control, to improve network utilisation, and deferring reinforcements.
- 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 (OMS).
- Extensive automation devices spread across the network.
- Increasing communications networks, including a network-wide roll-out of a Long-Range Wide Area Network (LoRaWAN) network to connect multiple sensors and other Internet of Things (IoT) devices.
- Enhancing real-time monitoring of asset and network condition.
- Advanced automation and protection solutions to enable networks to self-heal and minimise interruptions.

We endorse the work of the Electricity Network Association's Smart Technology Working Group, in particular its 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 section 7.2, which focuses on research and development work. Since we foresee investment in the future on open-access networks will be part of our business-as-usual, the provision for this work to commence 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 outlined in section 7.210.8.

10.5.2 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. However, as discussed in Chapter 2, we are starting to see uptake rates accelerate, with record numbers of applications in 2022. There have also been increased discussions about how networks should be operated to facilitate these trends, which are expected to become a material factor for electricity networks here soon, as they are in parts of Australia, the United Kingdom, the United States and Europe.

One clear network need that we see as common across all future open-access scenarios, is to gain good visibility of power flows and power quality. This is particularly important at the LV level, where most customers connect and where the impact of changing energy patterns will be most evident. Closely associated with this, albeit potentially somewhat later, is the 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 (and Distribution System Operator) may eventually be structured.

Therefore, we intend to commence with investments on 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 in a programme that will stretch over 10 years, we will prioritise rollout to our high-demand circuits or where we have known system constraints.
- **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

[79] For example: Electricity Authority, "Updating the regulatory settings for distribution networks (December 2022)"

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 our control centre. This will be expanded alongside the metering roll-out. This is in addition 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 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. Therefore, we include additional (limited) provision for power quality management devices to be installed progressively post FY24, including voltage regulators, capacitor banks, VAR compensators and automatic tap changing schemes.

If we do not commit to this investment now, in the absence of good visibility across our network, we will eventually have to manage network risks by applying conservatively based static analysis of worst-case scenarios. This will result in limits on the volumes and types of devices that can be connected to our network, or the need for substantial investments in network reinforcement.

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 and lower costs for our customers.

Preference for cross-industry collaboration

The bulk of the proposed open-access network 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 existing smart meters or other intelligent devices across the network. 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, in the main, not suitable to provide the support needed to effectively run open-access networks.

There would be a 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 FY26 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, we will revise the forecast expenditure in future.

10.6 DISTRIBUTION SYSTEM OPERATOR

To encourage the uptake of local, particularly renewable, generation, advanced economies are realising the importance of creating an electricity market at distribution network levels – the Distribution System Operator (DSO). Further, there is much activity on the development of the concept of open-access networks internationally. The DSO concept is usually discussed in conjunction with open-access networks (see prior section) as they are an essential DSO enabler. In New Zealand, the EA is supportive of this concept. However, there has still been little progress in discussing how it might be achieved. This may change in the near future, with the EA now taking an active interest in the regulation of distribution utilities.[80]

Powerco is still committed to evolving from a distribution network operator to a DSO in the future (to the extent the New Zealand electricity market will permit this). In anticipation of some form of DSO and distribution electricity market in New Zealand, we are looking to ensure that the essential (distribution network) enablers for this are being developed. These developments are largely agnostic to who will take on the role of the DSO, as the basic requirements will be similar for any party in this role.

Our initial focus will be on operationalising the underground LV network, followed by the LV overhead network. In most cases, the investment will be directed to ensuring we can safely and efficiently utilise backfeed and sectionalising opportunities on our LV network. We have also allowed for additional expenditure to upgrade sections of the LV network where capacity constraints arise because of the EV and photovoltaic panels (PV) uptake increase.

The types of initiatives include:

- Replacement of LV feeder interconnection points on the underground LV network with operational linkboxes.
- Installing resettable LV fuses on high-value customer loads.
- Creating operable LV link points on our LV overhead network to facilitate backfeeding.
- Upgrading LV cable and conductors in areas of our network where we are seeing high PV and EV uptake.

These initiatives and the overall strategy to improve the operational effectiveness of our LV network are discussed in more detail in Chapter 7 We expect this investment in our LV network to increase from about FY26.

Complementing this investment is our LV monitoring programme, discussed in the previous section. Together, these investments will move us towards a fully administered LV network, capable of being operated much like our HV network.

[80] Supra note 79

10.7 CRITICAL SYSTEMS AND INFRASTRUCTURE

10.7.1 OVERVIEW

The systems and infrastructure that encompass our communications network, Advanced Distribution Management System (ADMS) platform, and virtual infrastructure are strongly focused to ensure a robust, flexible, and scalable platform that can support and enable the successful implementation of our ADMS programme.

Timely access to data for real-time decision-making is becoming increasingly important and challenging as more devices and more data are required as we move closer to an open access/DSO model for the future of the network.

Such connectivity is challenging given a large part of our network is rural. This, coupled with the lack of terrestrial public network services at many locations, means we must establish our own communications. 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.

We already need increased visibility and a degree of real-time control of many disparate devices to feed our SCADA platforms. This has accelerated as we implement wider LV visibility and, in turn, feed this into ADMS. This requires a reliable, robust, secure, low-latency communications network.

The key drivers to achieve these outcomes are:

- **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** – enabling networks to be designed and delivered in a manner that responds dynamically to changing demands and needs.
- **Modernising the grid edge** – using 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. This is key to enabling our ADMS strategy.

While this is complex, and building this type of capability is important, we also need to be considerate of the costs associated with such a development. Our planning approach will help ensure there is consideration to effectively make trade-offs between current needs, future opportunities, and the costs associated with building out a largely rural communications network.

The communications network Asset Management Plan addresses these challenges. It is designed to enable the current and future business services that we need to have in place to ensure a reliable, safe, and sustainable power supply, which promotes safety and wellbeing for our communities.

10.7.2 COMMUNICATIONS NETWORK PRINCIPLES

Our communications network has been designed based on three key principles:

Reliable networks – communications engineered for resilience

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.

Flexible and scalable – agile and responsive to changing needs

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 and partners.

Leveraging investment – maximise the benefits of existing infrastructure

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 the 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.

10.7.3 CRITICAL SYSTEMS PLATFORM (VIRTUAL INFRASTRUCTURE)

Powerco's underlying data centre infrastructure (CSP) is central to hosting SCADA, ADMS and other core network functions. This is a secure independent platform with redundancy in both of our data centres to ensure business continuity and resiliency of our network operations. This system is due to be replaced and upgraded with a particular focus on scalability and resiliency to cater for current and future ADMS requirements. This is a core component to enable future operations as we transition towards the DSO of the future.

10.7.4 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

Powerco's ADMS programme is centred on the Open Systems International (OSI) platform that supports our network operations for SCADA and outage management. These advanced applications that make up the wider ADMS ecosystem are designed to provide us with more network visibility, improved switching operations, and network management capabilities, as well as critical network power, flows in real time.

At the same time, we will develop a more detailed network model and mobility solutions to give staff and service providers a real-time view of our network status.

This core smart grid platform will allow us to maintain network quality and reliability as our customers take increasing advantage of distributed energy resources, such as PV generation and local battery storage.

Alongside the growth in our communications network infrastructure, we need a real-time data platform to process increasing volumes and a variety of data from a proliferation of sensors, both in real-time for network operations and to enable trending and forecasting for asset management.

10.7.5 COMMUNICATIONS NETWORK PLATFORM

Powerco's communications network comprises the base layer Packet Transport Network, which is the backbone to which we transport a series of services.

These transport services include the following:

- Packet Transport Network platform (PTN)
- Digital Mobile Radio platform (DMR)
- Narrow band radio (UHF/VHF)
- Internet of Things (IoT) – LoRaWAN/4G
- Project Hauraki (Fibre)

10.7.6 PACKET TRANSPORT NETWORK PLATFORM (PTN)

The PTN is the main highway for data and voice communications back into Powerco's Network Operations Centre (NOC). The PTN is a Multiprotocol Label Switching (MPLS) based packet switching network that uses fibre, microwave, and leased line services to transport information. It is a critical component in the operation of Powerco's electricity grid. This network covers the expanse of our core network locations with a programme to extend into all substations.

10.7.7 DIGITAL MOBILE RADIO PLATFORM (DMR)

The DMR allows Powerco's NOC staff to communicate with field contractors in locations where public mobile services are unavailable. As the primary means of communication with field resources, DMR is built with a high level of redundancy to help ensure the health and safety of staff and contractors working in remote locations. We are constantly reviewing performance and testing additional functionality within this platform. There are additional sites to be deployed to enhance current coverage and trials are underway to provide SCADA telemetry via the DMR using this extended coverage.

10.7.8 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 our electricity grid. DMR SCADA and IoT functionality are being trialled and if this is successful, we will look to adopt these to enhance the existing fleet.

10.7.9 INTERNET OF THINGS (IOT)

The IoT platform (LoRaWAN) has the ability to use low-cost, low-power sensors and base stations that can cover a wide geographic area. This transport method is also being adopted in many of the other sensors and monitoring device types that we are implementing across the network. The IoT platform will provide us with additional insight and a considerable volume of new data points to better enable decision-making, fault finding and restoration.

Many of these data inputs from Line Fault Indicators (LFIs) and other sensors will become increasingly important in visibility, ensuring time to diagnose and repair faults is reduced.

10.7.9.1 PROJECT HAURAKI

This project is the investment and deployment of a fibre optic ring around the Coromandel Peninsula in conjunction with our business development team. This fibre will provide Powerco with additional diversity and redundancy on our microwave network in the area. It will also enable high-speed communications into our substations for protection, DMR radio, SCADA, and communication high sites servicing the region.

10.7.10 FUTURE ROLLOUTS

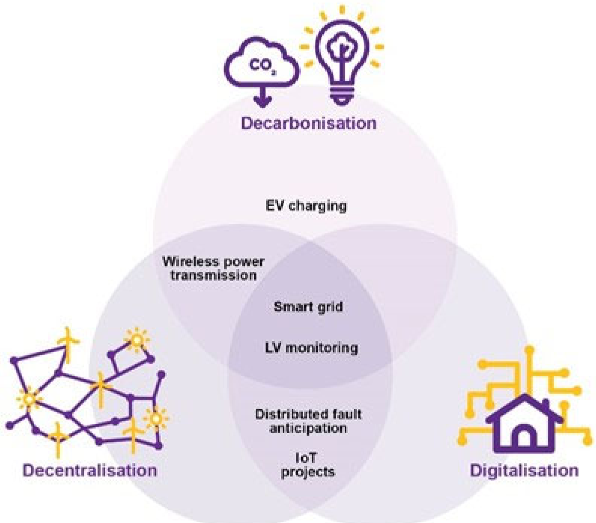
Our principal development programmes are built around these critical systems platforms, as shown in Table 10.2.

Table 10.2: Communications network development programme

FUTURE ROLLOUT PLATFORM	DETAIL
	Digital mobile radio network additional coverage and capacity.
Digital mobile radio platform	Implementation of data functionality.
	SCADA telemetry.
Packet Transport Network	Transport network expansion to all zone substations.
(PTN) platform	Cellular Transport Network – where PTN is not available
	Transport resilience – east to west microwave link.
	Migration of the distributed IP network to PTN.
	Leveraging other existing/new fibre assets.
	Project Hauraki.
Internet of Things (IoT)	SCADA integration from field sensors.
platform	IoT network build-out and operational integration of field devices.
	Expansion of IoT platform.
Other supporting initiatives	
Communications governance	Implementation of a new communications network governance structure.
Communications Service Level Agreements (SLA)	Finalisation of communications SLAs and reporting.
Fibre assets	Future consolidation and enhancements across the network.

10.8 NETWORK EVOLUTION

Decarbonisation, decentralisation, and digitalisation are three of the key factors influencing the future of our network. Understanding how the customer will respond to these factors is crucial in enabling us to evolve our network to meet these changing demands. We have several projects underway to help us develop our understanding.



10.8.1 ELECTRIC VEHICLE CHARGING PROJECT

EVs are widely accepted to be one of the key disruptive technologies that may impact electrical networks in the future.

This project aims to understand the impact of electric vehicle charging on our network.
The main objective of the project is to predict the additional peak load that can be expected as EVs become more prominent on our network footprint.

This project strongly aligns with the decarbonisation trend outlined in Chapter 7. To a lesser extent, this project also covers the digitalisation trend.

Each of the four network transformation scenarios outlined in Chapter 7.2 is likely to feature a strong concentration of EVs across the network. Decarbonisation is an undisputed global objective, and EVs are one of the leading means of achieving this.

As illustrated in Chapter 7.2, the increase in peak demand because of EV charging is strongly dependent on whether domestic EV charging is managed or unmanaged.
If unmanaged, there are significantly higher demand peaks expected. This would require additional investment in our network to cope with the additional load.

The true future scenario is likely to lie somewhere between Figure 7.4 and Figure 7.5. in chapter 7. This project intends to understand where we may end up on the spectrum between these two scenarios.

10.8.2 SMART GRID

PV and behind-the-meter battery storage are two other technologies that are likely to materially influence the future of the electricity distribution network. This project involves developing a small-scale smart grid in an existing subdivision on our network. This will be used to simulate a residential area with a high penetration of PV and battery storage. This project explores each of the three 'D' mega-trends – decentralisation, decarbonisation, and digitalisation.

A distribution network with a high proportion of PV and battery storage is quite different to a traditional network where power flows are unidirectional. As discussed in Chapter 7.2, the distribution network of the future is likely to lie somewhere between the extremes of a traditional network and a fully smart grid.

The four scenarios outlined in Chapter 7.2 would each contain differing concentrations of distributed energy resources. The traditional network, with a very low concentration of Distributed Energy Resources (DERs), is already well understood – this is our current distribution network.

A network containing a high concentration of DERs would be more closely aligned to the Intelligent Network scenario. By completing this project, the Intelligent Network scenario will be better understood. Understanding both scenarios allows us to better prepare for any eventuality between the extremes of these two scenarios.

10.8.3 LV MONITORING

This project complements the open-access network work described in section 10.3 and focuses on emerging monitoring technology. As discussed before, LV visibility is seen as a potentially major expenditure item on our network in future, so keeping a close watching brief on developments in this area to ensure we adapt to the most suitable, cost-efficient solutions is deemed essential.

10.8.4 IOT SENSORS AND LORAWAN

Establishing a low-power wide area network (LPWAN) is a key facilitator for the digitalisation mega-trend previously discussed. Our chosen technology is LoRaWAN.

A variety of different sensors are being trialled using LoRaWAN for communication. These sensors have a range of benefits, including fault localisation, reporting outage and power quality information. Some examples of these sensors are:

- **Smart line fault indicators** – these devices detect faults by sensing sudden increases in current through a conductor. When detected, the devices indicate faults by flashing a light. The trial LoRaWAN variant of this product will also immediately report this event to our network operations team.
- **LV monitoring equipment** – these trial sensors report outages and power quality information. These devices can also detect fallen HV conductors. This is a valuable safety feature, as traditional HV protection systems are not always able to detect this type of fault.
- **Drop-out fuse sensors** – a drop-out style fuse changes orientation when the fuse blows. This change in orientation can be detected by these trial sensors. The event is reported over LoRaWAN. This provides immediate indication and localisation of blown drop-out fuses.

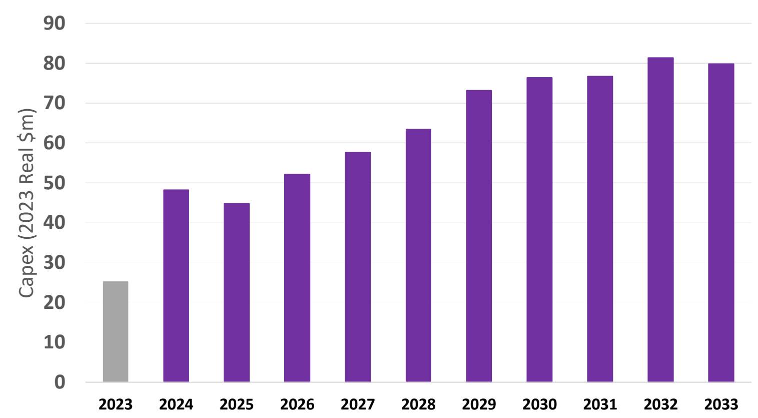
10.9 FORECAST GROWTH AND SECURITY CAPEX

Figure 10.4 shows the forecast Capex on our Growth and Security portfolios (excluding major and minor projects, which are separately discussed in Chapter 11).

FY23 expenditure is lower than normal, as a significant proportion of the FY23 Growth and Security budget is dedicated to the South Waikato National Grid connection (Arapuni to Putāruru) major project. Expenditure then returns to more normal levels during FY24 to FY26, except for increased communications investment in FY24 to support the Hauraki, ADMS and CSP projects. An increasing roll-out of network monitoring devices is also budgeted for.

Later in the period, we expect to see an increase in routine projects, supporting network upgrades on both the distribution and LV networks and supporting increased electricity use from decarbonisation drivers. This is driving the upward trend in expenditure in Figure 10.4.

Figure 10.4: Forecast Capex on Growth and Security (excluding major and minor projects)



11 AREA PLANS

11.1 CHAPTER OVERVIEW

Our network planning is based on 13 discrete areas. This chapter describes these areas and their significant planned investments related to Growth and Security.

Since our 2021 Asset Management Plan (AMP21), we have heavily reviewed and updated our major and minor project plans. Updated demand forecasts and contingency analysis have been used to identify capacity constraints, and project options have been evaluated. We have started to use our value framework to help with these assessments, and this is an area we will continue to develop to ensure our investments are prioritised and justified.

Our area plans are driven by our customers' needs. We work closely with our major customers to ensure they have an electrical supply that provides the capacity and security they need, at a time that suits their plans. With strong economic growth occurring in recent years, we have seen a marked increase in customer upgrades and developments leading to plans for upstream upgrades. We have also seen some initial interest in process heat conversion, and we are planning for this.

With demand forecasts increasing, capacity at several of our grid exit points (GXPs) is becoming constrained. This is also being influenced by grid-scale, where GXP export limits may be reached. We are working closely with Transpower on these bulk supply challenges, with an initial focus on the Western Bay of Plenty area. Both Powerco and Transpower will need to invest heavily in this area during the planning period to support our customers' electricity needs.

Decarbonisation in the regions, for example, electrification of transport, smart charging for EVs, and electrifying industries could impact the network. As demand increases, subtransmission and substation supply capacities could be exceeded, which would directly impact the security of supply to our customers. In addition, customers could be impacted by quality of supply issues, such as low voltages because of decarbonisation. Chapter 3.3 provides more information on decarbonisation.

For more detailed descriptions of the options considered for our large Growth and Security projects, refer to Appendix 7.

11.2 COROMANDEL

Strong growth in the Coromandel area has created legacy security issues, which is coupled with increasing expectations from customers regarding the reliability of supply, particularly from holiday homeowners on the Coromandel Peninsula. The existing lines and substations face significant capacity restraints and additional investment is required to improve network security and reliability. Major and minor project spend related to Growth and Security during the next 10 years is $19m.

11.2.1 AREA OVERVIEW

The Coromandel area covers the Coromandel Peninsula and a northern section of the Hauraki Plains. The main towns in the area are Thames, Coromandel, Whitianga, Tairua, and Ngātea.

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 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. These ring circuits have been operating in a closed loop after protection upgrades were made.

Voltage constraints and, in places, thermal capacity constraints, 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 area's rural nature 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.

There has been no significant network change in the Coromandel area since the AMP21. Project CORE and Matatoki second transformer projects, which are highlighted in the project list, are in the final stages of detail design. Construction is scheduled to commence after the design is completed.

The communications and protection upgrade at each zone substation (Kopu GXP, Whitianga, Tairua and Coromandel) to allow line differential protection is ongoing and expected to be completed by FY24.

Figure 11.1: Coromandel area overview

Table 11.1:Coromandel network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Whenuakite 66/11kV substation	Deferred to beyond the current AMP period.
Whenuakite second transformer	Deferred to beyond the current AMP period.
Kopu-Tairua 66kV line upgrade	Deferred to beyond the current AMP period.
Coromandel area voltage support	Deferred to beyond the current AMP period.
Tairua-Coroglen	Deferred to beyond the current AMP period.
New Kaimarama 66kV switching station	Substituted. This is replaced by the proposed new Lodestone Whitianga solar farm 66kV switching station
Matarangi 66/11kV substation	Substituted. This is replaced by project CORE
Coromandel substation alternative supply	Substituted. This is replaced by project CORE
Backup supply to Kerepehi substation	Substituted. This is replaced by Mangatarata or Rawerawe 66/11kV substation project
Kopu-Kauaeranga 110kV line	Securing easements

11.2.2 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	2022	2025	2030	2035
Coromandel	4.5	4.6	4.8	5.0
Kerepehi	10.4	11.4	13.2	13.7
Matatoki	4.5	5.6	5.8	5.9
Tairua	9.5	9.7	9.9	10.2
Thames T1 & T2	11.8	11.9	12.1	12.3
Thames T3	1.5	1.5	1.5	1.5
Whitianga	18.0	19.3	21.0	22.1

Growth is forecast to be steady, especially for those substations that supply popular holiday towns. Growth is linked to national economic prosperity, as demand in this area increases in response to additional holiday accommodation.

All of the Coromandel substations already exceed our security criteria. 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.

11.2.3 MAJOR CUSTOMERS

Table 11.3: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Claymark	Timber processing	Matatoki
Carter Holt Harvey	Timber processing	Matatoki
A & G Price Limited	Industrial Manufacturing and Mining	Thames
Thames Hospital	Public/State	Thames
Kerepehi ice-cream factory	Dairy	Kerepehi

Known and potential major industrial customer developments in the Coromandel area and their potential impact on our distribution network are as follows:

- Matatoki supplies Claymark – The customer has indicated plans to increase its load. The existing network has sufficient capacity to accommodate the load increase.
- Large solar farm connection applications – Lodestone Whitianga solar farm 23MW will be connected to our 66kV subtransmission network and there have been other grid-scale solar farm proposals in the area that will potentially connect to our subtransmission network. The solar farm power output could be limited depending on where it is connected to the Powerco network. The approval of the Lodestone 23MW, along with any other new large connections, could have an impact on the Transpower Kopu GXP because of the potential for reverse power flow at the GXP.

11.2.4 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 customer load because of its short peak duration – i.e., mostly during peak holiday periods/weekends.

Major constraints affecting the Coromandel area are shown in Table 11.4

Table 11.4: Coromandel constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Coromandel, Whitianga and Tairua substations	Coromandel, Whitianga and Tairua substation reliability. DG connection for customer solar farm.	Lodestone Solar Farm 66kV switching station (customer-driven).
Coromandel, Whitianga and Tairua substations	Kopu-Tairua 66kV line constraint.	Install distributed generation. Refer to Note 1.
Whitianga substation, Matarangi feeders	Whitianga feeder constraints.	Install distributed generation and non-network third-party solution. Refer to Note 1.
Whitianga substation, Whenuakite feeders	Demand exceeds the secure capacity of the two transformers at Whitianga. Whitianga feeder constraints supplying the Cooks Beach, Hahei and Whenuakite areas.	Install distributed generation and non-network third-party solution. Refer to Note 1.
Kerepehi substation	Kerepehi security and feeder constraints.	Mangatarata or Rawerawe 66/11kV substation
Coromandel substation	Coromandel substation reliability.	Install distributed generation. Refer to Note 1.
Matatoki substation	Substation capacity and security.	Matatoki second transformer.
Thames substation	Thames substation reliability and security.	Kopu-Kauaeranga 110kV line. Refer to Note 2.
Tairua substation	Demand exceeds the secure capacity of the two transformers.	Refer to Note 3.
Whitianga substation	Substation transformer capacity.	Refer to Note 4.
Kopu GXP	Peak load at Kopu is forecast to exceed the N-1 capacity of the supply transformers beyond 2027.	Refer to Note 5.

Notes:

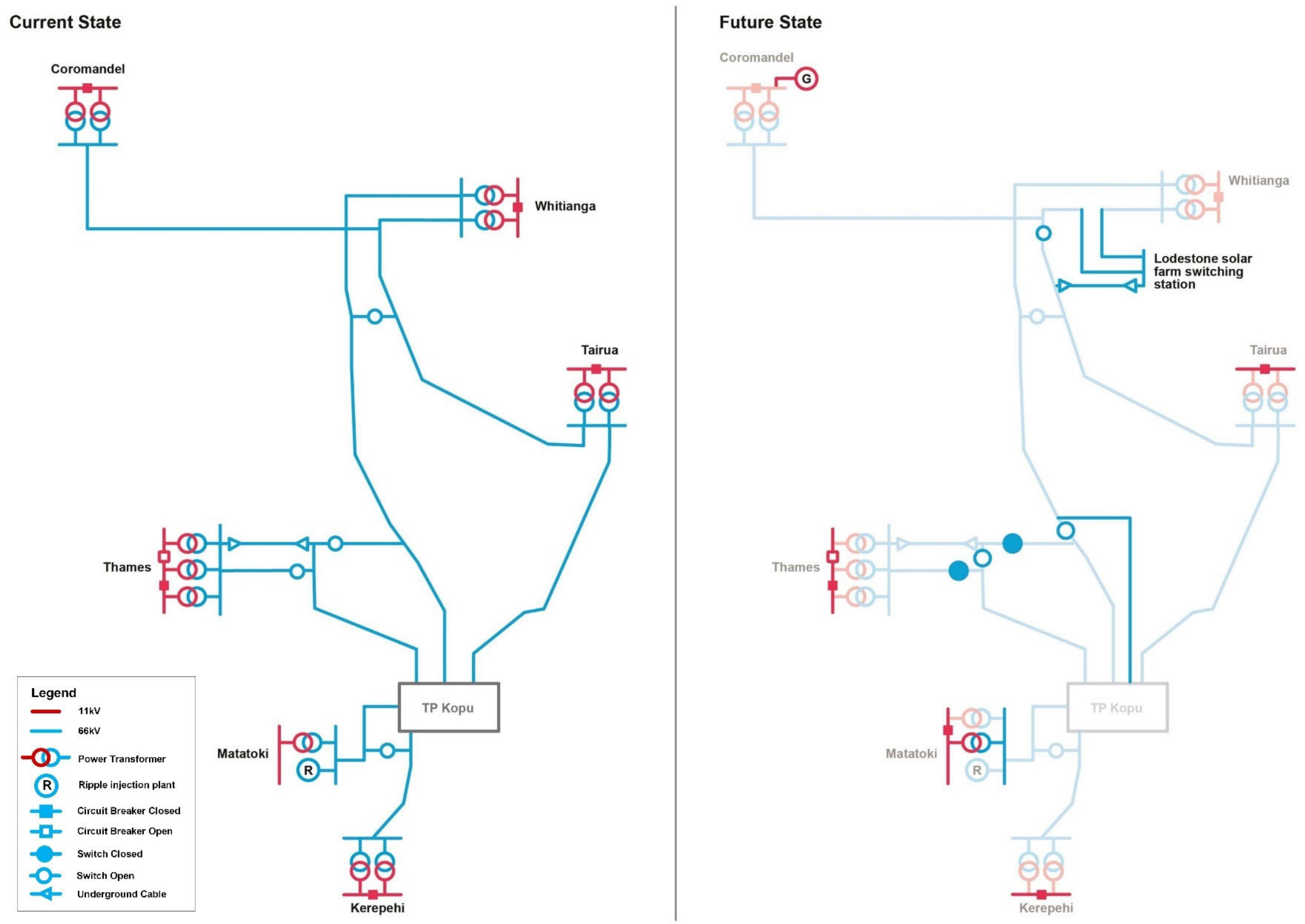
1. Coromandel area generation also referred to as Project CORE: This solution option is to introduce strategically scattered distributed generation (DG) units across the Coromandel Peninsula on the 11kV network to resolve a collection of the identified network issues in a cost-effective manner. Issues addressed are:

- **Kopu-Tairua line thermal constraints** – DG with third-party (solarZero) solution to install small-scattered DG (solar + battery) will offer demand side reduction of peak load and provide regional voltage support during a Kopu-Whitianga outage.

- **Matarangi** – One of the preferred locations for DG is at Matarangi to offer peak reduction on the 11kV network.
- **Whenuakite, Cooks Beach and Hahei** – Investigate alternative solutions at the 11kV distribution network level, such as microgrids and smart grid technology, to minimise the impact of outages on the area. While building a new substation at Whenuakite as a long-term solution will offload the 11kV feeders, the cost estimate currently does not justify the expense.
- **Coromandel substation alternative supply** – DG to offer subtransmission peak reduction and islanding-capable backup generation at Coromandel township.
- **Tairua-Coroglen line thermal constraints** – DG with third-party (solarZero) solution to install small-scattered DG (solar + battery) will offer demand side reduction of peak load and provide regional voltage support during a Kopu-Whitianga outage.

2. The Kopu-Kauaeranga 110kV project is still undergoing easement settlement with affected landowners. Most of the line route easements have been obtained, but a forestry parcel of land owned by the Crown is yet to be settled as part of the Treaty settlement with Hauraki iwi. The settlement process is complex, resulting in a longer timeline. Construction is anticipated to begin in the latter part of the planning horizon in FY29.
3. The risk of lost supply with these transformers is minimal and can be managed operationally until future transformer upgrades can be scheduled.
4. The transformer capacity is already constrained during an N-1 outage, but the risk is minimal as the peak demand only occurs for a short duration during the holiday peak period. Utilising the available limited 11kV backfeed from Tairua and Matarangi DG to reduce peak load will alleviate the transformer constrained during an N-1 outage.
5. Transpower Transmission Planning Report 2022 – The enhancement approach is to resolve the protection limit on the supply transformers that will provide sufficient N-1 capacity until the end of the forecast period.

Figure 11.2: Coromandel area network diagram



11.2.5 PROPOSED PROJECTS

Table 11.5: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Project CORE	$11,065	2021-2024	Growth and Security
Matatoki second transformer	$2,786	2022-2024	Growth and Security
Lodestone solar farm 66kV switching station	$1,985[1]	2022-2025	Growth and Security
Kopu-Kauaeranga 110kV	$9,057	2029-2031	Growth and Security
Mangatarata or Rawerawe 66/11kV substation	$11,001	2031-2036	Growth and Security

Note 1: This investment covers the Growth and Security component of this project, covering the network security benefits of the switching station. The majority of the investment is customer driven and funded.

11.2.6 POSSIBLE FUTURE 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.

Operation at 110kV is unlikely to occur until beyond the next decade. However, projects to date and those identified in future (new Kopu-Kauaeranga 110kV line) 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.

Transpower's dual circuit 110kV lines from Hamilton to Kopu, known as the Valley Spur, are forecast to exceed N-1 capacity by winter 2023, approximately. This has some impact on Kopu security, but the scope of any future upgrades is likely to be outside the Coromandel area.

The following projects have been identified as possibly occurring 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 will be confirmed closer to the time.

Table 11.6: Possible future developments

PROJECT	SOLUTIONS
Upgrade of SWER systems	The capacity of the SWER circuits north of Coromandel town is at their 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.
Whenuakite substation	The demand exceeds the existing Whitianga substation N-1 capacity. The 11kV feeders supplying Coroglen, Cooks Beach, Hahei and Hot Water Beach also have excessive ICP counts and insufficient backfeed capability. The preferred solution is to build a new Whenuakite 66/11kV substation. This will significantly improve network reliability in the area and cater for demand growth. The substation land and 66kV line route easements have been secured for a limited period from the AMP21 work. Powerco will also investigate the feasibility of a non-network solution to address the issues.
Matarangi substation	Two existing 11kV feeders supplying the Matarangi area have insufficient backfeed capability, which will be addressed with Project CORE. In the future, if more developments occur, the backfeed capacity will deteriorate and the feeders already have excessively high ICP counts. The option is to build a new Matarangi 66/11kV substation. The new 11kV feeders from the new substation will split the existing feeder supplying Matarangi, thus improving reliability and creating capacity for growth. As part of Project CORE, the substation land is being procured, 66kV line route easements have partly been secured, and we are working on securing the remainder of the route with affected landowners.
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.
Coromandel area voltage support	Coromandel area generation (refer to Note 1) will address the immediate voltage issues that exist on the network following a post-contingent event on the subtransmission network. Later in the planning period, increased demand may require further voltage support using a Static Synchronous Compensator (STATCOM) at Whitianga or the capacitor bank at Tairua to provide post-contingent reactive support.
Kopu-Tairua 66kV line upgrade	Coromandel area generation will offset the need for upgrading the subtransmission line. As the demand in the region grows, the generation capacity will eventually deteriorate and the need to upgrade the subtransmission conductor will need to be considered or further non-network solutions will need to be considered.
Tairua-Coroglen 66kV line upgrade	Coromandel area generation will offset the need for upgrading the subtransmission line. The DG will be used to provide peak lopping during a contingent event on the subtransmission network, reducing thermal constraints on the 66kV circuits. Therefore, the need to upgrade the subtransmission line can be deferred. Similar to the Kopu-Tairua line constraint, if the load in the Coromandel Peninsula grows in future, further non-network solutions will be considered to supplement the generation.

11.3 WAIKINO

The Waikino area includes the popular holiday town of Whangamatā, which is supplied by a single 33kV circuit from Waihi. We have installed an energy storage system comprising batteries and a diesel generator to provide a backup supply to the critical loads in the central business district of Whangamatā.

Major and minor project spend related to security during the next 10 years is forecast to be $91.0m.

11.3.1 AREA OVERVIEW

The Waikino area 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 operations.

The main towns in the Waikino area are Paeroa, Waihi and Whangamatā. 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 Whangamatā. The subtransmission system has a ring configuration between Waikino GXP and Waihi. A single circuit supplies Whangamatā from Waihi and a single circuit also supplies Waihi Beach. Two dedicated circuits supply 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.

Table 15.4 shows the network change in the Waikino network since AMP21.

Figure 11.3: Waikino area overview

Table 11.7: Waikino network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Waihi 33kV indoor switchboard	Under construction
Waihi Beach switchboard	Under construction
Waihi Beach second transformer	Under construction
Whangamatā Battery Energy Storage System (BESS)	Completed
Paeroa refurbished transformers installation	Completed

11.3.2 DEMAND FORECASTS

Demand forecasts for the Waikino zone substations are shown in Table 11.8, with further detail provided in Appendix 7.

Table 11.8: Waikino zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Paeroa	8.1	8.8	9.1	9.4
Waihi	18.4	25.5	41.1	44.7
Waihi Beach	6.4	6.6	6.9	7.2
Whangamatā	11.8	12.0	12.2	12.5

Growth in the area has been modest in recent years, except for 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. The OceanaGold mine drives the demand forecast for the Waihi area. It plans to increase its operations load in the near future, which may attract more small-scale commercial activities and increase residential growth in the town.

All the Waikino substations already exceed the secure class capacity.

11.3.3 MAJOR CUSTOMERS

Table 11.9: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
OceanaGold Limited	Industrial Manufacturing and Mining	Waihi

Known and potential major industrial customer developments in the Waikino area and their potential impact on our network are as follows:

- OceanaGold Limited – The customer has indicated potential significant load increase in the near future. Waihi substation does not have the capacity to supply the future load. The solution will be to supply the load from Waikino GXP as a dedicated feeder load.
- Potential queries for large-scale solar farms, which will be connected to our subtransmission network – The solar farm power output could be limited depending on where it is connected to the Powerco network. Paeroa 11kV distribution network will be constrained for solar farm connections as the substation transformers have limited capability to support reverse power flow to the 33kV network because of the tap changers.

11.3.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikino area are shown in Table 11.10.

Table 11.10: Waikino constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Waikino GXP	Line and transformer capacity and voltage constraints.	Waihi 33kV voltage support and Hinuera-Waikino 110kV. Refer to Note 1.
Whangamatā substation	Whangamatā substation reliability.	Refer to Note 2.
Waihi Beach substation	Waihi Beach substation reliability and capacity.	Install distributed generation. Refer to Note 3.
Whangamatā substation	Substation transformer capacity.	Whangamatā T2 transformer upgrade.
Waihi substation	Substation transformer capacity.	New dedicated substation for OceanaGold (customer-driven).

Notes:

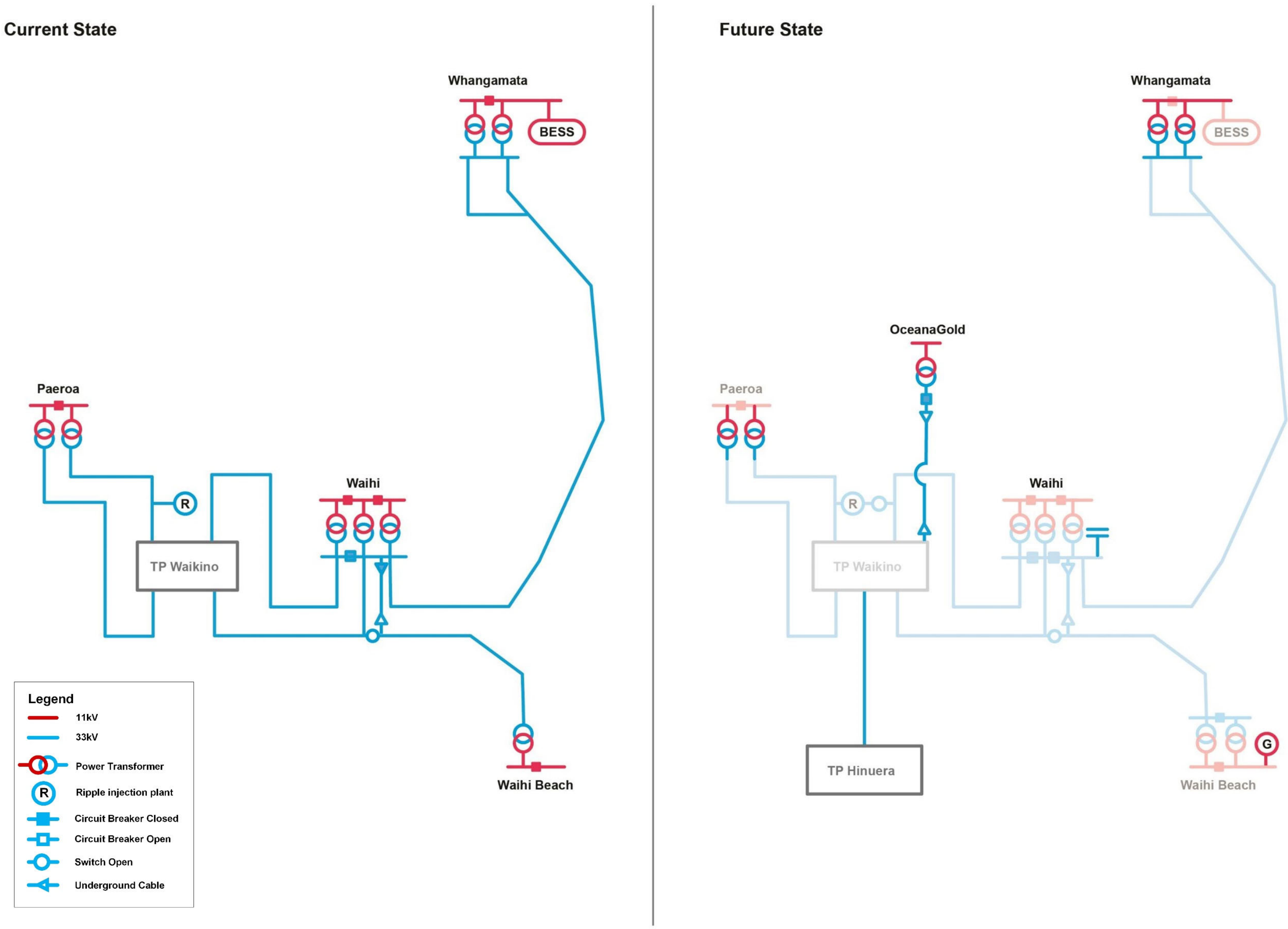
1. Transpower Transmission Planning Report 2022 – Transpower plans to replace the T1 transformer in the period 2033-2035. Later in the planning period, the Kopu and Waikino loads are expected to exceed the N-1 capacity of the Waihou-Waikino-1 and 2 circuits. These circuits are fed by the Hamilton-Piako-Waihou-1 and 2 circuits. In the short-term, Transpower has a few proposed upgrade options, such as installing a special protection scheme to manage load post--contingency and installing variable line rating to resolve thermal capacity issues, as well as installing capacitors at Waihou and Waikino to resolve voltage step and low voltage issues. We are investigating the feasibility of installing a new 110kV circuit between Hinuera and Waikino as an alternative to address the bulk supply constraints of the Valley spur.
2. The Battery Energy Storage System (BESS) partially feeds the commercial area in Whangamatā following a loss of supply to the Whangamatā substation during peak times, reducing the outage impact. If the outage occurs during off-peak times, the BESS can extend its supply beyond the commercial area, further reducing the outage impact. We have several routine growth distribution projects in the works plan that will reduce outage impacts even further when they are commissioned. These solutions reduce the risks to acceptable levels.
3. A single 33kV line supplies the Waihi Beach substation. An outage on the line results in a loss of supply to the Waihi Beach substation. Because of the limited 11kV backfeed capacity, we propose to install DG to support and increase the backfeed capacity from Kauri Point. In parallel with the DG solution, we will also consider third-party non-network alternatives similar to Project CORE to provide backup support. The transformer capacity is already constrained during an N-1 outage, but the risk is minimal as the peak demand only occurs for a short time during the holiday period. Utilising the available limited 11kV backfeed from Kauri Point and Waihi Beach DG to reduce peak load will alleviate the transformer constraint during an N-1 outage at peak periods.

11.3.5 PROPOSED PROJECTS

Table 11.11: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Waihi Beach distributed generation	$2,606	2023-2025	Growth and Security
OceanaGold substation	$16,827	2025-2031	Customer
Waihi 33kV voltage support	$1,730	2025-2027	Growth and Security
Whangamatā T2 transformer upgrade	$906	2029-2031	Growth and Security
Hinuera-Waikino 110kV	$84,033	2025-2030	Growth and Security

Figure 11.4: Waikino area network diagram



11.3.6 POSSIBLE FUTURE DEVELOPMENTS

The following projects have been identified as possibly occurring 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 will be confirmed closer to the time.

Table 11.12: Possible future developments

PROJECT	SOLUTIONS
Paeroa 33kV bus security	An outage on one of the subtransmission circuits from Waikino to Paeroa will also result in an outage to its associated supply transformer at the Paeroa substation. The preferred solution is to install a 33kV indoor switchboard to improve subtransmission reliability and lower the risk of exceeding transformer firm capacity.
Valley spur 110kV security	Powerco is evaluating and researching the possibility of implementing a long-term solution to establish a new 110kV circuit that connects Hinuera GXP and Waikino GXP. This will be done to address the issues related to the 110kV network, as previously mentioned in Note 1 under table 15.6.

11.4 TAURANGA

The Tauranga area 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 $118.5m.

11.4.1 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 of supply 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 area as a place to live, reflecting the good climate, terrain, and coastal setting, is the single biggest reason for its 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, 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 by the Tauranga and Kaitimako GXPs. Tauranga GXP is a grid offtake at both 11kV and 33kV.

The Tauranga GXP supplies 11 zone substations: Bethlehem, Tauranga 11kV (TP), Waihi Road, Hamilton Street, Sulphur Point, Otūmoetai, Matua, Ōmokoroa, Aongatete, Katikati and Kauri Point. The Kaitimako GXP supplies the Welcome Bay substation and the Pyes Pā substation.

The region uses a 33kV subtransmission voltage. Twin dedicated circuits feed each of the critical inner-city substations of Hamilton Street and Waihi Road.

Twin 33kV high-capacity circuits link Tauranga GXP with a major subtransmission interconnection point at the Greerton switching station. From this, two circuits supply the northern substations (Ōmokoroa, Aongatete and Katikati) via dual circuits and Kauri Point on a single circuit from Katikati.

A 33kV ring from Greerton also supplies Bethlehem via Otūmoetai. A new subtransmission circuit is expected to be completed between Greerton and Bethlehem by the end of 2023.

Otūmoetai is now supplied from twin radial subtransmission circuits from Greerton, with a single 33kV radial circuit from Otūmoetai supplying Matua.

The Bethlehem/Otūmoetai ring and the twin Ōmokoroa circuits share poles for several spans out of Greerton, which raises common types of failure risks and protection issues. A project is underway that will install a third subtransmission circuit from Greerton to Ōmokoroa and will reduce the number of poles shared between the Bethlehem/Otūmoetai ring.

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 11.5: Tauranga area overview

Table 11.13: Tauranga network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Katikati 33kV circuit – tee removal	Completed
Matua 5MVA hot standby transformer removed (fleet project)	Completed
Ōmokoroa 33kV circuit – construction	Issued for construction

11.4.2 DEMAND FORECASTS

Demand forecasts for the Tauranga zone substations are shown in Table 11.14, with further detail provided in Appendix 7.

Table 11.14: Tauranga zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Aongatete	4.5	4.8	5.2	5.6
Bethlehem	10.9	12.9	13.8	14.7
Hamilton Street	10.8	12.2	12.5	12.7
Katikati	10.8	13.3	13.9	14.5
Kauri Point	2.8	2.9	3.0	3.1
Matua	9.7	9.7	9.9	10.1
Ōmokoroa	12.3	14.0	15.1	16.2
Otūmoetai	14.9	15.3	15.9	16.5
Pyes Pā	19.8	34.5	82.6	91.5
Sulphur Point	6.5	12.5	22.5	24.5
Tauranga 11kV	27.3	29.1	30.7	32.3
Waihi Road	20.4	20.9	21.5	22.2
Welcome Bay	24.2	25.6	27.4	29.3

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, Ōmokoroa, Pyes Pā and Welcome Bay – supply the major subdivisions.

Pyes Pā substation has offloaded Tauranga GXP supplying the large industrial and residential developments in this area. The suburb of Pyes Pā comprises industrial and residential developments. Several large customer-initiated works projects have been indicated for development during the next few years, spearheaded by a large wallboard manufacturing factory.

The district council is also moving forward with significant residential rezoning development, which is expected to be completed within the planning period.

Ōmokoroa has substantial areas of land zoned for urban development on the peninsula and has experienced increased growth. In addition to the residential developments, a new primary school, secondary school, and town centre/commercial district are planned for the area.

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 in 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 Sulphur Point zone substation, potentially justifying the need for another dedicated subtransmission circuit.

Aongatete and Katikati demand is dominated more by significant increases from cool store loads, which are being driven by the horticulture market.

11.4.3 MAJOR CUSTOMERS

Table 11.15: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Apata Group Limited	Food processing	Ōmokoroa
Eastpack Limited	Food processing	Katikati
Hume Pack-N-Cool Limited	Food processing	Katikati
North Island Mussels Limited	Food processing	Tauranga 11kV
Mount Pack and Cool Limited	Food processing	Pyes Pā
Seeka Limited	Food processing	Katikati
Tauranga Hospital	Public/State	Tauranga 11kV
Te Pūkenga – New Zealand Institute of Skills and Technology	Public/State	Tauranga 11kV
Winston Wallboards Limited	Industrial Manufacturing and Mining	Pyes Pā
Port of Tauranga	Transportation	Sulphur Point
Claymark	Timber processing	Katikati
DMS Progrowers	Food processing	Bethlehem
Chapel Street wastewater treatment plant	Public/State	Hamilton Street
Grace Hospital	Public/State	Tauranga 11 kV

Known and potential major industrial customer developments in the Tauranga area and their potential impact on our distribution network are as follows:

- Tauranga Hospital has indicated plans to expand services. The existing hospital includes some buildings that are a seismic risk, so the hospital is considering whether to upgrade the existing site or relocate. Because of this lack of certainty, the impact on the network could be of concern. An upgrade at the current location would require additional subtransmission circuits from Tauranga 33kV GXP, resulting in the existing transformers incurring more demand. This would also increase demand on the 110/33kV transformers and the transmission circuits supplying Tauranga GXP.
- Port of Tauranga has recently upgraded its supply and is planning further upgrades within the AMP period. Its proposed upgrades will require new 33kV circuits from Waihi Road substation to Sulphur Point substation. This will increase demand at Tauranga 33kV GXP as well as the transmission circuits that supply it. Additionally, this customer project will need to be preceded by the network project to upgrade Waihi Road substation. The port is currently supplied by a single circuit at 33kV from Hamilton Street substation. A dedicated 11kV circuit is the primary backfeed to the port, which is also supplied from Hamilton Street. Two new 33kV circuits will need to be installed from Waihi Road substation to support the port's capacity upgrade.
- Winstone Wallboards Limited has recently upgraded its supply and has indicated that additional capacity may be required. Further investment may be required to deliver the additional capacity upgrades. In the near term, it is possible to utilise the available capacity on the existing 33kV subtransmission lines installed between Kaitimako and Tauranga GXPs, to support moderate increases by the customer. In the medium term, depending on the scale and timing of the customer requirements, Belk Road substation will be commissioned to supply the industrial developments in the area. Opportunities exist for Powerco and the customer to investigate alternatives to cater for load growth at this site, such as peak load shifting to efficiently utilise existing infrastructure. We will pursue these alternatives in the future.

11.4.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tauranga area are shown in Table 11.16.

Table 11.16: Tauranga constraints and needs

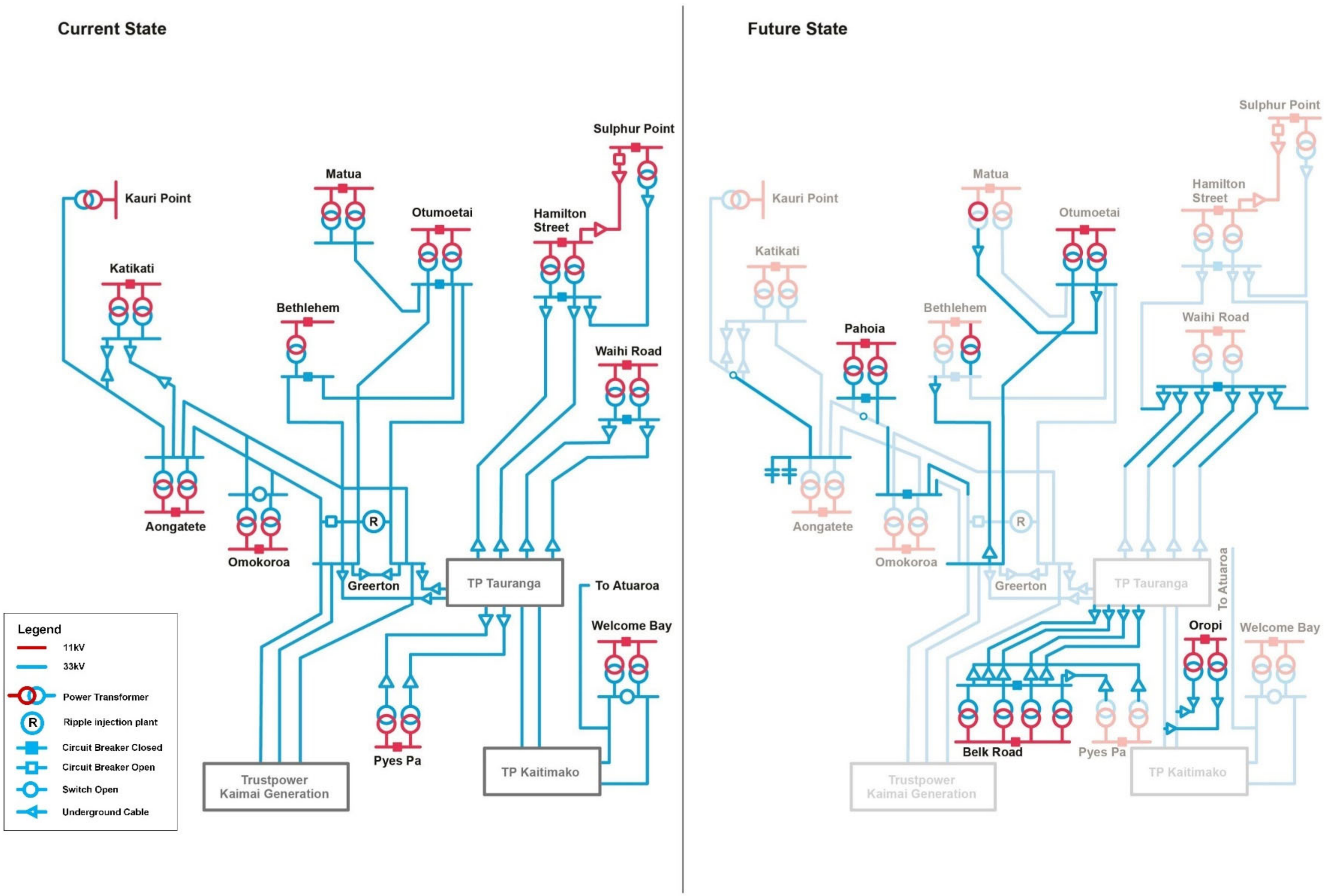
LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Tauranga GXP	Tauranga GXP capacity constraints.	Tauranga area security constraints. Refer to Note 1.
Ōmokoroa, Aongatete, Kauri Point and Katikati substations	Load growth exceeding N-1 security of existing subtransmission circuits. Tee connection to Ōmokoroa substation impacts substation supply security. Post-contingent low voltage issues.	Ōmokoroa capacity reinforcement. Aongatete 33kV voltage support. Ōmokoroa 33kV – substation design and construction.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Matua substation	Single transformer substation. Load growth forecast to exceed the backfeed capacity to Matua substation.	Matua – Install a second transformer. Refer to Note 2.
Bethlehem substation	Single transformer substation. 11kV post-contingency constraint.	Bethlehem substation – second 33kV transformer (T6).
Welcome Bay/ Tauranga 11kV substations	Load growth at Welcome Bay/Ohauiti causes Welcome Bay substation to exceed firm capacity.	Oropi/Ohauiti – proposed substation.
Ōmokoroa substation	Load growth at Ōmokoroa causes existing Ōmokoroa substation to exceed firm capacity.	Pahoia (Ōmokoroa urban zone) substation.
Pyes Pā substation	Significant development in Pyes Pā/Tauriko will exceed the firm capacity of Pyes Pā substation.	Belk Road zone substation.
Kaitimako GXP	Single transformer at Kaitimako GXP provides no firm capacity.	Refer to Note 4.
Katikati-Aongatete 33kV subtransmission line upgrade	Increasing load growth at Katikati and Kauri Point substations will cause post-contingency overloading.	Aongatete-Katikati – 33kV line upgrade.
Waihi Road/Hamilton Street substations	Load growth at these substations will cause subtransmission supply circuits to exceed firm capacity.	Waihi Road bus security project.

Notes:

1. We are in discussions with Transpower about possible long-term solutions to increase the capacity at Tauranga GXP and possibly other high-demand sites. Risk in the near term is mitigated by a Special Protection Scheme (SPS), plus the availability of generation from the Kaimai hydro scheme. Transpower is also suggesting the possible implementation of Variable Line Ratings (VLR) as a mitigation measure to lift capacity, as highlighted in its current Transmission Planning Report – Short-term projects identified for the area.
2. The 5MVA 33/11kV transformer at Matua zone substation has been refurbished and kept as a spare at Browne Street substation. The existing 33kV cable, operated at 11kV in conjunction with the surrounding 11kV network, can provide adequate backfeed until the second transformer project begins. It is proposed that this second transformer project will be coordinated with the Matua 11kV protection upgrade in future.
3. Because of the low probability of failure, there is only a small risk with single transformer substations or dual transformer substations where firm capacity is marginally exceeded. Options are considered to increase capacity or install new units as appropriate, as is economically cost-effective. At Bethlehem, it is cost-effective to install a second transformer to meet the security of supply requirements rather than improving 11kV backfeed capability and response times.
4. The existing Kaitimako GXP to Tauranga GXP 33kV circuits provide sufficient backfeed for Welcome Bay so that the Kaitimako GXP load is secure even with one supply transformer. When the load exceeds this backfeed capacity, we will need to investigate a second 110/33kV transformer with Transpower. The growth of the Welcome Bay and Pyes Pā loads will help justify the need for a second transformer at Kaitimako.

Figure 11.6: Tauranga area network diagram



11.4.5 PROPOSED PROJECTS

Table 11.17: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Ōmokoroa 33kV – cable installation	$8,768	2022-2024	Growth and Security
Belk Road substation	$56,243	2024-2029	Growth and Security
Bethlehem second transformer	$1,836	2024-2025	Growth and Security
Tauranga area security constraints	$32,129	2024-2030	Growth and Security
Pahoia substation	$6,799	2024-2028	Growth and Security
Oropi substation	$9,518	2024-2029	Growth and Security
Ōmokoroa substation	$5,645	2026-2028	Growth and Security
Matua second transformer	$1,943	2025-2026	Growth and Security
Aongatete – 33kV voltage support	$464	2024-2025	Growth and Security
Waihi Road bus security project	$3,018	2030-2033	Growth and Security
Katikati – 33kV OHL upgrade	$656	2029-2030	Growth and Security

11.4.6 POSSIBLE FUTURE DEVELOPMENTS

Several additional zone substations, which were previously identified in our long-term planning, will likely be commissioned during this planning period. These include Tauriko (Belk Road), Oropi and Ōmokoroa urban (Pahoia). Investment is not expected to begin until after 2024, but this will depend on the rate of growth and subdivision development.

The larger planned developments detailed above cover most of the significant risks exposed by subtransmission constraints. The timing of these investments will be flexible, based on the rate of development and the interdependence with other drivers.

Rapid development is taking place in Tauranga, and we expect this to continue during the planning period.

The two existing 110kV lines supplying Tauranga 33kV and 11kV GXPs will not be sufficient for the expected load growth; Tauranga GXPs' 110/33kV transformers are operating at their firm capacity and depend on Kaimai generation to manage post-contingency risks. So, several options are being investigated to increase the transmission capacity at Tauranga GXP.

Developing a transmission solution is a lengthy process. Therefore, we are looking at alternatives to resolve the transmission bulk supply risk in collaboration with Transpower and the local authorities. An option being investigated is installing another 110kV transmission cable between Kaitimako and Tauranga GXP and adding a third 110/33kV transformer.

Another option is extending the 220kV lines from Tārukenga into the south of Tauranga. The bulk supply upgrade seeks to develop a long-term solution that will meet the growing needs of the city and the surrounding region.

The Port of Tauranga has indicated a growth plan specifying its future requirements, with load potentially increasing from 8MVA currently to 20MVA in 2030. The forecast increase will eventually place significant strain on the Tauranga-Hamilton Street 33kV circuits, necessitating other network projects, such as the Waihi Road bus security project, to lift subtransmission capacity into the inner-city area.

We recently commissioned Sulphur Point substation to supply the port's growing load. While one 12.5/17MVA transformer has been installed at Sulphur Point, a second transformer and 33kV circuit will be installed when the port's load requires it. Eventually, the port will require its own dedicated 33kV circuits as its load grows further. These new circuits will be taken out of the Waihi Road substation following the completion of the Waihi Road bus security project.

Besides inner-city growth, which is spearheaded by the port and CBD redevelopment, Tauranga City Council is signalling an urban intensification plan for the Te Papa Peninsula. This plan will see the rezoning of the suburban area to allow for high-density population growth. In addition, the trend is to move towards more mixed-use development comprising high-rise residential and commercial complexes to encourage growth within the city.

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 distribution projects) is expected to be needed in the Tauranga area. New development and in-fill growth are considered in our medium-term distribution planning process to justify the need for new infrastructure development and upgrades on our network.

Kāinga Ora has indicated significant residential development for the Upper Belk Road area. A substation at Belk Road is also planned for the area. While allowance has been made for distribution infrastructure to cater for these proposed developments, the scale and speed of implementation by the Government will determine what solution we implement.

The following projects have been identified as possibly occurring 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 will be confirmed closer to the time.

Table 11.18: Possible future developments

PROJECT	SOLUTIONS
Welcome Bay 33kV reinforcement	Welcome Bay substation is supplied via two circuits from Kaitimako GXP. By the end of the planning period, forecast growth would result in a loss of one circuit causing the remaining circuit to operate above the rated capacity. The solution project would construct a third circuit from Kaitimako and install a 33kV solid bus to reinforce Welcome Bay substation.
Welcome Bay East substation	Welcome Bay substation is nearing firm capacity and the 11kV feeders each have high ICP counts. The district council has earmarked locations in Welcome Bay for residential development. Although currently deferred by the council, as demand for housing grows, these locations will be targeted for development, possibly towards the end of the planning period. The solution project for this eventuality would be Welcome Bay East substation, offloading Welcome Bay substation and lowering feeder ICP counts.
Gate Pā/Hospital substation	Tauranga Hospital's primary supply is via an 11kV feeder from Waihi Road substation. In the event of a fault, a backfeed is provided via the Tauranga 11kV substation. The hospital has plans to expand, and/or construct additional healthcare facilities in a new location. Growth is expected to exceed the 11kV backfeed capability of the network. The vicinity surrounding the hospital has also been identified by the district council for urban intensification, including mixed-use developments and high-rise buildings. The solution project would be Gate Pā/Hospital zone substation. This would entail installing new 33kV circuits from Tauranga 33kV GXP and commissioning a substation in the vicinity of the hospital should the hospital expand at this site. This is a customer-driven project and timing will be dependent on future district plans.
Sulphur Point upgrade	The Port of Tauranga could increase its supply by approximately 10MVA. This would be a customer-driven project requiring an additional 33/11kV transformer at Sulphur Point substation. In addition, the subtransmission circuits would require an upgrade as they could no longer be supplied from Hamilton Street substation. Depending on the customer requirements, Waihi Road bus security upgrade project would be a prerequisite project for these works to occur.

11.5 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. This substation also provides 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 $100m.

11.5.1 AREA OVERVIEW

The Mt Maunganui area covers the urban parts of Mt Maunganui, the developing area of Papamoa, and the Wairakei coastal strip.

It also encompasses Te Puke and surrounding rural areas down to Pongakawa and the inland foothills. In recent years we have constructed a dual 33kV circuit from Wairakei to Te Matai, which links the two areas. This has made area planning easier.

The Mt Maunganui area shares many of the features of the neighbouring Tauranga area, including terrain, climate, and land use. The region includes a long coastal strip and some rugged inland terrain. The coastal area contains severely deteriorated network equipment, which has impacted reliability and performance. The inland area is more rugged and presents difficulties for 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 rural areas, horticulture dominates. For example, there are many kiwifruit orchards around Te Puke that use the local cool stores and packhouses for their product. The Port of Tauranga is also a significant economic driver.

The area is supplied by the Mt Maunganui and Te Matai GXPs.

The Mt Maunganui GXP supplies five zone substations – Papamoa, Matapihi, Omanu, Te Maunga and Triton. The Te Matai GXP also supplies five zone substations – Wairakei, Te Puke, Atuaroa Avenue, 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. All new intensive subdivision is 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 to Papamoa substation as the tie point between the two GXPs.

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 Avenue and Welcome Bay substations. This provides limited backup to Atuaroa Avenue and Te Matai itself.

Figure 11.7: Mt Maunganui area overview

Table 11.19: Mt Maunganui network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Wairakei second transformer	Completed
Paengaroa new feeder – Young Road	Completed

11.5.2 DEMAND FORECASTS

Demand forecasts for the Mt Maunganui zone stations are shown in Table 11.20, with further detail provided in Appendix 7.

Table 11.20: Mt Maunganui zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Atuaroa Avenue	9.1	9.8	10.2	10.6
Matapihi	13.3	13.6	14.2	14.7
Omanu	12.9	13.5	14.3	15.2
Paengaroa	5.3	12.2	13.2	13.5
Papamoa	16.7	17.5	18.8	20.0
Pongakawa	4.6	5.5	5.7	5.9
Te Maunga	11.7	12.5	13.8	15.4
Te Puke	20.8	33.4	50.9	51.7
Triton	20.2	22.0	22.7	23.4
Wairakei	10.9	15.5	23.3	28.3

The Mt Maunganui area has one of the highest growth rates in our network. As a result, we have recently invested substantially 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 council has signalled section capacity in the Te Tumu area will be smaller than initially anticipated, but this only affects the final saturated electrical load density, not the immediate growth rate. The Te Tumu development is now expected to occur towards the end of the planning period.

We also expect the existing urban areas of Mt Maunganui to have high growth from in-fill and intensification. This shift from urban spread to the 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 large demand increase at the Te Puke substation, shown in Table 11.20, is primarily driven by the development of the Rangiuru Business Park, which has been a focus of past long-term planning. Development delays will now see the construction of Stage 1 in 2023, with Stage 2 to follow as demand dictates. This business park will encompass approximately 60 hectares of industrial land. The first loads are expected in 2025. However, the potential for these loads to develop earlier remains a planning risk.

The Te Puke and surrounding rural load continue to grow steadily, largely in response to kiwifruit and avocado growing operations.

11.5.3 MAJOR CUSTOMERS

Table 11.21: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Pukepine Sawmills Limited	Timber processing	Atuaroa
Apata Group Limited	Food processing	Paengaroa
AFFCO New Zealand	Food processing	Te Puke
Champion Flour	Food processing	Triton
Eastpack Limited	Food processing	Atuaroa
Seek Limited	Food processing	Paengaroa
Trevelyan's Pack & Cool Limited	Food processing	Te Puke
HR Cement Limited	Industrial Manufacturing and Mining	Omanu
Ballance Agri-Nutrients Limited	Chemicals	Triton

Known and potential major industrial customer developments in the Mt Maunganui area and their potential impact on our distribution network are as follows:

- Coolstore operators have indicated load increases during the next few years. This will require new 11kV feeders and distribution network reinforcement at Paengaroa, Te Puke and Atuaroa Avenue substations.

- The forecast loads at the Rangiuru Business Park will require a new zone substation to be constructed as part of the development. This new zone substation will also pick up future load from the Te Puke substation.
- The Golden Sands Town Centre will be constructed during the planning period, which will eventually require 11kV feeder strengthening from the Wairakei substation.
- Port of Tauranga has signalled significant load increases, which, if they occur, will most likely be at the end of the planning period. A third transformer at Triton substation may be necessary to meet this demand.

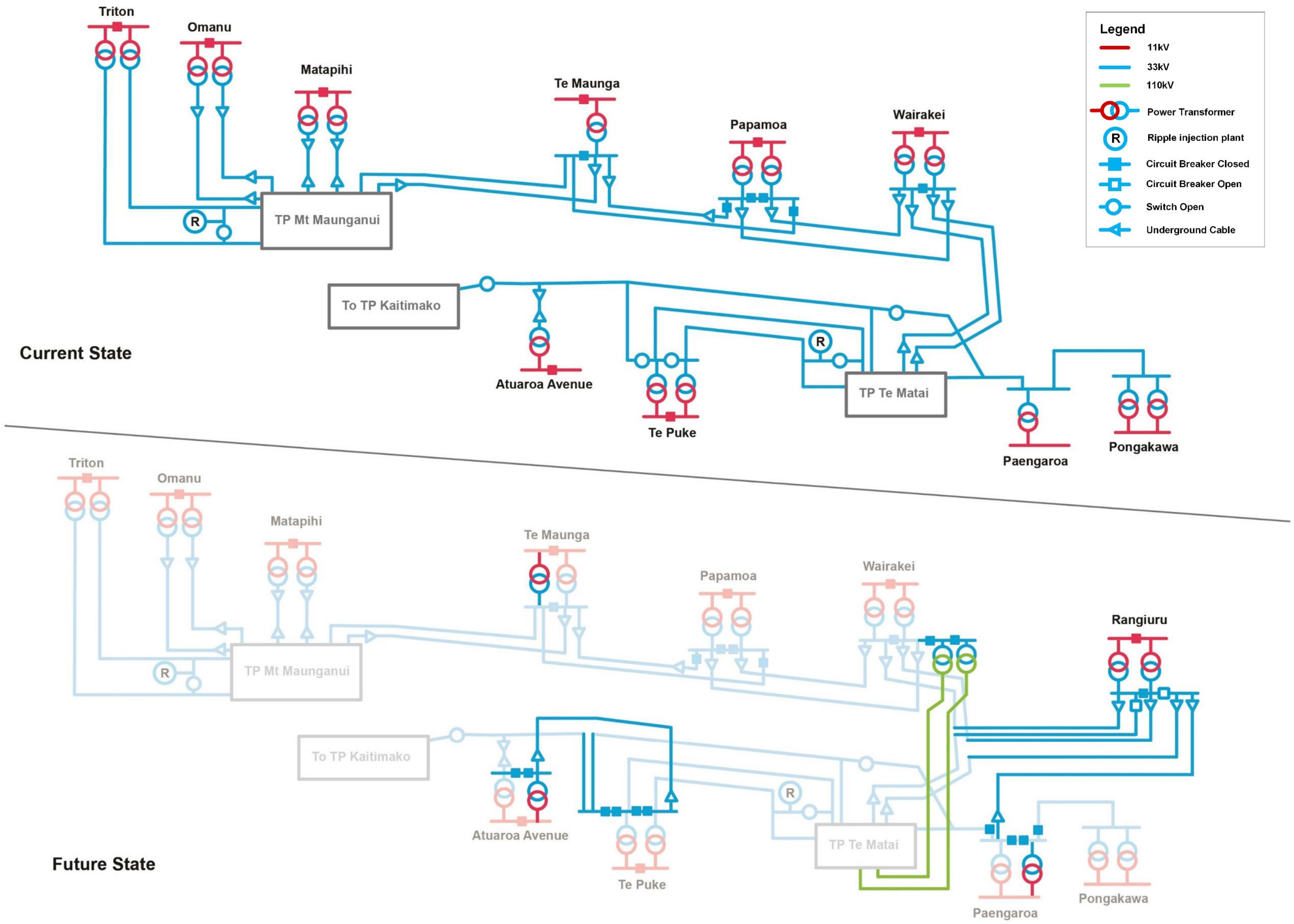
11.5.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Mt Maunganui area are shown in Table 11.22.

Table 11.22: Mt Maunganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Te Matai GXP	GXP capacity and security constraint.	Transpower to upgrade 110/33kV transformers. Mt Maunganui area security constraints project.
Rangiuru Business Park development	Load growth above the existing distribution network's capacity.	New Rangiuru zone substation.
Atuaroa Avenue substation	Atuaroa Avenue substation and subtransmission capacity and security constraint.	1. Atuaroa Avenue 33kV bus upgrade and install second transformer. 2. Second 33kV circuit into Atuaroa Avenue.
Te Puke substation	Te Puke substation capacity constraint under 33kV contingencies.	Te Puke 33kV bus upgrade.
Paengaroa substation	Paengaroa substation and subtransmission capacity and security constraint.	1. 33kV bus extension and second transformer. 2. Second 33kV circuit from the proposed Rangiuru substation.
Te Maunga substation	Single transformer substation.	Install a second 33/11kV transformer.

Figure 11.8: Mt Maunganui area network diagram



11.5.5 PROPOSED PROJECTS

Table 11.23: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Atuaroa Avenue second circuit	$5,481	2031-2033	Growth and Security
Atuaroa Avenue 33kV bus upgrade and second transformer	$4,813	2024-2027	Growth and Security
Te Puke bus security upgrade	$2,723	2027-2029	Growth and Security
Paengaroa and Pongakawa security of supply	$4,790	2024-2027	Growth and Security
Paengaroa second transformer and bus extension	$3,311	2023-2025	Growth and Security
Rangiuru Business Park substation	$11,947	2023-2030	Customer
Te Tumu substation	$17,132	2032-2035	Growth and Security
Te Maunga supply security	$1,355	2029-2030	Growth and Security
Te Puke N-1 security upgrade	$1,562	2032-2033	Growth and Security
Mt Maunganui area security constraints (Wairakei 110kV project)	$62,799	2025-2032	Growth and Security

11.5.6 POSSIBLE FUTURE DEVELOPMENTS

As with the Tauranga area, 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 explicitly identified but will be scoped when required in our programme of smaller routine Growth and Security projects.

We will continue to monitor the load on the 110kV line into the Mt Maunganui GXP. While our strategy to move Papamoa back to Mt Maunganui GXP will remove load off Te Matai GXP, this will put more load back onto the 110kV transmission between Kaitimako and Mt Maunganui, exacerbating the N-1 overload issue at the Poike tee. Should a contingency event occur on the transmission network, the risk will be managed operationally. Transpower has now indicated the renewal of the T1 transformer at Te Matai GXP will happen in 2025 with the option to upgrade T2 with a matching transformer at the same time at Powerco’s cost. After this upgrade, Papamoa will be shifted back to Te Matai GXP, and the load reduced at Mt Maunganui GXP. We are investigating the pricing impact on our customers should we choose to upgrade T2 at the same time as T1.

The forecasted high load growth rate in the eastern part of the area is driven by more residential developments, kiwifruit and avocado growing and processing, and the possibility of industrial decarbonisation. This growth will significantly exceed the capacity of Transpower’s Te Matai 110/33kV GXP, even with the upgrade of both transformers.

Supplying this load at 33kV from Te Matai is problematic as there are limited circuit route options and little to no route diversity options. Therefore, we are investigating extending the 110kV from Te Matai GXP into the Wairakei substation and establishing a 110/33kV interconnection at the substation. This 110/33kV interconnection would centralise the bulk load circulation on the 33kV subtransmission network by supplying Papamoa, Wairakei and Rangiuru substations and, eventually, the new residential developments in the Te Tumu catchment. An additional benefit to be investigated is that the Te Maunga load could also be supplied from the new 110kV supply point, further relieving the pressure on Transpower’s Mt Maunganui GXP. The existing Te Matai GXP would continue to supply Atuaroa Avenue, Te Puke, Paengaroa and Pongakawa substations.

The 110kV Okere-Te Matai circuit’s N-1 capacity constraint is another issue we are working on with Transpower to address in the long term. As load grows in the Te Matai region, the 110kV circuit will be thermally overloaded during an outage of the Kaitimako-Te Matai 110kV circuit at high load times.

The following projects have been identified as possibly occurring 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 will be confirmed closer to the time.

Table 11.24: Possible future developments

PROJECT	SOLUTIONS
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 and most likely to be at the end of the planning period.
Triton substation	Development of Port of Tauranga on the eastern side is signalled in the longer term once the western end is completed. It is anticipated that the load will increase substantially, which will likely exceed the firm capacity of the transformers at Triton. If future load grows, driven by the port expansion, then a third transformer may be required to support the load in the area. The timing of this project is customer-driven.

11.6 WAIKATO

Strong demand growth in the Waikato area has highlighted legacy security issues and requires additional investment to improve both network security and reliability.

During the past two years, we have completed several projects to improve network security to meet the forecast demand growth. The largest of these projects was constructing a new 110/33kV interconnection at Putāruru, supplied by the Arapuni GXP.

We will continue to implement other network development projects during the next 10 years to increase security and capacity to meet the high forecast demand growth in the area, especially around Morrinsville.

Major and minor project spend related to Growth and Security during the next 10 years is forecast to be $42m.

11.6.1 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 Putāruru.

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. However, 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. Because of its inland location, 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. In addition, several important industrial and food processing facilities are located within the area. These have been instrumental in driving recent demand and network developments.

The significant population centres are Morrinsville, Te Aroha, Matamata and Putāruru. 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. Tīrau is subject to tourism activity and the dairy plant is the largest single load.

The area is supplied by the Waihou, Piako, Hinuera and Arapuni GXPs.

- Waihou GXP supplies six zone substations – Mikkelsen Road, Tahuna, Waitoa Inghams, Farmer Road and Walton.
- Piako GXP supplies four zone substations – Piako, Morrinsville, Tatua and Waharoa.
- Hinuera GXP supplies three zone substations – Lake Road, Browne Street and Tower Road.
- The new Arapuni GXP supplies two zone substations – Putāruru and Tīrau.

Almost all subtransmission in the region is at 33kV, with a single 110kV subtransmission circuit supplying Putāruru zone substation from the Arapuni GXP.

The Waikato subtransmission network is best described as interconnected radial, with a mix of overhead lines and underground cables. With the completion of recent network reinforcement projects, some of the Waikato zone substations have been upgraded to have two dedicated circuits. The remaining substations rely on switched 33kV backfeeds from different GXPs, so it is not possible to have parallel operation of supply lines.

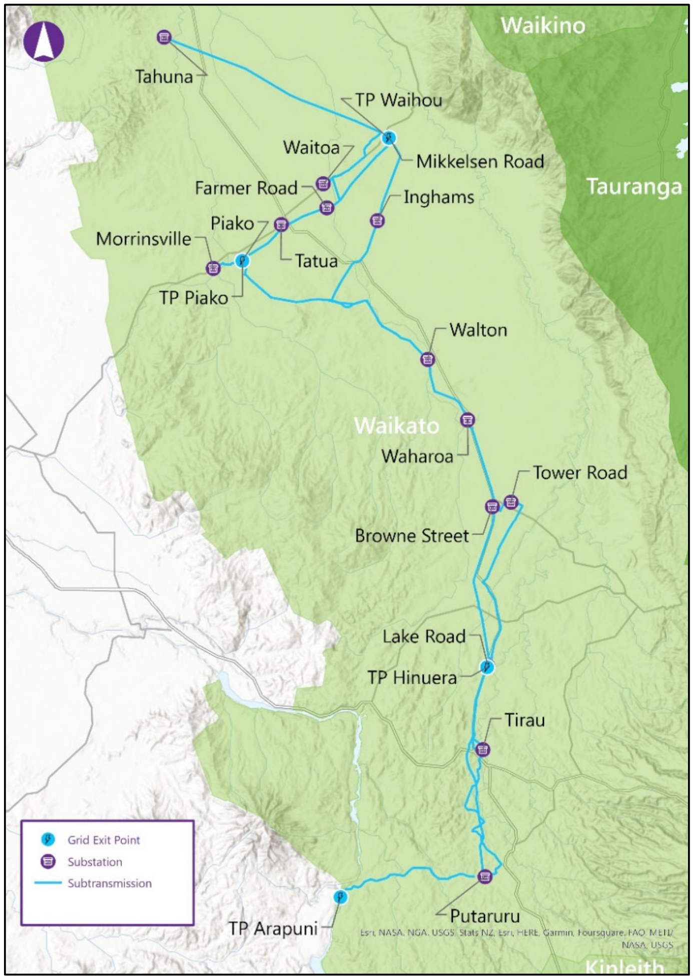
Tahuna is supplied via a long, single, 33kV circuit from the Waihou GXP, with no alternative source other than limited 11kV backfeed. This is well below our security standards.

The Waharoa zone substation 11kV bus is normally operated split, supplying Open Country Dairy Limited off the southern 11kV bus section and the surrounding rural area off the northern 11kV bus section. The substation security is a balance between our nominal security standards and the specific requirements of the major connected customer.

Transpower's radial 110kV circuits supply the GXPs in the area as follows:

- A single 110kV circuit supplies the Hinuera GXP from Karāpiro. This is a legacy of historical grid development and limits security to Matamata, Putāruru and Tīrau. However, our new South Waikato grid connection to Arapuni GXP will help to improve security of supply to the area.
- Dual 110kV circuits on a single tower structure line supply the GXPs along the Valley Spur (Piako, Waihou, Kopu and Waikino GXPs) from Hamilton.
  The peak load on the Valley Spur is forecast to exceed the N-1 capacity of this 110kV double circuit line from this year. We are working with Transpower to investigate options to reinforce their transmission network into the area (See section 11.15.10 for more details).

Figure 11.8: Waikato area overview



Note: The Arapuni-Putāruru 110 kV subtransmission circuit is scheduled to be commissioned at the end of March 2023. This map shows an indicative route of the 110kV subtransmission circuit from Arapuni to Putāruru as at the time of writing this report, the new Arapuni-Putāruru 110kV subtransmission circuit is still being constructed.

Table 11.25: Waikato network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Morrinsville second 33kV circuit	Completed
New Piako-Te Miro 11kV feeder	Completed
Kereone-Walton 33kV subtransmission enhancement	Completed
Putāruru 110/33kV interconnection	Completed
Putāruru-Tīrau 33kV underground cable	Completed
Lake Road second transformer	Completed
Tīrau second transformer	Completed
Hinuera outdoor to indoor (ODID) conversion	Completed
Wood Road (WIEL) substation and subtransmission network enhancement	Under construction
Waharoa 33kV outdoor to indoor (ODID) conversion	Deferred to beyond the current AMP period.
Three new 11kV feeders to Morrinsville north and west	Substituted. This is replaced by the proposed new Avenue Road North zone substation.

11.6.2 DEMAND FORECASTS

Demand forecasts for the Waikato zone substations are shown in Table 11.26, with further detail provided in Appendix 7.

Table 11.26: Waikato zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Browne Street	10.4	13.1	13.8	14.4
Farmer Road	6.4	15.1	21.0	22.3
Inghams	3.9	3.9	3.9	3.9
Lake Road	6.3	6.6	7.1	7.6
Mikkelsen Road	12.1	12.5	13.0	13.5
Morrinsville	8.4	10.0	10.3	10.6
Piako	14.1	16.2	18.0	18.6
Putāruru	12.1	15.0	16.8	17.2
Tahuna	5.5	5.7	5.9	6.2
Tatua	5.4	6.9	6.9	6.9
Tīrau	9.3	12.7	13.2	13.8
Tower Road	8.2	8.5	8.9	9.3
Waharoa North	3.6	3.7	3.9	4.1
Waharoa South	5.3	5.3	5.3	5.3
Waitoa	12.3	12.6	13.1	13.7
Walton	5.1	5.3	5.5	5.7

Demand growth is generally from small increases in population in urban centres, increased dairy activity, and industrial growth in the area. Historically, much of the area is a dairy stronghold. Some pockets of more recent conversion to dairy farming have increased the loading on our 11kV feeders. We are also monitoring the impact of potential changes to dairy refrigeration requirements on farms.

The demand forecast table shows that several Waikato substations already exceed our security criteria requirements. We are planning several large investments to resolve legacy security risks, which impose unacceptable economic costs in terms of the high-value load at risk or the large number of customers impacted by poor reliability.

11.6.3 MAJOR CUSTOMERS

Table 11.27: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Daltons Limited	Industrial Manufacturing and Mining	Browne Street
Silver Fern Farms	Food processing	Farmer Road Mikkelsen Road
Wallace Corporation	Food processing	Farmer Road
Inghams Group New Zealand Limited	Food processing	Inghams
Fonterra Co-operative Group Limited	Dairy	Morrinsville Tīrau Waitoa
Greenlea Premier Meats Limited	Food processing	Morrinsville
Ballance Agri-Nutrients	Chemicals	Piako
Evonik Industries	Chemicals	Piako
Kiwi Lumber Limited	Timber processing	Putāruru
The TATUA Co-operative Dairy Company Limited	Dairy	Tatua
Open Country Dairy Limited	Dairy	Waharoa
Matamata-Piako District Council; Wastewater Treatment Plant	Public/State	Piako

Known and potential major industrial customer developments in the Waikato area and their potential impact on our distribution network are as follows:

- Browne Street zone substation supplies Daltons Ltd at Matamata. The major customer has forecast some load increase during the AMP period. We will likely need to upgrade the Browne Street 33/11kV transformer and 33kV subtransmission capacity into Browne Street within the next 10 years to meet this increased load and general load growth in the area.
- Farmer Road zone substation supplies major industrial loads at the Waitoa Industrial Estate, including Silver Fern Farms. Following a recent change of ownership, rapid expansion is being planned for the existing site. We are constructing a dedicated substation for this site to meet the customer's growth strategy.

- Morrinsville zone substation supplies the Fonterra Morrinsville dairy factory and the Greenlea Premier Meats processing plant. The major customers have indicated the possibility of some load increase within the next five years. The proposed new Avenue Road North zone substation should provide sufficient capacity to accommodate the possible major customer load changes.
- Putāruru supplies Kiwi Lumber and the Putāruru Domain Industrial Estate. The major customers have indicated the possibility of some load increase within the next five years. The existing network should have sufficient capacity to accommodate the possible major customer load changes during the AMP period.
- Tatua zone substation provides a dedicated supply to the Tatua Dairy Company and has security specific to that customer. The major customer has indicated the possibility of expanding its wastewater treatment plant in stages from 2021 to 2026. We are working with the major customer to investigate network reinforcement options to meet its forecast load increase.
- We recently improved security to the Tīrau zone substation with a second, higher rated, 33/11kV transformer and a new 33kV Putāruru-Tīrau circuit. The Tīrau 11kV bus is now normally operated split to supply the Fonterra dairy factory off one bus section and the surrounding rural area off the other bus section. The major customer has indicated the possibility of some load increase within the next five years. We may likely need to upgrade the capacity of the lower rated 33/11kV transformer to match the rating of the recently installed transformer within the next five years.
- Waitoa substation provides a dedicated supply to Fonterra's Waitoa dairy factory. The major customer has indicated possible load increases at the site during the next five years, primarily around transport fleet decarbonisation. The existing network has sufficient capacity to accommodate the possible major customer load changes.

11.6.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikato area are shown in Table 11.28.

Table 11.28: Waikato constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Browne Street and Tower Road substations	33kV Lake Road-Browne Street N-1 capacity constraint.	33kV Lake Road-Browne Street circuit upgrade.
Browne Street substation	Browne Street substation N-1 capacity constraint.	Browne Street transformer upgrade.
Farmer Road substation	Farmer Road N-1 substation capacity constraint.	New WIEL zone substation (customer-driven).
Morrinsville and Piako substations	Morrinsville substation and Piako 11kV feeder capacity constraints.	Morrinsville substation 33kV bus and new Avenue Road North zone substation.
Tatua substation	Tatua substation security and capacity constraint.	Tatua 33/11kV transformer upgrade (customer-driven). See Note 1.
Tīrau substation	Tīrau 33/11kV transformer N-1 capacity.	Tīrau transformer upgrade.
Putāruru and Tīrau substations	Putāruru 110/33kV interconnection security	Putāruru 110/33kV security upgrade.
Walton, Waharoa, Browne Street substations	Piako-Kereone 33kV circuit capacity constraint.	Piako-Kereone 33kV subtransmission enhancement.

Notes

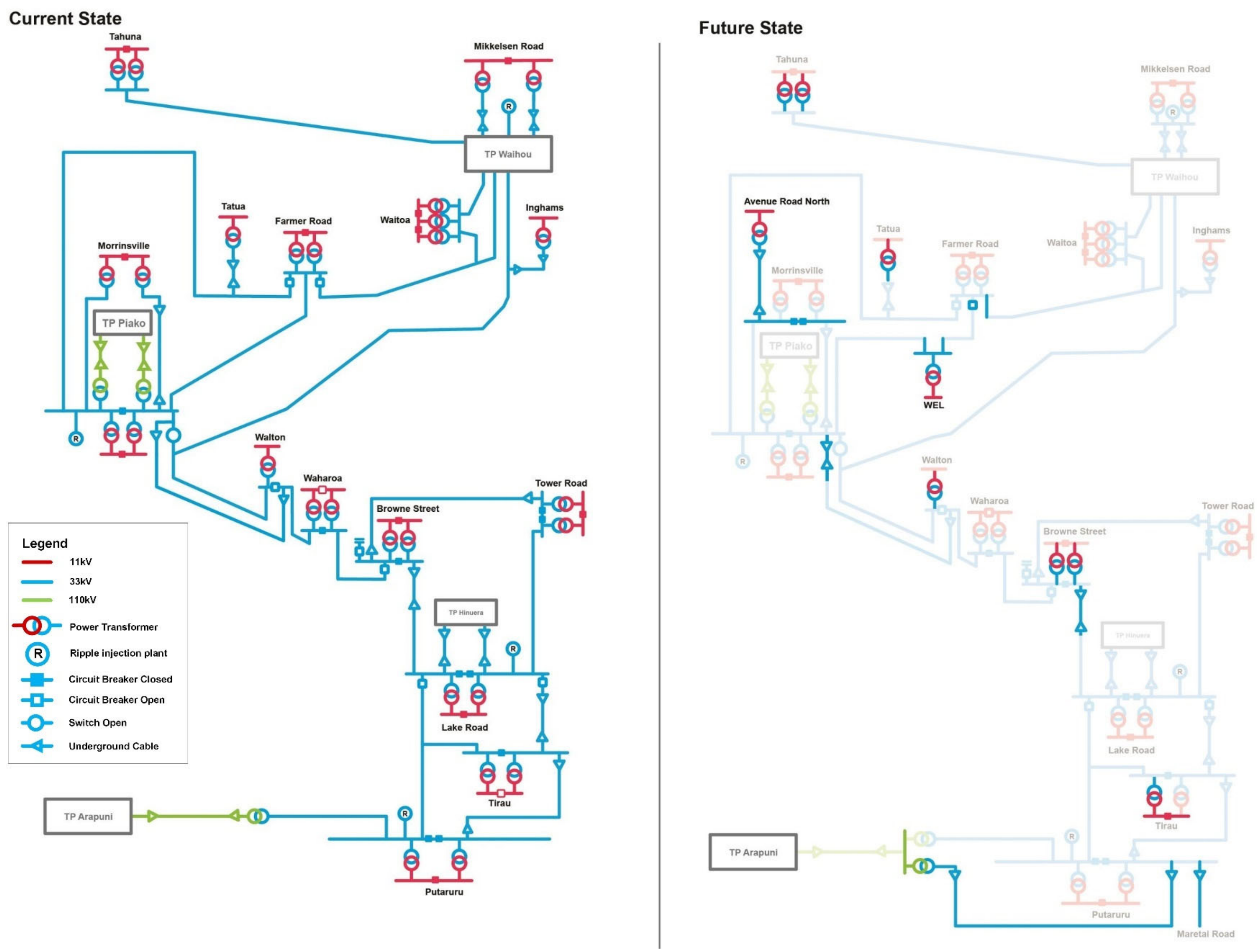
1. We are discussing with the customer the possibility of increasing capacity either with a second transformer or replacement of the existing transformer with a larger unit. Adding a second transformer at the site will increase Tatua's transformer firm capacity substantially but will require a 33kV bus to be constructed. The outcome will likely be a balance between our nominal security standards and the major customer requirements.

11.6.5 PROPOSED PROJECTS

Table 11.29: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
New WIEL zone substation	$9,545	2022-2026	Customer
Morrinsville zone substation 33kV bus	$6,563	2023-2028	Growth and Security
New Avenue Road North zone substation	$12,949	2023-2028	Growth and Security
Tatua 33/11kV transformer upgrade	$2,827	2025-2026	Customer
Putāruru 110/33kV security upgrade	$5,393	2025-2027	Growth and Security
Tīrau T1 transformer upgrade	$2,114	2026-2028	Growth and Security
33kV Lake Road-Browne Street circuit upgrade	$1,882	2029-2030	Growth and Security
Piako-Kereone 33kV subtransmission enhancement	$8,731	2030-2033	Growth and Security
Browne Street transformers upgrade	$3,064	2031-2033	Growth and Security

Figure 11.9: Waikato area network diagram



11.6.6 POSSIBLE FUTURE DEVELOPMENTS

In recent years, Matamata-Piako District Council has signalled future residential and industrial development at Matamata and Morrinsville. Some of the developments have already come online and it is expected growth will continue at the same pace. It will be necessary to reinforce the existing network infrastructure to cater for the planned development and growth.

The following projects have been identified as possibly occurring 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.

Table 11.30: Possible future developments

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.
Tatua subtransmission circuit capacity upgrade	The supply to Tatua is teed-off from one of the two subtransmission circuits between Piako and Farmer Rd. The single subtransmission circuit that supplies Tatua will be overloaded through the planned wastewater treatment plant expansion at Tatua. Following the proposed WIEL substation and subtransmission upgrade project mentioned earlier, further load increases in the region (Tatua and the proposed WIEL substations) can potentially overload the subtransmission circuit between Piako and Tatua. The proposed solution is to construct a second 33kV circuit between Piako and Tatua to address this constraint.
Avenue Road North subtransmission capacity upgrade	The new Avenue Road North zone substation will initially be a single 33/11kV transformer feeder from the proposed Morrinsville 33kV bus. A second 33/11kV transformer feeder will be added to the Avenue Road North zone substation when load in the wider Morrinsville area grows sufficiently.

11.7 KINLEITH

The Kinleith area includes Tokoroa and a major pulp and paper mill at Kinleith.

Major and minor project spend related to Growth and Security in this region during the next 10 years is $32m.

11.7.1 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 14,500.

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 and chicken 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.

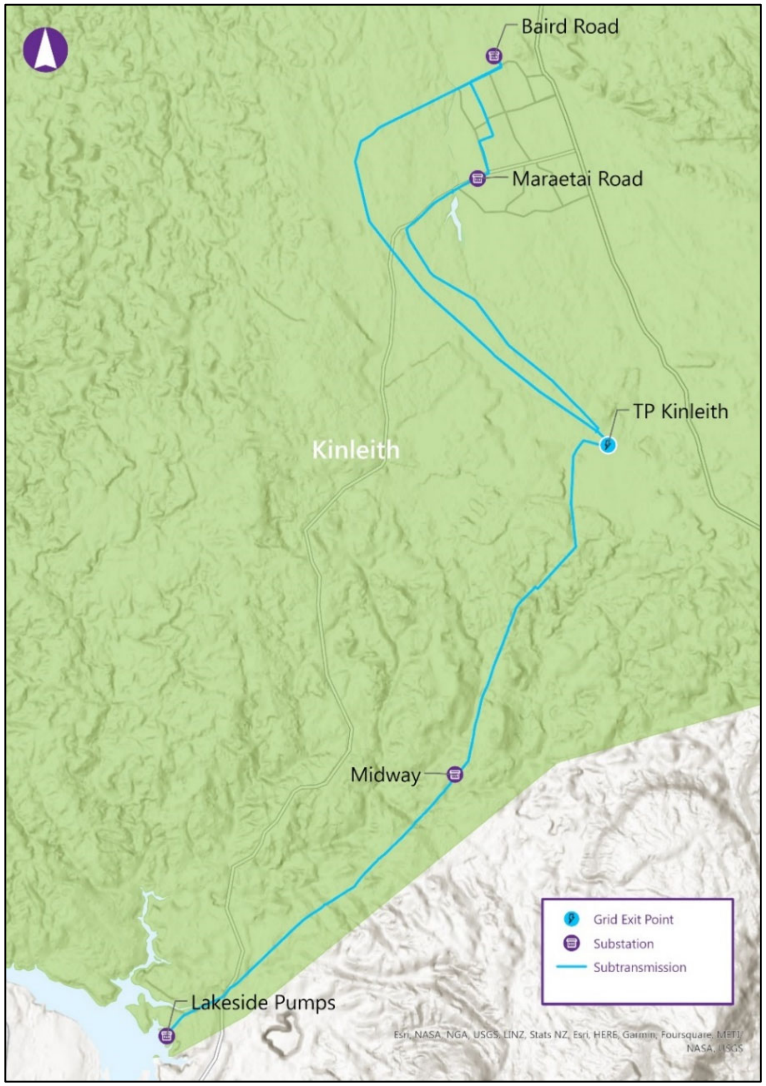
Kinleith GXP is the sole grid supply point for the area. There is no 33kV interconnection with other areas and only limited 11kV backfeed.

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 and both substations are connected to each other via a single circuit to form a 'ring' formation. 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 buses, with some limited degree of interconnection. The mill also operates a cogeneration plant that generates power into either one of the three-winding transformers (T5 or T9) on the 11kV winding side. Normally, the generation injects into the T5 11kV winding. During a T5 outage, the generation can be switched to inject into the T9 11kV winding.

There hasn't been a network change for the Tokoroa area since the AMP21.

Figure 11.10: Kinleith area overview



11.7.2 DEMAND FORECASTS

Demand forecasts for the Kinleith zone substations are shown in Table 11.31, with further detail provided in Appendix 7.

Table 11.31: Kinleith zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Baird Road	9.9	12.0	12.3	12.7
Maraetai Road	8.8	14.7	17.3	17.9
Midway/Lakeside	4.2	4.2	4.2	4.2

Demand growth in Tokoroa is considerable. The primary driver of the load forecast is the new dairy plant Olam Food Ingredients. Additionally, the council notes small-scale residential and commercial development in the area.

We are in contact with the Kinleith mill regarding any future development plans. Recently, there has been an inquiry from the mill about upgrading its wastewater systems. We are working with the mill to determine what load will be connected and determine what types of constraints could occur on our network and Transpower transmission network. These proposals are not reflected in the base forecast.

In the current planning period, we propose a 33kV link between Putāruru and Maraetai Road substation, which will transfer some load from Kinleith GXP to Putāruru. Depending on the size of new load, the 110kV circuits may be constrained during a post-contingency event. Upgrading these circuits would be complex as there are other third parties connected to the 110kV network. In the short-term planning period, the preference will be to have a post contingency load-shedding scheme to avoid constraints on the 110kV circuit during N-1 events.

11.7.3 MAJOR CUSTOMERS

Table 11.32: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Oji Fibre Solutions Limited	Timber processing	Kinleith 11kV

Known and potential major industrial customer developments in the Kinleith area and their potential impact on our distribution network are as follows:

- Dairy processing plant Olam Food Ingredients New Zealand Limited (OFI) has an initial request of 5MVA load when the plant is commissioned in late 2023. The load is anticipated to increase to 7.4MVA in the future. The existing 11kV network out of Maraetai Road substation will supply the initial stage. We are doing a detailed design for a new OFI zone substation and associated subtransmission supply circuit, which will supply the customer. Construction will commence following the completion of the detailed design.
- A query for a large-scale solar farm potentially connecting to our subtransmission network. The solar farm power output could be limited depending on where it is connected to the Powerco network. The subtransmission network has small-sized cables at the GXP end which could limit the power export.

11.7.4 EXISTING AND FORECAST CONSTRAINTS

The electricity supply is dominated by demand from the Kinleith mill. The mill has four 11kV buses, at which supply is taken, and two additional supplies at 33kV, which serve river pump substations. The security provided to the mill and pumps is determined through consultation with the customer, Oji Fibre Solutions.

In the past decade, the population growth in Tokoroa has been modest. The council is looking at the possibility of zoning specific areas around the edge of Tokoroa for rural residential (lifestyle block) development.

In Tokoroa south, new connections to small industries are ongoing, and a large area of industrial land is deemed suitable for major industry. The load request for up to 7.4MVA by Olam Food Ingredients will significantly impact the existing network's capacity. Therefore, a new subtransmission supply with a new substation is proposed to support the customer's load.

Major constraints affecting the Kinleith area are shown in Table 11.33.

Table 11.33: Kinleith constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Baird Road and Maraetai Road substations	Substation and subtransmission capacity constraints.	OFI substation and Putāruru and Maraetai Road 33kV link.
Kinleith GXP	Firm capacity for 110/11kV supply transformers is exceeded.	Refer to 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.	Putāruru and Maraetai Road 33kV link. Refer to Note 2.
Lakeside and Midway substations	Single circuit to Midway and Lakeside pump substations. An outage on either 33kV circuit will cause a loss of supply until repairs are completed.	Refer to Note 3.
Lakeside and Midway substations	Single supply transformer in each respective substation. No security provided.	Refer to Note 3.

Notes:

1. The security for the Kinleith mill is determined by the customer, Oji Fibre Solutions, and not the Powerco security standard. We continue to work with Kinleith mill and Transpower to improve the security of supply.
2. No-break N-1 security for the 33kV bus supplying Baird Road and Maraetai Road substations is not possible as the vector group for the 33kV windings on the new T9 and T5 transformers is not identical. The configuration requires a short loss of supply to the 33kV load when switching the 33kV bus between the two transformers. The 33kV load at Kinleith during the winter period exceeds the continuous capacity of T5, hence the 33kV load is at risk during a post-contingency event. Offloading the Kinleith GXP load over to Putāruru through the Putāruru-Maraetai Road 33kV link reduces the Kinleith GXP load and keeps it below the continuous rating of T5.
3. 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.

