WAIPĀ NETWORKS

ASSET MANAGEMENT PLAN

2024

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FOREWORD FROM THE CHIEF EXECUTIVE

Welcome to our 2024 Asset Management Plan (AMP). This plan reflects a significant step in our asset management journey – one that we committed to in 2023 and will continue to progress.

In this AMP, we have:

- Included comprehensive fleet plans for our key asset classes that set out the lifecycle strategies for asset management.
- Updated our network development plan, which includes new projects and programmes that enhance our network and respond to changes;
- Outlined our strategy to enhance the resilience of the network;
- Outlined our approach to developing a network transformation roadmap that provides a long-term plan for delivering electricity and enabling customers to exercise choice in a decarbonised world;

This plan sets out the key focus areas for our business and our investments. Our work on our regional supply security, transformation and resilience strategies is ongoing. In the coming 12 months, we will focus on future sub-transmission architecture review for the Te Awamutu network, natural hazard study, examining key elements under the network transformation roadmap and refining our approach to support the transformation.

We expect further changes to our forecast expenditure in the future, based on our evolving asset management program and changes to both customer requirements and supply chain conditions. Managing infrastructure assets requires considering a range of factors. Ensuring our infrastructure enables our region to successfully decarbonise, understanding and delivering the future electricity security and resilience expected by our customers, and ensuring a just and fair energy transition for our community are key considerations that define our asset management approach.

I invite you to read our 2024 AMP to understand how we are preparing our electricity network to support our Region's future.

Ngā mihi,

Sean Horgan
Chief Executive

1. EXECUTIVE SUMMARY

1.1 Progress on our asset management journey

Last year, we commenced our asset management journey to ensure we deliver electricity to our customers in a way consistent with New Zealand's electricity future[1]. This Asset Management Plan (AMP) reflects our business' evolution toward an electrified, net-zero future. We have made significant progress on our journey, yet more work is still ahead. In this AMP, we have included a new section on our network transformation, revised our network development plans, defined our resilience strategy, and introduced fleet plans for our key asset classes.

This executive summary highlights the key factors driving investment and performance, the strategies adopted to ensure the network responds to those factors, and the key programmes and projects supporting the strategy.

The ten-year forecast capital expenditure (capex), excluding non-network assets, has increased by $9m (6%) compared to AMP 2023, mainly driven by the additional works resulting from the revision to our development and lifecycle plans ($25m increase) and offset by customer connection ($16m reduction due to change in budgeting method). Our assessment of inflation based on observed Wāipa cost escalation is higher than the PPI for the same period, and this has also added to the capex increase.

We have progressed in our review of existing programmes and projects to align them to the asset management strategy, and the changes can be seen in the development plan and lifecycle plan sections. Over the next 12 months, we will work on detailed projects and programmes supporting the transformation and resilience strategies. As a result, we expect the forecast expenditure from FY30 will increase.

1.2 Purpose and structure of this AMP

This AMP communicates Waipā's approach to facilitating the safe, reliable, and cost-effective distribution of electricity to customers in our region. We are committed to the long-term stewardship of an electricity network that meets the needs of our stakeholders and supports the livelihoods of the people and businesses throughout the areas we serve.

We are seeking to communicate the alignment of our asset management strategy and the needs of our stakeholders. To aid this approach, this executive summary and the AMP are organised into three parts:

- **Part 1:** The key issues facing the network;
- **Part 2:** Strategies to address the key issues;
- **Part 3:** Implementation plans to deliver the strategy and the required level of performance.

This AMP continues to provide all the information to assure our stakeholders that:

- Our assets are being managed for the long term.
- The required level of performance is being delivered (and where there are gaps, improvement plans are being implemented).
- Our business is efficient (so the distribution prices are no higher than need be).

A reconciliation of the Information Disclosure requirements is included in the appendices.

1.3 The network

We own and operate the electricity distribution assets in Cambridge, Te Awamutu, and their surrounding rural areas. Our network covers parts of the Waikato, Waipā, Otorohanga, and Waitomo Districts.

We convey electricity on behalf of many energy retailers from Transpower's Cambridge and Te Awamutu Grid Exit Points (GXPs) via interconnected 11kV feeders, 11kV/400V transformers, and associated 400V/230V reticulation to around 29,000 customers. We also own the 110kV transmission line from Transpower's Hangatiki GXP to the Te Awamutu GXP, which was commissioned in 2016 to improve the security of supply to Te Awamutu.

Our network currently services all customers via its 11kV and 400V distribution networks. Over the past decade, the distribution network has been enhanced by adding additional feeders and voltage regulators to cater to growth and automated line reclosers to improve reliability. This incremental approach has mostly kept pace with growth. However, the increasing network demand and forecast growth have reached a point where an alternative network architecture is required. The next step in our work will be determining the long-term subtransmission and distribution network architectures that serve the growing demand.

Work on the Cambridge subtransmission network and new zone substation is in progress, and we envisage a similar shift for the Te Awamutu GXP supply area in the next 5 to 10 years. In FY25 we will conduct a network architecture study and quantify the costs of the possible future architecture

[1] *Net-zero future refers to a state in which the greenhouse gases going into the atmosphere are balanced by removal out of the atmosphere.*

(e.g., subtransmission, zone substations, and distribution). The costs will then be included in our expenditure schedule in future AMP submissions.

We are owned by the Waipā Networks Trust (the shareholder representing all connected customers). The customers connected to our network are the beneficiaries of the Trust.

This AMP sets out the effective stewardship of the business for the benefit of customers, and other stakeholders.

We are subject to "light-handed" regulation through the Information Disclosure regime administered by the Commerce Communication under Part 4 of the Commerce Act.

Summary of Part 1: The key issues facing the network

1.4 Summary of performance

The body of this AMP includes the full suite of performance metrics, all of which are important. At a strategic level, reliability and delivery performance are key inputs in developing the asset management strategy. We comment on these performance measures below.

Reliability performance

Figure 1 shows the unplanned reliability performance since the financial year 2013 (FY2013)[2] as measured by unplanned SAIDI[3]. Unplanned reliability has generally been satisfactory and met the target in six of the last ten years (and as measured by SAIFI, reliability met the target in nine of the previous ten years). The underlying reliability of the network has been acceptable, but we experienced several "one-off" events that caused actual performance to exceed target in FY15, FY20, FY22 and FY23.

The reliability targets in Figure 1 have evolved to ensure they provided the right incentives for the business4 in the corresponding periods. From FY2021, our measurement of reliability performance is consistent with fully regulated EDBs and excludes major events like Cyclone Dovi and Gabrielle (by normalisation). We have included the major weather events in Figure 1 as customers felt their impact while it is excluded from a measurement standard.

Planned outages have exceeded the target for three out of the last ten years. The higher planned outage reflects the specifics of the work programme in those years.

We have experienced a deterioration in headline reliability (as shown in Figure 2), mainly due to factors outside our control. The primary causes of the deterioration in headline SAIDI were adverse weather and third-party damage to the network. Cyclone Dovi and Gabrielle were the material contributors to adverse weather (we discuss this in more detail in the key issues section below).

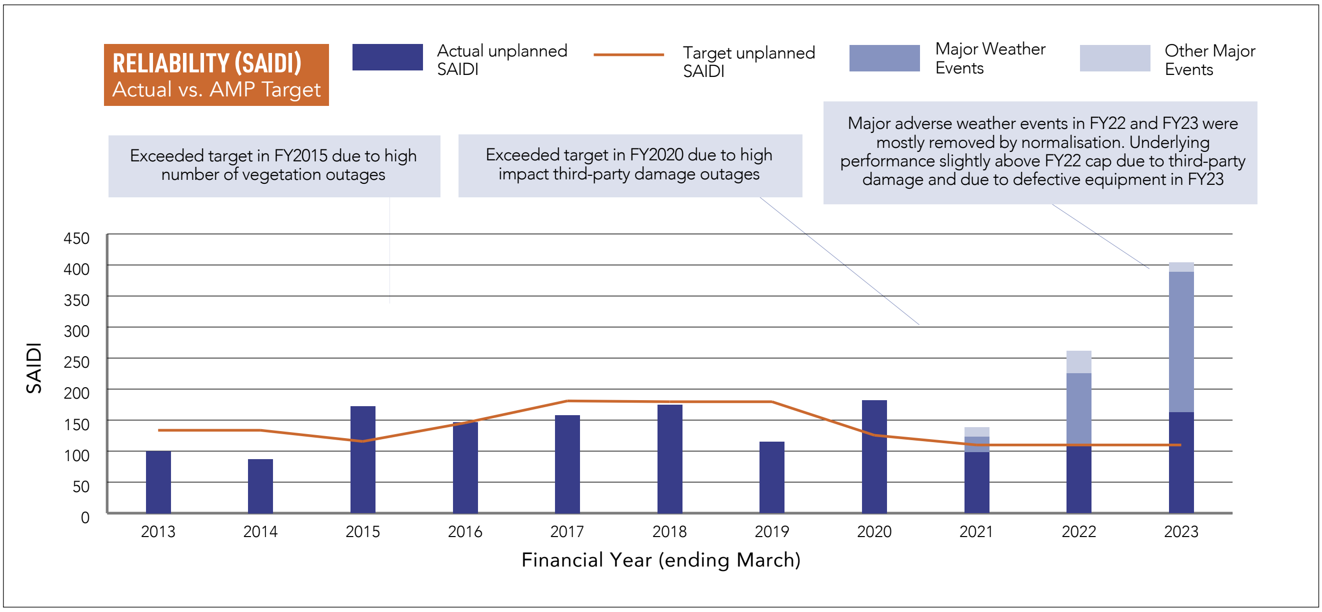

Figure 1: Historical unplanned reliability performance

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[2] *Wāipa Networks financial years range from 1 April to 31 March*

[3] *SAIDI, System Average Interruption Duration Index, is a measure of the average number of minutes customers were without supply for the year. Unplanned refers to the outage not being a result of planned work but because of other causes, like adverse weather, car vs pole or equipment failure.*

[4] *For FY2013 to FY2015 were set to reflect improvement over historical averages. From FY2016 to FY2020, the target was set at one standard deviation from the prior 5-year average. From FY21, the target cap was set based on the DPP3 methodology. The normalisation includes the current targets, and actual measurement differs from prior periods. The historical targets are as disclosed in the relevant year's AMP Schedule 12d.*

The increase in third-party damage reflects the increase in economic activity, population, and vehicle distance travelled in the region. We discuss this in more detail in the report's body.

We experienced an increase in defective equipment outages in FY23, particularly crossarms, 11kV conductor/cable, and air-break switches (ABS). We currently have an intensive renewal programme for the crossarms and ABS scheduled for the coming year. Our new fleet plans will progressively address other asset classes.

Vegetation interference continues to be a material cause of outages. Interference outside the 2.6 m notice zone for spans <150 m and 4 m for long spans continues to be a material issue. Obtaining customer approvals to trim trees (inside and outside of the notice zone) remains an issue that needs to be resolved as part of our vegetation management strategy.

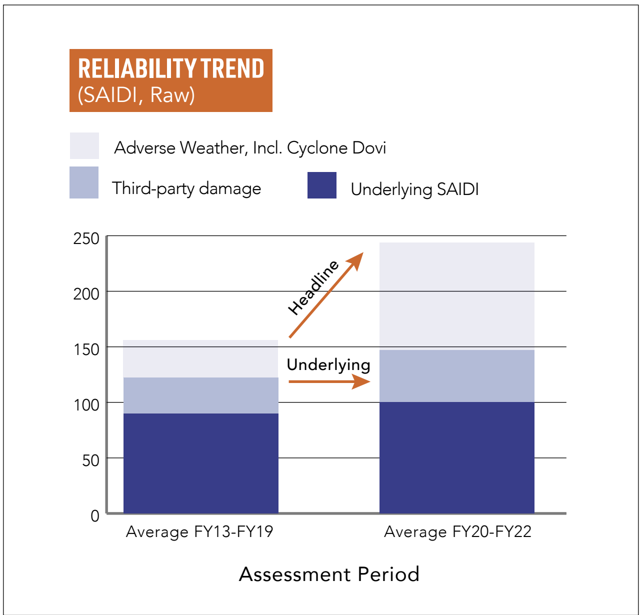

Figure 2: Reliability trend

Delivery of the work programme

Over the past four years, total opex has been within 6% of the forecast. Vegetation expenditures were below target due to resource constraints and COVID-19 limitations between FY20 and FY22 but increased materially in FY23. This increase in FY23 reflected greater work volumes and increased traffic management costs. System interruption and emergency expenditures have been consistently above target due to storm events. We have materially increased our forecast expenditure for these two categories in this AMP.

Network capital expenditures were behind forecasts between FY20 and FY22. This was driven mainly by consenting delays on the Swayne Road diesel generators (for managing peak demand at Cambridge GXP) and several capital programmes, as internal resources were constrained during COVID-19. In FY23, we exceeded the forecast due to a material increase in customer connection work (partly a catch-up from COVID-19-related delays).

Non-network capital expenditure significantly exceeded the budget in FY22 and FY23 due to land costs to support future network development.

Given the forecast increase in opex and capex over the next ten years, our business is focused on improving work plan delivery (which is described below).

1.5 Customer feedback

We survey our customers annually and regularly engage with key customers and community organisations. Several EDBs in the industry use the survey, which serves as a basis for benchmarking. Last year's survey results indicate that overall customer satisfaction was 63%, slightly above the peer group average of 61%, and an improvement over last year. We continue to perform well in terms of value for money and reliability.

We are very pleased with the significant improvement to our image and reputation from a customer perspective. The business has focused on this, and the substantial improvement from 55% to 65% is very pleasing.

We remain focused on supply reliability to ensure fewer outages, improving response times, and communicating. The direction outlined in this AMP is consistent with the feedback received.

We have started the journey to enable customers' views to be better incorporated into our planning and asset management objective. This will be a two-way process as we must better communicate our future investment programmes and the associated implications to our communities and customers. The network transformation and development sections provide a solid starting point for future engagement.

1.6 The key factors that are driving investment and performance

This AMP sets out the range of programmes and projects to address a wide range of business-as-usual safety, network, customer, environmental, and regulatory issues. Navigating through this detail can be difficult, so we have highlighted the most important factors driving investment into our network and our performance being delivered from it. The four key factors are:

- The high regional population and industrial growth are driving demand growth.
- The need to manage future demand growth due to electrification.
- The aging of the network assets.
- The increasing incidents and impact of adverse weather events.

These factors drive the need for greater maturity in asset management to manage the issues above.

These factors are discussed in more detail in the body of the AMP and will change over time, but in brief:

The high regional population and industrial growth driving demand growth

Since 2013, we have consistently experienced the third-highest customer connection growth (in relative terms) of any distribution business in New Zealand. This has been driven by regional population growth of 2.8% p.a. Waipā has also experienced industrial demand growth.

The growth in the customer base has resulted in demand increasing by 25% to 85 MW over the past ten years. This high growth has resulted in capacity constraints at the Cambridge and Te Awamutu GXPs.

This high growth is forecast to continue for the foreseeable future based on our network transformation work (where we undertook a regional study and developed demand growth scenarios).

The need to manage future demand growth due to electrification

Over the past 12 months, we prepared a regional study that assessed demand growth. Electrification is expected to generate significant demand growth, requiring investment in additional network capacity or alternatives. The drive to decarbonise New Zealand will also drive the connection of new types of devices that allow new ways of using the network.

We have developed future scenarios that indicate that demand could grow from 85 MW to between 142 MW and 187 MW over the next decade. The difference between the high and low forecasts relates to variability in future population growth, the pace of industrial decarbonisation, EV uptake, charging behaviour and flexibility (in particular, EV charging, load shifting and the role of hot water load control). It is yet to be determined how these growth drivers will unfold; however, what is clear is that we can expect a significant increase in demand growth.

The extent of electrification demand growth, the availability and firmness of flexibility services, and the cost of accessing flexibility services are key areas of uncertainty for the business, and we must consider this uncertainty in our planning decisions.

As electrification increases, there will be a stronger link between electricity and GDP. Electrification will also reduce energy diversity (e.g., transport fuel moving to electricity will concentrate residential and potentially commercial energy dependence on electricity). This is positive, provided electricity security and resilience are at the requisite level to minimise the impact of a range of scenarios, including low probability and high consequence events that interrupt supply for days or weeks – building this resilience is a key challenge for us and the industry.

The age of assets classes

The average age of our network is around 19 years [5], which is relatively young. However, below the headline, several asset classes now include a reasonable population of assets over 45 years old. As these asset fleets age, end-of-life drivers will increase, resulting in a deterioration of asset health unless the level of asset renewals increases. For example, around 88% of hardwood wood poles, 99% of softwood poles, 60% of overhead switches, and 54% of overhead transformers are older than the onset of unreliability for those assets.

This is not presently a material issue for the business. However, in the near to medium term, increased asset health deterioration must be managed through increasing asset renewals or maintenance.

The increasing incidents and impact of adverse weather events

We have experienced more significant impacts from adverse weather events in recent years, likely signalling an upward trend. Cyclone Dovi in FY22 and Cyclone Gabrielle in FY23 significantly impacted our network and customers.

The analysis indicates that for the four years to FY23, the average annual impact on SAIDI from adverse weather has increased by 600% and averaged 97 SAIDI minutes p.a. over that period (and 171 SAIDI minutes over the past two years).