11.7.5 PROPOSED PROJECTS

Table 11.34: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
OFI substation	$9,311	2021-2024	Customer
Putāruru and Maraetai Road 33kV link	$31,812	2024-2033	Growth and Security

11.7.6 POSSIBLE FUTURE DEVELOPMENTS

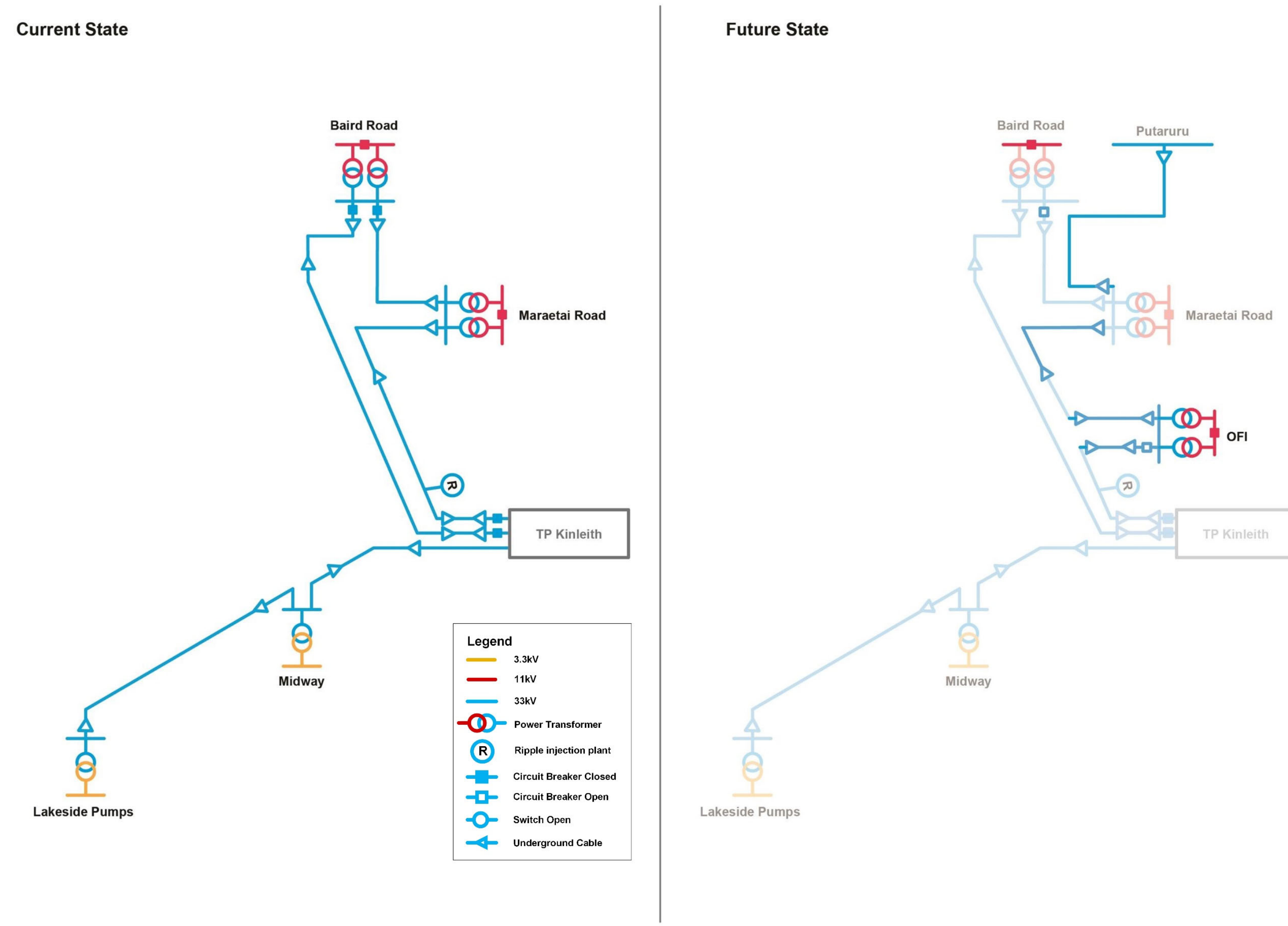
We will implement a staged programme to install differential protection on all 11kV feeder circuit cables at Kinleith mill. Protection upgrades will be carried out at the same time. The design has been constrained by the need to utilise the existing cable tunnels and by the inability to alter the feeder arrangement on the new switchboard significantly. We will coordinate with Transpower and the customer on this work.

Kinleith GXP is also affected by the grid capacity constraints on the 110kV between Tārukenga and Arapuni.

Table 11.35: Possible future developments

PROJECT	SOLUTIONS
Kinleith 33kV	Later in the planning horizon, we intend to collaborate with Transpower to upgrade the 33kV switchboard at Kinleith, which is owned by Transpower. Along with this upgrade, the 33kV feeder cables connection for the Baird Road and Maraetai Road substations will be upgraded. At present, the upgrade of the 33kV cables is limited because of the cable termination at the existing 33kV switchboard, which can only support 300sqmm sized copper cables. This restricts the increase in thermal capacity of the subtransmission circuit, hence the cost of cable upgrades cannot be justified for a small uplift in thermal capacity.

Figure 11.11: Kinleith area network diagram



11.8 TARANAKI

The most recent development work in the Taranaki area has been converting Inglewood substation supply voltage from 6.6kV to 11kV to improve the quality of supply and upgrading Eltham substation's two transformers from 10MVA to 17MVA in the first quarter of 2023.

Major and minor project spend related to Growth and Security during the next 10 years is $54m.

11.8.1 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 are 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 significantly impact 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 industries 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 by GXPs at Carrington St, Huirangi and Stratford.

The Carrington Street GXP supplies five zone substations – Brooklands, Moturoa, City, Katere and Ōākura. The Huirangi GXP supplies six zone substations – Bell Block, Waitara East, Waitara West, Mamaku Road, McKee, and Inglewood. The Stratford GXP supplies seven zone substations – Motukawa, Douglas, Cardiff, Cloton Road, Waihapa, Kaponga and Eltham.

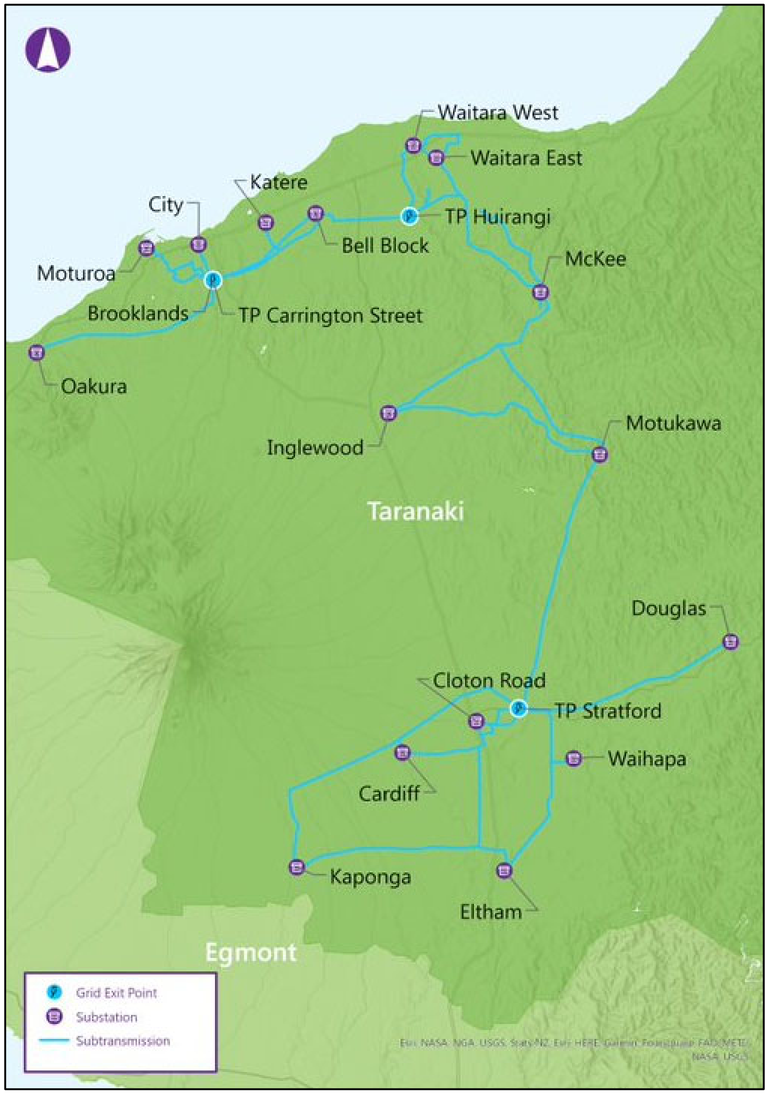
The subtransmission and distribution networks in the Taranaki area are mainly overhead.

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 are dedicated circuits directly from the GXP.

There haven't been any network changes in the Taranaki area since AMP21.

Figure 11.12: Taranaki area overview



11.8.2 DEMAND FORECASTS

Demand forecasts for the Taranaki zone substations are shown in Table 11.36, with further detail provided in Appendix 7.

Table 11.36: Taranaki zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Bell Block	15.6	16.2	17.2	18.2
Brooklands	19.3	21.0	22.9	23.6
Cardiff	1.7	1.8	1.8	1.9
City	16	17.1	17.7	18.3
Cloton Road	10.1	10.4	10.7	11.1
Douglas	1.4	1.4	1.5	1.5
Eltham	9.5	9.7	10	10.3
Inglewood	5.4	5.6	5.9	6.2
Kaponga	3.1	3.2	3.3	3.4
Katere	15.3	15.9	16.8	17.8
McKee	1.3	0.7	0.7	0.8
Motukawa	1.6	1.6	1.7	1.8
Moturoa	18.7	19.6	20.4	21.2
Ōākura	3.6	3.8	4.1	4.3
Waihapa	1.2	1.2	1.2	1.2
Waitara East	5	5.2	5.6	6
Waitara West	6.8	6.9	7.1	7.2

Major industrial customers in the area can have a significant impact on the demand forecast.

Taranaki Base Hospital is increasing its load from 1.3MVA to 3.5MVA in December 2023 and to 5.2MVA in December 2025. A distribution network upgrade project is being carried out to meet the requirements of the December 2023 additional load. Further distribution network upgrades will be required to meet the December 2025 demand forecast.

There has been an inquiry from Yarrow Stadium about increasing its load from 1MVA to 2.9MVA in December 2023. A significant distribution network upgrade will be required to supply the additional load.

McKee Gas Production station is shifting its 11kV supply from the Powerco McKee substation to its Mangahewa site substation in March 2023. Mangahewa takes 33kV supply from Powerco's 33kV line. The McKee and Mangahewa combined load would increase from the present 2.5MVA to 5.1MVA when they commission their Mangahewa C & D site new compressors.

We are not aware of any other significant changes in demand for other customers. However, such changes usually appear at relatively short notice. We will continue talking with our larger customers to establish as much lead time as possible for future developments.

The oil and gas industry impacts demand, both directly and indirectly, and can also drive upgrades for generation opportunities. The need to reduce carbon emissions and the moratorium on further oil and gas exploration permits will also have an impact.

The area could have hydrogen production facilities in the future. The move to hydrogen could have a substantial impact on electricity demand in the region, however, large-scale production plants are likely to be grid connected.

Overall demand growth in Taranaki has historically been relatively high, with large customer changes driving most of the growth. 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.

The demand growth of Ōākura and Inglewood substations exceeds our N-1 security of supply. Projects have been included in this AMP to address this issue.

11.8.3 MAJOR CUSTOMERS

Table 11.37: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Port Taranaki	Transportation	Moturoa
Taranaki Base Hospital	Public/State	Brooklands
McKechnie Aluminium Solutions	Industrial Manufacturing and Mining	Bell Block
Tegel Foods Limited	Food processing	Bell Block
Yarrow Stadium	Public/State	City
ANZCO Foods Limited	Food processing	Waitara West

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Fonterra Co-operative Group Limited	Food processing	Eltham
Taranaki Pine	Timber processing	Bell Block

11.8.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Taranaki area are shown in Table 11.38

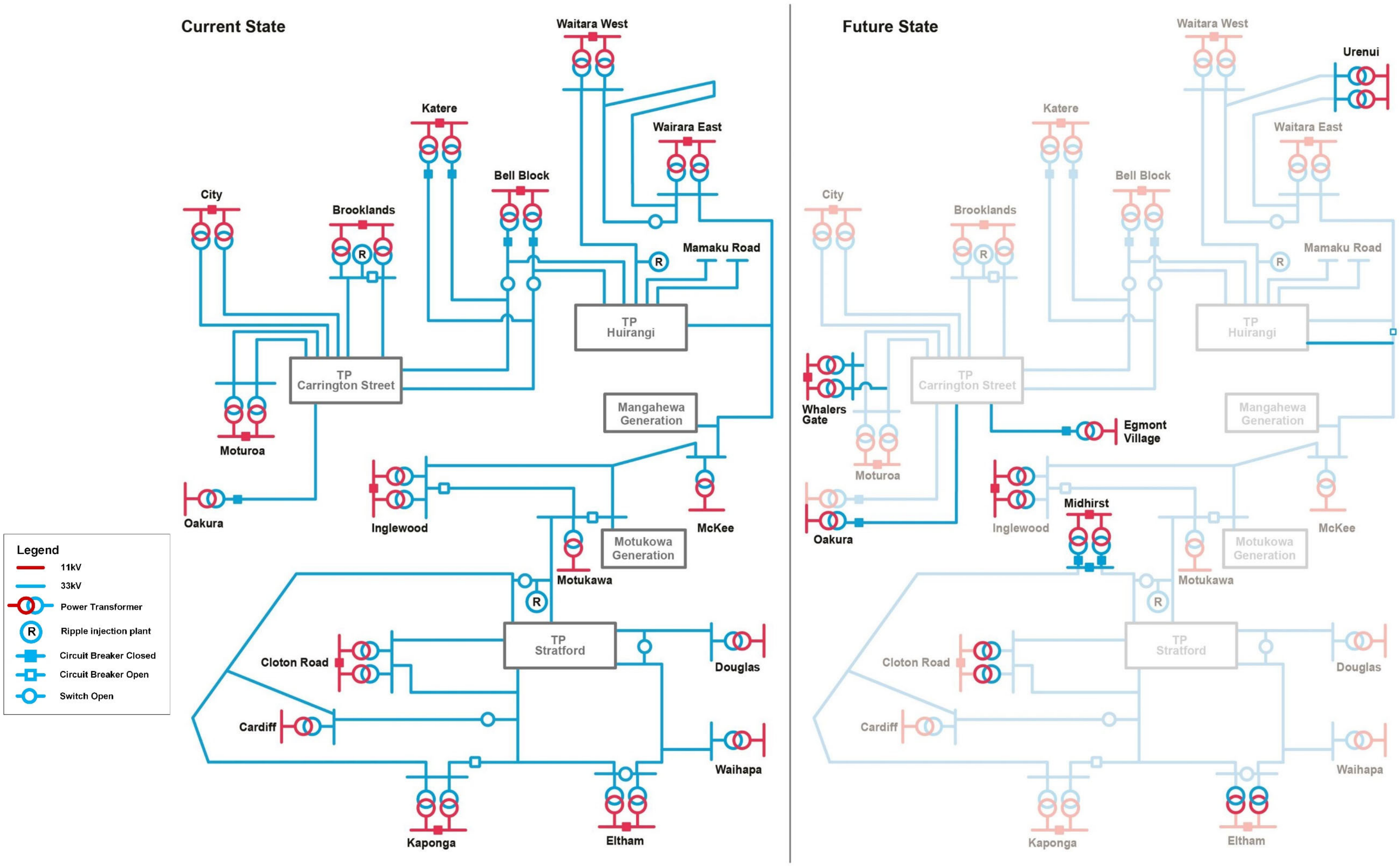
Table 11.38: Taranaki constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Inglewood substation distribution feeders	Poor voltage quality because of 6.6kV operating voltage.	Inglewood 6.6kV to 11kV conversion.
Eltham substation	Transformer's firm capacity constraint.	Eltham transformers upgrade.
Taranaki Base Hospital	Normal and backup supply feeders' capacity constraint because of load increase from 1.3MVA to 3.5MVA in December 2023.	Network upgrade for hospital - new 2.3MVA load.
Waitara East, West, McKee and Inglewood substations	Reliability and capacity constraint in N-1 situation.	Huirangi to McKee tee second 33kV line.
Brooklands and Moturoa substations	Substation and distribution feeders' capacity constraint.	Whalers Gate new zone substation.
Motukawa substation	Distribution feeders' poor voltage quality because of 6.6kV operating voltage.	Motukawa 6.6kV to 11kV conversion.
Ōākura substation	Reliability of supply.	Ōākura substation second 33kV line and second transformer.
Inglewood substation	Transformers' firm capacity and smaller voltage regulation range (10%) constraint.	Inglewood substation two transformers upgrade.
Midhurst 11kV regulating station	Distribution feeder voltage quality and capacity constraint.	New Midhurst zone substation.
Mangorei 11kV regulating station	Distribution feeders' voltage quality and regulator capacity constraint.	New Egmont Village zone substation.
Bell Block substation	Two industrial feeders' backup supply capacity constraint.	A new feeder from Katere substation.
Cloton Road and Eltham substation	Eltham West 33kV line N-1 capacity constraint.	Cloton Road substation second 33kV line.
Waitara East substation	Reliability of supply and poor voltage quality.	New Urenui zone substation.
Cardiff substation	The single-supply transformer does not provide sufficient security. Renewal is scheduled for 2022.	Refer to Note 1.
Kaponga substation	Demand exceeds secure capacity of the two transformers. Transformers are scheduled for replacement in 2026.	Refer to Note 1.
Motukawa substation	The single transformer does not provide sufficient security and is scheduled for replacement.	Refer to Note 1.
Douglas substation	The single supply transformer does not provide sufficient security.	Refer to Note 1.

Notes:

1. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.

Figure 11.13: Taranaki area network diagram



11.8.5 PROPOSED PROJECTS

Table 11.39: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Huirangi to McKee tee second 33kV line	$2,682	2022-2024	Growth and Security
New Whalers Gate zone substation	$9,225	2025-2028	Growth and Security
Motukawa 6.6kV to 11kV conversion	$4,185	2025-2027	Growth and Security
Ōākura second 33kV line and second transformer	$6,492	2026-2030	Growth and Security
Inglewood substation transformers upgrade	$3,783	2028-2030	Growth and Security
New Midhirst zone substation	$10,113	2029-2032	Growth and Security
Cloton Sub North 33kV feeder City area underground	$793	2030	Growth and Security
New Egmont Village zone substation	$7,201	2030-2033	Growth and Security
Cloton Road substation second dedicated 33kV line	$3,408	2030-2032	Growth and Security
New Urenui zone substation	$8,732	2031-2034	Growth and Security

11.8.6 POSSIBLE FUTURE DEVELOPMENTS

Transpower's grid developments can have a significant impact on network development, as seen with the recent removal of the New Plymouth GXP and the need for a new supply to the Moturoa substation.

New solar generation may require network development. 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 the availability of land and electricity markets and, therefore, are difficult to predict in terms of location and size. In addition, lead times are usually short, meaning that we must reconsider some of our network development plans quickly.

Taranaki has many spot-load increases driven by industrial customers, either those associated with agriculture or 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 possibly occurring 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.

Table 11.40: Possible future developments

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 backfeed capability from the distribution network of neighbouring substations. In the future, if the demand exceeds the present class capacity, there is a possibility of loss of supply at the substation for a transformer fault. The preferred solution is to add the second transformer to the substation.

11.9 EGMONT

The subtransmission configuration in this area consists of ring circuits providing adequate security, except for 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 $22m.

11.9.1 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 Hāwera, Manaia, Ōpunake and Pātea. Hāwera is the largest of these towns and its population is reasonably stable. Smaller towns in the area 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 severely impact 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 in Manaia. Some oil and gas processing are also present.

The Egmont area is supplied from the Hāwera and Ōpunake GXPs through two independent 33kV subtransmission systems. Ōpunake GXP supplies Pungarehu, Ngāriki and Tasman substations through two 33kV ring circuits. Ngāriki is common to both rings. Hāwera GXP supplies Kāpuni, Manaia, Cambria, Mokoia, and Livingstone substations.

A 33kV ring supplies Mokoia and Livingstone. A separate 33kV ring supplies Kāpuni and Manaia, although Manaia has a short section of single circuit teed off the ring.

Cambria substation, which is the main substation serving Hāwera township, is supplied by two dedicated 33kV oil-filled cables.

Historically, two different power companies owned the Ōpunake and Hāwera 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.

There haven't been any network changes in the Egmont area since AMP21.

Figure 11.14: Egmont area overview

11.9.2 DEMAND FORECASTS

Demand forecasts for the Egmont zone substations are shown in Table 11.41, with further detail provided in Appendix 7.

Table 11.41: Egmont zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Cambria	14.7	15.0	15.4	15.8
Kāpuni	5.5	5.5	5.5	5.5
Livingstone	2.7	2.8	2.8	2.9
Manaia	5.5	5.6	5.8	5.9
Mokoia	3.3	3.3	3.5	3.6
Ngāriki	2.68	2.6	2.7	2.8
Pungarehu	3.1	3.2	3.4	3.6
Tasman	6.4	6.5	6.7	6.9

Major industrial customers in the area have the most significant impact on the demand forecast through occasional and largely unpredictable significant increases in demand. Apart from this, the forecast demand growth in the Egmont area is relatively low.

As with the Taranaki area, generation proposals can necessitate capacity upgrades, tend to be unpredictable and, from a planning perspective, arise at short notice. Proposals also tend to depend on market conditions.

Manaia substation exceeds our security standards. Therefore, this AMP has included a project to improve the substation's security of supply.

11.9.3 MAJOR CUSTOMERS

Table 11.42: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Silver Fern Farms	Food processing	Cambria
Yarrows The Bakers	Food processing	Manaia
Ballance Agri-Nutrients	Chemicals	Kāpuni
OMV New Zealand Limited	Industrial Manufacturing and Mining	Tasman

11.9.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Egmont area are shown in Table 11.43.

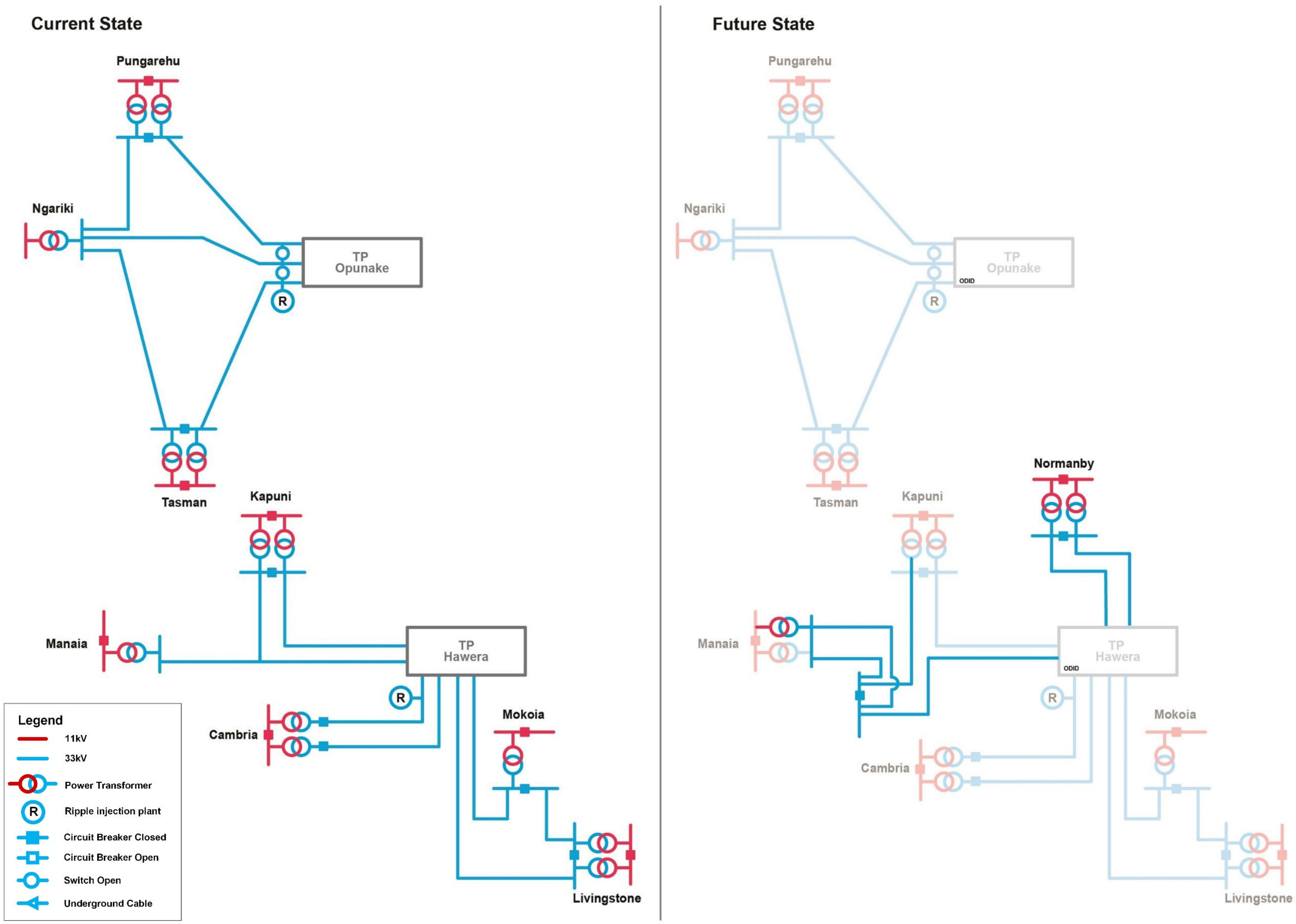
Table 11.43: Egmont constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hāwera GXP	Reliability of supply because of poor condition of outdoor switchgear.	Hāwera GXP 33kV ODID and taking ownership.
Ōpunake GXP	Reliability of supply because of poor condition of outdoor 33kV switchgear.	Ōpunake GXP 33kV ODID and taking ownership.
Cambria substation	Distribution feeders' capacity constraint.	New Normanby zone substation.
Manaia substation	Security of supply.	Manaia second 33kV line and second transformer.
Pungarehu substation	Demand exceeds secure capacity of the two transformers.	Refer to Note 1.
Livingstone substation	Transformer firm capacity has been exceeded. Transformers are scheduled for replacement in 2024.	Refer to Note 1.
Ngāriki substation	Single transformer. The 11kV backfeed does not meet security criteria.	Refer to Note 2.

Notes:

1. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.
2. Managed operationally.

Figure 11.15: Egmont area network diagram



11.9.5 PROPOSED PROJECTS

Table 11.44: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Ōpunake GXP 33kV ODID	$5,243	2022-2024	Growth and Security
Hāwera GXP 33kV ODID	$5,060	2022-2025	Growth and Security
New Normanby zone substation	$8,414	2028-2031	Growth and Security
Manaia second 33kV line and second transformer	$6,388	2031-2033	Growth and Security

11.9.6 POSSIBLE FUTURE DEVELOPMENTS

The following projects have been identified as possibly occurring during the planning period. The description represents the most probable solution, but the final solution and optimal timing is subject to further analysis and will be confirmed closer to the time.

Table 11.45: Possible future developments

PROJECT	SOLUTIONS
Livingstone substation supply transformers	There is limited backfeed capability from the 11kV distribution network. The preferred solution is to upgrade the transformers during the planned renewals replacement project.
Tasman zone substation transformers upgrade	The forecast Tasman substation demand by the year 2035 is 6.9MVA, which is close to its class capacity (7MVA), i.e., single transformer capacity plus available backup supply from neighbouring substations. If Tasman sees more load growth than expected, its two 5MVA transformers would need to be upgraded into two 7.5/10MVA transformers along with new foundations and oil bunding walls.

11.10 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 underway in the area include a second 33kV circuit to the Taupō Quay and Peat Street substations. Major and minor project spend related to Growth and Security during the next 10 years is $27m.

11.10.1 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.

Waverley, a small South Taranaki town, 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 at 2,100 hours per annum. The area receives about 900mm of annual rainfall, and the Whanganui River is prone to flooding in heavy rain.

The Whanganui area can also be hit by occasional storms off the Tasman Sea. High winds cause the most disruption as they can fell trees and throw debris onto lines, which leads to widespread and prolonged outages.

The district's economy is driven by agriculture, forestry, and fishing. Whanganui City is the main service centre for the rural district and is 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. Wanganui and Brunswick GXPs supply Whanganui city and its surrounding areas. Waverley GXP supplies the town of Waverley.

There are nine zone substations in the Whanganui area, five of which – Blink Bonnie, Taupō Quay, Beach Road, Hatricks Wharf and Wanganui East – are supplied from the Wanganui GXP. Peat Street, Roberts Avenue, Kai Iwi, and 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, somewhat 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, providing the breakless or quick switching required to comply with our security criteria is problematic. However, 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 urban areas.

A planned renewal project will refurbish conductors and the river crossing towers between Wanganui GXP and Taupō Quay substations in the near term.

Figure 11.16: Whanganui area overview

Table 11.46: Whanganui network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Roberts Avenue to Peat Street new 33kV circuit	Under construction
Peat Street to Taupō Quay new 33kV circuit	Under construction
Waverley ODID	Under construction

11.10.2 DEMAND FORECASTS

Demand forecasts for the Whanganui zone substations are shown in Table 11.47, with further detail provided in Appendix 7.

Table 11.47: Whanganui zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Beach Road	11.9	12..2	12.3	12.5
Blink Bonnie	2.8	2.9	3.0	3.1
Castlecliff	9.7	11.3	11.5	11.6
Hatricks Wharf	9.8	10.0	10.3	10.5
Kai Iwi	2.2	2.3	2.4	2.5
Peat Street	14.5	14.7	15.0	15.4
Roberts Avenue	4.5	4.6	4.7	4.8
Taupō Quay	5.9	6.0	6.1	6.2
Wanganui East	5.9	5.9	6.0	6.1

Recent underlying growth in demand has been modest throughout the Whanganui area. However, major industrial customers can have a big impact on demand through significant changes in their load. Major industrial customer load change is partly behind the high demand forecast at Beach Road and the growth rate at Castlecliff.

The Mill Road industrial subdivision will add 0.5MVA to Castlecliff substation. Larger customers have been looking into expansion options around Castlecliff. There has been feasibility interest in substantial electrification near Pukepapa and Blink Bonnie substations. Hatricks Wharf will supply expanded art infrastructure in the city.

Growth and Security plans are moving towards security class capacity, improving security and reliability for the existing load base, and catering for future new load.

Growth and Security plans will balance a probabilistic theory, improve transfer capacity between critical substations, raise security at Brunswick GXP, and further mesh the subtransmission ring.

11.10.3 MAJOR CUSTOMERS

Table 11.48: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
AFFCO New Zealand	Food processing	Beach Road
Cavalier Spinners Limited	Industrial Manufacturing and Mining	Beach Road
Firstgas	Industrial Manufacturing and Mining	Blink Bonnie
Open Country Dairy Limited	Dairy	Beach Road
Silver Fern Farms	Food processing	Waverley
The Tasman Tanning Company Limited	Industrial Manufacturing and Mining	Beach Road
Waters and Farr	Industrial Manufacturing and Mining	Castlecliff
Whanganui Hospital	Public/State	Taupō Quay
Whanganui District Council water pumps	Public/State	Kai Iwi
Whanganui District Council Wastewater Treatment Plant	Public/State	Hatricks Wharf

Known and potential major industrial customer developments in the Whanganui area and their potential impact on our distribution network are as follows:

- Beach Road zone substation supplies major industrial loads within Whanganui CBD, such as the Open Country Dairy Limited, AFFCO New Zealand, Cavalier Spinners Limited and Tasman Tanning Company. Although Beach Road has N-1 security, the neighbouring substation loses its ability to fully backfeed under contingency. Therefore, it requires 33kV subtransmission upgrades.
- A major customer has indicated possible load growth in recent years.
- Another major customer has indicated a load increase at its plant for refrigeration. Waverley substation supplies this customer via Waitōtara feeder. This feeder is one of the worst-performing feeders. Because of the large

geographical spectrum, the feeder has thermal and voltage constraints and requires a significant upgrade to meet the customer's growth strategy.

11.10.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Whanganui area are shown in Table 11.49.

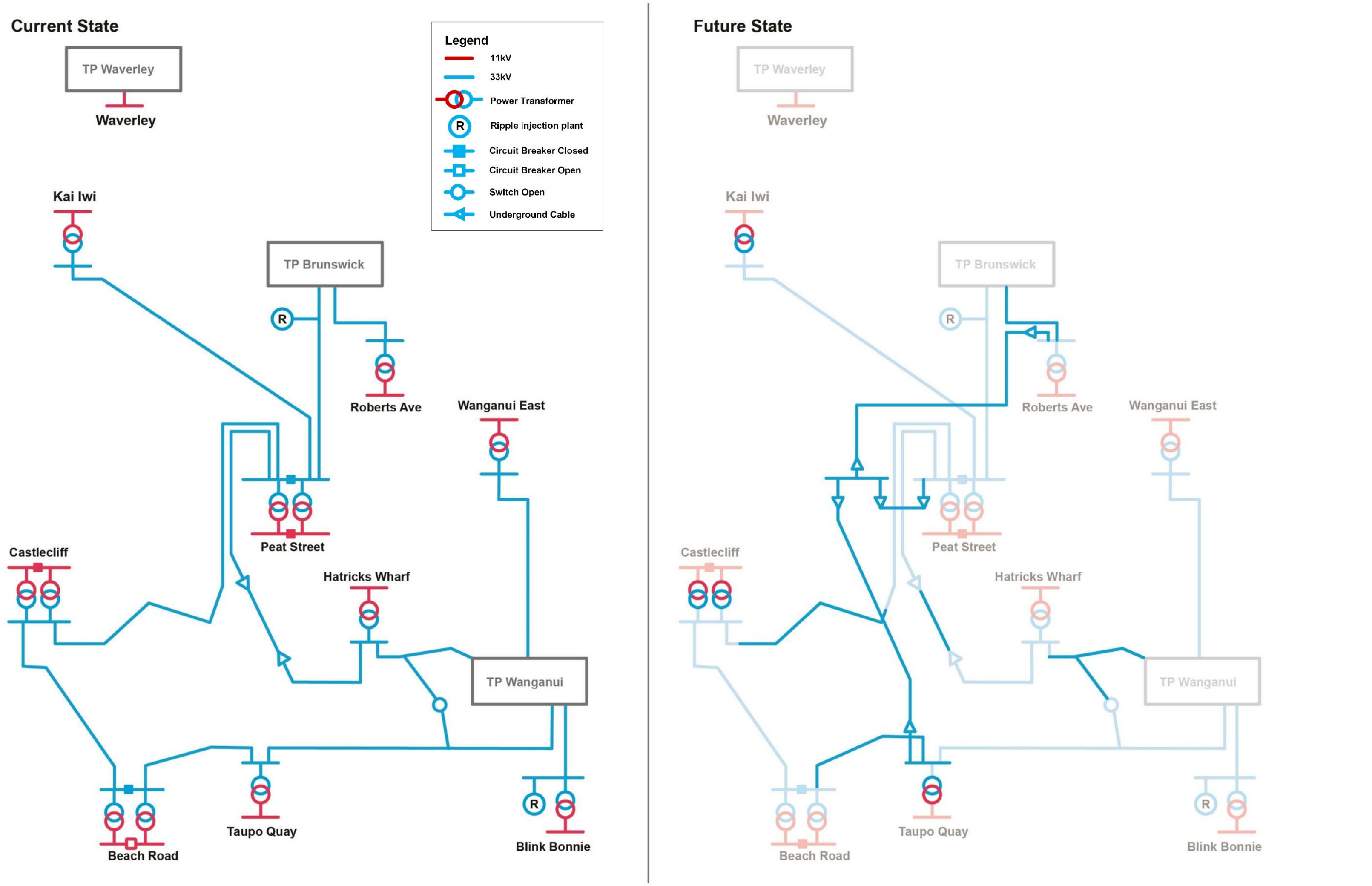
Table 11.49: Whanganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Taupō Quay and Beach Road substations	Line loading exceeds conductor capacity when supplying Castlecliff.	Underground existing 33kV circuit to 35MVA.
Wanganui GXP and Hatricks Wharf substation	Capacity constraint between Wanganui GXP and Hatricks Wharf sub when parallel supply is compromised.	Upgrade Wanganui GXP bus-L to Hatricks Wharf to above 23MVA.
Peat Street and Hatricks Wharf substations	Supply becomes overloaded on both the 630mm² cable and conductor section.	Upgrade 33kV circuit.
Peat Street and Castlecliff substations	Peat Street to Castlecliff ring loading 99% of the cable and conductor.	Underground existing 33kV circuit.
Roberts Avenue and Peat Street substations	Supply to Peat Street from Brunswick GXP is constrained during contingency.	There is a project underway delivering a new larger capacity cable between Roberts Avenue and Peat Street subs.
Beach Road and Castlecliff substations	Supply from Brunswick GXP to Beach Road is unachievable with available capacities of conductors.	Underground the existing 33kV line to higher capacity.
Beach Road and Taupō Quay substations	Insufficient supply to Beach Road under contingent configuration.	Peat Street to Taupō Quay new 33kV line is underway to install an additional 33kV circuit from Brunswick GXP into Taupō Quay.
Peat Street substation and broader ring	The capacity limitation is because there is only a single subtransmission feeder from Brunswick GXP into Peat Street.	Brunswick GXP third 33kV line
Hatricks Wharf and Taupō Quay substations	The existing transformer at Taupō Quay does not have the capacity to fully backfeed Hatricks Wharf load during an outage via the 11kV bus tie.	Taupō Quay transformer upgrade, Refer to Note 1.
Castlecliff substation	An outage of one transformer will load the single transformer to firm capacity.	Upgrade Castlecliff transformers to maintain AA+ security class.

Note:

1. Taupō Quay and Hatricks Wharf substations are linked by a high capacity 11kV bus tie. Hatricks Wharf can backfeed Taupō Quay in the case of a single transformer outage. Taupō Quay substation does not have adequate capacity to backfeed Hatricks Wharf, so the changeover scheme is on manual.

Figure 11.17: Whanganui area network diagram



11.10.5 PROPOSED PROJECTS

Table 11.50: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)	DRIVER
Taupō Quay to Beach Road	$855	2031-2033	Growth and Security
Wanganui GXP bus-L to Hatricks Wharf	$1,398	2032-2033	Growth and Security
Third 33kV circuit from Brunswick GXP	$7,909	2030-2032	Growth and Security
Hatricks Wharf to Peat Street	$1,398	2024-2026	Growth and Security
Peat Street to Castlecliff	$2,400	2025-2027	Growth and Security
Peat St to Hatricks Wharf 33kV Upgrade	$1,357	2026-2028	Growth and Security
Brunswick GXP to Roberts Avenue conductor	$1,350	2023-2024	Growth and Security
Roberts Avenue to Peat Street 33kV circuit	$5,152	2022-2023	Growth and Security
Peat Street to Taupō Quay new 33kV Line	$8,512	2022-2023	Growth and Security
Taupō Quay transformer upgrade	$1,751	2025	Growth and Security
Taupō Quay to Hatricks Wharf tie-point	$1,345	2024-2026	Growth and Security
Castlecliff transformers	$1,739	2027-2028	Growth and Security
Brunswick GXP 33kV ODID	$5,662	2025-2028	Growth and Security
Waverley GXP 11kV ODID	$1,995	2022-2024	Growth and Security

11.10.6 POSSIBLE FUTURE DEVELOPMENTS

Transpower's Wanganui GXP has one 30MVA and one 20MVA transformer. Maximum demand is about 41MVA. T1 is 51 years old, and T2 is 58 years old. T2 is planned for replacement by Transpower in 2023. This upgrade may be altered in scope, considering the 110kV network's utilised capacity and the new switchable level of supply from TP Marton into the Sanson Bulls interconnect.

We are investing in larger capacity out of Wanganui GXP in the near term. These projects will improve the ability to supply Taupō Quay, Hatricks Wharf and Beach Rd during peak maximum demand periods under contingency. However, under particular scenarios, several capacity constraints are still present in the subtransmission ring between Brunswick and Wanganui GXPs. The cross GXP subtransmission backfeeds and meshed nature of the network mean good protection and automation are required, which in turn relies on good communication links. We have recently upgraded the communication links through direct microwave links. The proposed new subtransmission projects will offer more opportunities to improve the communication systems by installing fibre cables on some key communication links.

We have pursued discussions with Transpower regarding dual transformers to Brunswick GXP. A second transformer at Brunswick was an original alternative option for the Peat St improvement projects, providing security into the critical substation. Brunswick GXP sees demand between 30 and 40MVA. Near-term Powerco investment in subtransmission ring capacity upgrades could enable further utilisation of Brunswick GXP and less of Wanganui GXP. Brunswick GXP has a single 50MVA transformer consisting of three single-phase tanks, plus a spare tank on site. Powerco is investigating route options for new 33kV feeders out of Brunswick to the new Peat Street switching station.

The following projects have been identified as possibly occurring during the planning period. The 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.

Table 11.51: Possible future developments

PROJECT	SOLUTIONS
Second transformer to TP Brunswick GXP	Agreement between Transpower and Powerco for the installation of a second-hand or new three-phase tank transformer into Brunswick. The transformer would be of similar capacity to the existing single-phase (s) transformer bank. The project would necessitate an expansion, likely an ODID of the 33kV switchyard at the site.
TP Brunswick ODID	The existing 33kV switchyard at Brunswick cannot accommodate a second transformer, so an ODID with Powerco ownership makes sense to pursue, alongside a second transformer. The region would also benefit from the option to install a third line out of Brunswick towards Peat St, which an ODID could provide.

PROJECT	SOLUTIONS
Waverley	The Waverley substation is Transpower-owned and operated. The 11kV bus and switchgear are aged and have limited ability to provide real-time monitoring of feeders by the Powerco Network Operations Centre (NOC). Faults can occur that are not cleared solely by the 11kV circuit breakers, instead tripping the upstream circuit breaker and single transformer. The TP Waverley 11kV ODID project would replace the aged switches and bus with a new indoor switchboard with full remote monitoring and operability for NOC. Alternatively, there is the option of installing new reclosers on the three circuits on the first pole out. This would provide both metering for NOC remote balancing of interconnected feeders and protection if needed.

11.11 RANGITĪKEI

Historically, a low-growth area, recently Rangitīkei has experienced an increase in industrial load growth. Customers have proposed an increase from 7MVA to 38MVA within the Marton region. With decarbonisation increasing, there has also been an increase in demand for EV charging at the public charging stations in Bulls, Taihape, and Waiouru township. Other than the Taihape substation, our area substations are supplied by single circuits and do not meet our security criteria. Major and minor project spend on Growth and Security during the next 10 years is $34m.

11.11.1 AREA OVERVIEW

The Rangitīkei area covers towns in the 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 countryside in Rangitīkei, and more rugged, mountainous terrain in the Ruapehu area, where the central plateau and mountains of the Tongariro National Park dominate.

The climate ranges from temperate in the Rangitīkei district to sub-alpine in the Ruapehu district. Snow can settle in places more than 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.

Primary production and downstream processing are the most prominent industries in the Rangitīkei economy. 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 the significant urban centres. Waiouru is dominated by a large armed forces camp.

The Rangitīkei area is connected to the grid through Marton, Mataroa and Ohakune GXPs. Mataroa and Ohakune GXPs have 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. The Pukepapa substation is directly beside Marton GXP. The Arahina substation supplies the Marton township, and Rātā is sub-fed from Arahina through a single 33kV line and services the upper Rangitīkei 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.

Between Pukepapa and Rātā, there is a 22kV distribution tie that serves as a backup for Rātā. 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 limited backfeed opportunities, especially on long spur lines.

Development projects have re-instated overhead switches out of Pukepapa substation, allowing more effective use of alternative subtransmission lines to Arahina and Rātā.

In recent years, a subdivision was developed in Bulls, and electric vehicle chargers were installed in the hills out of Taihape and downtown Bulls.

There has also been subdivision and commercial expansion feasibility work completed for larger customers supplied by Bulls, Rātā and Arahina.

Figure 11.18: Rangitīkei area overview

Table 11.52: Rangitīkei network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Marton ODID	Work in progress

11.11.2 DEMAND FORECASTS

Demand forecasts for the Rangitīkei zone substations are shown in Table 11.53, with further detail provided in Appendix 7.

Table 11.53: Rangitīkei zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Arahina	8.1	15.2	15.4	15.6
Bulls	5.5	5.7	5.9	6.1
Pukepapa	4.8	14.9	30.2	30.5
Rātā	2.8	2.9	2.9	3.0
Taihape	4.4	4.5	4.6	4.7
Waiouru	2.6	3.6	3.6	3.6

Upcoming activity signalled by a few major industrial customers has significantly increased our demand forecast for the Rangitīkei area.

We anticipate a step change in demand through converting generator-supplied irrigation loads to mains network supply in the Parewanui region.

As with other rural parts of our network, there are substations in the area that do not meet our security criteria, even at existing levels of load.

There are several proposed EV charging stations across Rangitīkei townships, Bulls, Mangaweka, Taihape, and Waiouru, on State Highway 1, which could impact the substations and the network.

11.11.3 MAJOR CUSTOMERS

Table 11.54: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
ANZCO Foods Limited	Food processing	Bulls
Farmland Foods Limited	Food processing	Pukepapa
Malteurop New Zealand Limited	Food processing	Arahina
Nestle Purina	Industrial Manufacturing and Mining	Arahina
Plentiful Limited	Industrial Manufacturing and Mining	Arahina
New Zealand Defence Force - Waiouru Military Camp	Public/State	Waiouru

Known and potential major industrial customer developments in the Rangitīkei area and their potential impact on our distribution network are as follows:

- A major customer has proposed to connect 7MVA of load at Marton. The new load will be supplied by Arahina substation.
- Another major customer indicated 6MVA of load growth at its manufacturing plant. The existing load is supplied by Arahina substation.

11.11.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Rangitīkei area are shown in Table 11.55.

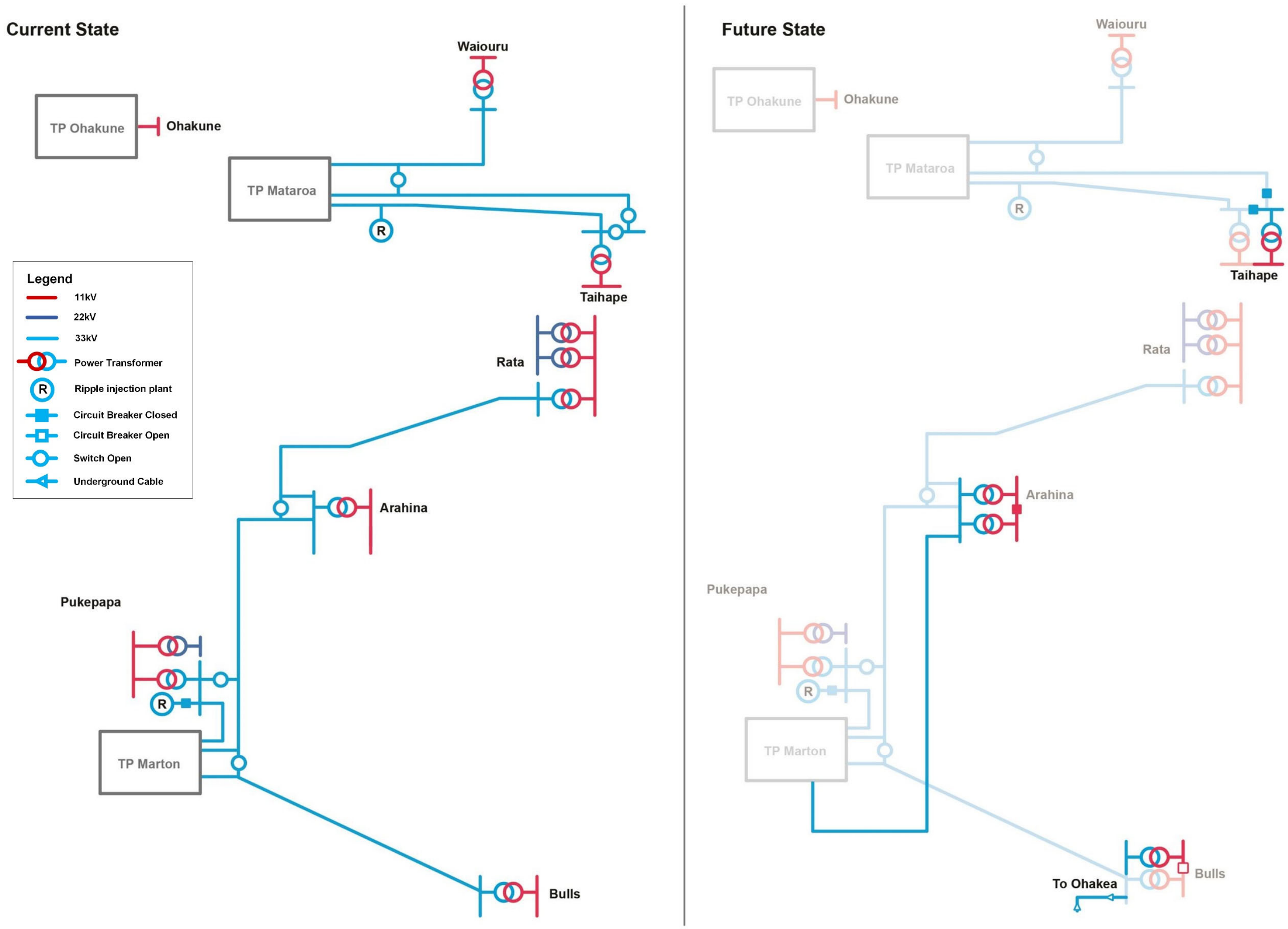
Table 11.55: Rangitīkei constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Taihape substation	The demand has exceeded the class capacity.	Install a new indoor 33kV switchroom and a second transformer.
Rātā substation	The demand has exceeded the class capacity.	Upgrade 22kV line and install pad and connection point for a temporary generator.
Bulls substation	The demand has exceeded the class capacity.	Install second transformer. Refer to Note 1.

Note:

1. The same result may be able to be achieved more efficiently if a second-hand transformer can be sourced from the network and condition, age and size are suitable.

Figure 11.19: Rangitīkei area network diagram



11.11.5 PROPOSED PROJECTS

Table 11.56: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)	DRIVER
Taihape install new switchboard	$1,024	2028	Growth and Security
Taihape second transformer	$2,309	2026-2028	Growth and Security
Bulls second transformer	$1,513	2025-2026	Growth and Security
Arahina 11kV switchroom and second transformer	$5,825	2023-2025	Customer
Arahina indoor 33kV installation	$2,595	2026-2028	Growth and Security
Pukepapa Road 11kV upgrade and a new 33kV circuit	$5,681	2024-2025	Customer
Bulls 33kV line upgrade	$635	2024	Growth and Security
Marton GXP 33kV ODID	$6,952	2023-2025	Growth and Security
Mataroa GXP 33kV ODID	$8,458	2029-2031	Growth and Security

11.11.6 POSSIBLE FUTURE DEVELOPMENTS

We will continue to monitor distribution feeder loading and voltages, and schedule upgrades required to meet demand growth. We will also focus on improving existing reliability, through backfeeding and automation, which can require the increased capacity of tie circuits, offload reconfigurations and new tie circuits or feeders.

To improve security performance, even if not fully meeting our standards, increased substation inter-tie capacity is being investigated for Waiouru, Bulls, Arahina and Rātā substations.

The following projects have been identified as possibly occurring during the planning period. The 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.

Table 11.57: Possible future developments

PROJECT	SOLUTIONS
Arahina substation second transformer and subtransmission supply	There is a project underway to install an additional 4km underground subtransmission circuit from Marton GXP into Arahina substation. There is another project to install a second 16/24 MVA transformer at the Arahina substation and replace the existing 11kV switchroom.
Arahina substation T1 replacement	The existing 10MVA transformer is getting close to its end of life. The capacity is not enough to supply the new load and has an N-1 security. The solution will be to replace T1 with an upgrade of 16/24MVA power transformer.
Arahina substation indoor 33kV switchgear installation and replace the existing conductor	The existing 33kV outdoor infrastructure does not allow for two 33kV circuits. The project to replace the 11kV switchroom building will include space for future 33kV indoor installation. With large customer connections, it is best to have N-1 security. The existing conductor size is Cockroach at 50°C. The thermal loading on the conductor will exceed the rating of the conductor when including the new demand forecast.

11.12 MANAWATŪ

Palmerston North CBD has a meshed network supplied by 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 in the area involves building two new 33kV circuits and a new inner-city substation at Ferguson St, with an estimated cost of $27m. Total major and minor project spend related to Growth and Security during the next 10 years is $95m.

11.12.1 AREA OVERVIEW

The Manawatū 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 Manawatū plains.

The more rugged, hilly terrain is found east of Palmerston North on the Tararua Range and northeast on the Ruahine Range. The Palmerston North area has a temperate but windy climate, with consistent wind in the Tararua and Ruahine ranges.

Wind generation is a major feature in the Manawatū 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 the protection and operation of the 33kV network.

Access to the area for fault repair and maintenance is good, especially on the Manawatū 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 signalled in local council planning documents.

Industry and commerce are also strong in the city. The Northeast Industrial area recognises Palmerston North's position as a growing transport and warehouse hub – the city is centrally located with immediate access to major transport links. 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 nearest major commercial centres.

Two of New Zealand's major military bases are also in the Manawatū 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 also significantly contribute to the city's vitality.

The Manawatū area is connected to the grid through the Bunnythorpe and Linton GXP substations. Bunnythorpe GXP supplies eight zone substations – Keith Street, Kelvin Grove, Main Street, Milson, Feilding, Kimbolton, Sanson and the new Ohakea substation. The Linton GXP supplies four zone substations – Kairanga, Pascal Street, Turitea and Ferguson. Both subtransmission networks supplied by these GXPs have 34MW generation feed from the Tararua Wind Farm.

The subtransmission and distribution networks in 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. The 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, i.e., 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 tapered capacity can severely limit backfeed and protection settings. We have been addressing this through a consolidated upgrade programme.

Figure 11.20: Manawatū area overview

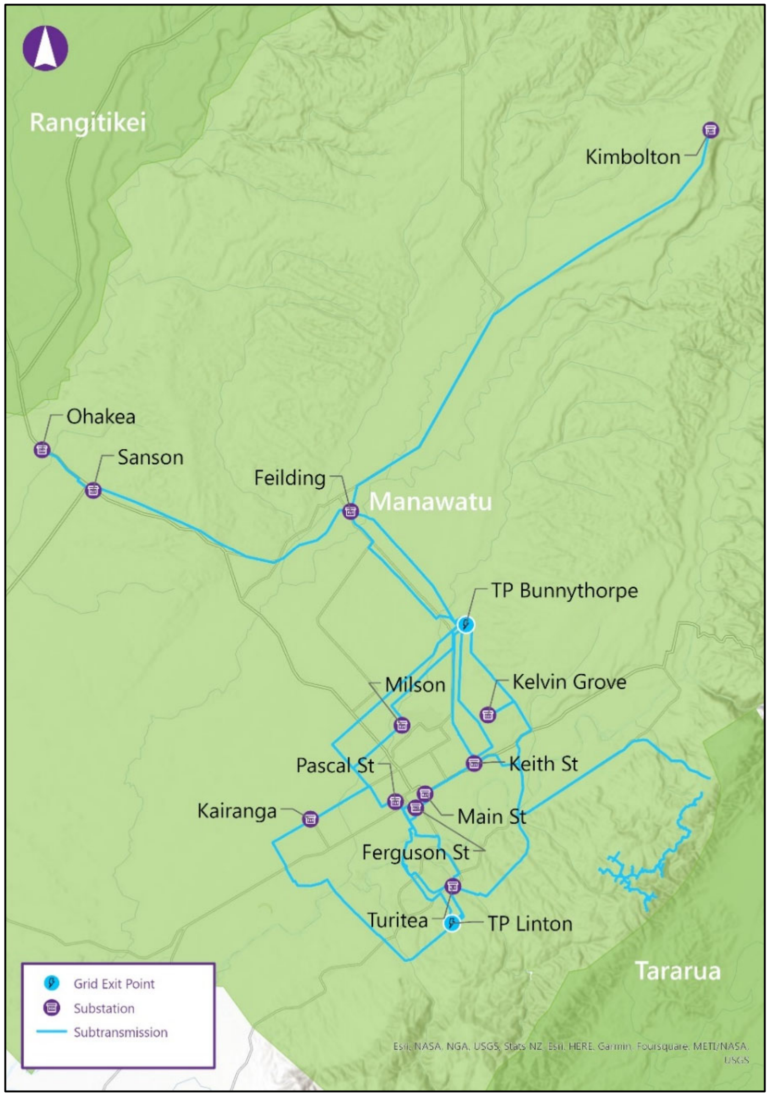


Table 11.58: Manawatū network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Palmerston North CBD	Completed
New Ohakea zone substation	Completed
Sanson-Bulls 33kV line	Under construction

11.12.2 DEMAND FORECASTS

Demand forecasts for the Manawatū area substations are shown in Table 11.59, with further detail provided in Appendix 7.

Table 11.59: Manawatū zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Feilding	23.3	23.9	25.0	26.1
Ferguson Street	11.2	11.3	11.5	11.7
Kairanga	18.0	19.9	20.6	21.2
Keith Street	18.6	19.9	21.4	22.0
Kelvin Grove	17.0	25.1	32.6	33.6
Kimbolton	3.0	3.1	3.2	3.3
Main Street	17.9	18.2	18.6	19.0
Milson	16.2	18.0	18.6	19.1
Ohakea	2.2	5.2	5.2	5.2
Pascal Street	14.9	15.1	15.4	15.7
Sanson	9.0	9.4	10.1	10.8
Turitea	14.2	17.9	22.0	23.2

Palmerston North city has experienced 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 Northeast 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 prepare for full-scale development.

The council's urban development planning anticipates strong residential growth on the city's southern side 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 has been 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 has increased. Oroua Downs is one area we are monitoring closely as it has the potential to impact on proposed Growth and Security projects.

11.12.3 MAJOR CUSTOMERS

Table 11.60: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
AFFCO New Zealand	Food processing	Feilding
New Zealand Defence Force – Ohakea Air Base	Public/State	Ohakea
New Zealand Defence Force – Linton Military Camp	Public/State	Turitea
Massey University	Public/State	Turitea
Palmerston North Hospital	Public/State	Keith St
Fonterra Co-operative Group Limited	Dairy	Kairanga
Ovation New Zealand Limited	Food processing	Feilding
Ernest Adams	Food processing	Pascal Street
Foodstuffs	Food processing	Kelvin Grove
Iplex Pipelines New Zealand	Industrial Manufacturing and Mining	Milson

Known and potential major industrial customer developments in the Manawatū area and their potential impact on our distribution network are as follows:

- Massey University is looking at the feasibility of electrifying its existing gas-fired heating systems, which would require about 4MW of additional electrical capacity. Linton Military Camp has also indicated a load increase at its site, which will impact Turitea substation.
- Palmerston North Hospital is upgrading its site and is also looking at the options to decarbonise its operations. Demand on its site is nearing the available capacity. A proposed High Voltage (HV) split of its supply will support its current needs. But we will need to add 1-2MVA of capacity during the next 12-24 months and another 3MVA in five years to meet its needs. This upgrade will require a dedicated 11kV feeder from Main Street substation or possibly a new zone substation.
- KiwiRail is progressing with plans for a high-tech, intermodal freight hub near the Northeast Industrial area. The initial load requirement is about 2-5MVA. We plan to build a new zone substation to support the load growth, which could potentially offload Kelvin Grove and Milson substations.
- Icepak is doing some major works onsite at Longburn, and Aotearoa New Zealand Made has relocated its business to this area. Customer step growth could mean a new substation is necessary at this site in the near future. We have proposed to rebuild the previously disestablished Longburn substation.

11.12.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Manawatū area are shown in Table 11.61.

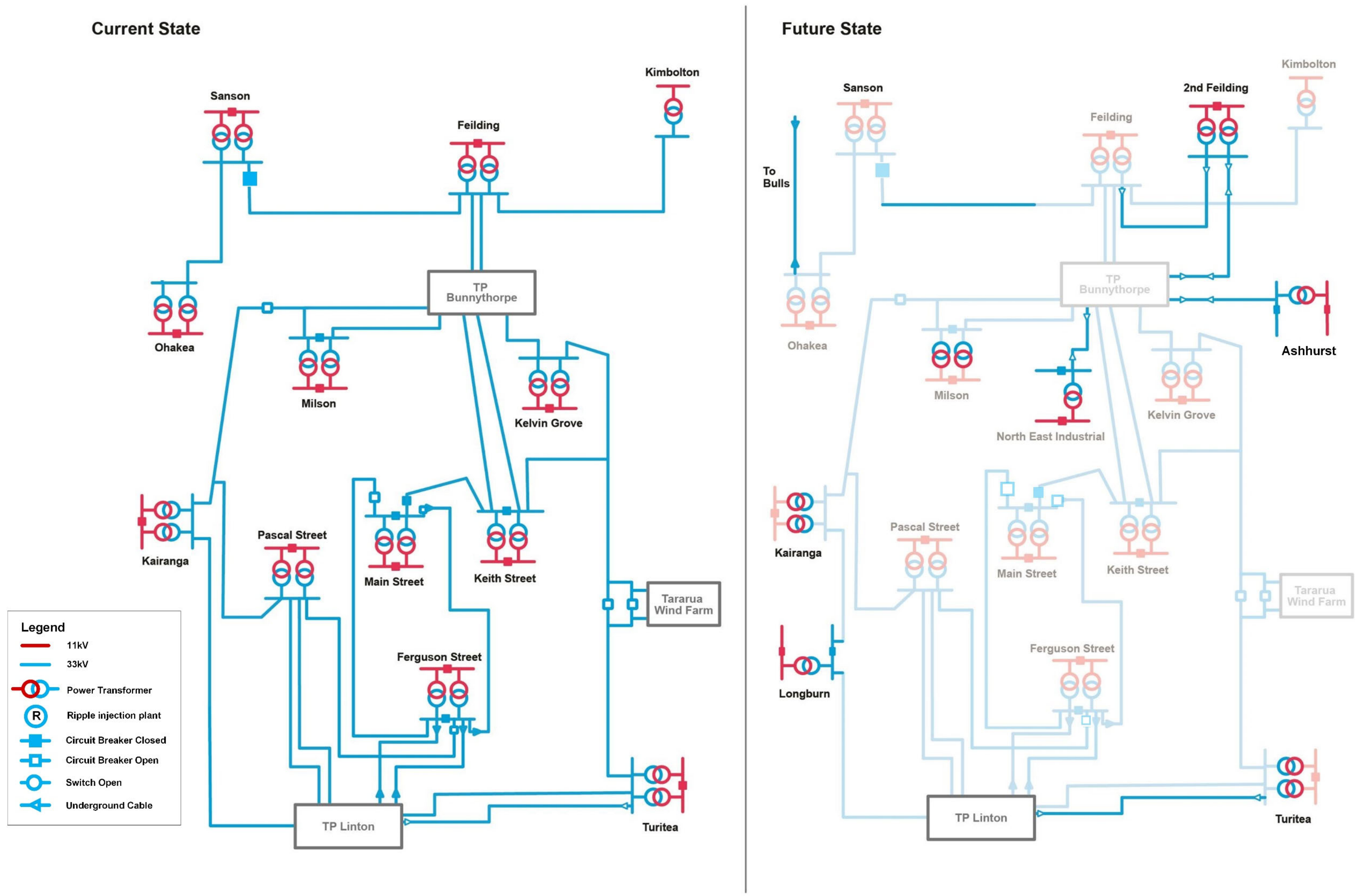
Table 11.61: Manawatū constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Sanson and Bulls substations	Lack of alternative 33kV supply feeds.	Sanson-Bulls 33kV line.
Turitea substation	Turitea substation single 33kV supply limits its security level to AA, but AAA is intended.	Turitea sub new 33kV line.
Sanson substation	Feilding-Sanson 33kV line capacity constraint.	Feilding-Sanson line upgrade.
Milson substation	Milson-2 33kV line N-1 constraint.	Milson-2 33kV line upgrade.
Feilding substation	Feilding East and West 33kV thermal capacity constraint.	Feilding sub new third 33kV line.
Sanson and Bulls substations	Sanson and Bulls out of sync ripple plant frequency operation.	Sanson-Bulls ripple injection plant.
Kelvin Grove substation	Kelvin Grove substation capacity constraint.	Kelvin Grove transformer upgrade or a new North-East Industrial zone substation.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Feilding substation	Feilding substation capacity constraint.	New second Feilding substation.
Kairanga substation	Kairanga substation capacity constraint.	Kairanga transformers upgrade.
Turitea substation	Turitea substation capacity constraint.	Turitea transformers upgrade.
Milson substation	Milson substation capacity constraint.	Milson transformers upgrade.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Sanson sub-Oroua Downs feeder	Oroua Downs feeder security of supply constraint.	Oroua Downs express feeder.
Keith Street substation – CB23 feeder	Keith Street CB23 feeder capacity constraint.	11kV express feeder to Palmerston North Hospital.
Kairanga substation – CB12 feeder	Awapuni CB12 feeder capacity constraint.	Rebuild Longburn substation.

Figure 11.21: Manawatū area network diagram



11.12.5 PROPOSED PROJECTS

Table 11.62: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)	DRIVER
Feilding-Sanson-Bulls design and construction	$1,125	2022	Growth and Security
Sanson-Bulls modification	$3,314	2022-2024	Growth and Security
Turitea substation new 33kV line	$2,068	2024-2025	Growth and Security
Feilding-Sanson line upgrade	$1,416	2025-2027	Growth and Security
Feilding new (third) 33kV line	$6,617	2026-2028	Growth and Security
New Bunnythorpe-North-East Industrial 33kV line	$4,045	2027-2029	Customer
New second Feilding zone substation	$7,822	2024-2027	Growth and Security
Existing Feilding to new second Feilding substation 33kV line	$3,143	2027-2028	Growth and Security
North-East industrial substation	$7,711	2025-2028	Customer
Kairanga substation – upsize transformers	$2,504	2025-2026	Growth and Security
Turitea substation – replace transformers	$2,884	2024-2025	Growth and Security
Milson substation – upgrade transformers	$2,459	2026-2027	Growth and Security
Oroua Downs express feeder	$9,479	2031-2033	Growth and Security
Rebuild Longburn substation	$3,960	2025-2027	Customer
Ashhurst substation	$6,449	2027-2030	Growth and Security
New Bunnythorpe-Ashhurst 33kV Line	$4,230	2029-2030	Growth and Security
Linton Military Camp substation	$5,778	2030-2033	Growth and Security
New 33kV line for Linton Military Camp zone substation	$5,547	2031-2033	Growth and Security
Rongotea substation, establish a new zone substation, Stage-1,2,3	$6,793	2028-2030	Growth and Security
Pascal Street substation – upgrade sub transformers to 16/24MVA	$1,946	2030-2032	Growth and Security
MainStreet – two new transformers to replace 59-year-old transformer	$2,010	2026-2028	Growth and Security

11.12.6 POSSIBLE FUTURE 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, the proposed automation of feeder inter-tie switching may warrant feeder upgrades.

We will need to upgrade feeders in rural areas for growth and to ensure adequate reliability, i.e.., backfeed capability. Most of these involve conductor replacements or voltage regulators.

Significant changes in demand, such as for rapid and concentrated uptake of irrigation, will likely result in a new substation, i.e.., 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 Manawatū area is known for its wind generation. Most 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, i.e., cogeneration in central Palmerston North.

The following projects have been identified as 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 will be confirmed closer to the time.

Table 11.63: Possible future developments

PROJECT	SOLUTIONS
Bunnythorpe GXP transformer upgrade	Transpower's Bunnythorpe GXP current 2 x 101MVA, 220/33kV transformers are insufficient for the expected load growth. Load forecast shows N-1 capacity of the supply transformers will be exceeded beyond 2025. The proposed long-term solution is to replace and upgrade the transformers to 2 x 150MVA units.
Linton Military Camp zone substation	Linton Military Camp's future planned upgrades require additional electrical supply provision. An additional 5MVA load is forecast, in addition to the existing 1.7MVA supply to the military base. The preferred solution is to establish a new 33/11kV substation within or adjacent to the military base. The initial primary supply for this new substation will come from the existing 33kV line.
Oroua Downs express feeder	To establish a long-term solution for Rongotea and the surrounding area and improve the voltage level and thermal capacity of this feeder by building a new 33kV capable line from Sanson substation and operate this as an additional 11kV feeder. This is in preparation for the proposed Rongotea zone substation.
Rongotea zone substation	The Rongotea area is supplied from the Sanson and Kairanga substations through several interconnected radial 11kV feeders. Because of strong growth in irrigation and other rural activities, these feeders are heavily loaded. Interim solutions, such as voltage regulators, have already been used. The proposed long-term solution involves building a new zone substation at Rongotea. The substation would supply parts of the existing Oroua Downs, Rongotea, Bainesse and Taikorea 11kV feeders. It will remove capacity constraints, shorten all the 11kV feeder lengths, therefore improving network voltages and reliability, and offload Sanson and Kairanga substations.
Ashhurst zone substation	Ashhurst is a town 10km to the east of Palmerston North. It is served by two distribution feeders, CB8 Pohangina and CB10 Ashhurst, from Kelvin Gr substation. Nearby, Bunnythorpe village is supplied by one feeder from Milson substation. The town of Ashhurst can no longer maintain adequate voltage regulation of the HV network. The preferred long-term solution is to establish a new zone substation, named Ashhurst, to cater for the load growth in this area.
Kimbolton substation security upgrade	Kimbolton is a single transformer substation. Its security level is A2. Its 11kV backup supply is not adequate for the supply of the substation load. Kimbolton's small load and the large distance to the substation makes a second 33kV circuit or a second transformer unlikely to be economic. The preferred solution is to increase backfeed capacity via the 11kV network.

11.13 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 $10m.

11.13.1 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 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

There have been no significant changes to the Tararua region since AMP21.

Figure 11.22: Tararua area overview

11.13.2 DEMAND FORECASTS

Demand forecasts for the Tararua zone substations are shown in Table 11.64, with further detail provided in Appendix 7.

Table 11.64: Tararua zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Alfredton	0.5	0.5	0.5	0.5
Mangamutu	12.5	12.7	13.0	13.3
Parkville	2.4	2.4	2.4	2.5
Pongaroa	0.7	0.7	0.7	0.8

The demand at Mangamutu substation incorporates the now-confirmed significant increase in capacity for Fonterra Pahiatua. Underlying growth at 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 increased irrigation. Future demand growth in the Tararua area is expected to be very low.

11.13.3 MAJOR CUSTOMERS

Table 11.65: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Fonterra Co-operative Group Limited	Food processing	Mangamutu

Decarbonisation has the potential to cause a step increase in load at Mangamutu substation because of the Fonterra Pahiatua factory. While there is capacity available, we will need to work closely with the customer to determine any necessary upgrade.

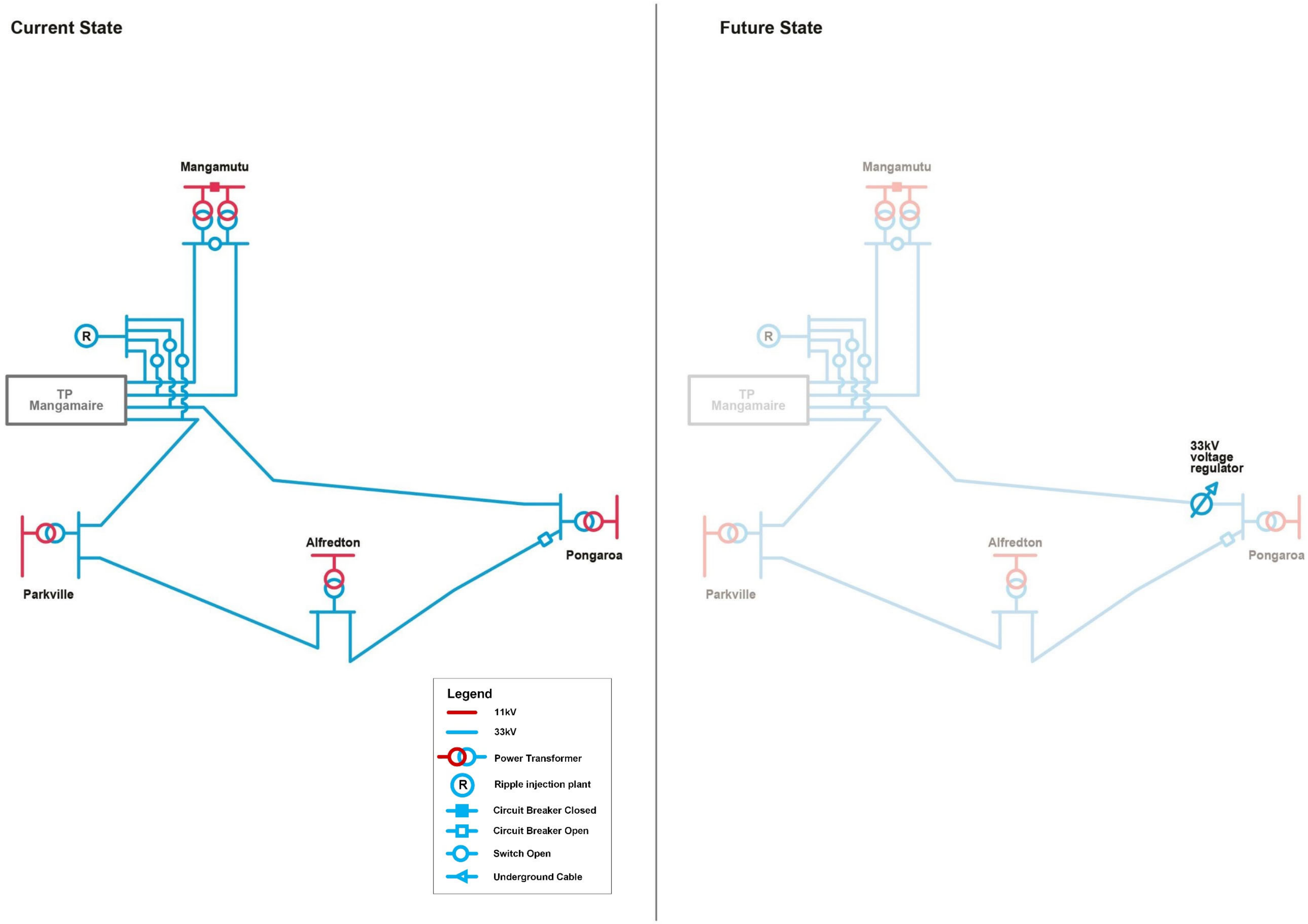
11.13.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tararua area are shown in Table 11.66.

Table 11.66: Tararua constraints and needs

LOAD AFFECTED	MAJOR ISSUES	PROJECTS
Pongaroa, Alfredton and Parkville substations	A contingency on the 33 kV network would cause the voltage to fall to an unacceptable level.	A new voltage regulator on the 33 kV Mangamaire-Pongaroa circuit.

Figure 11.23: Tararua area network diagram



11.13.5 PROPOSED PROJECTS

Table 11.67: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)	DRIVER
Pongaroa 33KV upgrade	$5,023	2028-2032	Growth and Security
Mangamaire GXP 33kV ODID	$4,045	2028-2029	Growth and Security

11.13.6 POSSIBLE FUTURE DEVELOPMENTS

The following projects have been identified as possibly occurring in the latter part of the planning period. 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.

Decarbonisation has the potential to cause a step increase in load at Mangamutu substation because of the Fonterra Pahiatua factory.

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.

Table 11.68: Possible future developments

PROJECT	SOLUTION
Parkville second transformer	Increase the capacity of Parkville substation and install a second transformer.
Mangamutu transformer	Replace both zone transformers with high-capacity transformers.
Mangamutu subtransmission	Rebuild Mangamutu-1 and Mangamutu-2 33kV feeders or build a third 33kV feeder to Mangamutu substation.

11.14 WAIRARAPA

The Wairarapa region has generally low growth, however, the centre of the region's load demand is shifting. 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 appears to be shifting further southwest.

Major and minor project spend related to Growth and Security during the next 10 years is $28m. In addition to the planned Growth and Security projects, routine expenditure will be needed on distribution circuits.

11.14.1 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, flat, and rolling area where the main urban centres are located. 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 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.

Increased wind generation and irrigation could significantly impact 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.

The Masterton GXP supplies eight zone substations – Norfolk, Akura, Chapel, Te Ore Ore, Awatoitoi, Tīnui, Clareville and Gladstone. The 33kV network has a meshed or ring architecture in Masterton. The Greytown GXP supplies five zone substations – Kempton, Featherston, Martinborough, Tuhitarata and Hau Nui. Similarly, a ring connects Martinborough and Featherston with Greytown (Transpower GXP).

Rural substations are generally supplied by single radial lines of quite a 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 backcountry and eastern coastal hills.

Figure 11.24: Wairarapa area overview

Table 11.69: Wairarapa network changes since AMP21

NETWORK DEVELOPMENT PROJECT	STATUS
Featherston second 33kV transformer	Completed

11.14.2 DEMAND FORECASTS

Demand forecasts for the Wairarapa zone substations are shown in Table 11.70, with further detail provided in Appendix 7.

Table 11.70: Wairarapa zone substation demand forecast

SUBSTATION	2022	2025	2030	2035
Akura	13.2	13.5	14.1	14.6
Awatoitoi	1.0	1.1	1.1	1.1
Chapel	13.6	13.9	14.3	14.8
Clareville	10.4	12.9	15.6	16.4
Featherston	3.9	4.0	4.2	4.4
Gladstone	0.9	0.9	0.9	0.9
Hau Nui	0.3	0.3	0.3	0.3
Kempton	4.8	5.0	5.3	5.5
Martinborough	4.6	4.8	5.1	5.4
Norfolk	6.4	8.4	8.6	8.7
Te Ore Ore	7.9	8.1	8.4	8.6
Tīnui	0.9	0.9	0.9	0.9
Tuhitarata	3.2	3.4	3.6	3.7

Growth in the Wairarapa area is modest. No significant residential demand increases, such as large subdivisions, are anticipated. A modest 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.

Several of the Wairarapa substations already exceed their security criteria. Therefore, development plans focus on improving the security and reliability for the existing load base rather than catering for future new load.

11.14.3 MAJOR CUSTOMERS

Table 11.71: Existing major customers

CUSTOMERS > 1.5MVA INSTALLED CAPACITY	SECTOR	SUBSTATION
Juken New Zealand Limited	Timber processing	Norfolk
Kiwi Lumber Limited	Timber processing	Norfolk
Webstar Limited	Timber processing	Akura
Wairarapa Hospital	Public/State	Chapel
Premier Beehive New Zealand	Food processing	Clareville

Kiwi Lumber is a major manufacturing plant in Masterton processing timber. This customer takes supply from the Norfolk substation and indicates it expects a demand growth up to 1.5MVA between 2024 and 2026.

Juken New Zealand, a major manufacturer of wood products in Masterton, is supplied from the Norfolk substation. It has indicated it anticipates a load increase during the next few years.

Wairarapa Hospital is seen as a critical customer for the region as more people consider living in Masterton and commuting to Wellington.

There is a high likelihood of decarbonisation projects within the next few years, and we would expect that these would accelerate demand growth in the region.

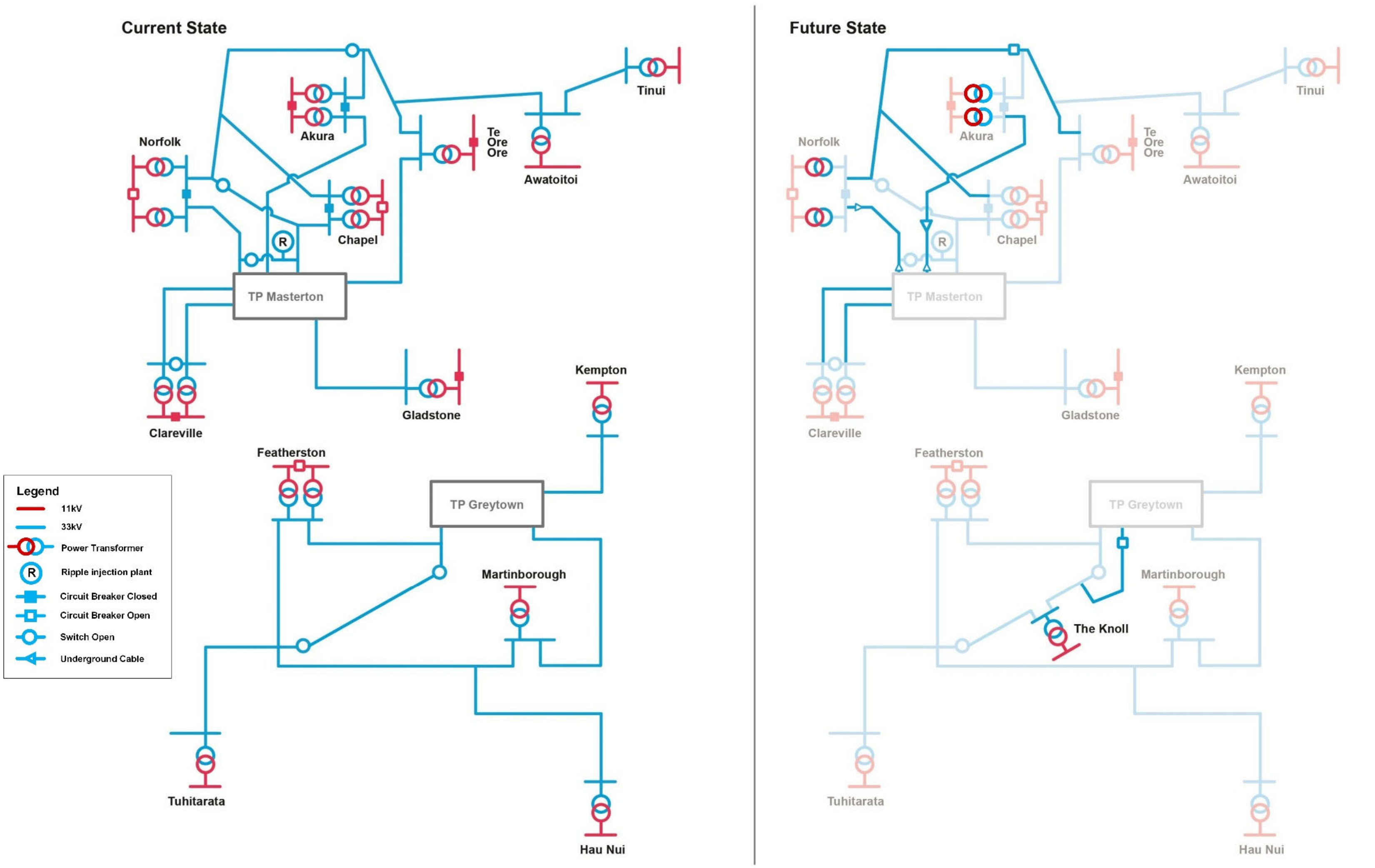
11.14.4 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Wairarapa area are shown in.

Table 11.72: Wairarapa constraints and needs

LOAD AFFECTED	MAJOR ISSUES	PROJECTS
Featherston, Martinborough, Hau Nui and Tuhitarata substations	Greytown-Featherston N-1 capacity constraints.	A 33kV feeder extension and new Bidwells Cutting “The Knoll” substation.
Clareville substation	Clareville-1 and -2 33kV circuits capacity constraint.	Re-tension 33kV circuits.
Norfolk substations	33kV N-1 substation capacity constraint.	Part undergrounding of 33kV line and re-tensioning of remaining overhead.
Norfolk and Chapel substations	Norfolk-Chapel 33kV tie capacity constraint.	Rebuild 2.2km of Chapel-Norfolk 33kV overhead line.
Akura, Te Ore Ore, Awatoitoi and Tinui substations	Contingency constraints.	Underground 2km Akura 33kV OH line.
Kempton substation	Kempton is on N security and capacity constraints.	New “The Knoll” zone substation in Bidwells Cutting.
Greytown GXP	Operational constraints.	New Powerco 33kV switchboard.
Akura substation	N-1 capacity constraints.	Upgrade transformers.
Clareville substation	N-1 capacity constraints.	Upgrade transformers.

Figure 11.25: Wairarapa area network diagram



11.14.5 PROPOSED PROJECTS

Table 11.73: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)	DRIVER
Bidwells 33kV feeder extension to Greytown GXP	$1,475	2025-2028	Growth and Security
New "The Knoll" zone substation in Bidwells Cutting	$3,736	2025-2028	Growth and Security
Re-tension Clareville 33kV-1 and -2 feeders	$767	2026-2028	Growth and Security
Akura 33kV and Norfolk 33kV – convert 600m overhead 33kV dual supply to underground and re-tension 1.1km of dual 33kV overhead line	$681	2024-2027	Growth and Security
Convert Akura 33kV 2km to underground	$573	2025	Growth and Security
Greytown 33kV switchgear outdoor to indoor conversion	$4,290	2022-2026	Growth and Security
Clareville transformer capacity upgrade (2 x 12.5/17MVA)	$4,253	2023-2026	Growth and Security

11.14.6 POSSIBLE FUTURE DEVELOPMENTS

Inquiries about large-scale electric vehicle charging stations have been received. The likely location for the first ultrafast charging station is Chapel Street or Renall Street in Masterton. Present upgrades to the Masterton-Norfolk-Chapel 33kV subtransmission ring and Chapel St substation will make the necessary capacity and security available for such a facility.

However, if electric vehicle uptake accelerates, a need for more charging stations could emerge along State Highway 2 and possibly even State Highway 53. In such a scenario, significant load increases would affect one or more of the Clareville, Kempton, Featherston, and Martinborough substations and may necessitate larger transformer units for the upgrades planned for Kempton, Featherston and Martinborough substations.

The forestry and timber industry is a mainstay in Masterton. The largest two customers are Juken New Zealand and Kiwi Lumber Limited. Both these customers are supplied by the Norfolk substation and are planning load increases that, in aggregate, exceed 3MVA.

Decarbonisation is also likely to have a significant impact on the area's industrial customers, and this may necessitate bringing forward or expanding planned major and minor projects.

Population overflow from Wellington city is starting to have a growth impact in areas connected to Wellington by rail. Retirement villages and lifestyle blocks are also adding to the area's growth.

These drivers introduce the possibility of additional work being required on existing subtransmission lines and substation capacity.

Table 11.74: Possible future developments

PROJECT	SOLUTION
Norfolk zone substation transformer	Increase the capacity of Norfolk substation transformers.
Kempton, Martinborough Featherston zone substation transformer	Increase capacity of one or more zone substation transformers.

11.15 GRID EXIT POINTS

Our network connects to the transmission grid mainly at 33kV but also at 110kV, 66kV, and 11kV. We have 31 points of supply or grid exit points (GXPs). Most assets at GXPs are owned by Transpower, although we own some transformers, circuit breakers, protection, and control equipment. The GXPs supplying our electricity network are detailed in Table 11.75, along with their respective peak load, capacity, and security characteristics, which consider any branch limits.

Table 11.75: GXP summary statistics for financial year 2022

GXP NAME	TRANSFORMER NAMEPLATE RATING (MVA)	N-1 CAPACITY SUMMER/WINTER (MVA)	2022 MAX OFFTAKE (MVA)	N-1 SECURE	2022 MAX EXPORT (MW)
Arapuni (ARI)	-	Refer to Note 1	-	No	-
Brunswick (BRK)	50	-	32.5	No	
Bunnythorpe (BPE)	83, 83	101/101	100.3	No	1
Carrington St (CST)	75, 75	104/109	69.5	Yes	
Greytown (GYT)	20, 20	20/20	16.3	Yes	2
Hāwera (HWA)	30, 30	35/35	29.1	Yes	22
Hinuera (HIN)	30, 50	37/40 Refer to Note 2	47.1	No	-
Huirangi (HUI)	60, 60	70/70	34.8	Yes	0
Kaitimako (KMO)	75	75/75	38.9	No	-
Kinleith 11kV Mill (KIN)	40, 40, 40	46/46	72.7	No	-
Kinleith 11kV Mill Cogen (KIN)	30,40	36/48	18.0	No	39
Kinleith 33kV (KIN)	20, 40	24/25	20.0	Yes	-
Kopu (KPU)	60, 60	60/60	48.6	Yes	-
Linton (LTN)	120, 100	81/81	58.9	Yes	14
Mangamaire (MGM)	30, 30	27/27	15.6	Yes	-
Marton (MTN)	20, 30	24/24	16.3	Yes	-
Masterton (MST)	60, 60	75/78	47.7	Yes	-
Mataroa (MTR)	30	-	6.7	No	-
Mt Maunganui (MTM)	75, 75	91/91	67.9	Yes	-
Ohakune (OKN)	20	-	2.2	No	-
Ōpunake (OPK)	30, 30	14/14	12.5	Yes	-
Piako (PAO)		Refer to Note 3	38.7	Yes	-
Stratford (SFD)	40, 40	55/55	26.9	Yes	-
Tauranga 11kV (TGA)	30, 30	36/36	25.4	Yes	-
Tauranga 33kV (TGA)	90, 120	108/108	91.8	Yes	3
Te Matai (TMI)	30, 40	36/39	46.8	No	-
Waihou (WHU)	80, 80	75/75	32.4	Yes	-
Waikino (WKO)	30, 43	41/41	37.2	Yes	-
Wanganui (WGN)	30, 20	24/24	29.7	No	-
Waverley (WVY)	10	-	4.4	No	-

Notes:

1. Putāruru is supplied from Arapuni GXP via a 110kV single circuit line from Arapuni.
2. Hinuera GXP is supplied via a 110kV single circuit line from Karapiro.
3. Piako GXP is supplied via two 110kV Piako-Morrinsville tee line sections connected directly to the Powerco 110/33kV transformers.

Table 11.76: Powerco transformer 110/33kV statistics

SITE NAME	TRANSFORMER NAMEPLATE RATING (MVA)	N-1 CAPACITY (MVA)	VECTOR GROUP
Piako (PAO)	60, 60	60	Dyn3
Putāruru (PTU)	40	-	Dyn3

Table 11.77: Powerco HV line statistics

CIRCUIT	VOLTAGE (KV)	SECTION LENGTH (KM)	CAPACITY (MVA)	N-1 SECURE
Arapuni-Putāruru	110	12.4	70	No

The supply transformers at Piako and Putāruru, as well as the Arapuni-Putāruru 110kV circuit, are owned by Powerco and are shown in Table 11.76 and Table 11.77, respectively.

11.15.1 THE REGIONAL OVERVIEW

The Powerco network consists of the Eastern and Western regions. The Eastern region is shown in Figure 11.26, while the Western region is displayed in three area maps (Figure 11.27, Figure 11.28, Figure 11.29) because of the large geographical area it covers. All the figures show Transpower's 220kV and 110kV transmission grid overlaid on our subtransmission network. Beyond the GXPs, certain localised grid constraints are of significance to our planning.

Figure 11.26: Eastern area overview

Figure 11.27: Taranaki area overview

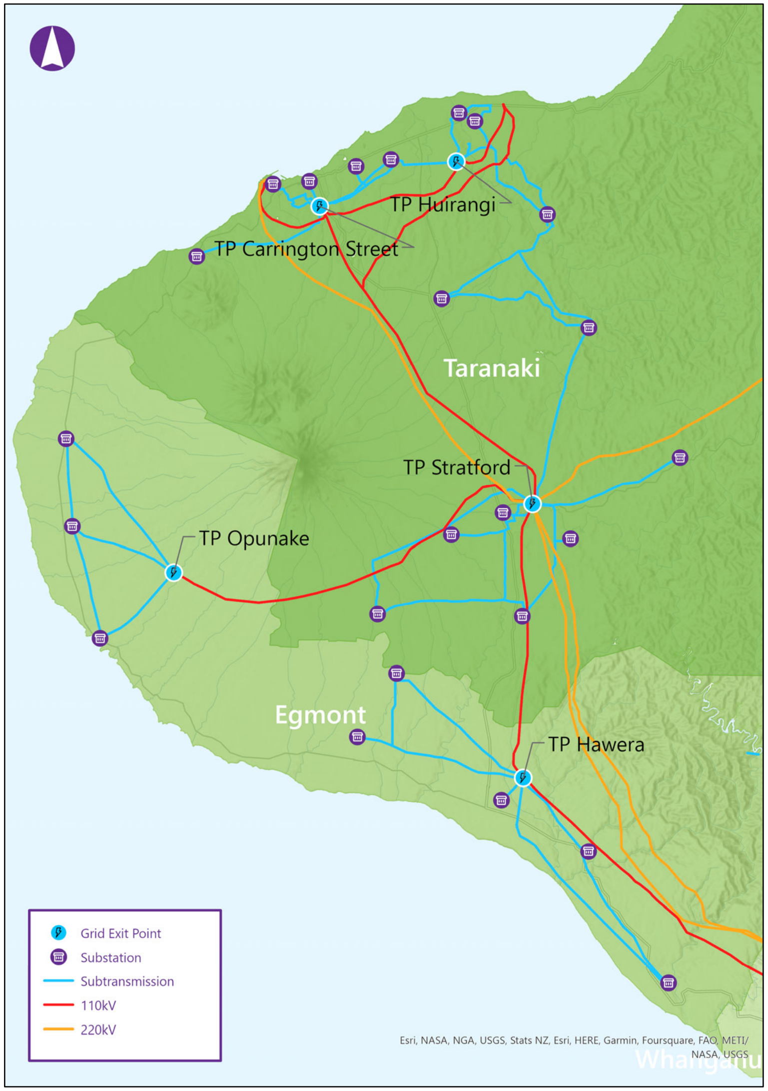


Figure 11.28: Whanganui area overview

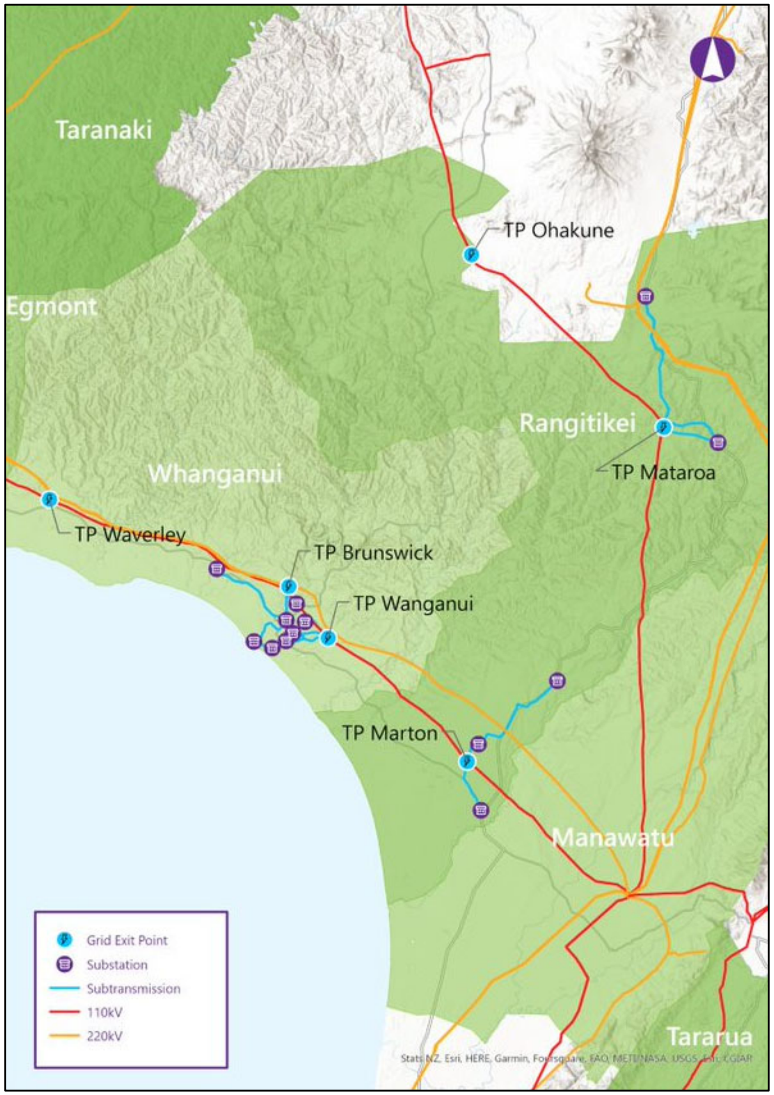
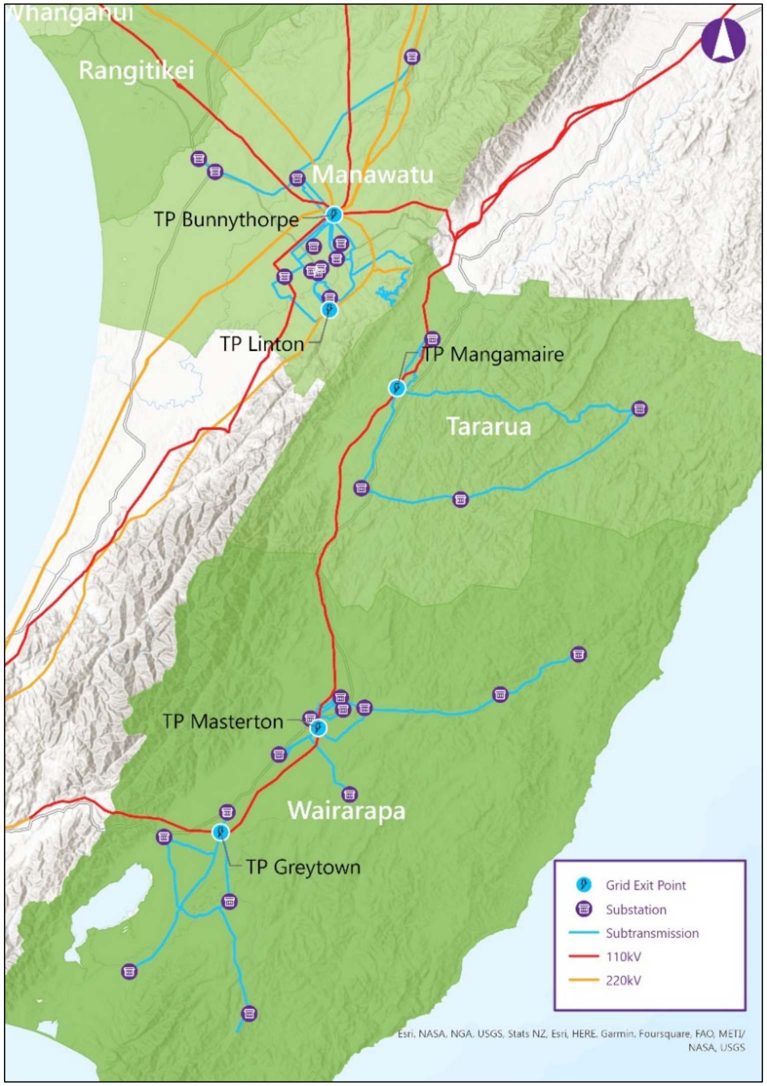


Figure 11.29: Manawatū-Wairarapa area overview



11.15.2 RADIAL SINGLE CIRCUIT GRID EXIT POINTS

Hinuera GXP is supplied via a single 110kV radial circuit from the Karāpiro substation and is therefore not N-1 secure. Improving the security of Hinuera GXP has been a significant focus of our Growth and Security plans for the past decade and is the main driver behind our new 110/33kV supply point at Putāruru. Putāruru is supplied via a single Powerco-owned 110kV radial circuit from Arapuni GXP and will be supplying Putāruru and Tīrau zone substations, previously supplied from Hinuera GXP. This new network configuration will increase the reliability of the zone substations previously supplied from Hinuera GXP.

11.15.3 SINGLE TRANSFORMER GRID EXIT POINTS

Mataroa, Ohakune and Waverley are smaller single transformer GXPs with relatively low demand – 6.6MVA, 2.2MVA, and 4.4MVA, respectively. Powerco cannot justify N-1 security for these GXPs, but Transpower contingency plans are in place, which include using the on-site spare transformer at Mataroa, using the mobile substation at Ohakune subject to its availability, and using the national spare transformer located off-site at Waverley.

Putāruru substation is the newest 110/33kV added to the Powerco fleet and commissioned with a single 40MVA transformer. Besides supplying the Putāruru 33/11kV loads, it will also pick up load from Hinuera GXP. The long-term plan is to address the N-security transformer supply capacity issue by obtaining the Te Matai T2 40MVA 110/33kV transformer and installing it at Putāruru once it becomes available from the Te Matai GXP site. We intend to carry out investigations to test the feasibility of this option.

Brunswick and Kaitimako are larger single transformer GXPs providing N-security. Brunswick has a partial backup from Wanganui GXP, which is limited as the load increases. Transpower has investigated the risk-based condition replacement of the Brunswick 220/33kV transformer, which presents an opportunity to add a second 220/33kV transformer to address the N-security issue.

Kaitimako has 33kV backfeed capability from Tauranga GXP. Once the load in the Welcome Bay and Ohauiti areas exceeds the backfeed capacity, discussions with Transpower will be required to request a second transformer at Kaitimako. Kaitimako is part of the Western Bay of Plenty Strategy.

11.15.4 GRID EXIT POINTS EXCEEDING THEIR N-1 CAPACITY

Table 11.78 lists GXPs that will exceed their N-1 capacity in the 10-year planning period because of load growth in the respective areas.

Table 11.78: GXPs exceeding their N-1 capacity

LOAD AFFECTED	MITIGATION
Bunnythorpe GXP	Planned load shift to Marton and Linton GXPs. Future N-1 exceedance to be managed operationally.
Hāwera GXP	The future exceedance will be discussed with Transpower.
Hinuera GXP	Planned load shift to new Arapuni GXP (Putāruru and Tīrau substation). Future N-1 exceedance to be managed operationally.
Kinleith 33kV GXP	Future N-1 exceedance to be managed operationally. Any large load increases require a discussion with Transpower as it involves a transmission solution. Discussed further in section 11.15.5.
Kopu GXP	Transpower to remove the protection limit to increase the N-1 capacity to 64/67MVA (summer/winter), which pushes the forecasted exceedance outside the 10-year window.
Marton GXP	Discussed further in section 11.15.6.
Mt Maunganui GXP	Planned load shift to Te Matai GXP, which resolves the N-1 capacity issue for the planning period. Mt Maunganui forms part of the Te Matai security constraints discussion in section 11.15.8.
Tauranga 11kV GXP	Discussed further in section 11.15.9.
Tauranga 33kV GXP	Discussed further in section 11.15.9.
Te Matai GXP	Discussed further in section 11.15.8.
Waikino GXP	Transpower is investigating the risk-based condition replacement of the Waikino T1 110/33kV transformer, which presents an opportunity to match the second 110/33kV transformer to address the future N-1 security issue.
Wanganui GXP	Transpower is investigating the risk-based condition replacement of the Wanganui T2 110/33kV transformer, which presents an opportunity to match the second 110/33kV transformer to address the future N-1 security issue. Wanganui T1 replacement will be done considering any security upgrades at Brunswick single transformer GXP.

11.15.5 ARAPUNI-KINLEITH-TĀRUKENGA 110KV CIRCUITS CONSTRAINTS

The Arapuni-Kinleith-Tārukenga 110kV circuits are normally configured as a spur originating from Tārukenga with Lichfield substation connected into the Kinleith-Tārukenga circuits via a double tee connection. Kinleith and Lichfield are supplied through four 110kV circuits which, according to Transpower, exceed their N-1 capacity under certain operating conditions. The circuit loadings are reliant on the generation at both Kinleith and Arapuni. These issues limit load growth at Kinleith. Transpower has indicated that any investment will be customer driven.

- Medium-term: Powerco to strengthen the 33kV network towards Putāruru by constructing the Putāruru-Maraetai Rd 33kV link and shifting load to the new Arapuni GXP (Putāruru substation). This reduces the load-at-risk at Kinleith GXP, keeping it under the continuous rating of the 20MVA T5 transformer should the 40MVA T9 transformer experience an outage. Transpower plans to carry out a minor thermal upgrade on the Lichfield-Tārukenga-1 110kV circuit to increase the summer rating by 5MVA.
- Longer-term: Transpower to provide a solution to unlock further load growth on the Arapuni-Kinleith-Tārukenga corridor. A costly alternative is for Powerco to consider building a 110kV circuit towards Tārukenga and obtaining a new GXP from Tārukenga. Another alternative is to construct a new 220kV connection from Kinleith to Transpower's Whakamaru GXP, which seeks to reduce the transmission constraints on the Tārukenga Lichfield-Kinleith-Arapuni circuits and, at the same time, support growth opportunities at Kinleith mill and our network.

11.15.6 MARTON LOW VOLTAGE AND SECURITY CONSTRAINTS

Marton 110/33kV GXP transformers do not have on-load tap-changers and are both tee-connected to the Bunnythorpe-Marton-Wanganui-1 and -2 110kV circuits.

Transpower indicated that the bus low voltage can be managed by changing the transformers' fixed tap position as load increases, as well as the implantation of a special protection scheme to manage the transformers' overload and low voltage issue.

The longer-term plan is for Transpower to bring forward the risk-based condition replacement of the Marton T2 110/33kV transformer, which presents an opportunity to match the second 110/33kV transformer to address the future N-1 security issue.

11.15.7 WESTERN BAY OF PLENTY STRATEGY

The Western Bay of Plenty area consists of Kaitimako, Tauranga, Mt Maunganui, and Te Matai areas, which experience high growth driven by new industrial, commercial, and residential developments. It has been identified that investment is required by Powerco and Transpower to ensure a reliable supply and to provide sufficient capacity for the load growth.

Powerco and Transpower are in discussions to develop a strategy to support investment in the Western Bay of Plenty. Transpower has discussed the grid issues in the 2022 Transmission Planning Report. Table 11.79 only shows grid issues where Powerco is, or potentially is, part of the solution.

Table 11.79: Western Bay of Plenty grid constraints (Powerco involvement)

GRID ISSUE	MITIGATION
Western Bay of Plenty grid low voltages	Installation of significant reactive support in the Western Bay of Plenty area. It might be required to install some of the reactive support within the Powerco network.
Tauranga and Mt Maunganui 110kV transmission capacity and security constraints	Discussed in section 11.15.9.
Tārukenga-Te Matai-Kaitimako transmission capacity and Te Matai low voltage	Medium-term: Powerco to defer shifting the Papamoa load from Mt Maunganui GXP to Te Matai GXP until after the Te Matai T1 110/33kV transformer upgrade. In addition, Transpower plans to implement a circuit overload Special Protection Scheme (SPS) on the Tārukenga-Te Matai 110kV circuits to shed Powerco load post-contingency and relieve the overload. Long-term: Transpower plans to reconductor the Kaitimako-Te Matai and Tārukenga-Okere-Te Matai 110kV circuits by increasing the capacity. Another option under investigation is constructing a new 220kV circuit interconnecting to a Tārukenga-Edgecumbe line.
Te Matai security constraints	Discussed in section 11.15.8.

11.15.8 TE MATAI SECURITY CONSTRAINTS

Te Matai 110/33kV transformers are running above their N-1 security limit and the excessive load growth in the area exacerbates the future exceedances.

Transpower has also indicated that Te Matai T1 transformer is due for risk-based replacement in the near term, which presents an opportunity to match Te Matai T2 110/33kV transformer with a higher capacity unit to address the transformer firm capacity limit. Powerco and Transpower are collaborating to come up with the correct transformer sizing for both Te Matai T1 and T2 considering the load forecast.

11.15.9 TAURANGA SECURITY CONSTRAINTS

The Kaitimako-Tauranga 110kV circuits are already reaching N-1 security limit and require Kaimai generation to assist with managing the load post-contingency. In addition, the Tauranga 110/33kV transformers are forecast to run above their N-1 security limit.

Powerco and Transpower are collaborating to come up with a long-term solution to increase the capacities at GXPs within the Western Bay of Plenty area. Various high-voltage options are being considered to resolve both constraints.

- Short-term: Powerco shifted Pyes Pā zone substation from Tauranga GXP to Kaitimako GXP.
- Medium-term: Transpower investigating the installation of a SPS to relieve overloads through load shedding on both Kaitimako-Tauranga 110kV circuits as well as the implementation of Variable Line Rating (VLR) on these circuits.
- Long-term: Powerco and Transpower investigating adding a third Kaitimako-Tauranga 110kV circuit, which includes the associated substation works at both Kaitimako and Tauranga GXP. In addition, the plan is to strengthen both the Tauranga 33kV and 11kV GXPs by adding a third 110/33kV transformer and to replace the 110/11kV transformers with two 33/11kV units. Another option that is being explored is the construction of an 110kV circuit between Kaitimako and the proposed Belk Rd substation and establishing a 110/33kV and 33/11kV presence at the site. This allows the opportunity to shift significant industrial and future load over to the new Belk Road substation and reduces the demand on the Kaitimako-Tauranga 110kV circuits.

11.15.10 HAMILTON-PIAKO-WAIHOU AND WAIHOU-WAIKINO 110KV SECURITY AND VOLTAGE CONSTRAINTS

The Hamilton-Piako-Waihou and Waihou-Waikino 110kV double circuit is commonly referred to the Valley Spur and supplies our Piako, Waihou, Waikino and Kopu GXPs. This circuit is forecast to approach its N-1 capacity in winter 2023. In addition, Transpower indicated that Piako, Waihou, Waikino and Kopu can experience low 110kV and 33kV bus voltages for certain outages.

Powerco and Transpower are investigating short, medium, and long-term options to alleviate the constraint. Transpower has indicated that any investment will be customer driven.

- Short-term: Transpower plans to apply variable line ratings to the Hamilton-Piako-Waihou 110kV circuits and to install 33kV capacitors at Waihou and Waikino GXPs. If required, the option exists for Powerco to bring forward the Waihi 33kV voltage support project as an alternative solution to Transpower-owned capacitors.
- Medium-term: Transpower plans to install overload SPS on the Hamilton-Piako-Waihou 110kV circuits.
- Long-term: Options being considered are to thermally uprate the Waihou-Waikino-A 110kV line, reconductor the Hamilton-Waihou-A 110kV line or to build a third 110kV line to connect the GXP substations along the Valley Spur. In addition, Powerco is investigating building a 110kV circuit from Hinuera towards the Valley Spur (either Waihou or Waikino) to alleviate the voltage and capacity constraints as an option.

11.15.11 SPUR ACQUISITIONS

Transpower's programme of asset divestment to distributors has lost momentum in the Powerco network area. Powerco and Transpower are not actively pursuing divestment opportunities for complete spur assets because both entities need 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.

11.15.12 TRANSFER OF 11KV AND 33KV ASSETS TO POWERCO

Transpower has an ongoing programme to replace existing 11kV and 33kV outdoor structures and switchgear with indoor switchboards. Powerco has already constructed several new 33kV switchyards at GXPs, replacing Transpower assets. Powerco and Transpower have an agreed memorandum of understanding for Powerco to take ownership of an additional five new switchboard projects. These are in various stages of design, with completion due during the next two years. 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.

11.16 EMBEDDED DISTRIBUTED GENERATORS

Table 11.80 lists the generators greater than 1MW in size that are connected to the Powerco networks.

Table 11.80: Distributed generation greater than 1MW by GXP

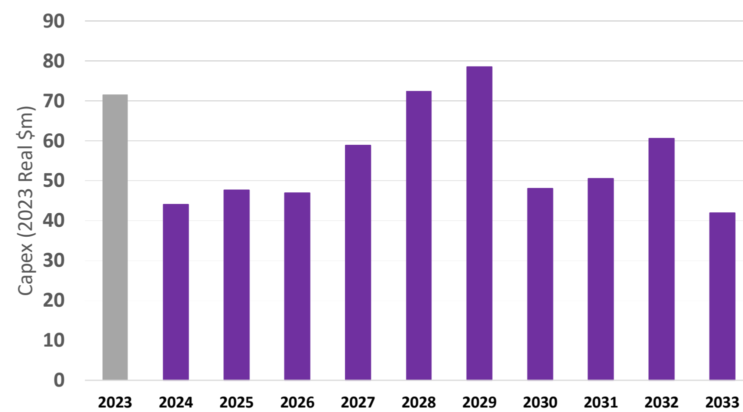
GXP	CAPACITY (KW)	VOLTAGE	GENERATION NAME	MOTIVE POWER
Tauranga 33	40,000	33kV	Kaimai Hydro Scheme	Hydro
Kinleith	40,000	11kV	Kinleith Cogen	Cogen
Bunnythorpe	34,000	33kV	Tararua Wind – North	Wind
Linton	34,000	33kV	Tararua Wind – South	Wind
Hāwera	30,000	110kV	Pātea Hydro	Hydro
Hāwera	2,500	11kV	Ballance Kāpuni	Cogen
Hāwera	1,200	11kV	Origin Hāwera	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
Hāwera	2,100	11kV	Todd Generation Solar Farm	PV Solar
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

11.17 FORECAST MAJOR AND MINOR PROJECTS CAPEX

Figure 11.30 shows the forecast Capex on major and minor projects. Completing our Customised Price Path (CPP) Major Projects is the reason for the considerable investment in FY23, primarily because of our Arapuni to Putāruru GXP project. These larger projects create 'lumpy' major project expenditure, which we balance as far as practicable by revising activity in the minor works portfolio.

We expect investment on major and minor Capex projects to remain high during the planning period, although noting the yearly fluctuations. The higher expenditure during FY27-29 is to support necessary bulk supply upgrades in the Western Bay of Plenty. The timing of individual projects will likely vary from this forecast as they reach construction because of uncertainties in property and consenting timelines, customer requirements and competing priorities.

Figure 11.30: Forecast Capex on major and minor projects



f

12 RELIABILITY AND AUTOMATION

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.

In this chapter, we consider only the reliability expenditure not specifically covered in our other sections – Network Development Plans, Fleet Management Plans, and Operational and Maintenance Plans. This primarily includes expenditure for 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 used to undertake reliability monitoring, 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 investment is important as it enables fast reliability improvements, and it 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 STRATEGY

Our recently updated Automation Strategy reflects the need to invest in network automation to improve our customers' experience by reducing the impact of unplanned outages and preparing the network for a significant increase in Distributed Energy Resources (DERs). The automation strategy focuses on two main work programmes:

- Our "Baseline" automation programme focuses on the "business as usual" application of reclosers, sectionalisers, automated ring main units and simple loop automation schemes. Targeting our worst-performing feeders first will help to improve overall network reliability indicators.
- The "Enhanced" automation programme focuses on delivering more advanced automation technology to increase network visibility and the amount of remote switching. This technology is required to facilitate our Advanced Distribution Management System (ADMS) strategy and to transition to an open-access network. It also supports the future distribution system operator (DSO) role.

Implementing our strategy will increase our automation expenditure significantly during the planning period. The increased expenditure will focus on:

- Remote operable switches at existing tie points on our overhead and underground distribution networks.
- Increased Supervisory Control and Data Acquisition (SCADA) visible fault passage indication.
- Power Quality metering at each substation.

Later in the planning period, we intend to expand the remote-control capabilities to enable faster sectionalising and minimisation of faulted areas through:

- Replacing more manually operated distribution switches on our rural network with remote control switches.
- Retrofitting strategically located ground-mounted switches with remote control operation in our high-value load areas.
- Adding remote monitoring of fused spur connections with LoRaWAN-based (Long Range Wide Area Network) IOT sensors to improve visibility.

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, on both urban and rural circuits. This assessment process minimises the 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 reduce the outage area and duration of faults.
- 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 complementary real-time measurements and can be used for advanced asset management.

- Automation provides the means to monitor and correct power quality issues, particularly issues that are likely to arise through increased distributed generation and two-way power flows.

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 real-time data availability and use increases, integration of field automation devices with modern ADMS modules such as Fault Location, Isolation and Restoration (FLISR) is essential. Our automation strategy focuses on installing devices that help us to step towards that future while providing immediate reliability benefits.

12.3.3 ASSET STEWARDSHIP

This objective requires that we manage our large number of diverse assets efficiently, keeping them in good health.

Network automation systems enable us to reconfigure networks remotely without the need for crews to be on-site. This enables faster restoration times and helps us manage our System Average Interruption Duration Index (SAIDI). Network automation systems also allow us to pinpoint fault causes and locations accurately, reducing the time spent by fault crews. Overall, 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. It is also an important investment area to enable us to manage our networks effectively in real-time.

The benefits of automation include:

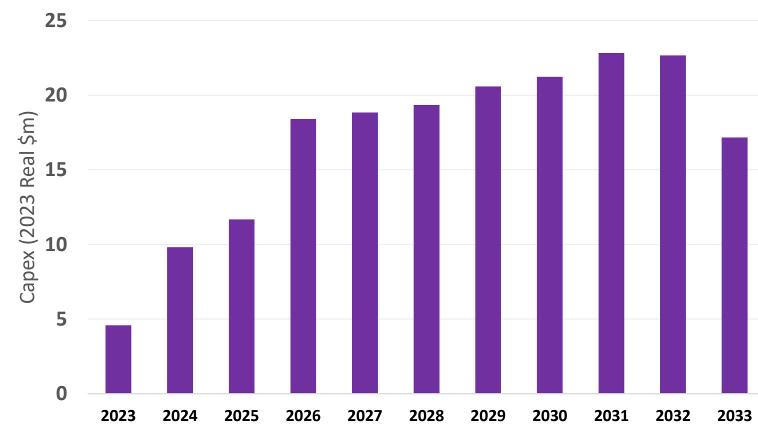
- Shorter outages through faster fault location and reduced time to reconfigure the network.
- Minimising the number of customers affected by faults.
- Reduced costs relating to line patrols, manual switching, and manual fault location.
- Reduced likelihood of equipment damage because of overloading, under-voltage, or slow protection settings.

12.4 EXPENDITURE FORECASTS

Our forecast expenditure is shown in Figure 122.1. 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 Low Voltage (LV) monitoring (network visibility), which is included in the Minor Growth and Security forecasts in Chapter 10.

Total expenditure over the 10-year planning period is $182.4m

Figure 122.1: Forecast Capex – reliability



The increase in expenditure during this planning period reflects the need to improve both fault response and network visibility, which will have a direct impact on improved customer experience. 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 CUSTOMER CONNECTIONS

13.1 CHAPTER OVERVIEW

Several thousand homes and businesses connect to our electricity network or upgrade their existing connections every year. These new and upgraded connections require investment in network infrastructure.
The expenditure we directly incur when connecting new customers, net of any contribution they make, is defined, and forecast as consumer connections Capex.

Chapter 9 provides an overview of our customer connection process. The process we use to connect new customers is designed to ensure that the cost of connection is economical and that we can complete connections quickly. This chapter explains how we forecast expenditure for these connections.

13.2 FORECAST EXPENDITURE

Below, we explain our forecast consumer connections Capex for the planning period.

13.2.1 EXPENDITURE DRIVERS

Consumer connections Capex is primarily driven by growth in population (residential) and the overall economy (commercial/industrial). Specifically, investment levels tend to be influenced by the following:

- New residential properties (stimulated 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 connections and load changes as businesses seek to expand operations. The connections range from small connections, such as water pumps and telecom cabinets, to large connections, such as factories and supermarkets.

We expect increasing decarbonisation and electrification to boost the drivers of investment listed above, particularly in the second half of the planning period. Commercial and industrial connections will need upgrades to allow the conversion of fossil-fuel process heat to electricity, and fast-charge EV stations could require significant upgrades to network capacity.

More recently, we have seen a marked increase in interest in grid-scale (>1MW) distributed generation (DG) connections, primarily solar farms. The incremental costs of network upgrades to facilitate these connections are also classified as consumer connections Capex. Although most of these DG connections are still in the concept, design, or consenting phases, we expect many of these connections to be constructed during the planning period.

13.2.2 FUNDING

Requests for new connections or upgrades of existing connections may impact assets owned by us. We contribute towards the cost of upgrading and constructing these assets because we receive some benefit from ongoing network charges, and, in some cases, new assets benefit our existing customers.

In most cases, the customer requesting the new or upgraded connection funds the majority of the cost. This approach ensures that these customers pay a fair amount for the assets used to serve their connection during its lifetime and ensures that 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 those of the customer. For example, customer service lines – the assets inside a customer's property boundary – are owned by the customer, and we do not contribute towards their construction and maintenance.[81]

Consumer connections Capex contributes to network development at Low Voltage (LV) and distribution levels, typically when connection requests lead to the expansion of the network. However, incremental growth from existing customers can lead to larger upgrades at the distribution level, where small step changes in load over time eventually require an upstream upgrade, which are funded by us. Similarly, reinforcement of our network at subtransmission levels is typically funded through our system growth expenditure unless the subtransmission assets are dedicated to a single customer.

13.2.3 FORECAST CAPEX

Our forecast is based on recent historical activity, overlaid with expected demand growth. First, we use the current in-year FY23 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 our forecasts of increasing electrification, combined with assumptions about customer contributions, to modify the baseline into a final forecast.

Our demand forecasts consider underlying organic growth (based on historical trends) and assumptions about the uptake of various electrification and decarbonisation drivers, including electric vehicles, process heat conversion and

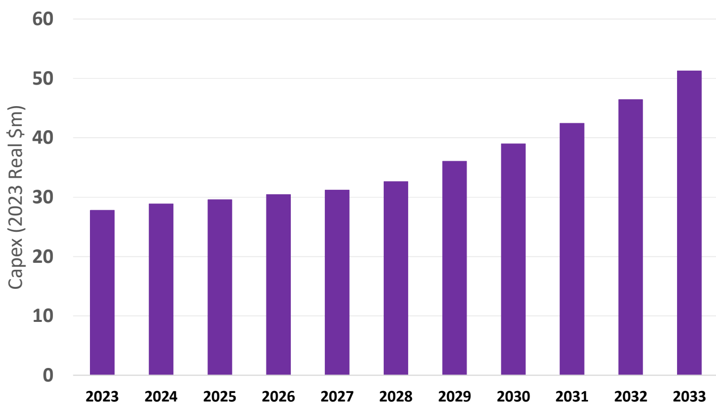
[81] A service fuse is required to complete customer service lines, and we contribute a nominal amount towards this. We do not consider this expenditure to be of a capital nature, so we don't include it in our Capex forecasts.

domestic gas substitution. This demand forecast is also used to inform our forecast for routine Growth and Security investments.

Grid-scale DG connection investment is a separate incremental assumption. This area is difficult to forecast accurately. There is significant interest in grid-scale connections (with a generation capacity greater than Powerco's total peak demand), but the actual number constructed, and the timing, are highly uncertain. We expect to improve the accuracy of this forecast over time.

Our forecast assumes that we continue our current capital contributions policy.

Figure 13.1: Forecast consumer connections 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. The forecast shows a steady increase in the second half of the planning period as the decarbonisation drivers take effect.

We expect a degree of variation year-on-year as major subdivisions and upgrade works are completed. However, we have limited ability to forecast this as third parties drive it. We also have limited scope to reschedule this work year-to-year as we look to satisfy customer requirements as promptly as possible. Economic cycles can also impact year-on-year trends, with this investment tightly linked to economic growth.

FLEET MANAGEMENT

Our plans to manage our existing assets to deliver a safe and reliable service.

14 OVERHEAD STRUCTURES

14.1 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, Asset Heath Indicator (AHI) and type. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

We expect to invest $378m in overhead structure renewals during the planning period. This portfolio accounts for 33% of renewals Capex during the period.

Continued investment is needed to support our Safety and Reliability objectives. Failure of overhead structures can significantly impact our safety and reliability performance. Overhead structures renewals Capex is driven by the need to:

– Deliver the appropriate investment strategies for the required level of service. Replace type issues in the pole and crossarm fleets.

– 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.

14.2 OVERHEAD STRUCTURES OBJECTIVES

Poles and crossarms are the primary components of our network. Combined with overhead conductors, they make up our overhead network (75% of the total network 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. The overhead network is accessible to the public and managing our overhead structure assets are critical to ensuring public safety.

We have defined portfolio objectives for our overhead structure assets to guide our day-to-day asset management activities. These are listed in Table 14.1. The objectives are linked to our Asset Management Objectives set out in Chapter 5.

Table 14.1: Overhead Structures portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No condition-driven failures resulting in injury and property damage.
	Committed to a sustainable future.
	Construct robust networks to perform to the designed lifecycle with consideration to the impacts of climate change.
Customers and Community	Maintain a high standard of reliability.
	Provide the correct investment to deliver the appropriate level of service.
	Investment renewals are planned with consideration for future network requirements.
Networks for Today and Tomorrow	Consider the use of alternative technologies and materials to improve reliability and network resilience.
	Ensure investments are aligned with sustainability goals.
Asset Stewardship	Continually monitor the performance and condition of the fleets to identify trends, such as type issues and end-of-life characteristics.
	Improve and refine our AHI assessment techniques and processes.
Operational Excellence	Continually improve and refine the modelling of AHI and risk for all the overhead fleets to inform prioritised renewal plans.

14.3 OVERHEAD STRUCTURE RENEWALS APPROACH

Our overhead structure renewal forecasts are determined using individual strategies that depend on the structure's environment, while also considering the whole-of-life cost and resilience.

14.4 POLES STRUCTURES

14.1.1 FLEET OVERVIEW

Our network comprises concrete poles (89%), timber poles (11%) 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, material, age, AHI, and a range of end-of-life characteristics.

Concrete poles

There are two main types of concrete poles – pre-stressed and mass-reinforced. Pre-stressed poles constitute most of our concrete pole fleet. We have used many concrete pole suppliers (the chosen supplier is often dependent on the network location), resulting in differences in design, manufacture, and material quality, and leading to differing lifecycle performance across our fleet.

Pre-stressed poles are a mature technology and are expected to perform their function reliably over a long period. Pre-stressed poles have been used for more than 50 years and are manufactured with tensioned steel tendons (wire) encased in concrete. 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 60 years.

Mass-reinforced poles containing reinforcing steel bars covered by concrete were regularly made and used from the 1960s to the 1990s, but less so during the past 30 years.

Figure 144.1: A modern pre-stressed concrete pole and a rural softwood pole

Timber poles

We categorise timber poles based on the wood type and species – hardwood, larch, and softwood.

Timber poles were historically used extensively in parts of the network because of their availability and the technology of the time.

In the proper application, timber poles are more suited to dynamic loading, such as severe weather events, than concrete pole equivalents.

Many hardwood species are used on our networks, most of which were installed before 1985.

The category of larch poles incorporates species such as Ponderosa pine, Douglas fir and Macrocarpa. We phased out the installation of larch poles in the 1990s.

Softwood poles are generally pine, treated with copper chrome arsenic (CCA). Softwood poles are lighter and lower cost than concrete pole equivalents, with a life expectancy of 45 years.

Life extension techniques, such as pole reinforcement, are used for timber poles, where the costs and complexity of rebuild are out of proportion with the projected economic value of pole replacement. Pole reinforcement is a certified engineered solution to extend the 'life' of a timber pole.

We continue to evaluate advanced condition assessment techniques for wooden poles to manage their safety and reliability and improve AHI accuracy.

Steel poles

We have a small number of steel poles in service. There are three main types – legacy 'rail iron' poles, modern tubular poles, and steel lattice towers.

We are organically replacing rail iron poles on the network.

Tubular steel poles are used for specific design loads where concrete and timber poles are not suitable. There is a small population of steel lattice towers on the network. These structures were used for major river crossings and legacy towers purchased from Transpower. We maintain the structures to a serviceable standard.

Fibre-reinforced concrete poles

Fibre-reinforced concrete poles have been introduced into network reconstruction as an option for pole replacement.

These poles are constructed from high-quality fibreglass combined with engineered concrete to create a highly durable pole material. This pole is suitable for corrosive environments, such as coastal frontage, estuaries, and wet areas.

Fibre-reinforced concrete poles have an expected design life of 70 years.

14.1.2 POPULATION AND AGE STATISTICS

Table 144.2 summarises our population of poles by type.

Table 144.2: Pole population by type

POLE GROUP	POLE TYPE	NUMBER OF POLES	% OF FLEET
Concrete	Pre-stressed	163,044	62
	Reinforced	71,008	27
Timber	Hardwood	5,663	2
	Larch	6,118	2
	Softwood	17,808	7
Steel	Steel	700	
Total		264,341	

Figure 144.2: Timber pole age profile

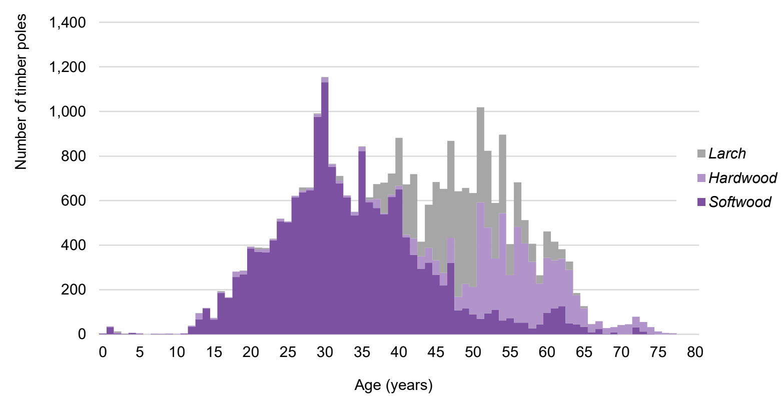
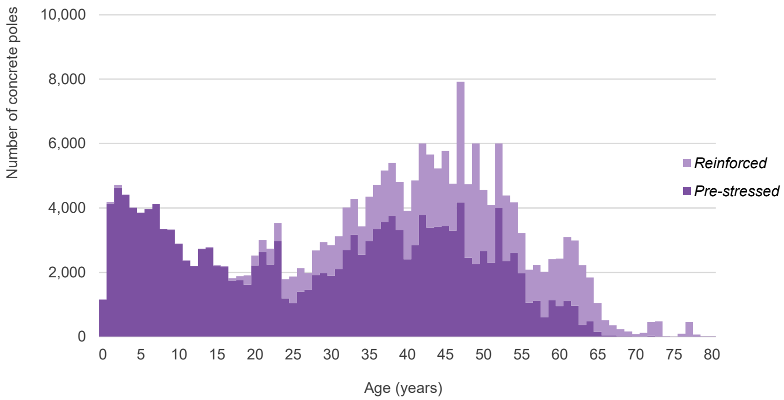


Figure 144.3: Concrete pole age profile



14.1.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Poles with a low AHI are replaced within our projected investments timeframe, which is the main driver for the pole renewal programme.

In-service pole failure is a significant safety issue, potentially exposing the public and workers to falling network equipment hazards and electrical hazards associated with live conductors dropping on the ground or reduced clearances to the ground.

In-service pole failure is also a significant reliability issue because it results in the loss of supply and network security. The reliability impacts can be extensive, and the restoration times extended should multiple failures occur.

Structural failure during maintenance or construction works is also a significant workplace safety hazard.

Meeting our portfolio objectives

Safety and Environment: We replace poles before failure using AHI information, thereby minimising safety risks.

Poles reported with structural defects can be replaced at any time outside the pole renewal programme under the defects and minor works process.

Vehicle versus pole

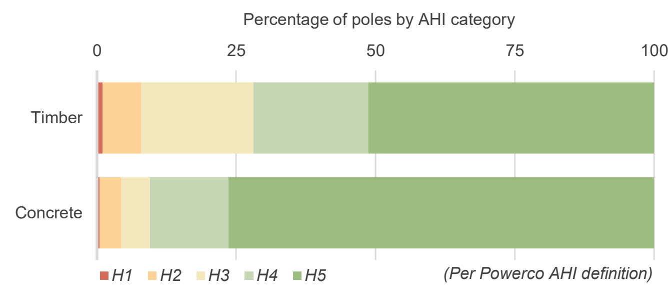
As part of a public safety and network reliability initiative, full modelling has been carried out to identify poles that are at high risk of being hit by a vehicle. The modelling used 40 years of crash data from the Waka Kotahi (NZTA) database and network pole data. The modelling shows that on the Powerco footprint, there are, on average, 4-5 fatalities and 200 incidents a year because of vehicle versus pole crashes.

The modelling highlighted high-risk poles that have been hit multiple times during the past 40 years. The poles have been identified as a high priority for redesign to mitigate the risk of vehicle versus pole.

Pole asset health

As outlined in Chapter 9, we have developed AHI that indicate the remaining life of an asset. Our AHI are calculated using a number of factors, including asset condition, age, type, environment, and criticality. Figure 14.4 shows the current overall AHI for our concrete and wooden pole population.

Figure 14.4: Timber and concrete pole asset health



Pole condition

We carry out five-yearly inspections of poles to verify their condition and to identify defects.

Structural defects are reported into the defects system as identified, regardless of the inspection cycles.

Our inspection results are one of the main inputs into the pole AHI model.

The pole AHI model allows investment forecasting of pole renewals for the planning period.

Table 14.3: Pole failure modes by type

POLE TYPE	FAILURE MODES
Pre-stressed concrete	Cracking in concrete allows moisture ingress, causing the internal steel pre-stressed tendons to corrode 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. Corrosion 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.
Hardwood	Decay in hardwood poles can occur near the ground line and at the pole head.
Softwood and larch	Decay in softwood and larch poles typically occurs from the inside out.
All poles	Structurally overloaded poles and foundation failure. Adverse weather and foreign interference.

Our inspection and defect process has been in place since 2008 and is constantly under review.

We have also conducted research to assess the residual strength of legacy pole types – this consists of break testing of samples of individual pole types. The break testing of poles is conducted in laboratory conditions and verifies pole strength and any manufacturing design flaws. The results of the break testing have identified type issues that have been added to the pole AHI assessment criteria.

Timber pole inspections

We have trialled a variety of techniques to improve the accuracy of the predictive models that inform our AHI forecasts. For example, we have adopted acoustic resonance tools in conjunction with traditional pole inspection techniques for timber pole condition assessment.

Meeting our portfolio objectives

Operational Excellence: We have trialled and are implementing improved pole condition assessment techniques to improve AHI accuracy and asset renewal timing.

Type issues

In addition to condition-related replacements, we also have several pole type issues[82] within the fleet. These poles are targeted for replacement and are replaced during any investment works.

<u>Pre-stressed concrete poles</u>

We have identified that through design and manufacture, some older pre-stressed concrete pole types have low strength compared with modern construction and design standards. As a result, they are replaced during pole and conductor renewals investments and in targeted investments.

<u>Mass-Mass reinforced concrete poles</u>

Type issues have also been identified within the reinforced concrete pole fleet – primarily premature spalling that exposes the reinforcement bars. As a result, they are replaced during pole and conductor renewals investments and in targeted investments.

14.1.4 DESIGN AND CONTSTRUCT

All new poles installed on the network are approved in Powerco standards or by engineering design.

We use a like-for-like approach when performing minor maintenance or renewal works, such as replacing a single pole or crossarm.

When performing more significant overhead line works, we undertake design analysis to ensure the new asset complies with our design and construction standards, which adhere to external rules and standards, such as AS/NZS:7000 – Overhead Line Design, and ECP34.

[82] A type issue is a problem affecting the reliability or safety or design life of a subset of equipment, often related to a particular design or manufacturing issue.

Pre-mature pole replacement relative to the timing suggested by AHI scores often occurs during conductor renewals because of an increase in design loads and compliance with AS/NZS:7000 – Overhead Line Design Standard.

14.1.5 OPERATE AND MAINTAIN

We inspect poles to assess their condition as part of our overhead network inspections.

Concrete poles are durable, static, and do not require mechanical or electrical maintenance work.

Timber poles that meet life extension criteria are selected for pole reinforcement. We continue to explore the technology available to perform diagnostic testing on our wooden pole fleet, which is easy to implement in the field and will enhance the quality of our pole AHI modelling.

Our pole inspections are summarised in Table 14.4. The detailed inspection regime for each type of pole is set out in our maintenance standards.

Table 14.4: Pole preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Unscheduled
Visual inspection of subtransmission crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	Five-yearly
Aerial condition photography to provide identification of condition and defects from a top-down view.	Five-yearly
Visual inspection of distribution and LV crossarms as part of overhead network inspections, completing a detailed condition assessment.	Five-yearly
Network wide LiDAR survey to identify ECP34 and vegetation violations that may impact safety and system performance	Five-yearly

Our structure inspection frequency is based on a combination of historically legislated time periods, industry best practice, and our experience.

We must inspect all poles regularly because they can be damaged or compromised by a third-party action, deterioration, poor ground conditions or land movement.

A key component of our routine inspections is identifying defects and reporting on asset condition. When a defect is detected, it is assessed for failure likelihood and prioritised for repair or replacement in our defects and minor works process.

Pole-top photography is based on a five-year cyclical programme to complement the ground-based inspections on rural poles. We are exploring other methods of capturing imagery of our urban pole fleet. Aerial photography offers a top-down visual inspection, which is not available from ground-based inspections.

14.1.6 RENEW OR DISPOSE

Renewal of poles is primarily determined by AHI.

SUMMARY OF POLES RENEWAL APPROACH	
Renewal trigger	Proactive condition-based and AHI
Forecasting approach	AHI
Type issues	Identified and confirmed by pole type testing

Meeting our portfolio objectives

Asset Stewardship: We are increasing the use of diagnostic condition assessment tools and models to inform and verify renewal investments and forecasting. We are also investigating different material and design approaches to build more resilient overhead networks.

Renewals forecasting

Our pole replacement quantity forecasting incorporates AHI. We have developed AHI models for each of our pole types and use these to forecast renewal quantities.

Pole disposal

Poles are disposed of when they are no longer needed. Common reasons they are no longer required are because of asset relocation, e.g., undergrounding, asset replacement, or following failure. When a pole fails, we may perform diagnostic inspection and testing to assess the root cause of the failure.
As trends emerge from the failure analysis, we incorporate them into our pole fleet asset strategy.

Requirements for recovery and disposal include safe work and site management processes, and appropriate environmental treatment of scrap material.

Pole life extension

As land use changes in remote areas, such as shifts from livestock farming to carbon forestry and honey production, we are observing that customer connection density on some remote feeders is declining. Extending the life of the poles on remote networks will allow the deferral of major renewal investments until either further deferral is not practicable or alternative standalone power supplies become more cost-effective.

Pole reinforcement

Having completed a trial in early 2020, we are now commencing an annual programme of pole reinforcements. A pole reinforcing truss is attached to the pole using high-strength steel banding, and no pole drilling is required. Each installation is designed and certified to provide ground line capacity against loading conditions specified by the current version of AS/NZS:7000.

The work does not require a planned outage and therefore doesn't impact our customers. Reinforcement defers renewal for up to 20 years, allowing us to minimise investment in our remote rural networks that are potentially suitable for alternative solutions in the future. We are also using this technology to quickly rectify high-risk defects identified on timber poles.

Vehicle versus pole

For the planning period, all poles at high risk of being hit by a vehicle have been scheduled for re-design to mitigate the vehicle versus pole risk.

Coordination with network development projects

As part of conductor upgrade investments, poles with low health scores are identified and replaced alongside the conductor upgrade to ensure efficient delivery and to minimise customer disruption. A complete detailed design confirms the exact requirements for each upgrade investment. Some poles with high AHI may require replacement for strength or clearance purposes.

Meeting our portfolio objectives

Customers and Community: Replacement works are coordinated across portfolios to minimise customer interruptions and ensure efficient delivery.

14.5 CROSSARMS

14.1.7 FLEET OVERVIEW

A crossarm assembly is part of the overall pole structure. Its role is to support and space the insulators connected to the overhead conductor and other support equipment. A crossarm assembly is made of one or more crossarms. A range of ancillary components can be mounted to it, such as insulators, high voltage fuses, surge arrestors, bird spikes, earthing systems, 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, for example, when distribution and Low Voltage (LV) circuits share the same structure. There are significant safety and performance risks associated with crossarm failure.

Figure 14.5: Single-circuit and multi-circuit structures

Our crossarms are typically made from hardwood and steel. Hardwood crossarms have insulating characteristics that limit fault currents. Hardwood crossarms can be easily drilled, allowing for simple installation of ancillary components. Steel crossarms are an alternative for high-strength requirements.

Crossarm components

Ancillary components may be replaced through the defect process, as reported by line inspections or field crews.

However, on average, it is more cost-effective from a lifecycle perspective to replace the entire assembly when the crossarm has a low AHI because of the expense of mobilisation and other fixed costs.

The purpose of insulators is to support the conductor while providing electrical separation from the crossarm and pole structure to energised conductors. There are many types of insulators. The insulators on our network are made from glazed porcelain, glass, or polymer.

Binders secure the conductor to the insulator. The modern method to 'bind' conductors to insulators uses pre-formed ties. Armour-rod wraps are also used around the conductor, protecting the conductor from chafing on the insulators and providing some dampening for conductor vibration.

14.1.8 POPULATION AND AGE STATISTICS

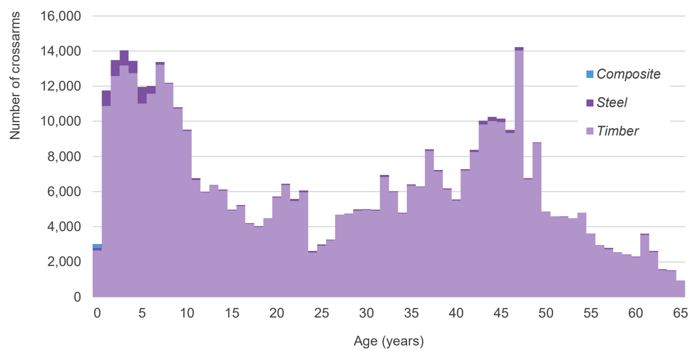
We have approximately 428,000 crossarms in service, of varying sizes and configurations.

Table 14.5: Crossarm population by type and voltage

CROSSARM TYPE	VOLTAGE	COUNT	% OF TOTAL
Timber	Subtransmission	19,957	4.7
	Distribution	155,763	36.4
	LV	242,893	56.7
Steel	Subtransmission	2,984	0.7
	Distribution	3,686	0.9
	LV	2,551	0.6
Composite	Subtransmission	0	0.0
	Distribution	59	0.0
	LV	134	0.0
Total		428,027	

Figure 144.6 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 a lower AHI score increases rapidly.

Figure 144.6: Crossarm age profile



We have compiled the crossarm age profile from different data sources. Age and voltage class are reliably recorded for crossarms installed since 2000. For some older crossarms, this information had to be derived. For example, replacing a crossarm at the same time as a pole is common, therefore, pole age is used as a proxy when the crossarm age is not recorded.

14.1.9 CONDITION, PERFORMANCE, INFORMATION 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 and loss of supply.

Hardwood crossarms typically fail from age-related deterioration, which causes a loss of strength, or from fungal decay, usually starting on the upper side because of exposure to moisture and other contaminants. Timber crossarms also fail because of burning caused by electrical tracking from insulation degradation. Environmental conditions strongly influence failure modes and rates of decay.

Crossarm components also fail. Binders fatigue over time and can loosen or break, allowing the conductor to swing free from the crossarm, usually resulting in an outage. These issues are repaired reactively through the faults and defects process.

We have identified problems with some types of subtransmission and distribution insulators. For example, older type insulators of two-piece porcelain construction are prone to cracking at the join, leading to separation. Because of the potential safety and reliability consequences of these failures, we are proactively replacing crossarms that have these insulators.[83]

Meeting our portfolio objectives

Safety and Environment: Crossarms are replaced proactively using AHI, thereby minimising safety, and reliability risks.

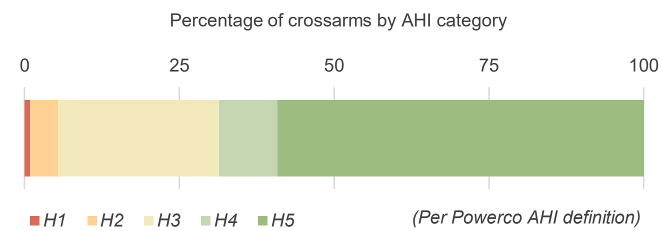
Insulators can crack or completely fail through shock loading, flashovers, or deterioration. These issues are fixed as needed, reactively.

Crossarm asset health

As outlined in Chapter 9, we have developed AHI that indicate the remaining life of an asset. Our AHI are calculated using a number of factors, including asset condition, age, type, environment, and criticality.

Figure 144.7 shows the current overall AHI for our crossarm population.

Figure 144.7: Crossarm asset health



We review Crossarm AHI frequently and, when required, undertake renewal investments to maintain our Safety and Reliability objectives. Within the planning period, there will be ongoing projects for crossarm replacement because of deteriorating crossarms and insulator type issues in the fleet.

[83] It is cost-effective to replace the whole crossarm assembly not just the insulators. These crossarms would need to be replaced in the medium-term anyway.

Crossarm condition

We conduct regular inspections of our crossarms to assess their condition and to identify defects. We are focused on improving the condition assessment regime for crossarms. As a result, we have changed the inspection methods for crossarms, the measures to address data gaps, provided additional training for field staff, and have greater confidence with pole-top photography.

14.1.10 DESIGN AND CONSTRUCT

While the crossarms on our network are typically made of hardwood, we are exploring the use of composite fibre crossarms.

We use high voltage (HV) post type insulators rather than pin type insulators to avoid the failure modes of hole elongation caused by wind loading, and the potential for failure at the cement pin interface.

Crossarm configurations are designed to AS/NZS:7000, and ECP34.

14.1.11 OPERATE AND MAINTAIN

We undertake various types of inspections on crossarms, as set out in Table 14.6. Crossarms are inspected as part of overall overhead network inspections. The detailed regime for each type of asset is set out in our standards.

Using pole-top photography allows a higher standard of crossarm condition assessment and defect identification.

Pole-top photography

Visual inspections have traditionally been ground-based. However, with ground-based inspections, the top side of the crossarm and components supported by the crossarm, such as insulators and conductor binders, cannot be seen and, therefore, cannot be accessed for defects or condition.

Aerial photography provides more accurate identification of defective equipment, allowing us to prioritise repairs and replacements. It also enables the assessment of overhead network components' condition and potential type issues, which improves asset renewal planning.

We cannot use helicopter aerial pole-top photography in urban settings. Potential alternatives we are trialling are drone technology and hot-stick-mounted GoPro cameras.

Table 144.6: Crossarm preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Unscheduled
Visual inspection of subtransmission crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	Five-yearly
Aerial condition photography to provide identification of condition and defects from a top-down view.	Five-yearly
Visual inspection of distribution and LV crossarms as part of overhead network inspections, completing a detailed condition assessment.	Five-yearly
Network wide LiDAR survey to identify ECP34 and vegetation violations that may impact safety and system performance	Five-yearly

Crossarm faults usually occur because of age-related deterioration. Fault and defect repairs involve the replacement of individual components or complete crossarm assembly replacement. Typical corrective work includes:

- Replace broken, rotten, or cracked arms.
- Replace broken or damaged arm braces and bolts.
- Replace individual cracked or failed insulators.

14.1.12 RENEW OR DISPOSE

We use AHI information to prioritise renewal work programmes.

In the short to medium term, our works will focus on replacing crossarms already marked with low AHI, and crossarms with insulator type issues. Where possible, we will deliver these renewals as part of large investments to ensure cost-effectiveness.

SUMMARY OF CROSSARM RENEWALS APPROACH	
Renewal trigger	Proactive condition-based, insulator type issues
Forecasting approach	AHI
Cost estimation	Cost models

Renewals forecasting

Our crossarm replacement quantity forecasting incorporates AHI. We have developed AHI models for each of our crossarm and insulator types and use these to forecast renewal quantities.

Meeting our portfolio objectives

Networks for Today and Tomorrow. When a network renewal investment is planned the use of alternative material and design is investigated. Where appropriate alternative materials and construction methods are used. The main drivers of investigating new materials are to enhance network resilience and reliability. Additionally, each investment must fit Powerco's economic and sustainability models

Coordination with network development projects

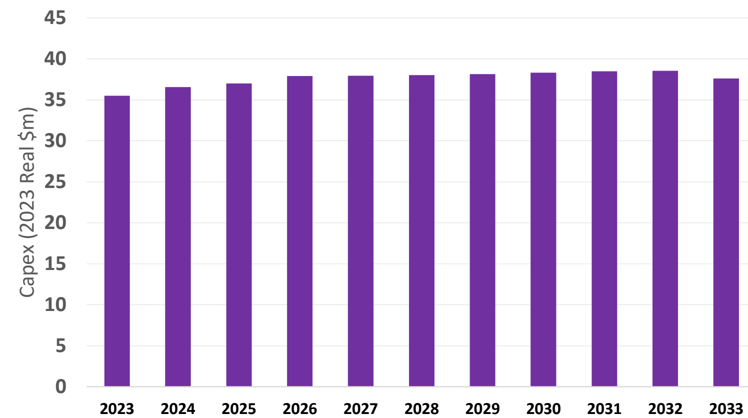
As part of conductor upgrade investments, crossarms with low health scores are identified and replaced alongside the conductor upgrade to ensure efficient delivery and to minimise customer disruption. A complete detailed design confirms the exact requirements for each upgrade investment. Some poles with high AHI may require replacement for strength or clearance purposes which includes all crossarms on the replaced structure.

14.6 OVERHEAD STRUCTURES RENEWALS FORECAST

Renewal Capex in our Overhead Structures portfolio includes planned investments in our conductor, pole and crossarm fleets. This renewal work will require an investment of approximately $378m during the planning period.

Figure 144.8 shows our forecast Capex on overhead structures during the planning period.

Figure 144.8: Overhead structures renewal forecast expenditure

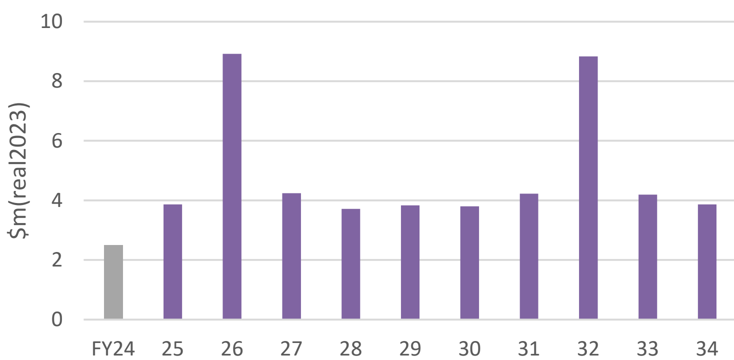


We lifted investment in this portfolio significantly during the past five years, and our forecast is to continue with that increased level during the planning period. This forecast reflects the level of investment needed to manage renewals within the fleets and includes expenditure on crossarms that require replacement.

14.7 OVERHEAD STRUCTURES PREVENTIVE MAINTENANCE FORECAST

The increase in spend in FY25 is largely attributed to the continuation of the pole-top photography programme which has added significant value to our renewal and defect management programmes. We also continue to explore new technologies to allow more comprehensive and safe inspections. The substantial increase in FY26 and FY32, as shown in Figure 144.9, is a provision for the continuation of the LiDAR acquisition program to further assist in resilience planning and vegetation management.

Figure 144.9: Overhead structures preventive maintenance forecast expenditure



15 OVERHEAD CONDUCTORS

15.1 CHAPTER OVERVIEW

This chapter describes our Overhead Conductors 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 Asset Health Indicator (AHI). 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 $11m in 2023 to $19m in 2033. This portfolio accounts for 15% 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 significantly impact our safety and reliability performance. This increase in renewals Capex is mainly driven by the need to replace end-of-life conductors because of their type and accelerated degradation because of environmental and reliability conditions.

We will:

- Continue to replace conductors with poor AHI.
- Ensure the ongoing safety and reliability of our conductor fleets.
- Continue to review material and design to build resilient overhead networks for the appropriate investment levels.
- Ensure conductor replacement meets current design standards.

Below we set out the Asset Management Objectives that guide our approach to managing our overhead conductor fleets.

15.2 OVERHEAD CONDUCTORS OBJECTIVES

Overhead conductors are a core component of the network and connect customers to the transmission system via grid exit points (GXPs). They enable the flow of electricity on circuits of varying voltage levels. Our network is long, predominantly rural, and most electrical circuits are overhead (75% of the total network length).

Our three overhead conductor fleets are defined according to operating voltages.

The same conductor type (material) is often used across voltages, albeit of different sub-types and sizes. However, the risks and criticality differ by the operating voltage.

Table 155.1: Overhead Conductors portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No condition-driven conductor failures resulting in injuries to the public or our service providers.
	No condition-driven conductor failures resulting in property damage, including fire damage.
	Dispose of a conductor responsibly when a conductor is replaced, including metal recycling.
	Construct a robust network to perform to the design lifecycle with consideration to the impacts of climate change.
Customers and Community	Minimise planned interruptions to customers by coordinating conductor replacement with other works.
	Minimise landowner disruption when undertaking renewal work.
	Maintain a high standard of reliability.
Networks for Today and Tomorrow	Investment renewals are designed to current industry standards with consideration for future requirements for the network.
	Consider the use of alternative options and technology to improve customer experience and/or minimise network investment costs, such as remote area power systems.
Asset Stewardship	Replace conductors with poor AHI scores to a sustainable level.
	Increase the use of conductor sampling and diagnostic testing to inform and verify AHI modelling.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
	Continually monitor the performance and condition of the conductor fleets to identify trends for end-of-life characteristics.
Operational Excellence	Continually improve and refine the modelling of AHI and risk for all the overhead conductor fleets to inform prioritised renewal plans.
	Improve our information of the LV overhead network, including conductor types, ages, and failure mechanisms.

15.3 SUBTRANSMISSION OVERHEAD CONDUCTORS

15.3.1 FLEET OVERVIEW

Subtransmission overhead conductors are classified as the conductors used in circuits operating at 33kV, 66kV and 110kV, connecting zone substations to GXPs, and interconnecting zone substations.

Figure 155.1: 66kV subtransmission overhead line in the Coromandel

Conductors used at subtransmission voltages are made of aluminium and copper, in various compositions. Hardened copper, which is highly conductive with good strength and weight characteristics, was the predominant type used on our networks until about 60 years ago.

During the 1950s, All Aluminium Conductors (AAC) and Aluminium Conductor Steel Reinforced (ACSR) conductors were used in place of copper.
AAC is a high-purity conductor, but its poor strength-to-weight ratio compared with other types means it is only used on shorter spans.

ACSR is the most widely used conductor on the 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 the conductor a high strength-to-weight ratio, making it ideal for long spans, like those in rural areas of the network.

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 has greater tensile strength than AAC and is significantly lighter than ACSR. AAAC also has good conducting properties.

15.3.2 POPULATION AND AHI STATISTICS

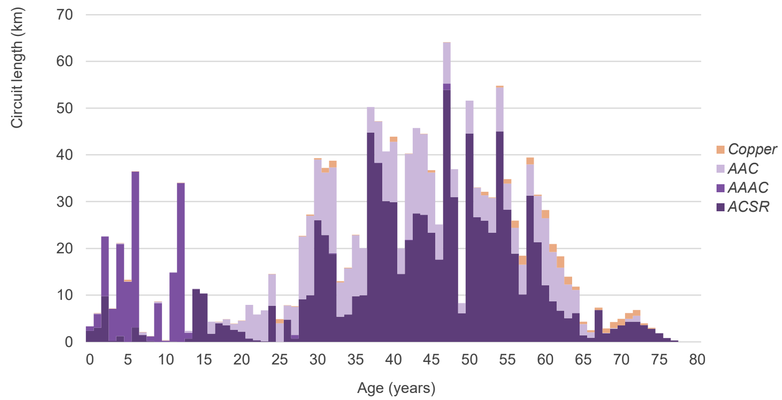
There are four types of subtransmission conductors, making up approximately 7% of our total conductor fleet. Table 15.2 shows that only small volumes of copper conductors remain in service.

Table 15.2: Subtransmission overhead conductors population by type

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	151	10%
AAC	420	28%
ACSR	906	60%
Copper	31	2%
Total	1,509	

Most of our conductors were installed in the 1960s, 1970s and 1980s. Figure 155.2 shows the age profile of the subtransmission conductors.

Figure 155.2: Subtransmission overhead conductors age profile



15.3.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Failure rates are lower within this fleet as subtransmission circuits are constructed more robustly than distribution and LV circuits. Subtransmission conductors are inspected more frequently because of their higher importance in maintaining a reliable supply. Subtransmission conductor failures may result in a high number of customers losing their electricity supply.

Table 155.3 describes the failure modes relating to the conductor fleets, including distribution and LV. These failure modes drive inspection programmes. The knowledge gained from inspection data is used in our asset health modelling.

Table 155.3: Conductor failure modes for all conductor voltages

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, fault currents and design operating temperatures. As effects are cumulative, aged conductors may have relatively lower tensile strength. Copper, AAC and AAAC conductors are more susceptible to annealing. The steel core of ACSR results in lower annealing rates. Smaller distribution conductors are also more susceptible to annealing.
Corrosion	Copper has good corrosion resistance, but there have been mixed results with aluminium, including variation within conductors of the same type and size. While the steel core of ACSR conductors is prone to corrosion, this has been managed through galvanising and greasing of the steel core. Ungreased conductors can rapidly corrode and fail.
Fretting and chafing	Fretting and chafing is caused by conductor swing resulting in 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. This issue occurs more on conductors such as AAC, AAAC and ACSR. This has a reasonable level of impact on conductor failures on our network. Armour rods or line guards (sacrificial metal sheaths) are typically used on all aluminium conductors at the point of binding to an insulator to avoid this failure mode.
Fatigue	Conductor fatigue is caused by the flexing of conductor strains near the bind points. Continuous 'working' of the conductors causes brittleness over time, resulting in failures. Vibration dampers are fitted to mitigate the damage. Copper, AAC and AAAC conductors are more susceptible to fatigue than ACSR.
Foreign object strikes	Foreign object strikes, for example, birds and vegetation, can break a conductor or weaken it to a point where it fails in high winds. Strikes can also cause conductor clashing, which usually results in the loss of conductor material because of the electrical arc. ACSR conductors are less susceptible to this issue because of the strength of the steel core. Large object strikes, for example, a tree falling across the lines, can also cause complete mechanical failure of the conductor.
Binder failure	Binder failure enables the conductor to swing free from the insulators and crossarm, which means the conductor can contact an alternative phase or a support structure. The resultant arcing, because of the fault current, can cause the conductor metal to melt and the conductor to break.

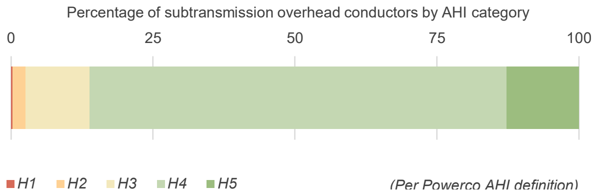
Subtransmission overhead conductors asset health

We have developed AHI modelling for the conductor fleets to enable us to predict the remaining life of the asset. In essence, our AHI models predict an asset's end-of-life and categorise its health score based on a set of rules.

We define end-of-life as when the assets can no longer be relied upon to safely carry their mechanical and electrical loads.

Figure 155.3 shows the current asset health for this fleet, based on conductor condition degradation using the Overhead Renewal Planning Tool (OHRPT) conductor model.

Figure 155.3: Subtransmission overhead conductors asset health



Most of the subtransmission conductor fleet is of aluminium type and, overall, the health of our aluminium conductors is acceptable. Subtransmission AHIs are subject to ongoing review and when required, renewal investments are undertaken to maintain our Safety and Reliability objectives. Copper conductors with a poor AHI are forecast to be replaced within the planning period.

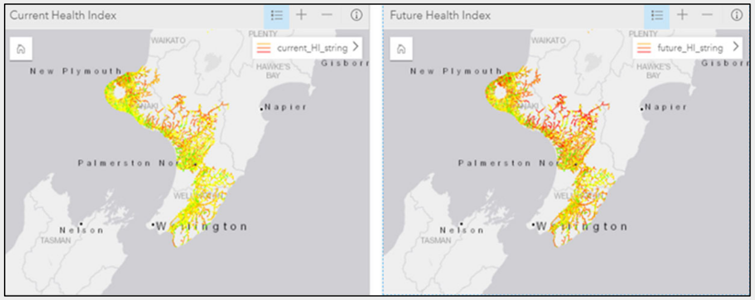
Conductor asset health modelling

There were more than 120 types of conductors installed on the network from pre-1940 to 2022. They are located in various environments, from inland alpine to coastal, and the conditions, including corrosion and windspeed, impact the conductor's expected life. Reliability factors also influence the expected life of conductors, including installation and construction methods, manufacturing faults, sustained fault currents and conductor vibration.

To understand our conductor asset health across all voltages, we have built a model using the Common Network Asset Indices Methodology (CNAIM) as a base. The model uses standard CNAIM inputs, such as the conductor's expected life, location, duty, type, and age. We also use additional health score modifiers where we have further information, such as known defects, visual assessments, manufacturing faults, sample test results and fault currents. The combination of these inputs calculates an asset health score for each conductor span.

We continue improving the quality of both the model inputs and outputs. Changes in source data are updated from field inspections and as-building. In addition, field validation and conductor samples are used to verify the model parameters.

The model also allows us to forecast the ageing rates on the conductor fleets. The future AHI scores of the conductor fleets allows us to make improved renewal forecasts to keep the fleet in stable health to maintain a safe and reliable network.



This figure shows a GIS map of current and forecast conductor health.

15.3.4 DESIGN AND CONSTRUCT

Any subtransmission conductor renewal investment includes a line design compliant with AS/NZS: 7000 and associated standards. The design considers reinstatement and worksite housekeeping issues to minimise impacts on landowners and the wider public.

Meeting our portfolio objectives

Customers and Community: The impact on stakeholders of overhead conductor renewal is anticipated and minimised during project design and construction.

15.3.5 OPERATE AND MAINTAIN

Maintenance and inspection regimes applied to overhead conductors generally involve visual inspections and condition assessments. Table 155.4 summarises the preventive maintenance and inspection tasks. The detailed regime for each type of subtransmission overhead conductor is set out in our maintenance standards.

Table 155.4: Subtransmission overhead conductors preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Unscheduled
Visual inspection of subtransmission crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	Five-yearly
Aerial condition photography to provide identification of condition and defects from a top-down view.	Five-yearly
Visual inspection of distribution and LV crossarms as part of overhead network inspections, completing a detailed condition assessment.	Five-yearly
Network wide LiDAR survey to identify ECP34 and vegetation violations that may impact safety and system performance	Five-yearly

Typically, conductors do not require routine servicing. However, wind-induced vibration, movement, and thermal cycling can make them corrode, work harden, and become brittle. Intrusive inspections are performed only, when necessary, for example, to support a major renewal decision.

There is a range of more sophisticated subtransmission conductor condition assessment tools available. These include thermography and acoustic testing to identify poor connections, failing joints and possible internal corrosion.

We are evaluating the use of these tools in our maintenance regimes across the conductor fleet. This includes assessing the additional costs against the benefits of more optimised replacement programmes and reduced failures.

As part of our increase in overhead conductor renewals, additional investment will be made in conductor forensic testing to improve our understanding of the fleet condition. This additional information will assist in optimising condition-based replacements.

15.3.6 RENEW OR DISPOSE

Our renewal strategy for subtransmission overhead conductors uses AHI scores to indicate that replacement is required and uses visual inspections to verify the model results. For example, the number of joints in a span may be an indicator of past failures because of a poor health score.

Meeting our portfolio objectives

Asset Stewardship: We will increase the use of diagnostic condition assessment tools and use this information in our modelling to inform and verify renewal investments.

Once identified for renewal using the factors discussed above, replacement is prioritised. It is based on an assessment of risk that considers factors such as the level of network security of supply, the economic impact of conductor failure and the safety risk.

SUMMARY OF SUBTRANSMISSION OVERHEAD CONDUCTORS RENEWALS APPROACH	
Renewal trigger	AHI-based, considering risk and consequence
Forecasting approach	AHI
Cost estimation	Desktop project estimates

Renewals forecasting

Our AHI modelling 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 circuits with poor AHI scores.

Coordination with network development projects

Subtransmission conductor works are also driven by load growth. As a result, we often need to increase the conductor size to continue meeting demand. Our options analysis considers the costs and benefits of accommodating future demand by increasing conductor size relative to other options, such as thermal re-tensioning, additional circuits, or non-network solutions. We also consider conductor condition in this analysis.

If the conductor requires replacement in the medium term, the preferred solution could involve replacing it with a larger conductor[84] to cater to growth and renewal needs.

Conductor renewals always consider future load growth when selecting a new conductor size. This consideration ensures that, as far as is practicable, new conductors will not need to be replaced before the end-of-design life because of load growth.

15.4 DISTRIBUTION OVERHEAD CONDUCTORS

15.4.1 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 155.4: Distribution overhead line with LV underbuilt

We generally use the same conductor types at the distribution and subtransmission levels. We also have a small population of steel wire[85] conductors.

84 Work and expenditure in this chapter only relates to renewals.

85 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.

The backbone of the main distribution network is formed of medium and heavy conductors.[86] There are significantly fewer failures on these conductors than on the small diameter lightweight types that are typically used on spur circuits and remote feeder lines.

15.4.2 POPULATION AND AHI STATISTICS

Approximately 66% of our total conductor fleet is at distribution voltages. Table 155.5 shows the five types of distribution conductors used on the network. As with subtransmission, the main conductor types are ACSR and AAC, although a higher proportion of copper conductors remain in this fleet. Since 2000, AAAC has been used as a replacement conductor in coastal sections of the distribution network as it is more corrosion resistant.

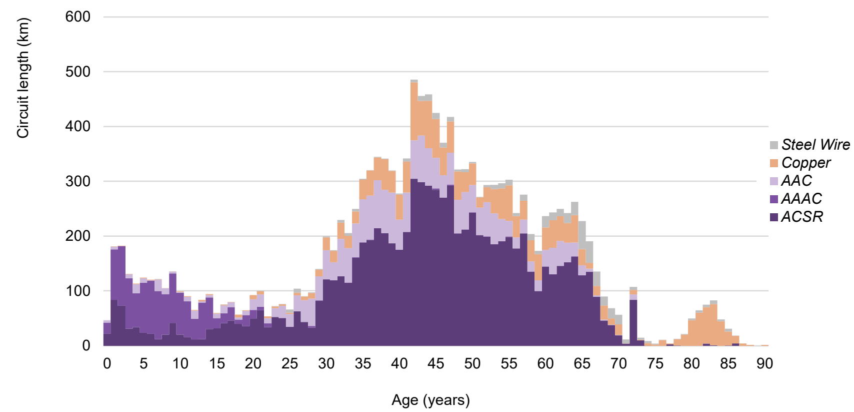
Table 155.5: Distribution overhead conductors population by type

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	1,252	9%
AAC	2,349	16%
ACSR	8,459	57%
Copper	2,218	15%
Steel wire	489	3%
Total	14,767	

Most of our distribution network construction occurred in the 1960s and 1970s, primarily using ACSR and AAC conductors. The 11kV circuits make up most of the distribution network, with smaller sections of the network comprising 6.6kV and 22kV. More than 120 conductor types and sizes were used.

Figure 155.5 shows the age profile of our distribution overhead conductors. A significant number of distribution conductors are approaching their design life of 60 years. However, conductors can exceed the expected life and still have a good AHI, therefore not requiring renewal. Since 2005, we have typically installed or replaced between 50km and 100km of distribution conductors per year. Since 2019, we have considerably increased our replacement to more than 200km per year

Figure 155.5: Distribution overhead conductors age profile



15.4.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Overhead conductors create risks to the public, property, and contractors, including:

- Lines falling, leading to an electrocution risk for people or livestock, either directly or indirectly (livening of 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 the public and contractors not associated with the electrical industry. For example, someone undertakes tree trimming and accidentally touches 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 on the subtransmission and distribution network. Other fault discrimination is used along distribution feeders by way of reclosers, sectionalisers and fusing. The LV network is protected by fusing installed at the distribution transformers.

Our asset health analysis has identified conductor type, age, location, and reliability factors as the main contributors to the condition of distribution overhead conductors.

[86] Medium and heavy conductors are defined as those of >80 ~~50~~mm^2 and >~~150~~ 120mm^2 equivalent aluminium cross-sectional area, respectively.

The interaction of several factors, rather than a single factor, will usually 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 circuits. The fretting and chafing leads to conductor failure over time.

Our renewal focus for this fleet uses a combination of these factors to prioritise the replacement of distribution overhead conductors to reduce overall failure rates.

Conductor sampling

We have recently started a programme of conductor sampling and diagnostic testing to improve our understanding of conductor end-of-life, and how it is influenced by conductor type, age, inland versus coastal environments, attachment points versus mid-span, and other factors.

Samples will be taken from conductors of various ages, types, locations, and at different points on the span. A variety of tests will be used to enable us to build up a profile of each degradation characteristic, such as external damage, annealing, corrosion, and fatigue.

This new information will improve our asset health modelling and enable us to more effectively manage public safety and reliability risk while minimising cost through efficient replacement programmes.

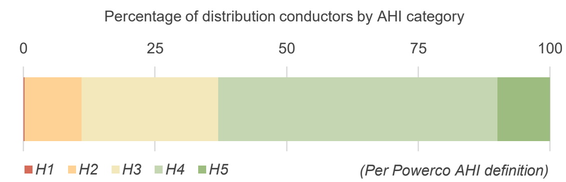
In general, small diameter ACSR conductors perform well, but the performance of the smaller light copper and AAC conductors can be poor, regardless of age.

Distribution overhead conductors asset health

We have developed an AHI that indicates the remaining life of an asset. In essence, our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For distribution overhead conductors, we define end-of-life as when the asset can no longer be relied upon to carry its mechanical and electrical loads safely.

Figure 155.6 shows the overall AHI for our distribution overhead conductor fleet. The AHI is based on known conductor types, age, environment, construction, fault current, manufacturing and expected condition degradation.

Figure 155.6: Distribution overhead conductors asset health



The overall health of our distribution conductor fleet is satisfactory. Smaller and medium size conductors will need to be replaced during the next 10 to 20 years because of deteriorating health.

15.4.4 DESIGN AND CONSTRUCT

The renewal of distribution overhead conductors usually requires a portion of the existing poles to be replaced regardless of their AHI, as some poles do not comply with the modern design requirements of AS/NZS: 7000 design standard.

Where large numbers of poles require replacement, we consider various options, including 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 we need to consider as part of the options analysis.

We 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 there is no damage. We may also consider realigning overhead lines to road reserves where practicable and cost-effective, or when land use has changed from farming to carbon and production forestry.

We are considering different design methods and materials to construct a robust network within AS/NZS: 7000 to meet all our portfolio requirements.

15.4.5 OPERATE AND MAINTAIN

Distribution overhead conductors are inspected less frequently than subtransmission conductors because of their lower criticality. Our inspection regime for distribution overhead conductors is summarised in Table 155.6. The detailed regime is set out in our maintenance standards.

Table 155.6: Distribution overhead conductors preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	Five-yearly
Aerial condition photography to provide identification of condition and defects from a top-down view.	Five-yearly
Network wide LiDAR survey to identify ECP34 and vegetation violations that may impact safety and system performance	Five-yearly

Corrective maintenance tasks on distribution overhead conductors are like those performed on subtransmission conductors.

Most conductor failure occurs during storms and is 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.

Conductor failure because of condition can occur for several reasons, including annealing, corrosion, fretting and fatigue, or a combination of the issues.

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. Because of terrain and other factors, physical access to poles and mid-span sections can often be difficult, compounding repair/outage times.

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.

15.4.6 RENEW OR DISPOSE

Our conductor health modelling and analysis indicate that without further conductor replacement, failure rates may rise. Visual inspections can identify some defect types – some corrosion and foreign object damage. However, for other modes of failure, we must rely more on modelling all factors to predict risk and consequence.

SUMMARY OF DISTRIBUTION OVERHEAD CONDUCTORS RENEWALS APPROACH	
Renewal trigger	AHI-based, considering risk
Forecasting approach	AHI
Cost estimation	Desktop project estimates

We are targeting the replacement of distribution conductors of highest risk, identified from our AHI modelling. Safety is our key concern regarding distribution conductor failure. We prioritise the renewal of conductors considering risks and consequences to all stakeholders.

Renewals forecasting

We forecast the amount of conductor renewal required to meet targets using our modelled AHI.

Meeting our portfolio objectives

Asset Stewardship: We are increasing the use of diagnostic condition assessment tools and models to inform and verify renewal investments. We aim to maintain the conductor fleet to a high standard of safety, reliability, and long-term sustainability.

Remote area power supplies (RAPS)

RAPS provide an option as a modern replacement asset at end-of-line on remote rural distribution feeders. In some situations, there may be just one small customer connected to the end of a feeder that requires asset renewal. Installing a RAPS unit to supply this customer can be more cost-effective than renewing the overhead line. Therefore, 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.

We match RAPS to the 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 approximately 29 RAPS units 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.

Coordination with network development projects

Distribution overhead conductor upgrades and installations can be triggered by load growth, such as from residential infill or greenfield development. This growth often requires feeder backbone upgrades to a larger conductor, thereby increasing conductor capacity.

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. Considering the load growth reduces the likelihood of upgrading the asset before it reaches its intended useful life. Where relevant, we also evaluate the voltage and alternative network configuration ability. For example, some smaller conductor types do not provide scope for alternative network configurations at increasing levels of maximum demand.

When renewing remote rural feeders, we consider using remote area power supplies (RAPS). RAPs can be used instead of traditional conductor replacement where the economic benefits are positive.

15.5 LOW VOLTAGE OVERHEAD CONDUCTORS

15.5.1 FLEET OVERVIEW

LV overhead conductors operate at 230/400V, and most are located in urban areas.

The types of conductors used in the LV network are AAC, ACSR, and copper. The conductors can be covered by a polyvinyl chloride (PVC) sleeve, or the conductor can be bare. LV networks can have standalone poles or use the poles from the HV circuit.

Our newer LV conductors are covered in a PVC outer sheath, which provides some insulation protection.[87] This helps to mitigate safety risks to the public and reduces vegetation-related faults. The LV conductor fleet also includes overhead LV transformer and service fuse assemblies.

Figure 155.7: LV overhead circuit

15.5.2 POPULATION AND AHI STATISTICS

We have 6,007km of LV overhead conductors, of a variety of types, making up 27% of the total conductor fleet. We also estimate we have 1,200,000 overhead LV transformer and service fuse assemblies, although the exact number is currently unknown.

Table 155.7 summarises our LV overhead conductor population by materials. Half of our LV conductors are made of copper. AAC (PVC covered) is now the preferred conductor. Its lower tensile strength, compared with other types of conductor, is less of a concern than for HV conductors, as LV spans are typically much shorter than that of distribution, especially in urban areas.

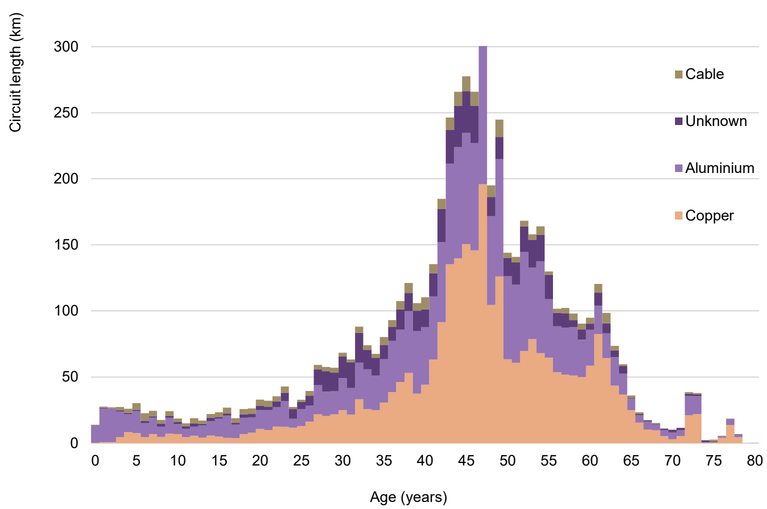
[87] The covering is not sufficient to classify the conductor as electrically insulated but does provide some mitigation of safety risk by reducing the likelihood of injury or death should accidental contact be made with the conductor.

Table 155.7: LV overhead conductors population by material

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
Copper	2,818	47%
Aluminium	2,183	37%
Unknown	688	11%
Cable (ABC)	318	5%
Total	6,007	

Our asset data is less complete for the LV fleet. We are aiming to increase the accuracy of this information through inspections. Some of the conductors recorded in our information systems are of unknown type or the material is unknown (11% of our LV conductors are of unknown material).

Figure 155.8: LV overhead conductors age profile



As with the other fleets, significant investment was carried out from 1960 to the mid-1980s in constructing the LV network. 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 the network has been constructed as underground circuits with almost no new LV overhead circuit construction.

Because of limitations on LV conductor data, we have estimated the age of about half our LV fleet using age data from associated poles.

15.5.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

As discussed previously, the failure of an overhead conductor creates significant safety risks for the public as most of the LV fleet is in more densely populated urban areas. Mitigating this risk is the key priority of our LV conductor fleet management.

Sometimes 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 time delay.

Covered conductors can partially mitigate the public safety risk of electrocution from downed LV overhead conductors. Our standard requires the use of covered conductors with renewal work.

Meeting our portfolio objectives

Operational Excellence: We are improving our information on the LV overhead network to allow for more informed asset management decision-making.

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.

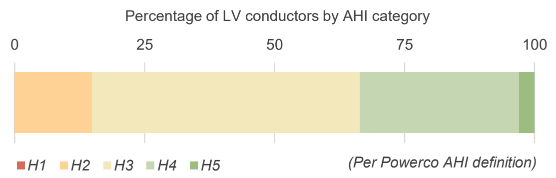
We are assessing the LV fuse fleet to understand the target aged of fuse assemblies and possible type issues. Once the analysis has been completed, a targeted programme for fuse assembly replacement may commence.

LV overhead conductors asset health

We have developed an AHI that indicates the remaining life of an asset, using our OHRPT. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For LV overhead conductors, we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical and electrical loads.

Figure 155.9 shows the overall AHI for our LV overhead conductor population. The overall AHI for this fleet is based on our understanding of the expected life and age of LV overhead conductors.

Figure 155.9: LV overhead conductors asset health



The overall health of our LV overhead conductor fleet is satisfactory. During the next 10 years, replacement is forecast for approximately 66% of the fleet, although with improved information about our LV conductors, we expect to refine this estimate.

15.5.4 DESIGN AND CONSTRUCT

Although not a new technology, we are investigating the use of Aerial Bundled Conductors (ABC) for use on our LV network. ABC has been used internationally 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, and 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 any earth point. Installation is also simpler, as insulators[88] and crossarms are typically not required. There is an additional cost for ABC and the visual impact differs from traditional four to six-wire systems.

We are trialling ABC conductors on our LV network. These trials will allow us to better understand the relative performance and cost of the product and customers' visual preferences.

15.5.5 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.

Table 155.8: LV overhead conductors preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of LV overhead conductors.	Five-yearly

[88] Insulated clamp brackets are still required.

15.5.6 RENEW OR DISPOSE

Limited data on the condition of the LV overhead 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, and 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 not satisfied with a largely reactive approach. Similarly, we are not satisfied with a reactive approach to the replacement of LV fuse assemblies.

As a result, we are actively refining the LV fleet data to update the AHI models to improve investment decisions.

SUMMARY OF LV OVERHEAD CONDUCTORS RENEWALS APPROACH	
Renewal trigger	AHI, considering failure risk and uninsulated conductors
Forecasting approach	AHI and type
Cost estimation	Desktop project estimates

Conductor type issues are unlikely to be as prevalent for the LV overhead fleet as with the distribution fleet. However, environmental conditions, reliability factors and ageing influence AHI scores.

We intend to plan for the replacement of LV overhead conductors that have poor AHI. More detailed fault information will enable us to better target the replacement of conductors with poor reliability.

Meeting our portfolio objectives

Safety and Environment: When prioritising conductor replacement and renewal works, we consider public safety and property damage risks caused by potential conductor failures.

For the LV fuse assemblies, replacement planning will consider fault data for an area, the age of the assembly, and condition sampling.

Renewals forecasting

We have recently shifted to using our LV conductor AHI model to forecast future renewal needs. Rather than a simple 'birthday' type age model, we use a CNAIM modelling approach. This approach reflects, more closely, actual replacement decisions.

The CNAIM modelling shows that the need for conductor renewal can be expected to arise at different ages depending on the conductor's condition, type, environment, and criticality. We plan to slowly increase renewals of LV conductors during the planning period, which will enable us to refine our understanding of the step change required before committing to a large renewal programme.

The focus on areas with older fuse assemblies and higher fault rates will improve asset health. With improved condition data, we can refine our forecasting approach.

We suspect the number of conductors needing to be renewed will increase as our data quality improves.

Coordination with network development projects

We coordinate LV overhead 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 continue to monitor technological changes and customer changes in the use of the network to ensure the LV network has the capacity for any future requirements. We will continue to coordinate growth and renewal investment and monitor developments as the use of grid edge technologies increases.

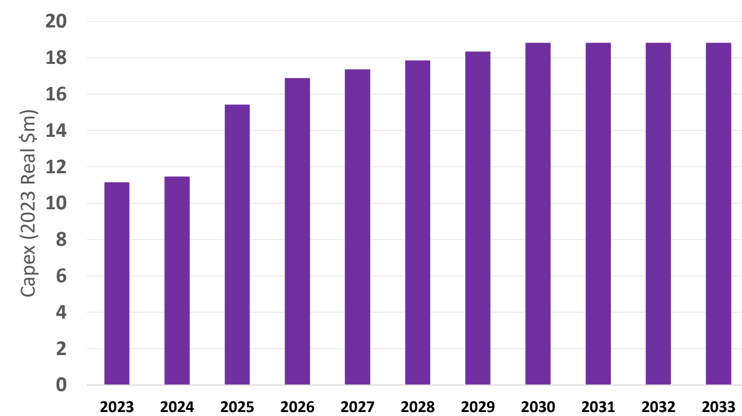
15.6 OVERHEAD CONDUCTORS RENEWALS FORECAST

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 maintain the conductor fleets to a sustainable level, targeting poor health conductors. The key driver for overhead conductor renewal is management of safety, risk, and consequence by addressing declining asset health. Failure of an overhead conductor presents a significant public hazard and has reliability implications.

Subtransmission reconductoring projects can be scoped at a high-level several years before implementation. This means we can carry out desktop cost estimates for each project, considering 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 AHI.

Figure 155.10 shows our forecast Capex on overhead conductors during the planning period. [89]

Figure 155.10: Overhead conductors renewals forecast expenditure



89 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.

Our conductor renewals investment is forecast to increase gradually during the next 10 years. This forecast reflects the increased level of investment needed to renew distribution and LV conductors. However, compared with projections from previous AMPs, we have reduced our expected renewal volumes of conductors because of the increased knowledge gained from our conductor health modelling.

Renewals are expected to remain at these increased levels beyond the 10-year planning horizon, as more conductors built between the 1950s and 1970s may require replacement.

16 CABLES

16.1 CHAPTER OVERVIEW

This chapter summarises our Cables portfolio and our associated Fleet Management Plan. The portfolio includes four asset fleets:

- Subtransmission cables
- Distribution cables
- Low Voltage (LV) cables
- Low Voltage Distribution boxes

The chapter provides an overview of asset population, age, and condition. It explains our lifecycle approach and provides expenditure forecasts for the planning period.

Portfolio summary

We forecast an investment of $179m during the planning period for renewal of our cable fleets, which accounts for 15% of renewals Capex during the period.

Our updated modelling shows that towards the end of the planning period, an increasing proportion of our distribution and LV cable fleets will reach end-of-life. As a result, we expect increased and ongoing renewal investment to be required. As the exact timing and indicators aren't yet fully known, we intend to focus on developing this modelling in the coming years.

To support this change from type issue renewal to end-of-life renewal, the lifecycle improvement initiatives planned for this period include:

- Working with our quality assurance programmes related to underground construction works for better adherence to Powerco's standards.
- Introducing advanced cable condition assessment methods and associated processes and standards to increase the efficiency of identifying work from our tests and inspections.
- Developing our cable performance reporting to better inform timely renewal programmes.
- Improving renewal forecasting by changing from age/type assessments to condition-based assessments.
- Working closer with councils and corridor management New Zealand Utilities Advisory Group (NZUAG) and Association of New Zealand Councils (ANZC) to reduce costs and disruptions to customers.
- Improving our inspection regime for our critical assets.

16.2 CABLE OBJECTIVES

Cable circuits are the backbone of our underground networks, providing a high-capacity and resilient supply to the businesses and households we supply. Underground cable circuits make up approximately 25% of our total network length, with the highest concentration in the denser (urban) areas on our distribution network.

Healthy cable assets are crucial for maintaining a reliable supply to our customers.

Cable types contain conductors of various sizes, similar to overhead line conductors, and are usually made of copper or aluminium. There are also various insulation types, typically impregnated paper, polyethylene, and PVC, with some oil-pressure cable circuits remaining. Cables are generally built with either one, three or four cores and can be "armoured" where additional mechanical protection is required

The type of environment cables are installed in can have a significant impact on the health of the cables. While generally "direct-buried" in native soil or in specialised backfill, they are now more commonly installed in ducts. To ensure long-term reliable operation, this environment requires proper care to prevent damage leading to reduced service life.

This environment is typically owned and managed by others, such as road corridors, bridges, and tunnels, typically owned by councils or NZTA. Some of our other assets are installed at large industrial customers. Work on these assets requires coordination with their corridor managers and other utilities.

Apart from cables, the fleet also includes joints, terminations, and hardware, including mounting hardware used in cable boxes or on pole risers. Furthermore, the fleet includes low-voltage distribution boxes and pits. Finally, some cable circuits operating environments present unique management risks, such as submarine cables and cables in tunnels. Our strategy includes considerations to improve managing this environment so that the risk and impact on our cables is reduced.

This chapter provides an overview of these assets, including their population, age, and condition. It identifies the main hazards and risks and then explains how our Asset Management Objectives inform our maintenance and renewals approach and improvement initiatives. Finally, it provides expenditure forecasts for the planning period.

The differing construction types have different rates of deterioration, impacting their specific maintenance and renewal requirements. For short sections of the damaged cable, it is economic to carry out repairs to restore reliability. However, for cables in poorer condition, in a challenging environment or where outages have a larger impact, it becomes economical to overlay new cable lengths.

We also observe that a significant portion of the underground network is deteriorated as a result of cable strikes by third parties. For example, the rollout of fibre for the internet has significantly increased the fault rate of LV cables. We intend to work even more closely with our local councils to improve this.

Table 16.1: Cables fleet portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No condition-driven failures resulting in injury and property damage.
	Committed to a sustainable future.
	Construct robust networks to perform to the designed lifecycle with consideration to the impacts of climate change.
Customers and Community	Maintain a high standard of reliability.
	Provide the correct investment to deliver the appropriate level of service.
Networks for Today and Tomorrow	Investment renewals are planned with consideration for future network requirements.
	Consider the use of alternative technologies and materials to improve reliability and network resilience.
Asset Stewardship	Ensure investments are aligned with sustainability goals.
	Continually monitor the performance and condition of the fleets to identify trends, such as type issues and end-of-life characteristics.
Operational Excellence	Improve and refine our AHI assessment techniques and processes.

Meeting our portfolio objectives

Asset Stewardship: Using newly introduced tools such as SAP and Copperleaf that provide new information and analysis enhances our ability to make efficient cable expenditure that balances risks and costs.

16.3 SUBTRANSMISSION CABLES

16.3.1 FLEET OVERVIEW

The subtransmission cable fleet predominantly operates at 33kV, although we have several kilometres of 66kV cable in the Coromandel area and two new 110kV circuits from Arapuni Hydro Station to Putāruru GXP. As this fleet is relatively young, it comprises primarily cross-linked polyethylene cables (XLPE), although we do operate some older paper-insulated lead-covered (PILC) circuits in our New Plymouth, Palmerston North and Masterton networks, and pressurised oil-filled cables (POF) out of Bunnythorpe and Hawera GXPs, which include oil pressure vessels and in-ground pits.

Subtransmission cable - strategy summary

- Standardise designs and installations for new circuits (for 33kV and 66kV) to improve construction quality, costs, and maintainability.
- Investigate alternatives to replacing oil-pressure cables to maximise the asset's life and reduce costs.
- Implement condition assessment and online monitoring to graduate to risk-based maintenance.

16.3.2 POPULATION AND AGE STATISTICS

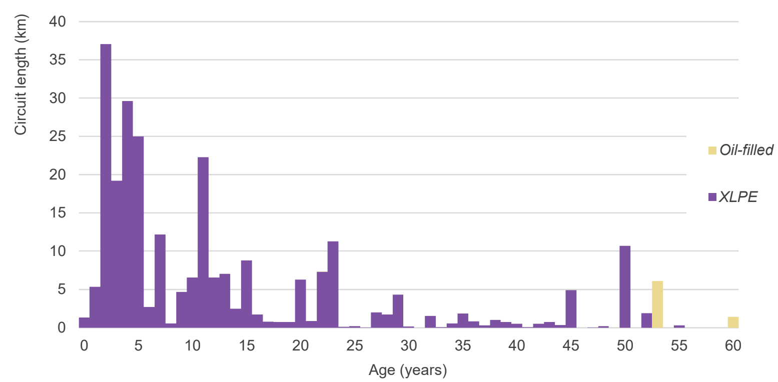
The majority of our 287km of subtransmission cable is XLPE cable. XLPE has been the preferred cable insulation technology for more than 30 years. Table **16.**2 summarises our subtransmission cable population.

Table 16.2: Subtransmission cable population by type

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	279	97%
Oil-filled	7	3%
Total	287	

The subtransmission cable fleet is relatively young, with an average age of 14 years. Figure 16.1 depicts our subtransmission cable age profile.

Figure 16.1: Subtransmission cable age profile



The age profile shows the gradual change of subtransmission cable technologies over time from oil-filled cable to XLPE.

Oil-filled cable has an expected life of 70 years and has generally given good service. However, these assets require specialised oil management equipment to remediate oil leaks. The diminishing availability of specialised equipment and expertise is a major factor in determining the end-of-life of pressurised oil-filled cable circuits. With this in mind, some circuits have recently been retired because of ongoing leaks and poor reliability issues.

16.3.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

16.3.3.1 PRESSURISED OIL-FILLED CABLE

We operate a small number of pressurised oil-filled cables, with a total length of 7.5 km. Known issues with these cables are a scarcity of highly specialised maintenance resources, high repair costs, and the potential for negative environmental impacts resulting from oil leaks.

We have decommissioned the one remaining oil-filled cable circuit in Palmerston North, which we had retained as an in-service backup. It has been electrically decommissioned with the oil pressure reduced to ambient pressure. With the Ferguson-Main subtransmission network upgrades complete, we have initiated a project to de-oil and fully retire these cables. The remainder of the oil-filled cable fleet has had a good performance. Moreover, they have not presented the same failure mode as our now decommissioned CBD circuits. This is because the remaining circuits do not contain the brand of joints with the particular failure mode. Therefore, we believe these remaining circuits are healthy and aren't currently exhibiting end-of-life symptoms. We plan to introduce more advanced condition assessment methodologies and maintenance and are investigating options for eventual replacement, should the condition of these cables worsen.

Environmental impact on and of cables

Environmental concerns associated with oil-pressurised subtransmission cables:

The main environmental concern of the cable fleet is oil loss to the environment from pressurised oil-filled cables. We undertook significant work between FY17 and FY19 to replace failing oil-filled subtransmission circuits in the Palmerston North CBD. Our remaining oil-filled cables are stable, and we monitor them for performance changes and further deterioration.

16.3.3.2 XLPE

While most of the XLPE fleet is still relatively young, we have some early generation XLPE from roughly 1980 to the mid-1990s in our Valley region and Palmerston North. Recent testing of our Baird Rd 33kV circuits in Tokoroa revealed some insulation defects, resulting in their replacement. As such, we expect some early-generation XLPE cables to reach end-of-life within the planning period. We plan to introduce more advanced diagnostics techniques to monitor their performance closely and plan for their renewal when required.

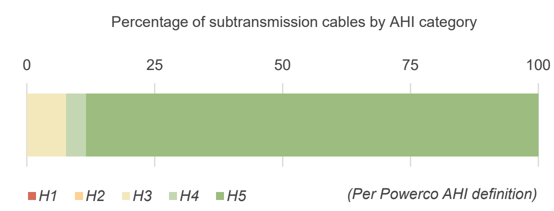
16.3.3.3 ACTIONS SUMMARY

- Build and roll out a condition assessment programme to find ageing joints and terminations, defective cable segments, and poorly installed accessories.
- Quality Assurance (QA) and training: To ensure good build quality as we continue to develop our subtransmission cable network, we will work closely with our service providers and suppliers.
- Improve cable health calculation and renewal logic.
- Investigate innovation in the market, such as self-healing dielectric fluid, as an alternative to replacement.

16.3.3.4 SUBTRANSMISSION CABLES CONDITION, ASSET HEALTH

Asset Health Indices (AHI) models indicate the remaining life of an asset and categorise its health based on defined rules, as outlined in Chapter 9 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. Figure 16.2 shows the overall AHI for our subtransmission cable fleet.

Figure 16.2: Subtransmission cables asset health



The health of the subtransmission cable fleet indicates that about 8% of the cables will require renewal in the next 10 years (H1-H3). These assets include our remaining oil-filled circuits and some early XLPE cable. The rest of the fleet is in good health, and no further replacement is expected in the next 10 years.

16.3.4 DESIGN AND CONSTRUCT

Because of the limited number being installed, we previously had bespoke designs for our 33kV cable installations. However, since the network now requires larger numbers of subtransmission links, we are moving to standard design approaches with our consultants. This will improve the cost of building and maintaining these circuits and installation quality. Standardisation assists ongoing fleet management by reducing spares, simplifying the maintenance and repair process, reducing costs, and engineering out design and installation issues on the fleet. In recent years, we have increased our standardisation of joints and fittings, as these are critical to the long-term reliability of cable circuits.

Meeting our Portfolio Objectives

Asset Stewardship: We are improving our design and specification standards to ensure our new subtransmission cables are built to a high quality that will ensure they last their full lifetime.

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.

16.3.5 DESIGN AND CONSTRUCT

While cables are generally maintenance-free, we perform inspections and diagnostic testing. Oil-filled cables require additional maintenance because of their pressurisation systems. Maintenance and inspections for subtransmission cables are summarised i**n table 16.**3.

Oil-filled cable circuits in Palmerston North are fitted with pressure monitoring equipment to provide alarms if the operating pressures drop below pre-set limits. Work is planned to fit alarms to the Hawera-Cambria circuits.

Table 16.3: Subtransmission cables asset health

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Check and inspection of oil pressurisation systems (POF).	Monthly
Monitor oil level (POF).	Continually online
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.	Five-yearly

As parts of the fleet near the end of their expected service lives, we plan to introduce more advanced cable testing and diagnostics, particularly of oil-filled subtransmission circuits, to accurately confirm the renewal requirements and timing.

New technology providing opportunities – cable monitoring

We are continually evaluating new technology to better manage cable fleet risks. For example, cable monitoring is a promising technology for real-time capacity ratings, condition monitoring, and third-party damage notifications. Two examples are distributed sensing by optic fibre, which we are installing with our 33kV cable circuits, and high-frequency signal monitoring, which we intend to trial during this planning period.

16.3.5.1 SPARES

Given the criticality and long repair time of subtransmission pressurised oil-filled cable systems, we have purchased spare oil stop joint kits and have established contracts with specialist service providers to ensure timely repair.

16.3.6 RENEW OR DISPOSE

We have no evidence that our remaining pressurised oil-filled cable circuits are prone to the same failure mode seen with the replaced Palmerston North CBD cables. However, there is some uncertainty about how long they will remain in use because they are vulnerable to ground movement due to earthquakes or nearby excavation, as well as the environmental impacts on failure.

Because of the uncertainty, our forecasts include replacements of the remaining pressurised oil-filled cable fleet on an age basis. The timing and scope of this work depend on investigations at the start of the period. In the meantime, we are preparing designs and consents for land easements to install new XLPE cable circuits for these routes. These plans are to be implemented if a cable is seriously damaged and rendered unserviceable.

Where we have replaced circuits, we cut in at key points, drain the oil, and then leave them capped in the ground to minimise the environmental impacts of oil loss.

We have estimated costs for these projects from desktop studies of proposed cable routes using typical component costs.

SUMMARY OF SUBTRANSMISSION CABLES RENEWALS APPROACH

Renewal trigger	Environmental and reliability risk
Forecasting approach	By circuit: Identified projects, type issues and age/type
Cost estimation	Desktop project estimates

We expect to undertake increased monitoring and testing during the period, to inform future replacement requirements for our ageing XLPE cables.

16.3.6.1 COORDINATION WITH NETWORK DEVELOPMENT PROJECTS

New subtransmission cable circuits require significant planning and lead time because of the need for consenting, securing easements, and the time needed for cable manufacture. Easements for underground circuits are more straightforward than overhead circuits – many councils restrict overhead lines in urban areas, with underground cables the preferred solution.

If a subtransmission cable circuit requires renewal, we coordinate growth and renewal needs and undertake an options analysis to deliver the best long-term solution.

16.4 DISTRIBUTION CABLES

16.4.1 FLEET OVERVIEW

The distribution fleet operates at 22kV, 11kV and 6.6kV. 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 polyethylene.

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.

Distribution cable - strategy summary

- Implement condition assessment and online monitoring.
- Improve cable commissioning tests to support better Quality Assurance.

16.4.2 POPULATION AND AGE STATISTICS

We have more than 2,000km of distribution cable, of which about 15% is PILC and 85% is XLPE. Table 164 shows the breakdown of distribution cables by insulation type.

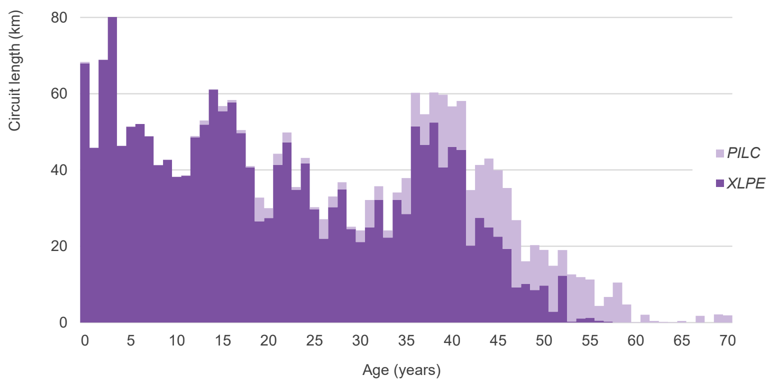
Table 16.4: Distribution cables population by type

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	1,967	85%
PILC	338	15%
Total	2,305	

We also have a small number of submarine cable crossings in Whitianga, Tairua and out to Matakana Island. Additional discussion on these can be found in section 20.4.3.