The increase in SAIDI is driven by the rise in adverse weather outages and an increase in the time taken to restore electricity during such events.

The need for greater maturity in asset management to effectively manage the issues above

As outlined above (and in the asset management strategy section below), the requirements for our business to have a greater breadth of quality information, undertake more complex modelling and analysis, and operate within a more interconnected and complex electricity sector are rapidly approaching. These demands require us to reach a higher level of asset management maturity over the next two years.

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5 *Based on the weighted average age of the asset categories in the 2023 RAB. This is a different calculation than we used in the 2023 AMP, and provides a more accurate picture.*

Summary of Part 2: Strategies to address the key issues

1.7 Asset management strategy

Our 2023 AMP described our asset management strategy. The asset management strategy was prepared in response to our key issues and to improve network performance, as discussed in our prior sections. Our asset management strategy comprises six initiatives, and work programmes (discussed later in our implementation section) are aligned under each initiative. Our asset management strategy supports our asset management policy, customer strategy, and service standards. It also provides the basis for ongoing engagement with stakeholders. The strategy remains unchanged (but will evolve over the coming decades as our business environment changes).

Initiative	In response to...
1. Improve regional supply security **2.** Develop and implement an energy transformation roadmap to further prepare for decarbonisation	• High population and demand growth • Future demand growth due to electrification • Uncertainty as to the availability of flexibility to manage demand • Customers' future needs and voices
3. Improve the resilience of our network	• The increasing importance of electricity to our customers • Increasing incidents and intensity of adverse weather • Increasing incidents of third-party damage
4. Develop comprehensive fleet plans and renewal forecasts	• Aging of our asset fleet • Increasing requirement for asset renewals
5. Improve asset management maturity	• A need to make quality decisions based on quality data • Increasing business complexity (e.g., managing flexibility)
6. Reduce the impact of vegetation on the network	• Continued material impact of vegetation interference on reliability

Table 1: Our asset management strategy

Further details on our asset management strategies are provided in Section 5.2 in the main body of the AMP.

Pursuing these strategies will require investment in people, systems, and network assets, much of which is already included in this AMP. We have further work to build our people capabilities, and planning for this will be a key focus for the coming year.

The extent and the pace of investment will require consideration of sustainability, security, and affordability, which we discuss in Section 1.10 below.

1.8 Customer strategy

A customer's direct experience with our organisation is often due to an outage or when they want to change their level of service. Our customer strategy is to:

- Consult and engage with customers about service standards and network performance that are required now and in the future;
- Engage with customers about their decarbonisation plans and expectations on future service levels;
- Achieve the customer service (reliability) targets;
- Achieve the customer satisfaction targets;
- Where possible, manage customers' expectations and communicate with them promptly;
- Engage with our community on areas of interest.

1.9 Performance targets

Customer service (reliability) targets

Reliability comprises planned and unplanned reliability measures. Figure 3 shows our target unplanned reliability target for FY2024 and the next five years. Given the increasing incidents of adverse weather, achieving this target is challenging. Assuming future performance reflects historical averages, there is a risk that we will exceed our internal target in the coming years while we work on delivering against our asset management strategy. In the coming year, we will review our service performance targets to ensure they always reflect customer expectations as we develop our network transformation roadmap.

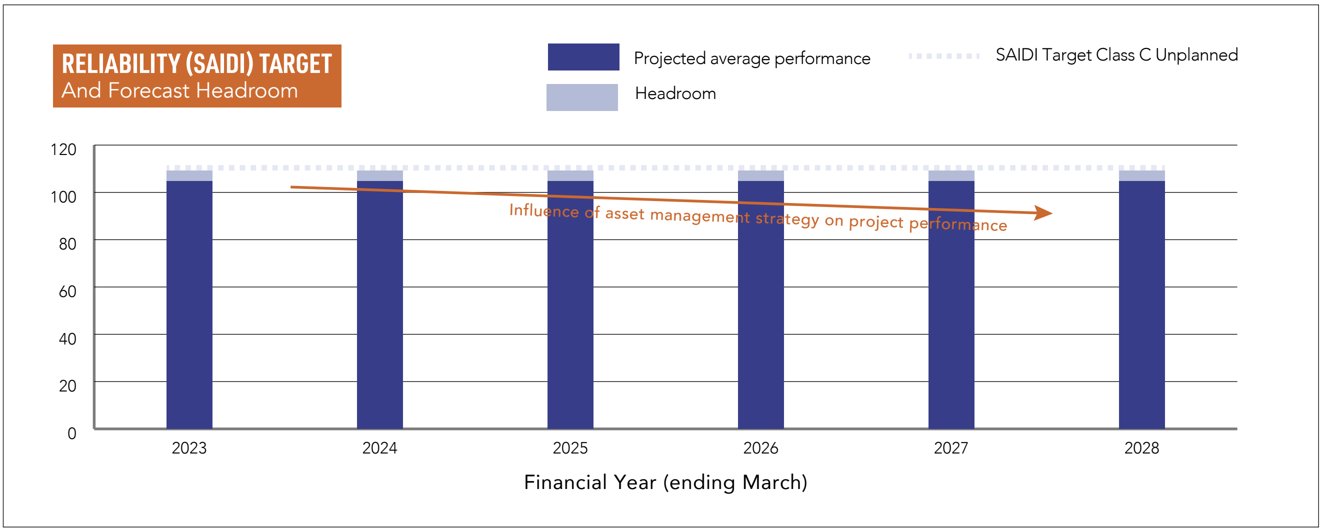


Figure 3: Target reliability

***Note:** The target performance is based on the methodology applied to regulated EDBs. We'll still be monitoring raw reliability performance (before normalisation for major events) as this is the out-turn that customers see.*

Reliability targets exist for planned and unplanned SAIDI and SAIFI. Even though we breached our SAIFI target in FY23, our unplanned SAIFI and planned reliability targets are less challenging for us to achieve.

Delivery target

We seek to maintain delivery of maintenance and fault response work (excluding significant weather events) within 5% of the target (actual vs forecast expenditure) and reduce our planned maintenance and vegetation category variances to 10% this coming year. We're seeking to improve our delivery of planned capital works to variances of 15% over the next two years[6]. A higher variance is being targeted for capex due to the influence of consenting process on project timelines.

Delivery improvement will be driven by our asset management maturity (AMM) improvement programme, which is discussed in Sections 1.11 and 5.5.

1.10 Our role towards a sustainable future

We understand we have a key role in enabling our region's transition to a sustainable future through electrification, and we have set out our network transformation roadmap in this AMP.

Ensuring our services support New Zealand's efforts towards a decarbonised and sustainable future, delivering the future security and resilience expected by our customers, and providing a just and fair energy transition are material issues for the business and our industry. Addressing these factors requires consultation, information, innovation, and good decision-making.

[6] *Excluding customer connection work, which is largely driven by customer needs and timing.*

Framework

The Energy Trilemma[7] is a well-recognised and useful framework (see Figure 4) when considering the energy transition. It is guiding the development of NZ's Energy Strategy.

In the energy context, the three limbs refer to:

- **Sustainability** means supporting New Zealand's energy transformation, minimising emissions, and adapting to climate change.
- **Security** means the ability to reliably meet current and future energy demands, as needed by our customers, including being resilient to external events.
- **Affordability:** meaning the cost of, and access to, energy (of which electricity is an increasingly important component).

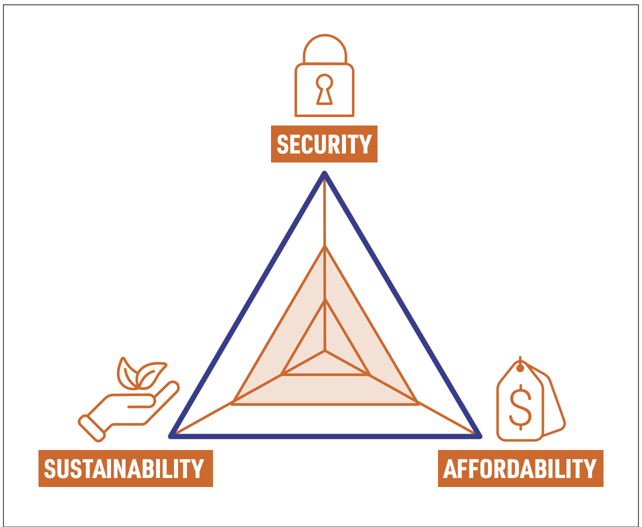


Figure 4: The energy trilemma

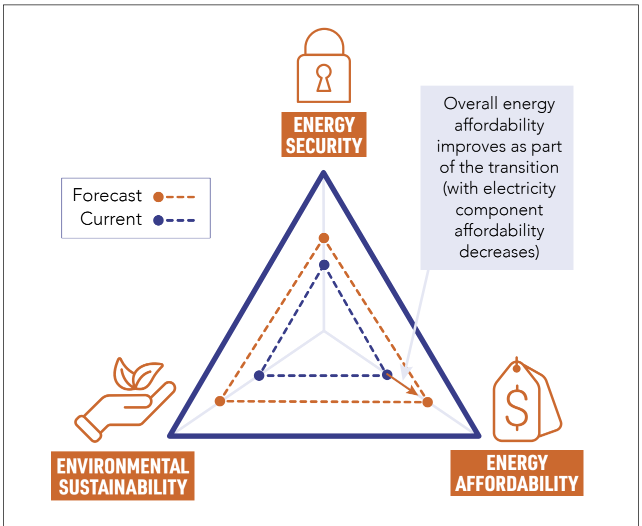


Figure 5: Assessment against the energy trilemma framework

How we are considering the factors

We envisage that in the future, customers will experience a lower overall energy cost with an increased electricity component and will also experience a more secure and resilient network. Figure 5 illustrates our assessment against the three limbs of the energy trilemma framework. This assessment indicates our current view on the direction of travel over the 10-year horizon of this AMP, which is:

1. **Sustainability is forecast to improve based on New Zealand's direction towards a sustainable and electrified future[8]**. This will be supported by the asset management initiatives discussed in Section 1.7: #1 (regional security) and #2 (energy transformation). Our core investment in the network and asset management initiative #5 (asset management) will also help manage the increasing complexity resulting from the energy transformation.
2. **Security and reliability are expected to improve.** As dependence on electricity grows, we hope our customers will require a more secure and reliable supply. We will engage with our community to better understand and define our customers' service level expectations now and in the future. This is on the back of investments to support asset management initiatives #1 (regional security), #3 (resilience), and #6 (vegetation). This is also backed by #3 (resilience) to improve the resilience of our network to climate-change-related impacts.
3. Electricity distribution costs will likely increase, but energy affordability should improve overall. Therefore, we must ensure a just and fair energy transition for all customers.

Improving sustainability and security simultaneously will require considerable investment into the network or alternative technology.

Increasing investment will lead to an increased cost of electricity supply. While the cost of electricity will likely increase, overall energy affordability should improve due to electrification[9]. We must ensure that transitioning to a net carbon-zero economy is just and fair for all customers.

Supporting a just and fair transition will be a business process separate from the AMP, ensuring our AMP process remains focused on prudent investment, maintenance, and operating needs for the network over the long term.

We envisage that in the future, customers will experience a lower overall energy cost with an increased electricity component and will also experience a more secure and resilient network.

[7] *Source: World Energy Council.*

[8] *Report by Boston Consulting Group "Climate Change in New Zealand: The Future is Electric" https://www.bcg.com/publications/2022/climate-change-in-new-zealand*

[9] *Assessed by Sapere in their recent report for the Electricity Networks Association https://www.ena.org.nz/news-and-events/news/total-household-energy-cost-to-reduce-over-time/*

Summary of part 3: implementation plans to deliver the strategy and the required level of performance

1.11 Improvement to asset management processes, systems, and data

Asset management maturity improvements

We have reassessed our asset management maturity and achieved good improvements in key areas but didn't achieve our targeted improvement in all areas. The effort required to implement improvements exceeded what was anticipated, and we experienced some resourcing constraints.

We continue to target improvements in our asset management maturity over the next year to ensure our business has the necessary capabilities to deliver on our asset management strategies (asset management strategy #5). Our current level of maturity and areas for improvement are shown in Figure 6.

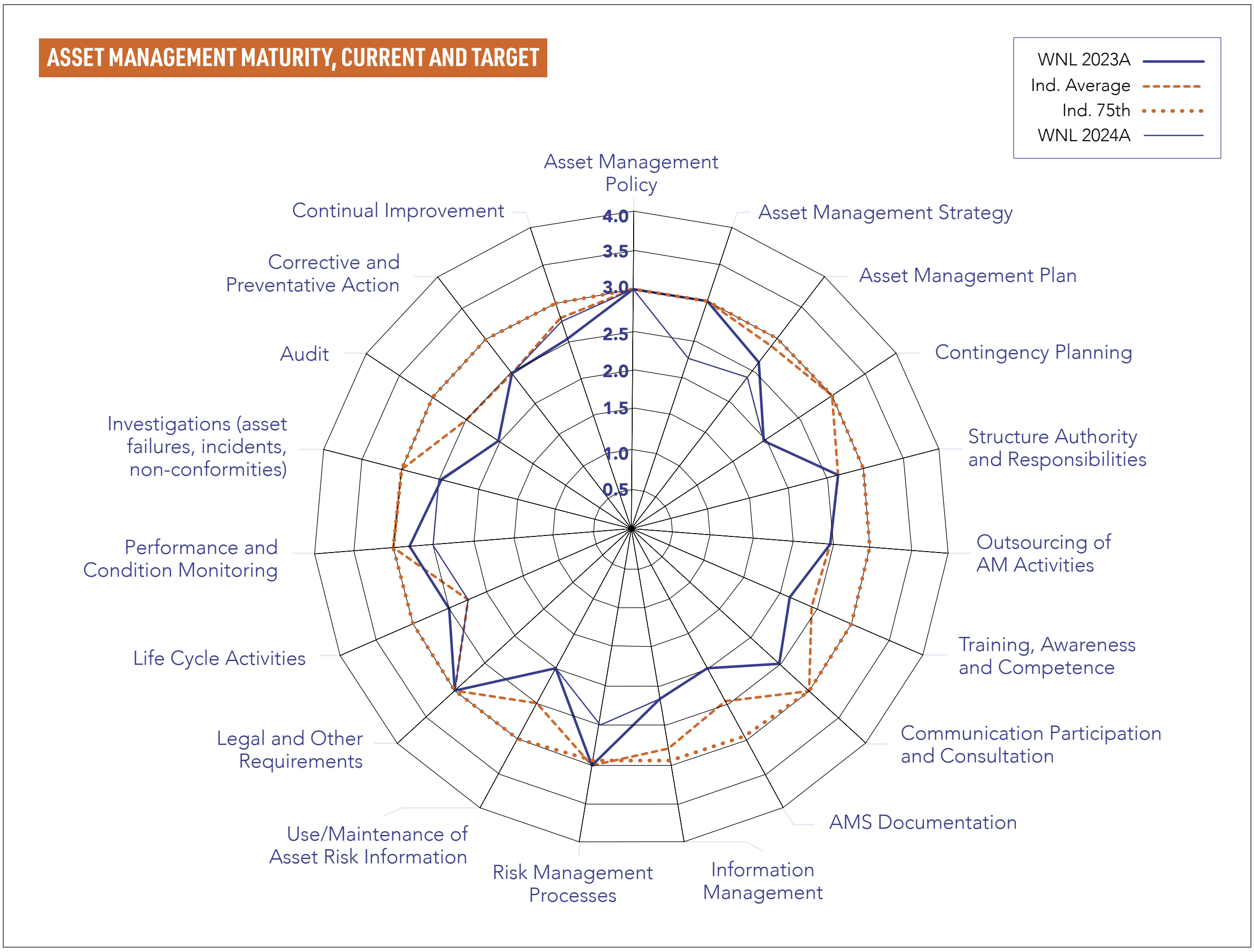


Figure 6: Asset management maturity

We have some resourcing building to do; hence, we will only achieve some of the previously targeted improvements by the end of FY25. We remain committed to our overall goal of a maturity rating of 3. However, acknowledging that progress is also dependent on priorities and improvement in resourcing, we have adjusted the programme timing to five years.

During FY2025, our focus areas will be:

- Continuing to enhance asset management practices, including investigations into asset failures and transitioning to risk-based asset renewal forecasting;
- Enhancing our contingency planning work and defining future competency requirements;
- Continuing our work on information management and improving data quality for some asset classes.

Information system development

Our programme to modernise our information systems enables more effective management of the business and assets, which will improves our asset management maturity. We have developed an Information Systems Strategic Plan (ISSP) with a roadmap for improving and updating systems to provide new integrated features and capabilities.

We have made significant progress on our systems:

- A new network modelling software (DigSILENT) went live in CY23;
- The new MagiQ cloud-based finance system went live in CY23;
- A new geographical information system (GIS) containing core asset information went live in CY22.
- Other systems that went live over the past three years include the Assura health and safety system, our new Service Management system, and a new billing and ICP management system.

Our new health and safety system allows access to information and process documentation in the field and facilitates improved safety management and reporting. Our Service Management system improves fault management, particularly during major events. Our new billing system provides a single platform view, automates billing processes and increases the security and management of ICP data. The new modelling software enables more efficient network load flow analysis to support our development planning work.

The next phase of proposed initiatives (including those under consideration) will enhance our operational capabilities and include the following:

- A replacement SCADA[10] and outage management system (OMS) to improve real-time network management, outage management, reporting and communication capability to remote devices;
- Field data mobility and vegetation management systems;
- A document management system to manage documents, standards, and drawings.