Figure 16.4 depicts our distribution cables age profile. Most cable installed during the past 40 years has been XLPE, with PILC being the predominant type before that.

Figure 16.4: Distribution cables 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, with most circuits operating well within the cables' expected life[90]. Significant levels of age-related replacement are, therefore, not expected for at least another decade.

However, several known type issues within the fleet will drive our short-term renewal plans. These are discussed in the next section.

16.4.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

16.4.3.1 TYPE ISSUES AND QUALITY ISSUES

The main type and quality issues that affect the distribution cable fleet are listed below:

PILC brittle lead sheaths

Some of the early 11kV PILC cables installed in the New Plymouth networks have brittle lead sheaths that are prone to cracking during ground movement, including our circuits out of the City Substation (New Plymouth). Cracking allows water to enter, leading to degradation and, ultimately, premature failure. 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. Where we have identified these deteriorated circuits, we allow for the overlay of new cable.

XLPE

First-generation XLPE cables installed during the late 1960s to mid-1970s were manufactured using a steam-curing process and raw materials containing contaminants, making them more prone to water treeing. Water treeing is a type of electro-chemical deterioration of the XLPE insulation brought on by contamination and water. Premature cable insulation failure because of contamination was not recognised when polymeric cable insulation was invented.

Incompatible semi-conductive materials and lack of triple extrusion also contributed to this type of problem. These issues have resulted in sufficient failures that warrant progressive replacement. We see problems with this type of cable predominantly in our Tokoroa/Kinleith networks and some areas of the Palmerston North network.

Water treeing was recognised as a phenomenon in the 1980s and was largely resolved. Since then, clean insulation material, water blocking, and water tree retardant have been introduced to extend the cable life. We still have some circuits with first-generation XLPE in the ground, and we are investigating methods to identify deteriorating cables to enable replacement before failure.

90 Expected lives for distribution cables are 55 and 70 years for XLPE and PILC respectively.

Aluminium screen wires

Some of our cables have aluminium screens or armour. However, aluminium screen wire is very susceptible to corrosion if there is damage to the outer sheath, compromising the ability of the cable to manage faults safely and leading to XLPE insulation deterioration that causes water treeing. This issue affects cables of all voltage levels; LV, distribution and subtransmission cables.

Single-layer PVC sheath

We have discovered that PVC sheaths of older cable style become brittle over time, allowing water underneath the sheath leading to internal corrosion. We are looking to identify these cables and schedule them for renewal.

16.4.3.2 SPECIAL CIRCUITS – HIGHER CRITICALLY/CONSEQUENCES AND UNCOMMON ENVIRONMENTS

We operate circuits whose operating environments present increased or unique risks, such as cables with high criticality, due to the number of reliant customers without backfeed option, or submarine cables and cables in tunnels.

Submarine cable

We operate 11km of 11kV submarine circuits near Tairua and Whitianga, and a crossing to Matakana Island. Through underwater inspections, we have identified that the movements of sandbanks over time can expose the cables, making them vulnerable to damage from boats and accelerated sheath degradation. Although we hold unique submarine joints for emergency repairs, the availability of jointing staff and a specialist cable barge means repair times are long. We are planning more frequent inspections of these circuits to manage this risk.

Cables in tunnels

We operate approximately 30km of PILC and XLPE 11kV cable at the Oji Fibre Solutions pulp and paper mill at Kinleith – a significant portion of which runs through Oji-owned tunnels. Given the high number of circuits adjacent to one another, their high faults levels, and the proximity to the Kinleith GXP, these cables have an increased risk of cascade failure (like the 2014 Penrose cable failure) and present a high arc flash risk for workers in the tunnels. We are installing differential protection on these circuits along with our 11kV switchboard upgrades, to improve protection speed, minimising these risks. We hold spare cables and joints onsite to respond quickly to faults.

Meeting our Portfolio Objectives

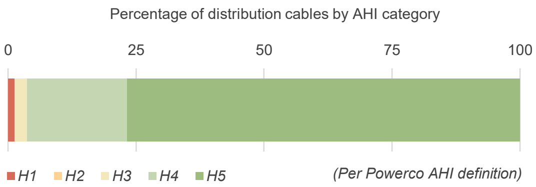
Asset Stewardship: Distribution cables with known high rates of failure are replaced to maintain overall fleet reliability and manage network System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

16.4.3.3 DISTRIBUTION CABLES ASSET HEALTH

As outlined in Chapter 8, we have developed a set of AHIs that indicate 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 as when the asset can no longer be relied upon to operate reliably and the cable should be replaced.

Figure 16.5 shows the 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 16.5: Distribution cables asset health



The health of the distribution cable fleet is generally very good – more than 95% of the fleet will likely not require replacement in the next 10 years (H4 and H5). Our programmes to replace the first-generation XLPE are mostly complete, which has led to an improvement in the overall health of the fleet. However, our health model shows an increase in cable length in average to very poor condition (H1 – H3) to 4% of the total population.

16.4.4 DESIGN AND CONSTRUCT

Design, procurement, and construction of distribution cable assets are optimised by using standard sizes of distribution cable that are common in the New Zealand and Australian electricity industry[91]. This standardisation assists in our ongoing management of the asset fleet, improving the ability to carry out repairs and replacements.

16.4.5 OPERATE AND MAINTAIN

Our distribution cable maintenance tasks are summarised in Table 5. The detailed regime for each type of cable is set out in our maintenance standard. The maintenance standard is being updated to include a condition assessment of joints and the bulk insulation of cable segments.

Table 16.5: Distribution cables preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Cable riser terminations visually inspected. Thermography and acoustic diagnostics of cable risers and terminations.	2.5 yearly
Cable diagnostics of the entire circuit.	As req'd

Cable damage most commonly occur because of third-party interference, such as dig-ins. When cables or their protection have degraded or are damaged, we undertake repairs to avoid faults. 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 are 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 tunnel cable fleets' health, given their higher criticality in supplying Oji Fibre Solutions. We are looking to identify strategic circuits for which this type of analysis is economical to refine our models of future replacement requirements.

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 risks so that we can perform condition testing and, where warranted, proactively replace cables. We are also beginning a programme of post-fault cable sampling and investigating the collection of cable data when we cut into circuits as part of renewal programmes. This information will assist us in better understanding the health of our distribution cable fleet.

SUMMARY OF DISTRIBUTION CABLES RENEWAL APPROACH	
Renewal	Volumetric, adjusted for terrain.

Based on our current knowledge, distribution cable renewal volumes 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

[91] Multicore aluminium with XLPE insulation and common sizes specialised cables, such as single core cables, or copper conductor, are used for specific applications where the common materials are not suitable.

replacement expenditure as significant quantities of XLPE and PILC reach their expected renewal age of 55 and 70 years respectively.

16.4.5.1 COORDINATION WITH NETWORK DEVELOPMENT PROJECTS AND OTHER UNDERGROUND UTILITIES

We work with councils and other utilities, particularly those with underground services located within the road reserve, to coordinate trenching works wherever feasible. We sometimes bring forward cable replacements to coincide with other excavating or road works. We are piloting a condition assessment regime to develop our understanding of our distribution cable fleets, and to verify our assumptions around ageing and future renewal needs.

With the introduction of Copperleaf, we are starting to use this to optimise the coordination of replacements across our different fleets to improve the lifecycle renewal of distribution sites and connected cable assets. This coordination will allow a more streamlined progression from renewal scoping to practical design/construction and enable us to replace the cable at a lower cost, and limit road traffic disruption and damage to pavement surfaces.

Road safety or road widening projects initiated by Waka Kotahi New Zealand Transport Agency often drive the need to relocate cables or underground an existing overhead line. This work is classified as asset relocation and is discussed further in Chapter 22.

> **Meeting our Portfolio Objectives**
>
> Customers and Community: Cable development and replacement are coordinated with other excavation work where practicable to minimise road traffic disruption and cost.

16.5 LOW VOLTAGE POWER CABLES

16.5.1 DESIGN AND CONSTRUCT

The LV cable fleet operates at below 1kV (230/400V). The fleet consists of LV mains cables, dedicated street lighting cables and hot water pilot cables.

Customer service cables are excluded from this fleet, as these are owned by the customer. Underground communications cables are also excluded.

Customer service cables connect to a fuse supplied by our LV cable network. These service cables run between the customer's switchboard and a service box, usually located on the property boundary.

The security of LV enclosures is a key public safety concern, which also impacts the LV cable fleet, as their cable terminations are present in those enclosures. Refer to Section 20.6 Low Voltage Distribution Boxes.

Because of the increasing criticality of our LV networks, we plan to move from reactive renewals to proactive condition-based renewals. We intend to start collecting more defect and failure information to improve our understanding of the performance of our LV cable fleet.

Figure 16.6: Typical urban LV cable environment

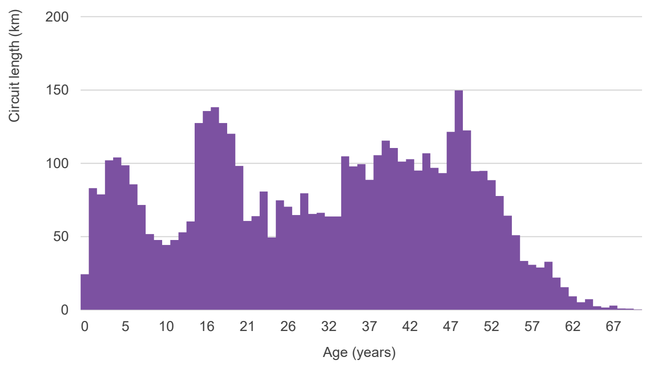
16.5.2 OPERATE AND MAINTAIN

Our LV underground network consists of 6,870km of cable. This includes 1,971km of dedicated street lighting circuits and 479km of hot water pilot circuits.

While our information on LV cable types is limited, we have reasonable age information. Figure 16.6 shows the age profile of the LV cable fleet, excluding street lighting and hot water circuits[92].

[92] About 10% of the fleet's age is unknown and has been excluded from the chart.

Figure 16.7: LV cables age profile



We use age as a proxy for condition and monitor performance by analysing failure trends. While network performance has been stable, we have observed a slight upward movement of LV cable faults attributed to the network ageing. With many LV cable assets nearing the end of their expected service lives, we will need to undertake more proactive cable renewal work to keep the network's performance stable. This increase in renewal work is discussed more in 16.5.4 Renew or Dispose.

Meeting our Portfolio Objectives

Asset Stewardship: We are improving our knowledge of the LV underground network through asset inspections to improve our fleet management decision-making and enable proactive renewals.

16.5.3 DESIGN AND CONSTRUCT

As the terminations are above ground and typically inside a pillar, they can present a public safety risk if not properly maintained and secured. 20.6.3 Condition Performance Information and Risks summarise these risks.

We record network fuse operations and cable repairs, which enable us to track the performance of specific circuits, similar to our distribution and subtransmission cables. We use these to identify circuits that have experienced multiple failures, deciding whether we should investigate a particular circuit for replacement. We intend to improve our decision-making by making this information more accessible and efficient to review, and by recording root cause and effect information that will enable us to update LV cable asset failure modes and effect information.

A safety concern with modern LV cables is that they do not contain a grounded wire shield around the live phases to prevent electric shock during dig-ins or punctures. As a result, we undertake regular safety campaigns to make the public and workers aware of the dangers of underground utility assets.

Planning for end-of-life renewals

The main risk associated with the LV cable fleet is controlling the network and financial impacts of increasing failure rates. Currently, the majority of the cable maintenance budget is spent on reactive repairs of LV cable. As the age profile of our LV fleet shows, in the coming 10 years, the LV cable fleet will continue to age, leading to increased lengths of cable coming to end-of-service life and leading to increased failure rates. By the end of the planning period, a higher rate of proactive replacement will be needed. We have identified the need to develop tools and methodologies to manage this risk profile change.

16.5.3.1 UTILITIES DEVELOPING EFFICIENT ASSET CONDITION PROCESSES

Due to the extent and complexity of the LV cable network, it is important to optimise management approaches.

As discussed above, ageing, and changing customer needs for our LV underground network are increasing the criticality of these networks, which were traditionally treated as run-to-failure. This increased importance means we are investigating what additional resourcing is needed to build and implement efficient condition assessment systems for LV underground assets. Furthermore, we intend to develop our centralised condition knowledge and collect condition information on our LV cable network.

Meeting our Portfolio Objectives

Asset Stewardship: Improving our condition and failure data analysis will help us understand LV cable life expectancy better and enhance our maintenance and renewal planning.

16.5.3.2 CONDITION, AGEING AND TYPE ISSUES

Because of the younger population and run-to-failure approach, knowledge of LV cables failure trends is less advanced than in our other fleets. Therefore, we use industry experience and engineering knowledge to assess the risks, including involvement in industry working groups such as CIGRE and Electricity Engineers' Association (EEA).

Industry experience indicates that single-sheathed PVC aluminium core LV cables have a shorter lifespan than PILC and modern HDPE sheathed cables.

TPS building wire installed underground is prone to damage because of an undersized sheath for its application.

16.5.3.3 CONDITION, AGEING AND TYPE ISSUES

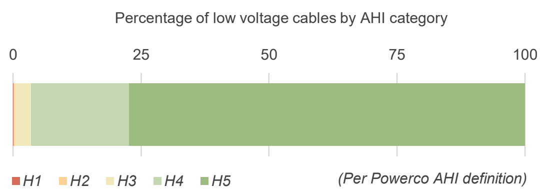
Cable failures commonly occur because of damage by third parties, requiring reactive repairs. It is an ongoing issue and significantly impacts the lifecycle costs of LV cables. Our focus is on improving our public education programmes, such as Dial-Before-U-Dig.

Meeting our Portfolio Objectives

Safety and Environment: We undertake regular public safety campaigns each year to educate the public and workers about the dangers of our network and how to keep themselves safe around electrical assets.

Figure 16.8 shows the overall AHI for our population of low-voltage cables. The AHI calculation is based on our knowledge of specific cable type issues and asset age.

Figure 16.8: Low voltage cables asset health



We expect the average health of the low voltage cable fleet will decline during the planning period as a significant proportion of the fleet reaches nominal end-of-life near the end of the planning period.

[93] ISN is the global leader in contractor and supplier management.

16.5.3.4 DESIGN AND CONSTRUCT

The design standards for LV cable networks are well-established, with standardised materials used. Our designs consider the expected load, voltage drop, fault current capacity and mechanical performance.

Correct cable laying, assembly, and backfilling are critical to achieving the target asset lives of our LV installations.

We have some well-established quality assurance measures. For example, we require that all contractors are registered with ISN[93]. In contrast, other quality assurance measures need further development, such as ensuring that contractors have mature quality processes, like those prescribed by ISO: 9001 quality standards.

16.5.3.5 OPERATE, INSPECT, AND MAINTAIN

The maintenance of the LV cable fleet consists of replacement of failed cable components and the inspection of LV cable ends combine with of the internals of LV distribution boxes, see Table 16.4 – LV distribution boxes network preventive maintenance and inspection tasks. Our goal is to implement a cost-effective condition assessment regime for the LV cable fleet, as described above in 20.5.3.1 Developing Efficient Asset Condition Processes

16.5.4 RENEW OR DISPOSE

We generally manage the renewal of buried LV cable using a run-to-failure strategy. Historically, this approach has been appropriate because:

- The consequence of failure is low because of the low number of affected customers.
- The failure of buried cable poses a low safety risk, except where third parties damage a cable.

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 target cables prone to failure.

We forecast our LV cable expenditure based on age.

SUMMARY OF LV CABLE RENEWALS APPROACH

Renewal trigger	Run-to-failure
Forecasting approach	Age-based
Cost estimation	Volumetric average historical rate

LV cable fleet renewal investment is forecast to remain relatively constant during the early part of the period but is expected to increase towards the end of the period 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.

We have initiated a number of programmes to improve our LV management – see Chapter 6 – Core Asset Management Strategies.

16.5.4.1 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 the costs of cable renewal – traffic management costs are avoided, trenching costs are often shared with other utilities, and there are few, if any, road surface reinstatement costs.

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. See chapter 10 for more information.

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 putting increased upgrade needs on the network, and plan accordingly.

16.6 LOW VOLTAGE DISTRIBUTION BOXES

16.6.1 FLEET OVERVIEW

LV distribution boxes fleet are predominantly installed in urban areas to supply nearby residential customer loads. LV distribution boxes contain equipment that operates at or below 1kV (230/400V), such as links, switches, fuses, relays, and connection points. The fleet consists of boxes, cabinets, pillars, panels, underground pits, and vaults. We collectively refer to common types, such as link pits, pillar boxes and service boxes as LV boxes.

One of the most common types is the LV service box, in which customer service cables connect to a fuse supplied from our LV cable network. These service cables run between the customer's switchboard and a service box, which is usually located on the property boundary.

The integrity of LV boxes is an important public safety concern.

We have a variety of styles and materials installed on our network. Common materials are a combination of plastic, steel, aluminium, concrete, and fibreglass – some typical examples are below.

Figure 16.8: LV boxes

Low voltage enclosures – strategy summary

- Improve maintenance standards to streamline inspection and maintenance.
- Improve asset maintenance and renewal decision-making by initiating and completing our asset information improvement programmes.
- Develop processes to investigate LV enclosure condition issues systematically.
- Implement monitoring for the LV underground network, possibly through smart meter data, to identify deteriorating connections.

The timing and detail of the LV enclosures strategies are heavily dependent on, and influenced by, the LV transformation set out in section 7.8 – LV Transformation Overview.

16.6.2 POPULATION AND AGE STATISTICS

Our LV network consists of 91,426 LV boxes. This includes 7,703 link boxes, 1,523 pillar boxes, and 82,200 service boxes.

Digital data on our LV distribution boxes fleet and network configuration is incomplete. Before the year 2000, detailed information was usually only partially captured in our database. Therefore, we are undertaking a programme of LV pillar and service box data capturing and labelling to fill the gap in our information records of the LV network (see LV Network Connectivity Programme progress below).

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. In addition, we will conduct a detailed condition inspection during this programme, with the results fed into our defects management system.

This programme is more than 80% complete, and we expect to finish it before the end of the planning period.

LV Network Connectivity Programme progress

ZONE	% LABELLED AS AT DEC 2022
Bay of Plenty/Tauranga	77%
Valley/Coromandel	92%
Taranaki	72%
Whanganui	80%
Manawatu/Palmerston North	90%
Masterton	78%

Meeting our portfolio objectives

Operational Excellence: We are improving our knowledge of the LV underground network through asset inspections to improve our LV network connectivity data and fleet management decision-making.

The average age of the LV cable fleet is 28 years. The age of the cables is a good indicator of the age of connected pillars, if slightly older. We expect a small increase in our expenditure during the next 10 years to keep this population's condition stable.

16.6.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

LV boxes can present a public safety risk if not correctly maintained because they are installed in urban areas and above ground at ground level. The key public hazards are:

- Electric shock to members of the public.
- Public or property damage because of fires or arc flash.
- Issues with neutral connections leading to shocks from residential taps/unearthed metal.

Exposure or degraded condition of boxes is identified through our defects process. Most defects are related to third-party damage and access difficulties, rather than a deterioration of condition over time.

16.6.3.1 TYPE ISSUES

Some older-style LV boxes were of metallic construction, which can be inadvertently livened, causing safety risks. Affected LV boxes have been identified and replacement is occurring through our defects process.

In the Tauranga region, we have identified a type issue with approximately 30 in-ground pitch-filled LV link pits. The boxes require special procedures to inspect, maintain and operate because of their design, which has exposed live parts with small clearances – a risk to our operators. These link boxes have failed explosively in networks overseas, highlighting their potential risk to public safety. We have initiated a programme to replace these with modern in-ground or above-ground equivalents during the next 8-10 years.

Replacement of these LV link boxes will enable us to significantly reduce the risk while improving the operability of the LV network within the Tauranga CBD.

Figure 16.9: Tauranga in-ground pitch-filled LV link pits

.

16.6.3.2 CONDITION ISSUES

Common types of LV box deterioration on our network include:

- Corroded neutral connections.
- UV deterioration of plastic and fibreglass.
- Rusting of thin steel panelling.

We have experienced some LV box failures because of overheating contacts and fuses. For example, older-style pull-cap fuses have proven prone to overheating as corrosion occurs between the tinned copper cap and aluminium conductor. This problem has led to pillar fires in the Tauranga region, where this problem is most prevalent.

The sections below cover other issues that we resolve through our defects process. We intend to improve our defect symptoms data capture to help us manage existing LV boxes and improve the specifications of new ones.

16.6.3.3 OPERATOR SAFETY HAZARD

Our inspections and surveys have identified overcrowded LV boxes, typically at infill developments. These overcrowded LV boxes present a safety hazard to operators during servicing and can also lead to overheating.

16.6.3.4 THIRD-PARTY DAMAGE

A significant portion of reported defects and faults are because of third-party damage, often caused by vehicle impacts and vandalism. 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, and protective bollards, are considered. Where practicable, we also replace them with underground-style boxes.

16.6.4 DESIGN AND CONTRACT

We source LV boxes from two manufacturers and have carefully evaluated them before approving them for use on the network. Through close cooperation with the suppliers, we have continually improved the designs and underlying specifications of the products. Having two suppliers mitigates risks associated with a single source of supply. We have observed some installation issues on some sites, so we are investigating whether our QA processes are working adequately.

16.6.5 OPERATE AND MAINTAIN

LV box inspections are the current focus of the LV underground maintenance regime. It is based on a fleet risk assessment, and the frequency of inspection is based on the safety criticality of the asset, with boxes in areas of higher risk inspected more often. Table 16.6 summarises our preventive maintenance and inspections of the LV boxes fleet. The detailed maintenance regime is set out in our maintenance standard.

Since we manage a significant number of LV pillars, optimising the inspection and maintenance process is important. Improving data quality and maintenance information processes are key to managing this fleet effectively. We also expect improvements in our work management system and mobile application – through the installation of SAP – will enable more effective processes from defect identification to remediation.

Table 16.6: LV distribution boxes 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.	Five-yearly

16.6.6 RENEW OR DISPOSE

There will be an ongoing need to reactively replace LV boxes damaged by third parties, and we are continuing our programme of replacing LV boxes with a known type issue.

We forecast LV box expenditure based on the quantities of known defects and historical replacement rates.

Replacing LV pillars because of failure or for an upgrade is the most economical approach. However, as the environment and expectations around the LV network change, this approach to end-of-life management will need to be re-evaluated.

SUMMARY OF LV DISTRIBUTION BOX RENEWALS APPROACH

Renewal trigger	Run-to-failure and condition/type
Forecasting approach	Historical trend and defect rates
Cost estimation	Volumetric average historical rate

We expect LV distribution boxes fleet renewal investment to increase slightly during the next 10 years. After this, renewals may need to grow as larger quantities of LV distribution boxes reach their expected end-of-life. Condition and failure data analysis will help us better understand LV distribution box life expectancy and plan renewals.

16.6.6.1 COORDINATION WITH NETWORK DEVELOPMENT PROJECTS

New loads connecting to the network will likely result in the need for network upgrades. Because of the cost and disruption of underground works, we will work carefully to coordinate renewal and growth needs. We will also consider PV and EV penetration when we plan upgrades.

16.7 RENEWALS

Renewal Capex in our Cables portfolio includes planned investments in our subtransmission, distribution and LV cable fleets. We plan to invest $63m in cable renewal during the planning period.

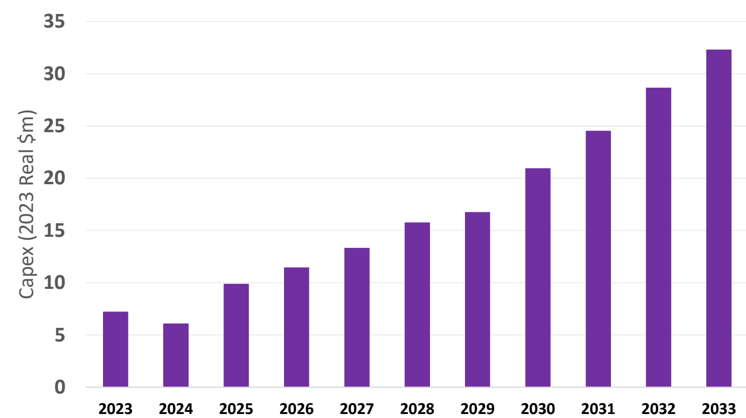
Managing safety risk is a key driver of expenditure for LV cable and LV boxes assets. Drivers for replacing oil-filled subtransmission cables are a combination of environmental and reliability concerns, cost, and poor condition. In the case of distribution cable, increasing failure rates because of deterioration of asset health from the ageing fleet are the key drivers of 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 24.

Where appropriate, our forecasts are integrated with the renewal needs of other fleets to ensure efficient delivery. Distribution cable replacement is often coordinated with ground-mounted switchgear and transformer renewal.

Figure 16.10 shows our forecast Capex on cables during the planning period.

Figure 16.10: Cables renewal forecast expenditure

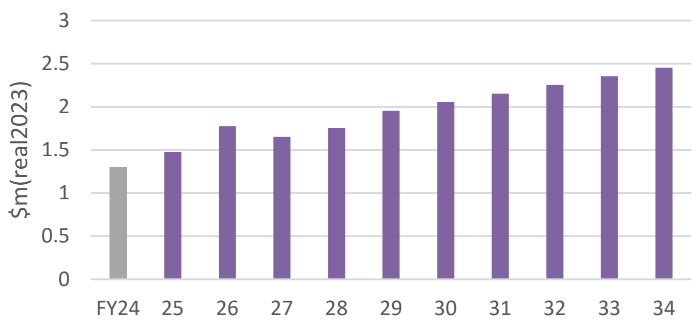


We expect the forecast renewal expenditure for the Cables portfolio to increase in line with the ageing of the fleet.

16.8 PREVENTIVE INSPECTION AND MAINTENANCE

Underground cables account for 11% of our maintenance expenditure, The increase in expenditure forecast is a result of more focus being placed on cable condition assessments and testing to better inform risk and renewal plans.

Figure 16.11: Cables preventive maintenance forecast expenditure



17 ZONE SUBSTATIONS

17.1 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 injection 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

We expect to invest $126m in zone substation renewals during the planning period. This accounts for 11% of our renewals Capex during the period.

We expect to sustain our current level of investment during the period to support the programmes we are undertaking to meet our Safety and Asset Stewardship objectives. This level of investment is driven by the need to:

- Renew assets at the end of service life or in poor condition. The bulk of our expenditure in this portfolio is driven by power transformers, indoor switchboards and outdoor switchgear reaching the end of their service lives, with observable increases in levels of component failures and Do Not Operate (DNO) tags on these critical assets.
- Stabilise asset health. Our Common Network Asset Indices Methodology (CNAIM) models indicate that we need to continue our level of expenditure to keep our network risk stable.
- Manage safety risks, particularly for field staff. Some of our 11kV switchboards have a higher than acceptable arc flash risk. Plans to reduce this risk include installing arc flash protection, arc blast-proof doors, and replacing ageing oil breakers. In some cases, complete new switchrooms and switchboards are needed where simple retrofit or replacement options aren't suitable, typically for obsolescence, seismic risk, or future development reasons.

To guide our asset management activities, we have defined a set of portfolio objectives for our zone substation assets. These are listed in Table 17.1. The objectives are linked to our Asset Management Objectives set out in Chapter 5.

17.2 ZONE SUBSTATIONS OBJECTIVES

Zone substations take supply from the national grid (grid exit points – GXPs) through subtransmission feeders. They provide connection and switching 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.

As major supply and control points, zone substations play a critical role in our network. Supply for many thousands of customers often depends on the performance of key assets within zone substations. Therefore, we design our sites to meet our security of supply standards – governing the levels of redundancy and spares. Prudent management of these assets is essential to ensure safe and reliable operation. These assets have the highest levels of Supervisory Control and Data Acquisition (SCADA) monitoring, alarming, and protective zones on our networks.

Table 17.1: Zone substations portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No harm injuries resulting from arc flash incidents.
	No power transformer oil leaks into adjacent land or waterways.
	We have investigated and approved viable sulphur hexafluoride (SF_6) alternatives and a plan to transition.
	Our switchrooms are weather tight, warm, and dry for the longevity of equipment and the health of workers.
	Phased improvement of our legacy outdoor switching structures to ensure they are safe to operate and maintain.
Customers and Community	Ensure the design and aesthetics of zone substations integrate with the neighbouring community.
	Ensure our sites and grounds are secure, neat and tidy.
Networks for Today and Tomorrow	Support improved system security when renewing power transformers and switchboards, allowing for increased growth.
Asset Stewardship	Utilise the mobile substation to help minimise outages during maintenance or planned upgrade work.
Operational Excellence	Further develop our use of asset health and criticality to support renewal decision-making, including the use of CNAIM approaches.
	Establish Reliability Centred Maintenance (RCM) processes to optimise our maintenance approaches.
	Rationalise zone substation equipment for better spares management and operability.

17.3 POWER TRANSFORMERS

17.3.1 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. They are mounted on pads and, because of the significant volumes of oil these carry, also include firewalls, bunding and oil separation systems.

Additionally, we have an 8MVA mobile substation available to improve supply reliability when carrying out major maintenance or upgrades at our substations, particularly at our smaller rural substations, which generally have limited 11kV backfeed for any major equipment outages.

Figure 17.1: Power transformer installation at Waharoa

17.3.2 POPULATION AND AGE STATISTICS

There are 188 power transformers in service on our network. Table 17.2 summarises our population of power transformers by rating.

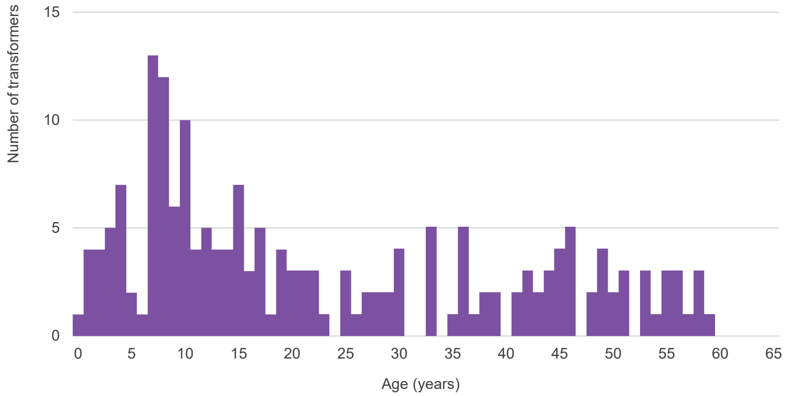
Table 17.2: Power transformers population by rating

MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
<5	15	8
≥5 to <10	73	39
≥10 to <15	19	10
≥15 to <20	46	24
≥20	35	19
Total	188	

Although we purchase standard sizes and configurations, we have some legacy orphan assets with unique vector groups or tapchangers with different tap steps. While this limits interchangeability and operational flexibility during repair or replacement, we have replaced the problematic units, such as autotransformers, which we continue to phase out as part of planned replacements as appropriate.

Figure 17.2 shows our power transformer age profile. The average age of all our zone substation transformers is 23 years.

Figure 17.2: Power transformers age profile



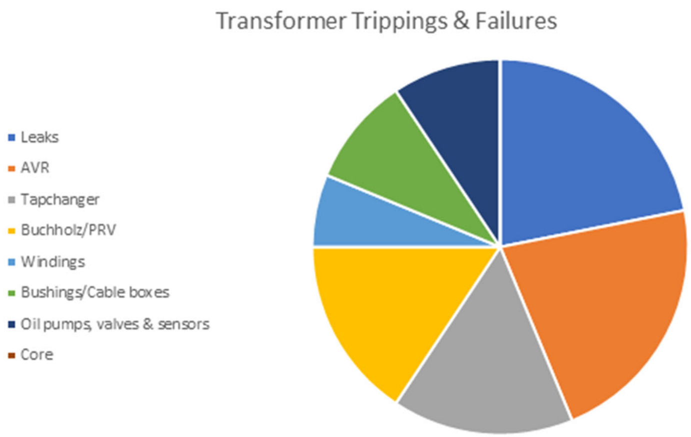
We have increasing maintenance issues with power transformers that are approaching their expected 60-year service life. This indicates a steady volume of replacement to keep on top of the average transformer age. Other areas of transformer risk are addressed below.

17.3.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

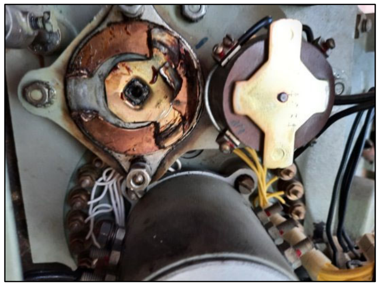
Power transformers are a mature technology, and major component failures are relatively rare.

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.

The diagram below outlines our recorded transformer issues. While the majority can be resolved via maintenance, a number of these have led to transformer trippings.



In the past few years, we have seen an increasing trend of major failures of our older and refurbished transformers, primarily around their tapchanger components and oil systems. Most recently we have seen tapchanger failures at our Livingstone, Bulls and Main St substations, and winding failure at McKee and Parkville. Our response is discussed further in 17.3.5 Operate and Maintain.



Because of the number of predecessor power boards, each of our regions has differences in specific transformer makes, mounting arrangements and vector groups, which we are standardising over time to improve interchangeability. We now install two major vector groups – Dyn11 and Yyn0.

A small number of our power transformers have inadequate or no oil containment facilities. A transformer that leaks oil may create an environmental hazard through soil contamination or, in more severe cases, runoff into water courses.

Through our existing bunding programmes, we have addressed the highest-risk sites. Still, throughout this planning period, where we don’t already have near-term plans for upgrade or renewal, we will further reduce this risk by continuing to install or upgrade oil containment to include both containment (bunding) and separator systems, including for our critical spares. 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: We are undertaking a programme of work to upgrade oil bund and containment facilities at our historic power transformer sites, to reduce the impact of oil spills.

Power transformers asset health

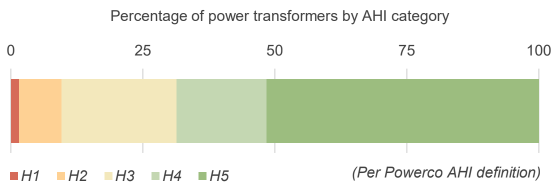
In our CNAIM models for our power transformers, we have used a combination of the Asset Health Indices (AHI) and risk profile to determine the optimum replacement schedule.

The risk ranking considers the estimated likelihood and consequences of failure. We first prioritise renewal on the CNAIM risk ranking followed by the AHI.

Our transformer health is stable, although we are beginning to see the loss of reliability of some of our older refurbished units, particularly in relation to tapchangers. Our current replacement programme prioritises our N-security transformer sites because of the higher maintenance requirements of these sites, and we hold system spares to help manage failures in service.

Figure 17.3 shows the overall AHI for our population of power transformers.

Figure 17.3: Power transformers asset health



17.3.4 DESIGN AND CONSTRUCT

We use a range of controls during the procurement phase of power transformers to ensure we get quality assets from our suppliers. In addition, 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[94] for 33/11kV transformers are:

- 7.5/10MVA
- 12.5/17MVA
- 16/24MVA

Sometimes a replacement power transformer is larger than the existing unit or is anticipated to generate more noise from 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: We check noise levels when new transformers are installed to minimise noise pollution.

94 Some units have two cooling ratings. They represent natural and forced, i.e., with pumps and fans, cooling.

17.3.5 OPERATE AND MAINTAIN

Power transformers and their ancillaries, such as tapchangers, undergo routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in Table 17.3.

To support our condition-based maintenance strategy we will continue to evaluate non-intrusive test techniques and online monitoring to minimise disruption to our customers and ensure reliability is maintained.

Table 17.3: Power transformers preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of insulating systems, cooling, bushing and insulators, tapchanger compartment, foundations, and other ancillaries.	Three-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. Tapchanger service.	Three-yearly

Mid-life refurbishment

When power transformers reach mid-life (25-35 years), we have historically undertaken major workshop-based overhauls, including major tapchanger servicing, upgraded Buchholz relays and Pressure Release Valves (PRV), repaint and, if required, re-clamping and drying of the windings. This overhaul has generally been triggered by the paint systems reaching end-of-life or load growth requiring an upgrade of the transformers. While an overhaul is taking place, a new or recently overhauled transformer is installed on-site in its place.

This approach has successfully managed the aged transformer fleet, allowing transformers to be rotated through the network with older units moved to less critical sites where the consequence of failure is lower. It also allows us to optimise the number of new transformers required on the network for growth reasons and extend the life of the transformer assets.

However, because of increasing difficulty in accessing spare parts and skilled service providers to service older tapchangers, many overhauled units are now nearing the need for outright replacement. We have also been experiencing increased failure rates, particularly with the tapchanger function.

Because of the increasing cost of major overhauls and the increasing serviceability issues of older units, this programme's benefits have lessened. As such, we continually assess the criteria used to determine the cost/risk implications of overhauling our aged power transformers. The decision to proceed with an overhaul will continue to be on a case-by-case basis.

Tapchanger maintenance audit

In response to the tapchanger servicing issues, we now engage specialist service providers to undertake an intrusive maintenance audit ensure to the older tapchangers remain serviceable. This audit identifies any potential risks in the fleet and informs our maintenance and spares strategy, which will ensure spare contacts, braids, and divertor resistors are available to facilitate short restoration times.

Spares

In addition to parts, we also have several whole transformer spares to support our N-security sites. Additionally, as part of our strategic spares programmes, to support our mobile substation, we have retained two moderate sized bushing transformers and a cabled 7.5/10MVA unit that can be mobilised in the event of a major transformer failure or a failure at one of our smaller single transformer substations.

17.3.6 RENEW OR DISPOSE

We use overall condition and network impact risk outputs from our CNAIM modelling to inform power transformer renewals. We want to avoid failure of power transformers because of the potential impacts on the network and customers, both of which depend on the security of the associated zone substation, and the risk of fire and explosion.

SUMMARY OF POWER TRANSFORMERS RENEWALS APPROACH

Renewal trigger	CNAIM
Forecasting approach	CNAIM
Cost estimation	Unit rates-based project estimates

Renewals forecasting

We use CNAIM modelling to forecast power transformer renewal requirements and the priority of individual transformer replacement.

Meeting our portfolio objectives

Operational Excellence: Power transformers 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 CNAIM risk ranking. Coordinating zone substation primary replacements or upgrades determines the final replacement timing and size.

As part of our power transformers renewal programme, we will upgrade bunding, oil containment and separation systems, install transformer firewalls where there is the risk of fire spread, and review and upgrade transformer foundations to ensure appropriate seismic performance.

We expect to replace three to four power transformers per year during the planning period. This amount of replacement will ensure our higher-risk transformers are replaced while also managing the remaining fleet's health through its lifecycle.

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-based renewal.

Coordination with network development projects

Power transformer refurbishments and replacements are coordinated with network development-related projects to develop an optimised programme. Some of our older power transformers equipped with a single resistor on load tapchangers have a limited capacity for reverse power flow, which may limit the capacity of embedded distributed generation connected to the transformer. This is considered when exploring potential embedded generation development.

Power transformer replacements are among the larger projects undertaken within a zone substation and often require civil works to upgrade oil bunding. We coordinate other zone substation works wherever practicable for delivery and cost efficiency, such as outdoor switchgear replacements.

17.4 INDOOR SWITCHGEAR

17.4.1 FLEET OVERVIEW

Indoor switchgear comprises individual switchgear panels assembled into a switchboard. These contain circuit breakers, isolation switches, busbars, and associated insulation and metering. They also contain protection and control devices and their associated current and voltage transformers.

Indoor switchgear has been used extensively for applications at 11kV, and since the late 1990s, when indoor 36kV rated switchboards became available, it has also been used for subtransmission switching applications. Indoor switchgear is generally more reliable than outdoor switchgear because it isn't exposed to environmental pollution, weather, and foreign interference, such as bird strikes. Indoor switchgear also has a much smaller footprint than outdoor switchyard equivalents, making it a practical solution in urban environments where space can be limited.

Figure 17.4: 11kV indoor switchboard at Main St, Palmerston North

17.4.2 POPULATION AND AGE STATISTICS

There are 187 subtransmission circuit breaker panels within 32 indoor switchboards, and 945 distribution circuit breaker panels within 110 indoor switchboards in service on our network. Most switchboards operate at 11kV, but we have a growing number of 33kV switchboards because of network security upgrades. As covered in Chapter 11: Area Plans, we are also working through a joint programme with Transpower to complete outdoor-to-indoor (TP ODID) conversions at older GXPs because of network risk. This will enable us to have closer control of our subtransmission circuits out of these locations.

Table 17.4 summarises our indoor switchgear population by type and number of circuit breakers and switchboards.

Table 17.4: Indoor switchgear circuit breaker and switchboard populations by type

VOLTAGE CLASS	INTERRUPTER TYPE	CIRCUIT BREAKERS
Subtransmission	SF_6 (sulphur hexafluoride)	176
	Vacuum	11
Distribution	Oil	270
	SF_6	74
	Vacuum	601
Total		1,132

Indoor switchgear technology has evolved. 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 Reyrolle LMT switchgear.

Modern switchgear uses vacuum or SF_6-based circuit breakers. These types generally have lower lifecycle maintenance requirements and faster operating speeds. During the past 25 years, most of the switchgear we have installed has been vacuum or SF_6-based.

Modern switchboards have been designed to IEC 62271-200 standards, which, compared to the older portions of the fleet, have much higher safety features to mitigate the impacts of internal failure, greatly improving safety for our operators. They offer arc flash venting, racking through blast-proof switchgear doors, and are installed with dedicated arc flash protection to quickly isolate arcing faults. Arc flash containment is now mandatory for new switchgear installed on our network.

Figure 17.5 and Figure 17.6 outline the age profile of the indoor switchgear fleet.

Figure 17.5: Subtransmission indoor switchgear (circuit breakers) age profile

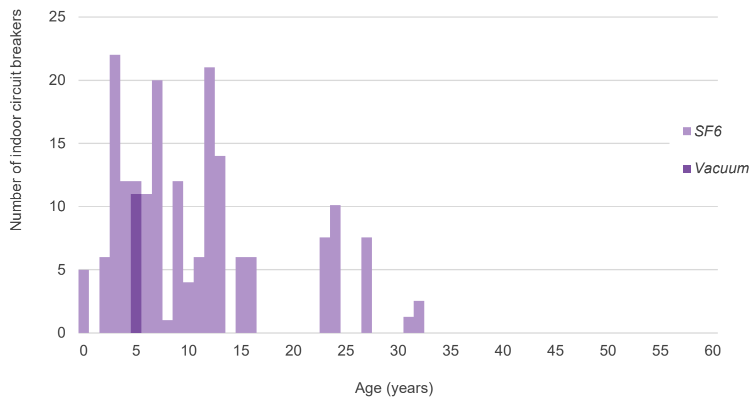
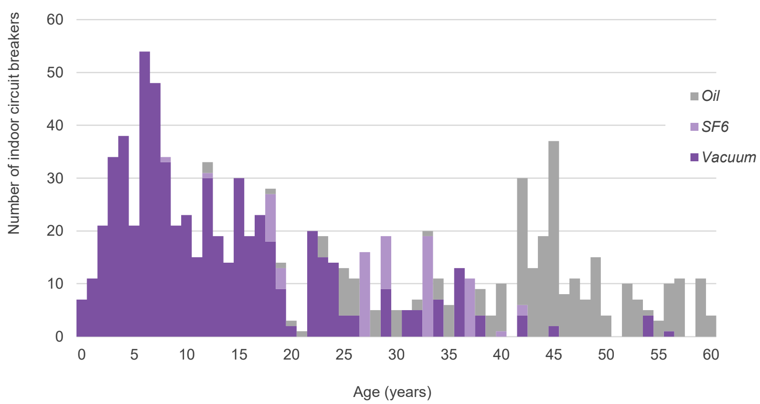


Figure 17.6: Distribution indoor switchgear (circuit breakers) age profile



We generally expect a useful life of approximately 45-50 years from our indoor switchgear assets. Some assets already exceed this guide and will likely need replacement during the next 5-10 years. In addition, at a small number of sites, there is mid-life degradation of ancillary assets, requiring intervention. This intervention is discussed in the following section.

17.4.3 CONDITION, PERFORMANCE AND RISKS

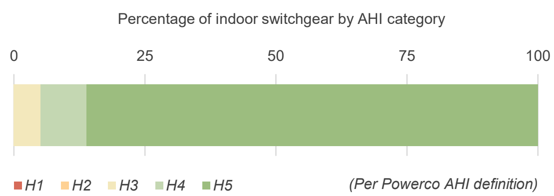
Indoor switchgear asset health

As outlined in Chapter 9 Asset Management Systems, we have developed CNAIM models that indicate 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.

The AHI is calculated using CNAIM. Figure 17.7 shows the AHI profile of the indoor switchgear fleet.

Figure 17.7: Indoor switchgear asset health



About 5% of our indoor switchgear requires replacement during the next 10 years (H1-H3)[95].

Switchgear environment

We have experienced partial discharge issues with cast resin-insulated instrument transformers in some of our early 33kV air insulated switchboards, which are approaching 20 years of age. After consultation with the switchboard manufacturers, these issues are remediated by replacing the defective components and building modifications to improve the weather-tightness or humidity control.

The root of these issues is deficiencies in the original design of the switchgear buildings to provide the temperature and humidity control needed for 33kV air insulated switchgear. We have implemented building weather tightness and environmental surveys of our 33kV switchgear buildings to better understand, and remediate, these issues.

Orphan equipment

Some of our switchboards manufactured from the 1980s-90s are no longer supported by manufacturers and we now consider these as orphaned equipment. Our current spares stock enables us to maintain the operation of these switchboards, however, our ability to continue their operation is regularly reviewed. We have found that manufacturers' support for 33kV air insulated switchboards finishes much earlier than the equipment life – typically at about 20 years of age.

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.

We are progressively replacing or upgrading these switchboards in the short to medium term. We have approximately five 11kV switchboards with oil that we estimate have arc flash energy above 8cal/cm² under normal operating conditions. We plan to rectify all these sites within the next five years.

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.

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.

17.4.4 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. Therefore, before we use a new type of switchgear 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. However, we have installed a small number of switchboards that are non-withdrawable, which are giving good performance. We are evaluating whether we should make further use of these types and expand these to our 33kV switchboards.

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 risks because incorrect racking can cause accidents, and potentially introduce issues during maintenance.

Non-withdrawable breakers do not provide a visible break. Therefore, a critical requirement for this equipment is that any indications are directly driven by the

95 The CNAIM model assumes the fleet is in 'operational condition' and therefore calculates very little assets in H1 health. As the model runs forwards in time, asset health degrades and the number of H1 assets increases.

internal mechanism so that these can be relied upon to reflect the operating state accurately.

The reliability of fixed pattern switchgear has improved, and vacuum and SF_6 circuit breakers do not need to be serviced, 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.

17.4.5 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 17.5.

Table 17.5: Indoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, cabinets and panels, **and** p**artial discharge** (**PD**) **scans.**	Three-monthly
Condition-test switchgear, **including thermal and partial discharge scans**.	Yearly
Insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. SF_6 gas pressure checks. PD scans of 33kV boards.	Three-yearly
Vacuum circuit breaker diagnostic tests, e.g., **High Voltage (HV) withstand. Switchboard partial discharge test.**	Six-yearly
Continuous online monitoring.	Unscheduled

PD detection is a reliable condition monitoring technique for determining many insulation-related failures that can lead to disruptive failure. Recent investigations into our zone substation buildings have highlighted the deteriorating condition of the environment in which the switchgear is housed. Moisture and humidity levels have increased to a point where we have found partial discharge activity in some sites.

To manage the risk while repairs are undertaken, we are investigating increasing our online monitoring systems to aid in the early detection of PD and inform maintenance requirements.

Continuous monitoring is utilised on a needs basis, rather than being scheduled cyclically, and will be used to manage risk on boards with known issues until repairs can be carried out. If this regime proves to be effective for monitoring insulation breakdown, our standards will be adjusted accordingly.

PD online monitoring

In 2018, we procured a set of online PD monitors to be used for condition assessment as well as real-time monitoring. These allow us to observe PD activity carefully over time and identify problem panels.

The use of PD monitors has been very beneficial in fault finding the internal discharge issues at our Keith St, Castlecliff and, most recently, Piako 33kV switchboards, pictured below.

Along with accurate observation from the field, these monitors allowed us to draw a connection between poor switchroom environmental conditions and the incidence of equipment issues. As a result, we brought in dehumidifiers to help stabilise degradation, allowing planned replacement of parts with issues.

Meeting our portfolio objectives

Asset Stewardship: The use of PD monitors greatly improved our ability to pinpoint the source of issues, therefore allowing us to carefully manage supply and minimise outages while continuing to diagnose and make repairs – as well as beginning our review of building environments.

Spares

Although switchboards, by design, generally deliver highly reliable service, they contain many components that are critical to their ongoing performance. We are working with suppliers to update our requirements for spares inventory, which is critical to maintaining serviceability. The availability of critical spares, where we can source them, is expected to improve our repair times on this equipment. Even with newer switchboards, lead times for replacement parts can be up to nine months, as evidenced by recent faults at Piako. Without early PD monitoring, we would have lost half a bus for close to a year. We hold limited stock of parts for older types of equipment, and we are managing these switchboards as part of our obsolescence strategy.

17.4.6 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, e.g., 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

When assessing Reyrolle LMT 11kV switchboards for renewal, we consider the feasibility of upgrading these switchboards by replacing their oil circuit breakers with vacuum circuit breakers. Arc fault containment doors, strengthening panels, and control cables are also fitted as part of this work. These upgrade options often provide cost-effective solutions to managing substation arc flash risks.

Renewals forecasting

Our indoor switchgear renewals forecast uses switchboard condition, reliability and arc flash risk information as inputs for the Common Network Asset Indices Methodology (CNAIM) model of the fleet. Our replacement programmes are, therefore, focused on the renewal of our older Reyrolle LMT switchboards and orphan board types.

We have a stable level of investment in indoor switchgear renewals to mitigate arc flash risks and address the asset health of some switchboards. We expect to continue at this level during the planning period. We also expect to replace or retrofit approximately four switchboards per year for the next 10 years.

Coordination with network development projects

New zone substation projects typically use indoor switchgear because of the greatly reduced footprint required compared with an equivalent outdoor switchgear bay. 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 considered to ensure any newly installed boards will have sufficient future capacity to accommodate the forecast load growth in the planning period.

17.5 OUTDOOR SWITCHGEAR

17.5.1 FLEET OVERVIEW

The zone substation outdoor switchgear fleet comprises asset types associated with HV outdoor switchyards, including outdoor circuit breakers, current transformers (CTs) and voltage transformers (VTs), isolator 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 for maintenance or repairs.

Circuit breakers and reclosers provide protection and control, while fuses provide protection and isolation only. Load break switches control and isolate and are used to break load current.

While outdoor switchgear generally provides good flexibility for emergency replacements during equipment failure, we are progressively converting these to indoor switchboards as our sites become more space constrained.

Figure 17.8: Typical outdoor 33kV switchgear bay

17.5.2 POPULATION AND AGE STATISTICS

Table 17.6 summarises our population of outdoor switchgear by type. Circuit breakers are also categorised by interrupter type.

Table 17.6: Outdoor switchgear population by type

SWITCHGEAR TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Air break switch		909	67
Circuit breaker		174	13
***of which*:**	Oil	89	
	SF_6	70	
	Vacuum	15	
Fuse		168	13
Recloser		92	7
Total		1,343	

Installed from the 1960s to the 1980s, oil circuit breakers still make up most of the fleet. Historically, these circuit breakers have given good performance, but many are now exceeding their expected service life. Issues are described further in the following section.

We are progressively phasing out this type of circuit breaker and replacing it with either vacuum or SF_6-based types.

We also have some 11kV recloser structures, which we use for several of our small rural sites. Where there are space issues, we are progressively converting these to indoor switchboards.

Figure 17.9 and Figure 17.10 show the age profile of our outdoor switchgear.

Figure 17.9: Outdoor fuse and switch age profile

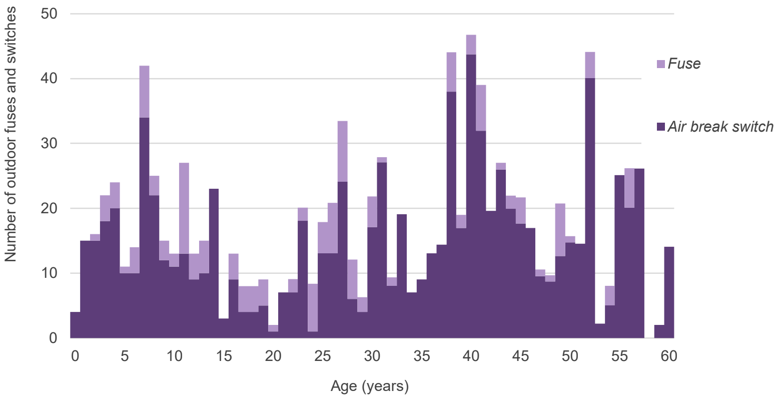
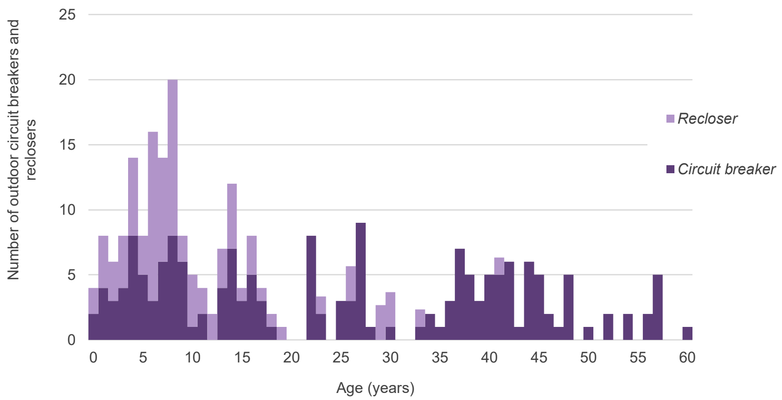


Figure 17.10: Outdoor circuit breaker and recloser age profile



We generally expect outdoor switchgear assets to require replacement at about 45 years of age. Therefore, more than 33% of the outdoor circuit breaker fleet is expected to require replacement during the next decade, although the actual replacement decisions are based on asset condition and risk.

17.5.3 CONDITION, PERFORMANCE AND RISKS

Failure of outdoor switchgear in service will generally lead to operational restrictions and loss of protection speed or, at worst, the temporary loss of supply and increased damage to equipment during a fault. The benefit of outdoor switchgear is that component failures can often be resolved by complete replacement via universal spares within 48 hours.

There are several failure modes for our outdoor switchgear, including failures in service and others identified during maintenance.

Lightning failures

We have had several lightning-induced failures, which generally result in complete loss of equipment, requiring replacement. In addition, some of our older switching structures were designed without means of lightning protection. We have recently updated our lightning protection standard, and we are progressively bringing these older sites up to current standards.

Animal interference

We have had flashovers at Livingstone and Motukawa substations because of possums entering our bushings. Issues with our normal possum guards at these sites have been resolved.

Spares

Our older oil circuit breaker types are now obsolete, making replacement parts difficult to source. If available, there can be 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 our programme of retiring these types.

Type Issues

“Dog-box” style circuit breakers typically comprise a SF_6 indoor breaker within a sheetmetal housing. There have been some historical issues with water ingress leading to internal tracking and breakdown. While we have not experienced this failure mode on our network, we will continue to monitor this via our routine PD inspections.

Outdoor switchgear asset health

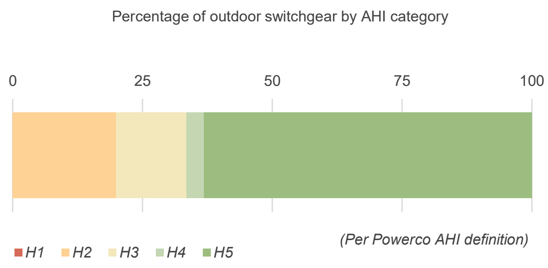
As outlined in Chapter 9 Asset Management Systems, we have developed CNAIM models that estimate the current and forecast health of our outdoor circuit breaker fleet. In contrast, the lower-cost isolators are forecast by more straightforward age-based AHI measures.

For outdoor switchgear, we define end-of-life as when the asset can no longer operate reliably and safely and should be replaced.

The AHI for outdoor circuit breakers is based on CNAIM.

Figure 17.101 shows the current overall AHI profile for our outdoor circuit breakers.

Figure 17.101: Outdoor switchgear (circuit breakers) asset health



The overall health of the outdoor switchgear fleet indicates that approximately 33% 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.

17.5.4 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 and 66kV circuit breaker replacement, we have standardised a small number of live tank SF_6 breakers and a deadtank vacuum breaker. SF_6 circuit breakers are the industry standard for HV outdoor applications. Vacuum and alternative gas circuit breakers would help reduce our holdings of SF_6 gas and its associated environmental risks. As we hold more than 1,000kg of SF_6, we are classified as a major user of SF_6 [96] and are subject to specific reporting requirements.

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 planned to coincide with power transformer replacements.

Figure 17.112: Live tank SF_6 outdoor 33kV circuit breaker

17.5.5 OPERATE AND MAINTAIN

Outdoor switchgear undergoes preventive maintenance to ensure safe and reliable operation. We also undertake preventive maintenance based on circuit breaker fault

[96] Annual reporting requirements to the Ministry for the Environment include: 1) The amount of SF_6 added to the network; 2) The amount used in maintenance top-ups; 3) The difference between total weight of gas in decommissioned equipment compared with nameplate weight; 4) Total SF_6 holdings.

operations for oil type breakers to mitigate against failure modes associated with excess duty.

Our various preventive maintenance tasks are summarised in Table 17.7. The detailed regime for each asset is set out in our maintenance standard.

Table 17.7: Outdoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, air break switches and reclosers.	Three-monthly
Operational tests on circuit breakers 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.	Three-yearly
Air break switches service of contacts and mechanism.	Six-yearly
Vacuum and SF_6 recloser checks and insulation tests.	Nine-yearly
Replace oil (if relevant). Contacts checked and resistance measured.	Operations-based

For oil-filled circuit breakers, more intensive oil sampling and analysis requirements have been implemented in our three-yearly maintenance to provide further insights into the remaining life of the breaker and to ensure continued reliable operation under fault conditions.

To identify the early onset of slowing circuit breaker mechanisms and support our condition-based maintenance strategy, we will evaluate online monitoring options through the intelligent electronic device (IED) relay, which can detect any fatigue in the mechanism and trigger a maintenance intervention. We will introduce more stringent control of lubrication and lubrication types in the interim.

Outdoor switchgear requires more preventive and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

Experience has shown that external corrosion issues and the availability of service and repair technical expertise often determine the service life of outdoor circuit breakers. As part of our improvements to maintenance strategies, we are investigating the use of aerial imagery (acoustic and thermal) as part of our inspection regime for outdoor switchyards to better inform our maintenance requirements.

17.5.6 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 long-term outdoor circuit breaker renewals forecast uses CNAIM-projected AHI and risk as a base for replacement needs – our air break and load break switches use age as a proxy for condition.

Older switchgear is more likely to be in poor condition because of prolonged exposure to corrosion conditions. Its mechanical components are also expected to have more wear, leading to slower operating speeds, which can increase fault clearance times.

Our renewals forecast also considers that older switchgear designs 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.

ODID conversion project[97] planning considers a range of drivers on top of the typical considerations of condition, safety, and criticality.

These additional drivers include environmental pollution and corrosion conditions, site aesthetics, site space/layout and equipment maintenance requirements. The high-level scope of these projects is used to develop an indicative cost estimate. We intend to refine our quantitative analysis further to help our like-for-like versus indoor conversion decision-making.

We have identified several substation candidates for ODID conversion. These substations generally have 33kV switchgear in poor condition, are subject to industrial or environmental pollution, or have cramped overhead buswork. These projects are discussed in more detail in Appendix 7.

97 ODID 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

We use indoor switchgear in most new zone substations because of its cost, footprint, reliability, and safety benefits relative to outdoor switchgear. 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.

Whangamata battery energy storage facility

Whangamata is a resort township located in the western Bay of Plenty on the picturesque beach of the same name. During holiday periods and special events, such as Whangamata's famous Beach Hop, the population can swell from a few thousand to tens of thousands. Whangamata's economic health relies on a reliable power supply, as its business community depends highly on holiday trade.

After consultation with business leaders in the Whangamata community, our Network Development Team decided to improve the security of supply by installing a 2MW/MWh battery energy storage system (BESS), coupled to a 2.5MVA diesel generator. While providing backup power to vulnerable businesses was the primary objective, a secondary purpose was to reduce subtransmission peak demand and provide dynamic voltage support to the wider Whangamata area.

Meeting our portfolio objectives

Customers and Community: Installing an energy storage facility minimises the impact of unplanned outages, provides backup power during maintenance operations, alleviates transmission line capacity constraints, and provides voltage support.

17.6 BUILDINGS

17.6.1 FLEET OVERVIEW

Zone substation buildings mainly house indoor switchgear and supporting control and monitoring equipment, such as protection relays, SCADA, direct current (DC) systems and communications.

Given the critical and sensitive nature of the equipment housed, zone substation sites need to be environmentally controlled, secure, and resilient. Buildings and equipment must be well secured for earthquakes and designed to minimise fire risk or harm to operating staff.

Figure 17.13: Masonry-constructed building

17.6.2 POPULATION AND AGE STATISTICS

We have 160 buildings[98] at our zone substations. Given the range of ages and installation environments, these comprise a mixture of styles, including steel portal frame buildings, timber buildings, concrete block, and Portacom-style buildings.

17.6.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Seismic risks

As building standards have evolved, the requirements for seismic performance have changed. As a result, 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 critical for the safety of the people who work in them and to maintain electricity in the event of a large earthquake. Remaining fully operational and safe will also enable access that will allow for quick restoration.[99]

In 2012, we started a programme to seismically assess all our substation buildings. We have assessed 140 of our zone substation buildings[100] 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 review indicated 53 of our buildings required seismic strengthening. A programme has been put in place to strengthen these buildings. To date, 17 buildings have been reinforced and the remaining 36 will be reinforced during the next 10 years.

Where equipment within the building has reached end of its service life, the suitability of the building to meet future demand is assessed before completing any reinforcement works. If the building is no longer suitable for the future growth of the network or replacement equipment, a new building is constructed.

Table 17.8 shows our zone substation buildings by NZSEE seismic grade.

Table 17.8: Zone substation buildings by NZSEE seismic grade

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS	% OF TOTAL
A+	>100	7	4
A	80-100	48	30
B	67-79	24	15

98 This excludes 'minor' buildings, such as sheds.

99 Zone substation buildings are considered a 'frequented location' and carry considerable community importance because of our function as a lifeline utility. Therefore, these buildings are of level 4 importance in accordance with AS/NZS: 1170.5, along with buildings used for medical emergency and surgery functions, and emergency services.

100 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.

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS	% OF TOTAL
C	34-66	39	24
D	20-33	12	8
E	<20	10	6
Not assessed100		20	13
Total		160	

Asbestos

We are conducting an extensive resampling review of our substation sites for the presence of asbestos. This should be completed by the end of FY23. The review will help inform future monitoring and remediation programmes.

To date, some non-friable asbestos boards have been found, and we will factor this into future building maintenance or modification work at these sites, such as when undertaking seismic strengthening, switchboard replacements or building extensions that may disturb the asbestos.

For any sites with high-risk friable materials, we will work with accredited asbestos removers to remediate in the short term.

Building environments

We have recently found that a few mid-life buildings have issues with proper sealing and moisture ingress, resulting in accelerated degradation of equipment with cast-resin components. In FY22, we engaged building inspectors to carry out weather tightness and environment control reviews of all our sites – the inspectors will complete their review by the end of FY23. Initial progress has identified a range of construction and maintenance issues, such as roofing reaching the end of its expected service life.

To date, 10 substations have been confirmed to have airborne mould containing toxigenic spores Stachybotrys, Chaetomium and Penicillium. Most of these sites are below the threshold for causing Health and Safety issues to personnel.

We are progressively working through the identified issues and have included allowances in our forecasts to address these issues.

17.6.4 DESIGN AND CONSTRUCT

When designing new zone substation buildings, we carefully consider the aesthetics of the proposed locations. 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 17.124: Urban zone substation building

17.6.5 OPERATE AND MAINTAIN

We routinely inspect our zone substation buildings to ensure they remain fit for purpose and that any remedial maintenance work is scheduled as required. Ensuring our buildings are secure is essential to prevent unauthorised access.

Table 17.9: Buildings preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of building. Check emergency lighting system.	Three-monthly
Detailed visual inspection, including weather tightness, checks of structure, roof, plumbing, drainage, electrics, and fittings. Check safety equipment and signs.	Yearly
Engineering review of zone substation buildings – weather tightness, and seismic assessments.	10-yearly
Routine asbestos assessment of sites with asbestos-containing materials.	Five-yearly

As part of our maintenance improvement strategies, we are investigating the use of aerial imagery (photo and thermal) in conjunction with our inspection regime for outdoor switchyards to better inform building conditions and maintenance requirements.

17.6.6 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

We aim to have all our zone substation buildings up to B grade standard or better by the end of the planning period. However, more case-by-case detailed work may show that we require more full replacements versus strengthening, which could increase the time and 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 strengthening works are based on previously completed jobs. We intend to refine these estimates further as we complete more strengthening work.

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.[101]

Coordination with network development projects

We typically build new zone substation buildings to house new indoor switchgear – from a complete switchboard renewal or a switchboard extension to serve additional feeders. Planning for these two fleets (zone substations and switchgear) is therefore carried out 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. Similarly, new greenfield zone substation buildings are planned and designed to meet the scope and needs of the overall development.

[101] Note that the cost of new buildings or building extensions is covered within the forecasts for the related asset, e.g., indoor switchgear.

17.7 LOAD CONTROL INJECTION PLANT

17.7.1 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, for example, 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 a customer's mains distribution board 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. Distribution network benefits of load control include more predictable peak demand and the deferral of distribution capacity increases. Wider benefits include a reduced need for peaking generation plants and transmission deferral.

Figure 17.135: Load control injection plant

17.7.2 POPULATION AND AGE STATISTICS

We operate 25 load control injection plants on our network, comprising both modern and aged equipment. Significant work undertaken since 2008 has resulted in a system that, while still containing some older technology plants, is able to be supported with readily available spares and technical support contracts.

A modern injection plant typically consists of a static converter and a coupling cell.

A static frequency converter describes the electronic system used to generate the signal frequency and monitor the operation of the signal injection process.

A coupling cell consists of a coupling transformer reactor unit and a number of capacitors, which are used to interface (couple) the signal frequency voltage to the HV network.

We operate a small number of injection plants with modern static frequency converters but with aged coupling cell components. These plants are referred to as mixed-aged injection plants. The age of a mixed plant is taken as the age of the static frequency converter.

We also operate three injection plants with dual frequency injection to support the older legacy frequency signalling system. After consultation with relevant industry stakeholders, we will move to industry best practice injection frequencies.

The mixed-age load control plants are compatible with our modern plants, and component replacement is handled on a case-by-case basis.

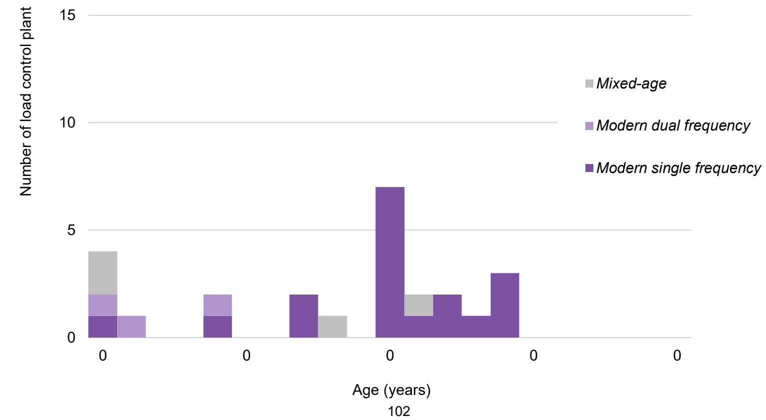
Table 17.10 summarises our load control injection plant population by type.

Table 17.10: Load control injection plant by type

TYPE	PLANT
Modern single frequency plant	18
Modern dual frequency plant	3
Mixed-age plant	4
Total	25

Figure 17.6 shows the age profile of our load control fleet.

Figure 17.16: Load control injection plant age profile



17.7.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

The condition and risks associated with the ripple injection plant assets have improved following several years of significant renewal and investment. Generally, the plants operate within design parameters and provide reliable signal levels on the network from reliable injection plants with easily accessed spares and support available.

Apart from the Waverley area network, which operates from Waverley GXP 11kV, all Powerco's network areas are now covered by ripple control signals transmitted from injection plants. Replacement receivers are available for these plants or can be implemented within the advanced metering equipment.

Pilot wire systems

Of note, is that each of the predecessor companies that now constitute Powerco had its own approach to implementing, operating, and maintaining pilot wire circuits (managed under the Overhead Conductors and Cables fleets) used for load control purposes. Often the load control pilot wire control receiver was used in conjunction with streetlight control equipment.

The question now for Powerco is to understand and categorise the use of its pilot wire circuits to determine the best ongoing management strategy and consult with meter owners as to how to achieve the desired outcome. With the development of meters with inbuilt load control receiver functionality, one of the major impediments to controlling load via ripple relay instead of pilot wire – switchboard space – is being addressed. Powerco's preferred option is to decommission hot water pilot wire circuits whenever the opportunity arises.

[102] Age of the injection plant is taken as the age of the static frequency controller, coupling cell components may be older

17.7.4 DESIGN AND CONSTRUCT

The standard for current and future plant is the DECABIT channel command format. We are in the process of rolling out DECABIT format signals in Tauranga and aim to exclusively use the DECABIT standard by FY30. 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 currently 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 in the transition.

17.7.5 OPERATE AND MAINTAIN

Because of the specialist nature of load control plant, as part of our new maintenance programmes we have established a backup and service support contract that covers our modern static installations. This contract covers annual inspections, holding of critical spares, and after-hours emergency support.

Table 17.11: Load control injection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of plant. Operational tests.	Three-monthly
Diagnostic tests, such as resonant frequency checks, signal injection levels and insulation resistance.	Yearly

17.7.6 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 have now been largely clarified and, since 2008, we have been replacing load control plant (transmitters). The majority are now of modern technology.

As mentioned earlier, we have some mixed-age plant that we replace based on condition assessments. Like most of our other ground-mounted plant and equipment, this replacement work is coordinated with other site works where possible. Some future replacements of modern plants will be driven by 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.

17.8 OTHER ZONE SUBSTATION ASSETS

17.8.1 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 122 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 steel or concrete structure, 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.

17.8.2 CONDITION, PERFORMANCE, INFORMATION AND RISKS

A key safety risk in our zone substations is managing step and touch potential hazards during faults. We use a layer of crushed metal (a type of rock) or asphalt 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 these sites.

Another key risk we manage is access and site security. Fencing around zone substations is crucial to secure the site and prevent unwanted access. Several older sites do not have adequate fencing and security systems compared with modern zone substations. Some fencing needs replacing as it is at end-of-life. We intend to bring all sites up to our fencing and security standards during the planning period. We will prioritise urban zone substations because they have the highest risk of unauthorised access.

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 buswork requires flexible conductors or sliding contacts in connection to primary plant to accommodate movement between fixed points during seismic events. A small number of 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 where identified.

17.8.3 OPERATE AND MAINTAIN

Our general zone substation preventive maintenance tasks are summarised in Table 17.12. The detailed regime is set out in our maintenance standards.

Table 17.12: 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.	Three-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.	Six-yearly

As part of our maintenance improvement strategies, we are investigating the use of aerial imagery (photo, acoustic and thermal) in conjunction with our inspection regime for outdoor switchyards to optimise our inspection routines and inform asset condition.

17.8.4 RENEW OR DISPOSE

We plan several programmes of renewal within this fleet, which are:

- Switchyard metalling
- Fencing and site security
- Lightning protection
- Switchroom building renewals

SUMMARY OF OTHER ZONE SUBSTATION ASSETS RENEWALS APPROACH	
Renewal trigger	Safety and reliability risk
Forecasting approach	Programmes
Cost estimation	Historical rates

17.9 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 injection plant
- Other zone substation assets

We plan to invest $126m in zone substation asset renewal during the planning period.

A key driver for replacing of our switchgear assets is managing safety risk, particularly risk to our field staff. Managing reliability risks from potential equipment failure, indicated by asset condition and health, is a further driver. As noted, a portion of our power transformer fleet has reached the end of service life, so we will also continue replacing this.

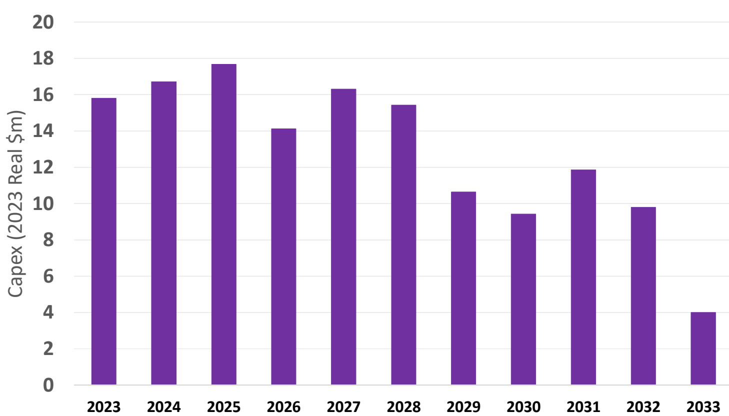
The combination of our six fleet forecasts, derived from bottom-up models, drives our total zone substations renewal expenditure. Although initially forecast as separate fleets, we combine the model outputs to allow us to identify delivery efficiencies.

We coordinate and align projects so 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 17.7 shows our forecast Capex on zone substation renewals during the planning period.

Figure 17.17: Zone substations renewals forecast expenditure



The forecast renewals expenditure for the Zone Substations portfolio represents a continuation of the expenditure levels we commenced during CPP, with our risk models now showing we are at a sustainable level of expenditure to keep our substation performance stable. In recent years, we have lifted investment levels and intend to continue at $10-15m per annum for the first half of the planning period.

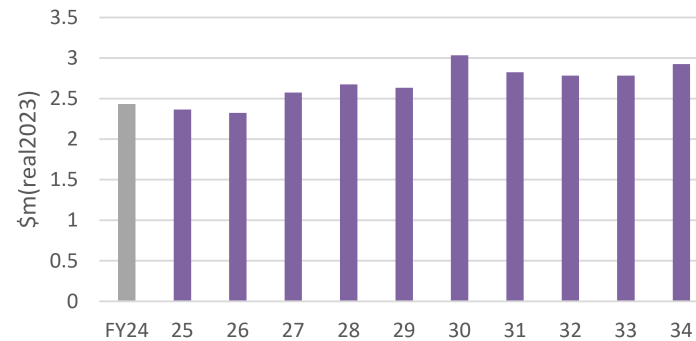
While historically some replacement has been aligned with growth augmentations, the current condition of the portfolio means that substantial renewal investment continues to be warranted.

Further details on expenditure forecasts are contained in Chapter 23.

17.10 ZONE SUBSTATIONS PREVENTIVE MAINTENANCE FORECAST

The critical role zone substations play in our network is reflected in how we maintain these assets to ensure safe and reliable operation. Approximately 20% of our preventive maintenance spending is allocated to zone substations to ensure these assets meet their end-of-life requirements. The increased expenditure from 2027 indicates our focus on using more specialised services for critical assets, such as power transformer tapchangers as well as an improved building maintenance programme to address historic weather tightness and asbestos issues.

Figure 17.148: Zone substations preventive maintenance expenditure forecast



18 DISTRIBUTION TRANSFORMERS

18.1 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 transformers, 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

We expect to invest $98m in distribution transformer renewals during the planning period. This accounts for 8% 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:

- Bring some large pole-mounted transformers into compliance with standards for seismic resilience, safety, or electrical clearances mandated by ECP34 (New Zealand Electrical Code of Practice for Electrical Safe Distances), focusing on larger units in urban areas first.

  Continue our distribution transformer replacement programmes, prioritised using asset condition, defect information and Copperleaf Common Network Asset Indices Methodology (CNAIM) modelling.

Below are the Asset Management Objectives that guide our approach to managing our distribution transformers fleets.

18.2 DISTRIBUTION TRANSFORMERS OBJECTIVES

Distribution transformers convert power at higher distribution voltages to a lower voltage for local supply – 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 various sizes, with the larger transformers generally mounted on the ground and smaller units up poles. Our transformers are oil-filled, which carries some environmental and fire risks if they fail. Proper lifecycle management of our distribution transformers assets, including correctly disposing of them 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 Table 18.1. The objectives are linked to our Asset Management Objectives in Chapter 5.

Table 18.1: Distribution Transformers portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Risk-targeted programme to bring legacy pole-mounted sites to meet modern regulation electrical clearances and consistent with industry good practice.
	Installations compliant with seismic codes to avoid injury and property damage.
	We proactively manage transformers in sensitive areas to avoid 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, e.g., transformer monitoring units. We understand current and future load needs, so units are sized correctly to supply loads now and in the future.
	Continue to refine the use of our CNAIM modelling to inform renewal decision-making.
Operational Excellence	Ensure our critical distribution substations are seismically compliant.
Asset Stewardship	Improve and refine our condition assessment techniques and processes.

18.3 POLE-MOUNTED DISTRIBUTION TRANSFORMERS

18.3.1 FLEET OVERVIEW

There are approximately 26,300 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 up to 300kVA.

Our standards set the maximum allowable capacity for a new pole-mounted transformer at 200kVA[103]. This standard means pole-mounted transformers greater than 200kVA that require replacement are likely to be converted to a ground-mounted equivalent or split into multiple transformer sites, if practical.

Following a major change to national seismic standards in 2002, some larger pole-mounted transformer structures are no longer compliant. In addition, some single or H-pole-mounted installations do not meet the electrical code of practice (ECP34) clearance and safety requirements. We will continue to replace these non-compliant units 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 those that do not meet the requirements are scheduled to be replaced with compliant pole-mounted or ground-mounted units to reduce safety risks.

Pole-mounted transformers are generally smaller and supply fewer customers than ground-mounted transformers. They are usually cheaper and quicker to replace, so reactive replacement can be undertaken quickly, affecting a relatively small number of customers. Suitable spare transformers are held in stock at service provider depots to ensure fast response times and return to service.

Figure 18.1: 100kVA pole-mounted transformer

18.3.2 POPULATION AND AGE STATISTICS

Table 18.2 summarises our population of pole-mounted distribution transformers by kVA rating. Most are very small, with almost 40% at 15kVA or below. A transformer of this size typically supplies a few houses in a rural area.

Table 18.2: Pole-mounted distribution transformers population by rating and voltage

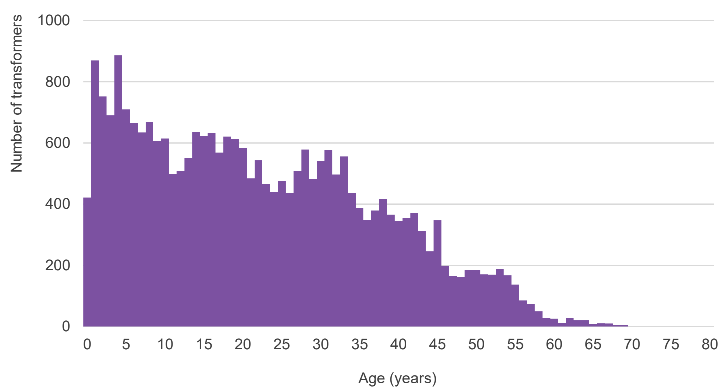
RATING	6.6KV	11/6.6KV	11KV	22KV	TOTAL
≤ 15kVA	242	158	9,784	114	**10,298**
> 15 and ≤ 30kVA	144	108	8,637	40	**8,929**
> 30 and ≤ 100kVA	77	61	6,273	27	**6,438**
> 100kVA	2		670	4	**676**
Total	**465**	**327**	**25,364**	**185**	**26,341**

[103] 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.

Local service (all ratings and voltages)	13

Figure 18.2 shows our pole-mounted distribution transformers 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 18.2: Pole-mounted distribution transformers age profile



18.3.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Failure modes

The main reasons for replacing pole-mounted transformers are age-related because of:

- External tank/enclosure damage and corrosion.
- Oil leaks through deteriorated seals.
- Deterioration of insulating oil.
- Load increases leading to insufficient capacity.

Some factors, such as tank corrosion or oil degradation (for some ground-mounted units) inform our Asset Health Indices (AHI) to forecast and prioritise replacement.

We also experience random failures each year caused by third parties, such as vehicle accidents impacting our network. We are now applying Waka Kotahi New Zealand Transport Agency modelling to determine the areas at the highest risk of vehicle impacts and relocating lines where appropriate. We have also revised our lightning protection standard, which covers new transformers.

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 a seismic event occur.

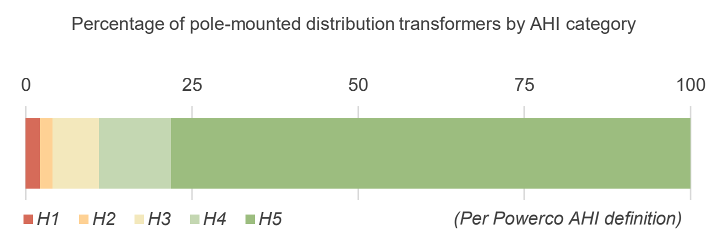
Because of the large number of failures from lightning, particularly in the Taranaki area, we are revising our surge/lightning protection requirements on transformers and other types of equipment.

Pole-mounted distribution transformers asset health

As outlined in Chapter 9, we have developed AHIs that indicate 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 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. We have set up a framework for a CNAIM model for pole-mounted transformers that we will integrate into our risk modelling approach for our other CNAIM-modelled assets in Copperleaf.

Figure 18.3 shows the overall AHI for our population of pole-mounted distribution transformers.

Figure 18.3: Pole-mounted distribution transformers asset health



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 replace a steady amount of H1 assets under reactive/defect processes.

18.3.4 DESIGN AND CONSTRUCT

To improve our seismic compliance, where practicable, we replace pole-mounted transformers above 200kVA with a ground-mounted transformer of equivalent/greater size. Where space on the ground is limited or unavailable, we use multiple transformer sites and reconfigure the Low Voltage (LV) network accordingly. Smaller pole-mounted transformers are replaced like-for-like.

We intend to fit distribution transformer monitors on some existing and new pole-mounted transformers.

We are embarking on improved data analysis to understand future network demands and distribution site capacity requirements.

18.3.5 OPERATE AND MAINTAIN

Pole-mounted transformers maintenance is minimal – generally limited to visual inspections, with repair or replacement initiated on an on-condition basis. Pole-mounted distribution transformers usually supply a smaller number of customers, and, as such, are less critical than their ground-mounted equivalents. Consequently, replacing them when they are close to failure is often more cost-effective than carrying out rigorous maintenance to extend life. Our preventive inspections are summarised in Table 18.3. The detailed regime is set out in our maintenance standard.

Table 18.3: Pole-mounted distribution transformers preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Inspect tank and general fittings for corrosion and inspect the earthing connection.	Five-yearly
Pole-top photography – aerial inspection of pole structures and mounted assets.	Five-yearly

The five-yearly inspection interval for the pole-mounted transformers fleet is based on defects analysis and historically mandated requirements. The interval also coincides with our pole inspection programme, which provides cost efficiencies.

Our pole-top photography programme complements traditional ground-based inspection by providing detailed condition data from an aerial perspective. We intend to use the learnings from this programme to improve our Maintenance Strategy.

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 rotating spares, although with increasing labour rates this may soon become uneconomic. At service provider depots, appropriate levels of spares are kept for each part of the network.

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 faulty 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.

18.3.6 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. Renewal of pole-mounted transformers usually involves replacing the pole, crossarm and ancillaries at the same time, to minimise the need for future planned outages.

SUMMARY OF POLE-MOUNTED DISTRIBUTION TRANSFORMERS RENEWALS APPROACH

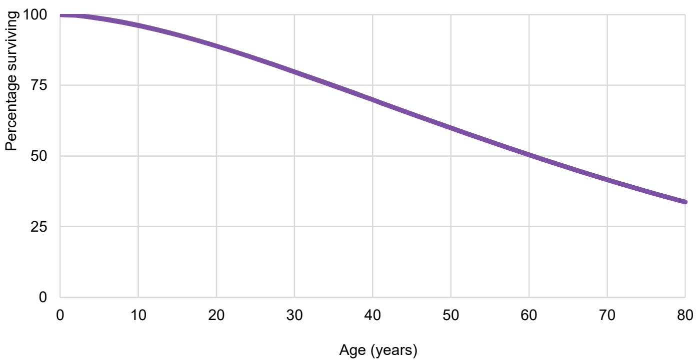
Renewal trigger	Reactive and condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

Our pole-mounted distribution transformers replacement forecast incorporates historical survivorship analysis. We have developed a survivor curve to forecast expected renewal quantities.

Figure 18.4 shows a pole-mounted distribution transformers survivor curve. The curve indicates the percentage of the transformer population remaining at a given age.

Figure 18.4: Pole-mounted distribution transformers survivor curve



We found that pole-mounted distribution transformer replacement occurs over a wide range of ages, primarily because of factors such as type, manufacturer, location, and inherent durability. Therefore, the survivorship forecasting approach is more robust than a purely age-based approach.

We have also identified larger pole-mounted distribution transformers on pole structures that may be at risk of failing during seismic events. Additionally, as described in Section 22.3.3, some large pole-mounted transformers do not comply with the standards for electrical clearances mandated by ECP34, and we have taken a targeted approach to address this.

We have approximately 459 transformer sites that do not comply with ECP34 and may be at risk when the numbers of non-compliant small and large overhead pole-mounted transformers are combined. Given the large number of sites, we prioritise based on risk. For example, priority is given to those within urban areas or next to major roads. We expect to continue this programme, either rebuilding these sites to modern design requirements or converting them to ground-mounted installations, ensuring they meet today's safety standards for both seismic events and safety clearances.

As discussed in Section 18.3.3, our pole-mounted transformer fleet is maintained in good health by our condition-based renewal programme.

Pole-mounted transformers refurbishment

Sometimes good-condition units are removed from the network for non-condition reasons, such as because network demand increases. Before entering the pool of rotable spares, these units undergo minor repairs, such as repainting.

Pole-mounted transformers disposal

When pole-mounted distribution transformers are replaced for condition reasons, they are decommissioned and disposed of. The principal transformer components of steel, copper and oil are recycled.

The oil in pre-1970 transformers often contained polychlorinated biphenyls (PCB), which are 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 various growth-related factors, including new developments or increases in customer load through customer-initiated works (CIW).

Sometimes, a replacement 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 minimise cost and customer disruptions.

Meeting our portfolio objectives

Customers and Community: Pole-mounted transformer replacements are, where possible, coordinated with other works to minimise customer disruption.

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.

18.4 GROUND-MOUNTED DISTRIBUTION TRANSFORMERS

18.4.1 FLEET OVERVIEW

There are approximately 9,100 ground-mounted distribution transformers on our network. These are usually located in our underground networks, typically servicing suburban areas, CBDs, or our large commercial or industrial customers.

Because of foundation and cabling requirements, ground-mounted transformers are generally more expensive to install and maintain than pole-mounted transformers, and generally serve larger network areas than typical pole-mounted units.

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 and industrial areas. Larger units of the fleet – ranging from 2-3MVA and above – are predominantly installed at industrial sites.

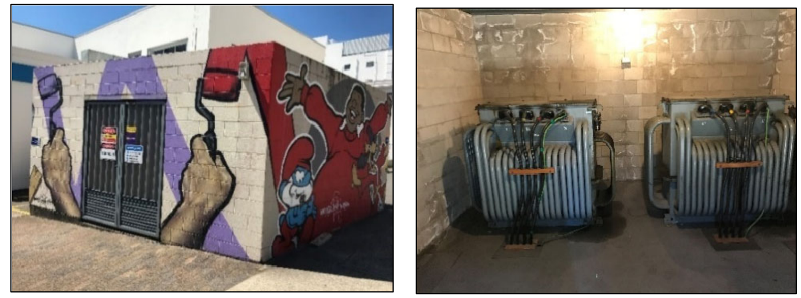
Most of the fleet are berm-mounted, either within a road reserve or in their own easement and are stored in a variety of legacy lightweight steel, fibreglass or cast concrete enclosure types or newer all-in-one single pad solutions containing the transformer and LV panels we started installing in the 1980s.

Recently, we have approved some of the new enclosure types that include provision for larger High Voltage (HV) switchgear solutions and have started to install a small number of these where we require additional capacity.

Figure 18.5: 300kVA ground-mounted transformer

In urban areas, some transformers are enclosed in a customer's building, housed in standalone concrete block enclosures or, at a small number of outdoor sites, in fenced-off areas. We have about 400 "building" kiosks, generally housing the HV switchgear, transformer, LV panel and associated cabling.

Figure 18.6: Concrete block distribution substation



18.4.2 POPULATION AND AGE STATISTICS

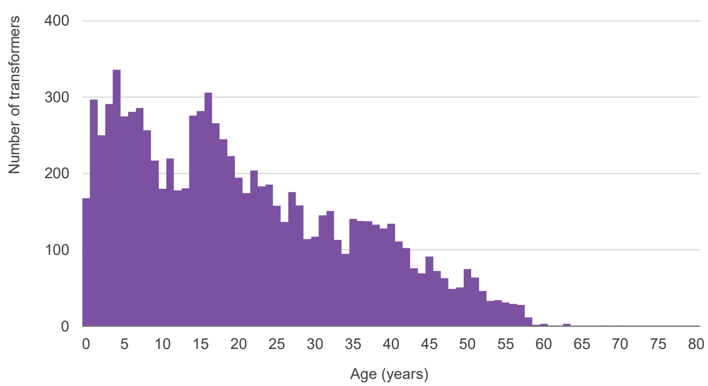
Table 18.4 summarises our population of ground-mounted distribution transformers by kVA rating.

Table 18.4: Ground-mounted distribution transformers population by rating

RATING	6.6KV	11/6.6KV	11KV	22KV	TOTAL
≤ 100kVA	10	5	2,977	6	**2,998**
> 100 and ≤ 200kVA	16	10	2,206	3	**2,235**
> 200 and ≤ 300kVA	17	10	2,195	4	**2,226**
> 300kVA	5	3	1,634		**1,642**
Total	**48**	**28**	**9,012**	**13**	**9,101**
Local service (all ratings and voltages)					**116**

Figure 18.7 shows our ground-mounted distribution transformers age profile.

Figure 18.7: Ground-mounted distribution transformers age profile



The ground-mounted transformer fleet is relatively young, with an average age of 20. Ground-mounted transformers generally have longer expected lives (55 to 70 years) than pole-mounted units (45 to 60 years). This is because ground-mounted transformers are more frequently maintained due to their accessibility and higher criticality. They are also often located inside enclosures, providing greater protection from environmental degradation. Because of the low average age of this fleet, we expect only a relatively small number of condition-based renewals during the planning period.

18.4.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Failure modes

The main reasons for replacing ground-mounted transformers are age-related because of:

- External tank/enclosure damage and corrosion.
- Oil leaks through deteriorated seals.
- Deterioration of insulating oil.
- Load increases leading to insufficient capacity.

We also experience many random failures each year caused by third parties, such as vehicle accidents impacting our network. We are now applying Waka Kotahi NZTA modelling to determine the areas at the highest risk of vehicle impacts and relocating transformers where appropriate. We have also revised our lightning protection standard, which covers new transformers.

LV panels

Renewals of LV panels can occur separately to the transformer unit, typically in the case of reactive replacement following a failure or as part of our type of issue replacement programmes. LV panels fail mainly because of overheating or insulation failure and can often result in a fire. While rare, we have had failures of LV boards. We investigate all failures to help us better detect and identify these points of failure at 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 deteriorating J-type fusing. There are approximately 107 porcelain J-type fused boards of 300kVA and above across the network. We are improving our inspections to identify these boards and are taking a proactive approach to replacing them.

Type issues

Some of our older lightweight kiosk types make it difficult to inspect transformers properly for oil leaks or rust. We generally include these for renewal when doing other work on the network. We have approximately 100 “T-blade” transformers, which are a type of compact transformer with inbuilt three-way switches used heavily in our Valley networks. Because of historic reliability issues with these switches, we no longer operate the switchgear and have a prioritised plan to replace these with modern fusing arrangements where they are directly on the main trunks of our feeders. We expect to complete this towards the end of the current planning period.

Distribution substation buildings – seismic performance

We have identified that some of our older distribution substation buildings do not meet current requirements for seismic performance. We are systematically working through identifying common issues among our various building designs and investigating the seismic capability of the buildings to ensure we meet our commitments as a lifeline utility by addressing any weaknesses via strengthening or renewal programmes.

We prioritise strengthening or reconstruction work on sites that supply customers critical to disaster recovery following an earthquake, such as emergency services (police, fire, ambulance), medical centres and hospitals, Civil Defence centres and three-waters infrastructure (storm water, drinking water, wastewater).

More on our General Resilience strategy can be found in Chapter 7.

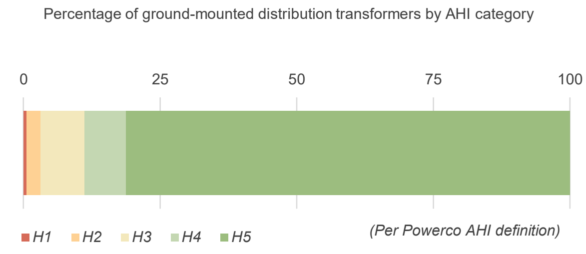
> **Meeting our portfolio objectives**
>
> Customers and Community: We are embarking on a programme to investigate the seismic capability of distribution substation buildings to ensure we meet our commitments as a lifeline utility by addressing any weaknesses via strengthening or renewal programmes.

Ground-mounted distribution transformers asset health

As outlined in Chapter 9 we have developed CNAIM models that reflect the health and risk of our asset fleets. For ground-mounted transformers, end-of-life is defined as when the asset fails because of condition drivers.

Figure 18.8 shows the overall AHI for our population of ground-mounted transformers as calculated by our CNAIM model.

Figure 18.8: Ground-mounted distribution transformers asset health



As with the pole-mounted fleet, the overall health of our ground-mounted transformers is generally good. CNAIM 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 ageing of some of the 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.

18.4.4 DESIGN AND CONSTRUCT

The scope of the transformer monitoring initiative discussed in Section 18.3 also includes the ground-mounted fleet. Some ground-mounted distribution transformers may be fitted with monitors when renewed. We are also re-specifying the design of our new ground-mounted distribution transformers to ensure we can install transformer monitors on them in the future.

18.4.5 OPERATE AND MAINTAIN

As most ground-mounted transformers are in the road reserve and easily accessible to the public, we conduct frequent inspections of our sites to ensure they are secure. Additionally, because of their size and the number of customers they supply, we tend to carry out additional maintenance tasks, such as oil tests, to monitor rarer failure modes.

Our distribution substation buildings and kiosks usually house a combination of HV switchgear, distribution transformers, LV panel and associated cabling. We coordinate the maintenance of these components to minimise costs.

Our various preventive maintenance tasks are summarised in Table 18.5. The detailed regime is set out in our maintenance standard.

Table 18.5: Ground-mounted distribution transformers preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Ground-mounted distribution transformers	Visual safety inspection – check asset is secure.	Six-monthly
	General visual inspection, check transformer tank, fittings for corrosion and damage. A thermal scan of connections and log Maximum Demand Indicator (MDI) readings.	Yearly
	Detailed inspection, thermal scan of connections and condition assessment. Oil sample on units >499kVA.	Five-yearly
Distribution transformer kiosks and buildings	General visual inspection of the kiosk/building – access or security, weather tightness, associated infrastructure, and vegetation waterways are in good order.	Six-monthly
	Detailed condition assessment and general clean of the kiosk/building – access or security, weather tightness, associated infrastructure, vegetation waterways.	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 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. We use 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.

Typical corrective work following inspections includes:

- Re-levelling base pads.
- Replacing blown fuses.
- Removing vegetation from enclosures.
- Removing graffiti.
- Corrosion treatment.

18.4.6 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. We proactively renew ground-mounted distribution transformers using prioritisation criteria, such as failure consequence, safety risk, and security.

When our buildings or kiosks are assessed as being seismically prone, we will strengthen the buildings or, in cases where the cost of replacement/remediation is prohibitive, we will rebuild the site as a modern compact substation.

Meeting our portfolio objectives

Safety and Environment: To reduce public safety risks, we proactively replace ground-mounted distribution transformers before they fail.

SUMMARY OF GROUND-MOUNTED DISTRIBUTION TRANSFORMERS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

We have recently calibrated our CNAIM models to assist in replacement forecasting and replacement prioritisation. This analysis allows us to manage the fleet on a condition and risk basis. As a result, we can maintain the current level of risk without further increasing expenditure by prioritising higher-risk assets for replacement and deferring the 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. We have highlighted these type issue LV boards in our current round of inspection, so these are more easily integrated into our renewal programmes, where appropriate.

Ground-mounted transformers refurbishment

Life-extending refurbishment is rarely undertaken for the ground-mounted distribution transformers fleet because installing a new transformer is usually more cost-effective. As with the pole-mounted transformers fleet, good-condition units are sometimes removed from the network for non-condition reasons, such as increases in network demand. Before entering the pool of rotable spares, these units undergo minor repairs, such as repainting.

Ground-mounted transformers disposal

When ground-mounted distribution transformers are replaced for condition reasons, they are decommissioned and disposed of. 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 various growth-related causes but is most often driven by specific customer requirements through CIW.

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.

18.5 OTHER DISTRIBUTION TRANSFORMERS

18.5.1 FLEET OVERVIEW

This section covers our remaining distribution voltage regulating equipment, such as conversion and SWER isolation transformers, capacitors, and voltage regulators. The population of this sub-fleet is a relatively small part of the Distribution Transformers portfolio and is quite varied.

Conversion transformers

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. While physically similar to distribution transformers, these transformers typically have a higher capacity and supply a bigger downstream distribution network than a typical distribution transformer. Therefore, in the event of failure, they tend to have a higher reliability impact than a distribution transformer. They can be found in the remaining parts of the 6.6kV network we have in Taranaki, and there is still a small number on the 22kV network in our Rangitikei area.

Single Wire Earth Return (SWER) transformers

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

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

Voltage regulators are typically two or three-bank, single-phase 11kV transformers fitted with controls to measure the network voltage and correct this back within regulated limits. 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 a heavier load. The fleet is a mix of pole-mounted and ground-mounted. We also manage a small number of mobile units that can assist in voltage support during planned network outages.

Figure 18.9: Collection of other distribution transformers

Capacitors | Voltage regulator | SWER isolation transformer

18.5.2 POPULATION AND AGE STATISTICS

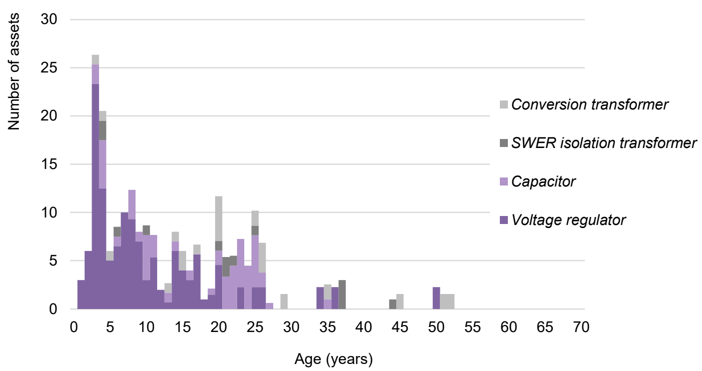
Table 18.6 summarises our population of other distribution transformers by type. Voltage regulators make up the largest portion of the fleet. We have been installing increasing numbers of these devices during the past 15-20 years to manage voltage on the network.

Table 18.6: Other distribution transformers population by type

TYPE	NUMBER OF ASSETS	% OF TOTAL
Voltage regulator	133	60
Capacitor	50	23
Conversion transformer	25	11
SWER isolation transformer	13	6
Total	221	

Figure 18.10 shows the age profile of our other distribution transformers. The population is young, with an average age of 14 years. This is largely because of our recent investment in voltage regulators and capacitors to help manage voltage. A small number of assets exceed their expected life of 50 years.

Figure 18.10: Other distribution transformers age profile



18.5.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

These other types of 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. Therefore, they undergo a more comprehensive set of tests than pole-mounted transformers.

Similar to other secondary systems assets, such as protection relays and Supervisory Control And Data Acquisition (SCADA) Remote Terminal Units (RTU), we expect that controllers for voltage regulators will need replacement much earlier than primary equipment, so we have included an allowance in our forecast.

Given the young age of the fleet, its condition is relatively good, with no known type issues. We do not anticipate a need for a significant renewals programme and, for now, envision replacing these transformers when they approach the end of their expected service life.

Spares

Given the long lead times for voltage regulators and their controllers, we hold a number of 200kVA and 300kVA regulator tanks as critical spares to keep repair response times short.

18.5.4 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, 200A and 300A nominal capacity.

18.5.5 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 contain mechanical switching devices and electronic controls and require a more thorough maintenance regime.

Capacitors are built differently than transformers, have different types of failure modes, and have their own maintenance regime.

Our various preventive maintenance tasks are summarised in Table 18.7. The detailed regime is set out in our maintenance standards.

Table 18.7: Other distribution transformers 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, and leaks.	Five-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 the voltage regulator and housing, check asset is secure (ground-mounted only).	Six-monthly
	Thermal imaging scan.	2.5-yearly
	Inspect tank and general fittings for corrosion. Carry out oil dielectric strength, acidity, and moisture testing.	Five-yearly
	Winding insulation tests, tapchanger operational checks	15-yearly
SWER and conversion transformers	See pole and ground-mounted distribution transformer maintenance.	

18.5.6 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 TRANSFORMERS 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

Several solutions for voltage issues exist, particularly on long rural feeders. It is usually more cost-effective to install a voltage regulator than to upgrade the overhead line or to install a Remote Area Power Supply (RAPS) if the line also requires renewal.

As rural businesses grow, such as the dairy sector, 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.

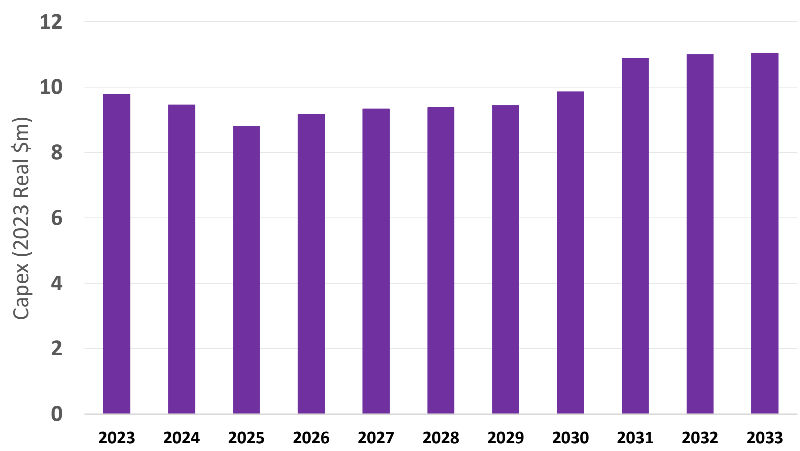
18.6 DISTRIBUTION TRANSFORMERS RENEWALS FORECAST

Renewal Capex in our Distribution Transformers portfolio includes planned investments in our pole-mounted, ground-mounted, and other distribution transformers fleets. We plan to invest approximately $98m in distribution transformers renewals during the planning period.

Renewals are derived from bottom-up models. These forecasts are volumetric estimates, which are explained in Chapter 24. 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.

Figure 18.11 shows our forecast Capex on distribution transformers during the planning period.

Figure 18.11: Distribution transformers renewal forecast expenditure

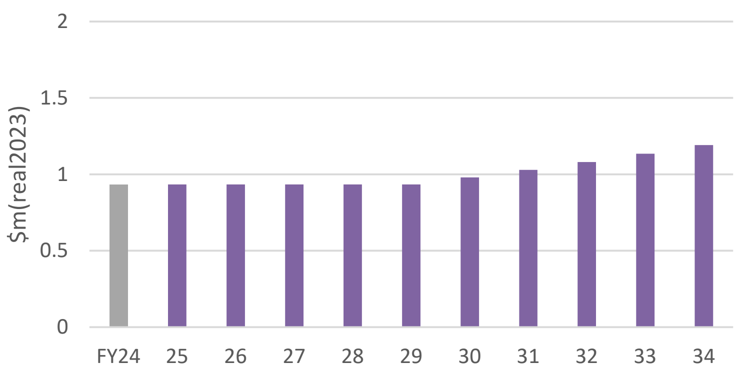


Forecast renewal expenditure is generally in line with historical levels.

18.7 DISTRIBUTION TRANSFORMERS PREVENTIVE MAINTENANCE FORECAST

Our fleet is well maintained, with most maintenance activities focused on regular safety inspections and corrosion prevention. Major maintenance is predominantly driven by performance and reliability, allowing us to manage costs.

Figure 18.12: Distribution transformers preventive maintenance forecast



Distribution transformers account for approximately 8% of our preventive maintenance spend, which targets corrosion management and public safety. The deployment of the LV monitoring strategy will add further to the condition assessment knowledge of these assets, which may see the maintenance approach evolve in the future.

19 DISTRIBUTION SWITCHGEAR

19.1 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

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

We plan to invest $128m in distribution switchgear renewal during the planning period.

Continued investment is needed to support our Safety and Reliability objectives. Renewal Capex is driven by:

- Continual phasing out of our outdoor oil RMU fleet and replaced with modern arc flash-rated switchgear, to reduce operator and public safety risk.
- Retirements of older orphaned switchgear types to standardise our fleet.
- Continuation of our programme of arc flash safety upgrades on our older 11kV switchboards at the Kinleith pulp and paper mill – estimated for completion FY31.

Below we set out the Asset Management Objectives that guide our approach to managing our distribution switchgear fleets.

19.2 DISTRIBUTION SWITCHGEAR OBJECTIVES

The Distribution Switchgear portfolio contains a diverse population of switching assets with a wide range of types and manufacturers.

These are generally separated into off-load (for isolation) or on-load switches (load break).

Load break switchgear technology has evolved with general improvements to operator safety and reliability, and reductions in intrusive maintenance requirements, particularly in the movement from oil quenched switchgear to gas and vacuum interrupter types.

While oil switchgear is no longer used for new installations, because of the age of the network, we still have large quantities of oil-based switchgear – about half of the ground-mounted switchgear fleet is oil-based.

We have defined portfolio objectives for our distribution switchgear fleets to guide our asset management activities. These are listed in Table 19.1. The objectives are linked to our Asset Management Objectives as set out in Chapter 5.

Table 19.1: Distribution Switchgear portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No injuries from explosive failure or maloperation of ground-mounted switchgear.
Customers and Community	Minimise interruptions to customers because of equipment failure via timely maintenance or replacement.
	Ensure that switchgear is available to be used as intended, providing the required network flexibility to minimise customer interruptions during network switching and facilitating rapid restoration of outages.
Networks for Today and Tomorrow	Increase the use of Supervisory Control and Data Acquisition (SCADA) and remote switching to further improve fault isolation and restoration times for customers.
	Continue to evaluate new switchgear technology for general or specific use on the network, with a view to improving network operation and safety, and managing lifecycle cost.
Asset Stewardship	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.

19.3 GROUND-MOUNTED SWITCHGEAR

19.3.1 FLEET OVERVIEW

Ground-mounted switchgear provides the ability to isolate, protect and switch our underground networks. Ground-mounted switchgear includes RMUs, switches, fuse switches, links, and associated enclosures.

The fleet comprises a range of makes and models with various insulating media because of advances in technology over time. During the past decade, we have predominantly installed SF_6 (sulphur hexafluoride) switchgear but continue to operate a large fleet of oil-filled and cast resin switchgear.

In urban areas, while some of our ground-mounted switchgear is installed within purpose-built switchrooms, most are standalone in the road berm or within lightweight kiosk enclosures.

Figure 19.1: Ground-mounted switchgear

19.3.2 POPULATION AND AGE STATISTICS

Table 19.2 shows our population of ground-mounted switchgear by insulating media.

This fleet has significant diversity because of the age profile and the range of makes and models – switchgear from more than 20 manufacturers is used on our network. This diversity increases maintenance and servicing costs, as well as the training required for field personnel to operate this wide range of switchgear. In addition, older switchgear does not meet our modern requirements around arc flash containment, presenting a risk to operators and the public under failure.

As such, our replacement strategies include the removal of older and less represented "orphan" models from the fleet.

Table 19.2: Ground-mounted switchgear population by type

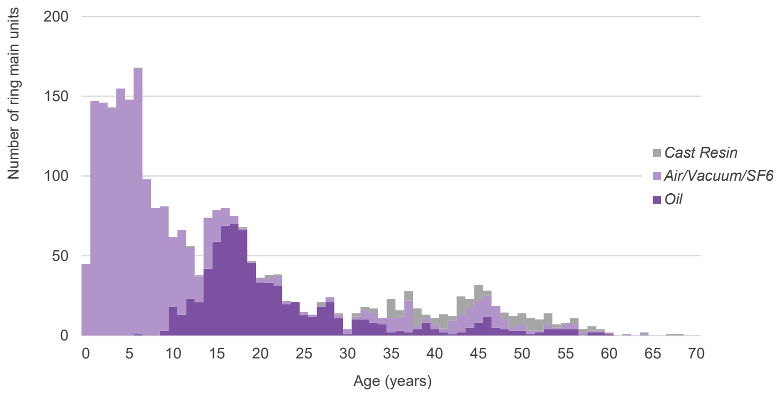
INSULATION TYPE	NUMBER OF RING MAIN UNITS	NUMBER OF INDIVIDUAL SWITCH UNITS
Oil	772	1,015
Air/Vacuum/SF_6	1,615	194
Cast resin	160	12
Total	2,547	1,221

Meeting our portfolio objectives

Asset Stewardship: Asset replacement over time will remove older oil 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 19.2 shows the age profile of our population of RMUs.

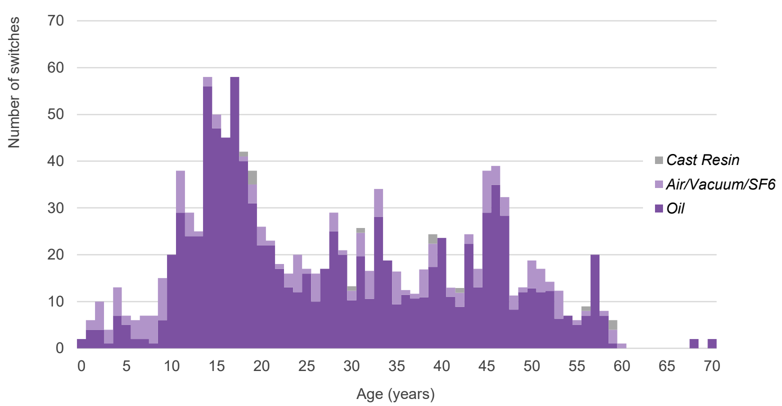
Figure 19.2: RMU age profile



We now install SF_6 and vacuum RMUs because of their improved safety measures and lower maintenance requirements compared with legacy models.

Figure 19.3 shows the age profile of our population of standalone ground-mounted switches, which we often connect as a bank of switch and fuse ways. These types of switches generally pre-date RMUs, and they have a much greater level of manufacturer diversity.

Figure 19.3: Individual switch age profile



Many units exceed their expected life of approximately 45 years. As a result, we expect an increasing amount of renewals in this area, noting that renewal decisions are based on asset condition and risk.

19.3.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

While generally in good condition, because of the quantities of switchgear we operate, their proximity to operators and the public, and the high impacts of failure in service, we constantly review potential failure modes to ensure they are well understood, and options for mitigation are implemented.

Details of potential issues and mitigation measures for each general type are discussed below.

Cast resin switchgear

Our Magnefix cast resin switchgear fleet has generally performed well when maintained in dust-free, dry environments. We have observed that some installations in poor environments can lead to electrical tracking and deterioration. This issue was prevalent in our coastal networks in Taranaki, Thames, Valley, and Waikato, so we are continuing to phase out this equipment in these regions.

The significant Magnefix fleet in the Palmerston North network will be kept - opting for a like-for-like replacement, because of other type switchgear having a larger footprint causing costs and installation complexity to increase dramatically. Because of some limitations in automation and operational constraints when transferring load, we have been working on automating key network locations with new three-phase switchgear.

Oil switchgear

Oil switchgear, installed from the early 1960s to the mid-2000s, is relatively cost-effective and simple in design for high-voltage protection and switching, which is why it represents a significant portion of our current operational fleet. However, compared with modern switchgear, it requires more regular maintenance to monitor oil quality and, under certain circumstances, has the potential to fail explosively, which has happened in New Zealand, Australia, and the United Kingdom. For this reason, we have adopted remote operating devices, such as mechanical actuator units or lanyards, when operating oil switchgear, to help protect our operators in the event of a failure while switching.

Because of the age of the fleet, the majority of our oil switchgear is no longer supported by their manufacturers, with a lack of spares impacting their serviceability.

Some types of oil switchgear have minimal designed electrical clearances within their tanks, which makes them more susceptible to failure because of internal deterioration. As a small number of failures have occurred within New Zealand, we are targeting models installed in densely populated public areas for replacement.

We have also experienced failures on some earlier busbar extension chambers. The manufacturer identified this issue and released service instructions, but the problem was not systematically corrected. We are now fixing this issue through our revised intrusive maintenance programme. Because of the high impact of failure, we carefully mitigate the failure risk of the fleet through routine maintenance, condition monitoring, operating procedures, and operating restrictions. Where they are available, we also require remote switching or portable actuators to reduce the likelihood of operator injury.

Risk is also impacted by the installation context. We have subdivided our oil RMU fleet into two major sub-categories:

- Outdoor RMUs
- Indoor RMUs

Outdoor RMUs

A significant proportion of our ground-mounted switchgear fleet is located outdoors, much of it in road berms. We have found that this type of switchgear degrades faster in outdoor environments because of rust, particularly in our coastal networks in Tauranga, Taranaki, and Whanganui. We schedule replacement based on type, condition, and location to manage public safety risks.

Indoor RMUs

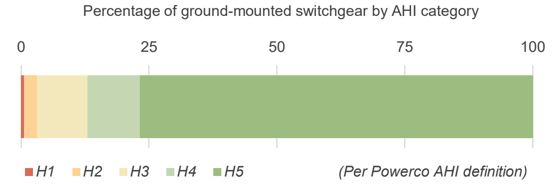
The indoor switchgear fleet is generally older than our outdoor fleet but is in good condition considering its age. In some older distribution substations, arc flash risk, combined with a restricted operating position, can limit effective egress, presenting a risk to our field staff. We are prioritising remedial work for these situations, according to their risk profiles.

Ground-mounted switchgear asset health

As outlined in Chapter 9, we use Common Network Asset Indices Methodology (CNAIM) models that indicate the remaining life of each asset. These models categorise each asset's health based on a set of rules that enable 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 Asset Health Indices (AHI) are based on multiple data sources, including asset age, environmental situation, condition, historical performance and known type issues. Figure 19.4 shows the current overall AHI for our ground-mounted switchgear fleet.

Figure 19.4: Ground-mounted switchgear asset health



A small proportion of the fleet is assigned health grades of H1 and H2. Most of the assets with these grades are poor-condition switchgear, which we plan to replace.

19.3.4 DESIGN AND CONSTRUCT

Ground-mounted distribution switchgear is classified as class A equipment 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 operators and the public, we require new switchgear 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 so that any people near the switch are safe.

Oil switchgear was not tested for internal arc flash containment and does not have an IAC classification.

Newly 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 allows equipment to be operated without an observer, this type of automation is only applied to new installations with enclosures designed with full arc flash containment.

Switchgear is generally berm-mounted and therefore exposed to weather deterioration and damage from vehicles. We minimise the incidence of damage by carefully choosing the location of switchgear and, in some cases, by installing protective bollards.

19.3.5 OPERATE AND MAINTAIN

Regular inspection and maintenance of our ground-mounted switchgear are required to ensure the safe operation of our distribution network. As this switchgear is often located in areas accessible to the public, the enclosures must always be locked and secure.

Our various preventive maintenance tasks are summarised in Table 19.3. The detailed regime is set out in our maintenance standards.

Table 19.3: Ground-mounted switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General inspection of switchgear buildings/enclosures.	Six-monthly
General inspection of switchgear condition. Partial discharge and acoustic diagnostic tests.	Yearly
Switchgear service and operating checks. Diagnostic thermal scan.	Five-yearly
Major maintenance, oil sample test and oil replacement for oil switchgear.	10-yearly

Manufacturers' recommendations and our experience in maintaining and operating each asset type within our local operating environments have determined maintenance requirements. Our six-monthly and yearly inspections are non-invasive safety-driven inspections. Switchgear components usually have a limited number of operations they can perform, with SF_6 or vacuum gear being "non-maintainable". In contrast, older style oil switchgear can undergo major servicing, but an outage is required to complete this.

We have an intensive maintenance programme for our oil filled RMU fleet, which includes oil analysis, oil replacement, internal inspection, and minor repairs to:

- Ensure the fleet can operate safely and reliably until end-of-life.
- Supplement our current condition data to better inform our replacement programme.
- Proactively identify any underlying type issues with our older fleet.

To align with our condition-based maintenance strategy and build on this maintenance programme, we continue investigating suitable online oil condition monitoring devices.

Corrective actions for switchgear include:

- 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.

19.3.6 RENEW OR DISPOSE

Renewal plans for ground-mounted distribution switchgear are now integrated into our Copperleaf system via CNAIM models.

Renewal decisions are made on a risk-prioritised basis, combining the condition and likelihood of failure with the consequences of failure, safety risks, customer service, lifecycle costs, and environmental impacts. This approach prioritises expenditure on equipment with the highest combined likelihood and consequences of failure, predominantly older oil types situated in publicly accessible areas. Switchgear with industry known type issues is given high priority for replacement. The individual sites are then prioritised according to CNAIM risk rankings.

We do not foresee wholesale removal of our cast resin switchgear population at this time but expect the older portions of this fleet to be coming up for replacement, and we will prioritise replacement based on asset condition and potential network performance impact.

SUMMARY OF GROUND-MOUNTED SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	CNAIM
Forecasting approach	CNAIM
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our CNAIM models also allow us to develop asset health and risk forecasts to determine our future renewal requirements.

Our planned investment will address existing assets identified as having industry known type issues, or those in poor health. Overall, in planning switchgear replacement programmes, we aim to retain our present risk profile.

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 the visual impact on the surrounding neighbourhood.

Where possible, we coordinate ground-mounted switchgear replacements with underground cable and ground-mounted distribution transformer renewals to minimise costs and disruption to customers and the community. New switches are procured with remote operation capability, so we can use this capability to implement network automation schemes if required.

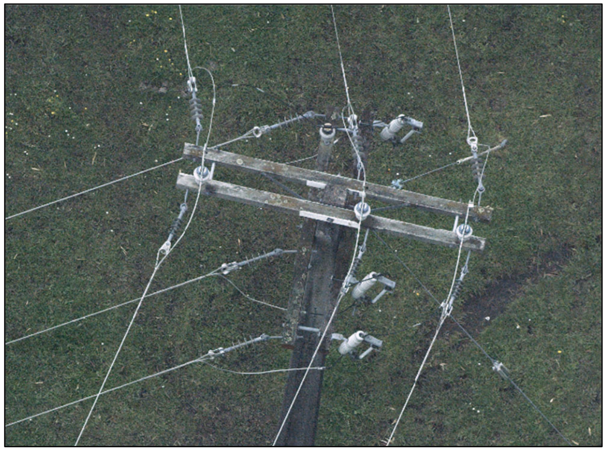
19.4 POLE-MOUNTED FUSES

19.4.1 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. However, several feeder trunks still use them as in-line fusing for distance protection. These fuses are principally used outdoors at distribution voltages.

Pole-mounted fuses are non-ganged, single pole devices that are mechanically simple, using mature and proven technology. High Voltage (HV) fuses occur most commonly as expulsion drop out (EDO) fuses and consist of a tube through which a fuse element passes. Under fault conditions, the fault current melts the fuse element allowing the EDO to drop out of the fuse holder isolating the fault.

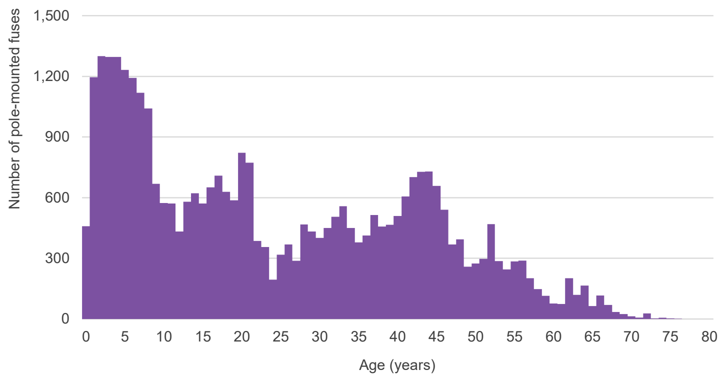
Figure 19.5: Pole-mounted drop out fuse



19.4.2 POPULATION AND AGE STATISTICS

The population of our pole-mounted fuse fleet is approximately 35,000. Many manufacturers are represented, but the equipment is all very similar in design and function.

Figure 19.6: Pole-mounted fuses age profile



19.4.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Risks

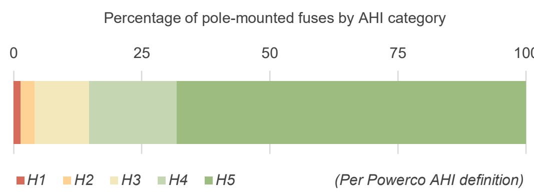
EDOs that fail to operate will cause upstream protection devices (reclosers, circuit breakers) to clear the fault, increasing the network outage area.

Pole-mounted fuses asset health

As outlined in Chapter 9, we have developed AHI that indicate the remaining life of each asset. Our AHI models categorise asset health based on defined rules. For pole-mounted fuses, we are developing our AHI using a combination of age, type, condition, and environment.

Figure 196 shows the current AHI for our population of pole-mounted fuses.

Figure 19.7: Pole-mounted fuses asset health



The AHI profile indicates that the fleet is broadly in good condition, with approximately 15% likely to require renewal during the next 10 years (H1-H3). The AHI profile also shows that some fuses require renewal in the short term (H1). These will be identified and rectified through our condition assessment and defect processes.

19.4.4 DESIGN AND CONSTRUCT

EDO selection is based on the network's specific protection and operating needs.

The EDOs used on our network must comply with industry standards. Before a new type of EDO can be used on the network it must be evaluated to ensure the equipment is fit for purpose.

19.4.5 OPERATE AND MAINTAIN

Our EDO fleet is inspected as part of our overhead line inspections. The inspection criteria include condition and defects. Any defects identified are managed via our defect process. The inspection task and frequency are summarised in Table 19.4. The detailed regime is set out in our maintenance standards.

Table 19.4: Pole-mounted fuses preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection for corrosion and defects.	Five-yearly

19.4.6 RENEW OR DISPOSE

Our renewal strategy for EDOs is based on AHI. Alternatively, we may target the renewal of known problematic types or those nearing end-of-life during network overhead renewal projects. Fuses are also replaced when required.

The consequences of failure are minor, and replacement can be carried out quickly.

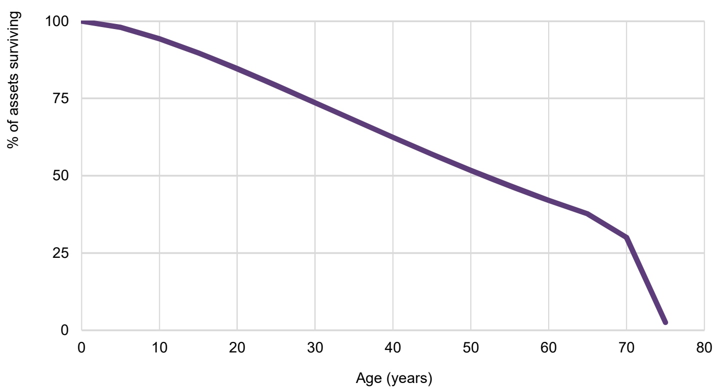
SUMMARY OF POLE-MOUNTED FUSES RENEWALS APPROACH	
Renewal trigger	Reactive
Forecasting approach	AHI
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our EDO replacement forecast is based on AHI scores.

Figure 197 shows the pole-mounted fuse survivor curve. The curve indicates the percentage of the population remaining at a given age.

Figure 19.8: Pole-mounted fuse survivor curve



Based on AHI EDOs with a low score will be targeted for replacement in annual renewal plans.

Coordination with network development projects

Before renewing a network EDO, we conduct an engineering analysis of the location. This considers capacity, functionality, and the network requirements for equipment in that position. The engineering analysis may find that the EDO needs to be upgraded to an air break switch (ABS), recloser, or even retired completely.

19.5 POLE-MOUNTED SWITCHES

19.5.1 FLEET OVERVIEW

The pole-mounted switch fleet is comprised of vacuum, gas, ABS, and isolators.

Air break switch (ABS)

An ABS is a ganged switch that is manually operated. It is used for network sectionalising and isolating subtransmission and distribution networks. ABS is critical in fault finding, creating open points between feeders, and isolating the network for maintenance or construction works.

An ABS requires regular maintenance to ensure it operates correctly.

The ABS has undergone various design and material specification improvements over time. Newer types have improved alignment, which has reduced maintenance requirements and operating issues. They also have better corrosion performance.

Two types of ABS are used on the network: load break and non-load break.

Distribution automated switch (DAS)

DAS (vacuum and gas) is a load break device installed on the overhead distribution network. It is not rated for breaking fault current. A DAS is installed where there is a requirement to open or close network switching points when feeders are energised and have load flowing. A DAS can be manually operated or controlled remotely if required.

Figure 19.9: Air break switch (ABS)

19.5.2 POPULATION AND AGE STATISTICS

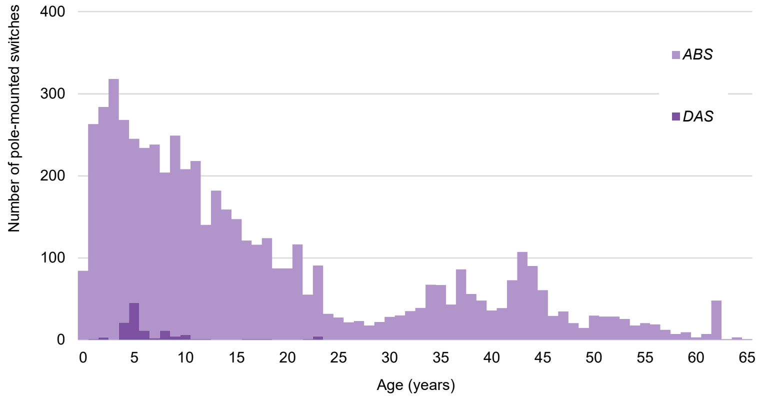
We have approximately 5,600 pole-mounted distribution switches on our network. There is significant diversity in our ABS fleet, with many manufacturers represented. The diversity increases the costs of maintaining equipment.

Table 19.5 summarises our population of pole-mounted switches by type.

Table 19.5: Pole-mounted switches population by type

TYPE	NUMBER OF ASSETS	% OF TOTAL
ABS distribution	5,527	98
DAS	114	2
Total	**5,641**	

Figure 19.10: Pole-mounted switches age profile



19.5.3 CONDITION, PERFORMANCE, INFORMATION 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. Switch operators are required to wear PPE.

If an ABS or DAS cannot be operated, alternative switching will be required, disrupting energy supply to a greater area of the network.

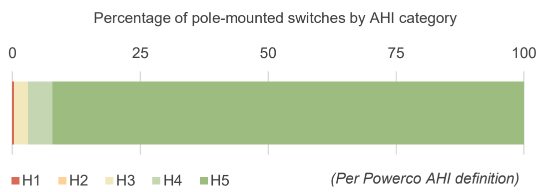
We have some installations where distribution ABS was installed underneath sub-transmission overhead lines. During load breaking operation of the switch, there is a risk that arcing during operation could cause flashover to the circuits above, leading to explosive switch failure and loss of supply. We are identifying the high-risk sites to prioritise the replacement of existing switches with enclosed switches.

The risk associated with a defective ABS population is the mechanical failure of the switch under operation.

Pole-mounted switches asset health

As outlined in Chapter 9, we have developed AHI that indicate the remaining life of each asset. Our AHI models categorise asset health based on defined rules. For ABS and DAS, we are developing our AHI using a combination of age, type, condition, and environment.
Figure 19.11 shows the current overall AHI for our pole-mounted switches fleet.

Figure 19.11: Pole-mounted switches asset health



The figure indicates that about 3% of our fleet will require renewal in the next 10 years (H1-H3).

19.5.4 DESIGN AND CONSTRUCT

ABS and DAS selection is based on the specific operating needs of the network.

The ABS and DAS used on our network must comply with industry standards. Before a new type of ABS or DAS can be used, it must be evaluated to ensure the equipment is fit for purpose.

19.5.5 OPERATE AND MAINTAIN

Our ABS and DAS fleet is inspected as part of our overhead line inspections. The inspection criteria include condition and defects. Any defects identified are managed via our defects process. The inspection task and frequency are summarised in Table 19.6. The inspection criteria are set out in Powerco's standards.

Table 19.6: Pole-mounted switches preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
ABS – built-up area	Operation and major maintenance of contacts, pantographs, and mechanisms.	Five-yearly
	Contacts and jumpers thermal scan.	2.5-yearly
ABS – rural area	Visual inspections of contacts, pantographs. Inspect, lubricate, and operate switch.	Five-yearly
	Operation and major maintenance of contacts, pantographs, and mechanisms.	10-yearly
DAS (vacuum and gas)	External visual inspection and thermal scan.	Five-yearly

We have recently 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.

19.5.6 RENEW OR DISPOSE

Our renewal strategy for pole-mounted switches is AHI-based replacement. Switches with identified defects are scheduled for replacement as part of the defect management process.

We are replacing aged ABS with modern low-maintenance types of ABS or DAS.

SUMMARY OF POLE-MOUNTED SWITCHES RENEWALS APPROACH	
Renewal trigger	AHI
Forecasting approach	AHI
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewals forecast uses AHI. ABS is a relatively simple mechanical device that is exposed to the elements, and therefore its 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.

Coordination with network development projects

Before renewing a pole-mounted switch, we review the ongoing need for the equipment in that location.

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.

19.6 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

19.6.1 FLEET OVERVIEW

Circuit breakers, reclosers and sectionalisers are used when distribution switchgear needs to fulfil a protection function, such as detecting and isolating network faults. This type of switchgear includes relays for protection sensing and tripping, some of which can be programmed for distribution automation schemes. As with other types of switchgear, we operate a fleet with a mixture of models as technology has changed over time from oil to SF_6 and vacuum.

Circuit breakers

Circuit breakers, in the context of this fleet, cover circuit breaker assets that are not located in our zone substations and are generally associated with distribution substations – the majority of which are installed within major customer facilities.[104]

Distribution circuit breakers, such as these, are often of similar technology to those located in a zone substation. They provide isolation of faults on downstream circuits and equipment, allowing access to the customer network for maintenance and construction works.[105]

Reclosers

Reclosers are three-phase fault break devices that clear temporary faults in the network where necessary and isolate permanent faults. When a fault is detected by a recloser, after a defined period, the recloser will open to isolate the fault. A defined number of attempts will be made to re-energise the network section downstream of the recloser. If the fault is temporary, the reclose process will be successful, and supply will be restored to that section of the network. If the fault is permanent, after the defined number of attempts, the recloser will open and remain open, isolating the faulted network from supply. Our network uses gas-insulated, solid dielectric (vacuum) and oil-filled reclosers.

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.

The technology for these devices has undergone a great deal of change over time. Most of the advances relate to electronic control functionality, which now has greater capability to support distribution automation. The electronic controls require management of firmware and settings, and we expect the electronic control equipment will likely require replacement before the switchgear itself.

Sectionalisers

Sectionalisers are similar to reclosers in that they have the ability to measure current and voltage but are generally designed to work in coordination with an upstream recloser.

Sectionalisers are off-load devices that work with reclosers to disconnect sections of the network under fault conditions to attempt to isolate faulted sections of the network. Sectionalisers are located downstream of reclosers and monitor the fault current and circuit interruption of the upstream devices. After a pre-programmed number of recloser re-energisation attempts, the sectionaliser will open during the open period of the recloser. If the fault is on the section of line that the sectionaliser disconnected, the next reclose attempt will result in the successful re-energisation of the network section downstream of the recloser. Sectionalisers are not rated for breaking load current and must be opened during the open cycle of the upstream recloser.

104 Zone substation circuit breakers are discussed in Chapter 17.

105 Of note is the Oji Fibre Solutions and Carter Holt Harvey site at Kinleith, which houses 26 switchboards, comprising approximately half of the distribution circuit breaker fleet.

Figure 19.52: A pole-mounted sectionaliser

19.6.2 POPULATION AND AGE STATISTICS

Table 19.7 summarises our populations of circuit breakers, reclosers and sectionalisers, distinguished by interrupter type. This is important because oil-based interrupters have higher maintenance requirements and increased safety risks under failure. In addition, older recloser types have limited protection and remote operability, reducing their flexibility.

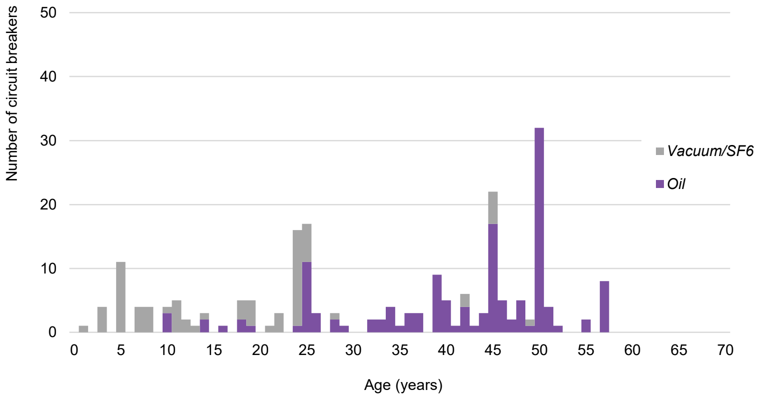
Approximately 64% of the circuit breaker fleet is oil-based, almost half of which is located at the Oji Fibre Solutions pulp and paper mill at Kinleith.

Table 19.7: Circuit breakers, reclosers and sectionalisers population by type

TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Circuit breakers	Oil	145	16
	SF_6/vacuum	80	9
Reclosers	Oil	3	0
	SF_6/vacuum	477	53
Sectionalisers	Oil	3	0
	SF_6/vacuum	197	22
Total		**905**	

Figure 19.63 shows our circuit breakers age profile. Our circuit breakers are ageing, with a large number close to or exceeding their expected life of 45 years.

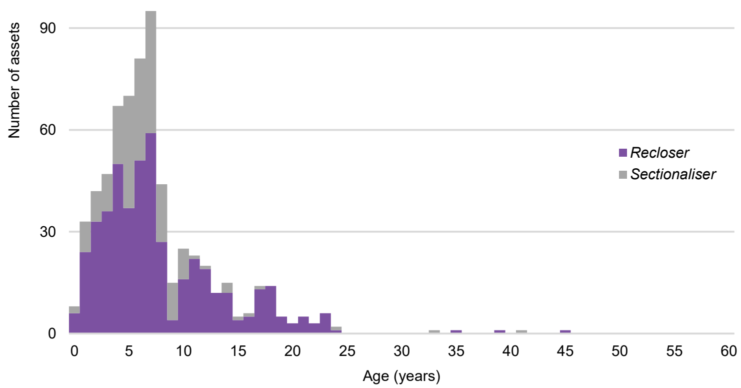
Figure 19.63: Circuit breakers age profile



Older assets in the age profile are mostly the oil-filled circuit breakers at the Kinleith site. Since 2019, we have been progressively upgrading the switchboards at this site. 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 20 years as part of our automation programmes. We have been installing larger numbers of these devices to reduce the size of outage areas during faults. 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 19.74: Reclosers and sectionalisers age profile



19.6.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Risks

Distribution circuit breakers

Oil type circuit breakers have good reliability on our network, but the age of the fleet means there is an increased risk to operator safety and loss of supply from an explosion, fire, arc flash, arc blast and oil spills. The safety and 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 low voltage (LV) reticulation, and other services.

The 11kV fault levels at Kinleith have recently been reduced as Transpower has installed neutral earthing resistors (NERs) and higher impedance power transformers. However, given that these boards do not meet our current requirements for arc flash containment, the fleet presents a high arc flash safety risk to operators. As a component of the 11kV switchboard upgrade programme, arc flash doors, end panels, arc flash protection and local remote circuit breaker operation are being installed. This will mitigate the arc flash safety risk.

Some of the oil type circuit breakers are manually operated. This is considered unsafe, especially given the 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.

Reclosers

We have a small number of oil-immersed recloser types, such as early KFMEs or OYTs, which do not provide the functionality or visibility to our control room that we require of modern reclosers. There have also been occasions when they have failed to operate on faults, extending outage areas and restoration times. We have an existing programme to replace these with modern reclosers, which is expected to be completed in FY25.

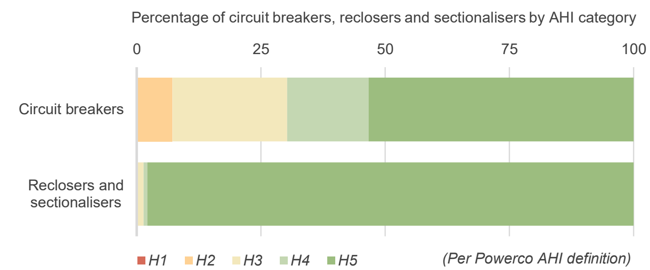
The key risks associated with sectionalisers are that, on occasion, expulsion drop out fuse sectionalisers have not operated under fault conditions. This issue impacts reliability and safety because it increases the likelihood of conductors exceeding their safe operating temperatures and failing because of improper functioning of the fuses.

Circuit breakers, reclosers and sectionalisers asset health

As outlined in Chapter 9, we have developed CNAIM models that reflect risk and indicate the remaining life of each asset. Our CNAIM 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 risk 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 19.85 shows the overall AHI for our population of circuit breakers, reclosers and sectionalisers.

Figure 19.85: Circuit breakers, reclosers and sectionalisers asset health



The asset health of the combined recloser and sectionaliser sub-fleet is generally good. As mentioned above, we are working through a programme to replace our KFME and OYT type reclosers. Less than 1.5% (H1-H3) will likely require replacement in the next 10 years.

In contrast, the health of our distribution circuit breakers is poor, and a significant risk, and we have categorised many of our oil circuit breakers as having type related issues requiring replacement. This assessment is based on our experience of operating this switchgear and the experience of others within the industry

The health of our distribution circuit breakers is skewed by our large fleet of oil circuit breakers at Oji Fibre Solutions' Kinleith plant, for which we are undertaking a significant renewal programme. This renewal programme is taking longer than initially planned because of increased material and labour costs associated with this type of work.

19.6.4 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 evaluation 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.

19.6.5 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 frequent invasive 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 19.8 summarises our preventive maintenance tasks for this fleet. The detailed regime is set out in our maintenance standards.

Table 19.8: 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/remote terminal unit (RTU) batteries. Communications check.	Yearly
	Thermal imaging scan.	2.5-yearly
	Major maintenance of oil reclosers. External inspections of vacuum and gas interrupter units. Battery replacements.	Five-yearly
	Major maintenance of mechanisms for vacuum and gas devices.	10-yearly
Circuit breakers	General visual inspection.	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.	Five-yearly
	Vacuum and gas circuit breaker interrupter withstand tests.	10-yearly

19.6.6 RENEW OR DISPOSE

Renewal of circuit breakers, reclosers and sectionalisers is based on asset condition and type-related safety or performance issues. We are prioritising certain types of oil circuit breakers for replacement because of safety issues from design flaws or stricter risk tolerances, such as for arc flash.

SUMMARY OF CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS RENEWALS APPROACH

Renewal trigger	CNAIM
Forecasting approach	CNAIM
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. In general, older designs of switchgear also have fewer safety features, such as arc flash containment. The evolution in the design of switchgear has improved safety and reliability. The renewal need for this fleet is higher than in the past because of the need to renew oil circuit breakers with safety issues and the significant quantities of circuit breakers requiring renewal at Kinleith – we expect to complete this programme by FY31.
Additionally, we have a focused programme to replace our remaining KFME and OYT reclosers, which have reliability issues leading to trip failures. We expect to complete this replacement programme in FY25.

Coordination with network development projects

The increasing use of network automation is a key part of this fleet's development planning. Network automation seeks to improve network System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance by enhancing the network's sectionalising capability following faults and providing better network operational visibility. It 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.

19.7 DISTRIBUTION SWITCHGEAR RENEWALS FORECAST

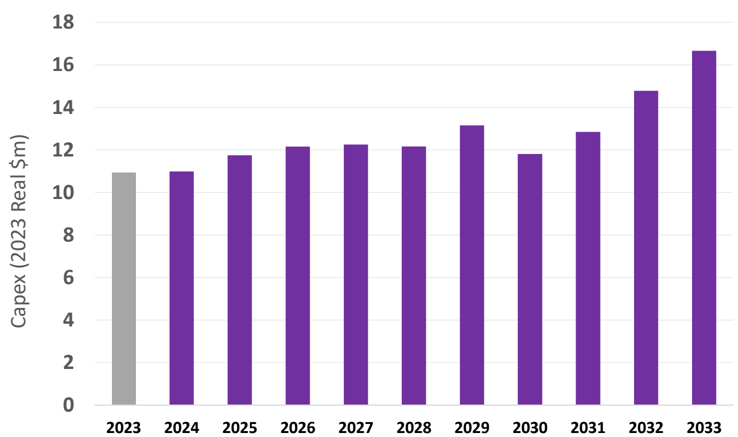
Renewal Capex in our Distribution Switchgear portfolio includes planned investments in our ground-mounted switchgear, pole-mounted fuses, pole-mounted switches, circuit breakers, reclosers, and sectionalisers fleets.

We intend to invest approximately $128m in distribution switchgear renewal during the planning period, increasing as the fleet ages. Safety is a key driver of renewal, particularly for our oil-filled ground-mounted switchgear.

Distribution switchgear renewals are derived from bottom-up models. These forecasts are generally volumetric estimates (explained in Chapter 24).

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 that are based on analysis of equivalent historical costs for a like-for-like replacement. For new technology, costs have been estimated based on purchase and installation costs.

Figure 19.96 shows our forecast Capex on distribution switchgear during the planning period. Figure 19.96: Distribution switchgear renewal forecast expenditure

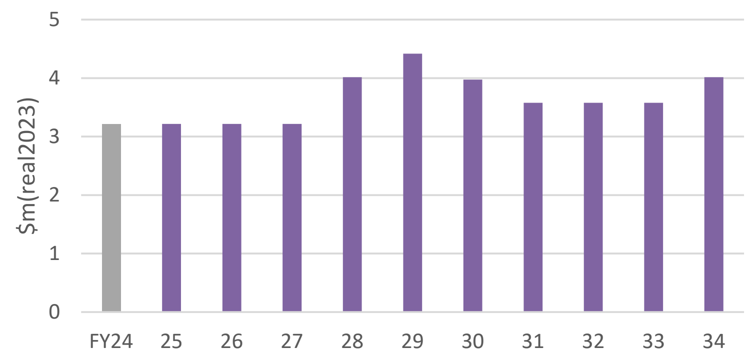


The forecast renewal expenditure is generally in line with historical levels. Further details on expenditure forecasts are contained in Chapter 24.

19.8 DISTRIBUTION SWITCHGEAR PREVENTIVE MAINTENANCE FORECAST

Our preventive maintenance expenditure for distribution switchgear accounts for 27% of our current maintenance Opex expenditure. Our safety-driven oil-filled RMU maintenance programme continues to return good results with the full cycle completed in 2029. As we work through the cycle of major maintenance, optimisations can take place to ensure these assets remain fit for service and can be operated safely until their end of life.

Figure 19.107: Preventive maintenance expenditure forecast



20 SECONDARY SYSTEMS

20.1 CHAPTER OVERVIEW

This chapter describes our Secondary Systems portfolio and summarises our associated Fleet Management Plan. The portfolio includes four asset fleets:

- Supervisory Control And Data Acquisition (SCADA) and communications
- Protection systems
- Direct Current (DC) supplies
- Metering

This chapter describes 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 $77m in secondary systems. This accounts for 7% of renewals Capex during the period. This is an increase in our current spend, mainly driven by our Extended Reserves programme. The level of renewal across the secondary systems fleets is in line with historical expenditure.

The main driver for asset replacement in the Secondary Systems portfolio is obsolescence and aged-based degradation. 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. We are expecting to complete this replacement in FY30.
– Consolidate the communications protocols for our 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.
– 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.

20.2 SECONDARY SYSTEMS OBJECTIVES

Secondary systems are crucial for the safe and reliable operation of our electricity network, as they allow for the control and operation of most primary equipment such as switchgear.

While their replacement cost is usually lower than the primary equipment that they control or monitor, they generally have shorter service lives. 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 20.1. The objectives are linked to our overall Asset Management Objectives set out in Chapter 5.

Table 20.1: 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	DC supply systems provide their specified carry-over time in the event of an outage.
	Enable remote engineering access to modern numerical relays to allow us to retrieve disturbance records, helping identify the cause of faults and facilitate rapid restoration of supply.
Operational Excellence	Continue to use improved asset information gathered and recorded by modern numerical relays.

20.3 SCADA AND COMMUNICATIONS

20.3.1 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 by implementing design packages/templates using Powerco-approved equipment.

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 is in Auckland.

Our master stations use an industry-standard communications protocol – Distributed Network Protocol version 3.0 (DNP3).

Remote terminal unit (RTU)

An RTU is an electronic device that interfaces network equipment with SCADA, such as transformer control units, DC supplies, protection relays, and recloser controls. It transmits telemetry data to the master station and relays communications from the master station to control connected devices.

A range of RTUs are used across our networks. With the consolidation of our master system, 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.

The change of communication protocol has allowed intelligent electronic devices (IEDs) to be 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 200.1: A legacy RTU

Figure 200.2: 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 implementing line differential protection between substations.

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.

Remote engineering access (REA)

Our modern RTUs are capable of providing remote engineering access (REA) to our substation protection system. These allow us to provide a much better response time during fault events where relay data and event files are needed to be accessed so that protection analysis can be carried out. The REA runs on a separate communications channel from the SCADA. This can be via our Powerco Transport Network (PTN) or through a cellular modem connection.

To date, we have 118 zone substations with REA and the remaining zone substations will have REA when the protection relays and RTUs are planned for renewal.

Figure 20.3: Communications mast with associated radio antennae

20.3.2 POPULATION AND AGE STATISTICS

During the past five years, we have undertaken a number of projects to modernise our RTUs 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 from modern RTUs, which includes DNP3 connectivity and REA to substation protection relays.

Table 20.2 summarises our population of RTUs by type. [106]

Table 20.2: RTU population by type

TYPE	RTU	% OF TOTAL
Zone Substation	142	43
Distribution	189	57
Total	331	

At the end of this replacement 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 intelligent electronic devices (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. We are working to improve our records of communications assets and record these in our asset information systems.

20.3.3 CONDITION, PERFORMANCE, INFORMATION 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 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 a third party gaining control of our switchgear through a cyber attack on our SCADA system. As more automated devices become visible and controllable on the network, the potential safety, reliability, and cost consequences from an attack on the system become increasingly serious. The increasing risk of a cyber attack is driving us to improve the security levels of our SCADA system.

Improving our levels of cyber security is a key element of our Information and Technology Strategy and is discussed in more detail in Chapter 5.

Meeting our portfolio objectives

Safety and Environment: We continually review the security of our SCADA against cyber attacks to ensure the operational safety of the network.

20.3.4 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 status, indications, and analogue data on our SCADA without the need to go through a third party.

106 This population excludes telemetered sites with IEDs directly connected to the SCADA network, such as those on modern automated reclosers.

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 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 the 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.

20.3.5 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 20.3: 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.	Six-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 is covered by a specialist team.	As required

20.3.6 RENEW OR DISPOSE

SCADA and communications asset renewal is based on functional obsolescence and age-based degradation. As detailed earlier, we still have a small number of legacy RTUs on the network, which is 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.

SCADA and communications equipment will generally need to be replaced at least every 15 years (life of the equipment[107]).

We hold a small quantity of RTU spares which allows us to replace these quickly when they fail. We also hold a range of older RTUs, which are no longer supported, to allow us to manage the impacts of failure before planned retirement.

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 15. 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	Age
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewal forecasts are based on identifying asset types that require replacement (see above). This includes the legacy RTUs, SCADA radios and REA modems.

The renewal forecast of supporting communications infrastructure has been estimated on a serviceable lifecycle replacement schedule, given the complexity of the PTN backhaul to service voice radio, SCADA, and other services.

Longer term, we expect SCADA and communications renewals to remain at least at current levels. As the IED population continues to grow, we have allowed for an increasing level of replacement towards the end of the forecast period. Additionally, future capability requirements and an expansion of the communications network are likely to increase the renewal need long term.

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,

107 Based on observed onset of unreliability of the current RTU fleet.

configuration, and communications. Similarly, our network automation programme[108] is extending the control and monitoring capability to selected distribution switches.

20.4 PROTECTION SYSTEMS

20.4.1 FLEET OVERVIEW

Protection assets ensure the safe and appropriate operation of the network. These relays (or integrated controllers) are used to detect and measure faults on our HV electricity network and through coordination with circuit breakers, clear and isolate faults. When working correctly and in coordination with other devices, they have a significant impact on minimising network damage and outage areas when the network faults.

Protection systems include auxiliary equipment, such as current and voltage instrument transformers, communication interfaces, special function relays, auxiliary relays and interconnecting wiring.

Protection relay technology has 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 simple, legacy protection technology that has provided many years of reliable performance. While basic in design – each relay providing a specific function – they lack the flexibility in configuration and functionality that we require of modern protection technology.

Electromechanical relays require ongoing calibration because of the 'drift' of their mechanical 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 the oldest is more than 50 years.

[108] We discuss the network automation programme in Chapter 16

Figure 20.4: Electromechanical relays providing transformer protection

Static relays

Static relays gain their name from the absence of moving parts – in contrast to the electromechanical relays – instead, relying on analogue electronic components to create the relay characteristic.

Being solid-state, they can have improved sensitivity, speed and repeatability compared with electromechanical relays. However, early electronic components were quite susceptible to deterioration and drift because of time and temperature, affecting the performance and reliability of relays.

Static relays have an expected life of approximately 20 years. Spare parts can no longer be sourced, 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 in their configuration. 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 in functionality over previous technologies. These include SCADA integration, the ability for data to be accessed remotely, real-time, and historical information about the power system, the protection and control systems, fault location and type, before, during and post fault currents and voltages.

Furthermore, these 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 a reduced cost compared with those available in the past.

Being electronic devices, they have a much shorter expected life than electromechanical relays – approximately 20 years. Obsolescence is also a driver for replacement, which is typically dictated by protocol, software and firmware, compatibility with other devices, and discontinued vendor manufacturing/support.

Figure 20.5: Modern numerical relays

20.4.2 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 76% 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.

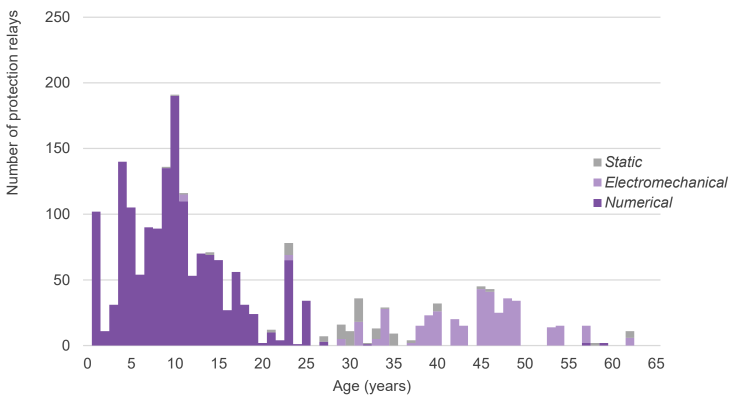
Table 20.4: Protection relays population by type

TYPE	RELAYS	% OF TOTAL
Electromechanical	393	19
Numerical	1,576	76
Static	98	5
Total	**2,067**	

As technology has evolved, the types of relays used on the network have changed. 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 20.6 shows the age profile of our protection relays population. Many electromechanical relays exceed 40 years of life and are now due for replacement.

Figure 20.6: Protection relays age profile



20.4.3 CONDITION, PERFORMANCE, INFORMATION AND RISKS

Condition

While electromechanical relays have a proven performance and long lives, having moving parts means they are subject to wear. 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. We are upgrading the last of our electromechanical relays as described in 24.4.6 Renew and Dispose.

The solid-state or static relays do provide additional functionality, such as a SCADA interface, however, these relays still lack disturbance recording capability. Most of our static relay fleet is no longer supported by the manufacturer and spare parts are no longer available. Compared with other relay types, they experience a greater number of reliability issues because of component failure. 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 substation air conditioning. Numerical relays generally provide an indication when they malfunction, which allows maintenance intervals to be extended.

Risks

Performance and reliability

The key safety risk for the protection fleet is that network faults are not detected and cleared because of a relay malfunction. These faults can then put the public or service provider in danger, and can cause network equipment failure, extended outages, or overload. For these reasons, protection systems are designed with cascading backups, but these are designed to take longer to clear the fault to ensure protection discrimination and, being further upstream in the network, generally result in a larger outage area. As longer fault clearance times stress the network more, these can sometimes result in equipment damage, live power lines on the ground, or fires.

Cyber security threats

It is also noted that the introduction of more numerical relays could pose an increased risk of exposure to cyber attacks. Security measures to address system vulnerabilities from cyber attacks must be in place.

Diversity

By limiting the type/model of the protection relay fleet, it is expected to have significant improvements in terms of whole-of-life support. This will reduce the number of protection standards/schemes that need to be supported, leading to a reduction in deployment and maintenance costs.

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 (EA) is implementing new requirements for Extended Reserves, which involve transitioning from a two-blocks load shedding scheme to four-blocks. The new requirements also 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 FY23 – FY25 period.

20.4.4 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, e.g., power swings and current reversals, and must 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, e.g., 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.

20.4.5 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 20.5. The detailed regime is set out in our maintenance standards.

Table 20.5: Protection relays 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.	Three-monthly
Detailed condition assessment and operational checks for electromechanical and static relays. Perform diagnostic tests relevant to relay function, e.g., overcurrent, and distance.	Three-yearly
Detailed condition assessment and operational checks for numerical relays. Perform diagnostic tests relevant to relay function, e.g., overcurrent, and distance.	Nine-yearly
Automatic under-frequency load shedding (AUFLS) relays – regulatory compliance testing	10-yearly

20.4.6 RENEW OR DISPOSE

Our strategy is to replace electromechanical and static relays based on functional obsolescence, reliability, and 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).

We expect to complete the replacement of our electromechanical and static relay population by FY30.

We have observed increasing component failures in our first-generation numerical relays, which are now reaching the end of their service life at 20 years. This, combined with the limited functionality these provide compared with more modern numerical relays, means we are starting to replace our oldest relays of this type within the planning period.

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. This allows 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, e.g., 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 2023-25 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, as well as the replacement of load shedding relays.

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.

Duplicate protection

Our HV circuits require a fast and reliable protection system and, therefore, protection duplication is required. This is included in the relay renewals forecast and will be done alongside HV switchboard renewals.

Coordination with network development projects

Protection relay replacement work is, as far as practicable, 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.

20.5 DC SUPPLIES

20.5.1 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 20.7: DC charger and battery bank

20.5.2 POPULATION AND AGE STATISTICS

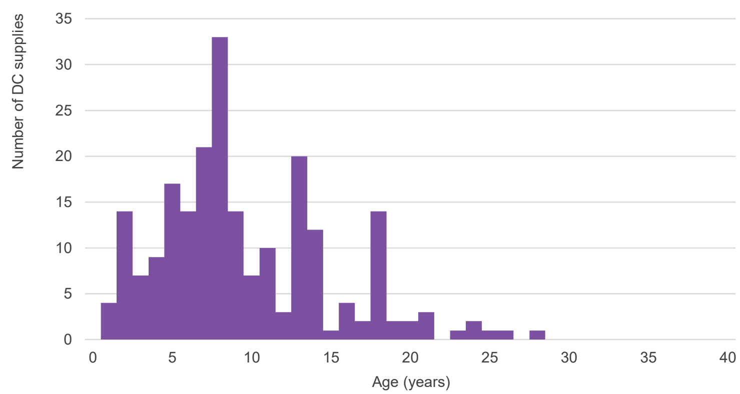
Table 20.6 summarises our population of DC supply systems by type. DC systems have been installed using many supply voltages because of different load requirements and network amalgamation. We expect the diversity to reduce as we replace non-standard voltage systems with modern equivalents.

Table 20.6: DC supplies population by voltage

VOLTAGE	DC SYSTEMS	% OF TOTAL
110V	93	42
48V	25	12
36V	1	-
30V	2	1
24V	91	42
12V	7	3
Total	**219**	

Figure 20.8 shows the age profile of our population of DC supplies. The DC supply system batteries typically get renewed every eight years for valve-regulated lead acid (VRLA) type or 10 years for absorbent glass mat (AGM)/gel type. The charger/rectifiers are expected to last up to 20 years. A number of DC system types have recently been identified as having an increasing risk of failure – these will be prioritised for replacement.

Figure 20.8: Zone substation DC supplies charger/rectifier age profile



20.5.3 CONDITION, PERFORMANCE, INFORMATION 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 are dry solder joints and capacitors swelling within the power circuitry. The consequence of failure is high, which can include a lack of protection at substations and a lack of control. The need to revert to manual operation can put workers at increased risk of switchgear failure and arc flash.

20.5.4 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 20.7. The detailed regime is set out in our maintenance standard.

Table 20.7: 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, carry out impedance testing and thermal imaging of connections. Charger alarms operational, giving correct status.	Three-monthly
Visual inspection of radio repeater and communication hub DC systems. Check batteries for distortion, correct electrolyte levels, carry out impedance testing and thermal imaging of connections. Charger alarms operational, giving correct status.	Six-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.	Yearly
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.

20.5.5 RENEW OR DISPOSE

DC supplies are critical assets as failure means we potentially lose visibility and control of our field sites. It is essential that these are scheduled for renewal as they reached the end of their life. The DC supplies are also being reviewed as part of the protection relay and/or SCADA/comms renewal to ensure that these can still provide the functionality expected and the capacity required.

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.

SUMMARY OF DC SUPPLIES RENEWALS APPROACH	
Renewal trigger	Capacity 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[109] 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.

20.6 METERING

20.6.1 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 by Transpower at GXPs. We have replaced all of our older technology GXP meters with advanced capability modern meters. Modern GXP meters are able to communicate via the DNP3 protocol and provide remote access functionality and rich data, e.g., peak, and average kVA, and power factor and power quality reporting

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.[110]

20.6.2 POPULATION AND AGE STATISTICS

Table 20.8 summarises our population of GXP meters by type. Our GXP meter replacement programme has upgraded the majority of metering units to modern ION meters.

Table 20.8: GXP metering population by type

TYPE	GXP METERS
ION meter	28
Total	28

In addition to the GXP meters, we have 131 HV metering units and approximately 1,500 ripple receiver relays.

Figure 20.9 shows the age profile of our GXP meter population. The young age of the GXP metering fleet reflects the recent modernisation of the assets.

Figure 20.9: GXP metering age profile

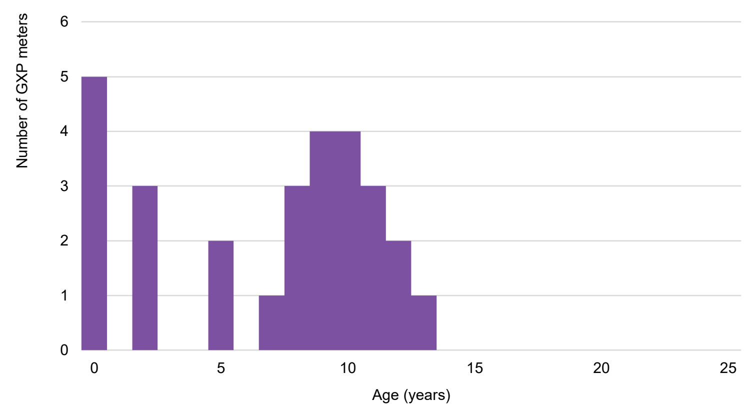


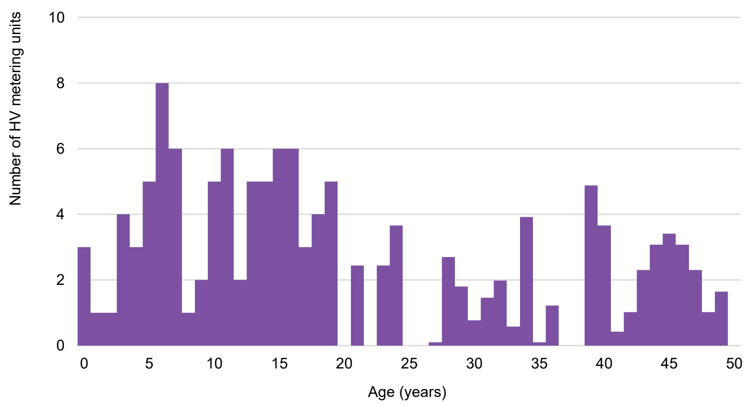
Figure 20.10 shows the age profile of our HV metering unit population. The HV metering unit fleet is relatively young. Experience has shown us that life spans of more than 20 years are common for most metering units, with replacement or upgrade normally being related to changes in the load profiles of connected customers.

In the absence of other information, we have assumed that units located within switchboards have a life of 40-45 years, similar to the associated switchgear.

109 'Carry-over time' means the time the DC system can supply the connected load in the event of an outage.

110 We discuss our load control plant fleet in Chapter 21.

Figure 20.10: HV metering unit age profile



20.6.3 CONDITION, PERFORMANCE, INFORMATION 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.

20.6.4 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 20.9. The detailed regime is set out in our maintenance standards.

Table 20.9: 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.	Five-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.

20.6.5 RENEW OR DISPOSE

Obsolescence is the primary driver for the 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

Significant work undertaken since 2010 has resulted in our GXP metering being upgraded to modern devices with advanced capability. Future renewals will be based on changes as a result of ODID projects or to meet the requirements of AUFLs load shed reporting.

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.

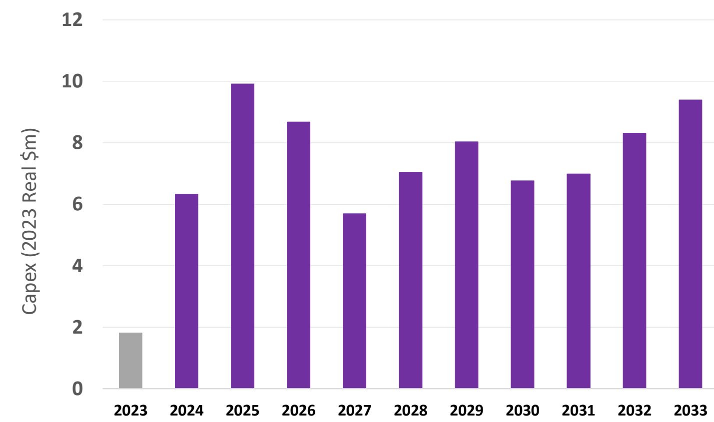
20.7 SECONDARY SYSTEMS RENEWALS FORECAST

Renewal Capex in our Secondary Systems portfolio includes planned investments in the SCADA and communications, protection systems, DC supplies, and metering fleets. During the planning period, we intend to invest $77m 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 are explained in Chapter 24. We typically use averaged unit rates based on analysis of equivalent historical costs, along with building block costs for protection replacements.

Figure 20.21 shows our forecast Capex on secondary systems during the planning period.

Figure 20.21: Secondary systems renewal forecast expenditure



Renewal expenditure is expected to increase during the planning period. This is primarily because of:

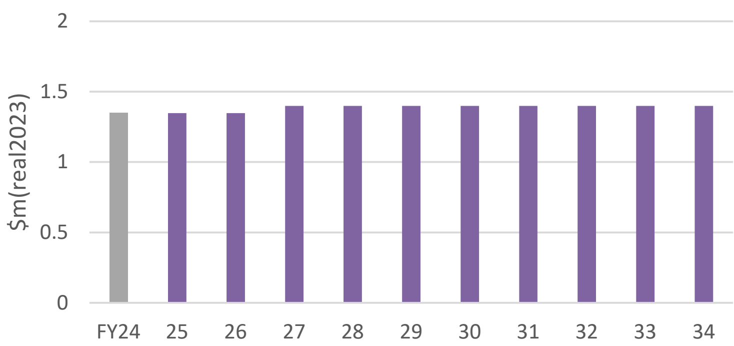
- Our programme of load-shedding relay replacements in FY23-25, to meet compliance with the Extended Reserves scheme.
- Increasing protection relay replacements, particularly of early numerical relays.
- A programme of duplicate protection investments to improve the resilience of our protection systems, in particular against a cyber attack.

Other expenditure forecasts within this fleet are generally in line with historical levels.

20.8 SECONDARY SYSTEMS PREVENTIVE MAINTENANCE FORECAST

Secondary systems maintenance accounts for 10% of our preventive maintenance expenditure. This level of expenditure is expected to remain relatively consistent, although the electromechanical relays will be phased out and maintenance intervals can be increased to nine-yearly.

Figure 20.32: Secondary systems preventive maintenance forecast



21.1 OVERVIEW

21.1.1 COMPLIANCE

Vegetation near power lines is a significant hazard and has the potential to impact safety, quality of supply and network reliability. Although network operators don't own vegetation near power lines, they have obligations regarding the management of it. These are documented in the Tree Regulations[111], which prescribe the minimum distance that trees must be kept from overhead lines and set out the responsibilities for tree trimming.

Trees near lines are declared by landowners as either being of interest, or no interest to them. For trees in which they have a declared interest, the owners have an obligation to keep them maintained and clear of our network. Powerco has an obligation to notify owners so they can maintain trees before they infringe on clearance zones. These requirements are logistically complex when considered in the context of Powerco's large overhead network.

Tree regulations

The Electricity (Hazards from Trees) Regulations 2003 require us to identify trees or vegetation that are 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.

Powerco carries out its obligations under the regulations through a cyclical tree-trimming programme. The network is surveyed within a defined period and landowners are notified of their obligations. The tree-trimming programme is then developed incorporating optimal cutting plans and methods. The trimming cycle times vary based on environmental conditions and network criticality. Our vegetation management approach has focused on maximising the length of power lines that is compliant with minimum clearance zone requirements, this is due to the large volume of vegetation and optimising spend.

This approach, by necessity, prioritises short-term compliance over long-term performance and cost by limiting our ability to:

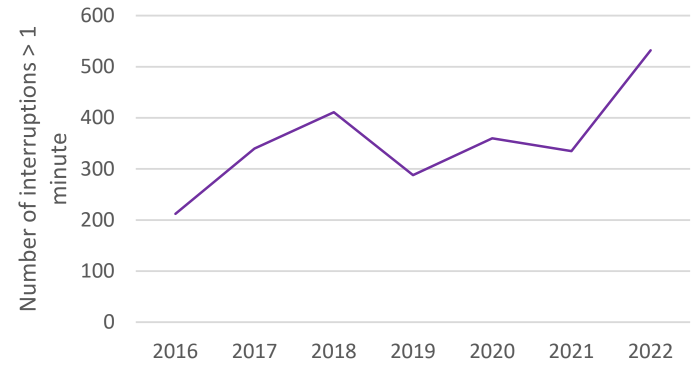
- Remove rather than trim trees.
- Implement long-term methods such as spraying and mulching.
- Address at-risk trees that are outside of the prescribed clearance zone.

Our operating environment and network reliability is being impacted by the effects of climate change, evident through an increase in network faults caused by out-of-zone trees. To address this, we have increased our focus on managing high-risk trees outside the traditional clearance zones over and above our cyclical tree-trimming programme.

21.1.2 PERFORMANCE

Outages caused by vegetation are a significant contributor to our overall System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). The trend of vegetation-related outages is shown in Figure 21.1.

Figure 21.1: Number of vegetation-related events causing >1 min outages



Our cyclical strategy is consistent with good practice, however, developments in Light Detection and Ranging (LiDAR) surveying, vegetation analytics and risk-based planning may provide opportunities to improve the safety, performance, and cost optimisation of our vegetation management activities. Information gathered from our 2020 LiDAR survey has been used in the field with success, and we are reviewing our Vegetation Management Strategy to maximise the impact of future programmes. The focus is shifting to a more risk-based prioritisation methodology positioning us to maximise the effectiveness of our plans.

[111] Electricity (Hazards from Trees) Regulations 2003 (SR 2003/375)

21.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high-level objectives for vegetation management.

Table 21.1: Vegetation Management portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reduce the potential risk of incidents to improve public safety and comply with regulations. Reduce safety hazards by prioritising higher-risk trees.
Customers and Community	Improve relations with tree owners and minimise disruption when undertaking tree management by coordinating with other network activities. Contribute to 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, enabling assets to achieve expected life and to support our overall reliability objectives.
Operational Excellence	Achieve good practice vegetation management through enhanced cyclical and risk work programmes. Utilising technology such as LiDAR to direct investment. Improve the quality of vegetation fault information to better understand trends from vegetation-related outages.

21.3 ONGOING VEGETATION MANAGEMENT INITIATIVES

Powerco is implementing a range of ongoing improvement initiatives, which are discussed in Table 21.2**.**

Table 21.2: Vegetation management improvement initiatives

INITIATIVE	UPDATE
Develop a risk-based approach for trees beyond the mandated clearance limits.	The definition of the risk-based approach to vegetation assessment is underway, including considering industry guidelines with a view to improving system resilience. Regular LiDAR information is paramount in driving this strategy.
Improved stakeholder engagement	We are working with our service providers to improve stakeholder (local authority) engagement. In particular, we are working closely with the forestry industry and other electricity industry representatives to educate forest owners and harvesters about adequate setbacks to protect power lines, while also ensuring their crops are profitable to harvest.
Improved public education	We continue to run campaigns to educate communities on the risks of trees outside of the regulatory growth limit zones. There is an ongoing need to educate tree owners about safety issues, their responsibilities, and the effects the trees have on the communities they live in.
Trimming and felling efficiency improvements	We are continuing to work with our contractors to apply innovative, safer and more efficient tree management practices. Equipment now used as standard includes large diggers with tree shears, tracked all-terrain elevated work platforms, shelter trimmers and mulchers, as well as heli-spraying to manage regrowth and maintain corridors.
Data capture and mobility tools	We are revisiting the data requirements and quality control methods to ensure the information can lead to actionable outcomes. Part of this is exploring how to improve the ability to capture accurate information.

Figure 21.2: Improved vegetation management practices

Tree felling near power lines.

A tracked all-terrain elevated work platform allows easy access to trees as well as minimising the impact on surrounding land.

Shelter trimmer provides cost-effective tree work, removing the risk of people working on roadsides.

Eco-mulching provides a cost-effective way of creating a corridor around our subtransmission lines.

21.4 FUTURE IMPROVEMENTS

Our LiDAR survey has provided an objective and complete inventory of the vegetation that is near our power lines. We continue to develop vegetation analytical tools and look for opportunities to incorporate environmentally rich information, such as asset health, areas susceptible to storm events and ground conditions to allow an estimation of the risk that vegetation presents. We will use this information to develop a sustainable long-term strategy that moves our programme from a cyclical programme, based on achieving minimum clearance compliance, to a more efficient programme that achieves compliance and targets critical sections of the network while:

- Optimising long-term costs.
- Improving network resilience through the targeted removal of out-of-profile vegetation.
- Remaining dynamic to achieve an acceptable risk profile.

Achieving a sustainable strategy and optimal long-term savings will require a short-term increase in expenditure.

Key initiatives to achieve this are outlined in Table 21.3.

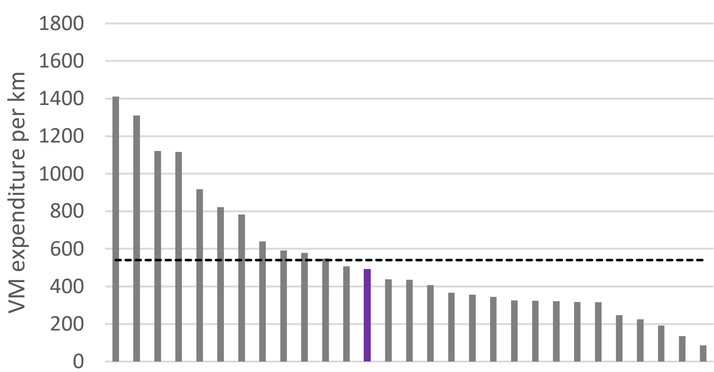
Table 21.3: Future vegetation management improvement initiatives

INITIATIVE	COMMENT
Strategy review and execution	We are using the data produced by the LiDAR survey to conduct a comprehensive review of our vegetation management strategy and its implementation. The availability of objective data will enable an analysis to determine the optimal balance between the short-term cost of investing in tree removals and the longer-term benefits of reduced cyclical trimming costs.
LiDAR information	LiDAR technology provides an accurate distance assessment of vegetation encroachment on the electricity line network. It also provides accurate distance assessment of any physical items, such as buildings and lines that are out of sag tolerance, to allow effective management of clearance (ECP34) violations. We are implementing a follow-up whole-of-network LiDAR survey to measure strategy performance and determine area-specific growth rates.
Satellite imagery	We will be exploring the use of different technologies, such as satellite imagery and analytics, to supplement our LiDAR information. This may be a cost-effective mechanism to identify potential risk hotspots and calculate growth rates at more regular intervals.
Risk-based treatment of out-of-zone trees	We will continue to identify instances where out-of-zone trees that are a risk can be cost-effectively treated. For example, senescent or diseased trees near critical sections of the network that are heavily populated.

21.5 VEGETATION MANAGEMENT OPEX FORECAST

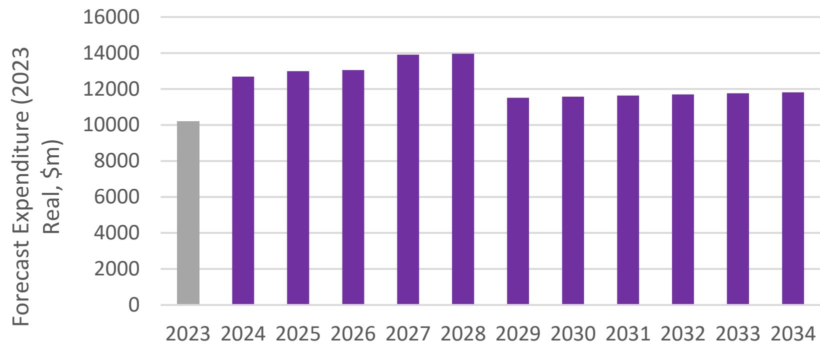
Figure 21.3 compares our previous (purple dot) and new (green dot) vegetation management expenditure per kilometre of overhead line with other Electricity Distribution Businesses (EDB). Before increasing our investment in 2019, our vegetation expenditure was low compared with other EDBs. Our recent increase has brought us in line with the industry average. We will still face the challenges of increased operational costs because of the current economic climate.

Figure 21.3: Vegetation Opex per km of overhead line compared with other EDBs (FY19-21 average)



Our Opex forecast is based on a strategy shift informed by LiDAR and targeted at improving system performance in the medium term based on a risk approach to vegetation management. We anticipate that our review of the Vegetation Management Strategy and its implementation, coupled with the ongoing review of the regulations and increasing external costs, will result in changes to this forecast when complete.

Figure 21.4: Vegetation management expenditure



22 ASSET RELOCATIONS

22.1 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.

22.2 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 Waka Kotahi New Zealand Transport Agency (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, e.g., stormwater pipelines, electricity transmission lines or telecommunications assets.
- **Development** – councils, commercial organisations, farmers, and residential landowners 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.

22.3 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. 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. 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.

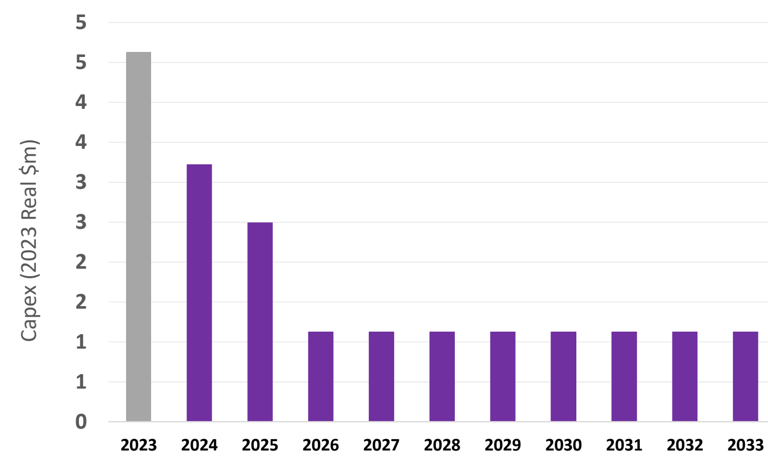
22.4 FORECAST EXPENDITURE

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.

Therefore, we use preceding financial years as the basis of our forecasts, overlaid with any known larger projects. In FY23, we expect to complete an asset relocation project for Waka Kotahi relating to the Takitimu North Link, in Bay of Plenty. Following this, we are currently forecasting expenditure to return to historical levels, but this remains uncertain.

Figure 22.1 shows our expected investment, net of contributions, in asset relocation works during the planning period.

Figure 22.1: Forecast asset relocation Capex (net of contributions)



23.1 CHAPTER OVERVIEW

Non-network assets include assets that support the operation of the electricity business, such as information and communications technology (ICT), asset management data and facilities. This chapter describes the investments required to enable the wider Asset Management Plan and Network Evolution. It also discusses our data quality improvement programme and other non-network assets, such as office buildings and vehicles.

Investment in ICT and data quality is forecast to grow during the planning period, driven by the need to reduce technology risk and strengthen our core business operations through the delivery of foundational business practices and technology. At the same time, these investments enable new capabilities, such as the operation of distributed energy resources, cyber security, and advanced analytics.

This chapter discusses:

- Data quality
- Planned ICT initiatives and investments during the period
- ICT expenditure forecasts
- Facilities portfolio approach and forecast

23.2 DATA QUALITY

All major network programmes (Reliability, Vegetation Management, Advanced Distribution Management etc) are hugely data intensive. Poor data quality reduces decision confidence resulting in sub-optimal investment and operational decisions, reporting inaccuracies, and contention over which data is appropriate/trusted.

In Chapter 9 we outlined the role of our Data Governance Group to ensure good stewardship of our data. Our goal is to improve our data management capability so that data quality is championed, measured, and improved.

The programme of work underway to improve our data and data management capabilities is described in the following sections.

23.2.1 DATA MANAGEMENT

Data management consists of the practices, techniques, and tools to consistently deliver accurate and complete data to meet the requirements of all applications and business processes.

Better data management is essential to improve our data quality, as this is the foundation for good decision-making. We are implementing the following initiatives alongside ICT projects that deliver the enabling technology.

Asset Information Standards

We are creating a suite of Asset Information Standards and data dictionaries to ensure the essential information is collected, categorised, and made available to end-users in an agreed format, to agreed levels of quality, and to agreed timescales. The Asset Information Standards will align with our existing engineering standards and procedures. They will also account for external regulatory and stakeholder requirements.

The key Asset Information Standards include:

- **Asset Information Standard:** A high-level standard that describes the key asset information objects we need, including structured records as well as unstructured documents.
- **Asset Register Standard** (including condition and criticality measures)**:** A consolidated view of our asset information requirements for each asset class.
- **Job Plan and Preventive Maintenance Standard:** Documents business rules, best practices, and governance arrangements to set up Job Plans and Preventive Maintenance Records in our Enterprise Resource Planning (ERP).
- **Work Order Standard:** Defines the information required to initiate, manage, and record both planned and unplanned work activity.
- **Content Management Standard:** A consolidated set of requirements for the storage, access, update, archiving and deletion of unstructured documents, including technical records, drawings, and Management System documents.

We will phase the development of Asset Information Standards and the implementation of information quality audits based on the business priorities and requirements.

Information steward

We are implementing software to provide data profiling and monitoring and information policy management. This will help us to gain a better understanding of data quality and assist data governance, resulting in:

- Improved visibility of data quality metrics.
- Enforcing consistent processes with consistent validation rules and guidelines.

Data Catalogue

We have multiple sources of data in current and legacy systems. The quantity of data available is going to increase as we transition to an intelligent, open-access network. The challenge of managing this data increases along with the amount of data we collect.

We are implementing a data catalogue to make working with data easier for end users by allowing for active data curation. This will improve the speed and quality of data analysis by assisting in:

- **Dataset searching:** Natural language search capabilities across all ERP systems by non-technical users. Ranking of search results by relevance and by frequency of use.
- **Dataset evaluation:** Evaluate the suitability of data for an analysis use case, including the ability to preview a dataset, see all associated metadata, view related use cases, and view data quality information.
- **Data access:** Limiting access to restricted datasets to specific approved users and preventing the combination of certain datasets. This will help ensure the security, privacy, and compliance of our customers' sensitive data.

23.2.2 INSTALLATION CONTROL POINT (ICP) RECONCILIATION

As we prepare for the transition to an intelligent, open-access grid, the need to improve information about our customer connections becomes more important. The ICP Reconciliation programme will improve our ICP records by:

- Correcting corrupted registry records, validating incorrect information, and archiving de-commissioned ICPs.
- Updating our information with feedback from the field to get accurate records for each customer.

23.2.3 ASSET DATA

Accurate and complete information on our assets is a building block for our distribution system operator (DSO) future. We have programmes of work in place to improve the data quality of the following key asset attributes.

Low Voltage (LV) network

Alongside our ICP reconciliation programme, we need accurate LV network information as this is where the majority of renewable generation is to be connected. The LV network has historically been the largest blind spot for electricity distributors in New Zealand and we are working to plug this gap through our LV connectivity programme.

Conductor information

High Voltage (HV) and LV overhead conductors form a large portion of our fleet. However, planning for their renewal has been difficult because of low-quality asset information. Having knowledge about the capacity of the network becomes more important as we increase the amount of renewable generation connected within the network and as we deploy more automation. Our conductor information programme is a focused effort between the asset information teams and field service providers to improve this information.

Nameplate data

Our nameplate data collection programme is aimed at improving the data quality of our more critical assets. This includes zone substation assets (power transformers, circuit breakers, and switchboards) as well as underground distribution assets (ring main units – RMUs).

23.3 PLANNED ICT INVESTMENTS DURING THE PERIOD

At Powerco, we have changed our approach to how business improvements and projects are managed. This has included changing our delivery approach and the structure of our teams to deliver improvements aligned with our business plan. The delivery of ICT investments is now managed by value streams – these are oriented around a basic definition of what Powerco does. The value streams are split into two types:

1. Asset lifecycle phases (core value streams).
2. Activities that support our core (enabling value streams).

There are currently two value streams operating, with a third planned for FY24:

- Works management – design and delivery of asset works.
- Enterprise improvement – improve the functions that support our core, including upgrades for existing technology solutions.
- Customer experience – re-wire the customer experience within Powerco.

The value streams are dynamic and will be stood up or down depending on the requirements of the business plan to deliver on our strategic objectives.

The main initiatives that will be delivered fall largely within the above value streams and are described below.

Business Intelligence, Reporting and Data Management (BIRD)

In 2021, Powerco's business plan acknowledged the importance of insights and data quality in driving and achieving Powerco's objectives. This means increasing oversight and broadening the usage of insights to improve decision-making and business process. A BIRD roadmap was developed outlining the approach. The first phase of the roadmap – to install BW/4HANA and inject SAP datasets – has been completed. The second phase is largely completed and, starting in FY24, phase three will commence. This involves replacing the legacy Datawarehouse and Master Data Store (MDS) systems and continuous data visualisations.

Geospatial Information Systems (GIS)

GIS is one of the key strategic platforms for Powerco to enable the business to make accurate and timely decisions regarding its assets. The GIS platform is made up of multiple components, which have varying levels of support. However, the majority are out of support and must be upgraded. This upgrade is also required to enable a shift to the new Utility Network platform in FY26. The Utility Network product from international GIS software company Esri is more aligned to utility businesses and allows for scalability that is not available in the older versions, among other features. It will be important to move to this model to further leverage the smart grid platform incorporated within our planned Advanced Distribution Management System (ADMS).

Technology lifecycles

Technology is constantly evolving and changing. Keeping current with upgrades to existing technology solutions and reviewing systems to ensure they are still appropriate for Powerco is critical for supporting and enabling our core business.

Various systems upgrades are planned for the regulatory period including SAP, Blueworx mobility, website platform, and drawing management systems, among others. Hardware life-cycling, including desktop and end-user devices and unified communications hardware, are also programmed within this period.

Customer systems

Powerco implemented a new ERP system (SAP) in 2019. Future phases of SAP originally included replacing our customer suite of applications. Powerco has been focused on embedding the new system and getting the core modules, including the respective business processes, operating effectively and efficiently. This has resulted in a delay in the planned future phases of SAP. The next phase is intended to incorporate billing, customer works management system, and customer initiated works. Customer experience is a key strategic objective for Powerco and, therefore, a significant investment is needed in these legacy systems to either implement within SAP or to identify alternative solutions to deliver these critical capabilities.

23.3.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

After completing our pre-requisite lifecycle upgrades we are embarking on the development of a more detailed network model which will give us the ability to expand the capabilities available to us on the platform and support the advanced network functions. In parallel we are developing our Switch Order Management approach and enhancing the way that work flows through from our customers to the operations team for delivery.

We have already deployed a mobility solution to give staff and service providers a real-time view of our network status.

During the next regulatory period, we will continue to implement ADMS modules 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 a real-time data platform to process increasing volumes, and a variety of data from a proliferation of sensors, both in real-time for network operations and to enable trending and forecasting for asset management.

Internet of Things (IoT) data services and advanced analysis of telemetry data will be an area of continued focus throughout the planning period as more network insight and information is required to operate the network efficiently.

23.3.2 INFORMATION SECURITY

What's important to Powerco is evolving – our business strategy will see the organisation establish stronger ties with each of our customers, and it is likely that we will leverage digital technology in doing so. In this context, continuing to provide safe, secure, and reliable digital services is paramount.

Through continuously refining the tools we use and the practices we follow, and developing a pool of highly talented people who embed cyber security into everything they do, we help ensure that our organisation remains resilient in the face of change. Given that the cyber threat landscape is continuing to evolve, and Powerco continues to make greater use of technology and automation, we expect to grow our investment in Information Security initiatives that allow our organisation to achieve its strategic goals. The current Information Security strategy, spanning 2023 and 2024, sees a continued focus on four key areas:

Integrated cyber risk management

As Powerco continues to grow, and the flow of information across both informational (IT) and operational technology (OT) becomes essential in maintaining a competitive edge, so too will the risks posed by this high level of interconnectedness. In alignment with our broader risk management framework, we will continue to refine our cyber risk management practices in such a way that we can effectively track change over time and drive ownership into lower levels of the organisation.

Customer data security

Powerco is executing a strategic shift from an energy utility to a customer-focused infrastructure owner and operator. To better understand and interact with our customers, it's likely we will process and store more data that customers place in our care. As such, we will maintain our current ISO: 27001 accreditation for those systems that process customer data in parallel with migrating to newer revisions of this standard, which incorporate updated controls that seek to manage newly emerging threats.

Cyber incident response and resiliency

While Powerco takes all reasonably practicable steps to secure its cyber ecosystem, no organisation is fully immune from threats. Through good design, a simple process, and regularly practising our response activities, we will continue to ensure our people are ready to respond if needed.

Preparing for the Internet of Things (IoT)

Powerco's electricity and gas distribution networks are becoming increasingly automated – automation that is fed by sensors distributed throughout our physical network. In managing the unique risks associated with OT and IoT, we will continue to set high standards for the use of IoT in a business-critical context.

23.4 ICT EXPENDITURE FORECASTS

23.4.1 OVERVIEW

We distinguish between two ICT portfolios.

- **ICT Capex:** This portfolio includes investments in ICT change initiatives and network-related ICT. It covers the Business Improvement initiatives and projects that ensure our processes, technology and systems help deliver our Asset Management Objectives.
- **ICT Opex:** This 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.[112]

Our expenditure forecasts are based on historical costs, expected unit costs, consumers price index (CPI) and price trends. We have worked with trusted suppliers to determine unit costs for current technologies or their likely replacements.

23.4.2 TRENDS IN ICT EXPENDITURE

Two main trends will impact ICT expenditure during the planning period – the evolution to an intelligent grid and the continued adoption of cloud services.

[112] ICT Opex is included as part of our business support expenditure forecasts (refer to Chapter 26).

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 Capex and Opex, during the planning period. This will increase communications network, data services and cyber security costs.

Examples of new requirements:

- Make power quality and protections device data from substations available to network planning so that they can see power quality trends and transients to build and respond to those events.
- Automated field network recovery via smart assets so that unplanned outage durations are minimised.
- 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 LV level.
- Devices as close as practicable to our customers so we can view what's happening at the fringes of our grid.
- Increased cyber security risks arising as our traditional mechanical electricity network evolves to a connected, intelligent digital grid. The additional cyber security investment is essential to support safe and secure network operations.

In most cases, the trend is for the new communications, data processing and cyber security capabilities 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.

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, increase business agility, and also provide many IT operational and cyber security benefits. In many instances today, and increasingly in the future, the cloud will be the only method of consuming applications 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 has seen all new corporate solutions implemented using cloud services, and in 2021, Powerco's corporate systems were migrated to the cloud.

Powerco's ERP system uses a combination of infrastructure and software as a service (IaaS, SaaS).

Cloud services continue to 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 the implementation time, flexibility, reliability, scalability, cyber security, and automation.

It is important to note that our approach for real-time systems, 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.

As Powerco is still relatively new to cloud services, it is difficult to predict the impact of the cloud on our operational expenditure. In FY18, Powerco spent 1% of the total ICT budget on public cloud services. This had doubled to 2% by FY21. An IT benchmark of 112 utilities from around the globe (Gartner, December 2020) shows that, on average, utilities spend 3% of the 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%. The cloud spend continues to grow year on year as a percentage of total spend and Powerco is no exception to this trend.

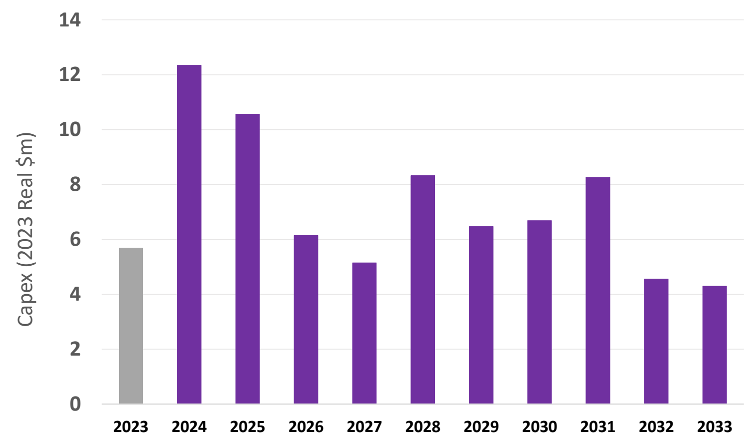
While we have been able to offset some of the Opex impacts by entering into pre-payment contracts, which allow us to capitalise the cost of the Powerco-dedicated computer resources (also attracting a significant discount reducing overall expenditure), increases in SaaS, public cloud computing and associated network spend will continue to shift ICT Capex to Opex.

Given the benefits of the cloud, the regulatory framework needs to be updated to reflect this shift for the overall benefit of customers.

23.4.3 EXPENDITURE FORECASTS

Figure 23.1 shows our forecast ICT capital expenditure for the planning period.

Figure 23.1: ICT Capex forecast



The initial increase in capital expenditure in FY24 and FY25 is largely because of the continued investment in the BIRD programme of work. This then reduces over the remaining portion of the regulatory period to more business-as-usual and continuous improvement levels.

Following this, annual average capital expenditure returns to historical levels before increasing again in line with further ERP and ADMS investments.

23.5 FACILITIES PORTFOLIO APPROACH AND FORECAST

23.5.1 OFFICES

Our long-term property plan is in place to ensure our offices:

- Are safe and secure for our employees, contractors, and visitors.
- Are functional and fit for purpose.
- Can support future staff growth.
- Support improved productivity and efficiency.

- Are cost-effective and efficient to operate.
- Are modern, resilient, professional, and comfortable.

We have four main regional offices throughout the North Island, all positioned to match our broad geographical coverage and ensure we are close to our assets and the work being undertaken across our network. In addition, we have three smaller offices that also support areas that are a little out of reach for the main regional offices.

Our corporate office moved to Junction St during FY23 in a move to consolidate New Plymouth offices and bring people together. Our four major regional offices are shown in Table 23.1.

23.5.2 DEPOTS

A long-term depot strategy is underway and is planned to be completed in FY23. This document is being developed to ensure:

- There is context and understanding around the geographic positioning of the seven depots.
- There is an overarching plan to guide Capex and Opex expenditure both short-term and long-term.
- Depots are functional, fit for purpose, and provisioned for future network requirements They are equipped to sort, productivity, efficiency, and effective delivery of network requirements.
- Are cost-effective and efficient to operate and maintain.
- Are modern, resilient, professional, and comfortable.

We have seven main depots positioned throughout the North Island. Like the offices, the positioning of these depots is strategic to support the response and maintenance activity on the network. Our seven depot locations are shown in Table 23.1.

Table 23.1: Office and depot facilities

LOCATION	OWNERSHIP
Junction St office and depot (New Plymouth), Mihaere Dr depot (Palmerston North), Ngaumutawa Rd office and depot (Masterton). Depots – Coromandel, Pahiatua, Taihape, Raetihi.	Owned
Grey St office (Wellington), Tauranga office, Te Aroha office, Whanganui office, Palmerston North office.	Leased

Increased staff and contractor numbers to deliver the CPP programme has placed added pressure on many of the facilities. Therefore, our facilities strategy remains 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 that support the post-COVID working habits/working styles that have emerged as a result of the pandemic. The Kaimai Building upgrade was completed at Junction St during FY22 and created space for an additional 70 staff. The new Junction St corporate office to accommodate the Liardet St staff is scheduled for completion in the final quarter of FY22. Tauranga growth has recently been addressed with a new part-floor in the existing leased building to accommodate current and future requirements.

23.5.3 VEHICLES

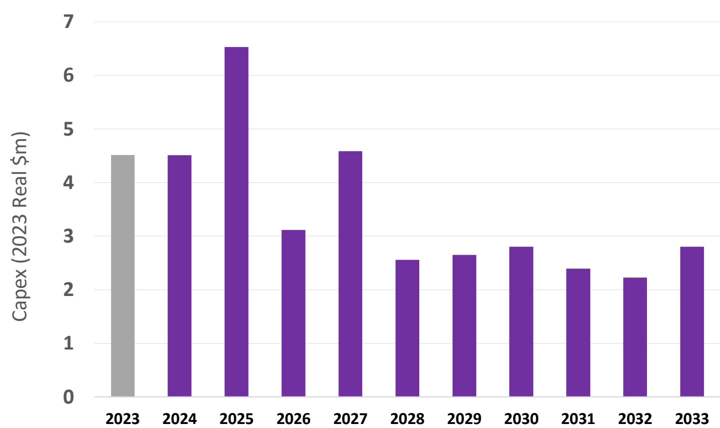
There are 81 leased vehicles in the Powerco fleet. The fleet is made up of 62 allocated vehicles and 19 pool vehicles that support corporate functions.

Vehicle numbers have been relatively stable during the past 24 months, with only a small increase to support new roles. Moving forward, it is expected that vehicle numbers will decrease as the business looks at ways to rationalise and finetune the existing fleet. Vehicle consolidation and a planned phase-out of the 2WD Ford Rangers to a more sustainable Toyota RAV4 Hybrid vehicle have had a positive impact on C02 emissions and fuel consumption. This planned phase-out is part of the recent Powerco commitment to transition to a Net Zero fleet by 2030. The vehicles have been selected based on several criteria, including safety, fit for purpose, and cost, and with input from our drivers and ELT. All vehicles are fitted with the EROAD GPS system to encourage and promote positive driver behaviours and help ensure compliance and effective vehicle utilisation.

23.5.4 EXPENDITURE FORECAST

Figure 23.2 shows our facilities Capex forecast.

Figure 23.2: Facilities Capex forecast



One of the key drivers of facilities Capex is the upgrade of the Junction St site to accommodate the continued growth at this facility and ensure that the facilities can accommodate scalable operational needs.

EXPENDITURE FORECASTS

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

24 EXPENDITURE FORECASTS

24.1 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 2023 financial year (2022-23) 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 FY23 dollars. The schedules in Appendix 2 also show expenditure in FY23 constant price terms.

24.2 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.

24.2.1 CAPEX

Our forecast for total Capex shows a steady increase across the planning period. This is heavily attributed to the impact of predicted growth and decarbonisation

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 10 – 12.
- **Renewals Capex** – discussed in Chapters 14 – 20.
- **Other network Capex** – discussed in Chapters 10[103], 13, and 22
- **Non-network Capex** – discussed in Chapter 23

The increasing forecast across 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, and changes in accounting treatment of software assets. Figure 24.1 sets out our total forecast Capex for the planning period.