Asset information

Maintaining and improving asset data is a continuing focus for the business. The new GIS system contains existing asset data transferred from prior systems. It has also been populated with data from the recent LiDAR pole-top survey of the overhead network. Asset condition data is being captured and is accessible in the GIS. The GIS also provides the base data for the network modelling software.

Our fleet plan development has revealed some data gaps concerning cable, conductor, and overhead switches, and we will work to resolve these, where possible, over the coming few years. Our data is generally good for above-ground assets and will be improved through the ongoing inspection programme.

We plan to develop the LV network information in GIS. This will enable LV outage management and real-time monitoring for our low-voltage network. The LV network monitoring (including congestion and static/dynamic operating envelope) will become essential and is a key step in our network transformation roadmap.

Asset defect information (that has health and safety implications) is captured via Assura. The data drives corrective work and tracking of health and safety measures. The system enables workforce safety and tracks public safety inspections and remedial work.

1.12 Network transformation

Introduction

Reducing emissions through electrification and increasing renewable generation is critical to New Zealand achieving its net-zero goal by 2050. Electrification of transport and heat (both process and general), expanding the use of distributed energy resources (DERs)[11], increasing the availability and use of flexibility, and 100% renewable electricity are central pillars of decarbonisation towards the net-zero future.

Customers are at the centre of the energy transformation. Some customers are changing their energy usage choices and how they use distribution services. New technologies make alternative ways of generating electricity and storage possible, changing how customers interact with the network. Waipā's role is to ensure that our business model and services cater to all customers.

We have a key role in providing energy security to customers who continue to depend on grid-supplied electricity. However, we must support all customers in adopting (and fully benefiting from) new energy technology, such as EVs and DERs. We also need to utilise flexibility (where practical and economic) to minimise capital expenditure on network upgrades. This will require an evolution in our business model (refer to Section 8.7).

Regional review

Last year, we completed a regional review that identified potential drivers of change within our network and produced Waipā specific decarbonisation scenarios. The review anticipated:

- Continued population and economic growth that will lead to new connections growing at a rate faster than what we have seen over the past decade;
- Fossil gas use transitioning to biogas, hydrogen, or electricity. For residential and commercial customers, the transition is expected to be from gas to electricity;
- An increase in EV uptake due to the reducing cost of EVs, the expansion of regional charging infrastructure, and the development of smart charging options;

[10] *Supervisory, Control and Data Acquisition (SCADA) system that is used to remotely monitor and control the network.*

[11] *Distributed energy resources (DERs) are small-scale electricity supply or demand resources that are connected to the electric network and usually situated near sites of electricity use, such as rooftop solar panels and battery storage.*

- Some small industrial processes heat converting to electricity. However, large users are expected to transition to biofuels or directly connect to the transmission grid;
- A material increase in customers installing small-scale solar PV installations due to the falling cost and increasing efficiency of solar panels; and,
- An increasing number of customers with EV chargers, solar PV installations with batteries, smart appliances, and controllable hot water systems, offer these assets into flexibility markets where we or others can control them.

The analysis developed two scenarios for future network demand. The difference between the high and low scenarios relates broadly to population growth, industrial decarbonisation, EV uptake, and flexibility (in particular, EV charging and load shifting). It is not yet clear how the industry will deploy flexibility, as 66% of the benefits can be attributable to non-distribution sectors of the industry.[12]

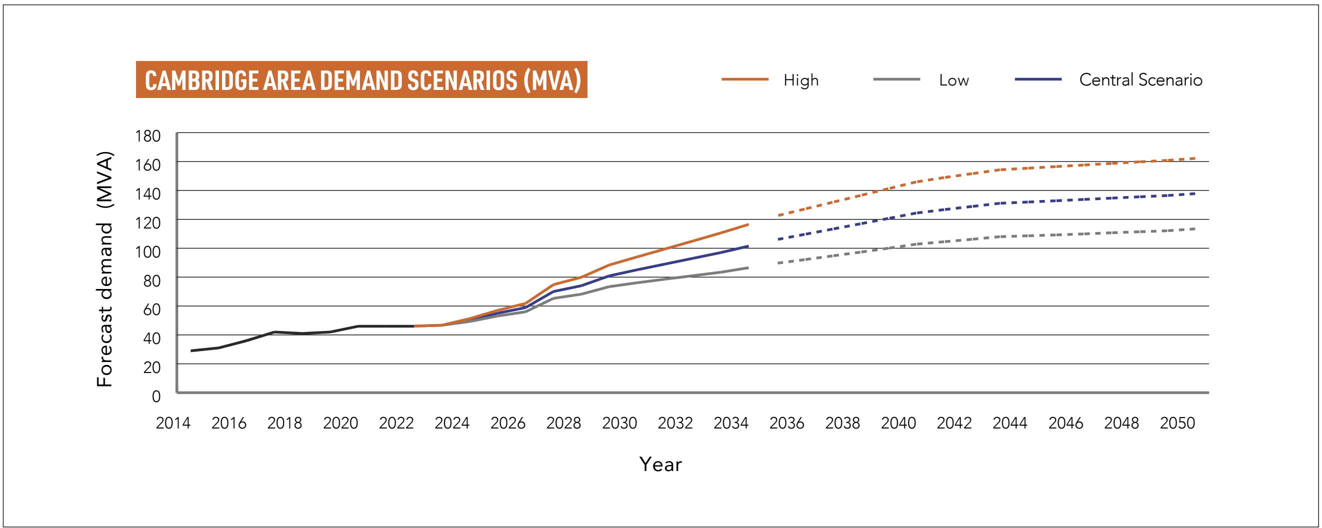


Figure 7: Cambridge scenario comparison

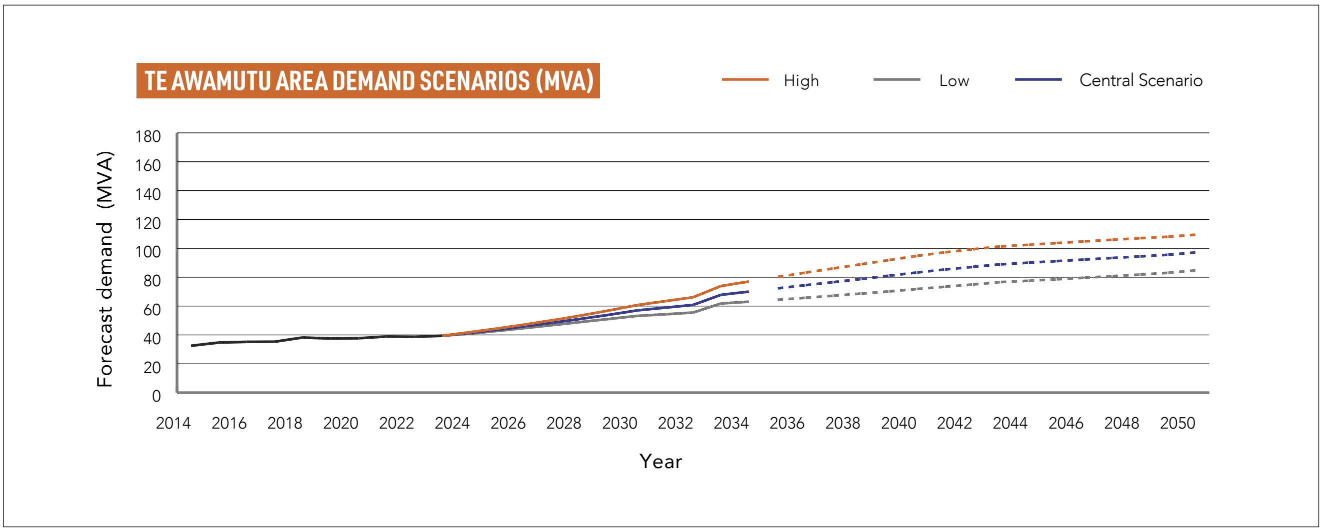


Figure 8: Te Awamutu scenario comparison

[12] *D. Reeve, T Stevenson & C. Comendant (2021) Cost benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority, Wellington, New Zealand*

Waipā's network transformation roadmap

We started work supporting our region's energy transformation. Our focus in the short to medium term is capability building and to progress investments that will be utilised (as far as can be reasonably foreseen) across the range of scenarios.

We have commenced developing a network transformation roadmap for Waipā. We monitor government, regulatory, industry, and technology developments to inform and ensure our roadmap we're developing is consistent with our operating environment. The roadmap development aims to ensure that Waipā can support New Zealand's energy transformation and decarbonisation at the least cost to our customers over the long term.

The roadmap will ensure that:

- We have the capability, services, and network capacity to allow customers to increase their electricity use to replace fossil fuels;
- We can connect and integrate DERs into the network and allow the owners of DERs to participate in energy markets and flexibility markets;
- We progress "low regret" investments and capability building to ensure our network will be able to deliver the services customers require when they require them and that there is a low risk of future investment stranding;
- We achieve network security and reliability that meets customer expectations.

Community engagement is important and will be part of various activities. It will be particularly important in terms of services and pricing.

It is intended that the roadmap will provide direction on how we will:

- Build our people and system capabilities to respond to the transition;
- Develop the network and its architecture to meet customers' future needs;
- Monitor the network (in particular, LV) to ensure reliability and security is maintained;
- Develop our business model to engage with customers, other industry players and flexibility markets;
- Develop our prices to influence customer behaviour to reduce peak demand;
- Optimise network investments, including utilising non-network alternatives;
- Develop standards to improve resilience and minimise complexity, network risks and operating costs.

We intend to present our network transformation roadmap in the 2025 AMP.

1.13 Material network development programmes and projects

Introduction

Over the past year, we have worked on understanding our network, improving the tools, systems, and processes we use to visualise what is happening on our network, and continuing to build our people's capacity and capability to advance capital projects that will secure capacity for the region and customers.

The development plan aligns with our asset management strategy, particularly with strategies #1 (Improve regional supply security) and #3 (Improve the resilience of our network). As part of this strategy, we recognise the need to review our network architecture to determine a configuration that can support the forecast load in the long term. We will include the cost of the possible future architecture in the schedule when we have decided on a preferred future architecture and associated development path.

Drivers of network development

Our planning criteria encompass security of supply, network capacity, reliability, utilisation, and losses. Whenever the planning criteria are forecast to be breached, network development projects are established to prevent constraints from forming on the network. Our assessment of development projects includes consideration of alternatives.

Demand growth, voltage compliance and reliability are the main drivers of network development projects included in this AMP.

Network resilience

The increasing use of electricity to decarbonise transport, industrial process heat, and commercial and domestic heating will increase the reliance on electricity and reduce fuel diversity. In the future, a loss of supply will have more significant community and economic consequences. Therefore, Waipā's (and the electricity sector's) resilience must be commensurate with its increasing dominance as an energy source.

Improving resilience will take a multi-faceted approach over the next decade. We have developed a resilience strategy (as per our asset management strategy #3) that will drive improvement through risk reduction, readiness and response activities.

Key initiatives include:

- Detailed natural hazard assessment to identify and remediate network vulnerabilities,
- Revisions to design standards to increase the inherent capabilities of the assets,
- Improving the physical resilience of critical assets in vulnerable locations,
- Minimising the impact of outages when they occur, and
- Enhancing operational management and response to events when they occur.

After completing the natural hazard assessment and related work, we expect an increase in our forecast for resilience-related capex expenditure. This increase will be visible in the 2025 and 2026 AMPs.

Material network development projects

In response to the development drivers, this plan includes the following material development projects:

Driver	Project	Cost	Status
GXP capacity constraints in the Cambridge region	The new Transpower Hautapu GXP will provide significant capacity for the Cambridge region for the next 20-30 years and will be the foundation for the new 33kV subtransmission network.	Funded through Transpower	In progress, due early FY26
	The new Forrest Rd substation adjacent to the new Hautapu GXP will provide feeder capacity to support growth to around FY32	$9.3m	
	The new Bardowie substation will be installed close to the Hautapu industrial development to support industrial growth.	TBA	Planning, targeted for FY28, timing is dependent on the pace of industrial developments
	The new Leamington substation will provide further capacity to the Cambridge area beyond FY32.	TBA	Under consideration
Distribution feeder capacity constraints in Cambridge regions	Existing feeder reinforcements and integration with new substations	$4.3m	Planning, Due FY26
	Two new distribution feeders into Leamington (33kV cables operating at 11kV)	$7m	Planning, Due FY27
GXP capacity and distribution network constraints in the Te Awamutu region	We have commenced the discovery works and options study that considers subtransmission and distribution system architecture to meet future growth needs and provide a foundation to improve reliability and voltage on the distribution system.	TBA	Under consideration, Due FY30+
Distribution feeder capacity constraints at the Te Awamutu GXP	Upgrade selected low-capacity cables	$3.6m	In progress, due FY24-FY25

Table 2: Material network development projects

This plan also includes ongoing programmes to address:

- Feeder capacity and voltage constraints through targeted conductor and cable upgrades. These programmes amount to $13.1m over the next decade,
- Reliability and resilience through installing feeder reclosers, remote-controlled switches, targeted undergrounding, line deviations and seismic strengthening. These programmes amount to $5.1m over the next decade, and
- Constraints on our communication network through upgrading to a fully digital communication network for $1.8m.

Customer connections

Connection growth remains strong, with around 520 new customers expected to connect in FY2025, growing to 600 in FY2028. This high growth aligns with Waipā's long-term growth forecasts.

1.14 Material asset lifecycle programmes and projects

Comprehensive fleet plan and renewal forecasts

We have developed comprehensive asset fleet plans for our material asset classes (which are aligned to asset management strategies #4 and #5). As mentioned in Section 1.6, we expect to observe more end-of-life drivers over the coming decade.

Over the last 12 months, we considered adopting the DNO Common Asset Indices methodology or the EEA Asset Health Indices (AHI) methodology. We have adopted the EEA AHI approach as this was the best fit for Waipā assets (as the DNO methodology did not incorporate several of our material asset classes). [13]The AHI measures an asset's lifecycle stage and fitness to continue safe, compliant, cost-effective service. All fleet plans include an asset health assessment for all fleet assets. These new fleet plans are included in Section 11.

We are revising our inspection standards to ensure they capture information supporting health assessments. New inspections to the new standards are in progress, and the health assessment will evolve as new condition data is assessed.

We still need to complete our work on asset criticality and asset risk. We expect our fleet plans to transition to risk-based forecasting over the next two years. Asset criticality will be used with asset health to define a risk-based approach for asset renewals, inspection and maintenance, and renewal programmes. Given the current aging of the network, we are comfortable that the current state of our network assets does not present any undue risk.

Asset health assessment

Figure 9 and Figure 10 show the evolution of our asset health assessment and renewal forecasts for our material asset classes in this AMP. H1 or H2 refer to assets with low health, meaning replacement is required or where EOL drivers are present, and there is a high risk of asset failure.

Figure 9 shows the material changes in the asset health since the 2023 AMP. These include:

- A reduction in low-health wood poles (35% of wood pole structures are judged as H1 or H2) due to the ongoing asset renewal programme (which has a material impact due to the relatively small fleet),
- A reduction in low health crossarms due to the continuing asset renewal programme and the use of condition data (where over half of the H1 and H2 crossarms were derived from condition data),
- A reduction in low-health pole-mounted transformers due to the use of condition data,
- An increase in low health voltage regulators and reclosers, which reflects the use of condition data for these fleets and
- There has been a material reduction in low-health overhead switches due to the revised health forecasting methodology. However, the extent of low-health assets is likely to be understated, as the health of this fleet is largely age-based, and 40% of the fleet has unknown ages.

The asset classes showing a high proportion of low health are wood poles, crossarms, pole-mounted transformers and voltage regulators. Asset classes showing a high proportion of low health are:

- The wood pole fleet is relatively small (at 1,300 poles) and is currently subject to an intensive renewal programme targeting the renewal of all low-health poles over the next five years. This strategy has resulted in an increase in forecast renewals over the 2023 AMP,
- The crossarm fleet is material and is subject to an intensive renewal programme targeting the renewal of all low-health poles over the next ten years. This strategy has resulted in an increase in forecast renewals over the 2023 AMP,
- For pole-mounted transformers, the renewals are forecast to replace 150% of H1 assets over the next five years. This is consistent with the failure and defect-driven replacement strategy due to the relatively low risk of failure associated with these assets,
- The forecast renewal of voltage regulators has reduced from that forecast in the 2023 AMP due to better condition-driven health forecasts. This renewal forecast excludes the replacement of voltage regulators for seismic strengthening and
- The forecast renewal of overhead switches has increased over the 2023 AMP. The renewals are currently above the forecast level of H1 and H2 assets due to the uncertainty associated with this asset class. Most of the assets due for replacement are ABSs. Replacement of dropout fuses and links will be a failure or defect-driven replacement.