Figure 24.1: Total forecast Capex for the planning period

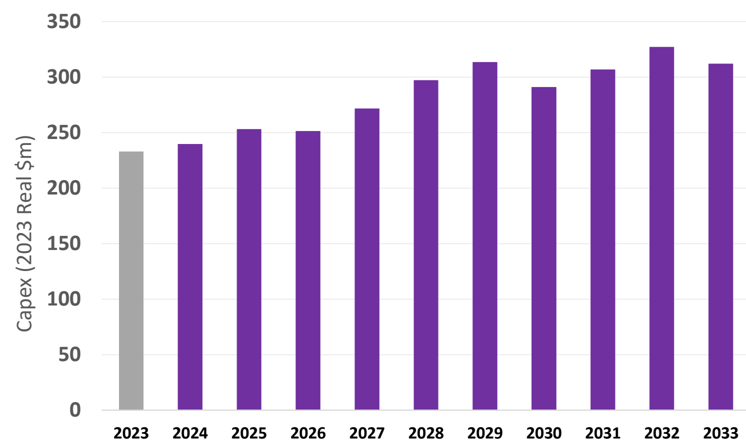


Table 24.1: Total forecast Capex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
233.0	239.5	252.9	251.2	271.6	297.0	313.4	290.8	306.8	327.1	312.0

Our Capex profile reflects the underlying network needs discussed in this AMP. The general stability of our investment profile is underpinned by our traditional

103 Network Evolution is discussed as an area of Growth and Security investment in Chapter 10. To remain consistent with our Customised Price-quality Path (CPP) application, the Network Evolution expenditure forecast is included in the other network Capex expenditure category.

network investments, with the increasing total Capex profile reflecting the adoption of new network strategies as described in Chapter 8.

24.2.1.1 GROWTH AND SECURITY CAPEX

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 in Figure 24.2.

Figure 24.2: Total Growth and Security Capex for the planning period

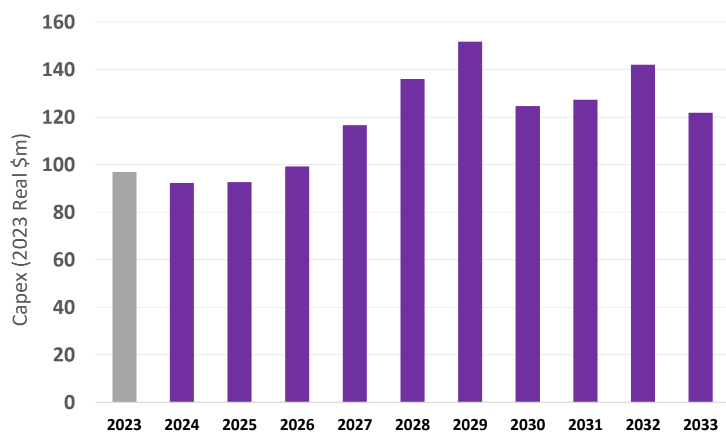


Table 24.2: Total Growth and Security Capex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
96.7	92.2	92.4	99.1	116.5	135.8	151.7	124.4	127.2	141.9	121.7

Network growth investment is forecast to increase steadily from FY27 through to the end of the planning period. This increase is driven primarily by investment into automation, Low Voltage (LV) monitoring, and the impact of decarbonisation on distribution networks.

24.2.1.2 RENEWALS CAPEX

As discussed in Chapters 14 – 20, 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 in Figure 24.3.

Figure 24.3: Total renewals Capex for the planning period

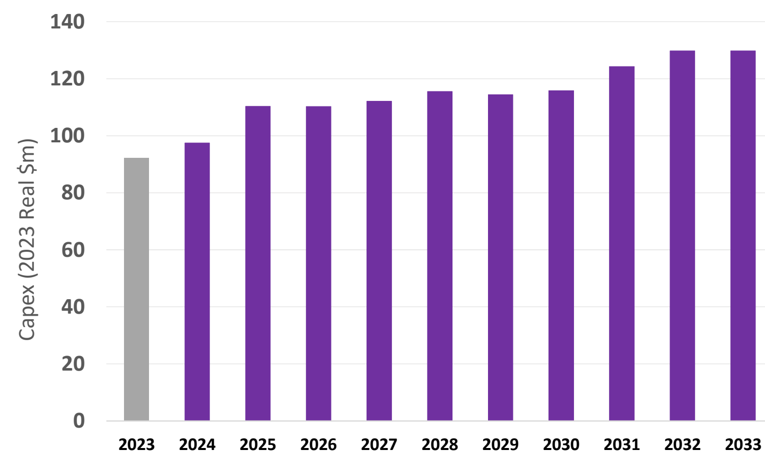


Table 24.3: Total renewals Capex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
92.2	97.5	110.3	110.3	112.1	115.6	114.4	115.8	124.3	129.8	129.8

Renewals expenditure has increased from historical levels to address cable replacement requirements. For the rest of the asset fleets, investment forecasts remain stable at recent levels. Expected efficiencies arising from improved asset management practices are expected to help offset increasing costs in other areas.

24.2.1.3 OTHER NETWORK CAPEX

Other network Capex is split into three portfolios. These are:

- Network Evolution
- Customer connections
- Asset relocations

The combined expenditure in these portfolios is shown in Figure 24.4.

Figure 24.4: Total other network Capex for the planning period

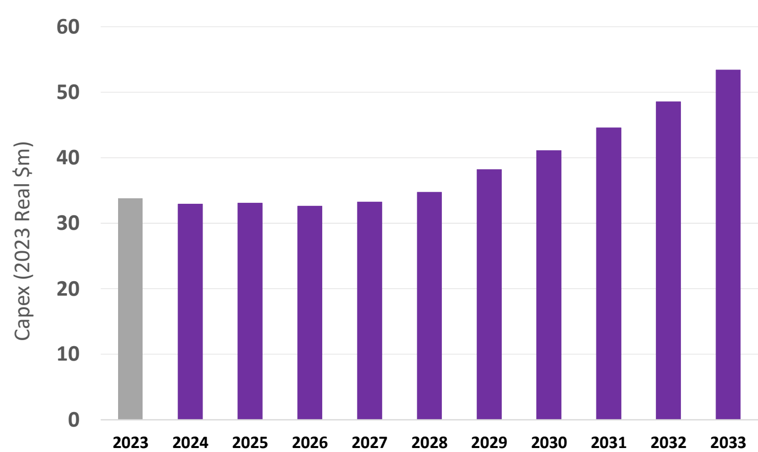


Table 24.4: Total other network Capex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
33.9	32.9	33.1	32.6	33.3	34.7	38.2	41.1	44.6	48.6	53.4

The profile for other network Capex is influenced by the variability in customer connections, and large one-off customer projects. Network Evolution expenditure is fairly stable during the planning period.

24.2.1.4 NON-NETWORK CAPEX

As discussed in Chapter 23, our non-network Capex is split into two portfolios. These are:

- Information and Communications Technology (ICT) Capex
- Facilities Capex

The combined expenditure in these portfolios is shown in Figure 24.5.

Figure 24.5: Total non-network Capex for the planning period

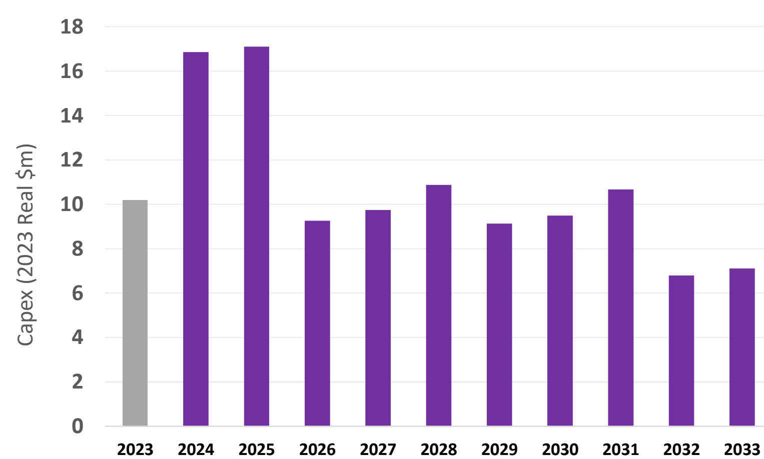


Table 24.5: Non-network Capex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10.2	16.9	17.1	9.3	9.7	10.9	9.1	9.5	10.7	6.8	7.1

ICT investments during the planning period include advancements in cyber security and analytics capabilities and supporting the evolution of an intelligent grid, and the cost of maintaining an increased number of digital capabilities upon which our business now depends.

Facilities Capex includes investment in new office space and upgrades to better accommodate the increased levels of staff and contractors and to ensure our staff are well supported in modern and productive environments.

These non-network investments are critical enablers of capacity and capability improvements needed to efficiently deliver increased work volumes and lift asset management capability.

24.2.2 OPEX

Total Opex includes the following two expenditure categories:

- **Network Opex**[104]
- **Non-network Opex**

In Figure 24.6, we set out our forecast for total Opex during the planning period. Our Opex profile reflects the underlying network needs discussed in this Asset Management Plan (AMP) and represents our best forecasts using available information.

Figure 24.6: Total Opex for the planning period

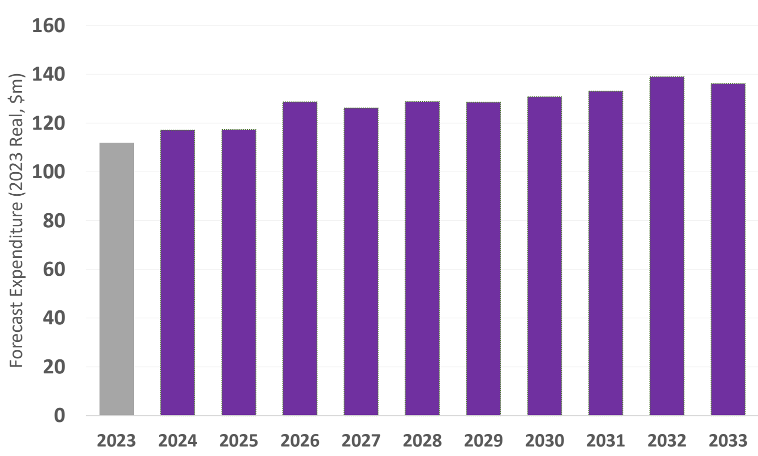


Table 24.6: Total forecast Opex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
111.9	117.1	117.3	128.6	126.1	128.8	128.5	130.7	133.0	139.0	136.1

Opex is forecast to increase during the planning period. This increase is driven by the need to resource our organisation to plan and deliver outcomes in line with New Zealand’s resilience and decarbonisation goals. A shift to cloud-based IT solutions increases the pressures on operating expenditure.

24.2.2.1 NETWORK OPEX

Our network Opex forecast includes expenditure in the following portfolios:

- **Preventive maintenance and inspection** – is scheduled work, including servicing to maintain asset integrity, and inspections to compile condition information for subsequent analysis and planning.
- **Corrective maintenance** – restores assets that have aged, been damaged, or do not meet their intended functional condition. It is undertaken to ensure assets remain safe, secure, and reliable.
- **Reactive maintenance** – activities required to restore the network to a safe and operational state following asset failures, faults, and other network incidents.
- **Vegetation management** – encompasses all tree trimming activities and support tasks, such as customer liaison and inspections to determine the work required to keep trees clear of our overhead network.
- **System Operations and Network Support (SONS)** – comprises our engineering staff and others who directly support electricity network operations. It also covers related network support expenses, such as professional advice, engineering reviews, quality assurance, and network running costs.

The combined expenditure in these portfolios is shown in Figure 24.7.

[104] System Operations and Network Support (SONS) is part of our Network Opex category.

Figure 24.7: Network Opex for the planning period

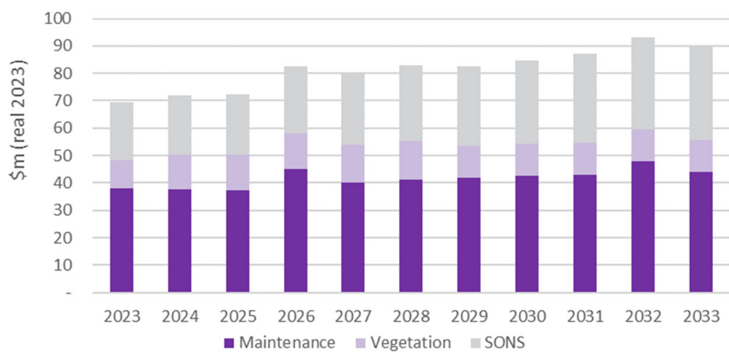


Table 24.7: Network Opex for the planning period ($m real 2023)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
69.5	72.1	72.3	82.7	80.2	82.8	82.5	84.7	87.0	93.0	90.1

Network Opex gradually increases during the planning period. This is primarily because of the forecast need for spend on energy partners to supply localised supply.

Maintenance forecasts are expected to continue at current levels, with one-off costs for Light Detection and Ranging (LiDAR) and pole-top photography re-capture events in FY26 and FY32

We expect to maintain our current levels of vegetation Opex and deliver a proactive vegetation management programme.

Our SONS forecast reflects ongoing investment in developing our people and their capabilities to support more advanced asset management maturity. We are also forecasting a need to spend on energy partners to contribute localised supply on request.

24.2.2.2 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 24.8: Non-network Opex for the planning period

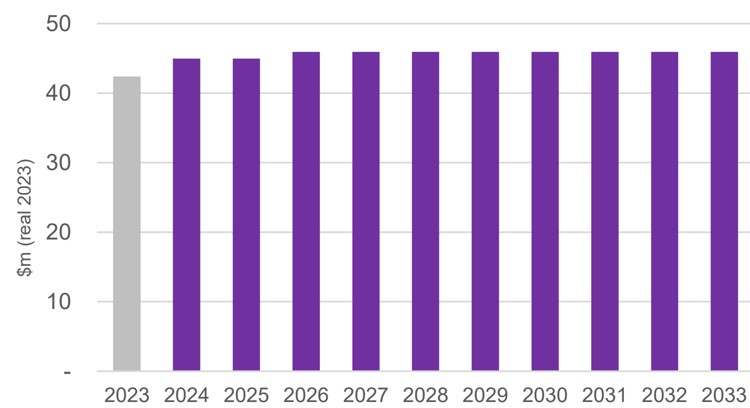


Table 24.8: Non-network Opex for the planning period ($m real 2021)

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
42.4	45.0	45.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0

Our non-network Opex is forecast to increase in FY24, and again in FY26, owing to further consolidation of our IT contracts to cloud-based services. From FY26 onwards it is then forecast to remain stable.

24.3 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.

24.3.1 FORECASTING INPUTS AND ASSUMPTIONS

Table 24.9 sets out the main inputs and assumptions underpinning our forecasts for the planning period.

Table 24.9: 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 Chapters14 – 20.
Expected asset lives, based on experience operating our network, provide an appropriate proxy for longer-term asset replacement forecasting.	For longer-term forecasting, at times we 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 14 – 20.
Historical relationships between load growth and related drivers (local GDP, installation control point – 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 6) 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.
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 LV feeders 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 Electricity Networks Association (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, except where we have identified specific areas of potential cost saving, e.g., overhead construction design, discussed in Chapter 14.
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.
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.

24.3.2 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.[105]

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 we face, including material, labour, and overhead components.
- CPI forecasts consistent with the Commerce 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[106].

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.

24.4 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[107].

Our forecasts beyond two years use a combination of the following approaches:[108]

- **Customised estimates (Capex)** – used for large single projects (>$500,000) that require individual tailored investigation.
- **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)** – 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.

24.4.1 CUSTOMISED ESTIMATES

This approach involves developing cost estimates based on project scopes, with larger projects supplemented with cost estimates from external consultants (where available). Project scopes are determined from desktop reviews of asset information, such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. Where a future project's cost can be estimated based on recent similar projects this will be used. 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, e.g., 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

105 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.

106 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.

107 The P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.

108 Budgeting for the earlier part of the period is based on tendered work, detailed project-specific estimates, or maintenance delivery plans.

the period. These desktop estimates are mainly informed by historical tenders and discussions with vendors.

24.4.2 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[109] 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.

24.4.3 BASE-STEP-TREND

We have used a base-step-trend approach to forecast part of our expenditure[110]. The approach is used by many utilities and economic regulators for forecasting expenditure that is recurring[111]. Figure 24.9 sets out the steps in developing base-step-trend forecasts.

Figure 24.9: Base-step-trend forecasting steps

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 expected in future years. If there are significant events, such as a major storm, an adjustment is made to remove their 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.

[109] The net impact of cost variances will tend to diminish in a portfolio containing a large number of P50 estimates.

[110] 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.

[111] The base-step-trend approach has been used by energy network businesses regulated by the Australian Energy Regulator. Its forecast assessment guidelines are available at www.aer.gov.au/node/18864. The approach is also conceptually similar to the Commerce Commission's approach to Opex used in setting DPPs in 2012 and 2014.

24.5 INFORMATION DISCLOSURE CATEGORIES

24.5.1 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[112].

- **System growth** – these investments are classified under our Growth and Security category, excluding reliability investments, and also include our Network Evolution investments. The investment plans are described in detail in Chapters 10 – 12.
- **Asset replacement and renewal** – these investments are classified under our renewals category. The investment plans are described in detail in Chapters 14 – 23.
- **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 14 – 23. Reliability investments include our automation programme (part of Growth and Security), discussed in Chapter 16.
- **Customer connections** – our customer connections portfolio is consistent with the Information Disclosure definition. These investments are discussed in Chapter 13.
- **Asset relocations** – our asset relocations portfolio is consistent with the Information Disclosure definition. These investments are discussed in Chapter 22.

24.5.2 NETWORK OPEX

As 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.

- **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 Commerce 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 SONS portfolio is consistent with the Information Disclosure definition, although we classify SONS as network Opex.

[112] Our non-network Capex categories align with the disclosure requirements and are discussed in Chapter 23.

APPENDICES

This section provides additional information to support our AMP. It includes our Information Disclosure schedules.

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.

ABC means Aerial Bundled 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 several 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. Should also include explanation of the H1-H5 scale.

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 can 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.

BESS means Battery Energy Storage System.

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.

CB is a Circuit Breaker. These are critical switching devices on our network

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.

CDR is a Conceptual Design Report

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.

CNAIM means Common Network Asset Indices Methodology. It is the UK standard for modelling asset risk and degradation.

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.

CT means Current Transformer

CIW means Customer-initiated Works

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.

DC means direct current....

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.

DNO is a Do Not Operate notice is assigned to assets deemed unsafe for operators to switch without extra operational precautions.

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 can 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.

EHV means Extremely High Voltage

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.

IAC is internal arc flash containment.

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.

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.

LPWAN is a low-power wide area network

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.

MD means maximum demand

MDI means Maximum Demand Indicator

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.

MV is mega volts or 1,000 volts

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.

NAPA means Network Access Planning Application

NAT means Network Approval Test process, which is applied to assess the suitability of equipment for use on the network.

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.

NOM is the Powerco Network Operations Manual. A comprehensive group of standards and forms that provide internal operational rules and guidance for work carried out on Powerco Electricity networks.

NZSEE is the New Zealand Society of Earthquake Engineering.

NZTA is the New Zealand Transport Agency.

NZUAG is the New Zealand Utilities Advisory Group

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.

OHRPT means Overhead Renewal Planning Tool

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.

PQM is a Power Quality Meter

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.

RFI/ROI means Request for Information and Registration of Interest

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.

SMEI is the Safety Manual for the Electricity Industry

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.

VAR stands for Mega Volt*Amps Reactive, also known as the apparent power.

VLF means Very Low Frequency spectrum

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.

3Ds means decarbonisation, decentralisation, and digitalisation.

APPENDIX 2 DISCLOSURE SCHEDULES

A2.1 SCHEDULE 11A

Included below is our Schedule 11A disclosure. Constant price figures in this schedule are in 2023 real dollars.

Company Name	Powerco
AMP Planning Period	1 April 2023 - 31 Mar 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	77,478	83,374	88,674	92,267	96,646	103,129	116,240	128,291	142,482	159,022	179,163
11		System growth	93,580	87,420	88,963	91,687	113,245	137,625	157,973	127,227	131,463	153,158	137,257
12		Asset replacement and renewal	87,773	94,359	107,225	112,724	120,334	126,830	128,100	132,640	146,253	156,284	160,681
13		Asset relocations	9,055	6,541	5,234	2,408	2,463	2,513	2,564	2,616	2,670	2,724	2,781
14		Reliability, safety and environment:											
15		Quality of supply	4,577	10,338	12,766	20,731	21,833	22,872	24,826	26,130	28,659	29,041	22,526
16		Legislative and regulatory	550	2,873	4,718	2,437	-	-	-	-	-	-	-
17		Other reliability, safety and environment	3,843	5,352	8,378	8,545	8,765	8,949	9,137	9,167	9,194	9,387	8,379
18		**Total reliability, safety and environment**	8,970	18,563	25,862	31,713	30,598	31,821	33,963	35,297	37,853	38,428	30,905
19		**Expenditure on network assets**	276,856	290,257	315,958	330,799	363,286	401,918	438,840	426,071	460,721	509,616	510,787
20		Expenditure on non-network assets	10,196	17,225	17,806	9,834	10,539	12,003	10,267	10,893	12,486	8,112	8,651
21		**Expenditure on assets**	287,052	307,482	333,764	340,633	373,825	413,921	449,107	436,964	473,207	517,728	519,438
22													
23	*plus*	Cost of financing	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078
24	*less*	Value of capital contributions	54,090	56,087	58,787	59,105	61,724	65,782	73,990	81,535	90,418	100,766	113,361
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	235,040	253,473	277,055	283,606	314,179	350,217	377,195	357,507	384,867	419,040	408,155
28													
29		Assets commissioned	249,000	263,459	259,941	273,606	293,004	362,256	369,059	375,097	373,914	406,575	416,658
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 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
32			**$000 (in 2021 constant prices)**										
33		Consumer connection	77,478	80,670	83,601	84,973	87,092	91,113	100,671	108,907	118,550	129,683	143,204
34		System growth	93,580	83,248	81,733	81,787	98,592	117,511	132,096	104,177	105,374	120,277	105,563
35		Asset replacement and renewal	87,774	89,692	98,306	100,452	104,520	107,934	106,800	108,341	116,980	122,453	123,328
36		Asset relocations	9,055	6,308	4,909	2,204	2,204	2,204	2,204	2,204	2,204	2,204	2,204
37		Reliability, safety and environment:											
38		Quality of supply	4,577	9,804	11,664	18,377	18,822	19,328	20,569	21,217	22,810	22,646	17,152
39		Legislative and regulatory	550	2,747	4,368	2,198	-	-	-	-	-	-	-
40		Other reliability, safety and environment	3,843	5,082	7,670	7,619	7,619	7,619	7,619	7,487	7,356	7,356	6,433
41		**Total reliability, safety and environment**	8,970	17,633	23,702	28,194	26,441	26,947	28,188	28,704	30,166	30,002	23,585
42		**Expenditure on network assets**	276,857	277,551	292,251	297,610	318,849	345,709	369,959	352,333	373,274	404,619	397,884
43		Expenditure on non-network assets	10,195	16,851	17,089	9,256	9,730	10,869	9,117	9,484	10,657	6,788	7,097
44		**Expenditure on assets**	287,052	294,402	309,340	306,866	328,579	356,578	379,076	361,817	383,931	411,407	404,981
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 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	2,704	5,073	7,294	9,554	12,016	15,569	19,384	23,932	29,339	35,959
System growth	-	4,172	7,230	9,900	14,653	20,114	25,877	23,050	26,089	32,881	31,694
Asset replacement and renewal	(1)	4,667	8,919	12,272	15,814	18,896	21,300	24,299	29,273	33,831	37,353
Asset relocations	-	233	325	204	259	309	360	412	466	520	577
Reliability, safety and environment:											
Quality of supply	-	534	1,102	2,354	3,011	3,544	4,257	4,913	5,849	6,395	5,374
Legislative and regulatory	-	126	350	239	-	-	-	-	-	-	-
Other reliability, safety and environment	-	270	708	926	1,146	1,330	1,518	1,680	1,838	2,031	1,946
Total reliability, safety and environment	-	930	2,160	3,519	4,157	4,874	5,775	6,593	7,687	8,426	7,320
Expenditure on network assets	(1)	12,706	23,707	33,189	44,437	56,209	68,881	73,738	87,447	104,997	112,903
Expenditure on non-network assets	1	374	717	578	809	1,134	1,150	1,409	1,829	1,324	1,554
Expenditure on assets	-	13,080	24,424	33,767	45,246	57,343	70,031	75,147	89,276	106,321	114,457

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
*Consumer types defined by EDB**	$000 (in constant prices)					
All Consumers	77,478	80,670	83,601	84,973	87,092	91,113
**include additional rows if needed*						
Consumer connection expenditure	77,478	80,670	83,601	84,973	87,092	91,113
less Capital contributions funding consumer connection	49,667	51,783	54,001	54,545	55,905	58,486
Consumer connection less capital contributions	27,811	28,887	29,600	30,428	31,187	32,627

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	49,134	8,950	13,503	7,884	16,359	36,299
Zone substations	22,225	30,872	29,902	35,077	39,508	32,476
Distribution and LV lines	5,114	7,158	7,449	8,289	9,770	9,596
Distribution and LV cables	4,544	8,138	7,562	7,915	9,157	13,120
Distribution substations and transformers	731	1,023	1,713	3,690	1,920	1,269
Distribution switchgear	4,384	6,136	6,171	6,398	6,798	7,594
Other network assets	7,448	20,971	15,433	12,534	15,080	17,157
System growth expenditure	93,580	83,248	81,733	81,787	98,592	117,511
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	93,580	83,248	81,733	81,787	98,592	117,511

11a(iv): Asset Replacement and Renewal

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
$000 (in constant prices)						
Subtransmission	2,772	3,277	3,478	4,738	5,394	6,392
Zone substations	16,579	19,368	21,738	17,400	18,928	19,742
Distribution and LV lines	42,217	40,945	43,634	46,594	47,126	47,700
Distribution and LV cables	7,214	5,891	9,453	10,763	11,967	13,404
Distribution substations and transformers	7,429	7,997	7,436	7,990	8,048	8,086
Distribution switchgear	11,068	11,291	11,519	11,740	11,947	11,852
Other network assets	495	923	1,048	1,227	1,110	758
Asset replacement and renewal expenditure	87,774	89,692	98,306	100,452	104,520	107,934
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	87,774	89,692	98,306	100,452	104,520	107,934

11a(v):Asset Relocations

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
*Project or programme** / **$000 (in constant prices)**						
Waka Kotahi undergrounding (SH2 TGA to Katikati)	6,882	4,100	2,700	-	-	-
**include additional rows if needed*						
All other project or programmes - asset relocations	2,173	2,208	2,209	2,204	2,204	2,204
Asset relocations expenditure	9,055	6,308	4,909	2,204	2,204	2,204
less Capital contributions funding asset relocations	4,423	3,085	2,416	1,078	1,078	1,078
Asset relocations less capital contributions	4,632	3,223	2,493	1,126	1,126	1,126

11a(vi):Quality of Supply

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
*Project or programme** / **$000 (in constant prices)**						
**include additional rows if needed*						
All other projects or programmes - quality of supply	4,577	9,804	11,664	18,377	18,822	19,328
Quality of supply expenditure	4,577	9,804	11,664	18,377	18,822	19,328
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	4,577	9,804	11,664	18,377	18,822	19,328

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28

11a(vii): Legislative and Regulatory

*Project or programme**	$000 (in constant prices)					
Secondary systems (relay replacement for extended reserves)	550	2,747	4,368	2,198	-	-
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	550	2,747	4,368	2,198	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	550	2,747	4,368	2,198	-	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28

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

*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment	3,843	5,082	7,670	7,619	7,619	7,619
Other reliability, safety and environment expenditure	3,843	5,082	7,670	7,619	7,619	7,619
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	3,843	5,082	7,670	7,619	7,619	7,619

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28

11a(ix): Non-Network Assets

Routine expenditure						
*Project or programme**	$000 (in constant prices)					
ICT capex	5,682	12,344	10,563	6,144	5,148	8,317
Facilities	962	2,004	465	1,480	846	1,099
Leases	2,114	2,376	1,453	1,632	2,890	1,453
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	8,758	16,724	12,481	9,256	8,884	10,869
Atypical expenditure						
*Project or programme**						
ICT capex (new capability)	-	-	-	-	-	-
Facilities	1,437	127	4,608	-	846	-
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	1,437	127	4,608	-	846	-
Expenditure on non-network assets	10,195	16,851	17,089	9,256	9,730	10,869

A2.2 SCHEDULE 11B

Included below is our Schedule 11B disclosure. Constant price figures in this schedule are in 2023 real dollars.

Company Name	Powerco
AMP Planning Period	1 April 2023 - 31 Mar 2033

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		*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 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	7,754	8,132	8,481	8,803	9,136	9,374	9,619	9,872	10,131	10,396	10,669
11	Vegetation management	10,183	13,234	14,060	14,579	16,029	16,429	13,837	14,196	14,564	14,942	15,329
12	Routine and corrective maintenance and inspection	18,132	19,835	20,575	29,060	24,713	26,316	27,548	28,808	29,916	36,865	32,367
13	Asset replacement and renewal	12,109	11,437	11,616	12,496	12,491	12,954	13,264	13,580	13,905	14,237	14,578
14	**Network Opex**	48,178	52,638	54,732	64,938	62,369	65,073	64,268	66,456	68,516	76,440	72,943
15	System operations and network support	21,336	22,183	22,749	26,201	28,361	30,476	32,766	35,192	37,940	39,771	41,738
16	Business support	42,397	45,971	46,861	48,849	49,797	50,771	51,772	52,803	53,859	54,937	56,035
17	**Non-network opex**	63,733	68,154	69,610	75,050	78,158	81,247	84,538	87,995	91,799	94,708	97,773
18	**Operational expenditure**	111,911	120,792	124,342	139,988	140,527	146,320	148,806	154,451	160,315	171,148	170,716
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
21		**$000 (in 2021 constant prices)**										
22	Service interruptions and emergencies	7,754	7,796	7,838	7,881	7,924	7,966	8,009	8,053	8,096	8,140	8,184
23	Vegetation management	10,183	12,687	12,994	13,052	13,903	13,961	11,520	11,579	11,638	11,698	11,758
24	Routine and corrective maintenance and inspection	18,132	18,967	18,945	25,918	21,367	22,293	22,866	23,430	23,840	28,785	24,763
25	Asset replacement and renewal	12,109	10,937	10,696	11,145	10,800	10,974	11,010	11,045	11,081	11,117	11,153
26	**Network Opex**	48,178	50,387	50,473	57,996	53,994	55,194	53,405	54,107	54,655	59,740	55,858
27	System operations and network support	21,336	21,701	21,832	24,658	26,183	27,595	29,095	30,639	32,384	33,281	34,242
28	Business support	42,397	44,972	44,972	45,972	45,972	45,972	45,972	45,972	45,972	45,972	45,972
29	**Non-network opex**	63,733	66,673	66,804	70,630	72,155	73,567	75,067	76,611	78,356	79,253	80,214
30	**Operational expenditure**	111,911	117,060	117,277	128,626	126,149	128,761	128,472	130,718	133,011	138,993	136,072
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												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	336	643	922	1,212	1,408	1,610	1,819	2,035	2,256	2,485
43	Vegetation management	-	547	1,066	1,527	2,126	2,468	2,317	2,617	2,926	3,244	3,571
44	Routine and corrective maintenance and inspection	-	868	1,630	3,142	3,346	4,023	4,682	5,378	6,076	8,080	7,604
45	Asset replacement and renewal	-	500	920	1,351	1,691	1,980	2,254	2,535	2,824	3,120	3,425
46	**Network Opex**	-	2,251	4,259	6,942	8,375	9,879	10,863	12,349	13,861	16,700	17,085
47	System operations and network support	-	482	917	1,543	2,178	2,881	3,671	4,553	5,556	6,490	7,496
48	Business support	-	999	1,889	2,877	3,825	4,799	5,800	6,831	7,887	8,965	10,063
49	**Non-network opex**	-	1,481	2,806	4,420	6,003	7,680	9,471	11,384	13,443	15,455	17,559
50	**Operational expenditure**	-	3,732	7,065	11,362	14,378	17,559	20,334	23,733	27,304	32,155	34,644

A2.3 SCHEDULE 12A

											Company Name	**Powerco**
											AMP Planning Period	**1 April 2023 - 31 March 2033**

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

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**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**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.5%	3.9%	5.2%	14.2%	76.2%	-	4	5.6%
11	All	Overhead Line	Wood poles	No.	1.0%	6.9%	20.2%	20.5%	51.3%	-	3	6.7%
12	All	Overhead Line	Other pole types	No.	0.0%	0.1%	53.1%	26.6%	20.3%	-	3	3.2%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.3%	2.2%	11.2%	73.5%	12.7%	-	4	4.6%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	0.7%	6.2%	2.6%	90.4%	-	3	4.0%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	100.0%	-	-	-	4	11.6%
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	-	-	-	73.4%	26.6%	-	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.	7.2%	36.7%	17.3%	32.4%	6.5%	-	3	12.0%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	3.1%	-	96.9%	-	4	3.4%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	18.6%	14.4%	3.7%	63.3%	-	4	21.3%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	21.6%	-	78.4%	-	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	1.3%	52.7%	5.2%	40.8%	-	4	4.7%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	100.0%	-	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.	-	33.3%	5.6%	-	61.1%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	5.4%	10.7%	83.9%	-	3	27.0%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	4.4%	-	95.6%	-	3	-
35												

	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	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
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1.6%	8.0%	21.8%	17.0%	51.6%	-	4	6.5%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.2%	10.9%	25.9%	52.9%	9.9%	0.2%	3	9.3%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	-
42	HV	Distribution Line	SWER conductor	km	-	4.8%	28.0%	58.2%	8.9%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1.0%	0.6%	3.6%	18.9%	75.8%	-	3	4.2%
44	HV	Distribution Cable	Distribution UG PILC	km	1.1%	0.5%	0.9%	25.6%	71.8%	-	3	9.5%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	100.0%	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.2%	-	1.2%	0.8%	97.9%	-	3	5.0%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	7.2%	23.1%	16.4%	53.3%	-	4	24.8%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.0%	-	11.0%	18.0%	71.0%	-	3	7.3%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1.0%	5.3%	16.4%	15.5%	61.7%	-	3	11.5%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.3%	1.2%	6.4%	7.7%	84.4%	-	3	2.7%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.0%	1.9%	7.3%	11.6%	77.2%	-	3	6.7%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.6%	2.6%	8.1%	7.5%	81.2%	-	4	1.9%
53	HV	Distribution Transformer	Voltage regulators	No.	1.7%	-	-	3.4%	94.9%	-	4	1.5%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.5%	1.5%	6.0%	9.9%	81.1%	-	2	0.7%
55	LV	LV Line	LV OH Conductor	km	0.0%	13.9%	48.3%	28.8%	2.7%	6.3%	2	13.9%
56	LV	LV Cable	LV UG Cable	km	0.1%	0.2%	3.2%	19.2%	77.3%	-	2	0.4%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	2.0%	4.6%	33.0%	19.5%	38.2%	2.7%	2	5.1%
58	LV	Connections	OH/UG consumer service connections	No.	-	1.4%	62.2%	7.9%	28.5%	-	2	0.1%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	31.8%	4.5%	26.4%	37.3%	-	3	7.4%
60	All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	-	14.6%	23.6%	30.9%	30.9%	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	2.0%	98.0%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	-	60.0%	40.0%	-	-	4	4.0%
63	All	Load Control	Relays	No.	44.2%	2.3%	2.1%	7.3%	44.1%	-	1	-
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 2023 – 31 March 2033**

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

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**	**Explanation**
8										
9	Coromandel	5	1	N-1	1	451%	6	78%	No constraint within +5 yea	Single 66kV circuit. Distributed generation project for backup..
10	Kerepehi	10	-	N-1SW	6	-	-	-	Subtransmission Circuit	Single 66kV circuit. Some increase in 11kV backfeed capacity in the short term with routine projects.
11	Matatoki	5	-	N	2	-	-	-	Subtransmission circuit	2nd transformer will improve Tx firm capacity. Single subtransmission circuit remains constraint
12	Tairua	9	8	N	-	127%	8	130%	Transformer	Tx firm capacity constraint remains due to Whenuakite substation being deferred
13	Thames T1& T2	12	-	N-1	2	-	-	-	Subtransmission circuit	Deferral of Kopu-Kauaeranga project keeps Thames on N security
14	Thames T3	2	7	N-1SW	7	22%	7	22%	No constraint within +5 yea	Customer agreed security. No load increase indicated.
15	Whitianga	18	19	N-1SW	3	94%	16	124%	Transformer	Whenuakite project deferral results in Tx firm capacity constraint in the future
16	Paeroa	8	11	N-1	2	76%	10	88%	No constraint within +5 yea	Transformer feeder arrangement restricts firm capacity to transformer capacity. Risk managed operationally in the interim.
17	Waihi	18	21	N-1	1	86%	21	149%	Transformer and Subtransm	Customer agreed security. Proposed OceanaGold substation will eventually offload Waihi substation and resolve firm capacity constraint
18	Waihi Beach	6	3	N	3	193%	6	115%	Subtransmission circuit	Single 33kV cct. 2nd Transformer mid-2023 commissioning. Proposed backup distributed generation post-2025. Removal of tee near Waihi to improve reliability.
19	Whangamata	12	4	N	1	295%	4	302%	Subtransmission circuit	11kV link to Tairua for backup.
20	Aongatete	5	5	N-1	2	90%	5	99%	No constraint within +5 yea	Planned renewal of Aongatete substation
21	Bethlehem	11	8	N	8	136%	24	55%	No constraint within +5 yea	Single transformer Substation - 2nd Tx proposed 2025
22	Hamilton St	11	21	N-1	12	51%	21	58%	No constraint within +5 yea	
23	Katikati	11	14	N-1SW	5	79%	14	100%	No constraint within +5 yea	
24	Kauri Pt	3	2	N-1	2	176%	2	128%	Transformer and Subtransm	Single Tx and subtransmission circuit. Reliant on 11kV backfeed strengthening
25	Matua	10	-	N-1	8	-	21	46%	No constraint within +5 yea	Second transformer and conversion of 11kV feeder to 33kV subtransmission second circuit
26	Omokoroa	12	13	N-1SW	3	93%	13	109%	Transformer	Proposed Pahoia substation to offload Omokoroa substation
27	Otumoetai	15	14	N-1SW	11	110%	14	114%	Transformer	Minor constraint - managed operationally. Bethlehem second transformer project will offload Otumoetai and reduce its MD
28	Pyes Pa	20	24	N-1	8	82%	24	298%	Transformer and Subtransm	Possible constraint depending on the rate of commercial/industrial growth. New Belk Road substation planned 2022-2027 to offload Pyes Pa.
29	Waihi Rd	20	24	N-1	10	85%	24	88%	No constraint within +5 yea	
30	Welcome Bay	24	21	N	4	113%	21	123%	Transformer and Subtransm	Managed operationally. New Oropi substation planned 2024-2027 will relieve constraints at Welcome Bay.
31	Matapihi	13	24	N-1	14	55%	24	57%	No constraint within +5 yea	
32	Omanu	13	24	N-1	12	53%	24	57%	No constraint within +5 yea	
33	Papamoa	17	21	N-1	10	79%	21	84%	No constraint within +5 yea	11kV offload with new feeders from Wairakei substation
34	Te Maunga	12	10	N	10	113%	10	126%	Transformer	Proposed Te Maunga 2nd transformer lifts N-1 Tx capacity
35	Triton	20	21	N-1SW	10	95%	21	104%	No constraint within +5 yea	Transformers upgraded and load shift to Omanu

7	**12b(i): System Growth – Zone Substations**									
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**	**Explanation**
36	Wairakei	11	24	N-1	6	45%	24	77%	No constraint within +5 yea	
37	Atuaroa Ave	9	-	N	7	-	-	-	Subtransmission Circuit an	33kV second circuit 2026 and 2nd transformer 2025
38	Paengaroa	5	4	N-1SW	4	146%	15	89%	No constraint within +5 yea	Second transformer and second 33kV circuit proposed for the
39	Pongakawa	5	1	N-1	1	351%	4	150%	Subtransmission Circuit	Single 33kV circuit, limited 11kV backfeed capacity increase
40	Te Puke	21	23	N-1	11	91%	23	176%	Transformer and Subtransn	Proposed Rangiuru Business Park will offload Te Puke load
41	Farmer Rd	6	-	N-1SW	1	-	-	-	Subtransmission circuit & tr	Customer's planned load growth will exceed existing transfomer capacity and overload existing 33kV subtranmission circuit. Proposed WIEL substation.
42	Inghams	4	-	N	-	-	-	-	Subtransmission Circuit & T	Customer agreed security
43	Mikkelsen Rd	12	19	N-1	4	63%	19	66%	No constraint within +5 yea	
44	Morrinsville	8	11	N-1	2	77%	11	93%	No constraint within +5 yea	Morrinsville 33kV bus and proposed Avenue Road North substation will reduce Morrinsville load
45	Piako	14	18	N-1	7	80%	18	100%	No constraint within +5 yea	
46	Tahuna	6	1	N-1SW	1	787%	5	125%	Subtransmission Circuit	Single 33kV circuit. Risk mitigated operationally via increased 11kV backfeeds
47	Tatua	5	-	N	-	-	-	-	Subtransmission Circuit an	Transformer upgrade planned. Customer agreed security.
48	Waitoa	12	19	N-1	-	65%	19	65%	No constraint within +5 yea	
49	Walton	5	-	N	2	-	-	-	Transformer	Single Transformer. Risk managed operationally
50	Browne St	10	11	N-1SW	7	98%	11	127%	Transformer	Very minor, low risk. Managed operationally
51	Lake Rd	6	5	N-1SW	2	126%	5	136%	Transformer	11kV backfeeds to manage risk operationally
52	Tirau	9	9	N-1SW	-	106%	17	76%	No constraint within +5 yea	Transformer upgrade to increase Tx firm capacity
53	Putaruru	12	17	N-1	1	70%	17	95%	No constraint within +5 yea	
54	Tower Rd	8	17	N-1	5	50%	17	52%	No constraint within +5 yea	
55	Waharoa Nth	4	3	N	-	142%	-	-	No constraint within +5 yea	
56	Waharoa Sth	5	-	N	-	-	-	-	No constraint within +5 yea	Customer agreed security
57	Baird Rd	10	19	N-1	7	51%	19	63%	No constraint within +5 yea	
58	Midway / Lakeside	4	-	N	-	-	-	-	Subtransmission Circuit & T	Customer agreed security at both substations
59	Maraetai Rd	9	19	N-1	7	46%	19	81%	No constraint within +5 yea	
60	Bell Block	16	25	N-1	9	64%	25	68%	No constraint within +5 yea	Load transfer planned post 2024
61	Brooklands	19	24	N-1	7	80%	24	94%	No constraint within +5 yea	
62	Cardiff	2	3	N-1SW	3	68%	3	71%	No constraint within +5 yea	
63	City	16	20	N-1	12	80%	20	86%	No constraint within +5 yea	Capacity upgrade planned post 2027
64	Cloton Rd	10	13	N-1	1	78%	13	81%	No constraint within +5 yea	
65	Douglas	1	2	N-1SW	2	83%	2	85%	No constraint within +5 yea	Single circuit. Very low risk. Most load can be backfed.
66	Eltham	9	11	N-1SW	3	84%	15	64%	No constraint within +5 yea	Transformer upgrade ~2024
67	Inglewood	5	6	N-1SW	3	87%	6	92%	No constraint within +5 yea	Load transfer planned post 2025
68	Kaponga	3	3	N-1SW	2	104%	3	108%	Transformer	Low risk of failure. Operationally managed.
69	Katere	15	24	N-1	11	63%	24	67%	No constraint within +5 yea	
70	McKee	1	-	N	-	-	-	-	Transformer and Subtransn	
71	Motukawa	2	1	N	1	121%	1	126%	Transformer	Single transformer. Most load can be backfed.
72	Moturoa	19	24	N-1	7	78%	30	66%	No constraint within +5 yea	New 33kV circuits and transformers 2019/20
73	Oakura	4	-	N	-	-	20	20%	Subtransmission circuit	Single cct & Tx. 11kV backfed adequate
74	Waihapa	1	2	N-1SW	2	50%	2	50%	No constraint within +5 yea	

7	12b(i): System Growth – Zone Substations										
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	Explanation
75	Waitara East	5	6	N-1	4	85%	6	91%	No constraint within +5 yea	
76	Waitara West	7	6	N-1SW	8	106%	10	70%	No constraint within +5 yea	Transformer upgrade planned resuing Pohokura units
77	Cambria	15	17	N-1	5	87%	17	89%	No constraint within +5 yea	Transformer & Subtrans upgrade planned ~2026
78	Kapuni	6	11	N-1	4	52%	11	99%	No constraint within +5 yea	
79	Livingstone	3	3	N-1SW	1	91%	5	56%	No constraint within +5 yea	Transformers scheduled for replacement ~2025 (higher cap)
80	Manaia	6	5	N	5	111%	5	114%	Transformer	Single Tx bank (after renewal)
81	Ngariki	3	4	N-1SW	4	66%	4	68%	No constraint within +5 yea	
82	Pungarehu	3	5	N-1	2	69%	5	73%	No constraint within +5 yea	
83	Tasman	6	6	N-1SW	3	103%	6	107%	Transformer	Low risk – operationally managed (e.g. backfeeds)
84	Mokoia	3	3	N-1SW	4	105%	3	110%	Transformer	Low risk – managed operationally through backfeeds
85	Beach Rd	10	16	N-1	3	64%	16	65%	No constraint within +5 yea	
86	Blink Bonnie	3	3	N-1SW	3	94%	3	97%	No constraint within +5 yea	Low risk of failure. Security upgrades planned post 2026
87	Castlecliff	9	9	N-1SW	5	109%	13	87%	No constraint within +5 yea	Transformers to be upgraded
88	Hatricks Wharf	10	-	N	6	-	10	101%	Transformer	Single transf, but 11kV bus tie (Taupo Quay) mitigates risk
89	Kai Iwi	2	1	N	1	209%	1	218%	Subtransmission Circuit	Single 33kV cct & single Tx. Also N security GXP.
90	Peat St	14	-	N-1	6	-	-	-	Transpower	GXP on N-security
91	Roberts Ave	5	6	N-1SW	6	79%	6	80%	No constraint within +5 yea	
92	Taupo Quay	6	-	N-1SW	8	-	10	60%	Transformer	Transformer upgrade lifts capacity
93	Wanganui East	6	3	N	3	173%	3	175%	Subtransmission Circuit	Single 33kV cct and Tx. Reliant on backfeeds
94	Taihape	4	1	N	1	546%	10	45%	Transformer	2nd Transformer and new switchboard
95	Waiouru	3	1	N	1	516%	1	514%	Transformer and Subtransm	N secure GXP, 33kV & Tx.
96	Arahina	8	3	N	3	262%	24	65%	No constraint within +5 yea	N secure GXP, second Arahina 33kV circuit
97	Bulls	6	2	N	2	276%	2	287%	Transformer	~2023 2nd 33kV. Post 2024 2nd transformer.
98	Pukepapa	5	2	N	2	250%	25	100%	Transformer and Subtransm	New Putaruru 33kV circuit
99	Rata	3	1	N	1	407%	1	416%	Subtransmission circuit	Single 33kV cct and Tx. Post 2028 plan for 11kV Upgrade.
100	Feilding	23	24	N-1SW	2	98%	24	103%	No constraint within +5 yea	Re-rate transformers 2023 and post 2023 33kV upgrade and new zone substation
101	Ferguson St	11	24	N-1	15	47%	24	48%	No constraint within +5 yea	
102	Kairanga	18	19	N-1SW	8	94%	24	85%	No constraint within +5 yea	
103	Keith St	19	22	N-1	-	85%	22	96%	No constraint within +5 yea	
104	Kelvin Grove	17	17	N-1SW	5	99%	24	135%	Transformer and Subtransm	Offload to proposed North East Industrial substation
105	Kimbolton	3	1	N	1	215%	1	224%	Subtransmission Circuit	Single 33kV circuit & single transformer. Remote Sub.
106	Main St	18	17	N-1	13	105%	25	74%	No constraint within +5 yea	New Fergusson sub & 33kV cables address ex. high risk
107	Milson	16	18	N-1SW	5	90%	19	95%	No constraint within +5 yea	Possible TX and subtransmission upgrade post 2023
108	Ohakea	2	-	N	1	-	-	-	Transformer	Single 33kV circuit & single transformer. 2nd 33kV circuit in 3 years.
109	Pascal St	15	17	N-1	12	87%	25	62%	No constraint within +5 yea	New Fergusson sub & 33kV cables address ex. high risk
110	Sanson	9	-	N-1SW	4	-	11	86%	No constraint within +5 yea	33kV backfeed secures load. New Sanson-Bulls 33kV link and new Ohakea Sub
111	Turitea	14	-	N-1	5	-	-	-	Subtransmission Circuit	Switched 33kV security – Second 33kV circuit and TX upgrade post 2025
112	Alfredton	1	1	N	0	39%	1	39%	No constraint within +5 yea	Single Transf. but adequate backfeed.
113	Mangamutu	13	13	N-1	1	98%	13	100%	Transformer	Major customer largely determines security requirements.

7	**12b(i): System Growth – Zone Substations**									
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**	**Explanation**
114	Parkville	2	-	N	-	-	-	-	Transformer	Single transformer
115	Pongaroa	1	3	N	1	26%	3	26%	No constraint within +5 year	
116	Akura	13	9	N-1SW	7	146%	15	92%	No constraint within +5 year	Txs replaced & 33kV circuits upgrade planned
117	Awatoitoi	1	3	N	1	34%	3	35%	No constraint within +5 year	
118	Chapel	14	14	N-1	5	98%	23	61%	No constraint within +5 year	Upgrade short section of 33kV cable
119	Clareville	10	9	N	1	111%	17	89%	Transformer	Transformer and 33kV upgrade post 2024
120	Featherston	4	7	N-1	0	55%	7	58%	No constraint within +5 year	
121	Gladstone	1	1	N	0	62%	1	64%	No constraint within +5 year	
122	Hau Nui	0	-	N	-	-	-	-	Subtransmission Circuit & T	Generation site. Not economic to provide higher security
123	Kempton	5	0	N	0	1,201%	0	1,271%	Transformer and Subtransm	Post 2024: 2nd 33kV supply & upgraded 2nd transformer, 2025 new sub to increase transfer capacity
124	Martinborough	5	0	N	0	4,593%	0	4,885%	Transformer and Subtransm	Single transformer. 2nd Tx planned post 2024, 2025 new sub to increase transfer capacity
125	Norfolk	6	11	N-1	4	61%	18	47%	No constraint within +5 year	Future 33kV circuits upgrade
126	Te Ore Ore	8	7	N	7	117%	7	121%	Transformer	Single transformer. Risk is managed operationally and acceptable
127	Tinui	1	1	N	1	64%	1	67%	No constraint within +5 year	Reliant on 11kV backfeeds
128	Tuhitarata	3	-	N	-	-	1	343%	Subtransmission circuit	Single 33kV circuit & single transformer, 2025 New Sub to increase transfer capacity

[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation

A2.5 SCHEDULE 12C

Company Name	**Powerco Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

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

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**					
10			for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11		*Consumer types defined by EDB**		**RY23**	**RY24**	**RY25**	**RY26**	**RY27**	**RY28**
12		Small		4,471	4,827	4,827	4,827	4,827	4,827
13		Commercial		70	57	57	57	57	57
14		Industrial		19	18	18	18	18	18
15									
16									
17		**Connections total**		4,560	4,902	4,902	4,902	4,902	4,902
18		**include additional rows if needed*							
19	**Distributed generation**								
20		Number of connections		1,465	1,628	2,117	2,442	2,931	3,419
21		Installed connection capacity of distributed generation (MVA)		13.0	14.0	18.0	21.0	25.0	29.0

sch ref					Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
22	**12c(ii) System Demand**									
24	**Maximum coincident system demand (MW)**			for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
25			GXP demand		859	891	910	932	958	987
26		*plus*	Distributed generation output at HV and above		114	118	119	119	120	120
27			**Sch 12c Maximum coincident system demand [MW]**		974	1,009	1,028	1,051	1,077	1,107
28		*less*	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29			**Demand on system for supply to consumers' connection points**		974	1,009	1,028	1,051	1,077	1,107
30	**Electricity volumes carried (GWh)**									
31			Electricity supplied from GXPs		4,646	4,817	4,907	5,014	5,141	5,285
32		*less*	Electricity exports to GXPs		190	197	201	205	210	216
33		*plus*	Electricity supplied from distributed generation		893	926	943	964	988	1,016
34		*less*	Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35			**Electricity entering system for supply to ICPs**		5,349	5,546	5,650	5,773	5,919	6,085
36		*less*	Total energy delivered to ICPs		5,071	5,258	5,356	5,473	5,612	5,768
37			**Losses**		278	288	294	300	308	316
38										
39			**Load factor**		63%	63%	63%	63%	63%	63%
40			**Loss ratio**		5.2%	5.2%	5.2%	5.2%	5.2%	5.2%

A2.6 SCHEDULE 12D

Company Name	**Powerco**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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

sch ref		*Current Year*					
8		*CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	92.8	94.1	90.2	91.3	90.0	88.4
12	Class C (unplanned interruptions on the network)	348.8	195.0	195.4	197.3	198.5	200.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.39	0.42	0.41	0.41	0.40	0.39
15	Class C (unplanned interruptions on the network)	2.43	2.25	2.26	2.28	2.31	2.33

Company Name	**Powerco**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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

sch ref		*Current Year*					
8		*CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	92.8	94.1	90.2	91.3	90.0	88.4
12	Class C (unplanned interruptions on the network)	348.8	195.0	195.4	197.3	198.5	200.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.39	0.42	0.41	0.41	0.40	0.39
15	Class C (unplanned interruptions on the network)	2.43	2.25	2.26	2.28	2.31	2.33

Company Name	**Powerco**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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

sch ref		*Current Year*					
8		*CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	92.8	94.1	90.2	91.3	90.0	88.4
12	Class C (unplanned interruptions on the network)	348.8	195.0	195.4	197.3	198.5	200.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.39	0.42	0.41	0.41	0.40	0.39
15	Class C (unplanned interruptions on the network)	2.43	2.25	2.26	2.28	2.31	2.33

A2.7 SCHEDULE 13

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY 2023

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3.5	A revised Asset Management Policy has been authorised by our CEO and circulated within Powerco. It was revised in 2022 to align with Powerco's new vision and asset management objectives. It is available on our document management system, referenced in our Strategic Asset Management Plan (contained in chapters 4 - 8 within this AMP). The policy has also been placed in mounted frames in strategic locations in every office and is discussed in our regular asset management system familiarisation sessions.	The AM Policy is a key facet of our asset management system, which was certified as being compliant with ISO55001 in January 2022. The increased scoring reflects this achievement.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3.5	Our asset management strategy and objectives are laid out in our Strategic Asset Management Plan (or SAMP), contained in chapters 4 - 8 of this AMP. Those closely align with our Asset Management Policy. The SAMP is a key facet of our asset management system (which we call our 'Business Capability Framework' or BCF). The BCF is a 150-page document that describes how each function of the business operates and how it interrelates with other functions. It is available to all staff via our intranet. By tying all functions together, the BCF helps to rationalise and homogenise the SAMP with other organisational policies and strategies, and directly addresses the needs of our stakeholders.	The SAMP is a key facet of our asset management system, which was certified as being compliant with ISO55001 in January 2022. The increased scoring reflects this achievement.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3.0	The Asset Strategy discusses growth and renewal strategies, described in 'asset fleet plans' in this AMP. Renewal is justified on the basis of asset condition or by proxy, age. Criticality measures help to prioritise capital spend. The methodologies are discussed in detail in this AMP and detailed expenditure forecasts provided.	We have increased the maturity score by a modest amount to reflect improvements in demand forecasting methods and fleet management practices. A major 'concept to completion' project is bringing about significant improvements in our end-to-end asset lifecycle processes.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3.0	We have continued to develop our suite of Fleet Management Plans, summarised in this AMP, that include work volumes across relevant time periods for all asset types, aligned to the asset information systems. Our planning procersses also identify the need for network growth or reinforcement in anticipation of demand increases.	We have increased last year's score to reflect refined demand forecasting and asset health assessment methods since the last assessment, and the now explicitly-defined scope of our life cycle activities in our SAMP and asset management system.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3.0	We use the AMP as a key tool to communicate plans to our staff as well as external stakeholders. The AMP is published on our website, hard copies are made available to key internal and external stakeholders. Fleet plans are available internally for fleet managers on SharePoint. 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 are uploaded to our Business Management System and Contractor Works Manual.	Communication of asset management objectives, plans and policy is a key facet of our asset management system, which was certified as being compliant with ISO55001 in January 2022. The increased scoring reflects this achievement.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3.0	There is a range of documents that detail asset management responsibilities. These include Powerco's Business Plan, our field servcies agreements with servcie providers, business unit tactical plans, position descriptions and employees' annual review and development forms. Process maps describe how conceptual plans are converted to actionable projects, and the designated responsibilities for each step of the process.	The modest increase in the scoring reflects the considerable amount of work that has been undertaken over the past two years to streamline our project delivery and asset settlement processes. This work is ongoing.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2.8	Our recently-reviewed field contract arrangements have been designed to make service providers accountable for quality and timely delivery. Internal and external service provider competency mapping provides guidance on the skills and levels of resource needed to deliver the plan. Our CEO also meets with service provider CEOs on a regular basis to discuss ways we can work better together. More improvements in monitoring and enforcement of service provider performance are planned for the coming two years.	The modest scoring increase reflects recent efforts to streamline end-to-end delivery processes, and to more regularly engage with our service provider executive to agree better ways of working together. The trusted partnerships that are being fostered are delivering noticable benefits.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3.2	Powerco has well developed and established procedures for dealing with emergencies and incidents, especially vegetation and storm-related damage to power lines and the associated risks to the public. We are also active participants in the regional 'lifelines' planning group, involving various local authorities. This group plans for worst-case contingent events including earthquakes that may disable local service depots for example. While the processes and plans we have enable us to respond well to contingent events, more work needs to be done to improve underlying network resilience.	We have recently reviewed our critical spare holdings and the way we manage spares. We are also continuing our work on developing contingency plans for key zone substations. This work reflects the modest increase in the score from last time.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

		Company Name	Powerco
		AMP Planning Period	1 April 2023 – 31 Mar 2033
		Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3.0	A number of governance committees monitor and take actions to improve our work practices and the delivery of our asset management objectives. The committees comprise members of the executive leadership team and company subject matter experts. The committees include: - An asset management steering committee - A data governance committee - XXX - XXX	The organisational structure has recently changed to reflect new approaches to our asset management practice, including a group specifically devising strategies to address changing technological, market and political direction; and a group called 'business transformation', tasked with enabling the business to adapt. We have maintained the AMMAT score as it was while these changes are bedding in.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3.0	The AMP provides an overview of delivability capability in the context of Powerco reverting to a DPP delivery model. This is considered in the outsourcing arrangements described in our field service contracts, and in internal competency mapping for the business. Operationally, our programme group continually assesses resource needs to achieve our rolling 2-year works plan. We are also constantly reviewing the impact of COVID on our supply chain to manage any disruptions to the works plan.	The modest increase in Ammat score reflects the improvements we have made in this area in the past two years.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3.0	The degree to which asset management objectives and strategies are being met is discussed at weekly executive leadership team (ELT) meetings, and the discussions then continue in each inidividual team. Successes are publicised in both internal and external communiques. The ELT has made a concerted push to achieve ISO550001 certification in the past two years, developing a comprehensive asset management system (which we call our 'Business Capability Framework'). This has a dedicated resource page on our intranet for informational and educational purposes.	Our asset management system was certified as being compliant with ISO55001 in January 2022. An important aspect of the system is the communications plan. The increased scoring reflects this achievement.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3.1	Significant monitoring is undertaken to monitor the performance of service providers, supplied assets, services delivered, financial performance and process performance. Powerco's selection process includes ISN reviews of new service providers. We also provide standover monitoring for service providers that we have not approved but are deemed competent to work on our network. Our competency framework for ensuring indivduals within the contractor's teams are suitably qualified. Tiered operational meetings between us and field contractors ensure work plans are understood and independent field auditors review workmanship and worksite safety.	Improvements in this area include a refined 'carrot and stick' approach that involves more stringent monitoring of contractor performance while also increasing dialogue to discuss performance issues. We have increased our scoring by a modest amount to reflect the improvements.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

						Company Name	Powerco	
						AMP Planning Period	1 April 2023 – 31 Mar 2033	
						Asset Management Standard Applied	ISO 55001	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.7	We have 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.	The increased scoring reflects improvements in this area but our overall resourcing strategy, competency management and training framework still need development.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.5	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.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.5			A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2.7	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. Change mangement processes have improved significantly.	Significant effort has been expended to develop operational dashboards to communicate asset management information, although these do not yet cover the full scope of AM activities. Standards and notifications are notified to service providers through the CWM portal. There is a dedicated internal comms team to help manage communication via the intranet. A communication plan has been developed as part of our asset management system. All of these improvements are reflected in the increased AMMAT score.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3.0	Our asset management system (which we call our 'Business Capability Framework' or BCF) provides a description of each aspect of the business and how each part inter-relates with others. This provides context to roles and decision-making processes. Powerco also has an extensive range of documentation to support its asset management system, such as standards, process maps and policies. The range of documents we use are described extensively throughout this AMP.	There has been significant effort in preparing the following documents as part of the ISO55001 cerrtification effort: - BCF Manual and intranet site - AM Capability Framework - AM Scope - Strategic Asset Management Plan These improvements are reflected in the increased AMMAT score.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3.0	The content of our data systems is under constant review, both for quality and substance The Data Governance Group is responsible for identifying and delivering our data content and quality improvement initiatives. We are also reviewing our data collection process by ensuring data requirements are reflected in the field devices that our workers use.	Asset information is considered just as much as asset as the equipment it describes. It includes asset performance information, which is used to direct vegetation, renewal and defect management strategies. There has been modest improvement in this aspect of our practices, reflected in the AMMAT score.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology,	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3.0	There has been significant effort in preparing the Asset Information Standard and a Documented Information Management Standard. We have established a formal Data Governance Group and corresponding Data Communities to oversee and manage our ongoing asset information needs. We have an asset information policy, and are developing several data dictionaries. Over the past 2 years we have implemented an Enterprise Resource Planning (ERP) system that has clear delegations and increased checks on data accuracy to ensure data quality now and into the future.	Asset information management is a vital facet of our asset management system, certified to ISO55001. Neverthless, there is still work to do in this area, so our AMMAT score remains the same as last time.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.8	There has been significant effort in preparing the Asset Information Standard and a Documented Information Management Standard. We have established a formal Data Governance Group and corresponding Data Communities to oversee and manage our ongoing asset information needs. We have an asset information policy, and are developing several data dictionaries. Over the past 2 years we have implemented an Enterprise Resource Planning (ERP) system that has clear delegations and increased checks on data accuracy to ensure data quality now and into the future. We have developed an Asset Information Strategy, and an (IS) Architecture Review Board to ensure improvements to the IS Systems are aligned. We are working on developing appropriate process to identify and develop the Asset Information Strategy on an ongoing basis.	Asset information management is a vital facet of our asset management system, certified to ISO55001. There has been improvement in this area, reflected as a modest increase in our AMMAT score.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3.0	In addition to updated risk policy, risk management framework / process and risk matrices, a newly-created Internal Audit and Assurance Plan has been rolled out to the business. This describes our three lines of defence and our corporate risk management protocols and processes. We monitor asset-related failure and safety risk separately using established fleet and defect management protocols, but are working to integrate the two risk management systems.	We have reflected these advances in a modest AMMAT score increase, acknowledging that there is morer work to be done in the areas of integration and staff training.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or
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?	2.8	In general terms, all of our investment decisions and associated asset management plans mitigate risk, for example the risk of asset failure or the risk of having insufficient capacity to meet growing customer demand. Risks are identified through well-established demand forecasting and asset health assessment methodologies, with both reactive and proactive maintenance practices embedded in our work processes. Resourcing levels are a direct function of the look-ahead work schedule, and resourcing to deal with asset failures and contingent events is a function of historical norms.	There is some work still to be done in terms of integrated resource planning and competency management, but there have been significant improvements in this area in recent years.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that
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	3.2	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 updates appropriate governance grouops and executive leadership. Powerco has a dedicated legal team to deal with both permitting and compliance issues. We have implemented a ComplyWith programme to keep track of our ongoing legal obligations.	We have been conducting legal compliance reviews through our Assurance Team for a considerable period and can be considered competent in this area. The AMMATscore remains unchanged.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement,	3.0	Recent work includes: - Development and publication of a 150-page asset management system manual - Deployment of an Enterprise Resource Planning (ERP) system - Mapping of our end-to-end capital works processes - Streamlining of the end-to-end capital works processes The Concept to Completion Process (as we call it) describes the project inception, justification, approval, design, implementation and settlement procedures and associated responsibilities. It relies on robust contracts with external suppliers, involving construction, commissioning and handover processes, and project management methods.	We have expended considerable effort in streamlining our end-to-end asset management processes and controls over the past two years. This has resulted in some significant efficiencies and improvements, including the speed at which assets can be registered on our regulated asset base. Nevertheless this work continues and we have maintained the previous AMMAT score.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk	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. The deployment of our new ERP has provided us opportunity to better manage our assets by reviewing the history of and controlling the implementation of our plans against each individual asset. We are developing competence in using its capabilities. We have also created dedicated roles to ensure that the appropriate maintence is carried out as outlined in our strategy and plans. This includes the preparation of maintenance procedures where required to supplement the standards.	While there has been many improvements in this area, we have maintained our previous 'competent' level AMMAT score.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3.0	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. To move twords more leading indicators, we have implemented common network asset indices models (CNAIM) to inform our decision making. These models are informing our condition assessment requirements that will in due course be deployed through our MyPM field devices.	We will continue to mature these systems as we roll out this approach for our entire fleet. For the moment our AMMAT score remains the same.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate
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	3.0	Fault response is outsourced to our service providers. Expectations are clearly communicated in our fault response standard and in our technical standards, which the service providers are required to conform with. We have also re-designed our incident investigation systems and processes, as well as continuing to develop our contigency plans for key sites on our network. Our HSEQ team helps ensure that investigations occur, actions are taken and responsibilities are clear. We now also have automatic escalation built into our systems. We also have weekly incident meetings and Executive Health and Safety meetings to monitor our internal and servcie provider performance in this area.	We are competent in this area, recognising that there is always room for improvement. We have made a modest increase in our AMMAT scoring to reflect improved processes and accountabilities in this area.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

				Company Name	Powerco	
				AMP Planning Period	1 April 2023 – 31 Mar 2033	
				Asset Management Standard Applied	ISO 55001	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	New Evidence	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2.8	A newly-created Internal Audit and Assurance Plan has been rolled out to the business. This describes our three lines of defence, our corporate risk management protocols and processes, and describes how we monitor and improve the performance of our asset management system, which underpins it all. We have devedolped better insights about the scope and range of external audits across our business. The results of these audits are now reviewed by our internal assurance team.	Risk and assurance management is an important aspect of our asset management system, which has been certified to ISO55001 standard. The increased AMMAT score reflects associated improvements in this area, but recognises that evidence that the improvements are effective will not be available until several audits have been completed.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any
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?	2.8	We have a range of corrective action processes, for example, field servcies provider relationship meetings, HSEQ meetings and operational meetings all support these processes. The Incident Management System is generally well executed. Our field auditing a programme is delivered by an external provider on our behalf. It covers - Worker safety in the field - Quality of workmanship - Work planning - Documentation and record keeping - Assurance of critical work and public safety controls	We have made a modest increase to our previous AMMAT score, recognising that furtehr work is needed in this area, both to improve contractor performance, and staff performance.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3.0	Our asset management system manual describes how we monitor performance, assess and prioritise investment needs, and manage our reactive and preventative maintenance programmes to deliver satisfactory levels of asset performance. Our investment decisions are generally justified on the basis of the risk cost they avoid - for example the risk of asset failure causing economic loss to customers. Powerco's governance committees have a large role to play in monitoring performance and driving improvement, especially in our decision-making processes. We have several feedback loops to inform our continual improvement requirements. These include processes such as: Log-an-idea, Project learnings, Standards feedback forms, safety observations and incident investigations. Our baseline KPIs are described in the AMP, our performance measured against those, and improvement measures implemented as required. It should be said that historically Powerco has had a good compliance record, maintaining satisfactory levels of power supply security and reliability at reasonable cost.	Our newly formed Asset Management Steering Committee monitors the effectiveness and performance of the asset management system itself. This is the group responsible for driving the achievement of ISO55001 certification and rolling associated training out to the business. The AMMAT score increase reflects the improvements in this area.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3.2	We actively participate in ENA and EEA working groups, 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. Our AMP includes a significant amount of commentary on the market and technological changes that can be expected in the drive towards carbon neutrality; and our AM strategies specifically take these into account.	Powerco is one of the industry leaders in this space. The AMMAT score reflects this position.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset

Company Name	Powerco
AMP Planning Period	1 April 2023 – 31 Mar 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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 24.
- 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 4.
- 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 2023 real dollars in the body of this AMP. Schedules 11a and 11b uses constant prices in 2023 real dollars, as per the Commerce Commission's information disclosure requirements for a 2023 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.

A2.1 MATERIAL CHANGES TO SCHEDULE 12A

The method for calculating our internal asset health indices (AHI), scored H1-H5, is consistent with the 2021 AMP for most fleets. This aligns with the EEA AHI 1-5 grades.

Since the 2021 AMP, we have developed improved asset health modelling for our overhead conductor fleets (described in further detail in Chapter 15). This has improved the evaluation of AHI for these fleets. These are also scored H1-H5.

Asset health is discussed in more detail in Chapter 9 and is used extensively throughout our fleet management chapters of this AMP.

A2.2 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.[113] Any changes to the metrics reported in 12b are due to adjustment made to the underlying parameters for a site.

A2.3 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.

A2.4 MATERIAL CHANGES TO SCHEDULE 12D

Our SAIDI/SAIFI forecasting approach is generally consistent with the 2021 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.

[113] See Chapter 10 for a description of our security standards.

APPENDIX 3 STAKEHOLDER INTERESTS

A3.1 APPENDIX OVERVIEW

The main objective of our Asset Management Plan is effective consultation with our stakeholders.

In Chapter 3 we provide an overview of our main stakeholders and their interests. Given the importance of our stakeholders to us, this appendix gives more details about each stakeholder and provides insights as to 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:

- 344,261 homes and businesses comprising:
  - Residential customers and small businesses ('mass market')
  - Medium-sized commercial businesses
  - Large commercial or industrial businesses
- 13 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 about their service.

A3.2.1 STAKEHOLDER INTEREST

The interests of each of our main customer groups are described in Chapter 2. These are as identified through consumer surveys, meetings with customers and consumer groups, and feedback from our hotlines. Customers' interests can be summarised as:

- **Reliability** – Our customers want us to minimise the frequency and duration of supply interruptions, as well as ensuring the quality of the 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 constantly evaluate 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 the 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 24 electricity retailers operating under multiple brands on our network. Of these, three serve 70% of our customers.

Like most electricity distribution businesses (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, which may have been directed to the retailer.
- How we operate under the Consumer Guarantees Act.
- Customer data and privacy

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:

- 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 (MBIE), WorkSafe NZ, and the Electricity Authority.

MBIE administers the Health and Safety at Work Act 2015 and the Electricity (Safety) Regulations 2010. The Safety Regulations 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 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 NZ is the regulator for ensuring the 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 Supervisory Control And Data Acquisition (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 at Work Act 2015
- 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. We aim to be actively involved in debates about district and regional plan changes and take part in hearings and submissions on local issues as we deliver our works. We will aim to provide constructive feedback as we transition away from the RMA.
- **Economic growth** – Authorities have an interest in promoting economic growth in their communities, and we work with them to understand where we may need to invest to support this.
- **A valued customer** – Local councils are also often our customers, supplying lifeline utility services, such as water and sewerage systems. We work closely with councils to understand their supply needs and coordinate any outages.

A3.8 OUR EMPLOYEES

We have about 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 well-being are key employee tenets.

Our teams have an interest in managing the network competently and doing the 'right thing', therefore it is of great importance that we effectively communicate our Asset Management Plan with them.

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.

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 expenditure during the AMP planning period, we will work closely with our service providers to ensure we can deliver a 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 can cause 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.

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.

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, such as 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 WORKS PROGRAMME COMPLETION

A4.1 APPENDIX OVERVIEW

This appendix provides information on our progress against physical and financial plans set out in our 2021 AMP.

In summary, we completed 89% of our scheduled capital works programme for FY23, and overall completed 95% of our inspection programme which was impacted by Cyclone Gabrielle.

We saw spend on our minor projects increase over CPP Year Four. The $6.6m under-spend against forecast in FY21 reversed in FY22, as more projects progressed from the planning and design phases into construction.

Minor project spend $000	Actual	Forecast
FY21	6,711	13,317
FY22	14,480	7,004

We didn't spend as much on building assets as we'd forecast for the year – with $27.1m spent on major projects against a forecast of $37.4m – we expect to see that spend increase in CPP Year Five as we start construction on those remaining projects

A4.2 DEVELOPMENT PROJECT COMPLETION

During FY23 we undertook a series of network development projects. These projects make up significant portions of our overall capital spend whilst delivering key advances in network security of supply and capacity growth.

In the North Western region of our network, We've been working on a $20 million investment to secure Whanganui's power now and allow for future growth. During 2022, we installed almost 8km of underground cable across the city, between our Roberts Ave and Peat St substation, to our Taupo Quay substation. To install the cable, we used directional drilling, rather than open trenching, to reduce the impact on the community and road users. This additional 33kV circuit means there's alternatives to restore power to the Whanganui community more quickly and safely if there's a power cut. This is particularly important in the city centre, as Taupo Quay substation provides critical power supply to the CBD, as well as the hospital. The Whanganui River (awa) is an important part of the community and the city's history. We've collaborated with Ngā Tāngata Tiaki o Whanganui and Te Runanga o Tupoho to make sure these electricity projects do not negatively impact the awa or cultural sites of importance.

In Inglewood we replaced about 100 6.6kV transformers with dual 6.6kV/11kV transformers in preparation for the changeover to 11kV. We also installed two new autotransformers to switch between 6.6kV and 11kV to enable our Network Operations team to backfeed to both the 11kV and the remaining 6.6kV parts of the Inglewood area if needed.

Our South Western region, Palmerston North CBD is the second-largest central business district we serve, and our largest exclusively underground network. We've completed a number of projects for the Palmerston North community to expand, renew and rebalance our assets and ensure our customers have continued security of power supply.
The $27.4 million electricity investment programme completed projects included:

- Construction of a new substation on the corner of Linton and Ferguson streets
- Installation of a second transformer at the new substation
- Upgrade of underground cabling between Linton and Pascal Street substations
- Construction of a new indoor 33kV switch room at our Linton substation
- Construction of two new underground circuits from Linton substation to the new Ferguson St substation
- Installation of larger capacity cables between Ferguson and Main Street substations
- Removal of power poles and overhead lines between Keith St and Main St substations

Our Eastern regional centres, encompassing the Tauranga and Valley regions we've upgraded our substation on Walton Road between Morrinsville and Matamata and installed a new 10km underground electricity cable in a $14m project that will keep our South Waikato customers connected well into the future. We've also installed a new 33kV and 11kV switchboards and constructed a new substation building to keep the new equipment sheltered from the elements.
The new building and equipment is modern and safe for our crews to work with, helping ensure we can continue to provide reliable supply. We've also installed a new 33kV underground cable between the Walton Road substation and the corner of Kereone Road. The 10km cable increases capacity to serve our South Waikato customers and helps ensure we can continue to supply customers with electricity in the event that any nearby Transpower Grid Exit Points experience an outage or are undergoing maintenance.

In Whangamata CBD we used BESS (our Battery Energy Storage Solution which provides back-up electricity supply) to minimise the number of customers affected by an outage, including the CBD.

Shops and services in Whangamatā remained on during the day Whilst our contractors replaced cross arms and hardware on our overhead poles between Whangamatā and Waihi.
This work will help ensure the electricity supply in the area is reliable and resilient well into the future.

A4.3 MAINTENANCE PROGRAMME DELIVERY

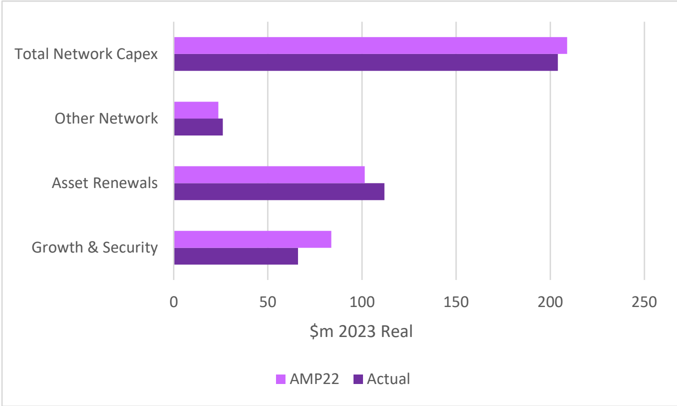
For the FY22 maintenance programme we completed 97% of the maintenance we had planned to carry out for CPP Year Four, and 18,000 more inspections than the year before – a great result considering the challenges posed by COVID. At the start of the year, we had 32,188 asset defects to address across our network, identified through things like site visits and our pole-top photography project. Our field crews reported another 23,444 during the course of their work. We addressed 19,870 of those, and our team also found a number of defects that had either been reported multiple times in our system or had already been resolved. We cleansed those duplicates, giving us a true picture of the number of issues needing to be addressed.

A4.4 FINANCIAL PROGRESS AGAINST PLAN

A4.4.1 NETWORK CAPEX

Total network Capex for FY22 ($204.2M) was below the 2022 AMP forecast ($209.0M) by $4.8M (-2.3%). The underspend was a combination of overspends and underspends in all areas.

Figure A4.1: Network Capex variance FY22



Consumer connection expenditure was over target by $3.1m (+12%).

Growth & Security expenditure was less than forecast by $18.1m (-21%). Delays in delivering large scale projects account for the majority of this variance. These investments are at the time of writing this AMP are close to completion in FY23.

Renewals expenditure was $10m or (10%) higher than forecast. Renewal spend on our Overhead portfolio was increased during FY22 as a result of resource releasing up from the large scale projects that were delayed (above).

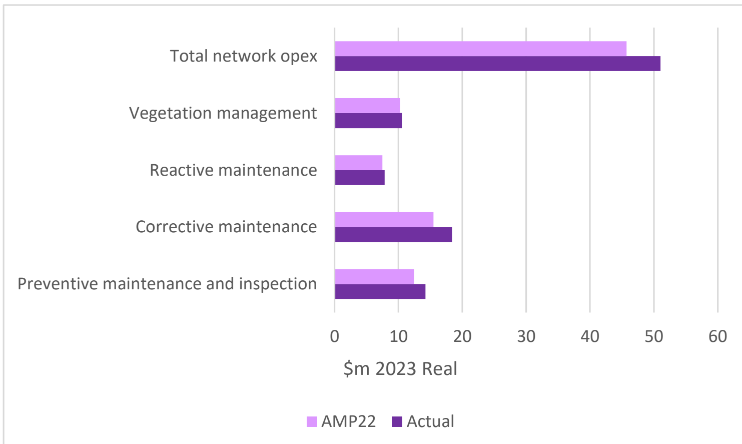
Customer initiated works demand increased during the pandemic $2.0M (+10%)

A4.4.2 NETWORK OPEX

The figure below shows our FY22 Opex actuals were higher than our AMP22 operational expenditure levels. Total Network Opex was above target by $5m (+12%).

This network opex overspend was primarily in Routine and Corrective Maintenance and Inspection, driven by increased impact from weather related incidents, and continued focus on CPP defect backlog targets

Figure A4.2: Network Opex variance FY22



APPENDIX 5 GENERAL NETWORK RISKS

PRIORITY AREA	PRIORITY DESCRIPTION	RISK DESCRIPTION	RISK SCORE - CURRENT	SUMMARY CONTROL DESCRIPTION
1. CUSTOMERS AND COMMUNITIES	• **Deliver a safe and reliable network of essential infrastructure to our communities that is future ready & cost effective**	High number of customer disconnections, increasing cost to serve leading to an increase in tariff or stranded network assets	**Medium**	– Political and industry engagement – Public relations processes – Customer engagement
		Subsidies for micro-generation promote uneconomic uptake of disruptive technology	**Medium**	– Energy partners approach to network growth – Commercial assessment of new technology – Evaluation and changes to pricing model to support delivery of grid-connected supply
		Fatality or serious harm to third parties or the public	**Medium**	– Asset strategy including defect management and preventative maintenance – Safety in design – Public safety management system (NZS7901) – Physical security – Public awareness programme and locate services
		Natural disaster which severely impacts the network (likely to be on a regional basis e.g., Palmerston North earthquake or Taranaki eruption)	**Medium**	– Crisis response plans and business continuity framework – Backup network operations facilities in New Plymouth and network triage capability from Tauranga – Material damage and business interruption insurance for office / network restoration – $100m revolving facility for non-insured assets (e.g., poles and lines) Scenario analysis of sufficient access to funding
		Severe weather event which adversely affects Powerco's ability to respond to network and customer issues.	**Medium**	– Capital programme resources to respond to storms and other events – Resource planning and local hub activation to mitigate dependence on control room co-ordination in peak events – CIMS Training of Powerco and Downer employees – Alternate NOC facilities.
		Falling demand driven by population, energy efficiency and/or changed network utilization. Notes: The likelihood of falling demand is low. Population growth will continue to be the biggest driver of demand for the foreseeable future Consequence/impact of demand changes will be muted in the first instance - this is because allowable revenue is set by building blocks methodology	**Low**	– Design and implementation of a customer-led energy platform strategy to help position Powerco to ensure assets remain used and useful (i.e., avoid stranding) over a broad range of energy market scenarios
		Unable to meet customer demand for new connections	**Low**	– Process re-design – Flexible resource model to match demand – Forecasting of future demand from decarbonisation
	• **Enable NZ's decarbonisation and positively impact environmental and social causes**	Capital requirements to fund electrification across Powerco footprint	**Low**	– Energy partners / smart energy solutions – Political and Regulatory engagement – Treasury Policy & Strategy
		Rate of decarbonisation	**Medium**	Forecasting of future demand from decarbonisation
		Rapid build of renewable generation exceeds network access process	**Medium**	– Flexible resource model to match demand – Forecasting of future demand from decarbonisation

PRIORITY AREA	PRIORITY DESCRIPTION	RISK DESCRIPTION	RISK SCORE - CURRENT	SUMMARY CONTROL DESCRIPTION
		Failure to enable smart electricity system	Low	– Energy Partners approach – ADMS / IOT programme – Business Development Strategy
		Lack of co-ordination across national energy strategy	Medium	– Political and industry engagement
2. CORE DELIVERY	• **Invest in our networks to deliver fit for customer networks for today and tomorrow**	Insufficient expenditure allowance post CPP to maintain the network at the standard necessary to meet quality, safety, and longer-term reliability levels.	Medium	– DPP transition planning – Asset management maturity to deliver future network expenditure – Relationship management with Commerce Commission
	• **Operate efficient networks; focusing on improving our operating performance to deliver value for customers**	Inaccurate as-build data	Medium	– Contract standards and processes in place and regularly updated for recording of assets and as building requirements – EFSA KPI as built quality monitored and followed up monthly – Monitoring and follow up of work in progress to identify outstanding work packs and associated documents – focus through C2C project.
		Inaccurate and/or incomplete HV information being provided to service providers / contractors / third parties.	Medium	– Waivers are issued with supplied data for plan issuers. – Safe working practices used in the field including stand-over requirement for excavations near Powerco underground cables and pipes. – Electricity strategic standard now in place – Job is stopped if data supplied does not match what is in the field – Standards and processes in place and regularly updated for service provider recording of assets and as building requirements – HV connectivity is checked daily – Contractors required to provide corrected data if information supplied is inaccurate or incomplete
		Risk of data integrity issues within the oms application that is not detected and is used to produce incorrect SAIDI / SAIFI, CPP ADR and/or EFSA KPI disclosures.	Medium	– OMS system has much improved data integrity than previous version – Internal and external assurance audits of both system and data disclosures completed annually – SAIDI / SAIFI audited annually – Data checked daily
		Loss or disruption to critical business information and operational control systems	Medium	– Availability across Junction Street and Albany Data Centres – Backups maintained to allow system restoration – Ability to divert critical services to multiple office locations – Specialised equipment, devices, and software monitoring operating environment – Crisis response and business continuity plans
		Upstream electricity infrastructure failure	Medium	– Emergency response plans – Regulatory and industry protocols – SCADA monitoring of key assets – Load shedding and contractual arrangement – Smart networks and distributed storage
		Negative environmental impacts which adversely affects Powerco's ability to respond to network and customer issues	Low	– Environmental management system – Network preventative maintenance and inspection programme – Network design standards – Customer and stakeholder engagement
		Breach of regulatory disclosures	Medium	– Relationship management with commerce commission – Asset management maturity – Active monitoring of price/quality standards – Quality assurance programme and external audit of regulatory disclosures
		Supply chain disruption	Low	– Capital and maintenance programme scheduling – Contractor performance monitoring – Critical inventories

PRIORITY AREA	PRIORITY DESCRIPTION	RISK DESCRIPTION	RISK SCORE - CURRENT	SUMMARY CONTROL DESCRIPTION
	• **Improve long term investment decisions to create value for stakeholders**	Inaccurate scenario planning regarding investment decisions	**Low**	– Corporate modelling & multiple scenario analysis – Investment decision oversight and governance
	• **Maintain gas business and regulatory performance while transitioning to a zero-carbon future**	Upstream gas infrastructure failure accelerates electrification uptake	**Medium**	– Emergency response plans – Regulatory and industry protocols – Monitoring of key assets – Critical Contingency Protocols – Regular participation in emergency exercises
		Network decisions create uncertainty in transition to zero carbon future	**Medium**	– Stakeholder engagement regarding transitional pathways – Integrated business planning to co-ordinate future decarbonisation programmes
	• **Create a workplace where our people are engaged, safe and well and are inspired to meet our customers' needs now and, in the future,**	Key personnel turnover	**Low**	– Succession planning including identification of critical roles, staff back-up and knowledge sharing. – Career pathways
		Fatality or serious harm to employees or approved contractors	**Medium**	– Asset strategy including defect management – Safety-in-design – Contractor competency, approval system and works manual – HSE risk management framework – Staff HSE induction and training – Field audit programme – HSE forums to promote collaboration
		Ongoing impact of COVID-19 Pandemic	**Low**	– COVID-19 response plan – Business continuity plans including critical team protection and remote working
		Inability to recruit/access the required skills	**Low**	– Core HR practices including recruitment, talent management, wellbeing, succession planning, remuneration and reward, continuity planning
3. FUTURE READINESS	• **Work with customers and others to anticipate future needs and invest to meet them**	Insufficient cash flow to maintain the network assets	**Medium**	– Modelling of future cashflows – Treasury Policy – Management of network capex/opex programmes
	• **Enable New Zealand's low carbon economy through new asset opportunities and technology.**	Technology change	**Medium**	– Monitoring of new technologies – Participation in energy / technology forums
		Failure to adopt smart network technologies (LV visibility / ADMS)	**Low**	– ADMS / IoT programme – Monitoring of new technologies
	• **Ensure the regulatory and policy settings support a positive investment and operating environment**	Adverse change in regulatory environment	**Medium**	– Political and Regulatory stakeholder management and engagement – Monitoring of trends e.g., uptake of technologies
		Regulator seeks ex-post investment optimisation	**Medium**	– Review process participation – Regulatory engagement
		RMA reforms fail to deliver fit for purpose consenting frameworks to enable rapid renewable deployment	**Medium**	– Political and Regulatory stakeholder management – Policy review participation – Customer engagement
		Damage to the environment	**Low**	– Environmental management system

PRIORITY AREA	PRIORITY DESCRIPTION	RISK DESCRIPTION	RISK SCORE - CURRENT	SUMMARY CONTROL DESCRIPTION
	• **Exceed our stakeholders' expectations on ESG performance**			− Network preventative maintenance and inspection programme − Network design standards − Customer and stakeholder engagement
		Societal ESG expectations	**Medium**	− Stakeholder management system − Sustainability programme − TCFD programme

APPENDIX 6 DEMAND FORECASTS

A6.1 APPENDIX OVERVIEW

This appendix sets out our 15-year demand forecasts for our zone substations.

A6.2 DEMAND FORECAST FOR COROMANDEL AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coromandel	0.8%	4.5	4.5	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.9	4.9	5.0	5.0	5.0
Kerepehi	1.0%	10.4	10.5	10.6	11.4	12.1	12.9	13.0	13.1	13.2	13.3	13.4	13.5	13.6	13.7	13.8
Matatoki	0.7%	4.5	4.9	5.3	5.6	5.6	5.7	5.7	5.7	5.8	5.8	5.8	5.9	5.9	5.9	5.9
Tairua	0.6%	9.5	9.5	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.3
Thames T1 & T2	0.4%	11.8	11.8	11.9	11.9	12.0	12.0	12.0	12.1	12.1	12.2	12.2	12.3	12.3	12.3	12.4
Thames T3	0.0%	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Whitianga	1.2%	18.0	18.5	18.9	19.3	19.7	20.0	20.4	20.8	21.0	21.2	21.5	21.7	21.9	22.1	22.3

A6.3 DEMAND FORECAST FOR WAIKINO AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Paeroa	0.8%	8.1	8.4	8.8	8.8	8.9	8.9	9.0	9.1	9.1	9.2	9.3	9.3	9.4	9.4	9.5
Waihi	1.0%	18.4	19.1	22.4	25.5	28.7	31.8	34.9	38.0	41.1	44.2	44.4	44.5	44.6	44.7	44.8
Waihi Beach	0.5%	6.4	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.1	7.2	7.3
Whangamatā	0.6%	11.8	11.9	11.9	12.0	12.0	12.1	12.1	12.2	12.2	12.3	12.3	12.4	12.4	12.5	12.6

A6.4 DEMAND FORECAST FOR TAURANGA AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Aongatete	2.0%	4.5	4.6	4.7	4.8	4.9	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.6	5.7
Bethlehem	1.7%	10.9	12.1	12.7	12.9	13.1	13.3	13.5	13.6	13.8	14.0	14.2	14.3	14.5	14.7	14.9
Hamilton Street	0.5%	10.8	11.5	12.1	12.2	12.2	12.3	12.4	12.4	12.5	12.5	12.6	12.6	12.7	12.7	12.8
Katikati	1.1%	10.8	12.0	13.2	13.3	13.5	13.6	13.7	13.8	13.9	14.0	14.2	14.3	14.4	14.5	14.6
Kauri Point	0.9%	2.8	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2
Matua	0.3%	9.7	9.7	9.7	9.7	9.8	9.8	9.8	9.9	9.9	9.9	10.0	10.0	10.0	10.1	10.1
Ōmokoroa	1.9%	12.3	12.5	13.2	14.0	14.2	14.4	14.6	14.9	15.1	15.3	15.5	15.8	16.0	16.2	16.4
Otūmoetai	0.8%	14.9	15.0	15.1	15.3	15.4	15.5	15.6	15.7	15.9	16.0	16.1	16.2	16.3	16.5	16.6
Pyes Pā	9.9%	19.8	26.1	29.2	34.5	68.2	71.8	75.4	79.0	82.6	86.2	87.6	88.9	90.2	91.5	92.9
Sulphur Point	0.0%	6.5	8.5	10.5	12.5	14.5	16.5	18.5	20.5	22.5	24.5	24.5	24.5	24.5	24.5	24.5
Tauranga 11kV	1.2%	27.3	28.1	28.8	29.1	29.4	29.7	30.0	30.4	30.7	31.0	31.3	31.6	31.9	32.3	32.6
Waihi Road	0.7%	20.4	20.6	20.7	20.9	21.0	21.1	21.3	21.4	21.5	21.7	21.8	21.9	22.1	22.2	22.3
Welcome Bay	1.5%	24.2	24.7	25.2	25.6	26.0	26.3	26.7	27.1	27.4	27.8	28.2	28.6	28.9	29.3	29.7

A6.5 DEMAND FORECAST FOR MOUNT MAUNGANUI AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Atuaroa Avenue	0.9%	9.1	9.6	9.7	9.8	9.9	10.0	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.6	10.7
Matapihi	0.8%	13.3	13.4	13.5	13.6	13.7	13.9	14.0	14.1	14.2	14.3	14.4	14.5	14.6	14.7	14.8
Omanu	1.4%	12.9	13.1	13.3	13.5	13.6	13.8	14.0	14.2	14.3	14.5	14.7	14.9	15.1	15.2	15.4
Paengaroa	1.1%	5.3	6.6	9.4	12.2	13.0	13.1	13.1	13.2	13.2	13.3	13.3	13.4	13.5	13.5	13.6
Papamoa	1.5%	16.7	17.0	17.2	17.5	17.8	18.0	18.3	18.5	18.8	19.0	19.3	19.5	19.8	20.0	20.3
Pongakawa	0.9%	4.6	5.0	5.4	5.5	5.5	5.6	5.6	5.6	5.7	5.7	5.8	5.8	5.8	5.9	5.9
Te Maunga	2.3%	11.7	11.9	12.2	12.5	12.7	13.0	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.1	15.4
Te Puke	0.8%	20.8	24.7	27.4	33.4	36.9	40.4	43.9	47.4	50.9	51.0	51.2	51.3	51.5	51.7	51.8
Triton	0.7%	20.0	20.2	20.9	21.8	22.0	22.1	22.2	22.4	22.5	22.7	22.8	22.9	23.1	23.2	23.4
Wairakei	6.9%	10.9	12.4	14.0	15.5	17.1	18.6	20.2	21.7	23.3	24.8	26.4	27.0	27.7	28.3	29.0

A6.6 DEMAND FORECAST FOR WAIKATO AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Browne Street	1.3%	10.4	11.7	13.0	13.1	13.2	13.4	13.5	13.6	13.8	13.9	14.0	14.2	14.3	14.4	14.6
Farmer Road	0.5%	6.4	7.1	13.9	15.1	16.3	17.4	18.6	19.8	21.0	22.2	22.2	22.2	22.3	22.3	22.3
Inghams	0.0%	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Lake Road	1.5%	6.3	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.6
Mikkelsen Road	0.9%	12.1	12.2	12.4	12.5	12.6	12.7	12.8	12.9	13.0	13.1	13.2	13.3	13.4	13.5	13.6
Morrinsville	0.7%	8.4	9.2	10.0	10.0	10.1	10.1	10.2	10.3	10.3	10.4	10.4	10.5	10.5	10.6	10.7
Piako	0.8%	14.1	14.7	15.5	16.2	16.9	17.7	17.8	17.9	18.0	18.2	18.3	18.4	18.5	18.6	18.7
Putāruru	0.7%	12.1	12.2	13.6	15.0	16.4	16.5	16.6	16.7	16.8	16.8	16.9	17.0	17.1	17.2	17.2
Tahuna	0.9%	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2
Tatua	0.0%	5.4	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Tirau	1.2%	9.3	9.4	11.0	12.7	12.8	12.9	13.0	13.1	13.2	13.3	13.4	13.6	13.7	13.8	13.9
Tower Road	1.1%	8.2	8.3	8.4	8.5	8.6	8.7	8.7	8.8	8.9	9.0	9.1	9.2	9.3	9.3	9.4
Waharoa North	1.2%	3.6	3.6	3.6	3.7	3.7	3.8	3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.1
Waharoa South	0.0%	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Waitoa	0.0%	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Walton	0.9%	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.5	5.6	5.6	5.7	5.7	5.8

A6.7 DEMAND FORECAST FOR KINLEITH AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Baird Road	0.7%	9.9	10.6	11.9	12.0	12.1	12.1	12.2	12.3	12.3	12.4	12.5	12.6	12.6	12.7	12.8
Maraetai Road	0.4%	8.8	9.1	11.9	14.7	14.9	15.6	16.2	16.9	17.3	17.8	17.8	17.9	17.9	17.9	18.0
Midway / Lakeside	0.0%	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2

A6.8 DEMAND FORECAST FOR TARANAKI AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Bell Block	1.3%	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2	17.4	17.6	17.8	18.0	18.2	18.4
Brooklands	0.7%	19.3	19.4	19.6	21.0	22.3	22.5	22.6	22.8	22.9	23.0	23.2	23.3	23.4	23.6	23.7
Cardiff	0.9%	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9
City	0.8%	16.0	16.5	17.0	17.1	17.2	17.3	17.5	17.6	17.7	17.8	18.0	18.1	18.2	18.3	18.5
Cloton Road	0.8%	10.1	10.2	10.3	10.4	10.4	10.5	10.6	10.7	10.7	10.8	10.9	11.0	11.0	11.1	11.2
Douglas	0.6%	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Eltham	0.6%	9.5	9.6	9.6	9.7	9.7	9.8	9.9	9.9	10.0	10.0	10.1	10.2	10.2	10.3	10.3
Inglewood	1.1%	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.9	5.9	6.0	6.0	6.1	6.2	6.2	6.3
Kaponga	0.8%	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.5
Katere	1.3%	15.3	15.5	15.7	15.9	16.0	16.2	16.4	16.6	16.8	17.0	17.2	17.4	17.6	17.8	18.0
McKee	0.4%	1.3	1.3	3.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.4
Motukawa	1.0%	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8
Moturoa	0.9%	18.2	18.3	18.5	18.6	18.8	18.9	19.1	19.2	19.4	19.5	19.7	19.8	19.9	20.1	20.2
Ōākura	1.5%	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4
Waihapa	0.0%	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	1.5%	5.0	5.1	5.2	5.2	5.3	5.4	5.5	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.0
Waitara West	0.5%	6.8	6.8	6.9	6.9	6.9	7.0	7.0	7.0	7.1	7.1	7.1	7.2	7.2	7.2	7.3

A6.9 DEMAND FORECAST FOR EGMONT AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cambria	0.6%	14.7	14.8	14.9	15.0	15.1	15.2	15.2	15.3	15.4	15.5	15.6	15.6	15.7	15.8	15.9
Kāpuni	0.3%	5.5	5.6	5.6	8.1	10.6	10.6	10.6	10.6	10.7	10.7	10.7	10.7	10.7	10.7	10.7
Livingstone	0.5%	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9
Manaia	0.6%	5.5	5.5	5.6	5.6	5.6	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9	5.9
Mokoia	0.9%	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6
Ngāriki	0.8%	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.9
Pungarehu	1.2%	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6
Tasman	0.6%	6.4	6.5	6.5	6.5	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.9	6.9	6.9	7.0

A6.10 DEMAND FORECAST FOR WHANGANUI AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Beach Road	0.4%	10.4	10.4	10.4	10.4	10.5	10.5	10.5	10.6	10.6	10.7	10.7	10.7	10.8	10.8	10.9
Blink Bonnie	0.6%	2.8	2.8	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.1
Castlecliff	0.4%	9.5	10.3	11.0	11.1	11.1	11.1	11.2	11.2	11.3	11.3	11.3	11.4	11.4	11.4	11.5
Hatricks Wharf	0.6%	9.8	9.9	9.9	10.0	10.0	10.1	10.2	10.2	10.3	10.3	10.4	10.4	10.5	10.5	10.6
Kai Iwi	0.9%	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Peat Street	0.5%	14.5	14.5	14.6	14.7	14.7	14.8	14.9	15.0	15.0	15.1	15.2	15.2	15.3	15.4	15.5
Roberts Avenue	0.5%	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.9
Taupō Quay	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
Wanganui East	0.3%	5.9	5.9	5.9	5.9	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.1	6.1	6.1
Waverley	0.0%	4.7	4.7	5.2	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7

A6.11 DEMAND FORECAST FOR RANGITĪKEI AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Arahina	0.5%	8.1	10.5	12.9	15.2	15.3	15.3	15.3	15.4	15.4	15.5	15.5	15.5	15.6	15.6	15.6
Bulls	0.9%	5.5	5.6	5.6	5.7	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2
Ohakune	0.3%	2.0	2.0	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
Pukepapa	1.2%	4.8	4.8	9.9	14.9	20.0	25.0	30.1	30.1	30.2	30.2	30.3	30.3	30.4	30.5	30.5
Rātā	0.4%	2.8	2.9	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
Taihape	0.6%	4.4	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	4.7
Waiouru	-0.1%	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6

A6.12 DEMAND FORECAST FOR MANAWATŪ AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Feilding	1.0%	23.3	23.5	23.7	23.9	24.2	24.4	24.6	24.8	25.0	25.3	25.5	25.7	25.9	26.1	26.4
Ferguson Street	0.4%	11.2	11.2	11.3	11.3	11.4	11.4	11.4	11.5	11.5	11.6	11.6	11.7	11.7	11.7	11.8
Kairanga	0.7%	18.0	18.6	19.3	19.9	20.0	20.2	20.3	20.4	20.6	20.7	20.8	20.9	21.1	21.2	21.3
Keith Street	0.7%	18.6	18.7	18.8	19.9	21.0	21.1	21.2	21.3	21.4	21.6	21.7	21.8	21.9	22.0	22.2
Kelvin Grove	1.2%	17.0	17.2	17.9	25.1	31.8	32.0	32.2	32.4	32.6	32.8	33.0	33.2	33.4	33.6	33.8
Kimbolton	0.9%	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4
Main Street	0.5%	17.9	18.0	18.1	18.2	18.2	18.3	18.4	18.5	18.6	18.7	18.8	18.9	18.9	19.0	19.1
Milson	0.6%	16.2	16.3	17.2	18.0	18.1	18.2	18.3	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2
Ohakea	0.0%	2.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Pascal Street	0.4%	14.9	14.9	15.0	15.1	15.1	15.2	15.3	15.3	15.4	15.5	15.5	15.6	15.7	15.7	15.8
Sanson	1.5%	9.0	9.2	9.3	9.4	9.6	9.7	9.8	10.0	10.1	10.2	10.4	10.5	10.6	10.8	10.9
Turitea	1.6%	14.2	14.4	14.6	17.9	21.1	21.3	21.6	21.8	22.0	22.2	22.5	22.7	22.9	23.2	23.4

A6.13 DEMAND FORECAST FOR TARARUA AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Alfredton	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	0.5%	12.5	12.6	12.7	12.7	12.8	12.8	12.9	12.9	13.0	13.1	13.1	13.2	13.2	13.3	13.3
Parkville	0.4%	2.4	2.4	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
Pongaroa	0.1%	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

A6.14 DEMAND FORECAST FOR WAIRARAPA AREA SUBSTATIONS

SUBSTATION	GROWTH	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Akura	0.9%	13.2	13.3	13.4	13.5	13.6	13.7	13.8	14.0	14.1	14.2	14.3	14.4	14.5	14.6	14.7
Awatoitoi	0.9%	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	1.1	1.1
Chapel	0.7%	13.6	13.7	13.8	13.9	14.0	14.0	14.1	14.2	14.3	14.4	14.5	14.6	14.7	4.8	14.9
Clareville	1.5%	10.4	10.5	10.7	12.9	15.0	15.2	15.3	15.5	15.6	15.8	15.9	16.1	16.2	16.4	16.5
Featherston	1.2%	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.4	4.5
Gladstone	0.7%	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0
Hau Nui	0.5%	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Kempton	1.2%	4.8	4.9	4.9	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6
Martinborough	1.3%	4.6	4.7	4.7	4.8	4.8	4.9	4.9	5.0	5.1	5.1	5.2	5.2	5.3	5.4	5.4
Norfolk	0.6%	6.4	6.5	7.4	8.4	8.4	8.4	8.5	8.5	8.5	8.6	8.6	8.7	8.7	8.7	8.8
Te Ore	0.7%	7.9	8.0	8.1	8.1	8.2	8.2	8.3	8.3	8.4	8.4	8.5	8.6	8.6	8.7	8.7
Tinui	0.8%	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Tuhitarata	1.2%	3.2	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8

APPENDIX 7 GROWTH SECURITY AND RENEWAL PROJECTS

A7.1 APPENDIX OVERVIEW

This appendix provides additional details for planned projects outlined in our Fleet Management and Network Development plans.