[13] *EEA Asset Health Indicator (AHI) Guidelines 2019*

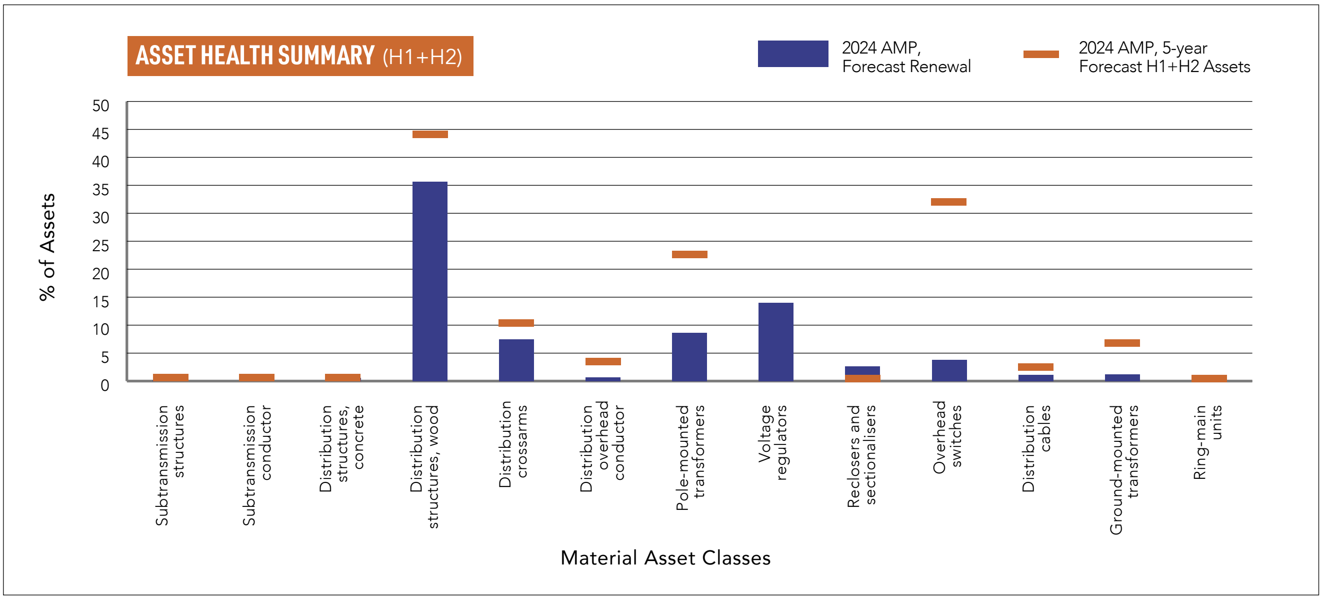


Figure 9: Asset health summary for material asset classes

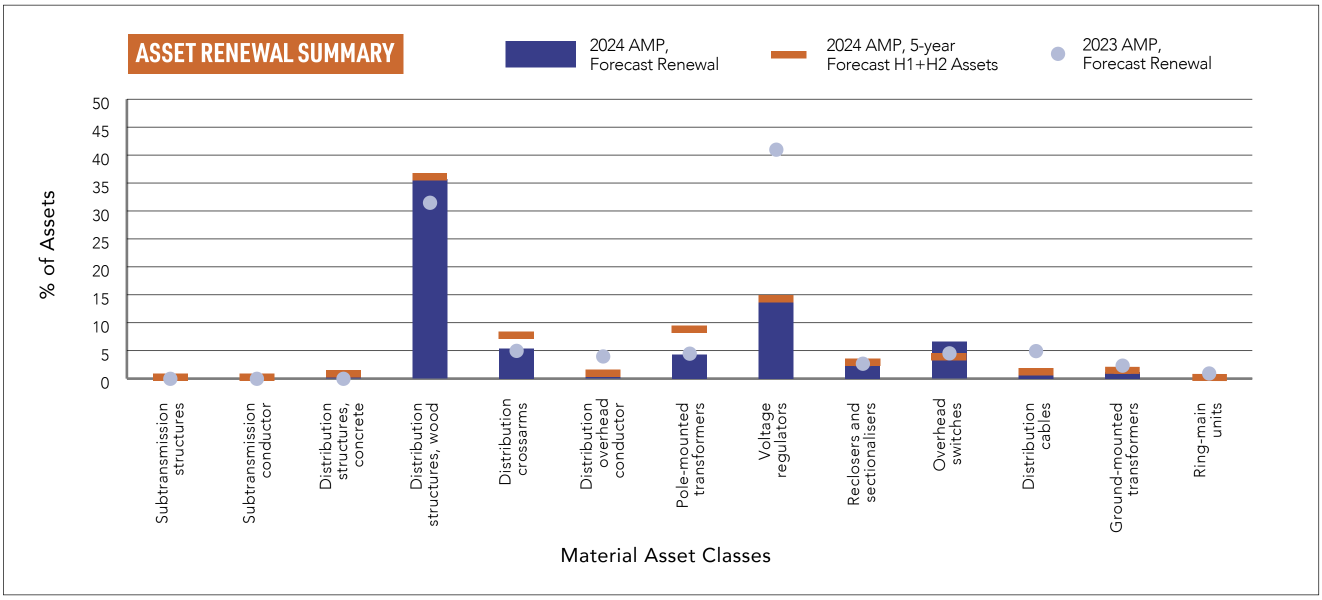


Figure 10: Asset renewal summary for material asset classes for the ten-year planning period

The revisions to our fleet plans have resulted in changes in renewal expenditure forecasts for some asset classes.

Fault response, maintenance and inspection

In response to the increasing trend in weather-related outages and fault restoration times, we increased the system interruption and emergency budget by 35% in the 2024 AMP. We have increased the forecast by a further 30% over the next ten years (in real$) in this AMP due to the continued increase in the cost of fault response see Section 12.3.

Our new fleet plans have driven changes to our inspection program and some minor changes to our maintenance activities. Given the increase in the number of assets and the progressive aging of our network, work volumes are expected to increase. As a result, forecast expenditure on routine and corrective maintenance and inspection increased 36% over the next ten years (compared to the 2023 AMP).

Full details on our various programmes are covered in Section 11.21.

Vegetation management

Mitigating vegetation-related outages is a key strategy for our business (asset management strategy #6). This strategy was initiated as vegetation outages continue to be a major cause of network outages.

Over the past year, the team reviewed our vegetation management approach and strategy. Our vegetation management strategy aims to identify and address vegetation growth issues before they become safety hazards or impact network reliability.

Achieving these objectives will see a reduction in outages caused by vegetation, a decrease in damage to the network, a reduction in public safety risk, and tree owners carrying the cost of managing their trees near powerlines. Our target is to reduce underlying vegetation SAIDI by 36% by FY30. Improvement is forecasted to start in FY26 when we should begin to see the benefits of the strategy.

The strategy has four key initiatives, each responding to the above mentioned drivers. The new strategy has four key initiatives:

- Emphasise more regular vegetation inspections, reducing the current 3-year cycle to 1-year for line sections closer to the GXPs,
- Implement a practical risk-based vegetation control programme based on inspection findings,
- Increase community engagement, and
- Continuous improvement.

To support the strategy, vegetation management expenditure has been increased by 16% over the next ten years (compared to our 2023 AMP). This is in addition to the 40% increase included in the 2023 AMP. The increase included in this AMP accounts for undertaking the new baseline inspections and the increasing cost of traffic management.

1.15 Key asset risks and controls

We use an ISO 31000-compliant risk management system and regularly assess asset risks, risk controls and their effectiveness. We updated our Risk Policy and Risk Management Framework and reviewed the network risk registers in CY23. Risk level for several high-focus risks in the previous AMP have reduced with implementation of controls (e.g., Cambridge GXP capacity constraints or Te Awamutu GXP capacity constraints).

Our updated key network risks become:

- Poor or unknown condition of overhead lines/poles causing lines or pole failure and public safety hazards.
- Unauthorised/public access to unsecured pillar boxes (note: no reported incident so far).
- Demand increase from electrification (e.g., switching to electrical appliances from gas, and EVs) and a reduction in the capacity of hot water control, causing increased peak load.
- Major regional storm (tropical cyclone) causes widespread network damage,
- Unlawful or unsafe network (service main) connection
- Access to ground mount equipment (RMU, transformers, and pillars) is left unsecured or is compromised by 3rd party, creating the potential for unauthorised public access.
- Other equipment earthquake risk – depot
- Cable capacity out of Te Awamutu GXP
- Fire started by overhead lines, auto reclose or field activities.
- SCADA system failure & security breach

Effective controls are in place, or treatments are being deployed or planned for these risks; refer to Appendix D.

We have drafted and/or developed emergency management plans for natural disasters, extreme weather, or cyber-attacks. These include minimum stock holdings for support during major events. We also incorporate learnings from major events to inform continuous improvement in our practices.

1.16 Delivery and deliverability

We have an in-house field service resource, and this will be our preferred option for delivering the fault restoration, inspections, maintenance, and routine capex work outlined in this AMP. We'll use contracted external resources for non-routine work, e.g., major projects such as building a new zone substation or specialist work such as civil engineering design.

Our Annual Work Planning process ensures the capacity and capability to deliver the required work program throughout the financial year. Regular review of progress against the annual works plan will allow us to adjust internal and third-party resource requirements as needed.

In addition to the Annual Work Planning process, we have also completed a ten-year resource forecast. This model uses a similar approach to the annual resource forecast model. However, the forecasts are undertaken at the cost category level rather than at the project or asset category level. Two key assumptions in the modelling are that we will outsource most major System Growth projects from FY25 to FY28 through competitive tenders, which have been excluded from the 10-year resource estimation model. Customer connections and Asset relocation expenditure forecasts for customers and relocation have been extrapolated using the historical five-year average.

From FY26 to FY29, we anticipate a shortfall in internal resources of approximately 5,000 hours a year to deliver the current AMP capital expenditure. In FY25, we will decide how to address this shortfall. Options include introducing a 6th Line Team or outsourcing the 5,000 hours per year to an external provider.

1.17 Network expenditure forecasts

Summary of forecast capex

Figure 11 shows the forecast capex for the period FY25 to FY34. The ten-year forecast table is provided in Appendix F. Figure 11 shows that capex has increased by $15.3m (16%) over FY25 to FY29 compared to the 2023 AMP (in comparable constant prices). The increase is mainly driven by:

- An increase in wood pole and crossarm renewal,
- The 11kV integration plan associated with the new Forrest Road substation in the Cambridge region,
- Ongoing 11kV cable and conductor upgrades to mitigate capacity and voltage constraints.

Several significant system-related projects are under consideration between FY29 and FY34. We have not yet quantified investments that depend on a confirmed long-term architecture, so they are not included in the forecast. Once the work is done, we expect the outcome to affect the forecast expenditure for the second half of the planning period.

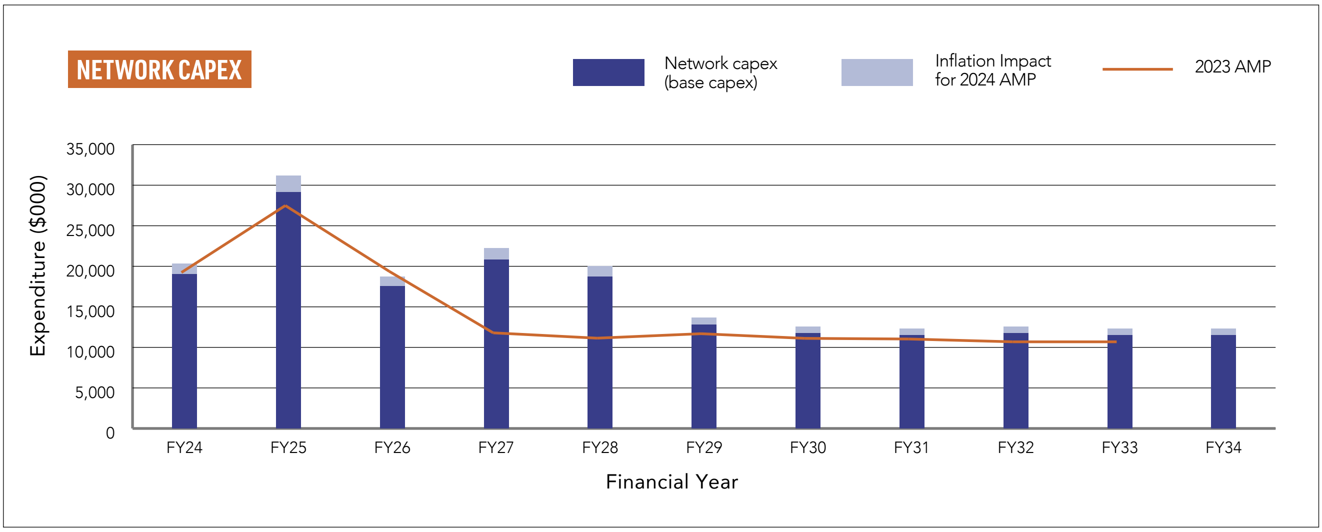


Figure 11: Summary of forecast capex (constant $k)

Summary of forecast opex

Figure 12 shows the forecast opex for FY25 to FY34, which comprises network and non-network opex. The ten-year forecast for the network opex has increased by $8m (18%) over the ten years compared to the 2023 AMP (in comparable, constant prices), principally driven by:

- Higher costs in responding to faults (including labour and services such as traffic management,
- Increase in vegetation management activities, including the additional patroller and increased traffic management costs and
- Increase cost in planned asset inspection and maintenance activity.

Our options analysis process for network development investments and asset lifecycle (renewal) investments considers the trade-off between capex and opex, as the alternatives can either be opex or capex. The evolving viability of flexibility markets could lead to an increase in the opex.

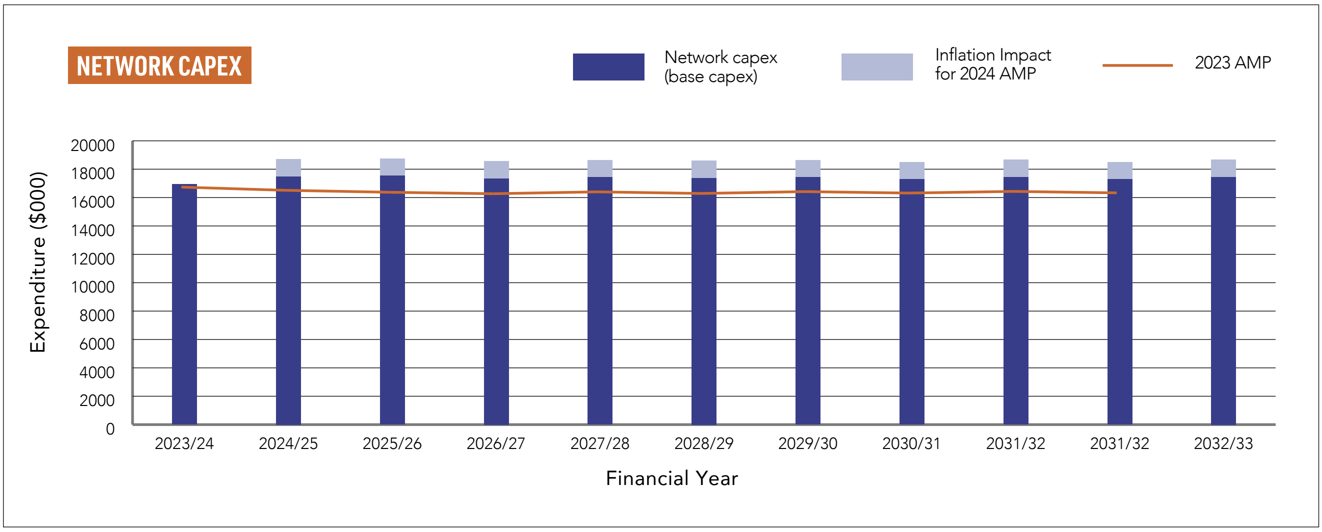


Figure 12: Operating Expenditure ($k)

1.18 Concluding comments

This AMP communicates our key issues, asset management strategy, and programmes and projects impacting our network. This AMP includes significant revisions to our network development and asset lifecycle sections and provides a detailed view of our network transformation roadmap and resilience strategies.

The network transformation roadmap will ensure that we can support New Zealand's energy transformation and decarbonisation in a manner that presents the least cost to our customers over the long term while maintaining appropriate supply security.

Introducing the fleet plans has enhanced our understanding of our assets, and we have aligned our expenditure forecasts to ensure the assets are monitored, maintained, and renewed appropriately.

The performance delivered from the network has generally been acceptable; however, we are concerned with what appears to be a worsening reliability trend and are taking initiatives in response. We continue to be exposed to increasing major weather events. Progressing our resilience strategy will be key to reducing the risks and effectively managing these events in the future.

Delivering on the asset management improvements, network transformation roadmap, and resilience strategy will require us to build our people and system capabilities. Building capabilities is a challenge for the electricity sector and will be a key focus for our business in the coming years.

The planned network architecture review will inform how we will develop the network in response to the forecast growth, influencing the expenditure forecast in the FY29-34 period and beyond. The expenditure forecast in this AMP still needs to include the cost of the possible future architecture.

Our analysis of the network constraints forecast asset health and related development and renewal projects demonstrates that our assets are being managed for the long term. We recognise that our network is at a point where existing capacity is becoming fully utilised, and our assets are ageing to a point when end-of-life drivers will emerge in the coming years. We are confident that the programmes, projects, and expenditure forecasts over the next five years are sufficient to address the known constraints and issues. Whilst forecast system growth will likely increase in the 2025 AMP, the current network risks are known, controls are in place, and/or additional treatments are planned.

2. BACKGROUND, OBJECTIVES AND RESPONSIBILITIES

2.1 Purpose of this AMP

This AMP outlines how we plan to manage our assets over the next ten years and beyond. It covers the current state of our network, our understanding of our customers' future expectations, how we maintain our assets, the new capabilities we need to develop, and how we've structured and resourced ourselves to deliver our plan.

We are transitioning from a period of steady incremental growth to one of significant regional growth and change, driven by climate change and the need to decarbonise. Our approach ensures we deliver a network that serves immediate needs and builds a foundation for a network that meets the needs of our customers in a future that will be highly electrified.

2.1.1 Basis of AMP

The AMP document outlines our asset management intent, strategies and processes that enable us to achieve our asset management objectives and target service levels. It includes investment and operations plans that inform our annual budgets.

The AMP describes assets and their conditions, how our network needs to adapt to change, including any network development required, our fleet lifecycle management, and our resulting forecast expenditure needed to meet our asset management objectives and service levels.

We are subject to regulatory oversight by the Commerce Commission through information disclosure regulation, including monitoring levels of return on investment. However, as a Trust-owned business, we're exempt from the Commerce Commission's default price/quality path requirements.

We prepare and disclose our AMP each year to comply with the requirements of Section 2.6 and Attachment A of the Commerce Commission's Electricity Distribution Information Disclosure (ID) Determination 2012. This assists our asset management improvement path and provides information for interested stakeholders.

2.1.2 Asset management objectives

Our asset management objectives ensure safe and reliable electricity distribution, balancing affordability, reliability, and sustainability. The objectives driving our AMP are:

- **Safety:** Provide a safe environment for the public and staff by embedding safety considerations in network design, equipment choice, and operations
- **Customers and stakeholders:** Deliver the needs of customers and stakeholders supported by improving understanding of what our customers and stakeholders value most to ensure their needs are reflected in our plans and strategies.
- Assets: Minimise asset life cycle costs by maximising asset utility and network performance that meets service level targets.
- Capability: Continuously improve our asset knowledge and asset management processes and systems to deliver performance and efficiency improvements

The objectives are informed by our business strategy and other factors driving changes in our network.

2.1.3 Period covered

This AMP covers ten-year planning from 1 April 2024 to 31 March 2034. Consistent with Information Disclosure requirements, greater detail is provided for the first five years of this period.

Our Chief Executive and Board of Directors approved the AMP on 31 March 2024. A statutory declaration has been made to the Commerce Commission on behalf of our Networks Directorate for this full AMP.

2.1.4 Key stakeholders

This AMP also communicates our asset management intentions to stakeholders to give them certainty and confidence in how we're managing our network. Our key stakeholders are:

- Our owner, the Waipā Networks Trust, who represents our wider customers.
- The public within our region.
- Mana whenua within our network area.
- Our customers that take supply from our over 28,000 installation connection points (ICPs) to whom we deliver electricity (some of whom receive supply at 11kV).
- Generators directly connected and embedded within our network who deliver electricity into the network for others.
- The electricity retailers who operate over our network.
- The territorial authorities, Waka Kotahi (NZTA), and other government agencies we engage with.
- Our team and contractors who work in or on our network or work on connections to our network.

We assess the interests of these and other stakeholders through engagement that informs the objectives that drive our strategy, plans, and actions set out in this AMP. These objectives are generally expressed through compliance achievement and measurable service level targets set within this plan.

2.2 Structure of this AMP

In this 2024 AMP, we describe how we align our asset management strategy and performance targets to the interests of our stakeholders. We've organised the AMP into three parts:

- **Part 1:** The key issues facing our network.
- **Part 2:** Strategies to address the key issues.
- **Part 3:** Implementation plans to deliver the strategy and the required level of performance.

We've also included a reconciliation of the Information Disclosure requirements in the appendices. Notwithstanding the reorganisation, this AMP continues to provide all the information to assure stakeholders that:

- Our assets are being managed for the long term.
- Our required level of performance is being delivered (and where there are gaps, improvement plans are being implemented).
- Our business is efficient (so the distribution prices are no higher than they should be).

2.3 Accountabilities and responsibilities for asset management

2.3.1 Responsibilities

Our Network team decides our network enhancement and asset maintenance programmes, the various security of supply levels, and the standards for automation and system operations to improve network reliability and technical and economic efficiency.

- Our General Manager Network is responsible for disclosing the AMP and associated schedules, and our Asset Strategy Manager completes the AMMAT assessment. Other areas of our business are consulted as required.
- The AMP is then prepared by our Asset Strategy Manager, reviewed by our General Manager Network, recommended for approval by our Chief Executive, and approved and certified by our Directors.
- Our Network Development and Engineering team is responsible for network planning, including new connection and outage assessments, distribution planning, design and construction standards, and other specialist engineering support.
- Our Network Information Team is responsible for managing records of network assets.
- Management and Company Directors review the AMP to ensure it accurately reflects our strategic direction, current SCI, and forecast performance and expenditure. Once approved, the following stages occur:
- Specific approval of major projects is tabled at appropriate Board meetings for our Directors' evaluation and appropriate approval.
- Our General Manager Network provides monthly reports to our Directors on progress against our annual capital and maintenance plan targets, system reliability, and performance targets.
- Our Board reports to the Waipā Networks Trust bi-annually on progress against our targets and plans agreed in the Statement of Corporate Intent.

Our Works Planning team is responsible for the design, project management, works scheduling and delivery planning of our Capital Expenditure program.

Our Operation team is responsible for our network's construction, maintenance, operation, and inspection activities.

Our Finance and Commercial team collates the budgets, reports expenditures, and financial information disclosure schedules.

Our People, Safety & Wellbeing team is responsible for human resources, recruitment, training, liaison with WorkSafe NZ, industry compliance, and accreditation of our Public Safety Management System and Workplace Safety Management Practices.

Our Technology team is responsible for corporate business systems and IT functions within our business.

Figure 13 shows our organisation chart depicting asset management and AMP disclosure responsibilities.

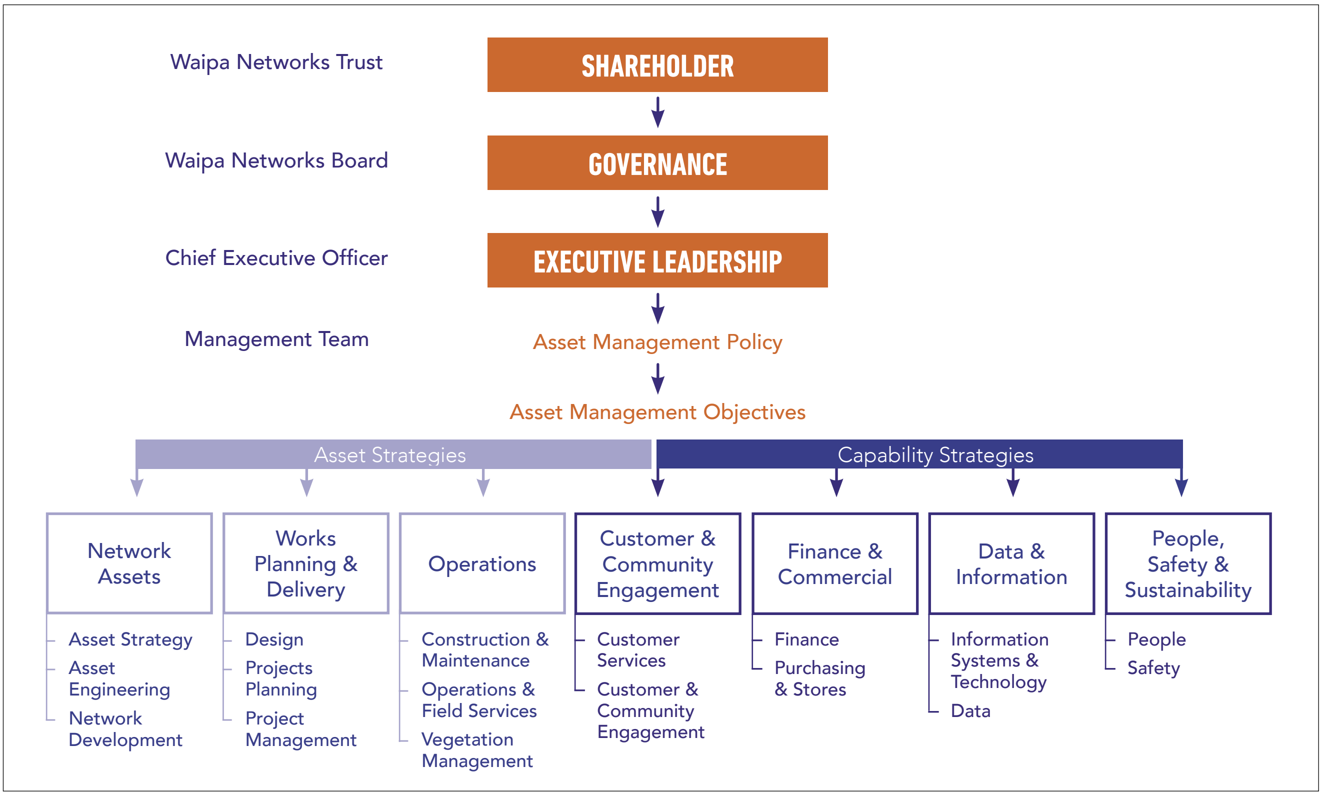


Figure 13: Our ownership, governance, and responsibilities

2.3.2 Resourcing asset management

We use internal resources to complete most of our planned and unplanned cable and pole line work and vegetation management. External service providers are contracted when internal resources are insufficient:

- Identify required skill sets on a timeframe equal to this AMP and ensure that recruitment and training plans are consistent with our needs and, where appropriate, use relevant contractors.
- Endeavour to procure resources locally, where and when appropriate.
- Retain our current field services staff for fault restoration, inspections, maintenance, and capital work.
- Use contractors/consultants where our staff doesn't have the required skill sets, where resources are inadequate for our works programmes, or where it is more cost-effective to do so, e.g.:
  - specialist work includes civil engineering design and radio equipment installation and maintenance.
  - asset inspection and surveys, earth testing and repairs, partial discharge, and acoustic monitoring surveys.
  - contracted out Control Room and Call Centre services,
  - aspects of SCADA and communication work, and
  - traffic management on most roadside lines and vegetation management works.
- Regularly review our work management and delivery processes to ensure deliverability and enhance operational efficiency.

2.4 Communication and participation processes

Our policies, standards, and AMP communicate our asset management practices internally and externally. Table 3 summarises the processes and systems that support communication and participation.

Processes/ systems/ plans within the asset management system	Description and purpose	Stakeholders and communication of processes/systems/ plans	Management of processes/systems/plans
Waipā's Policies, Procedures and Plans	Waipā has a system of controlled documents, including several policies and procedures for asset management held and available through the intranet.	Waipā's team participate in periodic reviews of Policies/Procedures. Senior management oversees issues arising from policies and/or procedures within the system. Waipā has policies and procedures about the engagement and management of Consultants and Contractors working on the network.	Each Policy/ Procedure within the system is internally reviewed periodically. The external Public Safety Management System audit is undertaken annually on relevant parts of the system.
Waipā's Construction Manual	Waipā's Construction Manual that the internal field services use for constructing and installing equipment on the network. This standard is disseminated to external contracting staff as appropriate.	Internal design team, in-house Contracting department, and external Contractors engaged by Waipā. Waipā will instruct external contractors as part of the procurement process that works are to be undertaken per applicable elements of Waipā's Manual.	The Manual is reviewed and updated internally on an as-needed basis.
Waipā's Network Design Manual	Waipā's Network Design Manual is driven by safety and recognised good industry practice and is used by Waipā's staff in developing designs for network assets.	Internal design team, in-house Contracting department, and external Consultants engaged by Waipā. The Network Design Manual is available through the intranet.	The Manual is reviewed and updated internally on an as-needed basis.
Waipā's Maintenance Standard	Waipā's Planned Maintenance Standards and network inspection criteria specify processes and procedures relating to the maintenance of assets on Waipā's network. This includes inspection requirements and frequency.	The Network Development and Engineering Manager communicates the document to relevant team members.	In-house management of the maintenance standards by Waipā's Network Development and Engineering Manager.
Other relevant industry Standards	Designs should be undertaken per relevant industry best practices (i.e., following current applicable standards). Examples are the construction of new switch room buildings or foundations supporting sub-transmission poles in soft ground. Consultant engineers engaged by Waipā must undertake design according to relevant industry standards, such as AS/ NZS 1170.5: 2004 – Structural design actions, Part 5: Earthquake actions. Another example is AS/NZS 7000: 2010 – Overhead line design: Detailed procedures.	Waipā's staff work to applicable standards. The internal standards are formulated based on relevant national/ international standards.	Waipā is a subscriber to Standards New Zealand. Waipā receives electronic notification when relevant standards are updated.
Asset Management Plan	Summary of assets and their management for the next ten-year period.	Numerous stakeholders. AMP is publicly disclosed.	Regulated by the Commerce Commission. Internally reviewed, updated, and signed off by the Board.

Table 3: Summary of asset management processes/documentation

2.5 Link to other documents

Our suite of documents on asset management practices is constructed around our vision and aligned with our organisation's purpose and values. The objectives of the AMP align with other corporate goals and business planning processes. Documents related to this AMP include:

- **Statement of Corporate Intent (SCI):** The SCI is published annually and is available on our website. This document sets our key strategic objectives each year, including network reliability targets, customer engagement objectives, business development goals (accreditations, etc.), customer discounts, and rate of return to shareholders. Asset-related objectives in the SCI are included within this AMP. Our SCI is a requirement under Section 39 of the Energy Companies Act 1992. It forms the principal accountability mechanism between our Board and our shareholders.
- **The Strategic Plan:** The Strategic Plan has identified Asset Management as a fundamental component for achieving the corporate objectives. Specifically, our asset management team is responsible for:
  - Keeping abreast of technology with the ability to impact our business and develop strategies to respond appropriately to the challenges and opportunities they present.
  - Ensuring the appropriate addition of new distribution capacity matches actual and forecast demand.
  - Incorporating non-network solutions, demand management, and developing technologies when formulating network development plans.
  - Reducing operating costs and optimise the use of capital to achieve commercial efficiency and effectiveness through prudent management of assets, liabilities, risks, and costs; and
  - Delivering distribution service that meets the reliability and resiliency that our customers want.
- **Annual Business Plan and Budgets:** The Annual Business Plan and Budgets are informed by the AMP and provide implementation details and the financial ability to achieve the outcomes of the AMP. Our Directors approve the Annual Business Plan, Network Capital, and Operational Budgets at the March Board meeting for the year ahead.
- **Information disclosures (schedules 1 to 10):** required by the industry regulations administered by the Commerce Commission.
- Annual works plan: The annual works plan covers the delivery plan for the first year of this AMP and is updated for each successive year.
- Internal standards, policies, and procedures ensure that works are undertaken safely, to appropriate quality standards, and in consideration of our stakeholders' interests.

2.6 Compliance

One of the key drivers of our asset management objectives is the need to comply with legislative requirements. The following are some of the key statutory Acts and Regulations that direct our asset management activities:

- Health and Safety at Work Act 2015
- Electricity Act 1992 (including subsequent amendments)
- Electricity Industry Participation Code
- Commerce Act 1986
- Utilities Access Act 2010
- Energy Companies Act 1992
- Companies Act 1993
- Electricity (Safety) Regulations 2010 (and subsequent amendments)
- Electricity (Hazards from Trees) Regulations 2003
- Various Electrical Codes of Practice (tied to the Electricity (Safety) Regulations)
- Resource Management Act 1991

Other legislation and regulations about our activities (for example, the Employment Relations Act 2000) exist. They are not included here for the sake of brevity.

Our procedures and policies are written to comply with legislative requirements and codes. They're updated as and when revisions come into effect.

Our senior management regularly reviews our legislative compliance via a company-wide assessment using ComplyWith. Reports are provided to our Chief Executive and our Board on a six-monthly basis. Legislative breaches are reported to our Board as they occur.

2.7 Public safety and amenity values

We have implemented a Public Safety Management System that is audited by external auditors annually.

We'll take all practicable steps to eliminate the risk of injury to people and animals and damage to property by ensuring that:

- All electrified assets are secure from unintentional or accidental contact by the public.
- All equipment earthing complies with industry standards.
- All network assets are maintained in good, safe working order.
- All faults are automatically detected, and faulted equipment is disconnected from the supply and made safe.

We'll consider the requirements of the Resource Management Act, Waipā District Council Plans, Waikato District Council Plans, Otorohanga District Council Plans, Waitomo District Council Plans, Waka Kotahi/New Zealand Transport Agency requirements, and On Track requirements when constructing new assets.

These steps are consistent with our objective to ensure our practices are environmentally friendly and sustainable.

PART 1:

THE KEY ISSUES FACING THE NETWORK

WAIPĀ NETWORKS

3. NETWORK OVERVIEW

This section summarises our network and the region we operate in, drivers of network demand, network configuration, and the factors driving investment and performance.

3.1 Background to our network

Our network originally began as two historically distinct networks established more than 100 years ago:

- The Te Awamutu Power Board and
- The Cambridge Borough Council electricity department.

In 1993, the company merged to form Waipā Power, later renamed Waipā Networks Limited in 1998, with the shares held by the Waipā Networks Trust. The beneficiaries of the Trust are the customers connected to our network.

We distribute electricity throughout the Waipā region to more than 29,000 customers (ICPs) on behalf of 26 energy retailers. Our position is to operate the distribution function in the electricity supply industry, shown as D and E in Figure 14.