The appendix describes the constraints, technical options and preferred solution for the Growth and Security projects outlined in Chapter 15. In general, only projects scheduled to commence in the next five years are listed unless they are of significance to the overall zone substation or area plan. Towards the later part of the planning period, project needs and solutions are less certain. This is because of 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, be refined over time and become firmer as the projects move closer to commencement.

This appendix also includes a description of our larger renewal projects. Only zone substation and subtransmission projects with expected costs exceeding $500,000 have been included and, again, only those that are scheduled to commence in the next five years. Like Growth and Security projects, our renewal projects are continuously reviewed against updated condition assessment and asset health information, and plans updated and adjusted.

The Electricity Distribution Information Disclosure Determination requires us to disclose our forecast expenditures under specific categories. The categories mostly used in this section include:

GRO - System Growth

ARR - Asset Replacement and Renewal

QoS - Quality of Supply

ORS - Other Reliability, Safety and Environment

A7.2 ORS – OTHER RELIABILITY, SAFETY AND ENVIRONMENTCOROMANDEL

A7.2.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Blitz Kopu 1102-Kerepehi 66kV Rearm	ARR	$1,800	2024-2029
Blitz Tairua-Coroglen 66kV rearm	ARR	$1,200	2024-2029

Network issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching 'end of design life' investments for replacement are included in the current overhead renewal planning.

Option

Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

1. The subtransmission network when constructed in the 1960's through to the 1990's the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substations. Also there has been an Engineering Instruction (EI) issued to ban all 'live line' work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.
2. The subtransmissiojn network also has the glass Pilkington insulators used. This type of insulator also, over time, is also electrically breaking down due to hairline cracking and require replacement. The result of the insulator breaking down can lead to the loss of supply to zone substations.
3. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators can cause 'flashovers' at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.

Options

1. Replace the insulators on the existing arms.
2. Replace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient.

A7.2.1.1 LODESTONE SOLAR FARM 66KV SWITCHING STATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
LODESTONE SOLAR FARM 66kV SWITCHING STATION	GRO/CUSTOMER	$1,985	2022-2025

Network issue

The combined 2021 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 is often overloaded during peak demand 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 because of the long overhead lines that cross rugged and exposed terrain, coupled with the existing meshed configuration and tee connections. The Coromandel area's subtransmission network is our worst performing area in terms of System Average Interruption Duration Index (SAIDI).

There is a particular issue with the Coromandel substation, 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

Re-conductor existing Kaimarama-Whitianga 66kV lines.

New Kaimarama-Whitianga 66kV overhead line.

New Kaimarama-Whitianga 66kV underground cable.

New Kaimarama-Whitianga 110kV overhead line (initially operated at 66kV).

New Kaimarama-Whitianga 110kV underground cable (initially operated at 66kV).

Kaimarama 110kV-capable switching station.

Preferred option

Currently, the preferred option is to reconfigure the Powerco 66kV network through the new Lodestone solar farm 66kV switching station and also enable solar farm connection for Lodestone. The site will also have adequate space to install future 110kV transformer, in long-term the Coromandel area can be supplied 110kV from Kopu GXP as the future projects identified will be 110kV capable in anticipation of significant potential voltage change. The project is at the detailed design stage

A7.2.1.2 PROJECT CORE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PROJECT CORE	GRO	$11,065	2021-2024

Network issue

The combined 2021 peak demand on the Coromandel, Whitianga and Tairua substations was ~30MVA. During an outage anywhere on the long 66kV line from Kopu GXP (grid exit point) 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 (i.e., 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) regarding the subtransmission network.

Options

1. Re-conductor existing Kopu-Tairua 66kV line.
2. Duplex the existing Kopu-Tairua 66kV line.
3. Build a second Kopu-Tairua 66kV line.
4. Alternative non-network solution (Project CORE) – distributed generation (DG).

Preferred option

Option 4 to install a non-network solution (also referred to as project CORE) in the form of distributed generation at Coromandel and Matarangi and a third-party solution in the form of solar and battery to provide network support in the northern Coromandel Peninsula. The distribution generation will provide peak demand reduction during an outage to the Kopu-Whitianga line and provide improvement to the Coromandel substation during an outage to a single 66kV line. It will also provide 11kV network support during backfeed. The distribution generation detail design is completed, and construction is to commence soon after.

A7.2.2 ZONE SUBSTATION PROJECTS

A7.2.2.1 KEREPEHI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KEREPEHI REFURBISH 11kV SWITCHBOARD & SWITCHROOM	ARR	$2,569	2026-2028
KEREPEHI 66kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$244	2027-2028

Fleet issue

The existing 11kV switchboard at Kerepehi substation does not meet modern arc flash standards and has oil quenched circuit breakers. The Kerepehi switchroom has been seismically strengthened, however, the adjacent crane room has not been seismically strengthened and there are geotechnical issues with the existing switchroom foundations. The outdoor 66kV circuit breaker is unreliable and is scheduled for replacement.

Options

1. Refurbish the existing Kerepehi 11kV switchboard including arc flash protection, arc flash doors and end panels. Replace the 66KV outdoor circuit breaker.
2. Install a new 11kV switchboard in a new Kerepehi switchroom. Replace the 66kV outdoor circuit breaker.

Preferred option

The preferred option is option 2, to build a new 11kV switchroom, install a new 11kV switchboard and replace the 66kV outdoor circuit breaker.

A7.2.2.2 MATATOKI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATATOKI SEISMIC STRENGTHENING	ARR	$200	2024
MATATOKI REFURBISH 11kV SWITCHBOARD	ARR	$416	2025-2026
MATATOKI REPLACE 66kV CIRCUIT BREAKERS	ARR	$484	2026-2027
MATATOKI SECOND TRANSFORMER	GRO	$2,786	2022-2024

Network issue

Matatoki is supplied from a single 7.5MVA 66/11kV transformer. An outage on this transformer causes loss of supply to the substation. Existing 11kV backfeed capacity is insufficient to support the maximum demand load. This means that the substation does not meet Powerco's Security of Supply Standard.

Options

1. Install a second transformer at Matatoki substation.
2. Increase 11kV backfeed capacity to Matatoki.

Preferred option

The preferred solution is option 1, which is to install a second 7.5MVA 66/11kV transformer at Matatoki substation. This will provide backup to the existing unit and cater for future load growth. Currently, the detail design has been completed and construction to commence in FY23. Option 2, to further increase 11kV backfeed capacity, will involve substantial 11kV infrastructure investment and is not economically attractive.

Fleet issue

The Matatoki 11kV switchroom has a seismic strength of 35% New Building Standard (NBS), below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Matatoki substation does not meet modern arc flash standards, has oil quenched circuit breakers and electromechanical relays.

Options

1. Seismically reinforce the existing switchroom and refurbish the existing 11kV switchgear. Replace the 66kV outdoor circuit breakers.
2. Build a new switchroom and install new 11kV switchgear in the new switchroom. Replace the 66kV outdoor circuit breakers.

Preferred option

The preferred option is to reinforce the existing switchroom and refurbish the existing 11kV switchgear (Option 1), separately replace the outdoor 66kV circuit breakers.

A7.2.2.3 TAIRUA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAIRUA SWITCHROOM REBUILD REPLACE 11kV SWITCHGEAR	ORS	$2,287	2027-29

Fleet issue

The existing switchroom building has a seismic strength of 50% New Building Standard (NBS), which is below the 67% NBS value required for seismic compliance.Half of the board has electromechanical relays and oil-quenched circuit breakers.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom to 67% NBS.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard with additional feeder panels.

Preferred option

The switchroom, switchgear and ancillary equipment require renewal, together with additional feeders. A new switchroom will be required to accommodate this. Option 3 is the preferred option.

A7.2.2.4 THAMES SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
THAMES SEISMIC STRENGTHENING, REPLACE 11kV SWITCHBOARD	ARR	$3,625	2023-2025
REPLACE 2x66kV OUTDOOR CIRCUIT BREAKERS	ARR	$488	2032-2033

Fleet issue

The Thames 11kV switchroom has a seismic strength of 19% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Thames substation does not meet modern arc flash standards and is a switchboard type, which is only used in one other Powerco zone substation. Two of the existing 66kV transformer circuit breakers at Thames require replacement. They are minimum oil type and are 44 years old.

Options

1. Seismically reinforce the existing switchroom and replace the existing 11kV switchgear. Replace the 66kV outdoor circuit breakers.
2. Build a new switchroom and install new 11kV switchgear in the new switchroom. Replace the 66kV outdoor circuit breakers.

Preferred option

The preferred option is to replace the existing switchroom and replace the existing 11kV switchgear (option 2). The non standard nature of the existing 11kV switchgear will make it uneconomic to install standard 11kV switchgear in the existing switchroom. Separately replace the two outdoor 66kV circuit breakers at a later date.

A7.2.2.5 WHITIANGA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHITIANGA SEISMIC STRENGTHENING	ARR	$239	2025
WHITIANGA REFURBISH 11kV SWITCHBOARD	ARR	$1,116	2027-2028

Fleet issue

The Whitianga 11kV switchroom has a seismic strength of 65% NBS, below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Whitianga substation does not meet modern arc flash standards and is oil quenched. There is insufficient room to add new panels to the 11kV switchboard.

Options

1. Seismically reinforce the existing switchroom to 67% of NBS and refurbish the existing 11kV switchgear.
2. Build a new switchroom and install new 11kV switchgear in the new switchroom.

Preferred option

The preferred solution is option 1, to reinforce the existing switchroom and refurbish the existing 11kV switchgear.

A7.3 WAIKINO

A7.3.1 SUBTRANSMISSION NETWORK PROJECTS

A7.3.1.1 NEW OCEANAGOLD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OCEANAGOLD SUBSTATION	CUSTOMER	$16,827	2025-2031

Network issue

OceanaGold plans to increase their operation load in future. Due to the significant load increase, there is a forecast n-1 thermal capacity issue on the 110kV Hamilton-Morrinsville sections of the 110kV Hamilton-Piako-Waihou circuits. The existing transformer T1 at Waikino GXP will be constrained during an outage to larger transformer T2. There already exists voltage step issues at Waihou and Waikino GXP during an outage on the valler spur at high load, the additional load increase will further worsen the voltage step.

Additionally, Powerco’s two existing Waikino-Waihi 33kV circuits, the Waihi substation’s three transformer 33/11kV supply capacity, and the two existing 11kV feeders that supply the mine would also become capacity-constrained during system normal.

Options

1. Install a dedicated new 33kV cable from Waikino GXP to a new substation site.
2. Install a new 33kV cable from Waikino GXP to Waihi 33kV new board to a new substation site.

Preferred option

Both options 1 and 2 for the substation site refer to a location within the OceanaGold property. The preferred solution is option 1, a dedicated 33kV feeder from Waikino GXP to the new substation site. Option 1 is N security, but the risk of cable outage compared with overhead line is much lower and there is limited 11kV backup available from the existing 11kV feeders during an outage on the new 33kV. Although option 1 has N security, option 2 has its own drawbacks even though it has limited n-1 security, since the third new circuit will be underground and the existing 33kV circuits are both overhead lines, it will introduce unbalanced load sharing between the underground circuit and overhead circuits due to the cable's low impedance characteristics which would cause the cable circuit to carry bulk of the load and constraint the cable in system normal. During an n-1 scenario in option 2, if either of the overhead circuits were out, the cable circuit will be constrained and if the cable circuit were out, both overhead circuits will be constrained, this option requires post contingecy load shedding at Waihi Gold during an n-1 scenario. Improving the load sharing between all three circuits would be expensive and would require 33kV series reactors in option 2 for load balancing. While there are still transmission network issues, the short to medium term preference would be to implement special protection scheme to load shed during a constraint on 110kV either transformer or circuit outage to avoid a total blackout. It will be easier to implement with option 1. Using variable line rating and voltage support in form of capacitor bank or STATCOM will also be investigated to address the thermal capacity and voltage constraints.

A7.3.1.2 WAIHI 33KV VOLTAGE SUPPORT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WAIHI 33kV VOLTAGE SUPPORT	GRO	$1,720	2025-2027

Network issue

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 postcontingent voltage step change is excessive. This voltage constraint means Powerco cannot meet voltage regulation and voltage quality requirements.

During an outage on one of the Hamilton-Piako-Waihou circuit during high load period will cause supply bus votlage steps to exceed five percent and for the same outage, Kopu 110kV voltage is forecasted to drop below 0.9pu from 2024, Transpower highlights the issue in their 2022 transmission planning report.

Options

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 options

The preferred solution is option 1, which is to install a switched multistaged capacitor bank at Waihi 33kV bus to provide voltage support in the area. As part of the current 33kV indoor switchboard project, we have acquired a spare 33kV circuit breaker for a future capacitor bank.

Option 2, to install a STATCOM will be much more expensive, although it will offer faster response compared to the switched 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 because of resonance.

A7.3.1.3 HINUERA – WAIKINO 110 KV CIRCUIT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HAMILTON–PIAKO–WAIHOU AND WAIHOU–WAIKINO 110 KV SECURITY AND VOLTAGE CONSTRAINTS	GRO	$84,033	2025-2030

Network issue

The Hamilton–Piako–Waihou and Waihou–Waikino 110 kV double circuit is commonly referred to as the Valley Spur and supplies our Piako, Waihou, Waikino and Kopu GXPs. This circuit is forecasted to approach its N-1 capacity in winter 2023. In addition, Transpower indicated that Piako, Waihou, Waikino and Kopu can experience low 110 kV and 33kV bus voltages for certain outages.

OceanaGold load growth of over 180% over the next 10 years and future growth in the Piako, Waikino and Kopu region will aggrevate the loading on the Hamilton–Piako–Waihou and Waihou–Waikino 110 kV double circuit lines.

Transpower indicated that during an N-1 outage on the Valley Spur at high load periods, the bus voltage step changes at Piako, Waihou, Waikino and Kopu can exceed five percent.

Transpower indicated that any investment will be customer driven. Short and medium-term solutions are discussed in section 15.15.10 and will provide some relieve but do not eliminate the need for a long-term solution for the area.

Options:

1. Waihou Waikino-A 110 kV circuit thermal uprate (Transpower)
2. Third 110 kV Valley Spur circuit to connect the existing GXP substations (Transpower)
3. Hinuera – Waikino 110 kV circuit

Preferred option

Powerco and Transpower are investigating the long-term options to alleviate the constraint. The technical viability is being investigated on the above-mentioned options. The preferred long-term solution being explored is option 3. A feasibility study will be launched to determine constructability, potential circuit routes, equipment layout and preliminary project estimates.

The new line will offload some loading from the existing Piako- Waihou-Waikino circuits and allow future growth to be accommodated. It will also add additional security to Hinuera GXP and by removing load from the existing Valley Spur circuits, potentially solve both the N-1 110 kV circuit constraint as well as the voltage step issues.

A7.3.2 ZONE SUBSTATION PROJECTS

A7.3.2.1 WAIHI BEACH SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WAIHI BEACH DISTRIBUTED GENERATION	GRO	$2,606	2023-2025

Network issue

Waihi Beach substation is supplied via single subtransmission 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 on the subtransmission circuit. This results in a high risk of failure that causes an outage to both circuits. Waihi Beach substation is supplied via single subtransmission 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 on the subtransmission circuit. This results in a high risk of failure that causes an outage to both circuits.

Waihi Beach substation is supplied via a single subtransmission 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 on the subtransmission circuit. This results in a high risk of failure that causes an outage to both circuits.

Options:

1. Increased 11kV backfeed: 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. New 33kV circuit from Waihi substation to Waihi Beach substation.
3. Standby Distributed Generation at Waihi Beach substation or third party non-network solution

Preferred options

The proposed solution is to install standby DG option 3. The DG would be remotely operable and will support load during an outage. It is not economic for an additional second 33kV circuit because of the small load at risk. In parallel with the DG option, Powerco will explore a third party non-network solution similar to Project CORE's approach.

A7.3.2.2 WHANGAMATA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHANGAMATA SEISMIC STRENGTHENING	ARR	$223	2022-2023
WHANGAMATA REFURBISH 11kV SWITCHBOARD	ARR	$1,116	2027-2028
WHANGAMATA T2 TRANSFORMER UPGRADE	GRO	$906	2029-2031
WHANGAMATA TI TRANSFORMER UPGRADE	ARR	$1,114	2030-2031

Fleet issue

The Whangamata 11kV switchroom has a seismic strength of 15% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Whangamata substation does not meet modern arc flash standards and has a mixture of vacuum and oil circuit breakers. It has modern protection relays. Current transformers are mis-matched 5MVA and 7.5/10VA and aged.

Options

1. Seismically reinforce the existing switchroom to 67% NBS and refurbish the existing 11kV switchgear, including arc flash protection.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 1, to seismically reinforce the switchroom and refurbish the 11kV switchgear. At a later date, upgrade the Whangamata transformers.

A7.3.2.3 PAEROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAEROA T1 & T2 POWER TRANSFORMER REPLACEMENT	ARR	$1,814	2029-2031

Fleet issue

Paeroa zone substation has 2 x 7.5MVA power transfomers installed which were manufactured in 1966. Both of these transformers are approaching renewal or replacement as determined by the Copperleaf CNAIM value model. The CNAIM model is prinicipally determined by age, condition and loading. The maximum demand in 2022 was 8.5MVA. At present the timing of the renewal or replacement of the existing transformers is towards the end of the planning period.

Options

1. Refurbish the two existing 7.5MVA transformers manufactured in 1966.
2. Depending on demand growth, purchase and install 2 x 12.5/17MVA power transformers at Paeroa.

Preferred option

The preferred option will be determined by demand growth. Demand growth should be reviewed in 2028 or earlier. Preferred is option 2.

A7.4 TAURANGA

A7.4.1 SUBTRANSMISSION NETWORK PROJECTS

A7.4.1.1 OMOKOROA CAPACITY REINFORCEMENT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OMOKOROA 33kV-CABLE INSTALLATION	GRO	$8,767	2022-2024

Network issue

The region to the north-west of Tauranga is supplied by a 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 makes up two predominantly overhead circuits, approximately 12km long, that run north-west to Aongatete. Two tee-offs from these circuits supply Omokoroa. The peak load on these lines is approximately 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 thermal overload 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. In recent years, there has been rapid development of residential subdivisions, particularly in Omokoroa and Katikati.

The following constraints/issues exist:

1 The combined peak demand of all four substations is projected to exceed the N-1 thermal 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, resulting in the 33/11kV zone transformer tap-changers exceeding their tap range during periods of high load.

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 prone to sympathy tripping because of mutual coupling.

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. Solar photovoltaic (PV) 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 anticipated.

Neither generation nor demand side responses, already a component of our network strategies, would provide the 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 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 third 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 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.

This project is currently in progress. Delays due to works by Waka Kotahi in the area have resulted in Powerco not being able to complete one section of the project due to access issues. The cable between Greerton switching station and Bethlehem substation has one section which can only be completed in the latter half of 2023 once Waka Kotahi works have been completed. The first part of this project, between Greerton switching station and Omokoroa substation has been progressing on schedule and is expected to be completed by March 2023. This next stage of this project will then shift to the Omokoroa substation to enhance its security. However, the Waka Kotahi TNL - Stage 2 works could force the relocation of the existing Omokoroa substation depending on the finalised highway route. This project would conclude the capacity project by removing subtransmission tee-offs and installation of a 33kV indoor bus.

A7.4.1.2 TAURANGA GXP CAPACITY UPGRADE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAURANGA AREA SECURITY CONSTRAINTS	GRO	$32,129	2024-2030

Network issue

Tauranga GXP supplies 11 zone substations, with an area of supply covering the greater Tauranga region up to Kauri Point, north-west of the city. Several significant development projects planned within the Tauranga area of supply would add additional load to the subtransmission network. Powerco’s demand forecast indicates a potential increase at Tauranga GXP from 125MVA to 180MVA.

- Urban intensification planned for Te Papa Peninsula – the district council will encourage mixed-use residential and multi-storey buildings.
- Tauriko Business Park has seen significant growth in the past, with more commercial/industrial developments planned for the next few years.
- Tauriko West Housing development would add 3,000-6,000 new residential sections within the planning period.
- Omokoroa has experienced significant growth recently. There would be approximately 2,500 new residential sections added within the planning period. Shopping districts, commercial and industrial zones are also planned for the area.
- The suburb of Ohauiti will have 1,600 new residential sections added within the planning period.
- Uptake in electric vehicle adoption and switchover from residential gas supply to electricity.

The increase in demand will exceed the firm capacity of the two existing 110/33kV transformers and subtransmission circuits currently supplying Tauranga GXP.

In addition to the forecasted growth exceeding the firm capacity at Tauranga GXP, fault levels at Transpower’s Tauranga GXP 11kV bus are too high, despite series reactors being installed at the bus to lower the fault level. This poses a potential health and safety risk to the public and could also generate stress on equipment because of the high fault duty. Reduction of earth fault level can be achieved by replacing the two existing small impedance 110/11kV transformers with 33/11kV units.

Options

1. Kaitimako – Tauranga 110kV circuit and Tauranga substation upgrade
2. Kaitimako – Greerton 110kV circuit and Greerton 110/33kV substation
3. Kaitimako – Belk Road 110kV circuit and Belk Road 110/33kV substation
4. Kaitimako – Tarukenga 220kV and Belk Road 110/33kV substation
5. Kaitimako – Tarukenga 220kV and Belk Road 220/33kV substation

Preferred option

The preferred long-term solution being explored is option 1. A feasibility study has been completed to determine physical constructability, potential underground cable routes, equipment layout and preliminary project estimates. This option provides the necessary capacity to reliably cater for Tauranga's growth during the planning period, while also reducing the high earth fault level at Tauranga 11kV substation. Powerco and Transpower are collaborating to progress solutions to address the capacity constraints in the Western Bay of Plenty region. Option 3 is also being explored to establish 110/33 kV at Belk Road substation and supply it via a Kaitimako-Belk Road 110 kV circuit. This opportunity allows to shift significant industrial and future load to the new Belk Road substation and reduces the demand on the Kaitimako-Tauranga 110 kV circuits. Both options require significant investigations work to be ready for resource consenting.

Short to medium term options to mitigate the load increases suggest use of a special protection scheme to shed load or a variable line rating approach. Transpower have scheduled a variable line rating project on the Tauranga – Kaitimako dual 110kV circuits in their latest Transmission Planning Report under short term projects.

A7.4.2 ZONE SUBSTATION PROJECTS

A7.4.2.1 AONGATETE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
AONGATETE REPLACE 11kV SWITCHBOARD AND OUTDOOR 33kV SWITCHYARD	ARR	$5,651	2023-2026
AONGATETE 33kV VOLTAGE SUPPORT	GRO	$464	2024-2025
AONGATETE - T6 & T7 POWER TRANSFORMER REPLACEMENT	ARR	$1,814	2030-2031

Network issue

The northern ring has significant development scheduled primarily at Omokoroa and Katikati. The third 33kV circuit to Omokoroa will improve capacity to the region. However, there still exists the risk of post contingency voltage collapse at Aongatete, Katikati and Kauri Point.

Options

1. Install capacitor banks at Aongatete substation
2. Install additional 33kV circuit between Bethlehem and Omokoroa substations

Preferred option

Option 1 is the preferred option. The potential risk will be mitigated in the interim by a routine project that will address the post contingency voltage collapse, which could occur at Aongatete, Katikati and Kauri Point substations. This will be achieved through installation of two sets of 5 MVAR capacitor banks installed at Aongatete 33kV bus. Both will be switched on in the event of an outage of a 33kV Greerton-Omokoroa-Aongatete circuit.

Fleet issue

The Aongatete 11kV switchroom has a seismic strength of 15% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard does not meet modern arc flash standards and has oil circuit breakers with electromechanical relays.

The 33kV outdoor switchyard has oil circuit breakers that are due for replacement. Arranging 33kV outages for switch, bus and insulator maintenance is problematic.

Options

1. Seismically reinforce the existing switchroom and refurbish the existing 11kV switchgear, including arc flash protection. Upgrade and extend the existing outdoor 33kV bus, including new 33kV circuit breakers.
2. Build a combined 11kV and 33kV switchroom and install indoor arc flash compliant 11kV and 33kV switchgear. Dismantle the existing 33kV outdoor switchyard to make more space available for additional 33kV circuits, capacitor banks and transformer bank upgrades.

Preferred option

The preferred solution is option 2, to build a combined 11kV and 33kV switchroom with new 11kV and 33kV switchgear. This will align with Network Development priorities as additional 33kV and 11kV circuits are required to meet projected demand growth and security of supply criteria for Aongatete, Katikati and Kauri Point zone substations.

A7.4.2.2 MATUA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATUA SECOND TRANSFORMER	GRO	$1,942	2025-2026
MATUA SEISMIC STRENGTHENING	ARR	$242	2027-2028
MATUA REFURBISH 11kV SWITCHBOARD	ARR	$699	2028-2029
MATUA RENEWAL OF OUTDOOR 33kV CIRCUIT BREAKERS	ARR	$338	2029-2030

Network issue

Matua zone substation provides supply to the residential suburb of Matua. There are five existing 11kV feeders emanating from the substation serving 4,131 ICPs. Matua substation is classified as AA in terms of network security criteria because of the nature and magnitude of the supplied load. Matua zone substation is normally supplied by one 12.5/17MVA 33/11kV transformer. The 5MVA transformer has been refurbished and kept in store in 2021, making room for the future 2nd transformer. This was necessary to comply with environmental requirements due to no bunding for the 5MVA transformer and the proximity to nearby wetlands. Existing 11kV backfeed capacity is sufficient to fully support the existing load, and it also involves multiple switching movements on the 11kV network to restore supply. With forecasted load growth, 11kV restoration will cause constraints at Otumoetai and Hamilton St substations. It is probable that demand on Otumoetai and Hamilton St substations will reach a level (16.5 and 12.9MVA respectively) that may cause constraints by backfeeding Matua’s full load by 2026.

Options

1. Install new 12.5/17MVA33/11kV transformer at Matua substation.
2. Increase 11kV inter-tie capacity.

Preferred option

The preferred solution is option 1, which is to install a new 12.5/17MVA transformer unit to match the existing unit. There is a 33kV-capable circuit that is energised at 11kV, supplied from Otumoetai substation, which provides the primary backup to Matua. When the new transformer is installed, this backup feeder will be re-energised at 33kV, and the 33kV configuration at Matua will change to become transformer feeders supplied from Otumoetai. The existing outdoor 33kV bus frame and switchgear will be removed and a new transformer bund is to be constructed.

Fleet issue

The Matua 11kV switchroom has a seismic strength of 50% NBS. The existing 11kV switchboard at Matua substation does not meet modern arc flash standards, has a mixture of vacuum and oil circuit breakers, and has electromechanical protection relays.

Options

1. Seismically reinforce the existing switchroom and refurbish the existing 11kV switchgear, including arc flash protection.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 1, to reinforce the existing switchroom and refurbish the existing 11kV switchgear.

A7.4.2.3 BETHLEHEM SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BETHLEHEM SECOND TRANSFORMER	GRO	$1,835	2024-2025

Network issue

Bethlehem zone substation provides supply to the residential suburb of Bethlehem. There are six existing 11kV feeders emanating from the substation, serving 4133 ICPs. Bethlehem substation is classified as AA+ in terms of network security criteria because of the nature and magnitude of the supplied load. Bethlehem zone substation is supplied by one 16/24MVA 33/11kV transformer, with provision having been made for a second transformer. An outage of this transformer or subtransmission line causes loss of 33kV supply. Existing 11kV backfeed capacity is insufficient to support the entire load and involves extensive switching on the 11kV network to restore supply.

Options

1. Install a second transformer at Bethlehem substation.
2. Increase 11kV inter-tie capacity.

Preferred option

The preferred solution is option 1, to install a second 16/24 MVA 33/11kV transformer at Bethlehem substation, which will provide backup to the existing unit. This is the most effective method to ensure that the load is restored within the time period corresponding to the substation’s security class, while also catering for future growth in Bethlehem.

A7.4.2.4 WELCOME BAY SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WELCOME BAY 11kV SWITCHBOARD REFURBISHMENT	ARR	$852	2027-2029
WELCOME BAY 33kV CIRCUIT BREAKER REPLACEMENT	ARR	$580	2029-2030

Fleet issue

The Welcome Bay 11kV switchroom has a seismic strength of 82% NBS and is not an earthquake risk. The existing 11kV switchboard at Welcome Bay substation does not meet modern arc flash standards, has a mixture of vacuum and oil circuit breakers, and has electromechanical protection relays.

Options

1. Supply the area from a new zone substation if the present Welcome Bay zone substation landowners are unable to extend the current lease or sell the land to Powerco.
2. Refurbish the existing 11kV switchgear, including installing new arc flash protection.
3. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 2, to refurbish the existing 11kV switchgear. Powerco does not own the land on which the Welcome Bay zone substation is located. Any expenditure at Welcome Bay zone substation will require land ownership to be confirmed before commencing construction works at site. At a later date renew the two outdoor 33kV circuit breakers.

A7.4.2.5 OMOKOROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OMOKOROA SUBSTATION UPGRADE	GRO	$5,645	2026-2028

Network issue

As part of the Northern ring reinforcement, additional capacity in the form of a third circuit will be commissioned between Greerton and Omokoroa. Currently, it is not possible to terminate the proposed circuit at the substation because of coinciding works with Waka Kotahi (the Takitimu Northern Link road project), which may require the relocation of the entire substation. There would not be enough space in the current outdoor 33kV circuit breaker arrangement to cater for the full configuration of eight 33kV circuit breakers and bus section.

Options

1. Install the switchboard and lay the cables to the substation.
2. Await finalisation of the Takitimu Northern Link route and confirmation of the substation final position before completing the cabling and switchgear work.

Preferred option

Option 2 is preferred because of the cost saving and practicality. This option will result in increased capacity to the Omokoroa area. More reliability and greater flexibility can be achieved once the existing tee-offs are removed and the proposed third circuit is accommodated in a new 33kV switchroom. Allowance will also be made to link the proposed Pahoia substation to Omokoroa substation should the existing 33kV circuits run out of capacity in future. This may be possible due to the Takitimu Northern Link road passing the existing substation and ending at the proposed new one.

A7.4.2.6 PAHOIA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAHOIA ZONE SUBSTATION	GRO	$6,799	2024-2028

Network issue

Omokoroa substation (OMO) provides supply to the residential suburb of Omokoroa. There are six existing 11kV feeders emanating from the substation, serving 4803 ICPs. Omokoroa is classified as AA in terms of network security criteria because of the nature and magnitude of the supplied load. Omokoroa zone substation is normally supplied by two 10/12.5MVA 33/11kV transformers and is almost at the firm capacity of the substation. The suburb is experiencing significant residential development, with 2,500 new homes expected to be constructed during the next five years. In addition, there is a new town centre planned for the area, along with two new schools, commercial and industrial areas. The existing Omokoroa substation will become capacity constrained by the proposed new developments. As a result, existing 11kV feeders will encounter capacity and low voltage issues, which worsen during backfeeds. There is also a significant existing industrial load (Apata cool store) supplied by the substation.

Options

1. Staged construction of new 11kV feeders from Omokoroa substation to the area to support growth.
2. Build a new substation in the Pahoia vicinity supplied off one of the Omokoroa-Aongatete 33kV circuits.

Preferred option

Option 2 is preferred, primarily to offload the existing substation and reinforce the 11kV network surrounding the developing load centre. Option 1 is not preferred, as 11kV infrastructure development will likely be more expensive and will not provide the same capacity increase of the substation-based options. In addition, Waka Kotahi have purchased large tracts of land between the existing substation and the load centre for Stage 2 of the TNL project. Any new infrastructure would need to be relocated at Powerco's full cost should they move forward with the highway. Powerco are actively negotiating with two land owners to acquire a substation site to enable efficient 11kV distribution.

A7.4.2.7 BELK ROAD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BELK ROAD SUBSTATION	GRO	$56,243	2024-2029

Network issue

The suburbs of Pyes Pa and Tauriko are supplied from Pyes Pa and Tauranga 11kV substations. Because of the existing load and distance from Tauranga 11kV substation, very little additional capacity can be utilised to support growth in Pyes Pa. The area is primarily urban residential subdivisions, mixed with commercial and industrial developments. Pyes Pa substation is relatively new and has available capacity. Load uptake in the Pyes Pa/Tauriko industrial park is increasing rapidly because of the strong economy in the region. District council plans show potential for 3,000-6,000 new residential developments in the vicinity of Belk Rd, Keenan Rd and Tauriko West. The additional load would exceed Pyes Pa's firm load within the planning period. Tauranga City Council has confirmed its decision to intensify development in the Tauriko area as opposed to Welcome Bay, because of the existing infrastructure being capable of supporting growth. Significant investment in roads, and land settlements are required at other locations. The housing department has also expressed an intention to further development in the Upper Belk Road area for residential homes.

There are several industrial and commercial developments in the vicinity of the Belk Road area. A major customer-initiated works (CIW) project has been completed this year with the full load likely to be seen at Pyes Pa from end 2023. A large wallboard factory has been constructed in the Tauriko Business Estate with a connected capacity of 9.5MVA. The existing Pyes Pa substation can reliably supply the wallboard factory. However, as the residential development is completed, demand will exceed the firm load of Pyes Pa substation, breaching Powerco's network security criteria. Industrial decarbonization is possible and with a large business estate attracting more businesses to Tauranga and electricity the primary energy solution, significant investment is necessary to meet demands within the next 10 years.

Options

1. Install 2x110kV cables (1 operated at 33kV and 1 operated at 110kV) to Belk Road substation
2. Install 2x110kV cables (operated at 33kV) to Belk Road substation
3. Install 2x33kV cables to Belk Road substation

Preferred option

Option 1 is the preferred solution. The potential for rapid growth within the planning period necessitates the need for a GXP in the area to significantly increase capacity more efficiently than via subtransmission options. Significant industrial and residential growth is forecast for the area, with the possibility to expand further into the upper Belk Road area outside of the planning period. One 16/24MVA transformer would be installed at Belk Road to support the rapidly developing area. As the region develops, a second transformer can be installed to maintain network security. Additional transformer capacity would be customer dependant.

Powerco have a potential site that can accommodate the infrastructure necessary to commission a new GXP. Geotechnical studies and negotiations are ongoing. Initially two 110kV cables will be constructed between Tauranga and the proposed Belk Road site. One of these cables will be operated at 110kV and the second will be operated at 33kV. The existing cables which supply Pyes Pa will be extended to the proposed Belk Road site. Collectively, the three cables operated at 33kV will form the back up security to the 110kV cable. This option will require significant works at Tauranga GXP to enable an additional 110kV outdoor circuit breaker. These works should begin before Pyes Pa load exceeds 30MVA.

A7.4.2.8 OROPI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OROPI SUBSTATION	GRO	$9,518	2024-2029

Network issue

The suburb of Oropi, south of Tauranga, and its surrounds are supplied from long 11kV feeders out of Welcome Bay substation. The area has historically been predominantly used for rural lifestyle, mixed with horticulture farming. In recent years, strong growth in Tauranga has seen the development of new residential subdivisions in the region. Consequently, this is putting pressure on the existing 11kV infrastructure to maintain security of supply and support the growing demand.

A recent study commissioned by Tauranga City Council has deferred the additional residential development plans for Welcome Bay suburb because of the extensive infrastructure investment required. However, approximately 1,600 proposed homes will proceed in the upper Ohauiti area. The 11kV network in the vicinity of the proposed development is supplied from Tauranga GXP 11kV substation and Welcome Bay substation. Both these substations are forecast to reachfirm capacity within the planning period and the distance to the proposed development will make backfeeding difficult. The ICP numbers on the existing 11kV feeders at Welcome Bay have exceeded our security standard target levels, bringing associated unacceptable reliability risks. Network automation schemes have been installed to try to mitigate the SAIDI issue, but backfeed capacity remains limited because of voltage constraints. Constraints at Welcome Bay will occur as more stages of the residential sections develop.

Options

1. Staged construction of new 11kV feeders to the area to support growth.
2. Build a new substation at Oropi to supply the growing load in the area, and offload demand from Welcome Bay and Tauranga GXP 11kV substations.

Preferred option

Option 2, to build a new substation at Oropi, is the preferred solution as it will not only increase supply capacity in the region but will also improve reliability issues by shortening the 11kV feeder circuits (reducing ICPs per feeder), maintaining the network security criteria for residential loads, and increase backfeed capacity. The new substation will be supplied via 33kV subtransmission cables connected to the Tauranga GXP-Kaitimako GXP 33kV circuits. Once commissioned, the new substation will offload demand from Welcome Bay substation.

Option 1 is not preferred as 11kV infrastructure development will likely be more expensive and cannot provide the same benefits as option 2.

A7.5 MOUNT MAUNGANUI

A7.5.1 ZONE SUBSTATION PROJECTS

A7.5.1.1 ATUAROA AVENUE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ATUAROA AVENUE SECOND TRANSFORMER AND 33kV INDOOR SWITCHBOARD	GRO	$4,813	2024-2027

Network issue

At the Atuaroa Avenue zone substation, there is a single 12.5/17MVA supply transformer. An outage of the transformer at high load times makes it difficult to backfeed because of limited capacity from adjacent substations. Further load growth will worsen the situation and result in voltage constraints across the 11kV network. The relevant local council has indicated industrial growth in the Te Puke west area and a new industrial zone change at Washer Rd. Local cool stores are expecting major expansion, and new residential subdivisions are also located near the substation. All this load growth puts a significant burden on the single transformer. The existing 33kV subtransmission circuit supplying Atuaroa Avenue terminates directly to the transformer. Atuaroa Avenue does not have a 33kV bus. This limits options to improve subtransmission security of supply to the substation.

Options

1. Build new 33kV switchboard at Atuaroa Avenue substation and install a second 12.5/17MVA transformer.
2. Increase 11kV backfeed capacity into Atuaroa Avenue.
3. Install standby diesel generators within the substation site.

Preferred option

Currently, the preferred solution is option 1, which involves the construction of a new 33kV indoor switchboard and installing a second 33/11kV 12.5/17MVA transformer to parallel the existing transformer at Atuaroa Avenue zone substation. The new 33kV switchboard will facilitate the connection of a future 33kV circuit from Te Puke. 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, causing air pollution and noise. The existing substation site is also space-constrained to make this option impractical.

A7.5.1.2 TE PUKE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TE PUKE BUS SECURITY UPGRADE	GRO	$2,723	2027-2029

Network issue

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 Avenue 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, because of the 33kV bus normally operating as a split bus arrangement. The Te Puke region has and will continue to see large growth in the industrial and residential sector. In the medium term 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.

Options

1. Construct a third Te Matai GXP-Te Puke 33kV circuit.
2. Implement a secure 33kV bus at Te Puke substation complete with bus zone protection.
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 33kV bus. Additional line circuit breakers are required, including a new bus coupler, communications systems upgrade and a fast bus differential protection scheme. The existing Te Matai GXP-Atuaroa Avenue 33kV circuit will be terminated to this bus, creating three 33kV circuits between Te Matai GXP and Te Puke substation. Option 1, to construct a third Te Matai GXP-Te Puke 33kV circuit, would be uneconomical and expensive to construct because of difficult terrain and suitable line route. Option 3, to further increase 11kV backfeed capacity, would involve substantial 11kV infrastructure investment and is unlikely to be economical.

A7.5.1.3 PAENGAROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAENGAROA SECOND TRANSFORMER AND BUS EXTENSION	GRO	$3,311	2023-2025

Network issue

The single transformer at Paengaroa limits the security of the substation. In the event of a transformer outage, 11kV backfeed from neighbouring substations is required. At current peak demands the backfeeds are not able to fully maintain supply, and this will get worse as demand grows. The existing switchboards, both 33kV and 11kV, have no bus section therefore any bus outage will affect the total Paengaroa load. A bus outage on the 33kV will also cause a complete loss of supply to Pongakawa. The proposed switchboards will have a bus section which will minimise the impact of any bus outage. A 2nd transformer enables substation maintenance to be undertaken and provides capacity for backfeed into Pongakawa and Te Puke (future Rangiuru Business Park substation) to enable distribution network maintenance and during a contingency.

Options

1. Install a second transformer at Paengaroa.
2. Increase automated 11kV backfeed capacity to Paengaroa.
3. Install generation on-site.

Preferred option

The preferred solution is option 1. A second transformer will provide quick resupply to the 11kV board in a transformer fault scenario. With the increase in recent horticulture demand in the region, a second transformer provides the capacity needed for this growth. Expanding the 33kV bus to fit this transformer will give fast bus protection. This, coupled with the new 33kV capable cable from Paengaroa up Youngs Rd, will offer the substation full N-1 security in the future.

Option 2 increases automated 11kV backfeed capacity to Paengaroa and resolves the restoration of supply constraint. However, it does not provide enough capacity for growth because of 11kV feeder constraints.

Option 3 involves installing diesel generation at Paengaroa to improve response time in a fault scenario. The indicated future increase in load on Paengaroa substation will bring the existing transformer over its installed capacity. For this reason, generation will not be viable as it will need to be run during system normal operation in order to keep supply going. This option is not economical when accounting for these factors compared with the costs of the others.

A7.5.1.4 PONGAKAWA

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PONGAKAWA 11kV SWITCHGEAR REPLACEMENT	ARR	$3,360	2022-2023
PONGAKAWA 33kV CIRCUIT BREAKER REPLACEMENT	ARR	$335	2032-2033

Fleet issue

The Pongakawa 11kV switchroom has a seismic strength of 15% NBS, and is an earthquake risk. The existing 11kV switchboard at Pongakawa substation does not meet modern arc flash standards, has oil circuit breakers, and has first generation electronic protection relays that have type issues.

Options

1. Refurbish the existing 11kV switchgear, including installing new arc flash protection.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 2, to build a new switch groom and install 11kV arc flash compliant switchgear in the switchroom. This option will allow for additional 11kV feeder circuit breakers to be added to the switchboard, including switchgear for future diesel generation, which will be needed to meet network security of supply standards.

A7.5.1.5 PAENGAROA AND PONGAKAWA SUBSTATIONS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAENGAROA AND PONGAKAWA SECURITY OF SUPPLY	REL	$4,790	2024-2027

Network issue

Paengaroa and Pongakawa substations are supplied by a single 33kV circuit from the Te Matai GXP, with the circuit being predominately overhead. An outage on any section of the line will result in a total loss of supply to both substations or the Pongakawa substation depending on the outage location. The load of both substations cannot be supplied at 11kV from Te Puke as capacity and voltage constraints rapidly occur. With the forecast load in the area, this problem will only be compounded resulting in unacceptable outage times to commercial and residential customers.

Options

1. Install diesel generation at Pongakawa
2. Second 33kV circuit from Te Matai GXP to Pongakawa via Paengaroa.
3. Second 33kV circuit to Paengaroa and reinforce 11kV connection to Pongakawa

Preferred Option

Option 3 is the preferred solution.as the most economic and most reliable. A second circuit to Paengaroa can be established from the proposed Rangiuru substation site and utilising the existing 33kV cable currently operated at 11kV. Reinforcing the 11kV ties between Paengaroa and Pongakawa is more cost effective than building approximately 9km of 33kV circuit between the two substations. With security of supply established at Paengaroa, by two 33kV circuits, the voltage on the 11kV ties can be managed.

Option1 and 2 are more expensive than the preferred option.

A7.5.1.6 RANGIURU BUSINESS PARK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW RANGIURU SUBSTATION	GRO	$11.947	2023-2030

Network issue

A proposed 148ha industrial park located at Rangiuru is in council district plans, and is promoted by the Western Bay of Plenty District Council's development arm. Powerco is 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 business park civil works have commenced and stage 1 is scheduled to be completed in 2024. This also includes connection onto the Tauranga Eastern Link highway, which would help growth take off in the area. This project is now seen to be in the medium-term horizon, as load can be initially supported by the existing 11kV and the new Youngs Rd feeder. Although the area is supplied via 11kV feeders from Te Puke substation, future load growth in the area will place significant pressure on the 11kV network to support the expected load increase at the business park.

Options

1. Build new 11kV feeders from Te Puke substation and Paengaroa substation.
2. Construct two new 33kV circuits from Te Matai GXP to a new Rangiuru Business Park zone substation.
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

Currently, the preferred solution is 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.

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 with 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.

A7.5.1.7 TRITON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRITON ODID CONVERSION	ARR	$3,672	2022-2023
TRITON SUBSTATION TRANSFORMER REPLACEMENT	ARR	$,2,654	2022-2023

Fleet issue

The Triton 11kV switchroom has a seismic strength of 30% NBS and is an earthquake risk. The existing 11kV switchboard at Triton substation does not meet modern arc flash standards, has oil circuit breakers, and electromechanical relays. The existing switchroom has insufficient space for additional 11kV feeder panels to be added to the switchboard.

Options

1. Refurbish the existing 11kV switchgear, including installing new arc flash protection. Install two new 24MVA rated power transformers.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom. Install two new 24MVA rated power transformers.

Preferred option

The preferred solution is option 2, to build a new switchroom, install 11kV arc flash compliant switchgear in the switchroom and replace the existing transformers with two new 24MVA rated power transformers. The transformers will be supplied by 33kV transformer feeders in the short term, which will ensure that no additional land has to be purchased and will eliminate maintenance outages on the existing 33kV outdoor bus and incomer circuits.

A7.5.1.8 MOUNT MAUNGANUI AREA SECURITY CONSTRAINT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WAIRAKEI 110/33KV SUBSTATION	GRO	$62,799	2025-2032

Network issue

Momentous load growth of over 130% is expected to occur in the eastern Bay of Plenty over the next ten years. This is driven by the expanding kiwifruit and avocado industries, commercial and industrial developments, residential spread together with decarbonisation. This growth will outstrip the existing Transpower Te Matai GXP's ability to securely supply the demand at an economic cost. The Te Matai GXP is located in a rural setting surrounded by kiwifruit orchards and on a narrow road with shelter belt trees on both sides. There are currently 6 x 33kV circuits out of Te Matai supplying Te Puke, Paengaroa, Pongakawa and the Wairakei area of Papamoa. Doing nothing is not an option. The area is constrained in enabling further multiple outgoing 33kV circuits and to provide route diversity.

Options

1. Expand the 33kV Bus at Te Matai and run more 33kV circuits supply the load
2. Establish a 110/33kV substation at Rangiuru
3. Establish a 110/33kV substation at Wairakei

Preferred option

Option 3 is the preferred solution. Powerco has sufficient land at its Wairakei substation to establish a 110kV substation and there are several line/cable routes identified as being possible from either the Te Matai GXP or possibly connecting to Transpower's Te Matai – Kaitimako 110kV line. This site is close to the load centre and allows for straightforward distribution of bulk load at 33kV to where it is required. Added benefits is the possibility of extending the 110kV to the Mount Maunganui GXP in future to provide a secure ring to the region and relief the pressure on the Mount Maunganui line constraint. This is a long term solution that can be built in stages as the load dictates.

Option 1 and 2 are not favoured due to difficulties in categorising satisfactory line routes over more difficult terrain with appropriate route diversity to ensure security and land to build the necessary substations. Both options provide a medium-term solution before further enhancement works will be necessary to meet the load demands.

A7.6 WAIKATO

A7.6.1 SUBTRANSMISSION NETWORK PROJECTS

A7.6.1.1 MORRINSVILLE AREA NETWORK ENHANCEMENT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MORRINSVILLE SUBSTATION 33KV BUS	GRO	$6,563	2023-2028
AVENUE ROAD NORTH SUBSTATION	GRO	$12,949	2023-2028

Network issue

Morrinsville and Piako substations supply the Morrinsville township, commercial, residential and surrounding rural area. Major industrial customers include Greenlea Meats processing plant and Fonterra. The Morrinsville area has experienced rapid residential and industrial growth and this is expected to continue.

Two of the existing Piako 11 kV feeders supplying the Morrinsville area are already at capacity.

Morrinsville substation is supplied on two 33 kV transformer feeders from Piako. The Morrinsville substation load is forecast to exceed the transformer's N-1 capacity within the next five years.

Although some 11 kV backfeed from Piako and Tahuna is available, this is insufficient to meet the forecast growing demand.

Fleet issue

The existing Morrinsville substation is space constrained and will not accommodate larger power transformers. The Morrinsville 11kV switchboard does not have a bus section and the switchboard cannot be extended within the footprint of the existing switchroom.

The Piako 33 kV switchboard cannot be extended beyond a single 33 kV transformer feeder to supply a new substation in the Morrinsville area

Options

1. Morrinsville 33 kV bus and new Avenue Road North substation
2. New Avenue Road North substation supplied from Piako 33 kV bus
3. Upgrade Morrinsville substation transformers to 16/24MVA and increase 11 kV feeder capacity into the Morrinsville area.

Preferred option

The preferred solution is option 1, to construct a new switchroom for the new Morrinsville 33 kV switchboard and a new 33/11 kV substation at Avenue Road North, Morrinsville.

With the existing Morrinsville 33 kV transformer feeder configuration, an outage on one of the existing 33 kV circuits into Morrinsville substation will limit the capacity of the substation to the capacity of the remaining Morrinsville transformer feeder. A 33 kV bus at Morrinsville substation will increase the 33 kV subtransmission security and capacity into the Morrinsville area. With a 33 kV bus at Morrinsville substation, if one of the 33 kV Piako-Morrinsville circuits is out of service, the remaining 33 kV Piako-Morrinsvlle circuit would be able to supply the total Morrinsville and new Avenue Road North substation loads for the foreseeable future.

A new 33/11 kV substation at Avenue Road North would be located near to the forecast demand growth area. The new substation would relieve the Morrinsville substation load and eliminate the need to increase its transformer capacity to meet the forecast demand growth. It would also be more economical to construct new 11 kV feeders out of this new substation than from Piako and Morrinsville substations. The intention is to reconfigure the 11kV network to pick up some of the load that is presently supplied by Piako and Morrinsville substations, in addition to supplying the forecast industrial and residential growth in the area. This will free up some capacity at Piako and Morrinsville substations and the heavily loaded Piako 11 kV feeders. The new Avenue Road North suvbstation would initially be supplied from a single transformer feeder from the new Morrinsville 33 kV bus, with provision to add a second transformer feeder when required to meet load growth in the area.

Option 2, to supply the new Avenue Road North substation from Piako is limited due to space constraints at Piako. The Piako indoor 33 kV bus only has space to supply one 33 kV Avenue Road North substation transformer feeder. There will be no space to be able to supply a second 33 kV Avenue Road North substation transformer feeder to meet future load growth.

Option 3, to upgrade the Morrinsville transformer capacity and install additional 11 kV feeders out of Morrinsville and Piako is unlikely to be economic:

- As the existing Morrinsville substation does not have sufficient space to accommodate larger power transformers and the new transformers and would require additional land to be purchased to install the new transformers
- Due to the great distance and challenges to construct new 11 kV feeders from Piako and Morrinsville substations to supply the Morrinsville load growth area.

A7.6.1.2 PUTARURU 110/33 KV SECURITY UPGRADE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PUTARURU SECOND 110/33 kV TRANSFORMER	GRO	$5,393	2025-2027

Network issue

With the recently completed Putaruru 110/33 kV interconnection project, Putaruru and Tirau substations are now normally supplied on N security by a single 110/33 kV transformer feeder from the Arapuni GXP. The 33 kV subtransmission network has switched backfeed capability to be able to supply Putaruru and Tirau from the Hinuera GXP if the Arapuni-Putaruru transformer feeder is out of service.

Putaruru and Tirau substations supply several industrial customers, including Fonterra (Tirau), Buttermilk (Putaruru), and Kiwi Lumber (Putaruru).

Once the proposed Putaruru to Maraetai 33kV link is established (See Section 0: Kinleith Security for more details), Maraetai and the proposed new OFI zone substations will be supplied from Putaruru. The total load with the additional zone substations is forecast to exceed the capacity of the single Putaruru 110/33 kV transformer within the planning horizon.

Options

The following network solutions are being considered:

1. A second 110/33 kV transformer to increase the 110/33 kV interconnection security at Putaruru
2. A second 110/33 kV transformer feeder (110/33 kV transformer and 33 kV overhead line) from Arapuni.

Preferred option

The preferred solution is option 1, a second 110/33 kV transformer to increase the 110/33 kV interconnection security at Putaruru. We are in discussions with Transpower about re-using the existing Te Matai 110/33 kV, 40 MVA transformer at

Putaruru should Te Matai's total supply transformer capacity be increased as part of transformer renewal works scheduled for 2026[32]. We are in negotiations with Transpower to purchase that transformer to increase the 110/33 kV transformer security at Putaruru.

Alternative option 2 is unlikely to be economic due to the hgh cost of constructing a second 110 kV transmission line from Arapuni to Putaruru, especially as the 33 kV subtransmission network has the capability to backfeed Putaruru and Tirau from the Hinuera GXP if required.

A7.6.1.3 LAKE ROAD – BROWNE STREET CIRCUIT UPGRADE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33 kV LAKE ROAD – BROWNE STREET CIRCUIT UPGRADE	GRO	1,882	2029-2030

Network issue

The 33 kV subtransmisison network forms a ring between Lake Road, Tower Road and Browne Street substations, with a single 33 kV backup circuit connection to Waharoa from Browne Street that is normally operated open.

The 33 kV Browne Street – Lake Road circuit is limited by the rating of a 300 mm^2, Aluminium cable section and is the lowest capacity circuit in this ring. If the 33 kV Lake Road-Tower Road circuit is out of service, the 33 kV Lake Road - Browne Street circuit would not be able to supply the forecast combined peak Browne Street and Tower Road substation load within the planning horizon.

Options

Non-network options were considered, but only larger scale non-renewable generation could provide the required quantity to be able to supply both Tower Road and Browne Street substations. A Co-gen arrangement would be the most likely scenario where this might be viable, but no synergistic commercial opportunities to implement a Co-gen solution have yet been identified.

The following network solutions were considered:

1. Upgrading the limiting cable section on the 33 kV Lake-Road-Browne Street circuit to a higher capacity cable
2. Increase the 11 kV inter-tie capacity to be able to backfeed Browne Street and Tower Road when the 33 kV Lake Road-Tower Road circuit is out of service.
3. New 33 kV circuit from Lake Road substation to either Browne Street or Tower Road substations

Preferred option

The preferred solution is option 1, upgrade the limiting cable section on the 33 kV Lake-Road-Browne Street circuit to a higher capacity cable. This solution will provide sufficient capacity to supply Browne Street and Tower Road substations during peak load periods for the foreseeable future. In the interim, we will operationally manage the overload by transferring some load from Browne Street to Tower Road post-contingency.

Alternative options 2 and 3 are unlikely to be economic due to the high cost of the projects compared to the benefits they would provide.

A7.6.1.4 PIAKO SUBSTATION - KEREONE TEE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PIAKO - KEREONE 33kV SUBTRANSMISSION ENHANCEMENT	GRO	$8,731	2030-2033

Network issue

The recent Kereone-Walton 33 kV subtransmission project installed a new high-capacity cable between Kereone and Walton substation and reconfigured the 33 kV network to:

- Supply Walton substation from Waihou GXP, and
- Relocate the 33 kV operational split from the Waharoa 33 kV bus to Browne Street substation to supply the whole Waharoa substation from Piako GXP. This arrangement is intended to provide the ability to backfeed Browne Street substation from Piako GXP if supply from Hinuera is not available.

The Piako-Waharoa 33 kV circuit is limited by the rating of the overhead line between Piako and Kereone. It currently has sufficient capacity to supply the total Waharoa load only. It does not have sufficient capacity to supply both Waharoa and Browne Street substations if supply from Hinuera is not available at peak load times.

Options

Non-network options were considered, but only larger scale non-renewable generation could provide the required quantity to be able to support both Waharoa and Browne Street substations. A Co-gen arrangement would be the most likely

[32] Transpower's 2022 Transmission Planning Report, Section 10.5.10

scenario where this might be viable, but no synergistic commercial opportunities to implement a Co-gen solution have yet been identified.

The following network solutions were considered:

1. New high-capacity 33 kV cable from Piako to Kereone to match the capacity of the recently installed 33 kV Kereone to Walton cable. Renew the existing 33kV overhead line and re-use as a future 11kV feeder out of Piako substation.
2. Thermally upgrade the Piako Kereone 33kV overhead line.
3. Re-conductor the Piako-Kereone 33kV overhead line.

Preferred option

The preferred solution is option 1, install a new high-capacity 33 kV cable from Piako to Keroene. This solution will allow us to be able to backfeed Browne Street substation when supply from Hinuera is not available. The existing overhead 33kV Piako-Kereone section will be renewed and used as a future 11kV feeder out of Piako substation to increase capacity and improve reliability in the Walton area.

Alternative options 2 and 3 require costly upgrade work to the existing Piako-Keroene overhead line, and still would not have sufficient capacity to backfeed Waharoa and Browne Street when factoring for future growth.

A7.6.2 ZONE SUBSTATION PROJECTS

A7.6.2.1 FARMER ROAD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WIEL SUBSTATION	GRO	$9,545	2022-2026
FARMER ROAD SEISMIC STRENGTHENING	ARR	$200	2027

Network issue

Two 5/6.25MVA, 33/11kV transformers at Farmer Road substation supply the surrounding area and Waitoa Industrial Estate Limited (WIEL). The substation peak demand already exceeds the transformer N-1 capacity. Customer driven industrial load is forecast to grow rapidly over the short term, triggered by expansion plans at WIEL. The Farmer Road substation load is forecast to increase above the total transformer installed capacity within the next three years. Backup supply options are limited, further constraining the ability to support the forecast load increase.

Options

1. Install two identical 12.5/17MVA, 33/11kV transformers at Farmer Road substation, an additional 33kV underground circuit from Piako GXP to Tatua site, and network reconfiguration.
2. Build a dedicated substation for WIEL along with subtransmission network reinforcement.

Preferred option

The preferred solution for Powerco and the customer is option 2, to build a dedicated substation for WIEL. In the interim, we will install a 33 kV rated cable from Farmer Road substation to the customer site operating at 11kV to supply the first stage of their development. Ultimately, this cable will be converted to operate at 33 kV to supply the proposed WIEL substation once it is established. Once the future load increase comes online at WIEL, this option allows:

- the existing load supplied from Farmer Rd to be offloaded to the new substation, and
- transferring the Farmer Rd substation to be supplied from the Waihou GXP.

Fleet issue

The existing switchroom building is at 35% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom to 67% NBS.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard.

Preferred option

The lowest cost preferred solution is option 2, to seismically strengthen the existing switchroom. Option 3 is not preferred as it will be higher cost than option 2. The decision on whether to seismically strengthen Farmer Road substation will also be dependent on the timing of construction of the WIEL substation.

A7.6.2.2 TATUA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TATUA 33/11 kV TRANSFORMER UPGRADE	GRO	$2,827	2025-2026

Network issue

A single 33/11 kV, 7.5 MVA transformer at Tatua substation supplies the whole Tatua industrial site. The supply security is specific to that customer and is a balance between our nominal security standards and the major customer requirements. There is also limited backfeed capability from the neighbouring 11kV feeder and this is not desirable.

With planned expansion of the wastewater treatment plant at Tatua, the demand is forecast to exceed the capacity of the single Tatua 33/11 kV transformer. The major customer at Tatua has also signalled its intention to further expand their operations during the next few years.

Fleet issue

The existing transformer is rated at 7.5MVA, has a maximum demand (MD) of 5.4 MVA and was manufactured in 1967. It is designated for replacement towards the end of the planning period**.**

Options

1. Replace the existing 33/11 kV transformer with a higher capacity transformer and reconfigure the 33kV network supplying Tatua.
2. Install a second 33/11 kV transformer and reconfigure the 33kV network supplying Tatua.

Preferred option

Option 1 is preferred. Although the existing Tatua transformer is planned for replacement towards the end of the planning period, Powerco is working with the major customer at Tatua to bring the upgrade of the transformer forward in the timeline to meet their growth requirements.

Option 2 to add a second 33/11kV transformer is not required at this stage because the customer accepts the N-security risk.

A7.6.2.3 TAHUNA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAHUNA SEISMIC STRENGTHENING	ARR	$200	2026
TAHUNA T1 & T2 POWER TRANSFORMER REPLACEMENT	ARR	$1,773	2025-2027

Network issue

Tahuna substation is supplied via a long single subtransmission circuit and 11kV backup is limited. A second subtransmission circuit is likely to be expensive because of the distance involved. Council growth plans proposed for Tahuna in the long term may trigger the need to invest in infrastructure upgrade.

Fleet issue

The Tahuna 11kV switchroom has a seismic strength of 15% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard has previously been upgraded to include arc flash protection. The Tahuna T1 & T2 power transformers are approaching end of life as assessed by the CNAIM value model and are planned for replacement in 2027.

Options

1. Seismically reinforce the existing switchroom and replace the two power transformers
2. Build a new switchroom and move the existing 11kV switchgear to the new switchroom or install new 11kV switchgear in the new switchroom. Replace the two power transformers.

Preferred option

The preferred solution is option 1, to reinforce the existing switchroom as this will be lower cost than building a new switchroom. Replace the two power transformers.

A7.6.2.4 TIRAU SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TIRAU TRANSFORMER UPGRADE	GRO	$2,960	2026-2028
TIRAU 11kV INDOOR SWITCHGEAR	ARR	$784	2025-2026

Network issue

Two 33/11 kV transformers supply the Tirau 11 kV load:

- A 12.5/17 MVA transformer (T2) provides a dedicated supply to the large dairy factory at the site
- A 7.5/10 MVA transformer (T1) supplies the surrounding area and provides a backup supply to the dairy factory.

Due to the different transformer sizes, the Tirau 11 kV bus is normnally operated split. If one of the transformers is out of service, the 11 kV bus will be operated solid to enable the remaining transformer to supply the total substation load.

The total Tirau substation load is forecast to exceed the transformer N-1 capacity within the next five years.

Options

1. Replace the existing T1 transformer with a new 12.5/17MVA 33/11kV power transformer. This would match the existing T2 power transformer and give full N-1 security of supply, based on installed transformer capacity, and would allow transformer maintenance to be carried out on either bank when required.
2. Increase 11kV inter-tie capacity by connecting additional 11kV feeders and/or re-conductoring existing 11kV feeders. Improving 11kV transfer capacity can be complex operationally and, potentially, has a high cost.

Preferred option

The preferred solution is Option 1, upgrade the existing 7.5 MVA transformer to 12.5/17MVA match the higher capacity transformer. This will allow them to operate in parallel and mitigate operational issues associated with transformer overloading.

Fleet issue

The existing 11kV switchboard at Tirau substation does not meet modern arc flash standards, has oil quenched circuit breakers, and electromechanical relays. The existing 11kV switchroom seismic capacity is 80% NBS and is therefore seismically compliant.

Options

1. Refurbish the existing Tirau substation 11kV switchboard, including adding arc flash protection, arc flash doors and end panels.
2. Construct a new 11kV switchroom at Tirau and install new 11kV switchgear that meets arc flash standards.

Preferred option

The preferred solution is option 1 as this will maximise arc flash risk reduction vs capital expenditure. The existing 11kV switchroom is seismically compliant so does not require seismic reinforcement or the construction of a new switchroom.

A7.6.2.5 BROWNE STREET SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BROWNE STREET TRANSFORMER UPGRADE	GRO	$3,064	2031-2033

Network issue

Two 33/11 kV, 7.5/9.4 MVA, transformers at Browne Street substation supply part of Matamata township and the surrounding area including a major industrial customer. The load growth in the area is forecast to exceed the Browne Street 33/11 kV transformer N-1 capacity within the next five years. Backup supply options are limited, further constraining the ability to support the foreast load increase.

Options

1. Upgrade the two existing Browne Street 33/11 kV transformers to 12.5/17MVA. transformers.
2. Increase the 11 kV inter-tie capacity to be able to backfeed Browne Street from adjacemt substations.

Fleet issue

The existing transformers are rated at 7.5/9.4 MVA and have a maximum demand (MD) of 9.4 MVA. They were manufactured in 1967 and are 55 years old. The transformers were originally ONAN 7.5MVA units and were subsequently retrofitted with fans to increase their rating to 9.4 MVA. They are planned for replacement within the planning horizon with the principle driver being load growth.

Preferred option

The preferred solution is option 1, to upgrade the existing transformers to 12.5/17 MVA transformers. This solution will provide sufficient capacity to supply Browne Street substation during peak load periods for the foreseeable future.

Option 2, to increase the 11 kV feeder inter-tie capacity to be able to backfeed Browne Street from afjacent substations is unlikely to be economic due to high cost of the project compared to the benefit it would provide.

A7.7 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A7.7.1 MAUNGATAUTARI AREA

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MAUNGATAUTARI AREA REINFORCEMENT	GRO	$1,396	2023-2025
VOLTAGE REGULATOR AND AUTOMATION – MAUNGATAUTARI AREA IMPROVEMENT	GRO	$787	2023-2024

Network issue

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 hampered by distance and terrain. A total of 746 ICPs are supplied by Cambridge Rd feeder, and 11 kV backfeed capacity from Lake Road substation is minimal because of the great distance.

Historically, the time taken to restore supply in this area is longer after an outage. Because of the terrain involved, accessing the site for fault-finding and repair is more difficult.

Options

1. Reconfiguring the Totman Rd and Cambridge Rd feeders by creating a new underground cable linking the two feeders, new voltage regulator on the Cambridge feeder from Tirau, along with the implementation of automation devices.
2. Install new 33/11kV substation with new 33kV circuit.
3. Install distributed generation (DG) equipment for islanded operation.

Preferred option

The preferred solution is option 1, to install:

1. A new underground cable link to offload a portion of Cambridge Rd feeder over to Totman Rd feeder; and
2. a new voltage regulator on the Cambridge feeder out of Tirau substation along with additional automation devices.

This will also address the existing voltage constraint on this feeder during high load times. Along with the underground link to Cambridge Rd feeder and loop automation scheme, this strategy also serves to improve the voltage at the fringes of Cambridge feeder and support the load in the Maungatautari region during an outage.

It is challenging to find a suitable site in an area comprising lifestyle blocks and farmland to construct a new substation (option 2). The cost of installing a 33kV circuit and the substation is significantly higher than option 1.

Finding a suitable site on a lifestyle block to install DG equipment (option 3) requires lengthy landowner negotiation. This option does not offer benefits to the network supplied by Option 1.

Following completion of the Maungatautari area reinforcement project, we will monitor the reliability of the Cambridge feeder. If the 11 kV feeder reliability has not improved to an acceptable level, we will review option of installing distributed generation equipment for islanded operation along the feeder.

A7.8 KINLEITH

A7.8.1 SUBTRANSMISSION NETWORK PROJECTS

A7.8.1.1 KINLEITH SECURITY

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PUTARURU-MARAETAI ROAD 33KV LINK	GRO/REL	$31,812	2024-2033

Network issue

Transpower Kinleith GXP supplies the Tokoroa area via Baird Rd and Maraetai Rd 33kV substations. The existing combined load for both substations for the 2022 period was ~18.5MVA. The area is experiencing moderate growth, and the current subtransmission network and the substation capacity is expected to be constrained during an n-1 event. Additionally, the existing 11kV switchrooms at the Baird Rd and Maraetai Rd substations have limited space, making it difficult to install new 11kV feeders if they are needed. A new customer driven industrial load is forecast to grow over the long term, triggered by Olam Foods Ingredients (OFI) with an initial request for 5MVA load and expected to grow to 7.4MVA later in future.

The 33 kV load is supplied via the T9 single 40 MVA 110/33 kV transformer and has limited backup provided by the T5 transformer with firm capacity of 20 MVA. The 33kV load at Kinleith during winter period exceeds the firm continuous capacity of T5. The existing 110 kV grid is experiencing N-1 constraints due to the ratings of Arapuni–Kinleith–1 & 2 and Kinleith–Lichfield–Tarukenga–1 110 kV circuits. In addition, Mercury's Arapuni generation is also constrained by the N-1 line capacity. These issues are highlighted in the Transpower planning report 2022.

Options

1. Upgrade the existing Transpower 110kV circuits.
2. 33kV substransmission link between Putaruru substation and Maraetai Rd substation.

Preferred option

Option 2 to build Powerco new 33kV subtransmission link between Putaruru and Maraetai Rd substation to offload some load from Kinleith GXP to Putaruru. By offloading the load, the need to upgrade the 110kV circuits and installing a new 110/33kV transformer to replace the T5 transformer will be delayed in the planning period as the risk is reduced. This option also defers the need to upgrade the existing 33kV feeder GXP cables, which would otherwise be constrained during n-1 in the current configuration. Option 1 is not feasible, as the 110kV network is owned by Transpower and upgrading the 110kV circuits would be complex since other third parties are also connected to the 110kV network. The upgrade cost would involve all connected parties and would still leave the existing T5 transformer firm capacity constrained during an outage to the T9 transformer during peak periods.

A7.8.2 ZONE SUBSTATION PROJECTS

Below summarises the project planned for the Kinleith area.

A7.8.2.1 BAIRD ROAD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BAIRD RD 11kV SWITCHBOARD REPLACEMENT AND SEISMIC UPGRADE	ARR	$852,000	2023-2024

Network issue

Baird Rd 11kV cable terminations exiting the 11kV switchboard are undersized and need to be reconductored.

Fleet issue

The existing 11kV switchboard at Baird Rd substation does not meet modern arc flash standards and has electromechanical relays. The 11 kV switchroom seismic strength is 62% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Seismically reinforce the existing switchroom and upgrade the 11kV switchboard in the existing switchroom.
2. Install a new 11kV switchboard in new switchroom.

Preferred option

The preferred solution is option 1, to seismically reinforce the existing switchroom and upgrade the 11kV switchboard in situ.

A7.8.2.2 OFI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OFI SUBSTATION	CUSTOMER DRIVEN	$9,311	2021-2024

Network issue

The existing Maraetai Road substation is unable to accommodate Olam Food Ingredients New Zealand Limited's (OFI) full load as the existing feeder capacity will be constrained and the donor 11kV feeders do not have sufficient backfeed capability during an outage to supply the feeder and the load of the new dairy plant. The customer has requested for an initial 5MVA load when the plant is commissioned in 2023. Later in the future, the demand is likely to increase to 7.4MVA.

Options

1. Build new 11kV feeders from Maraetai Road substation.
2. Build a new 33/11kV substation.

Preferred option

Option 2 to build a new 33/11kV OFI substation to accommodate OFI's load is preferred. Over the planning period, OFI will gradually increase their load. An initial load of 5MVA will be supplied by the existing Maraetai Road 11kV feeder until the new OFI substation is commissioned which will temporarily be supplied from the existing 33kV Kinleith-Maraetai Road circuit via a 'tee' configuration. Option 1 is not a viable solution as the increasing load demands of OFI and regional growth will constrain the substation's transformer capacity during an n-1 event, and there is not enough space in the existing switchroom to install more new feeders**.**

A7.9 TARANAKI

A7.9.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Blitz Inglewood South 33kV rearm	ARR	$1.200	2023-2028

Network issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching 'end of design life' investments for replacement are included in the current overhead renewal planning.

Options

Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

1. The subtransmission network when constructed in the 1960's through to the 1990's the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substations. Also there has been an Engineering Instruction (EI) issued to ban all 'live line' work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.
2. The subtransmissiojn network also has the glass Pilkington insulators used. This type of insulator also, over time, is also electrically breaking down due to hairline cracking and require replacement. The result of the insulator breaking down can lead to the loss of supply to zone substations.
3. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators can cause 'flashovers' at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.

Options

1. Replace the insulators on the existing arms.
2. Relace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient.

A7.9.1.1 HUIRANGI GXP-MCKEE TEE 33KV LINE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HUIRANGI - McKEE TEE SECOND 33kV LINE	GRO	$2,889K	2022-24

Network issue

Two zone substations, Waitara East and Waitara West supply Waitara township and rural surrounds. Their 33kV supply is from Huirangi GXP through a ring network that also supply McKee and Inglewood zone substation through a tee-off line that runs 9.3km to reach Inglewood and from there another 14.3km to supply Inglewood. This tee-off line also takes 9MW of generation from Todd Mangahewa site (next to McKee) and 4.8MW Hydro generation from Trustpower Motukawa site through another tee-off line (11km long).

During peak demand periods, if the Waitara West line is unavailable, the single 33kV Waitara East circuit from Huirangi GXP has insufficient capacity (15.7MVA) to supply all four substations – Waitara East, Waitara West, McKee and Inglewood. The tee configuration of the Waitara East/McKee 33kV lines also causes protection issues and limits generation injection levels. There are 7,433 ICPs supplied by these substations.

Options

1. Construct a second circuit from Huirangi to McKee-Waitara Tee. This allows the tee to be removed and provides a dedicated circuit for each of the McKee and the Waitara East circuit. The new circuit will have enough capacity to resolve the existing constraints for contingencies on the Waitara West circuit.
2. Upgrade the existing 33kV circuit. This can resolve the capacity issue, but not the protection and network architecture issues presented by the tee configuration.
3. Secure generation availability. This option does not resolve the protection and configuration issues.

Preferred option

The preferred solution is option 1, to 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 secured standard network configuration that resolves all existing operational and protection issues.

A7.9.1.2 CARRINGTON GXP-OAKURA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OAKURA SECOND 33kV LINE AND SECOND TRANSFORMER	GRO	6,374K	2026-30

Network issue

The Oakura substation supplies Oakura township, Okato township, which is 12km south, and surrounding rural customers – mainly dairy and farming.

Oakura's 2022 demand was 3.6MVA (1,830 ICPs), and expected demand in 2030 is 4.1MVA. Present 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). The overhead line passes through several sections of tall trees, which has caused several outages in the past. Present single transformer also needs outage for routine maintenance work.

The 11kV backup supply from neighbouring Moturoa substation will be inadequate for Oakura's forecast demand from 2025. A large subdivision of 300 lots, next to Oakura substation, could be developed in the next five to 10 years.

Options

1. Install 5MVA of standby generation at Oakura.
2. Construct a second 33kV line from Carrington St GXP. Install a new 33kV circuit breaker at Carrington St GXP and Oakura, with a second 33/11kV 7.5/10MVA transformer into Oakura.

Preferred option

The preferred solution is option 2, to construct a second 33kV line (16km) from Carrington St GXP along with a second transformer at Oakura, as this option would be easy to implement and would provide more secured supply to Oakura substation.

Option 1 is not favoured, as it would be expensive to implement and maintain.

A7.9.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Taranaki area.

A7.9.2.1 CARDIFF SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
4700T POWER TRANSFORMER REPLACEMENT	ARR	$1,171	2030-32

Fleet issue

Cardiff is single transformer zone substation supplied by a single 33kV Schneider Dogbox circuit breaker . The power transformer is a 1962 GEC unit with a Ferranti tap-changer and will be 70 years old at the end of the planning period. The transformer is classed as H3 condition, in the event of a fault, parts are not freely available and we would likely need to mobilise our critical spare transformer. Cardiff has a good 11kV backfeed.

Options

1. Do nothing.
2. Replace the existing transformer with a new transformer.
3. Replace the existing transformer with a refurbished transformer unit.

Preferred option

We are currently proceeding with option 2. Doing nothing is not tenable for continued supply.

A7.9.2.2 CITY SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$1,783	2021-25
T1 & T2 POWER TRANSFORMER REPLACEMENT	ARR	$2,821	2030-32

Fleet issue

City has two Tyree power transformers with Ferranti DS2 tap-changers, which are currently H2 and are starting to show signs of aging (oil pump issues). The transformers were manufactured in 1978 and will be 54 years old at the end of the planning period.

The existing 11kV switchboard at City substation does not meet modern arc flash standards, has a mixture of vacuum and oil circuit breakers, and has electromechanical relays. Due to the constrained site within the New Plymouth urban area, a "greenfield" solution is not considered feasible – the currently switchroom has been assessed as being 93% NBS so does not need further seismic remediation work.

Options

1. Do nothing
2. Refurbish the existing City 11kV switchboard including arc flash protection, arc flash doors and end panels.
3. Install a new 11kV switchboard in the existing City switchroom. This will involve changes to the switchroom floor cutouts, cable terminations and switchgear mounting arrangements.

Preferred option

We are currently proceding with option 2, to refurbish the existing City 11kV switchboard. Option 3 is not preferred as it will be higher cost than option 2 as it will involve changes to the switchroom floor cutouts, cable terminations and switchgear mounting arrangements.

A7.9.2.3 LIVINGSTONE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
T1 AND T2 POWER TRANSFORMER REPLACEMENT	ARR	$1,931	2025-26

Fleet issue

The two transformers were purchased in 1964, are have signs of reaching end of life - these have had significant rust issues (rust-treated and re-painted in 2016), and mechanism failure issues in 2021 requiring repair and major servicing of the older CIII Reinhaussen tap-changers.

Options

1. Do nothing.
2. Replace a T1 & T2 with 2x new transformers
3. Replace a T1 & T2 with a single unit

Preferred option

We are currently proceeding with option 2. We don't believe Option 1 is tenable given the network risk. Replacement has already been deferred previously by undertaking some rust remediation.

A7.9.2.4 MOTUKAWA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV ODID	ARR	$1,888	2026-28
3x33kV CIRCUIT BREAKER REPLACEMENT	ARR	$752	2027-28

Fleet issue

The Motukawa outdoor 11kV bus work is suffering from corrosion and is space constrained, complicating maintenance and repair outage requirements.

Options

1. Do nothing.
2. Replace the outdoor 11kV switchyard, 11kV circuit breakers and 33kV circuit breakers on a like-for-like basis.
3. Replace the outdoor 11kV switchyard with an 11kV switchroom and indoor 11kV switchboard (ODID). Replace the 33kV outdoor circuit breakers on a like-for-like basis.

Preferred option

We are proceeding on the basis of option 3, noting that this renewal project is not scheduled until later in the planning period.

A7.9.2.5 WAITARA EAST SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV ENTIRE SWITCHBOARD REPLACEMENT	ARR	$830	2026-27

Fleet issue

The switchboard is ASEA (ABB) type HPA12 with SF_6 circuit breakers and is not arc flash rated. This type of switchboard is classified as obsolete by ABB and is only supported as detailed by the ABB lifecycle management policy. ASEA (ABB) type HPA12 switchgear is installed at two other Powerco zone substations, Waitara West in Taranaki, and Waitoa in the Thames Valley.

Options

1. Continue to monitor the condition and performance of the 11kV switchgear at Waitara East and renew the switchgear as recommended by the ABB lifecycle management policy.
2. Install a new, fully arc flash rated and arc flash protected 11kV switchboard in the existing Waitara East switchroom. This will involve, changes to the switchroom floor cutouts, cable terminations and switchgear mounting arrangements.

Preferred option

The preferred solution is option 2, to install a new, fully arc flash rated 11kV switchboard in the existing Waitara East switchroom. While this is likely to be the more expensive option it has the benefit of a) allowing the decommissioned switchgear to be used as spares for Waitara West and Waitoa zone substations and b) reducing the number of orphan types of switchgear on the Powerco network.

A7.9.2.6 INGLEWOOD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
INGLEWOOD SUBSTATION TRANSFORMERS UPGRADE	GRO	3,706K	2028-30

Network issue

The Inglewood substation supplies power to Inglewood town and the surrounding rural areas. The substation contains two 5MVA transformers. Its security class is AA, which requires restoration of supply within 45 minutes.

Inglewood's 2030 forecast demand of 5.9MVA would exceed the secure capacity of the present transformers (ie the capacity that can be supplied by one transformer plus available backfeed).

Being close to New Plymouth city, Inglewood township load is growing through the development of new subdivisions. In the past year, there have been three customer-initiated works (CIW) applications totalling 600kVA of transformers.

At times Inglewood supports neighbouring single transformer substation Motukawa, which has a demand of 1MVA and Midhurst network (demand 1MVA).

Present vector group mismatch between the Inglewood network and its New Plymouth side network restricts inter-feeder backfeeding among these networks.

Options

1. Upgrade Inglewood's two transformers to two 7.5/10MVA units. This will secure the load at Inglewood and provide adequate capacity for anticipated future load.
2. Construct additional 11kV feeders. This is not practical, as neighbouring Cloton Rd is also approaching firm capacity. Furthermore, it would need one dedicated 11kV feeder (23km long) along with one voltage regulator.
3. Generation or energy storage. This is not economical as costs for a generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs. Resource consenting for generator noise issues and the site suitability of earthing systems to expected fault levels could be difficult to resolve.

Preferred option

The preferred solution is option 1, as this is the least cost, long-term economically sustainable solution to meet the security of supply requirement (AA) and future load growth.

A7.9.2.7 KAPONGA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
4708T AND 4709T POWER TRANSFORMER REPLACEMENT	ARR	2,109K	2028-30

Fleet issue

Kaponga has two OEL power transformers. The transformers were manufactured in 1967 and will be 65 years old at the end of the planning period. We have had existing issues with voltage control on these units.

Options

1) Do nothing
2) Refurbish the existing Kaponga power transformers, depending on workshop evaluated condition.
3) Purchase and install new power transformers.

Preferred option

The preferred solution is option 2, due to the age of the transformers these units are no longer supportable with parts as required by Options 1 & 2..

A7.9.2.8 KAPUNI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2025
3x33kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$848	2025-26
11kV ENTIRE SWITCHBOARD REPLACEMENT	ARR	$959	2026-28
T1 and T2 POWER TRANSFORMER REPLACEMENT	ARR	$2,459	2030-32

Fleet issue

The 33kV outdoor Takaoka 30KO circuit breakers were manufactured in 1981, are oil quenched and are expected to be at end of service life partway through the period.. The existing switchroom building is at 40% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard was manufactured by GEC and contains BVRP1 circuit breakers. The 11kV switchboard is not arc flash rated or arc flash protected and is the only example of this type of switchgear on the Powerco network.

Kapuni has two Tyree power transformers with tap-changers supplied by Associated Tapchangers. The transformers were manufactured in 1968 and will be 64 years old at the end of the planning period.

Options

1) Do nothing.
2) Replace the outdoor 33kV Oil CBs with new 33kV circuit breakers on a like-for-like basis. Seismically strengthen the existing switchroom and install a new arc flash rated 11kV switchboard with arc flash protection. Review the ongoing demand at Kapuni and, if appropriate, replace the two power transformers with new 10MVA units.
3) Replace the outdoor 33kV OCBs with new 33kV circuit breakers on a like-for-like basis. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard. Review the ongoing demand at Kapuni and, if appropriate, replace the two power transformers with new 10MVA units.

Preferred option

The least cost, preferred solution is option 2. Option 3 is not preferred as it will be higher cost than option 2. A detailed conceptual design exercise examining and costing all options will be carried out to confirm the optimal solution.

A7.9.2.9 MIDHIRST NEW SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW MIDHIRST SUBSTATION	GRO	9,879K	2029-32

Network issue

Midhirst township and its large rural network (51km long) on its northern side is supplied through an 11kV voltage regulating station at Midhirst, located on land owned by Powerco. There are 328 ICPs supplied by this network and its 2019 demand was 1MVA.

An 11kV feeder from Cloton Rd substation supplies Midhirst regulating station. This feeder (7.1km) supplies another 607 ICPs enroute to Midhirst and has a demand of 130 amps (2.5MVA), including Midhirst network demand.

Voltage quality at the Midhurst regulator is just 1% above the threshold (95%). Being close to Stratford town, Midhirst network load is expected to grow. Last year, there were two CIW applications, to connect new 100kVA and 200kVA transformers.

At times, North feeder also supports half of Ratapiko feeder, Motukawa (a single transformer substation) and half of Mountain Rd feeder, Inglewood substation.

Options

1. Construct two dedicated 11kV feeders (each 4.8km) from Cloton Rd substation, along with two 11kV feeder circuit breakers, and upgrade Cloton Rd substation's two 10/13MVA transformers to 16/24MVA.
2. Establish a new 33/11kV zone substation (capacity 2 x 7.5/10MVA) at Midhirst Powerco land. Construct two 33kV lines - one from Stratford Cardiff 33kV line along Mountain Rd (5km) and another from Motukawa 33kV line along Beaconsfield Rd (7km) to supply this substation.

Preferred option

The preferred solution is option 2, to construct a new 33/11kV substation at Midhirst, as this would provide a long-term solution for this area and would offload Cloton Rd substation by 1.5MVA, which would defer the Cloton Rd substation transformers upgrade (see below) for some years.

Option 1 is not favoured as it is not a long-term sustainable solution, and the cost difference from option 2 is not large.

A7.9.2.10 WHALERS GATE NEW SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHALERS GATE NEW SUBSTATION	GRO	9,125K	2025-28

Network issue

The Moturoa substation supplies several important loads – Port Taranaki, Taranaki Base Hospital, Omata tank farm and the Moturoa commercial area within the west part of New Plymouth. There are about 8,900 customers supplied by this substation.

Brooklands substation provides backup supply to Base Hospital. The forecast 2030 demand of Moturoa and Brooklands is 20.4MVA and 22.9MVA respectively. Taranaki Base Hospital is increasing its demand load in December 2023 by 2.4MVA and in 2025 another 1.5MVA. Nearby Yarrows Stadium is also increasing its load from present 1MVA to 2.9 MVA in Dec 2023. At such demand, Brooklands would exceed its single transformer capacity (24MVA) and Moturoa would be close to its single transformer capacity (24MVA).

Any new subdivisions and developments in certain areas of New Plymouth, such as Whalers Gate, would add additional load to Moturoa.

Whalers Gate area is around 4.5km from Moturoa substation. Present feeders cannot support the load growth in this area due to the voltage and capacity constraint. Hospital and Yarrows Stadium are also close to Whalers Gate.

Options

1. Construct additional 11kV feeders from neighbouring substations. This is not practical as the neighbouring City substation, City, would then approach its firm

capacity. Furthermore, it would need the installation of cable for three new feeders (each about 4km long), which would be difficult to implement, as the route would be through the busy city area.

2. Establish a new zone substation at Whalers Gate. This resolves the capacity issue for Moturoa substation and provides enough spare capacity for future load growth in this area.

Preferred option

The preferred solution is option 2, to establish a new zone substation of 24MVA capacity at Whalers Gate. Land would need to be sought. Moturoa's two 33kV cables, installed last year, have a capacity of 40MVA, which would be adequate to supply both Moturoa and this new substation for at least 20 years of forecast demand growth.

Option 1 is not favoured as it would inhibit future load growth in the area.

A7.9.2.11 MOTUKAWA RURAL AREAS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MOTUKAWA 6.6kV TO 11kV CONVERSION	GRO	$4,166K	2025-27

Network issue

The Motukawa zone substation supplies power to Tarata and Ratapiko townships along with surrounding rural areas at 6.6kV. The substation contains one 5MVA 33/11-6.6kV transformer.Disadvantages with operating a 6.6kV network include:

- A 6.6 kV network has substantially lower power carrying capacity than 11 kV systems and also contributes to more severe voltage drop issues. Presently Ratapiko and Tarata feeders experience voltage at 0.3% and 2.5% below the acceptable level during peak demand period.
- The neighbouring Inglewood and Midhirst 6.6kV network is being converted into 11kV during the customised price-quality path (CPP1) period. Motukawa would then be the only remaining 6.6kV substation.
- The 6.6kV voltage is a non-standard Powerco distribution voltage.

Options

1. Continue to operate the Motukawa network at 6.6kV by installing two voltage regulators on two feeders and upgrading about 15km of backbone line to meet voltage quality.
2. 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 towards the start of the feeder, eventually carrying out a full conversion to 11kV.
3. Replace the remaining (about 130 out of 163) 6.6/0.415kV transformers with dual wound (11-6.6/0.415kV) transformers and then convert all feeders to 11kV within 2-3 years.

Preferred option

The preferred solution is option 3, which involves replacing all of the remaining 6.6kV/0.4kV distribution transformers in the Motukawa network with dual winding transformers (11-6.6kV/0.415kV) over a 2-3 years period.

Option 1 is not favoured because of the long length of feeder upgrades required and consequent high cost.

Option 2 is not favoured because of the higher capital cost of installation of 6.6kV/11kV step-up transformers on each feeder and, after 11kV conversion, there would not be any other places to reuse these step-up transformers.

A7.10 EGMONT

A7.10.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Blitz Kapuni No 2 33kV rearm	ARR	$1,700	2023-2028
Blitz Kapuni No1 33kV rearm	ARR	$1,800	2023-2028

Network issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching 'end of design life' investments for replacement are included in the current overhead renewal planning.

Option

Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

3. The subtransmission network when constructed in the 1960's through to the 1990's the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators

are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substations. Also there has been an Engineering Instruction (EI) issued to ban all 'live line' work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.

4. The subtransmissiojn network also has the glass Pilkington insulators used. This type of insulator also, over time, is also electrically breaking down due to hairline cracking and require replacement. The result of the insulator breaking down can lead to the loss of supply to zone substations.
5. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators can cause 'flashovers' at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.

Options

1. Replace the insulators on the existing arms.
2. Relace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient.

A7.10.1.1 HAWERA-CAMBRIA 33KV OIL CABLE REPLACEMENT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CAMBRIA WHITE/BLACK 33kV CABLE REPLACEMENT	ARR	2,121K	2024-30

Fleet issue

The 2x3km circuits running from Cambria substation were installed in 1968, and are expected to be 64 years of age at the end of the period.

While these are still in good condition, these circuits are costly to maintain – requiring regular inspections of oil levels and, because of the small amount of oil cable remaining in our network, it is becoming increasingly difficult to access specialist service providers who can repair or service these.

Options

1) Do nothing.
2) Replace 2x33kV circuits with new cross-linked poly ethylene (XLPE) cables.
3) Retrofit option
4) Replace 2x33kV with new overhead circuits.

Preferred option

Option 2 is our preferred option. It is the lowest risk option for reliable supply to Hawera township, and utilises our existing use rights of our circuits circuit running along Tawhiti Rd.

We are also exploring option 3 if there is any technology that will allow us to retrofit the circuits in place removing

Option 1 is not a preferred option. Given the age of the cables and their criticality to Cambria substation, a do nothing strategy introduces increasing amount cost of repairs and risk of loss of supply to Hawera township.

Option 4, while the least cost option, does not appear to have any feasible routes away from the current location, given the encroachment into the residential area of Hawera township, which increases the risk of supply loss.

A7.10.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Egmont area.

A7.10.2.1 HAWERA GXP 33KV SWITCHGEAR

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HAWERA GXP 33kV ODID	GRO	5,077K	2022-25

Network issue

Hawera is a Transpower 110/33kV GXP, located just outside Hawera township. It supplies five Powerco substations – Cambria, Manaia, Kapuni, Livingstone and Mokoia via eight outgoing 33kV feeders.

Transpower has identified that its outdoor 33kV switchgear is in poor condition and approaching the end of its life. Its preference is to replace this switchgear via an indoor conversion project.

Options

1. Powerco builds the indoor conversion through the installation of a new indoor 33kV board, on land provided by Transpower, and assumes asset ownership.
2. Transpower builds the indoor conversion and maintains asset ownership.

Preferred option

The preferred solution is option 1. Powerco has identified from a similar project at Te Matai, that its construction cost is lower. Furthermore, the ownership of a 33kV board provides Powerco more control and visibility at GXP level and removes the dependency on Transpower for the 33kV operation and maintenance.

A7.10.2.2 NGARIKI SUBSATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33kV REBUILD	ARR	$2,670	2024-27

Fleet issue

Ngariki 33kV outdoor switchyard is space constrained, such that any fault or maintenance work requires a complete 33kV bus outage. This has been particularly evident during multiple lightning-induced 33kV circuit breaker failures during the past few years. We have retained older decommissioned 33kV circuit breakers for spare parts to enable reactive repairs, this is medium term solution.

Options

1) Do nothing.
2) Rebuild outdoor 33kV structure with modern clearances and new 33kV outdoor circuit breakers.
3) 33kV ODID conversion.

Preferred option

Our preferred solution is option 2, given the ample room available on-site to expand. This is determined as the least cost lifecycle option to address the clearance and circuit breaker reliability issues at this rural substation.

Option 3 is not preferable due to the high cost at this smaller size rural site

We don’t believe a do nothing option is tenable, as we have already experienced multiple failures and current 33kV circuit breakers are in poor condition. We have limited spares remaining and this does not resolve the difficultly of obtaining outages to carry out repairs on the 33kV structure.

A7.10.2.3 OPUNAKE GXP 33KV SWITCHGEAR

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OPUNAKE GXP 33kV ODID	GRO	5,709K	2022-24

Network issue

Opunake is a Transpower 110/33kV GXP, located just outside Opunake township. It supplies three substations – Pungarehu, Ngariki and Tasman via three outgoing 33kV feeders.

Transpower has indicated that its outdoor 33kV switchgear is in poor condition and approaching the end of its life. Its preference is to replace this switchgear via an indoor conversion project.

Options

1. Powerco builds the indoor conversion through the installation of a new indoor 33kV board, on land provided by Transpower, and assumes asset ownership.
2. Transpower builds the indoor conversion and maintains ownership.

Preferred option

The preferred solution is option 1. Powerco has identified from a similar project at Te Matai, that its construction cost is lower. Furthermore, the ownership of a 33kV board provides Powerco more control and visibility at GXP level and removes the dependency on Transpower for the 33kV operation and maintenance.

A7.10.2.4 NORMANBY NEW SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NORMANBY NEW SUBSTATION	GRO	8,245K	2028-31

Network issue

Nromanby township and its large rural network on its northern side is supplied through an 11kV feeder (Tawhiti Rd) of Cambria substation. This feeder comprises of 88km 11kV line (mostly overhead and 190 distribution transformers. There are 1091 ICPs supplied by this feeder and its 2022 demand was 2.1 MVA.

The voltage quality at Normanby township and its downstream line drops to threshold during peak demand period. Such low voltage quality would not allow any new consumers' connection. This could result in customers' complaint to the regulators.

Also, being a large rural network, the reliability of supply of this feeder is poor.

Options

1. Construct one dedicated 11kV feeders (about 6km) from a new 11kV CB at Cambria substation, along with a voltage regulator at Normanby, and upgrade Cambria substation's two 12.5/17MVA transformers into 16/24MVA.
2. Construct a 33/11kV 7.5/10MVA capacity substation on a land (to be purchased) at Normanby along with a 8-panel indoor 11kV board and two new 33kV cables (each 4km) from Hawera GXP

Preferred option

The preferred solution is option 2, to construct a new 33/11kV substation at Normanby, as this would provide a long-term solution for this area and would offload Cambria substation by 1.5MVA, which would defer the Cambria substation transformers upgrade (see below) for some years.

Option 1 is not favoured as it is not a long-term sustainable solution, and the cost difference from option 2 is not large.

A7.10.2.5 TASMAN SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHBOARD ARC FLASH RETROFIT	ORS	$1,044	2026-28

Network issue

Fleet issue

The Tasman switchroom building is at 30% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard is a Reyrolle LMT board with is not arc flash/arc blast rated or arc flash protected, and includes oil circuit breakers (OCBs).