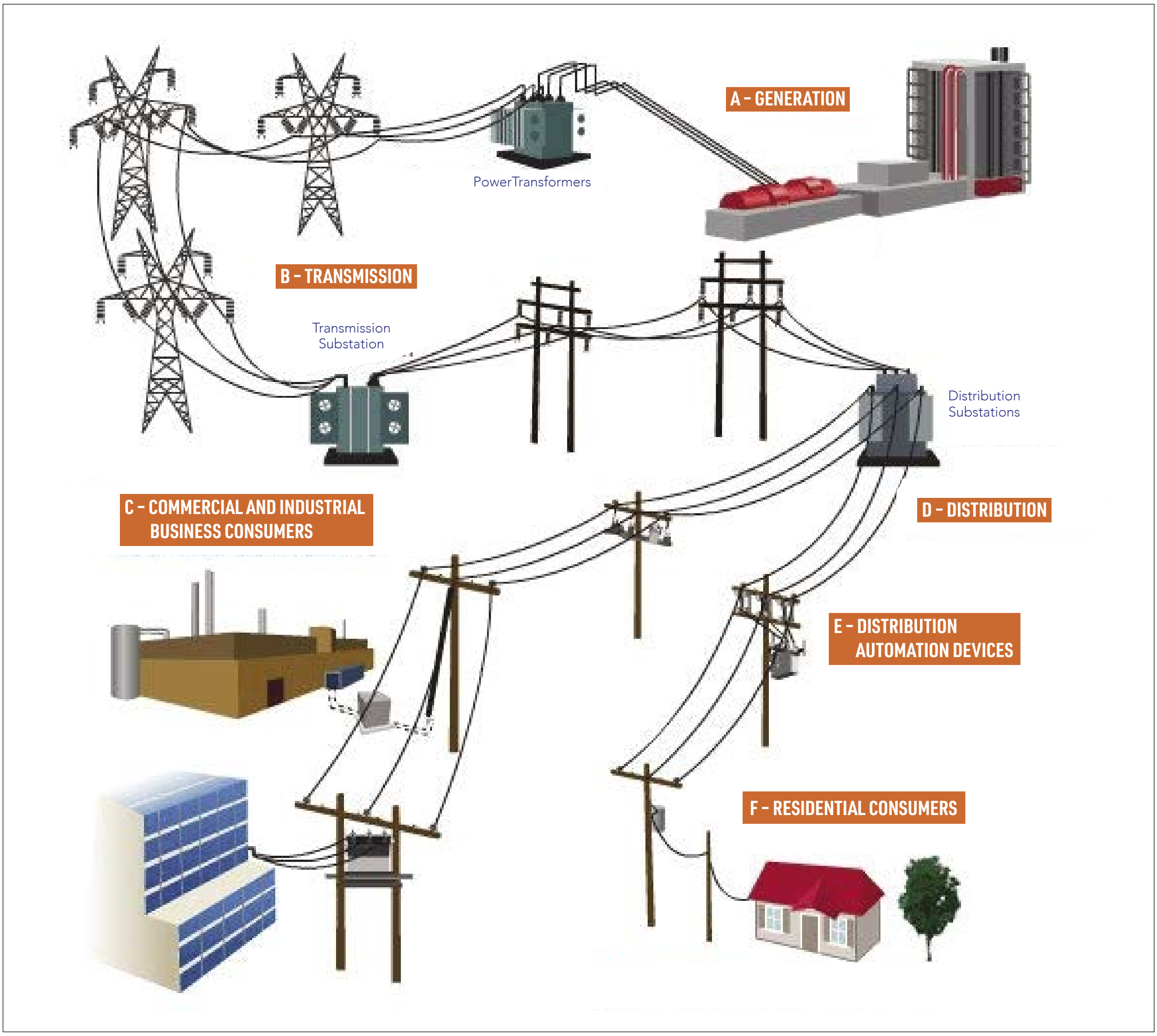


Figure 14: Illustration of the New Zealand electrical supply industry[14]

[14] *Image source: Electricity industry structure | WorkSafe (https://www.worksafe.govt.nz/topic-and-industry/energy-safety/electrical-industry-structure/)*

3.2 Region and context

Our network covers the Waipā area in the Waikato and King Country regions of the North Island, predominately in the local authority areas of Waipā and Otorohanga Districts, with minor reticulation in part of the Waikato District south of Hamilton and Waitomo District south of Kawhia as illustrated in Figure 15. Our distribution system covers 1,865 square kilometres.

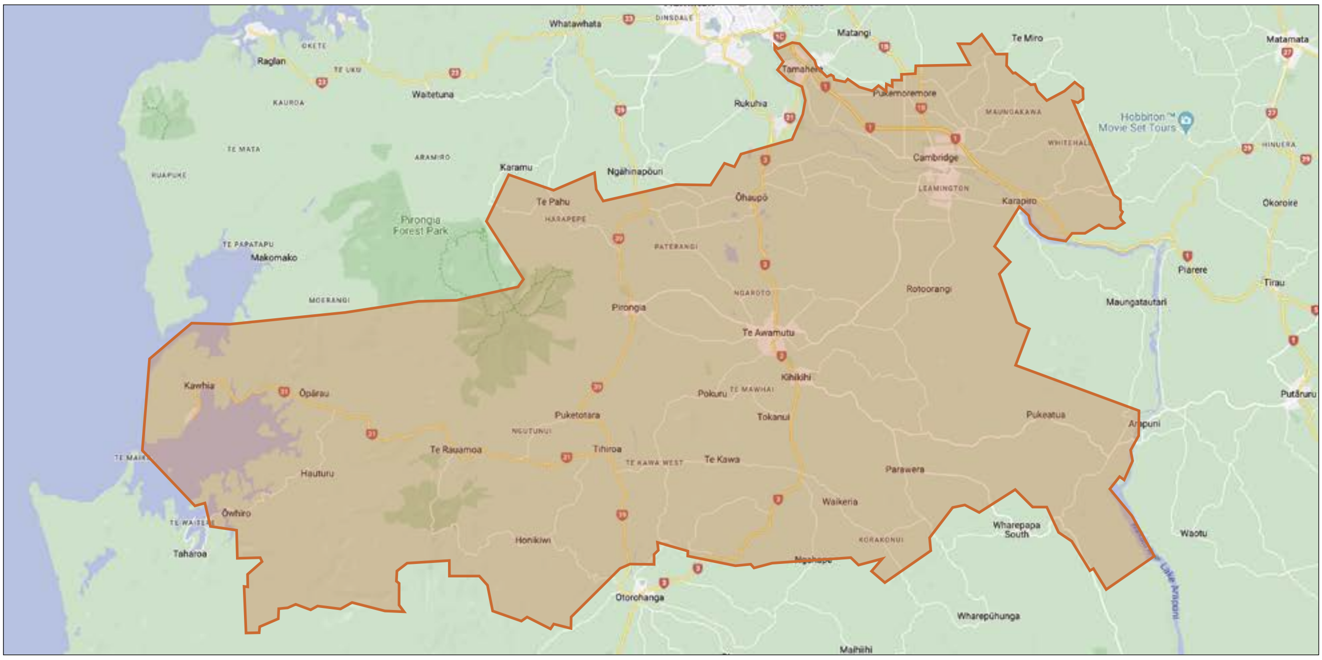


Figure 15: Network supply area overview

3.2.1 Supply area characteristics

Our distribution assets are generally located within the road reserve in the urban and suburban areas of Cambridge, Leamington, Te Awamutu, Hairini, Kihikihi, Ohaupo, Pirongia and Kawhia. In the rural areas of Tamahere, French Pass, Roto-O-Rangi and Kaipaki that surround Cambridge and in Paterangi, Pirongia, Pokuru, Kiokio, Waikeria, Pukeatua, and Mystery Creek that surround Te Awamutu, there are more areas where assets traverse private property as the most economical way to reticulate power in the area.

In the remote rural areas with low population densities, such as Kawhia and Hauturu, there are significant instances where our assets traverse private property.

Our network area is mainly flat but has relatively high rainfall and a temperate climate that encourages rapid vegetation growth, leading to the need for tree trimming and vegetation control on a short-return basis.

Most of our peak load is related to our residential connections peaking in winter. There is also relatively high demand in summer driven by dairy milking, processing, and an increase in irrigation load. This causes fairly high summer demands – particularly during prolonged dry and hot periods.

3.2.2 Urban areas

Te Awamutu and Cambridge contain a mix of residential, small commercial and industrial customers. Our maximum demand is predominately a result of winter heating in homes and typically occurs between 7am to 11am and 4pm to 8pm during cold temperatures. The towns of Te Awamutu and Cambridge represent approximately 43% of the total load.

Residential load is growing despite the increased use of energy-efficient lighting and other appliances and heat pumps rather than conventional heaters. Typically, growth in residential connections has been constrained by the availability of residential sections, which is now changing due to the currently active subdivision market.

3.2.3 Rural areas

A significant issue facing our business is high load growth and supply enhancements exceeding the capacity of 11kV feeders due to low voltage constraints.

In addition, environmental regulations and changes in line construction code requirements are now more stringent than when the lines were constructed. This makes it more involved to build new or upgrade 11kV feeders.

Factors such as low customer density increase both the cost of construction and the operation/maintenance of our network. These factors also reduce the overall operating efficiency of our network relative to installed capacity. Network revenue from more remote customers does not meet the costs incurred, and cross-subsidies are required from the rest of the customers across our network.

Location

Limited lines near the coastal areas are subject to salt spray. These lines require higher levels of inspection and maintenance, with special provisions needed to minimise corrosion damage to conductors and transformers, as well as managing salt build-up on insulators and the potential spalling on concrete poles.

Network access

Some existing lines were built on private or Government-owned land and constructed in the 1960s and 1970s, with access protected by wayleaves and the "existing works" provisions of the Electricity Act. We have limited easements over line routes. Therefore, upgrades that necessitate changes to the existing layout may require new easements to be created. This is a challenging, often costly, and time-consuming process.

3.2.4 Vegetation management

We have an ongoing programme of vegetation control to minimise interruptions caused by tree branches being blown across our lines. However, there are practical and regulatory limits to the amount of vegetation control undertaken, particularly given the sensitive environment in which these lines are constructed, the distances that branches can be blown, or the potential for trees to fall through lines. In some areas, the lines have been built in environmentally sensitive areas, and in others, the lines have been surrounded by forestry planted after the construction of our lines.

3.2.5 Regional risks

Earthquake (including liquefaction and tsunami)

Earthquake risk in our network area is medium risk in Transpower's category ranking system. However, a significant earthquake in the Waikato region is expected to result in widespread liquefaction due to the wide presence of peat soil.

Tsunami risk is considered minor due to the small area of our network exposed to the West Coast. A significant and rare earthquake on the Puyseger Trench (to the South and West of the South Island) could cause some inundation to settlements at Aotea and Kawhia, requiring relatively minor remediation of ground-mounted assets.

Significant adverse weather events

Our network is in an area of New Zealand that has one of the lowest recorded average wind speeds. However, seasonal storms have winds that blow debris into our overhead lines annually. In more major storms, such as the 2003 "weather bomb", February 2022 cyclone Dovi and February 2023 cyclone Gabrielle, our network suffered numerous outages with significant damage caused by trees well outside the regulatory growth limit zone being blown over our lines. This resulted in substantial restoration works.

Other regional natural hazards are further discussed in Chapter 6.2.

3.3 Customers and network demand

3.3.1 Customer overview

Our network supports approximately 29,000 connections and a population of 60,000 across four distinct demographic areas. While the Waipā region is one of the more affluent areas of Waikato, we still have significant diversity in our customer base and their needs.

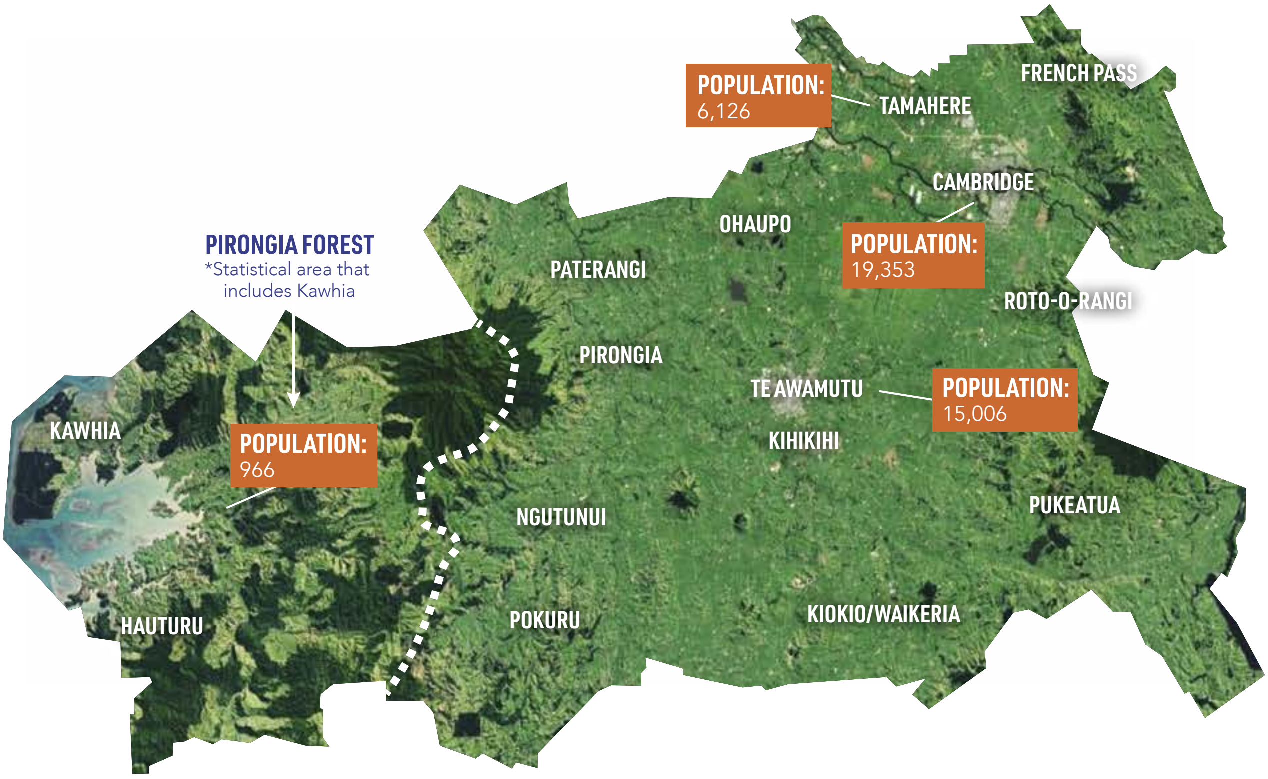
Our customers range from residential to large industrial, and our region is one of the fastest growing in New Zealand relative to size. Approx. 19% of our ICPs are from business customers, with 46% from the dairy and agriculture sector.

Within our residential customer group, we have significant economic diversity. Areas such as Cambridge and Tamahere have high disposable incomes and higher demand on our network. By comparison, areas such as Kawhiā have a disproportionally higher level of economic hardship, where disposable incomes are, on average, one-third of those in Tamahere, and many customers experience hardship. Figure 18 shows the population distribution in the network supply area and the differences in the unemployment rate.

Hardship can not only impact customers financially – continuity and quality of electricity supply can equally impact a customer's experience of hardship, particularly in the winter months when storms and adverse weather are generally more frequent.

A particular focus in the immediate term is to explore opportunities to improve network performance and enhance customer experience through an increased understanding of customer needs and emerging technology. We're prioritising customer groups and/or network areas more susceptible to supply disruption. We proactively undertake high-impact activities such as vegetation management, asset review and asset renewal to improve network performance and overall customer experience.

Understanding our existing connected customers and where future customer growth will come from (both industrial and residential) is equally important to ensure we can align asset and network development plans to future growth and demand.



PIRONGIA FOREST	TAMAHERE	CAMBRIDGE AREA	TE AWAMUTU AREA
Occupied: 411	Occupied: 1,989	Occupied: 7,374	Occupied: 5,691
Unoccupied: 414	Unoccupied: 120	Unoccupied: 420	Unoccupied: 345

Figure 16: Population distribution in the network supply area (2023)

Our core communications approach focuses on reaching our community through digital and print media on areas of interest such as outages, public safety, and pricing. In the coming year, we'll increase our presence by introducing content and engagement opportunities to inform and engage our customers and community on key industry trends and new technology. Our presence in supporting wider community activities, such as sponsorships, will be more closely aligned with our purpose, values, and strategy, allowing us to be more visible and connected to our customers. We're continuing to invest in systems that improve our ability to manage customer interactions and provide an improved customer experience through consistent messages, service, and provision of information.

When seeking feedback from or directly engaging with our customers, we utilise several methods, including surveys, focus groups, targeted individual customer discussions, and interactions via our customer-facing teams. Community engagement initiatives, such as our partnership with Ecobulb for the distribution of energy-saving, long-life light bulbs and community energy assessments and sponsorship of several community initiatives and groups, enable us to have a consistent community presence and a further opportunity for informal and indirect engagement with customers.

3.3.2 Demographics and economy[15]

Waipā District (which comprises most of Waipā's network area) had a resident population of about 61,100 people, a 1.8% average annual increase in 2023.