Tasman has two 5MVA power transformers with a Fuller F3 OLTC.
The transformers were manufactured in 1976 and will be 57 years old at the end of the planning period.

Options

1. Do nothing.
2. Seismically strengthen the switchroom and refurbish the existing 11kV switchboard with vacuum circuit breakers, arc flash protection and arc flash doors/end panels.
3. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard.

Preferred option

The least cost, preferred solution is option 2. Option 3 is not preferred as it will be higher cost.

A7.11 WHANGANUI

A7.11.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Blitz Castlecliff North 33kV rearm	ARR	$2,200	2024-2029

Fleet issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching 'end of design life' investments for replacement are included in the current overhead renewal planning.
Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

1. The subtransmission network when constructed in the 1960's through to the 1990's the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substations. Also there has been an Engineering Instruction (EI) issued to ban all 'live line' work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.
2. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators

can cause ‘flashovers’ at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.

Options

1. Replace the insulators on the existing arms.
2. Relace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient.

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Blitz Taupo Quay Steel Tower Replacement	ARR	$2,400	2024

Fleet Issue

Taupo Quay zone substation is supplied from the Whanagnui GXP via the Taupo Quay 33kV subtransmission line. The Steel Towers that support the Taupo Quay line over the Whanganui River were in poor condition with some severe corrosion evident on some steel members and string insulators. The conductor is Cockroach AAC Aluminium wire. The conductor was installed in 1960 making it 60 years old and is required to be replaced.

Options

1. Refurbish the existing trower structures and renew the conductor.
2. Replace the existing trower structures with mono steel poles and renew conductor.
3. Replace the existing trower structures ‘like for like’ and renew the conductor.

Preferred option

Option 3 is the preferred option for the following reasons

Refurbishing the existing trower structures would require sandblasting the existing steel work. To minimise the eviromental impact of this activity to the Whanganui River and surrounding riverbanks was complex, and therefore uneconomic.

Replacing the trower structures with mono steel poles would require extensive excavation works on both sides of the Whanganui River. The consenting process may take an extended period which put the existing structures at risk of failure. Replacing the existing steel structures ‘like for like’ required minimal excavation works with usual consentation for this type of replacement.

A7.11.1.1 HANGANUI GXP-HATRICKS WHARF

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHANGANUI GXP BUS L TO HATRICKS WHARF	GRO	$1,359	2032-2033

Network issue

Contingency analysis modelling indicates two different constraint scenarios present on the substransmission network. This is present when Peat St is supplied via WGN GXP in case of BRK maintenance. Secondly, under half Bus K outage scenario.

In winter, there is a capacity constraint between Whanganui GXP and Hatricks Wharf sub (12MVA), when parallel supply is compromised.

Options

1. Run a new high capacity cable from Whanganui Bus L to Hatricks Wharf. This route is through urban developed land east of the river and there is already a conductor route through.
2. Do nothing. This option prolongs the risk of a contingent capacity constraint, when parallel supply is compromised.

Preferred option

The preferred solution is option 1, to upgrade conductor capacity to above 23MVA, lessening the Brunswick GXP outage scenario constraint. The various conductor types would be upgraded to a uniform size by design.

A7.11.1.2 HATRICKS WHARF-PEAT ST

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HATRICKS WHARF TO PEAT ST	GRO	$1,366	2024-2026

Network issue

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 supply to Peat St.

When supply to Roberts Ave, Castlecliff or Peat St is compromised, supply between Hatricks Wharf and Peat St becomes over-loaded at later year demand forecast levels, on both 630mm2 cable and conductor portion.

Options

1. Upgrade subtransmission circuits through Beach Rd and Castlecliff to Peat St. Geographically, this option is too lengthy to make economic sense, even though these lines do also reach near capacity under certain switching configurations of the ring.
2. Link Taupo Quay to Peat St to bring high capacity from the Whanganui Bus K cable project that is under way. Upgrade of the existing line and cable is more cost effective than this option.

Preferred option

The preferred solution is option 1, 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 St to Hatricks Wharf is also required during a Whanganui GXP constraint.

A7.11.1.3 PEAT ST-CASTLECLIFF

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PEAT ST TO CASTLECLIFF	GRO	$2,400	2025-2027

Network issue

Taupo Quay subtransmission forms part of the Peat St, Beach Rd, Castlecliff and Hatricks Wharf ring. At year 2030, forecast demand outage modelling of a malfunction of the Taupo to Beach conductor, shows the alternative Peat St to Castlecliff ring loading 99% of the cable (300mm2 AL) and conductor (Cockroach).

The simple ring structure of the subtransmission ring does not allow direct supply of Beach Rd from Hatricks Wharf, so there is an inherent reliance of Castlecliff and Beach Rd substations on this circuit out of Peat St.

Options

1. Run a direct cable from Hatricks Wharf to Beach Rd.
2. The upgrade of the existing circuit is preferred for lowest cost.
3. A new line direct from Brunswick, past Peat St to join the ring near Beach Rd. While this breaks up the inherent ring limitations, it covers close to 15km and would be cost prohibitive for this singular constraint remediation.

Preferred option

The preferred solution is option 2, to upgrade existing cable and conductor to minimum 24MVA, allowing supply of Castlecliff and Beach Rd subs at forecast demand levels.

A7.11.1.4 BRUNSWICK GXP-ROBERTS AVE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BRUNSWICK GXP TO ROBERTS AVE CONDUCTOR	GRO	$1,354	2023-2024

Network issue

Supply to Peat St from Brunswick GXP is constrained upon an outage of the 5.49km 30MVA direct path conductor.

There is a 2019 project delivering a new large capacity cable between Roberts Ave and Peat St substations.

Once the Roberts Ave to Peat St new cable project is completed, there will be an alternative path for supply to Peat St. However, the capacity of the conductor upstream of Roberts Ave is only 22MVA.

The lower-capacity portion of this alternative path lessens future security of Peat St and dependent substations.

Options

1. Run a third circuit from Brunswick GXP to Peat St to provide the full security requirement. This would require more time for an ODID at Brunswick and a second transformer for subtransmission N-1.
2. Upgrade the conductor portion of Brunswick GXP to Roberts Ave.

Preferred option

The preferred solution is option 2, a conductor capacity upgrade for the 3.6km conductor between Brunswick GXP and Roberts Ave sub, ensuring adequate contingent supply through Roberts Ave.

This would ensure a high-capacity alternative supply path between Brunswick GXP and Peat St, and dependent subs beyond.

A7.11.1.5 ROBERTS AVE-PEAT ST

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ROBERTS AVE TO PEAT ST 33kV CIRCUIT	GRO	$5,160	2022-2023

Network issue

Peat St is the most critical substation in Whanganui but is supplied by a single circuit, meaning security is dependent on backfeed from Whanganui 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 Whanganui GXP are unavailable, there is insufficient capacity through Peat St to secure all dependent substations.

Kai Iwi is sub-fed from Peat St.

Under normal configuration, the loading of the subtransmission conductor between Peat St and Castlecliff is above 80% thermal capacity.

Under a contingent configuration, the Peat St to Hatricks Wharf cable and Taupo Quay to Beach Rd conductor are loaded above acceptable level.

Options

1. A new 33kV circuit between Roberts Ave and Peat St.
2. A second transformer into Brunswick. This provides security, but not capacity.
3. Upgrade of the existing circuits into Whanganui from Whanganui GXP. This option attracts SAIDI, encounters much urban underbuilt lines, and is limited by river crossing tower structures.

Preferred option

The preferred solution is option 1, the construction of a new 33kV circuit between Roberts Ave and Peat St substations. The project will provide a partial alternative supply to Peat St.

A subsequent AMP21 project will upgrade the existing 33kV circuit between Brunswick GXP and Roberts Ave substation. These projects will create a secure supply to Peat St and Roberts Ave substations.

The project is subject to considerations under the Te Awa Tupua Act related to the Whanganui River and adjacent lands and streams.

A7.11.1.6 PEAT ST-TAUPO QUAY

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PEAT ST TO TAUPO QUAY NEW 33kV LINE	GRO	$7,700	2022-2023

Network issue

Brunswick GXP is a critical supply point for the Whanganui subtransmission ring, but is limited in both security and capacity when compared with Whanganui GXP capability.

A recent initiative is progressing towards securing a second transformer for Brunswick GXP, and Transpower intends to replace the existing single phase bank transformer post 2025. A second transformer, even on a single bus connection, will provide valuable security to zone substations west of the river.

The capacity limitation is because of only having a single subtransmission feeder from Brunswick GXP into Peat St. This project seeks to double the available 36MVA capacity, reducing reliance primarily on the Castlecliff through Hatricks Wharf subtransmission circuits and, secondarily, on the Whanganui/Marton 110kV circuit.

Options

1. Expand the Whanganui GXP (Transpower) transformer capacities.
2. Bring new circuits out from Whanganui GXP (see Taupo Quay second 33kV project).
3. Establish a new substation off the 110kV, near Roberts Ave.
4. Instal a new circuit from Peat St to Taupo Quay.

Preferred option

The preferred solution is option 4. This second subtransmission line project aligns with present day thinking that capacity upgrades to Transpower's 110kV circuits are uncertain, and Whanganui ring reliance upon Brunswick GXP for future enabling capacity and security is advised.

A7.11.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Whanganui area.

A7.11.2.1 KAI IWI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER, SWITCHROOM AND SWITCHBOARD RENEWAL	ARR/ORS	$2,690	2022-24

Fleet issue

The Kai Iwi switchroom building is at 20% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard is not arc flash/arc blast rated or arc flash protected, and includes oil circuit breakers (OCBs).

Kai Iwi has one Bonar Long 4.8MVA power transformer with a Fuller F3 OLTC. The transformer was manufactured in 1965 and will be 65 years old at the end of the planning period. Kai Iwi has N transformer security with limited 11kV backfeed, so it is difficult to arrange an outage to carry out transformer maintenance.

Options

4. Do nothing.

5. Seismically strengthen the switchroom and refurbish the existing 11kV switchboard with vacuum circuit breakers, arc flash protection and arc flash doors/end panels. Replace the existing power transformer with a new low maintenance transformer. Upgrade the site for connection of the mobile transformer before installing the new transformer.
6. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard. Replace the existing power transformer with a new low maintenance transformer. Upgrade the site for connection of the mobile transformer before installing the new transformer.

Preferred option

We are currently proceeding with option 2 as the least cost option that resolves the site risks.

A7.11.2.2 PEAT ST SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ENTIRE SWITCHBOARD REPLACEMENT	ARR	$1,179	2028-29

Fleet issue

Peat St has one of two remaining Merlin Gerin FG1 switchboards, which are no longer supported by the manufacturer, and we have limited parts for. We are retiring the sister board at Kairanga which should give us some additional spares so we can us this board until expected end of service life. There are no current retrofit options to extend the life of this type of switchboard.

Options

1. Do nothing.
2. Replace the 11kV switchboard with new

Preferred option

The preferred solution is option 2, to replace the existing switchboard with a new unit. Option 1 is not tenable due to the safety and network risk.

A7.11.2.3 TAUPO QUAY SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAUPO QUAY TRANSFORMER UPGRADE	GRO/ARR	$1,716	2027-2028
NEW 11kV SWITCHROOM AND SWITCHBOARD	ARR	$1,400	2021-22

Network issue

The existing transformer at Taupo Quay is 10/12.5MVA rated. The maximum demand at Taupo Quay is 5.4MVA, therefore it does not have the capacity to fully backfeed Hatricks Wharf load (13.5MVA) during an outage via 11kV bus tie if Hatricks Wharf was to lose supply from Whanganui GXP.

Fleet issue

W30 is a 1973 Power Construction transformer, with an older-style Fuller tap-changer. While the condition is reasonable for its age, given the number of leaks and Taupo Quay being an N-security substation, this is showing up as a high risk transformer site in our CBRM modelling. This is ranked 17 out of 117 substations in terms of risk.

The 11kV switchroom is <33% NBS, and the existing 11kV board does not meet arc flash requirements. We have a project under way to rebuild the11kV switchroom and 11kV switchboard.

Options

3. Do nothing. Probabilistic standatairds might preference this option.
4. Upgrade the transformer at Taupo Quay to 16/24MVA to support the full load at Taupo Quay and Hatricks Wharf during planned and forced outages.

Preferred option

The preferred solution is option 2, to upgrade the existing transformer to provide adequate contingent capacity to supply the Taupo Quay demand, future growth, plus Hatricks Wharf demand.

Presently, there is room for only one transformer at Taupo Quay substation. The site easement doesn't allow for installation of a second transformer, hence the need to upgrade the existing unit.

A7.11.2.4 CASTLECLIFF SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CASTLECLIFF TRANSFORMERS	GRO	$2,716	2027-2028
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$828	2024-25
11/33kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$217	2024

Network issue

Castlecliff substation modelling, at present year forecast demand, shows an outage of one transformer will load the single transformer to firm capacity. There exists a local community preference to maintain a rating near to AA+ security class.

Options

1. Do nothing. Demand growth is healthy around the Peat St supply zone, although probabilistic standards might preference this option.

2. Upgrade both transformers with second-hand units. Two transformers from Kelvin Grove substation might become available if that upgrade is successful.

Preferred option

The preferred solution is option 2, to upgrade one or both transformers to provide firm capacity well above 10MVA, factoring for future growth. The present time suggestion would be for 1x17MVA transformer, although the exact rating would be decided during the feasibility design phase.

There might exist an opportunity to re-use 2x15MVA transformers from the Kelvin Grove upgrade, condition assessment pending, which introduces cost control.

Fleet issue

Castlecliff substation has mismatched transformers, which is an operational constraint. One of the power transformer units has experienced mech box failures. We have also had a number of issues with the 33kV switchboard, which is housed in an extension to the original 11kV switchroom. The extension was constructed in 2004 and has been found to have weather tightness issues, which we resolved in 2021.

The Castlecliff switchroom building is at 65% NBS, which is marginally below the 67% NBS required for seismic compliance. The 11kV switchboard is not arc flash/arc blast rated or arc flash protected, and includes OCBs. The 11kV switchboard does have more modern electronic protection relays, however these relays do not offer arc flash protection elements.

Options

1. Do nothing.
2. Seismically strengthen the 33/11kV switchroom and refurbish the existing 11kV switchboard with vacuum circuit breakers, arc flash protection and arc flash doors/end panels. Replace the existing power transformers.
3. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard. Replace the existing power transformers.

Preferred option

The preferred solution is option 2, to seismically strengthen the 33kV/11kV switchroom, arc flash retrofit the existing 11kV switchboard and replace the power transformers with new power transformers. The options proposed above will be examined in more detail at the conceptual design stage.

A7.11.2.5 ROBERTS AVE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
W23 POWER TRANSFORMER REPLACEMENT	ARR/GRO	$1,176	2027-2029

Fleet Issue

Roberts Ave substation has a 1969 Bonar Long 8.5MVA transformer. Due to the age and condition this unit is classed as having H2 health, and will be beyond expected service life at 65 years of age at the end of the period.

The substation has N-1 switched security. 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 switchroom building is at 20% NBS and as such is an earth quake prone building, but has a new 11kV switchboard that was installed in 2017.

Options

1. Do nothing.
2. Replace transformer with new 7.5/10MVA unit & seismically strengthen the existing switchroom
3. Retrofit current transformer & seismically strengthen the existing switchroom

Preferred option

Our preferred option is Option 3, to upgrade the existing transformer pad arrangements and installing a new transformer, as our strategy for our N-security sites is to install lower maintenance new transformer units to minimise network disrupртions, and this is the lowest cost option for resolving the fleet risks above.

A7.12 RANGITIKEI

A7.12.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Taihape A SOH Crossarm Replacement	ARR	$1,200	2024-2029

Network issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching 'end of design life' investments for replacement are included in the current overhead renewal planning.

Option

Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

1. The subtransmission network when constructed in the 1960's through to the 1990's the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substation(s). Also there has been an Engineering Instruction (EI) issued to ban all 'live line' work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.
2. The subtransmissiojn network also has the glass Pilkington insulators used. This type of insulator also, over time, is also electrically breaking down due to hairline cracking and require replacement. The result of the insulator breaking down can lead to the loss of supply to zone substations.
3. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators can cause 'flashovers' at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.

Options

1. Replace the insulators on the existing arms.
2. Relace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient.

A7.12.1.1 MARTON GXP-ARAHINA

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ARAHINA SECOND TRANSFORMER AND 11KV SWITCHROOM REPLACEMENT	GRO/ARR	$5,844	2023 - 2025
ARAHINA SECOND SUBTRANSMISSION AND 11KV UPGRADE	GRO	$1,345	2024-2025
ARAHINA 33KV INDOOR	GRO	$2,557	2026-2028

Network issue

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 new demand has exceeded size of the transformer rating , and there is potential for loss of supply at the substation for a transformer or subtransmission fault. The existing 33kV line is an overhead Cockroach conductor size with two 11kV feeder underneath causing reliability and security of supply issues.

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. Arahina has 8.2MVA load, therefore, the neighbouring zone substations do not have the capacity to backfeed.

With the new consumer loads connecting (13MVA), there are significant upgrades required at subtransmission level and at distribution level. The existing 11kV switchroom does not meet the requirements of the seismic restraints for buildings and structures standards. The 11kV circuit breakers has reached its maximum ratings hence there's no room for dedicated feeders for the large loads.

Options

1. Increased backfeed would be costly as there is no adequate transfer capacity, even with substantial distribution upgrade.
2. Second Substransmission line, increased transformer and a new 11kV switchroom with higher circuit breaker ratings.

Preferred option

The preferred option 2 is to install a second subtransmission supply and transformer at the substation.

Fleet issue

The 11kV switchroom is 35% NBS, which is below the 67% NBS required for seismic compliance. The 11kV switchboard consists of older Reyrolle OCBs without arc flash and arc blast protection. The single power transformer was manufactured in 1971 and has a Ferranti tap-changer. The transformer has a number of minor oil seeps and degraded paint, but is fully bunded. The fleet renewal drivers are weak, and so
any refurbishment or renewal may be delayed until FY31/32 or as determined by development drivers.

Options

The options for renewal will be reviewed in more detail closer to the future FY31/32 implementation date.

Preferred option

The preferred option at this stage will be seismic strengthening of the existing switchroom and to retrofit the existing 11kV switchboard with vacuum circuit breakers and arc flash protection. The least cost, preferred option will be reviewed in more detail before the future implementation date.

A7.12.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Rangitikei area.

A7.12.2.1 BULLS SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
W41 POWER TRANSFORMER REPLACEMENT	ARR	$1,171	2030-2032
Bulls Second Transformer	GRO	$1,835	2025-2026

Network issue

The Bulls substation supplies urban and rural loads. The substation is supplied by one single 33kV circuit from Marton GXP (N security). There will be second 33kV supply connecting from Bunnythorpe GXP in the future. With the GXP interconnect configuration, the existing transformer rating, 10MVA, will not suffice and the substation requires n-1 security transformers. With the new proposed loads and supply to substations downstreams under contingency, the new demand has exceeded the size of the transformer rating, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. The existing 33kV line is an overhead Cockroach and Dog conductor size with one 11kV feeder underneath causing reliability and security of supply issues.

With the two 33kV incomers in the future, the substation will require a second transformer for supply continuity as the existing transformer is coming closer to it's end of life.

Options

1. Increased backfeed would be costly as there is no adequate transfer capacity, even with substantial distribution upgrade.
2. Second transformer to have n-1 security of supply.
3. Do nothing

Preferred option

The preferred option 2 is to install a second transformer at the substation.

Fleet issue

Bulls has one 9.6 MVA power transformer with a Ferranti OLTC, a aged system spare installed as a temporary measure when the previous transformer on site failed in service 2019.
The current Bulls transformer was manufactured in 1971 and will be 63 years old at the end of the planning period. Bulls is N transformer security with limited 11kV backfeed, so it is difficult to arrange an outage to carry out transformer maintenance.

Options

4. Do nothing.
5. Replace transformer with new 12 / 17MVA unit
6. Retrofit current transformer

Preferred option

The preferred option is option 2, replacing the transformer with a new unit. The current transformer is aged and with the reduced ability to supply the site through the 11kV this increases the impact to customers of any maintenance or unplanned outaged. While the second transformer will improve the reliability of the site for single transformer outages, refurbishing the existing unit is unlikely to be economic.

A7.12.2.2 PUKEPAPA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ENTIRE SWITCHBOARD REPLACEMENT	ARR	$694	2025-27
W42 CONVERSTION TRANSFORMER REPLACEMENT	ARR	$1,238	2027-29

Network issue

The Pukepapa substation is adjacent to Transpower's Marton GXP and supplies Marton's surrounding 5.5MVA rural residential and irrigation loads. It is the main distribution backup supply for the Arahina substation and, to a lesser extent, to the Bulls substation. Its security level is A1, although demand is forecast to approach 6MW after 2030.

Fleet issue

The 11kV switchroom has been assessed as having a seismic capacity rating of 15% NBS. The 11kV switchboard consists of older Reyrolle OCBs without arc flash and arc flash protection. Pukepapa has two transformers – the 33/11kV transformer was manufactured in 1967 and the 11/22kV transformer was manufactured in 1988 by Tyree Power Construction Ltd.

Options

1. Do nothing.
2. Seismically reinforce the existing 11kV switchroom and upgrade the existing RPS switchboard with arc flash protection & renew conversion transformer.
3. Build a new seismically compliant 11kV switchroom and install new arc flash rated switchgear in the new switchroom & renew conversion transformer.

Preferred option

The preferred solution is option 3. With the Marton ODID we have decided to construct a new 11kV switchroom that will be able to house the new switchboard, allowing us to vacate the existing switchroom, which is earthquake-prone, and then phase a replacement of the poor condition conversion transformer afterwards.

A7.12.2.3 TAIHAPE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAIHAPE SECOND TRANSFORMER	GRO	$1,370	2026-2028
NEW 11/33KV BUILDING AND 11KV RENEWAL	ARR	$3,756	2025- 27

Network issue

The Taihape substation supplies Taihape township's urban and rural load. There are several essential services within the 4.4MVA Taihape township, including private and public hospitals, police and the fire department.

The substation contains a single supply 8.5MVA 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 the long distances and rural terrain.

Taihape substation has two 33kV incomers, which give the sub good security to expand the number of feeders and support any offloading plans of neighbouring substations.

Mangaweka feeder needs offloading through distribution ties and relocating switches. Voltage becomes marginal under normal configuration at end-of-line, and customer demand growth is difficult to supply. Overhead ties will be completed in stages in later years, along with switch moves, under the routine planning budget.

What is required is additional 33kV and 11kV circuit breakers and a tidy up of the unusual 11kV extended distribution bus arrangement.

Options

1. Increased 11kV backfeed is estimated to be costly in comparison to the other options, as there is no adequate transfer capacity.
2. Do nothing. With Mangaweka feeder requiring improvement, this option moves the need onto nearby substations, which would still need expansion works to support additional feeders for distribution of load purposes.
3. Install new 33kV and 11kV switchgear. The 33kV would be expanded, for future enabling of 33kV interconnects to new or uprated substations. The

11kV board would be simplified in arrangement but expanded in functional circuit breakers, to supply offloading feeds to Mangaweka and surrounding feeders.

Preferred option

The preferred option 3 is expansion works on the 33kV switch yard and a new expanded 11kV board. A solution project would install a second transformer at the substation. This will support the switchroom upgrade project also planned.

Fleet issue

The 11kV switchroom has been assessed as having a seismic capacity rating of 13% NBS. The 11kV switchboard consists of older Reyrolle circuit breakers without arc flash and arc blast protection, and due to heavy operation on rural feeders, are reaching end of expected service life.

Options

1. Do nothing.
2. Seismically reinforce the existing 11kV switchroom and upgrade the existing RPS switchboard with arc flash protection.
3. Build a new seismically compliant 11kV switchroom and install new arc flash rated switchgear in the new switchroom.

Preferred option

Preferred option 3 is to construct a new 11/33 kV switchroom with new 11kV switchboard, due to network risk in supporting the substation and lack of space for development of Option 2.

A7.12.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A7.12.3.1 WAIOURU SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
POWER TRANSFORMER REPLACEMENT	ARR	$1,195	2025-26
BACKFEED UPGRADE	GRO	$1,500	2026-28

Network issue

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.

The demand has exceeded the class capacity, sustaining about 2.9MVA, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. Because of these constraints, the Waiouru substation does not meet our required security level.

Options

1. Installation of a second subtransmission supply and transformer for the substation would be costly.
2. 11kV upgrade.

Preferred option

The preferred solution is option 2, increases 11kV distribution backfeed capability.

Fleet issue

Waiouru T1 is a 1963 Bonar Long transformer, which will be 71 years old at the end of the period, and is showing signs of leaking. This unit is classed as H2 due to the age and condtition. As an N-security substation with limited 11kV backfeed, so it is difficult to arrange an outage to carry out transformer maintenance.

The 11kV switchroom is 25% NBS and is classed as an earthquake prone building.

Options

1. Do nothing.
2. Refurbish existing transformer & seismically strengthen switchroom.
3. Replace transformer & seismically strengthen switchroom.

Preferred option

Given the age of the transformer, and limited supply redundancy, option 1 is not feasible. Option 2 is not preferred because of the age of the transformer and type of tap-changer, which are orphans. Our preferred solution is option 3, the replacement of the existing transformer with a new unit and seismically strengthen the existing switchroom to address the fleet risks.

A7.13 MANAWATU

A7.13.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Kelvin Grove to TWP 33kV rearm	ARR	$1,100	2024-2029

Network issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching ‘end of design life’ investments for replacement are included in the current overhead renewal planning.

Option

Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

1. The subtransmission network when constructed in the 1960’s through to the 1990’s the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substation(s). Also there has been an Engineering Instruction (EI) issued to ban all ‘live line’ work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.
2. The subtransmissiojn network also has the glass Pilkington insulators used. This type of insulator also, over time, is also electrically breaking down due to hairline cracking and require replacement. The result of the insulator breaking down can lead to the loss of supply to zone substations.
3. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators can cause ‘flashovers’ at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.
4. Replace the insulators on the existing arms.
5. Relace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient.

A7.13.1.1 SANSON-FEILDING-SANSON-BULLS

PROJECT	DRIVER	COST ($000)	TIMING (FY)
FEI-SAN-BULLS DESIGN AND CONSTRUCTION	GRO	$1,125	2022
SANSON-BULLS 33kV LINE	GRO	$5,73711,500	2022-2023
FEI-SAN-BULLS SUB MODIFICATION	GRO	$3,325	2022-2024

Network issue

The subtransmission network supplying Feilding, Sanson and Bulls townships, including RNZAF Ohakea air base, does not meet Powerco’s security of supply standards. There are capacity constraints on the existing circuits and a lack of alternative supply feeds during contingencies. Sanson substation is loaded beyond firm capacity, as is Transpower’s Bunnythorpe GXP. The latter supplies this region, including most of Palmerston North.

In addition, the New Zealand Defence Force (NZDF) has embarked on significant upgrades to the airbase at Ohakea and has requested increased capacity beyond what can be supplied from our existing network. Advice from the Ministry of Defence is that the capital works will eventually increase airbase demand to 8MVA.

Options

The N-security resulting from the single Feilding-Sanson 33kV line, means alternative 33kV circuits are the most effective solutions. Similarly, non-network options could not address the intrinsic need for secure subtransmission.

The following shortlisted options were considered:

1. Construct a new 33kV line from Feilding substation to Sanson substation and install an 11kV remote switching device at Bulls substation and voltage regulators to provide voltage support.
2. Thermally upgrade the Bunnythorpe to Feilding 33kV lines, construct a new 33/11kV substation at Ohakea, construct a new 33kV line from Bulls substation to the new Ohakea substation, and install an automatic load transfer facility at Sanson substation.

Preferred option

The preferred solution is option 2, which 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, and installing an automatic load transfer facility at Sanson substation.

In option 2, the Sanson substation will be normally supplied from Bulls via the new 33kV Bull-Ohakea-Sanson line. For a contingent event on the Bull-Ohakea-Sanson line, the automatic load transfer facility will ensure the Sanson zone substation will be switched over to be supplied from Feilding substation. The installation of the automated changeover switch (load transfer facility), will shift some load from the Bunnythorpe GXP to the Marton GXP, therefore relieving the congested Bunnythorpe GXP to Feilding 33kV circuits.

A7.13.1.2 LINTON GXP-TURITEA SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
TURITEA SUBSTATION NEW 33kV LINE	GRO	$2,07500	2024-2025

Network issue

The Turitea substation supplies Massey University, Linton Military Camp, New Zealand Pharmaceuticals, and residential and rural load to the south-east of Palmerston North. Its single 33kV supply limits its security level to 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.

Turitea substation 11kV backup supply is limited because it is located on the other side of Manawatu river and there is only three 11kV inter-tie to the feeders of other substations.

Because of these constraints, the Turitea substation does not meet our required security level.

Options

1. Construct a new 33kV line from Linton GXP to Turitea substation.
2. Increase the 11kV backfeed capability to Turitea substation.

Preferred option

The preferred solution is option 1, which involves constructing a new 33kV line from Linton GXP to Turitea substation. This will improve the security level of this substation.

Alternatives, such as increased backfeed, would be costly as there is no adequate transfer capacity.

A7.13.1.3 FEILDING-SANSON 33KV LINE

PROJECT	DRIVER	COST ($000)	TIMING (FY)
FEILDING-SANSON LINE UPGRADE	GRO	$1,406	2025-2027

Network issue

The Feilding-Sanson 33kV line supplies the Sanson zone substation through a single 33kV circuit (14.7km) with a section of Quail conductor, which has a thermal capacity of 9.5MVA (166A). The Sanson substation supplies 3,005 ICPs, including the RNZAF Base Ohakea, which will have a load increase of 3MVA. There is a project (IR14201) to upgrade a section of the Feilding-Sanson 33kV line to improve its thermal capacity to support the load increased at Ohakea. Upon completion of this project the new thermal limit of this line is 12.7MVA (Dog).

However, this 33kV line will also serve as an alternative supply to Bulls substation (current MD 5.7MVA) when the Sanson-Bulls 33kV interlink project, coupled with a new substation to supply Ohakea, is completed. This will link Sanson and Bulls substations at 33kV, providing the required security of supply to Sanson and Bulls as well as Ohakea. Total load for these three substations is about 18.6MVA.

The addition of Bulls substation load will overload the Sanson 33kV supply, hence a new line upgrade will be needed.

Options

1. Do nothing.
2. Upgrade Feilding-Sanson 33kV line to increase its thermal capacity.

Preferred option

The preferred solution is option 2. This will provide the capacity to support the additional loads.

A7.13.1.4 BUNNYTHORPE GXP-FEILDING

PROJECT	DRIVER	COST ($000)	TIMING (FY)
FEILDING NEW (THIRD) 33kV LINE	GRO	$6,5388,500	20264-2028

Network issue

Feilding substation takes its 33kV supply from Bunnythorpe GXP by two lines, one is 8.6km (FEI East) and the other is 9.1km (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 line and Kimbolton substation by another 26.5km 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.

Options

1. Do nothing.
2. Upgrade existing Feilding 33kV circuits.
3. Install a new 33kV line from Bunnythorpe GXP-Feilding substation.

Preferred option

The preferred solution is option 3.

These will provide adequate capacity for the future demand with appropriate security.

A7.13.1.5 BUNNYTHORPE GXP-NORTH-EAST INDUSTRIAL SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW 33kV LINE BPE-NEI	GRO	$3,970	2027-2029

Network issue

A 33kV supply will be needed for the proposed new zone substation in the North Industrial Area to accommodate the load growth on the north-east side of Palmerston North.

Options

1. Use the existing BPE-KST 33kV line to supply the new zone substation.
2. Install a new 33kV line from Bunnythorpe GXP to the new North-East Industrial zone substation.

Preferred Option

The preferred solution is option 2. This will increase the security of supply to the new zone substation.

Option 1 could be used initially to supply the new substation and as an alternative after the completion of the new 33kV line.

A7.13.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Manawatu area.

A7.13.2.1 KEITH STREET SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHBOARD REPLACEMENT	ARR	$1,193	2026-27

Fleet issue

Keith Street Zone Substation has a 12 panel 11kV RPS LMVP switchboard installed with a refurbishment carried out in April 2000. The refurbishment process extends the boards life for approximately 30yrs. The board is coming to the end of its life and renewal is required. During this project the 11kV protection relays and batteries/SCADA will be renewed. Additionally, the Copperleaf CNAIM value model predicts the asset is approaching approaching renewal or replacement as determined by the Copperleaf value models. The CNAIM model for ZS switchgear is principally determined by age, condition, network risk and environment.

Options

1. Do nothing.
2. Refurbish the existing RPS LMVP switchboard again.
3. Build a new 11kV switchboard that is fully arc flash compliant, with full manufacturer support for spares/faults.

Preferred option

Option 3 is the preferred solution is, to better future proof this site.

Option 1 is not viable due to increasing risk from the boards age.

Option 2 is not preferable because the RPS board has already been refurbished and spare parts are becoming hard to obtain.

A7.13.2.2 KELVIN GROVE SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW 33kV/11kV SWITCHROOM AND 33kV SWITCHBOARD	ARR	$3,528	2030-32
11kV SWITCHBOARD REPLACEMENT	ARR	$1,108	2035-36

Fleet issue

Kelvin Grove is a 33/11kV zone substation located on the North East side of Palmerston North. It has two 33/11kV 12.5/17MVA transformers.

The 33kV bus is fed from Transpower Bunnythorpe and the other side by the generator Taraura Wind Power. The 11kV circuit breakers are 1986 Toshiba VKs, an orphaned type of asset not used elsewhere within the Powerco footprint. On the

33kV outdoor bus are four 1986 Merlin Gerin FB4 SF6 breakers which have type issues related to internal moisture buildup. The existing indoor 11kV switchboard is an orphan, being the only board of its type on our network, is no longer supported, and is not arc flash rated. The 11kV switchgear building has a seismic capacity rating of 60% NBS.

Options

1. Do nothing.
2. Seismically reinforce the existing 11kV switchroom, install new 11kV switchgear, and replace the existing outdoor Schneider 33kV circuit breakers in their own new 33kV building
3. Build a new seismically compliant combined 11kV and 33kV switchroomand install a new 33kV indoor switchboard and a new 11kV switchboard within the building.

Preferred option

Option 3 is the preferred solution, to better future proof this key site. It provides a new fully seismic compliant building with indoor fully arc flash compliant circuit breakers for a comparable cost to option 2 with less network risk during construction.

Option 1 is not viable due to the switchgear being Orphans with no manufacturer support.

Option 2 is not preferable because of safety and supply risk in complete switchboard replacement into the existing building.

A7.13.2.3 FEILDING SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW FEILDING ZONE SUBSTATION	GRO	$7,7155,800	2024-2027
New FEI to New FEI Sub 33kV Line	GRO	$3,098	2027-2028
33kV OD to indoor	ARR	$3,905	2022-24
New 11kV switchboard	ARR	$2,298	2025-26

Network issue

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 load growth is high in areas covered by Feilding substation. The demand forecast for 2021/2025/2030 are 21.8/22.5/23.5MVA respectively, which will exceed the firm capacity of the transformers. Because of limitations in backfeed capability, the security of supply will not be adequate as load grows.

Options

1. Increased 11kV backfeed. The distance to Feilding from comparably sized secure substations precludes this option.
2. Install a third transformer. This would be a non-standard substation configuration, which we would prefer to avoid because of the additional protection complexity.
3. New zone substation. A new zone substation for Feilding is a viable long-term strategy. 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 preferred solution is option 3, to build another zone substation in Feilding. This is a more appropriate long-term strategy. The transformers at Feilding can be rerated to provide N-1 capacity giving sufficient time for the establishment of a second zone substation.

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.

Fleet issue

The existing overhead 33kV bus and structure arrangement is old and poses operational safety risks. Additionally, the existing switchroom building is at 65% NBS. The existing 11kV switchboard does not meet the Powerco requirement for arc flash mitigation and is a risk to operators.

The majority of the legacy 33kV and 11kV switchgear assets date back to 1965 and are at the end of life. The 33kV outdoor bulk oil circuit breakers and their associated instrument transformers are all original 1965 equipment – the oil current transformers have needed temporary repairs to stop leaks, and issues with one of the circuit breakers in 2011 required complete replacement as we no longer have parts to service these assets.

The existing 33kV outdoor switchyard has minimal room for future expansion and has 33kV clearance issues.

Options

1. Do nothing.
2. A full 33kV outdoor to indoor conversion (ODID) in a new combined 33kV/11kV switchroom. Installation of a new arc flash compliant 11kV switchboard.
3. Seismically strengthen the existing 11kV switchroom building. Carry out an arc flash upgrade on the existing 11kV switchboard combined with installing new 33kV outdoor circuit breakers.

Preferred options

Option 2 is the preferred solution and will include a full outdoor to indoor 33kV conversion (ODID) in a new combined 33kV/11kV switchroom, together with the installation of new arc flash compliant 11kV switchboard.

Option 1 does not resolve the seismic and arc flash issues.

Option 3 does not address the clearance issues in the 33kV outdoor switchyard.

A7.13.2.4 SANSON SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
T1 POWER TRANSFORMER REPLACEMENT	ARR	$1,356	2028-29

Fleet issue

Sanson T1 is a 7.5MVA Tyree Power 33/11kV Yy0 transformer installed in 1963. It recently had a large volume of oil lost due to a leak on the main tank lid. This was repaired as an OPEX project. The transformers age is showing it as approaching end of life and renewal should be carried out before the unit starts to fail further. Other historic defects include raised DGA levels indicating moisture ingress and historic leaks. Additionally, the Copperleaf CNAIM value model predicts the asset is approaching renewal or replacement as determined by the Copperleaf value models. The CNAIM model for transformers is principally determined by age, condition, network risk and environment.

Options

1. Do nothing.
2. Refurbish the existing Sanson T1 power transformer
3. Purchase and install a new 12.5/17MVA transformer complete with new bund sized at 16/24MVA and full oil capture system.

Preferred option

The preferred solution is option 3, to better future proof this site.

Option 1 is not viable with the Transformer approaching end of life and recent defects it presents too high of a risk.

Option 2 is not preferable because Sanson substation is experiencing load growth and as such the existing transformers will become undersized.

A7.13.2.5 NEW NORTH EAST INDUSTRIAL SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NORTH EAST INDUSTRIAL SUBSTATION	CON	$7,621300	2025-2028

Network issue

Kelvin Grove substation supplies several important loads, including the North East Industrial area.

The North East Industrial area has been planned as a transport and warehouse hub because of its strategic location in the national transport infrastructure.

There is major industrial load emerging within the industrial park and surrounding area. There are some commercial and small industrial customers, namely Leisureplex, Ezibuy, Allflex, Budget Plastics and Vesta.

Kelvin Grove substation forecast 2030 demand is about 19MVA and the transformers are scheduled to be upgraded in FY 2021-22 to 2x24MVA units. However, with the addition of the Woolworth hub (2MVA) plus the proposed Hiringa Energy refuelling station (1.4MW initially) and the proposed KiwiRail hub (2MW initially) in this area, Kelvin Grove would likely exceed the 24MVA capacity of its single transformer. Neighbouring Milson substation has 2x12.5/17MVA transformers and the demand forecast in 2030 is about 18MVA.

Options

1. Construct a new zone substation to accommodate the load growth on the north-east side of Palmerston North. A new 33kV circuit from Bunnythorpe GXP will be needed to supply this new substation.
2. Construct a new 11kV feeder from Kelvin Grove substation. Kelvin Grove zone substation transformers have exceeded their n-1 rating.
3. Upgrade existing 11kV feeders.

Preferred option

The preferred long-term solution is to establish a new zone substation, named North East Industrial to cater for the load growth in this area.

The other options are not enough to provide long-term security of supply in this area.

A7.13.2.6 NEW LINTON ARMY CAMP SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
LINTON ARMY CAMP SUBSTATION	GRO	$5,643	2030-203325
NEW 33kV LINE FOR LINTON ARMY CAMP ZS	GRO	$5,396	2031-2033

Network issue

The New Zealand Defence Force (NZDF) operates New Zealand's largest military barracks and associated facilities at Linton, near Palmerston North. Future planned upgrades to the military base include the decommissioning of coal fired boilers, which will increase the power demand. An additional 5MVA of load is forecast, in addition to the existing 1.7MVA supply to the military base.

Linton Army Camp is primary supplied at 11kV from CB6 (Linton Express feeder) at the Turitea substation. The backup supply is from Kairanga substation CB12 (Awapuni feeder).

There are thermal capacity (ampacity) and voltage drop restrictions on the existing overhead and cable 11kV feeders, which restrict the load that can be supplied from the existing distribution network.

The existing firm capacity of the zone substations and 11kV overhead lines supplying the military base can supply an additional 0.3MVA of load before network upgrades are required to facilitate the proposed load increase.

Options

1. Construct a new zone substation within or adjacent to the military base.
2. Construct a new 11kV feeder from Turitea substation.
3. Upgrade existing 11kV feeders.

Preferred option

The preferred solution is option 1, to establish a new 33/11 kV substation within or adjacent to the military base. The proximity of the proposed substation to the new load centres is such that 11kV voltage drop and conductor ampacity constraints to the upgraded NZDF 11kV network are minimised. The initial primary supply for this new substation will come from the existing 33kV line (Linton-Kairanga) near the Linton Army CampThe long-term plan for the 33kV supply is to build a new line from Linton GXP.

The other options are not enough to provide long-term security of supply for the base.

A7.13.2.7 KAIRANGA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KAIRANGA TRANSFORMERS	GRO	$2,501	2025-2026
NEW 11/33kV SWITCHROOM AND SWITCHBOARD	ARR	$4,491	2023-26

Network issue

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 forecast for 2021/2025/2030 is 18/18.5/19.1MVA respectively, which has exceeded the transformer firm capacity.

High growth is expected on this substation because of both residential and agricultural developments.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
2. Increase the 11kV backfeed capability to Kairanga substation. This option assumes that the backfeeding capability from neighbouring substations can be increased to cover the forecast demand.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeed capacity, is 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 for a substation outage.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term reliability of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs.

Fleet issue

The Kairanga 11kV switchboard experienced a fault on one of its circuit breakers initiated by rodent infestation. This highlighted the lack of suitable spares for Kairanga as the 11kV switchboard is an orphan (Merlin Gerin FLUARC FG1) and one of the last two remaining FG1 type switchboards on the Powerco network. This switchgear is no longer supported, cannot be extended, and spare parts cannot be sourced. This switchboard does not have a bus section circuit breaker instead using a section of 11kV cable between two feeder class circuit breakers. In addition, the existing switchroom has an assessed seismic capacity of 15% NBS. The switchroom has a number of cracks and signs of water ingress with the current site low lying, giving an increased risk of flooding.

The Kairanga outdoor 33kV switchyard has Takaoka circuit breakers, which were refurbished in 2013. These will be 49 years old at the end of the planning period and will be past their expected service life.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom, replace the 11kV indoor switchboard with a new equivalent 11kV switchboard, and replace the 33kV outdoor circuit breakers on a like-for-like basis.
3. Construct a new 11kV switchroom, install a new 11kV switchboard and replace the 33kV outdoor circuit breakers on a like-for-like basis.
4. Construct a new combined 33kV/11kV switchroom and install new 33kV and 11kV indoor switchboards.

Preferred option

Option 4 is the preferred solution, to construct a new 11kV switchroom, install a new 11kV switchboard, and replace the 33kV outdoor circuit breakers with indoor breakers.

Option 1 is not viable as doing nothing presents too great a risk from the building potentially collapsing during a seismic event or the orphaned switchgear failing with no suitable replacement or parts to repair.

Option 2 is not preferred, as upgrading the existing switchroom can not be carried out easily. It is in poor condition and has an assessed seismic capacity of 15% NBS.

Option 3 is not preferred since the transformer upgrade from the Network Issues above will require moving the 33kV circuit breaker locations. Necessitating rearrangement of buswork to accommodate with a higher cost as a result from extended outage times.

A7.13.2.8 TURITEA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TURITEA TRANSFORMERS	GRO/ARR	$2,894	2024-2025
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2022

Network issue

Turitea supplies Massey University, Linton Military Camp, New Zealand Pharmaceuticals and residential and rural load to the south-east of Palmerston North.

It has two 12.5/17MVA transformers, each of which have a continuous/4/2-hour rating of 15/19/21.9MVA. The transformers were manufactured in 1970 and the projected demands for 2020/2025/2030 are 16.6/17.6/18.7MVA. This will exceed the single transformer capacity.

A consultant was previously engaged by Massey to review the feasibility of electrifying its existing gas-fired heating systems. The consultant estimated an expected 10-15MW of additional demand if the heating system is changed to electricity from gas.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for future demand and improve the security level.
2. Increase the 11kV backfeed capability to Turitea substation. This option assumes that the backfeed capability from the neighbouring substation is sufficient to supply the projected Turitea increase in demand.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeeding capacity, is not favoured as the substation 11kV backup supply is limited because it is located on the other side of Manawatu river and there are only three 11kV inter-ties to the feeders of other substations.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term security of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution but have higher operational and maintenance costs.

Fleet issue

Turitea's matched pair of power transformers were originally installed at Feilding zone substation. These were manufactured in 1970 and have Ferranti tap-changers. They will be 61 years old at the end the planning period.

The 11kV switchroom building has an assessed seismic capacity of 15% NBS. The 11kV switchboard was renewed and upgraded in 2016, so it is arc flash compliant and does not contain any oil circuit breakers.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and replace older 33kV circuit breakers.

3. Construct a new seismically compliant 11kV switchroom, and install a new 11kV switchboard and replace older 33kV circuit breakers.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom and replace the outdoor circuit breakers like for like. Option 3 is not preferred as it will be higher cost with limited benefit, especially given the current 11kV switchboard was installed in 2016.

A7.13.2.9 MILSON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MILSON TRANSFORMERS	GRO	$2,442	2026-2027

Network issue

Milson supplies the industrial, commercial and residential load in western Palmerston North, including the airport and industrial park. It has two 12.5/17MVA transformers, each with a continuous/4/2-hour rating of 15/19.2/22.1MVA. The transformers were manufactured in 1980 and the forecast demands for 2020/2025/2030 are 16.8/17.3/17.8MVA, which is close to exceeding its single transformer capacity.

Also, there is an ongoing development along Airport Drive (CIW). The total area covered by the subdivision is about 30 hectares, but much of that is existing load. The land area available for new load is about 20 hectares. Based on transformer density for commercial/industrial land in Palmerston North, the new transformer capacity that might be installed in that development will be somewhere between 3.1MVA and 4.6MVA. This development will affect the demand on the Milson substation.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
2. Increase the 11kV backfeed capability to Milson substation. This option assumes that the backfeeding capability from the neighbouring substation can be increased to cover the forecast demand.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeeding capacity, is 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 for a substation outage.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term reliability of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs.

Fleet issue

Milson substation has a low level 33kV outdoors switching structure with associated 33kV Takaoka oil circuit breakers. The oil circuit breakers are now obsolete and present a fire risk. The low level 33kV structures present a Health & Safety risk to personnel operating on or near to them**.**

Options

1. Do nothing.
2. Replace the 33kV Takaoka circuit breakers with new outdoor breakers. Reconfigure outdoor buswork with modern construction to allow for adequate maintenance access.
3. Construct a new 33kV indoor switchroom to house new indoor 33kV breakers, removing the need for the outdoor buswork.

Preferred option

Option 2 is the least cost, preferred solution. Tthe 33kV switching structure is envisaged to be rearranged and modernised to provide the required clearances.

Option 1 is not acceptable due to the Health and Safety risks.

Option 3 is not preferred as it will be higher cost.

A7.13.2.10 ASHHURST SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW ASHHURST ZONE SUBSTATION	GRO	$6,321	2027-2030
NEW BPE-ASHHURST 33kV Line	GRO	$4,141	2029-2030

Network issue

Ashhurst is a town 10km to the east of Palmerston North. It is served by two distribution feeders, CB8 Pohangina and CB10 Ashhurst, from Kelvin Grove substation. Nearby, Bunnythorpe village is supplied by one feeder from Milson substation. The town of Ashhurst can no longer maintain adequate voltage regulation of the HV network. Voltage regulator 10081 on the Pohangina feeder boosts the voltage for part of Ashhurst and the Pohangina Valley but cannot supply all Ashhurst.

Options

1. Reconductoring the feeder. This is not enough to secure the future load growth on this area.
2. Build a new 11kV feeder from Kelvin Grove Substation. Kelvin Grove zone substation transformers have exceeded their n-1 rating.
3. New zone substation. A new zone substation for Ashhurst is a viable long-term strategy.

Preferred option

The preferred solution is option 3, to build a new zone substation in Ashhurst. This is a more appropriate long-term strategy. T

Our approach to the 33kV supply for the new Ashhurst substation is to build a new line from Bunnythorpe GXP

A7.13.2.11 REBUILD LONGBURN SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
REBUILD LONGBURN SUBSTATION	CON	$3,931	2025-2027

Network issue

Longburn is a disestablished single transformer zone substation through which the Linton Kairanga 33kV line passes. Its location is about 10.4km away from Linton GXP and about 4.4km away from Kairanga Sub. The Kairanga substation loading has already exceeded the transformers n-1 capacity. There is a project IR13365 to upgrade the transformers to maintain n-1security of supply however this is not enough to supply new load growth in the Longburn area. Expected incoming load is about 7MVA.

Customer step growth could mean a new sub is necessary at that site in near future.

Options

1. Reconductoring the feeder. This is not enough to secure the future load growth on this area.
2. Build a new 11kV feeder from Kairanga Substation. Kairanga zone substation transformers have exceeded their n-1 rating.
3. Rebuild Longburn substation. This is a viable long-term strategy.

Preferred option

The preferred solution is option 3, to rebuild Longburn substation. This is a more appropriate long-term strategy.

A7.13.2.12 RONGOTEA NEW ZONE SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
RONGOTEA SUB, ESTABLISH A NEW ZS	GRO	$6,656	2033-2035

Network issue

Sanson Sub's Oroua Downs 11kV feeder, extends around 25 km to supply the Himatangi township and surrounding rural areas. There is a voltage regulator but the voltage level is marginal at Himatangi and before the regulator. Himatangi beach is a popular tourist place. More new subdivisions and irrigational load are expected to emerge in the future and this supply arrangement is likely to be failed to maintain quality of supply. Proposed to establish a small zone substation (7.5/10MVA) at a suitable site near the corner of Himatangi Block Rd and Rangiotu Rd.

Proposed 33kV supply will come from Oroua Downs Express feeder project.

Options

1. Construct a new 17km express underground HV feeder, splitting Oroua Downs feeder, as the first phase for the proposed long-term solution – to build a new zone substation.
2. Build a new zone substation at a suitable site in Rongotea area.

Preferred option

The preferred solution is option 2, to build a new Rongotea zone substation. This is a more appropriate long-term strategy.

A7.13.2.13 PASCAL ST SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PASCAL ST SUB, UPGRADE SUB TRANSFORMERS	GRO	$1,907	2030-2032

Network issue

Pascal St Sub present two 20 MVA transformers were manufactured in 1976. A new Ferguson sub had been established to offload Pascal & Main St subs. Pascal's present 20MVA firm capacity is likely to be insufficient for the demand beyond 2030.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
2. Do nothing. Probabilistic standards might preference this option.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

A7.13.2.14 MAIN ST SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MAIN ST TWO NEW TRANSFORMERS TO REPLACE 59YRS OLD TRANSFORMERS	GRO	$1,995	2026-2028

Network issue

Main St Zone Sub present two 20MVA transformers will be 59 years old in 2023. However Main St's present 20MVA firm capacity is likely to be insufficient for the demand beyond 2024 due to the PN Hospital expected load increase to 5MVA and a new 11kV express feeder is proposed to come from Main St Sub to support this new load.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
2. Do nothing. Probabilistic standards might preference this option.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

A7.14 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A7.14.1 SANSON SUB-OROUA DOWNS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OROUA DOWNS EXPRESS FEEDER	GRO	$9,4785,500	2031-2033

Network issue

The Oroua Downs feeder from Sanson sub is, in its current configuration, very long and serving about 1,331 ICPs. There are two voltage regulators on this feeder, VR-4183 and 10269. The 11kV network from Rongotea Rd to Himatangi Beach along SH1 has experienced significant load growth from irrigation. Farmer feedback suggests that at certain times of the day during irrigation periods the network along Himatangi Beach Rd is below acceptable voltage level.

Because of the length and demand of the feeder, growth is constrained in this area and additional customer load cannot be added without voltage levels decreasing below regulated limits. Customers have expressed frustration at the inability to connect new large loads in this area. A voltage dip recently occurred in Himatangi area when work was being done on the network that necessitated high voltage (HV) switching, causing issues for irrigators.

There is an initiative for creating a link from Electra's network to resolve the issue and improve the capacity of the feeder in this area. However, discussion is still continuing.

A new substation (Rongotea) in the area would resolve the issue but would come at a significant cost. The approach to the 33kV supply for the proposed Rongotea zone substation is to build a new 33kV capable line from Kairanga or Sanson substation and initially operate as an additional 11kV feeder.

Options

1. Construct a new 17km express underground HV feeder, splitting Oroua Downs feeder, as the first phase for the proposed long-term solution – to build a new zone substation.
2. Upgrade existing 11kV feeders.

Preferred option

The preferred solution is option 1.

A7.15 TARARUA

A7.15.1 SUBTRANSMISSION NETWORK PROJECTS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
Alfredton to Parkville 33kV rearm	ARR	$1,200	2024-2029

Network issue

Subtransmission circuits with overhead components that have deteriorating Asset Health Indicators (AHI) and are approaching 'end of design life' investments for replacement are included in the current overhead renewal planning.

Option

Replace the component considering that 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 and ECP34. When conductor replacement is required future load growth is considered when selecting the conductor size.

There are 3 main type issue drivers for subtransmission overhead renewal investments

1. The subtransmission network when constructed in the 1960's through to the 1990's the insulator used was a porcelain pin type. The NZI porcelain insulator was manufactured in 2 pieces and cemented together. Over time the insulators are cracking and breaking down mechanically and electrically, which leads to unplanned outages and possible supply loss to zone substation(s). Also there has been an Engineering Instruction (EI) issued to ban all 'live line' work carried out on overhead conductors bound to the 2-piece insulator due to the unpredictability of the insulator failing.
2. The subtransmissiojn network also has the glass Pilkington insulators used. This type of insulator also, over time, is also electrically breaking down due to hairline cracking and require replacement. The result of the insulator breaking down can lead to the loss of supply to zone substations.
3. Minimum creepage distance on 33kV insulators become an issue when a Neutral Earthing Resistor (NER) is connected on the power transformers at Transpower Grid Exit Points (GXP). A fault occurring on 1 circuit will cause voltage raise on other circuits from the GXP. With minimum creepage distance on existing insulators can cause 'flashovers' at the insulators. The result is the loss of supply to the unfaulted circuits, increasing the loss of supply to a larger area.
4. Replace the insulators on the existing arms.
5. Relace the cross-arm assembly completely, including the insulators.

Preferred option

Option 2 is the preferred option for the following reasons

The labour costs have increased to a point that to remove the existing insulators costs more than the material replacement cost of the crossarm assembly including installation. In most cases the nuts and bolts have corroded to a state where they require cutting off with power tools. New bolt holes are required to be drilled before the new insulator can be fitted.

The whole of life cycle cost also needs to be considered, which is fitting new insulators on older crossarm that will need replacing within in the next 5 to 10 years is not cost efficient

A7.15.1.1 PARKVILLE SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW 5MVA TRANSFORMER	ARR	$1,575	2022-2024

Fleet issue

Parkville 11kV was upgraded in 2018. In FY21, power transformer T1 experienced a low voltage (LV) winding failure because of lightning. We have installed our emergency spare transformer to restore the network to normal. The use of the emergency spare transformer at Parkville is a temporary arrangement until the permanent replacement has been commissioned at site.

Options

1. Do nothing, retaining the old spare transformer.
2. Purchase/install a new 5MVA transformer.

Preferred option

Option 2 is the preferred solution – a new 5MVA cabled power transformer has been purchased to replace (and scrap) the emergency spare transformer.

Option 1 is not viable as the emergency spare is an older unit and only intended for temporary reinstatement. It was assessed as a candidate for full refurbishment however it has since been decided to scrap the spare once Parkville has the new transformer installed. Relying on the emergency spare unit is not ideal as this leaves an unacceptable level of risk remaining at this N-security site.

A7.16 WAIRARAPA

A7.16.1 SUBTRANSMISSION NETWORK PROJECTS

A7.16.1.1 GREYTOWN GXP-NEW "THE KNOLL" SUBSTATION AT BIDWELLS-CUTTING

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BIDWELLS 33kV FEEDER EXTENSION TO GREYTOWN GXP	GRO	$1,840	2025-28
NEW ZONE SUBSTATION IN BIDWELLS-CUTTING	GRO	$10,926	2025-28

Network issue

This project addresses multiple subtransmission security issues and zone transformer security issues.

Contingency modelling of the Greytown-Featherston-Martinborough 33kV ring (with its 33kV spur lines to Tuhitarata and Featherstone subs) shows insufficient N-1 capacity.

An outage on the Greytown-Martinborough 33kV feeder causes the Greytown-Featherston 33kV feeder to overload at 111% thermal loading, and causes 33kV bus voltages of 89.2%, 88.8% and 89.1% at Tuhitarata, Martinborough and Hau Nui zone substations respectively.

An outage on the Greytown-Featherston 33kV feeder causes the Greytown-Martinborough 33kV feeder to overload at 110% thermal loading, and 33kV bus voltage of 90% at Featherston zone substation.

Furthermore, Martinborough, Kempton, Tuhitarata and Hau Nui are all single transformer substations and, as such, require full or near full 11kV transfer capacity.

The relivening and extension of Bidwells' 33kV feeder solves the subtransmission security issue by adding 16MVA capacity to the Greytown-Featherston-Martinborough 33kV ring and providing voltage support during contingency to all substations supplied by this ring.

The new substation at Bidwells-Cutting, which draws dual 33kV supply from the relivened and extended Bidwells 33kV feeder, will improve transfer capacity to N-security substations Kempton, Tuhitarata and Hau Nui. This will defer, for a number of years, distribution capacity upgrades and dual transformer upgrades at these substations. This new substation is to be named "The Knoll" to avoid confusion with the existing Bidwells 33kV switching station.

Options

1. Upgrade Greytown-Featherston and Greytown-Martinborough 33kV feeders. Upgrade Dairy Factory, Kumenga, Dyerville, Cologne St and Moroa 11kV feeders.
2. Upgrade Greytown-Featherston and Greytown-Martinborough 33kV feeders. Convert Martinborough, Kempton and Tuhitarata to dual transformer substations.
3. Reliven and extend existing Bidwells 33kV feeder and build new zone substation in Bidwells-Cutting.

Preferred option

Option 3 is preferred because of the better cost benefit.

In addition, not only does adding a third 33kV line to the Greytown-Featherston-Martinborough ring cost less, it also provides significantly more capacity in comparison to rebuilding the existing ring for higher capacity.

A new substation also increases distribution feeder reliability for the feeders involved in transfer capacity.

A7.16.1.2 MASTERTON GXP-CLAREVILLE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
RE-TENSION CLAREVILLE-1&2 33kV FEEDER	GRO	$1,081	2026-28

Network issue

Clareville is an AA substation that supplies approximately 10MVA of load and 4,500 ICPs in Carterton township and surrounding areas. This substation is supplied by two 33kV feeders from Masterton GXP.

Clareville substation is expected to undergo significant growth because of load increases at industrial customers such as Premier Beehive, in the near future, and council plans for subdivisions. These include industrial and commercial lots in the southern areas of Carterton and more than 2,000 residential lots in the surrounding areas during the next 30 years.

Contingency analysis shows 96.6% loading on Clareville-1 33kV feeder and 95.9% loading on Clareville-2 33kV feeder.

Clareville substation transformer upgrades are due to commence in FY23.

Options

1. Rebuild Clareville-1 and Clareville-2 33kV feeders. These two feeders have recently had pole replacements carried out.
2. Re-tension Clareville-1 and Clareville-2 33kV feeders.
3. Strengthen automated 11kV backfeeds to Clareville substation. Clareville substation is surrounded by N-security substations, with the exception of Norfolk substation. However, the distribution feeder connection to Norfolk substation is weak, and even with a full overhead 11kV line upgrade of more than 14km, because of excessive length it fails to provide a significant part of Clareville substation's full load.

Preferred option

Option 2 is preferred. As Clareville-1 and Clareville-2 feeders have already had recent pole replacements, and the conductor is believed to be in reasonable condition, a full rebuild is unnecessary. In terms of 11kV backfeed, it is overall a more economical strategy to maintain sufficient N-1 capacity to Clareville substation and use this capacity to support the surrounding N-security substations, such as Kempton and Gladstone.

A7.16.1.3 MASTERTON GXP-NORFOLK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CONVERT 1.9KM OVERHEAD 33kV DUAL SUPPLY TO UNDERGROUND	GRO	$943	2025

Network issue

The Masterton-Norfolk 33kV feeder is part of the Masterton-Chapel-Norfolk 33kV ring that supplies Chapel and Norfolk zone substations.

Norfolk substation supplies about 6.5MVA of predominantly industrial load (300 ICPs) and is of AA+ security classification. Two of the largest customers supplied by this substation, JNL (4.2MVA) and Kiwi Lumber (1.8MVA) are planning load increases in the near future.

Chapel substation supplies about 15MVA of load (4,300 ICPs) and is classified as AAA. It supplies Masterton CBD and provides some 11kV backup to feeders from neighbouring substations. Notable customers are Masterton bus depot, major supermarkets in the area, and ChargeNet EV charger. As electric vehicle (EV) use in the region expands, this load is likely to grow rapidly.

Masterton-Chapel 33kV feeder is being upgraded, and upgrades to the 11kV and 33kV switchgear at Chapel substation, and upgrades to the distribution network off Chapel substation, are also planned.

Sufficient 33kV capacity and security on the Masterton-Chapel-Norfolk 33kV ring, in combination with these planned upgrades would:

Bring Chapel substation up to standard as per its security classification.

Enable increased utilisation of excess zone transformer capacity at Chapel substation for the purpose of increasing the security of neighbouring Akura and Te Ore Ore substations, through the 11kV network. This, therefore, defers investment on the Masterton-Akura-Te Ore Ore ring, which is also short of N-1 capacity.

However, contingency modelling shows Masterton-Norfolk 33kV feeder at 163% thermal loading.

Masterton-Norfolk 33kV feeder is a 1.91km long overhead line. It is built together side-by side with the first 1.91km of the Masterton-Akura 33kV feeder. These two feeders run up Cornwall Road from Masterton GXP, cross State Highway 2, and run up Norfolk Rd until they reach Norfolk substation.

On Norfolk Rd, there is 11kV and LV overhead built under the 33kV dual line in a non-standard configuration that makes servicing the 11kV line nearly impossible to be carried out safely without causing major outages. The 11kV feeder supplies Waingawa Industrial Park and, as such, would ideally be of high reliability.

Options

1. Re-tension or rebuild with higher capacity Jaguar conductor the Masterton-Norfolk 33kV feeder in present configuration. This option fails to resolve safety and reliability issues on Norfolk Rd.
2. Convert Norfolk Road part (800m) to underground and re-tension or rebuild with higher capacity Jaguar conductor the Cornwall Rd part (1.1km) of the 2x33kV feeder.
3. Convert the entire length (1.9km) along Norfolk Rd and Cornwall Rd of the 2x33kV feeders to underground.

Preferred option

Option 2 is preferred, as the Cornwall Rd part of the dual 33kV line is in good condition.

A7.16.1.4 CHAPEL SUBSTATION-NORFOLK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
REBUILD 2.2KM OF CHAPEL-NORFOLK 33kV OVERHEAD LINE	GRO	$706	2024

Network issue

The Chapel-Norfolk 33kV feeder is part of the Masterton-Chapel-Norfolk 33kV ring that supplies Chapel and Norfolk zone substations.

Norfolk substation supplies about 6.5MVA of predominantly industrial load (300 ICPs) and is of AA+ security classification. Two of the largest customers supplied by this substation, JNL (4.2MVA) and Kiwi Lumber (1.8MVA) are planning load increases in the near future.

Chapel substation supplies about 15MVA of load (4,300 ICPs) and is classified as AAA. It supplies Masterton CBD and provides some 11kV backup to feeders from neighbouring substations. Notable customers are Masterton bus depot, major supermarkets in the area, and ChargeNet EV charger. As EV use in the region expands, this load is likely to grow rapidly.

Masterton-Chapel 33kV feeder is being upgraded, and upgrades to the 11kV and 33kV switchgear at Chapel substation, and upgrades to the distribution network off Chapel substation, are also planned.

Sufficient 33kV capacity and security on the Masterton-Chapel-Norfolk 33kV ring, in combination with these planned upgrades would:

Bring Chapel substation up to standard as per its security classification.

Enable increased utilisation of excess zone transformer capacity at Chapel substation for the purpose of increasing the security of neighbouring Akura and Te Ore Ore substations, through the 11kV network. This, therefore, defers investment on the Masterton-Akura-Te Ore Ore ring, which is also short of N-1 capacity.

Chapel-Norfolk tie feeder is an overhead line just over 7km long. Contingency modelling shows 134% thermal loading.

Options

1. Re-tension existing Dingo conductor to 70°C.
2. Rebuild line with Jaguar conductor.
3. Add new feeder to the Masterton-Norfolk-Chapel 33kV circuit.

Preferred option

The preferred solution is option 2, as it optimally addresses the capacity issue on the ring, as well as the age and condition issue on the existing Chapel-Norfolk 33kV tie feeder.

A7.16.1.5 MASTERTON GXP-AKURA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33KV FEEDER CONVERT TO UNDERGROUND	GRO	$573	2025

Network issue

The Masterton-Akura 33kV feeder is a 6.9km long overhead line and is part of the Masterton-Akura-Te Ore Ore 33kV ring that supplies Akura and Te Ore Ore zone substations. A 33kV spur off this ring also supplies Awatoitoi and Tinui zone substations.

Akura substation supplies about 13MVA of load (4,500 ICPs) and is classified as AAA. It supplies the area stretching from the northern part of Masterton City to the Mount Bruce area. The northern Masterton area is a mix of urban residential, commercial and industrial loads.

Notable industrial customers supplied by Akura substation are Breadcraft Ltd, Hansells Ltd and Webstar Ltd.

Te Ore Ore zone substation supplies about 7MVA of load and 3,200 ICPs, including Masterton Hospital. Te Ore Ore substation has AA+ security classification.

Contingency modelling shows 125% loading on Masterton-Akura feeder.

On its GXP end, 1.9km of this feeder is planned to be upgraded under the Masterton-Norfolk 33kV upgrade.

Options

Convert the 2km Akura 33kV feeder to underground.

Do nothing.

Preferred option

Option 1 is preferred.

A7.16.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Wairarapa area.

A7.16.2.1 GREYTOWN GXP

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
GREYTOWN 33kV SWITCHGEAR OUTDOOR TO INDOOR CONVERSION	GRO	$5,607	2022-2026

Network issue

Powerco neither owns nor operates any of the 33kV switchgear at Greytown substation. There are no remotely operable bus coupling devices on the Greytown GXP 33kV bus. This means that Greytown GXP 33kV bus is at N-security. Isolation or repair of a bus fault at Greytown GXP generally takes four hours or more, causing, on average, more than $900,000 in lost load per outage, as Powerco relies on Transpower work parties at Haywards GXP travelling to Greytown to carry out any isolations and fault work.

Greytown GXP hosts only 3x33kV feeder circuit breakers.

A new feeder, Greytown-Bidwells 33kV line is planned for supplementing the N-1 capacity of the Greytown-Featherston-Martinborough 33kV ring and for supplying a new zone substation at Bidwells-Cutting, which is intended to provide 11kV transfer capacity to N transformer security zone substations in south Wairarapa.

Another new feeder, Greytown-Kempton 33kV, is planned to supply Kempton zone substation. This is because council plans and rezoning make it very likely there will be substantial growth at Kempton substation during the next 20 years.

The 33kV switchyard site can only accommodate one more 33kV outdoor circuit breaker bay because of limited space.

Options

1. Do nothing.
2. Like-for-like replacement option. This option addresses risks caused by ageing switchgear and buswork. However, the 33kV bus remains at N-security without provision for the planned new circuits.
3. Outdoor expansion of 33kV switchyard at new site. This option isn't feasible because the location of the 33kV switchyard is contingent upon the location of the 110kV switchyard.
4. 33kV ties to other circuits. The problem of N-security on the Greytown GXP 33kV bus can be addressed by building tie lines to the 33kV network of other GXPs. However, the south Wairarapa area that Greytown GXP supplies is somewhat geographically isolated, with the Pacific to the south and east, and the Rimutaka and Tararua ranges to the west. The only other GXP to which this 33kV network could connect is Masterton GXP. This option requires $5m at a minimum (single overhead line and 33kV voltage regulator), along with significant Opex, reliability costs, and as much as $10m for an underground cable. It leaves the need for new 33kV feeders unresolved.
5. Construct indoor switchroom to accommodate 2x4-panel indoor 33kV switchboards, under Powerco ownership, to facilitate the connection of existing and planned circuits off Greytown GXP.

Preferred option

The preferred solution is option 5, as it provides the best cost-benefit, addressing all the network and fleet issues at minimum cost.

A7.16.2.2 AKURA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER CAPACITY UPGRADE (12.5/17MVA) WITH 11kV SWITCHBOARD FULL REFURBISHMENT	ARR/GRO	$4,494	2022-24
AKURA NORFOLK DUAL 33KV UPGRADE	GRO	$681	2024-2027

Network issue

Akura substation supplies about 13MVA of load (4,500 ICPs) and is classified as AAA. It supplies the area stretching from the northern part of Masterton City to the Mount Bruce area. The northern Masterton area is a mix of urban residential, commercial and industrial loads.

Notable industrial customers supplied by Akura substation are Breadcraft Ltd, Hansells Ltd and Webstar Ltd.

Already, Akura substation is 3MVA over N-1 transformer capacity.

The 11kV cables are under sized and have to be uprated from 95mm² Al to 300mm² or similar cross-sectional area to increase the feeder capacity.

Fleet issue

The Akura substation's transformers were manufactured in 1965 and are approaching the end of their design life. Other issues with the transformers exist because of a lack of oil bunds. This gives a high risk of oil runoff to the nearby creek – an issue raised by Powerco's Environment & Sustainability Manager that requires action.

The 11kV RPS, 12-panel indoor LMT switchboard was manufactured in 1966 and requires an arc flash upgrade. This upgrade will include replacing the existing oil circuit breakers with vacuum type circuit breakers.

Some of the RPS 11kV indoor LMT panels have compound filled switchgear terminations. There may be an opportunity to upgrade these terminations to heat shrink terminations with arc flash sensors.

Options

1. Do nothing.
2. Retain the existing transformers, upgrade the 11kV switchboard, and retain the existing 11kV feeder cables.
3. Replace the existing transformers, upgrade the 11kV switchboard, and retain the existing 11kV feeder cables.
4. Replace the existing transformers, upgrade the 11kV switchboard and the existing 11kV feeder cables.

Preferred option

Option 4 is preferred as it future proofs the site.

Options 1 and 2 are not feasible as the transformer ratings don't cover the substation firm load.

Option 3 is not acceptable as the network is still constrained by the 11kV cables..

A7.16.2.3 CLAREVILLE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER CAPACITY UPGRADE (12.5/17MVA)	GRO	$5,778	2023-26

Network issue

Clareville is an AA classified substation that supplies approximately 10MVA of load and 4,500 ICPs in Carterton township and surrounding areas. This substation is supplied by two 33kV feeders from Masterton GXP.

Clareville substation is expected to undergo significant growth, with load increases at industrial customers such as Premier Beehive, in the near future, and council plans for subdivisions. These include industrial and commercial lots in the southern areas of Carterton and more than 2,000 residential lots in the surrounding areas during the next 30 years.

The zone transformers at Clareville substation are at almost full N-1 capacity, under normal configuration of its 11kV feeders.

Options

1. Swap existing zone transformers for refurbished transformers from another substation.
2. Upgrade to a 12.5/17MVA 1 x zone transformer with new unit, and defer investment on a second transformer.
3. Upgrade both zone transformers to 12.5/17MVA with new units.

Preferred option

The preferred solution is option 3 because of its lower losses and ongoing maintenance costs.

A7.16.2.4 KEMPTON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2024
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$596	2024-25
BUNDING UPGRADE	ORS	$148	2025

Fleet issue

The existing switchroom building is at 55% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard does not meet Powerco's requirement for arc flash mitigation and poses a risk to operators. The 5MVA power transformer does not have an oil bund. In the event of an insulation oil leak or spill the oil may flow into nearby waterways.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and carry out an arc flash retrofit of the existing switchboard. Install a transformer bund.
3. Construct a new seismically compliant 11kV switchroom, and install a new arc flash rated 11kV switchboard. Install a transformer bund.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom, carry out a switchboard arc flash upgrade, and install a transformer bund. Option 3 is not preferred as it will be higher cost.

A7.16.2.5 NORFOLK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER CAPACITY UPGRADE (12.5/17 MVA)	GRO	$2,845	2025-2028
NORFOLK – MASTERTON 33KV LINE UPGRADE	GRO	$943	2025

Network issue

Norfolk substation supplies about 6.5MVA of predominantly industrial load (300 ICPs) and is of AA+ security classification. Two of the largest customers supplied by this substation, JNL (4.2MVA) and Kiwi Lumber (1.8MVA), are planning substantial load increases in the near future. Therefore, the existing 7.5/8.3MVA zone transformers may be insufficient before FY25.

Options

1. Offload all of Waingawa Rd feeder (excluding Kiwi Lumber) to Chapel St substation and defer transformer upgrade. This option is likely to reduce reliability because of the long overhead feeder length to Waingawa Industrial Park.
2. Swap the existing 7.5/8.3MVA zone transformers for refurbished 7.5/10MVA transformers.
3. Install new 12.5/17MVA transformers.

Preferred option

The preferred solution is option 3, to install new 12.5/17MVA transformers. Option 2, installing refurbished transformers, will need to be considered on a case-by-case basis, but at this time we have no suitable candidates on the network.

A7.16.2.6 FEATHERSTON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW 7.5/10MVA TRANSFORMER INSTALLATION	GRO	$768	2022-23

Network issue

Featherston zone substation supplies about 5MVA of load and just over 2,000 ICPs. Featherston substation has AA security classification and supplies Featherston township and the northern and western shores of Lake Wairarapa. Featherston substation is one of the two main 11kV backup supplies to Tuhitarata substation, which has N subtransmission security. Notable loads are Davis Sawmilling Ltd and ChargeNet EV charger. As EV use in the region expands, this load is likely to grow rapidly.

A second new 7.5/10MVA zone transformer is being installed at Featherston substation, after which Featherston substation will have N-1 transformer and limited N-1 subtransmission security.

Options

1. Do nothing.
2. Install a refurbished 7.5/10MVA transformer.
3. Install a new transformer as second transformer.

Preferred option

The preferred solution is option 3. Featherston substation has limited transfer capacity and provides much of the existing transfer capacity for nearby Tuhitarata, Martinborough and Kempton substations. Because of this criticality, option 3 is chosen. Option 2, to install refurbished transformers, will need to be considered on a case-by-case basis, but at this time we have no suitable candidates on the network.

A7.16.2.7 MARTINBOROUGH SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
2x33kV CIRCUIT BREAKER REPLACEMENT	ARR	$1,379	2028-29

Fleet issue

The 33kV outdoor Takaoka & AEI circuit breakers are oil quenched and past their expected service life, with no parts available. The installed protection is not up to Powerco latest specifications.

Options

1. Do nothing.
2. Install two new outdoor 33kV circuit breakers.
3. Construct a new seismically compliant 33kV switchroom complete with new 33kV circuit breakers.

Preferred option

Option 2 is the least cost, preferred solution.

Option 1 is not viable due to the safety risk and operational risk from having no spare parts for repairs.

Option3 is not preferred as it will be higher cost.

8.1 OVERVIEW

This Chapter includes information to meet the new regulatory requirements published by the Commerce Commission in November 2022. Where the required information is already included in this Asset Management Plan, rather than duplicating it here, we have included a reference to the relevant chapter.

8.2 NOTICE OF PLANNED AND UNPLANNED INTERRUPTIONS

8.2.1 PLANNED OUTAGES

Powerco operates an interposed customer relations model with energy retailers. This means retailers are the customer's primary contact point.

If the planned outage is on Powerco's HV networks, Powerco notifies retailers of the need for the outage and which connections will be affected. The notification is sent via the Registry transfer hub (or email). Retailers, in turn, notify customers according to their notification preferences. Use of system agreements with retailers stipulates how many days in advance notification must be provided.

If the planned outage is on Powerco's LV network, the contractor performing the work may notify customers directly via a physical form or door-knocking if only a few customers will be affected. Retailers are informed of this notification via the Registry transfer hub (or via email).

Powerco's website will automatically display planned power cuts. Powerco's website allows anyone to search for planned outages affecting a specified property within the next 30 days. Customers can contact Powerco directly via a dedicated email address customerexperience@powerco.co.nz if they have any questions or concerns about a planned outage. Customers can request changes to planned outages via their retailer or directly via Powerco's website.

8.2.2 UNPLANNED OUTAGES

With the interposed customer relations model, energy retailers are the primary customer contact point for most communication regarding unplanned outages. Retailer fault teams can log faults directly into Powerco's Outage Management System (OMS). In addition, they can obtain status updates from OMS or Powerco's Customer Services team via a dedicated business-to-business phone line.

Powerco's website provides information on unplanned power cuts. This is available to retailers and end customers. The website is fed from OMS, and a known fault logged in OMS will automatically be shown on the website. Powerco's Customer Services (Dispatch) team can manually update the status of outages on the website.

8.3 VOLTAGE QUALITY

Powerco engineers its LV system through a commissioning process that optimises LV Power quality. Post commissioning Powerco monitors its HV network at the main substation and periodic positions such as voltage regulators or remote control switches. Power quality is maintained for contingent events and works using power system simulation software which ensures HV Voltage levels are maintained at an acceptable level.

To improve LV monitoring, Powerco has been deploying Low voltage monitors at its distribution substations. Specifically, multi circuit LV distribution transformers in towns. Powerco has installed some 500 multi circuit LV monitors and is in the process of deploying 750 ground and pole mounted units per year during the next 10 years.

Powerco ensures ongoing Power quality through direct monitoring where LV monitors are installed. Where monitors are not installed, voltage quality is managed through a controlled process for the introduction of new loads, this includes accepted assumptions of capacity constraints (such as transformer capacity and ADMD values (After Diversity Maximum Demand) and voltage drop calculation of the LV distribution network. Where ADMD value can be influenced by industrial loads, suspected consumer load increases, customer complaints or excessively high Maximum Demand Indication, Powerco may install a temporary (or permanent) monitor to assess loading and voltage condition.

Where voltage quality issues are known Powerco will commence the necessary capital upgrade works required, this may include increasing distribution transformer capacity, moving LV open point to an adjacent transformer, installing new LV circuits or upgrading LV conductors as required.

Voltage quality issues are often initiated by a customer complaint or are an escalation event during maintenance work. To confirm a voltage quality issue we typically install a temporary logging device that indicates network demand, harmonics and voltage noncompliance.

If issues are found to be valid, Powerco will notify customers of any work that may be required through a retailer notification process informing the customer of any outages required. The reasons for the outage will often be disclosed during the retailer notification process.

Key improvements planned to manage voltage quality issues include:

- Increasing the number of real time monitors installed on the rural and urban LV network
- Operationally managing the LV system in a similar way to operating its HV network.

- Partnering with transformer manufacturers to prepare transformer cubicles for LV monitoring equipment
- A network wide LoRaWan communication system that can enable monitoring even at the edge of the distribution network
- Improvements to Data quality of its LV GIS data
- A program of replacement of LV link boxes and control points that allows safer and easier switching of the LV distribution network
- Direct inputting of LV monitoring data to SCADA and outage management systems
- LV network schematics implemented in SCADA systems
- An enhanced process to allow quicker deployment of LV monitors for customer complaints or suspected network issues
- Developing advanced analytical software that can automate the identification of LV network issues such as voltage, Harmonics, Overloading and balancing
- Implementing OMS and web page enhancement that can inform customers and retailers of LV outages real time
- Mid and end point voltage monitoring of LV reticulation network

Chapter 7.2 described our enhanced network response programme that includes expanding voltage and frequency control applications.

8.4 CUSTOMER SERVICE PRACTICES

Our customer service practices are discussed in the following chapters of this AMP:

- Customer engagement protocols - Chapter 9.6
- Customer and community goals and initiatives - Chapter 5.6
- Specific customers and community targets we have set ourselves for the planning period - Chapter 8.3
- Customer strategy – Chapter 6.4
- Changing customer expectations – Chapters 2.3 and 5.6

Our approach to planning and managing customer complaint resolution is covered below.

8.4.1 COMPLAINTS MANAGEMENT

To meet the definition of a complaint, a communication must contain both an expression of dissatisfaction and an expectation (either implicit or explicit) of a response or resolution. In most cases, a claim will meet the definition of a complaint.

The Energy Complaints Scheme requires that Powerco comply with a documented complaints process appropriate to the nature of its services and the scale of its operations, including providing and keeping up-to-date information about the staff member(s) responsible for complaint handling.

The Customer Hub Manager co-ordinates the complaints management process via Customer Resolutions Officers (CROs). . Communications are received via various channels, and it is the Complaints Resolutions Officers' role to assess whether a communication meets the agreed definition of a complaint. If so, a complaint is recorded in Powerco's Customer Relationship Management System (Salesforce Service Cloud), and assigned to a CRO. The CRO is responsible for all subsequent communications with the complainant and the resolution of the complaint.

Powerco has two CROs (one for each electricity region – East and West). In addition, the Customer Hub Manager provides an escalation point for complaints and is responsible for maintaining Powerco's relationship with Utilities Disputes and driving continual improvement.

8.5 PRACTICES FOR CONNECTING NEW CONSUMERS AND ALTERING EXISTING CONNECTIONS

Residential customers requiring a new connection will generally first contact an electrician. Some electricians will manage the connection process, while others will direct customers to our Customer Services team.

When a customer contacts us, we supply them with our list of approved contractors.[5] These contractors work with the customer to determine what is required for their electricity supply, and they provide the customer with 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. As a result, the customer can 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 and subdivision developers will contact us directly to discuss their connection requirements. Alternatively, they often work with industrial

[5] There is also a list of approved contractors on our website https://www.powerco.co.nz/get-connected/electricity/powerco-approved-contractors

power specialists who are familiar with our requirements and standards for connection.

8.5.1 CONNECTION TIMEFRAMES

Residential connections

The typical timeframe is around six months. How long it will take depends on how much work is required to enable the connection, the availability of the Powerco-approved contractor, the level of demand for new connections, and the lead times to source electrical equipment.

Large commercial, industrial, and residential developments

How much network upgrade work is required will depend on factors like how much power the site needs, where our network is in relation to the site and who else is already using power in the area. If the project needs our National Grid operator Transpower to upgrade one of their Grid Exit Points, design and construction can take several years.

Here's an indication of the typical timeframes for a significant residential development (100 lots or more) or building or upgrading a large commercial or industrial site:

- 6 - 12 months to build a network line or cable to deliver electricity to your site.
- 18 - 24 months to upgrade one of our substation's transformers.
- 24 - 36 months to upgrade switchboards or construct substation housing.
- 12 - 24 months to upgrade a circuit that connects one of our substations to a Transpower substation.
- 2 - 4 years to upgrade a Transpower Grid Exit Point.

Our customer connection process is set out on our website.

8.6 NEW CONNECTIONS LIKELY TO HAVE A SIGNIFICANT IMPACT ON NETWORK OPERATIONS OR ASSET MANAGEMENT PRIORITIES

How we forecast new demand and assess its impact on our network is discussed in the following chapters of this AMP:

- Demand forecasting methodology – Chapter 9.3
- The impact of demand growth on network development – Chapter 6.3
- Our current observations of distributed generation, electric vehicles, and storage trends - Chapter 7.2
- The timing and uncertainty of new demand, generation, or storage capacity – Chapters 3 and 7
- Consideration of other factors, e.g. network location – Chapters 3 and 7
- Risk to the network posed by uncertain new demand – Chapters 3 and 7

8.7 INNOVATION PRACTICES

Our innovation practices are described in detail in Chapter 7 of this AMP.

APPENDIX 9 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 overviews the significant opportunities and challenges we foresee over the next ten years for electricity distribution and how Powerco intends to respond to these. Chapter 3.5 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 4 to 7. 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 3. 3.3.2: Our corporate objectives and their relationship with the AM process is discussed in Chapter 3.2and Chapter 5. 3.3.3: Chapter 3.2 identifies the key corporate plans, policies, and standards used to guide our asset management planning. 3.3.4: Chapter 6 demonstrates the line of sight from our corporate plans and objectives to our asset management strategies 3.3.5: Chapter 5 maps our corporate goals into our asset management objectives. These asset management objectives are broken into specific strategies in chapter 6.
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 2023 to 31 March 2033, as described in Chapter 3.3.
3.5 The date that it was approved by the directors	The AMP was approved on 23 March 2023 (refer to Appendix 10).
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 Chapter 3.4. A more detailed description of each main stakeholder's interests and how these are identified and accommodated in the asset management plan is provided 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: Chapter 9.16 outlines the responsibility of our board 3.7.2: Chapter 9.16 outlines the responsibilities of our Executives and the structure and functions of our Electricity Team. Chapter 9.17 outlines how we govern asset management activities. 3.7.3: Chapter 9.16 outlines how our field-works are outsourced. Chapter 9.8 describes our works management.

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, 3.8.3, 3.8.4: Chapter 24 describes the key assumptions and uncertainties in the development of the AMP. 3.8.5: Chapter 24 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.	Chapter 24 describes our forecasting inputs and assumptions. Chapter 2 overviews the significant opportunities and challenges we foresee over the next ten years for electricity distribution. Chapter 2.2 describes the key assumptions that underpin our demand forecasts. Chapter 4 highlights the externalities and uncertainties that Powerco considers when developing the strategy for our business. It also signals various macro drivers that drive our strategies and plan. The Capex and Opex forecasts reflect our current best view on how we could meet the investment challenges of the coming decade using our current assumed base case assumptions. However, there is a reasonable likelihood that these assumptions do not sufficiently cater for actual demand growth. Therefore, we have prepared a high scenario forecast and included it in Chapter 2, 'A decade of change ahead' to inform stakeholders of potential forward needs.
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 details Powerco's vision, mission and values and describes the interaction of these objectives with the Electricity Asset Management Strategy and Asset Management Policy. It also describes initiatives that Powerco is undertaking to achieve its objectives. Chapter 6 describes our core asset management strategies. Figure 6.1 illustrates how our Corporate Objectives, Asset Management Policy, and Asset Management Objectives feed into our various strategies. Chapter 7 outlines our evolving asset management strategies. Chapter 9 discusses lifecycle management and describes the organisational structures, responsibilities and accountabilities related to system performance, risk and cost control.
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	Our information management systems are described in Chapter 9.18. The systems used to manage asset data and record asset condition are described in chapter 9.19. The governance structure for ensuring data quality and systems modifications is described in Chapter 9.17. Our information technology architecture is described in chapter 9.18.1. A description of the systems and controls to manage the quality and accuracy of asset management data is provided in Chapter 23.2.
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 23.2 and 23.3. Disclosure schedule 12a in Appendix 2 outlines our data completeness for each asset type.
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: Chapter 9.3 outlines how our maintenance and vegetation programme is developed. Routine maintenance regimes for each fleet are listed in chapter 14-21. 3.13.2: Chapter 9.7 outlines how we develop our capital works programme. Chapter 9.8 outlines how we develop individual projects and Chapter 11 outlines our major network development projects for each area. 3.13.3: Our asset management and network performance measurements are listed in chapter 8

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 9 describe Powerco's Asset Management System and the processes contributing to Powerco's Strategic Asset Management Plan. Our Asset Management System is illustrated in Figure 9.1. There are no aspects of the AMS that are outsourced. Chapter 9.11 to 9.15 describes how we approach risk management in relation to asset management at Powerco. Chapter 9.14 describes our audit and review procedures in relation asset management at Powerco.
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	An overview of our key stakeholders and the key discussion with them is outlined in Chapter 3.4. Appendix 3 further outlines the interests for our stakeholders. Chapter 9 outlines the variety of means we use to engage with our customers and capture their feedback. We undertake regular staff engagement surveys, promote open-door access to senior managers, undertake regular team building activities, and are in the process of developing a Communications Plan.
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	Figures are reported in constant FY23 dollars.
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	The 2023 Electricity AMP is written so that an interested person external to Powerco can understand our investments and plans. (1) & (2): An overview of the AMP is provided in Chapter 3.5. Chapters 5 to 9 describe how we manage our assets. Cost and performance efficiencies are discussed throughout the AMP. A glossary is provided in Appendix 1 to assist understanding; and (3): Risk is discussed in Chapter 9 and Appendix 5. High Impact Low Probability (HILP) events are specifically addressed in Chapter 9.15.
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 Chapter 3.6 4.1.2: Large consumers and customer developments that potentially impact our distribution network are described in Chapter 11. 4.1.3: Load characteristics for our two network regions are described in Chapter 3.6, and for each of our planning areas throughout Chapter 11. Detailed demand forecasts are included in Appendix 6. 4.1.4: The load characteristics for each area are provided in the figures and tables in Chapter 11. Total energy delivered is provided in Table 3.2 in Chapter 3.6.

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 for each region are described in Chapter 11. Chapter 11.15 identifies the grid Exit Points (GXP) that we connect to on our network. The list of embedded (distributed) generators connected into Powerco networks is in Chapter 11.16. 4.2.2: The subtransmission system is described using text, maps and tables 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 14 to 20 describe the distribution system in more detail. 4.2.4: Chapter 11 outlines the demand and constraints for each of our Zone Substations. Chapter 17 outlines the plans for renewing our zone substations. Appendix 7 outlines the key options considered for managing the zone substation. Chapter 18 outlines our plans for managing our distribution transformers through their lifecycles. 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. 4.2.6: Chapter 20 describes our secondary systems portfolio and summaries our associated fleet management plan. 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.	Chapter 11 and Appendix 7 outline our network development and significant renewal plans for each our regions. Refer to the chapter details listed above.
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 3.7. Detailed information on each of our asset portfolios is provided in Chapters 14-20.
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.	The asset categories listed in 4.5.1- 4.5.8 are discussed in Chapters 14-20. 4.5.9: GXP meters installed at Transpower bulk supply points are discussed in Chapters 20.6 4.5.10: Chapter 17.3.1 discusses our mobile substation. 4.5.11: Powerco owns: • Several 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 15.5 • A small diesel generator used to back up our central control room power supply. • A 2MW/2MWh Battery Energy Storage System and 2.5MVA diesel generator located at the Whangamata Zone Substation. This asset is described in a grey box callout in Chapter 17.5 In FY24, Powerco plans to commission several small backup generators in remote parts of the western network to provide resilience improvements to these communities. Several larger generation units, expected to be commissioned in FY24/25, are also planned for the northern Coromandel, improving security of supply and resilience.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
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 8 sets out our network targets for the planning period. This chapter describes how the targets are aligned with the business strategies and asset management objectives.
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 8.3 discusses our unplanned SAIDI and SAIFI targets. Chapter 8.6 discusses our planned SAIDI and SAIFI targets. Schedule 12d in Appendix 2 provides our forecast values for the next five years.
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 8. 7.1: Chapter 8.3 provides customer-orientated indicators. The consumer types that we service are listed in Table 3.1. 7.2: Chapter 8.5 outlines the specific targets we have set for Asset Stewardship during the planning period.
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.	The basis for targets is discussed in Chapter 8.
9. Targets should be compared to historic values where available to provide context and scale to the reader.	The figures throughout Chapter 8 provide historical performance where available.
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.	Expenditure forecasts reflect the investment we believe is needed to achieve the performance targets listed in Chapter 8.
Network Development Planning	
11. AMPs must provide a detailed description of network development plans, including:	Network development planning is discussed in Chapter 10 and 11.
11.1 A description of the planning criteria and assumptions for network development	The planning criteria and assumptions are discussed in Chapter 6.3.
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	Our plans to use a probabilistic planning approach is discussed in Chapter 6.3 and Chapter 7.4.
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 14 to 20.
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	The use of standard designs and standardised assets is discussed throughout Chapters 14 to 20.
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.	Chapter 5.2 describes our environmental aspirations and objectives, including appropriate success measures, associated with energy efficiency improvements.
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.	The criteria used to determine the capacity of network equipment is discussed in Chapters 6.3. The capacity of the network and equipment is also discussed in Chapter 11 – Area plans.
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.	Chapter 9.4 describes how network development is prioritised.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
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	11.8.1: The demand forecasting methodology is described in Chapter 9.3.4 11.8.2-4: Forecasts at zone substation level, constraints and the impact of distributed generation are provided in Chapter 11 (refer to tables and figures for each region) and Appendix 6.
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	11.9.1, and 11.9.2: Appendix 7 discusses all network and non-network options considered for major projects. 11.9.3: Chapter 4 provides an overview of the forces shaping our network and the broad strategies that need to be employed to address them. Chapter 7 and Chapters 10.5 to 10.8 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 summarises our Area Plans and describes all significant network developments within the planning period. The timing for major projects in chapter 11 and appendix 7. Appendix 7 describes the technical options, preferred solution, and proposed timing of material network development projects outlined in Chapter 11.
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.	Our views on the uptake of flexibility services, such as distributed energy resources (DER) are outlined in Chapters 2 and 7.2. Our policies for connecting distributed generation are available on our website https://www.powerco.co.nz/get-connected/distributed-generation
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	Chapter 7, and Chapter 9.5 describe how we are increasingly considering non-network solutions as alternatives to, or in conjunction with, network investments for the deferment of, or instead of, traditional network investments.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
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 key drivers of asset maintenance and renewal are described in Chapter 9.3.
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 6.2.3 and 9.3. Each asset class fleet plan in Chapters 14 to 20 contains known issues and programmes of replacement, together with expenditure forecasts by asset category.
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: These are described in Chapter 6.2. Chapters 14-20 describe the renewal and replacement criteria for each asset fleet. 12.3.2: Chapter 6.2 describes our fleet management strategy to minimise asset lifecycle costs. Chapter 7 outlines our emerging strategies for enhancing network performance and improving asset utilisation. 12.3.3-5: Chapters 14 to 20 documents our replacement and renewal policies and programmes for our asset fleets. Key asset replacement and renewal projects over the planning period are identified in Appendix 7.
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.	Our fleet management plans are grouped by the asset categories listed in 4.5 above. See Chapters 14 to 20.
Non-Network Development, Maintenance and Renewal	
13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including:	Chapter 23 describes our non-network assets and contains associated maintenance plans, renewal plans, planned capital investments and expenditure forecasts.
13.1 A description of non-network assets	Chapter 9.18 provides a description of our non-network information system assets. Chapter 23.5 outlines our facilities.
13.2 Development, maintenance and renewal policies that cover them	Chapter 23 outlines our non-network renewal and development plans for our non-network assets.
13.3 A description of material capital expenditure projects (where known) planned for the next five years	Chapter 23 outlines our non-network expenditure.
13.4 A description of material maintenance and renewal projects (where known) planned for the next five years	Chapter 23 outlines our non-network renewal and development plans for our non-network assets, with expenditure forecasts in Chapter 24.
Risk management	
14. AMPs must provide details of risk policies, assessment, and mitigation, including:	Chapter 9.11 to 9.15 provides an overview of our risk management practice, 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 9.14 and 9.15.
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, 14.3: Chapter 7.6 describes our proposed response to climate change risk. HILP events are discussed in chapter 9.15.
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 14.2.	
14.4 Details of emergency response and contingency plans.	14.4: In Chapter 9.15 we discuss our emergency preparedness systems and response to civil emergencies.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
Evaluation of performance	
15. AMPs must provide details of performance measurement, evaluation, and improvement, including:	Chapter 8 sets out our Network Targets for the planning period, as well as our historical performance against these targets. We use these to gauge our performance in delivering our Asset Management Objectives.
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	15.1: Project and expenditures variances are described in Appendix 4. Additional material is provided throughout Chapters 14 to 20. Appendix 2.9 discusses any material changes in the approach to the population of information disclosure schedules.
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 8 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.	Chapter 8.6 outlines the progress of our asset management maturity. Schedule 13 in Appendix 2 outlines specific process improvement initiatives aimed at improving our asset management maturity.
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 8 includes commentary on initiatives to improve our performance against our network targets. 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. It also serves to provide an early indication of areas requiring intervention. Our asset management goals and supporting initiatives are listed in Chapter 5.
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.	Chapter 1.4 describes how we have ensured our expenditure forecasts are realistic. Chapters 5-8 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 9.16 describes the processes and organisational structure we use for implementing the AMP.
Requirements to provide qualitative information in narrative form	
17. AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
Notice of planned and unplanned interruptions	
17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	Appendix 8.2 describes how we communicate with consumers regarding planned and unplanned interruptions.
Voltage quality	
17.2 a description of the EDB's practices for monitoring voltage, including:	Our practices for monitoring voltage are described in Appendix 8.3. Chapter 7.2 described our enhanced network response programme that includes expanding voltage and frequency control applications.
17.2.1 the EDB's practices for monitoring voltage quality on its low voltage network;	
17.2.2 work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
17.2.3 how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	
17.2.4 how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	
17.2.5 any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above;	
Customer service practices	
17.3 a description of the EDB's customer service practices, including:	Our customer service practices are discussed in the following chapters of this AMP: • Customer engagement protocols - Chapter 9.6 • Customer and community goals and initiatives - Chapter 5.6 • Specific customers and community targets we have set ourselves for the planning period - Chapter 8.3 • Customer strategy – Chapter 6.4 • Changing customer expectations – Chapters 2.3 and 5.6
17.3.1 the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	
17.3.2 the EDB's approach to planning and managing customer complaint resolution;	Our approach to planning and managing customer complaint resolution is covered in Appendix 8.4
Practices for connecting new consumers and altering existing connections	
17.4 a description of the EDB's practices for connecting consumers, including:	Our practices for connecting consumers is discussed in Appendix 8.5
17.4.1 the EDB's approach to planning and management of- (a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and (b) alterations to existing connections (offtake and injection connections);	
17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections;	
17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections; and	
17.4.4 commonly encountered delays and potential timeframes for different connections.	
New connections likely to have a significant impact on network operations or asset management priorities	
17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	How we forecast new demand and assess its impact on our network is discussed in the following chapters of this AMP: • Demand forecasting methodology – Chapter 9.3 • The impact of demand growth on network development – Chapter 6.3 • Our current observations of distributed generation, electric vehicles, and storage trends - Chapter 7.2 • The timing and uncertainty of new demand, generation, or storage capacity – Chapters 3 and 7 • Consideration of other factors, e.g. network location – Chapters 3 and 7 • Risk to the network posed by uncertain new demand – Chapters 3 and 7
17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	
Innovation practices	
17.6 a description of the following:	Our innovation practices are described in detail in Chapter 7 of this AMP.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	
17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	
17.6.3 how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;	
17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	
17.6.5 the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	

Directors' Certificate – 2023 Electricity AMP

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pursuant to clause 2.9.1 of Section 2.9

We, John Laughlin 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 both align with Powerco's corporate vision and strategy and are documented in retained records.

Director	Director
23-3-23	23-3-23
Date	Date

This page intentionally left blank