The district has had an average gross domestic product (GDP) annual growth of 3.3% over the past ten years. However, economic wellbeing is not uniform across our network. There is a marked difference in affordability between areas, for example, Cambridge vs Kawhia. The differences influence the solutions we adopt for our network to ensure equity.

Figure 19 shows the historical GDP trend for the Waikato region. From this, we anticipate relatively constant customer connection growth at the historical average levels will continue over the ten-year planning period.

[15] *Regional Economic Profile: https://ecoprofile.infometrics.co.nz/Waipa%20District*

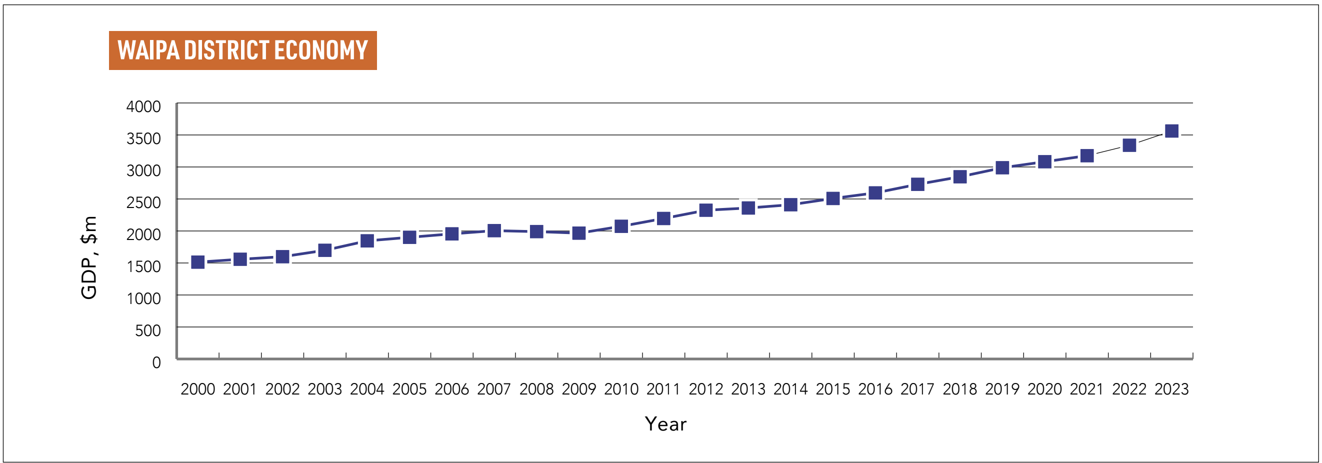


Figure 17: Waipā District gross domestic product (February 2023)

3.3.3 Key economic activities

The key economic activities in our network area include the following:

- Agriculture, Forestry and Fishing
- Improved transport links and new industrial subdivisions drive manufacturing growth.
- Construction

Factors that may impact economic activity in our area include:

- Markets for dairy products.
- Government policies on land use, particularly about forestry, water use/quality and climate change.
- Access to water for crop and stock irrigation.
- Growth in Health Care and Social Assistance includes retirement and assisted care living facilities.
- Therefore, any sustained climate change that impacts agriculture industries influences our area's economy.

Table 4 shows the impact of these issues on our electricity distribution business. Low probability outcomes are considered and addressed within our risk management framework.

Issue	Impact
Shifts in market demand for milk	There is a strong international demand for milk, with two large milk processing factories and significant dairy farming activities on our network. Electricity use from this sector is reasonably static, but changes in milk demand may alter this.
Government policy on nitrogen-based farming	This may lead to a contraction of dairy shed demand. This may lead to a contraction of dairy processing demand.
Milk prices	Higher milk prices may lead to the further conversion of pastoral land to dairying and subsequent increases in demand. However, this now appears unlikely due to environmental concerns and alternative high-value land uses.
Climate change increases the frequency of droughts.	This may lead to increased irrigation demand.
Lack of generation and/or electricity supply nationally	Curtailment of supply to our customers.
Increase in distributed generation, including photovoltaic installation on customer premises.	This could affect power flow patterns and power quality over our network, which may require changes to our pricing structure to ensure equity and fairness by greater recovery of costs on a fixed or capacity basis.

Table 4: Economic influences and impacts on our network

Generally, the load on our network consists of many small customers. While the loss of a large load would affect the operation of our network, the effect would be relatively minor compared to the overall impact of changes to the economy or a decline in one of the significant regional industries. For example, an overall sustained downturn in the dairy industry would have a much greater effect on the operation and development of our business than the loss or gain of two or three of our largest customers.

3.3.4 Emerging drivers of electricity use

Increased electrification to support decarbonisation is emerging as a significant driver of electricity use as polluting energy sources, such as coal, gas, and wood, are phased out. Relevant initiatives include:

- Transport: Charging electric vehicles (EVs) is becoming more prevalent. EV take-up is expected to be gradual within this planning period.
- Industrial: decarbonising industrial process heat to meet climate change targets may cause the electrification of dairy factories with potential large increases in demand. Using biomass with selective industrial heat pumps for low-grade process heat may reduce the impact.
- Gas-to-electricity conversion: transition from use of natural gas to electricity.
- Domestic: heat pumps are expected to become more common for domestic space heating and will likely be used as air conditioners in the summer.

A discussion on the expected impact of the decarbonisation-driven initiatives and possible response is presented in Section 8.

3.3.5 Large customers

We supply two large Fonterra dairy factories located at Hautapu and Te Awamutu. The Hautapu factory is approximately 4km from Cambridge GXP and is supplied via two dedicated 11kV overhead line feeders. The Te Awamutu factory is located 1km from Te Awamutu GXP and is supplied via two dedicated 11kV cable feeders. Fonterra contracts every year with us for each factory's maximum demand (MD) requirement. Currently, Hautapu's maximum demand does not exceed 10MW, and Te Awamutu MD does not exceed 4.5MW.

Fonterra's MD requirements significantly impact our system peak load control regime and available capacity at Transpower's Cambridge and Te Awamutu GXPs.

Architectural Profiles Limited (APL) is a new glass and aluminium joinery factory at Hautapu with a demand of 2.7 MVA on the Cambridge GXP. Subsequent stages could add another 10 – 12 MVA by 2028, requiring a new industrial zone substation at Hautapu in conjunction with the GXP capacity upgrade.

Table 5 summarises our five largest electricity customer groups.

Ranking by size	Nature of business	Nature of demand
1	Dairy processing	Dairy season variation – short winter down period
2	Combined dairy milking	Dairy season variation – short winter down period
3	Manufacturing	Constant throughout year
4	Food processing	Constant throughout year
5	Small residential and commercial	Seasonal heating variation, some influence of summer air conditioning

Table 5: Five largest customer groups

3.3.6 Load characteristics

Our current seasonal load profile is driven mainly by winter residential and commercial load and the ramp-up of dairy load in August and September. The maximum demand in summer is typically subject to dairy milking load depending on production. This is reflected in Figure 19, which shows a winter-peaking network. This Figure also shows a significant load growth in the combined GXP load between 2017 and 2022.

Network utilisation is expected to shift from past trends as the economy increases reliance on electricity driven by decarbonisation. We're developing tools and systems to track this shift and inform our network development approaches.

In FY2022/23, the network delivered 440GWh of electricity to approximately 29,000 connected customers. The maximum coincident (instantaneous) system demand was 88MW, with a load factor of 57%.

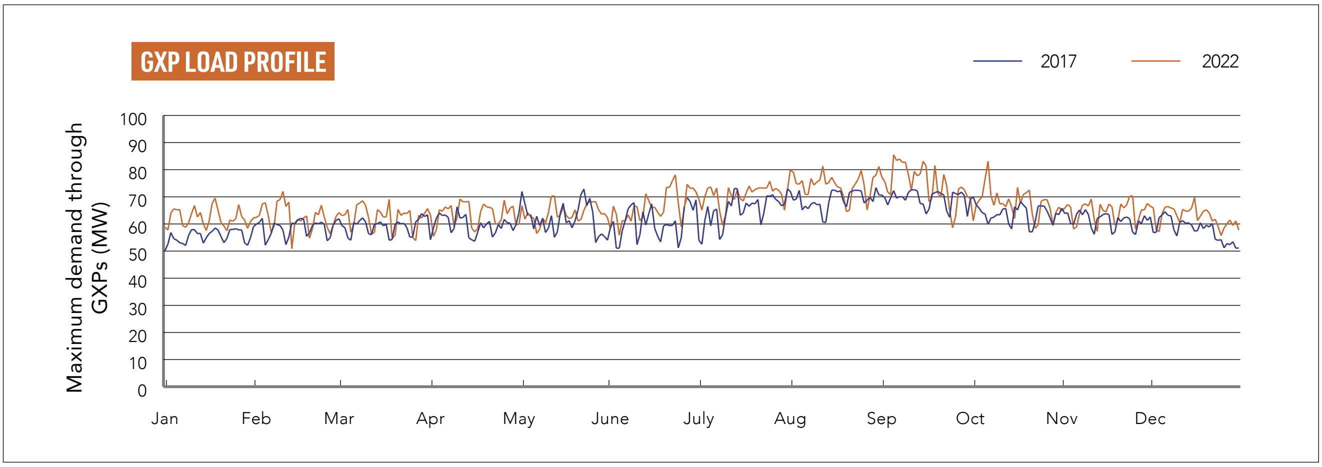
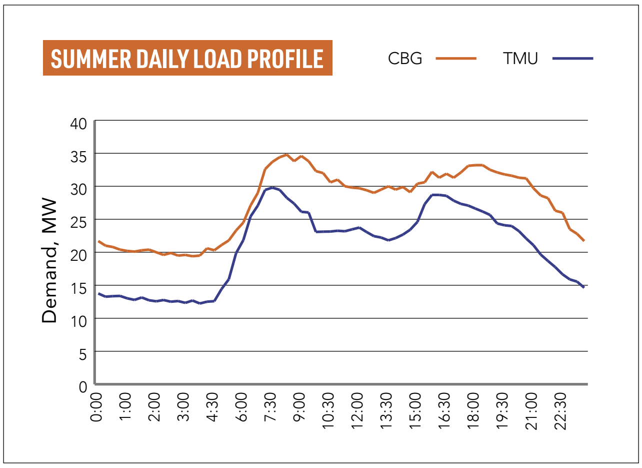


Figure 18: Our seasonal load profile (MVA)

Voltage limits mainly drive the feeder's capacity constraints at peak times and during back-feed situations. Our daily load profile, especially in winter, consists of twin peaks: one in the morning and another at night. Load management using ripple control is applied when appropriate. Our daily profile has peaks driven by dairy milking times, with dairy processing influencing the baseload load.



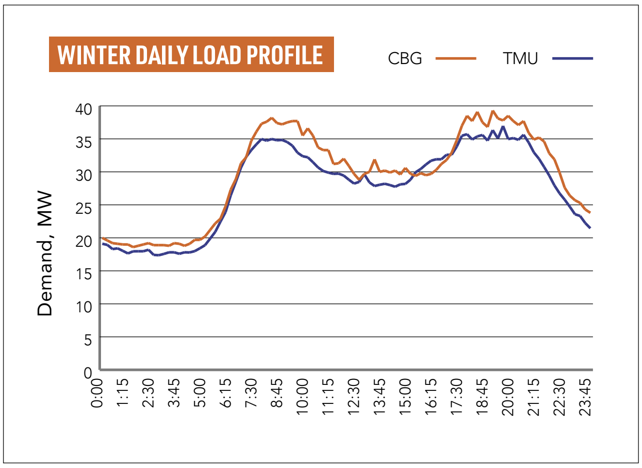
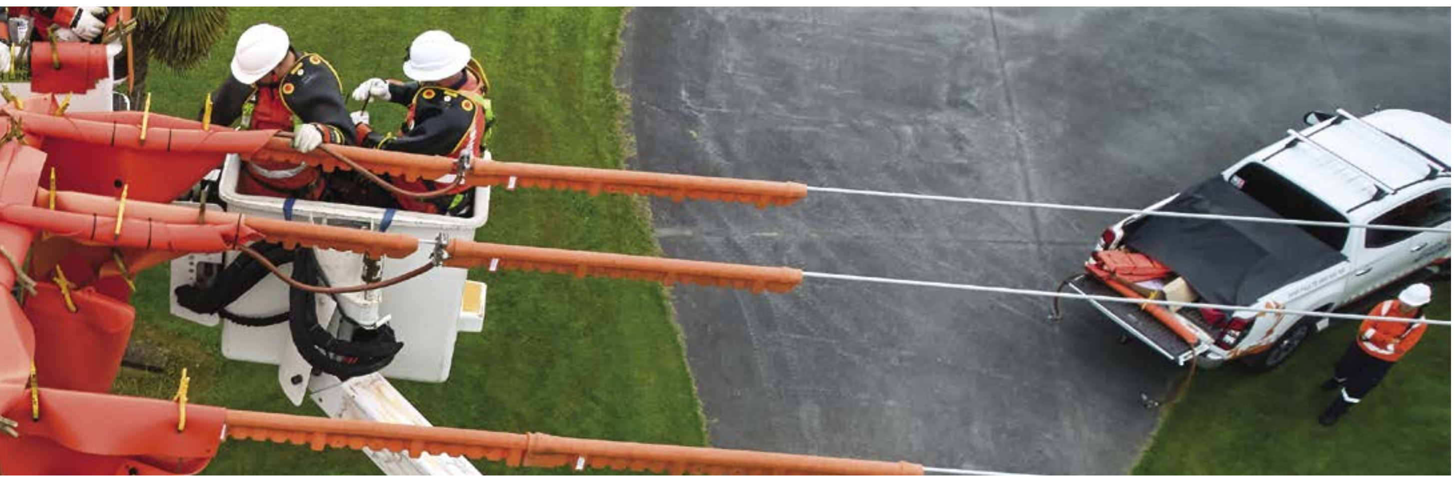


Figure 19: Daily GXP load profile



3.4 Our network configuration

We take supply from Transpower's Cambridge and Te Awamutu GXPs at 11kV, with no interconnections between the two 11kV networks. We currently don't own a sub-transmission system or zone substations.

Figure 20 shows the geographic view of the 29 x11kV feeders supplied by the two GXPs of Cambridge and Te Awamutu. Appendix A shows our 11kV feeder attributes as of 31 March 2023.

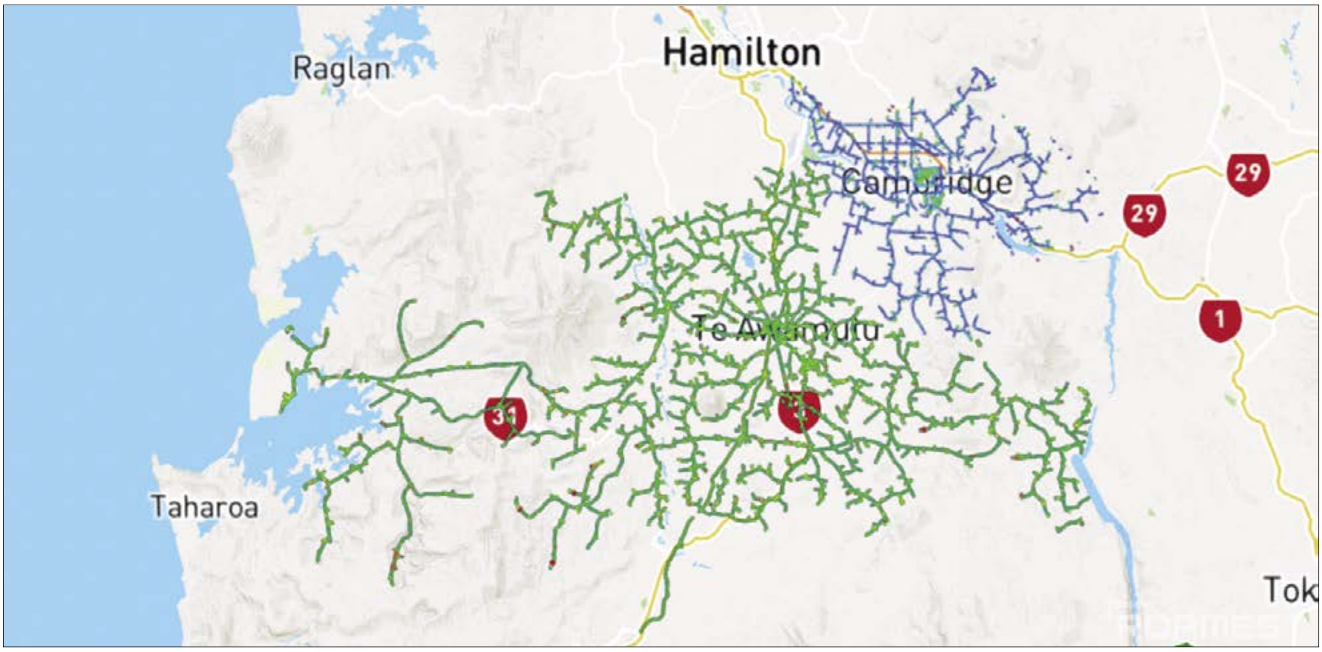


Figure 20: Extent of our network

Our assets extend to the customer point of supply, which (in most cases) is the property boundary line crossed by a customer's service line. This means that most of our customer service line is owned by the property owner, not us.

3.4.1 Major asset groups

Table 6 presents a summary of our major asset groups.

Type	Quantity	Average remaining age[16]	RAB value $000
110kV transmission lines	33 km	49 years	21,043
Distribution and LV lines	1,745 km	26 years	32,609
Distribution and LV cables	538 km	27 years	26,507
Distribution transformers	3,693	27 years	36,882
Distribution switchgear	5703	21 years	21,620
Other network assets	-	21 years	7,686
Non-network assets	-	16 years	15,895
Total			**162,242**

Table 6: Our major asset classes (RAB values from 2023 information disclosure)

3.4.2 Cambridge network configuration

14 x 11kV feeder circuit breakers at Cambridge GXP supply radial urban and rural feeders, including two dedicated feeders supplying the Fonterra dairy factory at Hautapu and one supplying the APL glass factory.

The fourteen 11kV interconnected radial urban and rural feeders are made predominately of concrete pole lines. These lines and associated 400V reticulation supply Cambridge, its suburbs, and rural areas adjacent to the Waikato River from Lake Karapiro to Tamahere on the outskirts of Hamilton.

In the urban and suburban areas, there is a moderate amount of underground reticulation with pad-mounted transformers and switchgear.

[16] *Average remaining age is based on expected asset life in the optimal deprival value (ODV) methodology.*

3.4.3 Te Awamutu network configuration

There are fifteen 11kV feeder circuit breakers at Te Awamutu GXP supplying radial urban and rural feeders, including two dedicated underground cable feeders supplying the Fonterra dairy factory in Te Awamutu and one feeder supplying the Department of Corrections Waikeria Prison.

The fifteen 11kV interconnected radial urban and rural feeders are predominantly concrete pole lines. These lines and associated 400V reticulation supply Te Awamutu's urban, suburban, and rural areas from Te Awamutu towards the north to Mystery Creek, south-east to Arapuni, south towards Otorohanga and west to Paterangi, Pirongia, Pokuru and Kawhia.

In the urban and suburban areas, there is a moderate amount of underground reticulation with pad-mounted transformers and switchgear.

3.4.4 Distribution network characteristics

We operate an 11kV distribution network, which is mainly radial with interconnections in urban and higher-density rural areas. Approximately 11% of the 11kV (by line length) is underground. The total length of cable and conductor operating at 11kV is about 1,405km.

The 11kV supplies from Cambridge and Te Awamutu GXPs aren't configured to be interconnected. An 11kV interconnection point to WEL Networks in the Te Pahu area was initially established to assist WEL with network conductor renewal.

Our distribution substations are predominantly pole-mounted transformers (up to 100kVA on single pole structures) as permitted by District Council Plan requirements, and in urban and suburban areas and industrial applications pad-mount substations (typically from 50kVA up to 1,500 kVA).

Our legacy 400V reticulation is predominantly overhead except for urban areas. New 400V reticulation is generally underground as required by the respective District Council Plans, except for rural and remote regions where overhead reticulation is permitted on economic grounds.

Our distribution system comprises (as of 31 March 2023):

Cambridge area

- 14 x 11kV feeder circuits connected to Cambridge GXP,
- 457km 11kV circuit (341km overhead line, 116km underground cable),
- 350km 400V circuit (150km overhead line, 200km underground cable),
- 1,455 11kV/400V transformers (137,657kVA capacity) and
- 6,958 Poles (6,036 Concrete, 922 Wooden, 14% of the total).

Te Awamutu area

- 15 x 11kV feeder circuits connected to Te Awamutu GXP,
- 948km 11kV circuit (895km overhead line, 53km underground cable),
- 500km 400V circuit (354km overhead line, 146km underground cable),
- 2,196 11kV/400V transformers (141,059kVA capacity) and
- 15,150 Poles (14,564 – Concrete, 586 – Wooden, 4% of the total).

System switching, isolation and protection are achieved via feeder circuit breakers at Transpower's GXP and our ring main units, line auto reclosers and sectionalisers, disconnectors, 11kV dropout fuses and 400V fuses.

SCADA and radio communication systems enable remote monitoring and control of distribution switchgear and voltage regulators.

Two 11kV ripple injection plants and receiving relays at customers' installations enable load management, control of street lighting and management of feeder loads and maximum demand at each GXP.

3.4.5 Transpower point of supply/ transmission lines

Cambridge

Transpower owns the 110kV line assets, the 110kV/11kV transformers and the 11kV switchboard supplying our 11kV feeders. Cambridge GXP is supplied via a double circuit 110kV line from Karapiro to Hamilton and has an n-1 capacity of 47 MVA. There are two 40 MVA transformers at Cambridge, giving a total installed nominal capacity of 80 MVA and a firm n-1 security post contingency capacity of 47 MVA. These transformers operate parallel and supply the 11kV bus bar via two incoming circuit breakers. The 11kV incomers and bus bar are rated at 2500A (47.6MVA).

We also own a 3MVA diesel generation plant embedded in the 11kV network. The facility is operated for peak lopping purposes to manage the network peak, as seen by the GXP.

The current peak load at Cambridge is 49MVA.

Due to continuous growth and major loads connecting to our network, development plans are underway to establish a new GXP and sub-transmission system in Cambridge to maintain reliability, security, and continuity of supply.

Te Awamutu

Transpower owns the 110kV line assets, the 110kV/11kV transformers and the 11kV switchboards to which our Te Awamutu 11kV feeders are connected. Te Awamutu GXP is supplied via a single-circuit Transpower 110kV transmission line from Karapiro and a Waipā-owned single-circuit 110kV transmission line from Hangatiki.

Te Awamutu has 7.5 MVA of embedded generation (typically operating to 5 MW) at the Fonterra dairy factory site connected to the Te Awamutu GXP via 11kV cables.

There are two 40 MVA transformers at Te Awamutu, giving a total installed capacity of 80 MVA and a firm n-1 security post-contingency capacity of 41 MVA. In 2023, Transpower completed a protection upgrade to increase the transformer capacity to 52 MVA (summer) and 54 MVA (winter). These transformers operate parallel and supply two 11kV bus bars via four incoming circuit breakers. Twelve 11kV circuit breakers supply urban and rural feeders, and two 11kV circuit breakers supply the Fonterra dairy factory site in Te Awamutu.

The current peak load at Te Awamutu is 39MVA.

3.4.6 Distributed generation on customer premises

Customer interest is expected to grow as the affordability of distributed generation (DG) systems improves, and some customers opt to offset their electricity consumption through distributed generation at their premises. Subscription-based ownership for residential installations is expected to contribute to adopting DG systems.

We connected 283 new distributed generation installations in 2023, adding 2.6 MVA installed capacity. Figure 21 shows that DG uptake (dominated by small-scale solar PV) has increased since 2013. New subdivisions and where developers require the connection of solar DG at every house will accelerate DG uptake.

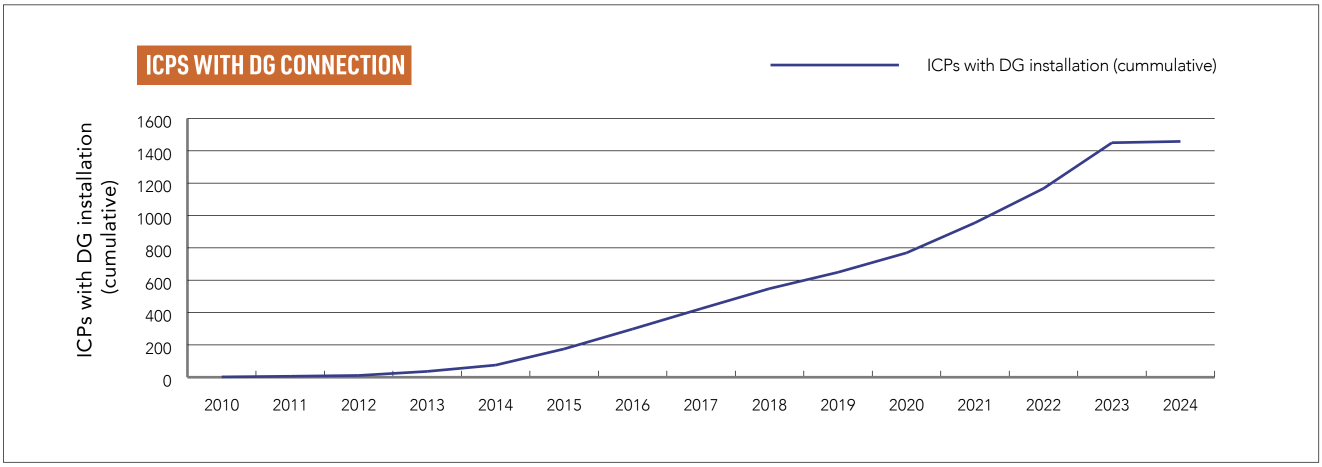


Figure 21: ICPs With DG Installation (Cumulative)

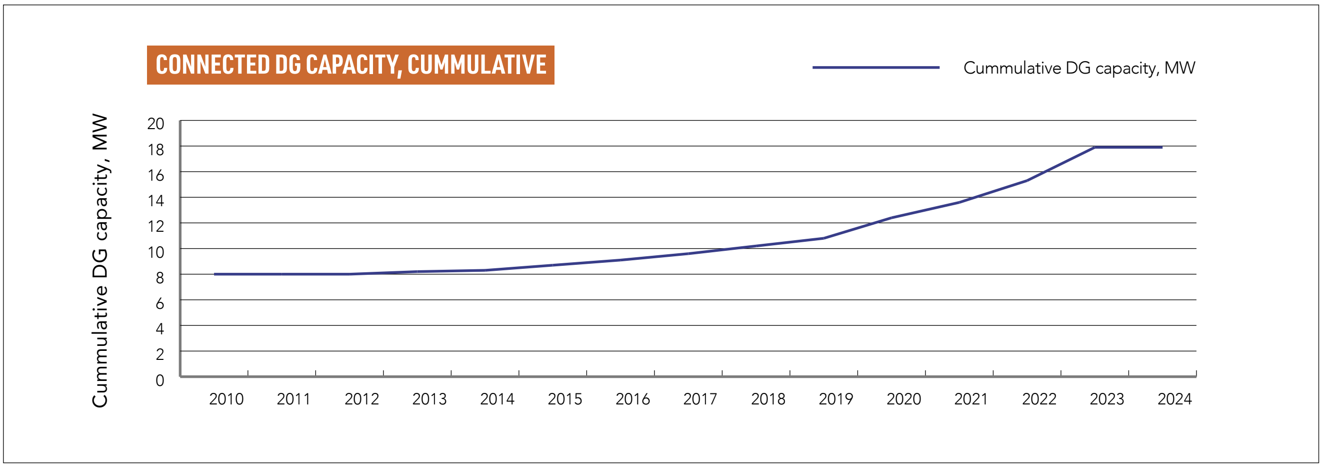


Figure 22: DG connected capacity (cumulative MW)

Customers with large or sensitive loads also have standby generation available for backup and/or demand management. These are typically diesel generators ranging from 10kW up to 1MW. Notable examples include communications sites, District Council water infrastructure and the Waikeria Prison.

3.4.7 Generation

The embedded co-generator at the Fonterra dairy factory in Te Awamutu occasionally exports electricity at 11kV, but typically, the site imports 1-2 MW and generates the balance of the site load.

Customers want to install new systems like distributed generation (DG). The impact of this technology must be managed to ensure that:

- our network voltage regulation is effectively managed to avoid excessive voltage rise, particularly on low-voltage networks.
- the effects of the generation on our line protection are considered; that work on the associated lines can be done safely and
- we don't become unduly constrained in our ability to manage our network.

3.4.8 Distribution system

Underground cable is more expensive to purchase and install than overhead line. Determining whether underground cable is more appropriate than overhead conductor considers factors such as surrounding land use, safety, public amenities, and effort needed to resolve faults.

Distribution substations step down the voltage from 11kV to 400V/230V in locations appropriate to service customers' needs.

In rural areas, the distance between customers typically limits the utilisation of low-voltage lines. Also, 11kV lines are built with a pole spacing of 80m to 100m on the flat, with a greater distance depending on the terrain. In many rural areas, customer locations result in customers having individual transformers with less use of an LV conductor.

3.4.9 Low voltage network

We operate a 400V low voltage (LV) reticulation network, totalling approximately 878km. About 41% (by length) of the LV is underground. There is limited feeder interconnection in urban business district areas.

Our LV network supplies most of the ICPs, mostly domestic customers (i.e., residential properties) in urban areas. Typically, LV supply to ICPs in most cases is single or two phases but can be three phases depending on the supply for the region and the needs of our customers.

3.4.10 Secondary systems

Power system protection: Protection devices, mainly reclosers and 11kV fuses, are installed across our network. Selecting locations for protection devices considers downstream customers, location, and cost.

Lightning protection is generally installed on all underground to overhead transitions and in other lightning-prone areas.

Ripple control system: We use the ripple control system to manage loads such as water heating and control street-lights. We 're using ripple control systems to help manage GXP peak demand and transmission charges and load within the 11kV network to avoid network constraints during peaks.

The Cambridge ripple injection plant is in our building at the GXP, and the Te Awamutu ripple injection plant is in a separate room within Transpower's Te Awamutu GXP switch room.

SCADA: Our SCADA system covers all the distribution feeders. This system allows monitoring and control of the network remotely. We also use the SCADA system to initiate ripple signal injection into the network to control load, street lighting and metering tariffs.

Communication systems: Communication for network operations consists of dedicated radio equipment, as well as the use of leased fibre and cell phone networks. We also use voice radio for communication between control and field crews.

Automation: We've installed automatic switching devices (sectionalisers, reclosers, etc.) at various points along radial spurs to minimise the areas affected by faults in our network. Over recent years, our dedicated SCADA radio system linked to our devices has been expanded and will be further developed to enable remote control of switching devices within our network.

3.5 The key factors that are driving investment and performance

3.5.1 The high regional population and industrial growth driving demand growth

The Waipā region is a desired place to live and is well-situated for business. In 30 years, the network is forecast to be considerably larger regarding customers and demand/usage, even before electrification growth due to decarbonisation is considered.

Since 2013, we have consistently experienced the third highest ICP growth rate of any EDB in New Zealand. This has been driven by regional population growth of 2.8% p.a. We've also experienced industrial demand growth.

The growth in our customer base has resulted in demand increasing by approximately 23% to 88 MW over the past ten years. This high growth has resulted in capacity constraints at the Cambridge GXP and Te Awamutu GXP.

This high growth is forecast to continue for the foreseeable future (based on regional economic and population growth estimates).[17]

3.5.2 Impacts of regional growth and energy transformation

New Zealand's path to a future is driven by the displacement of fossil fuel energy with 100% renewable electricity. EDBs across New Zealand are aware that we have a key role to play as electricity offsets other less environmentally friendly forms of energy, and this is expected to result in:

- significant demand growth that will require investment in additional network capacity,
- greater reliance on the electricity network that will require investment to improve reliability, resilience, and
- connection of new types of devices that allow new ways of using our network (including bi-directional power flows and 'flexibility services') that will require investment to operate with a new network architecture.

However, there needs to be more certainty on the magnitude and timing of these changes and the impact on network expenditure. As we confront this challenge, we recognise the importance of providing clear signals to customers, communities, and other stakeholders of this transition's likely medium to long-term implications.

Demand growth due to electrification

Electricity demand growth is expected to accelerate towards the end of the decade because of process heat and transport electrification. Section 8 details the potential impact of electrification on our network demand.

This increase is in addition to the ongoing residential, commercial, and industrial demand growth. Significantly higher growth from electrification could result if we are unable to work with our customers (through procuring flexibility services or similar) to shift EV charging to low-demand periods and/or unable to procure flexibility services from customer battery installations (referred to as controllable Distributed Energy Resources or DERs) or manage customers' water heating load.

Use cases driving demand growth from electrification

Six use cases are driving the impact of increased electrification on networks:

- Conversion of industrial process heat (e.g., replacement of coal or gas-fired boilers),
- Replacement of natural gas.
  - Rural and agriculture energy process conversion to electricity; commercial and industrial gas substitution (process heat conversion); residential gas substitution (cooking, space heating, water heating); hydrogen plants.
  - Limited penetration of reticulated gas in our network area means there will be relatively less impact on the network demand from residential customers' gas-to-electricity conversion.
- Electrification of the light vehicle fleet with dispersed charging at homes and businesses.
  - While the current EV uptake is relatively low, we expect it to accelerate, especially if more government incentives emerge to support this.
- Electrification of transport fleets with large-scale centralised charging (e.g., public transport – buses, trains, planes, and ferries).
  - Hydrogen is emerging as an alternative clean transport option; however, hydrogen plants will likely be supplied from the same electricity networks.
- Connection of large-scale renewable generation (e.g., solar and wind farms) and
- Connection of small-scale solar PV at homes and businesses.

In many of the above cases, electrification is the only option. However, current indications from the major industries are that to reduce carbon emissions, they are more likely to convert their plants to run on biomass than on electricity. Energy costs partly drive this and the limitations of using electricity to effectively drive high-temperature heat processes (as required, for example, for steam boilers).

[17] *Regional Economic Profile–Wāipa District, https://ecoprofile.infometrics.co.nz/Waipa District/Population*

Reliability and resilience

As electrification increases, there will be a stronger link between electricity and GDP. Electrification will also reduce energy diversity (e.g., transport fuel moving to electricity will concentrate residential and potentially commercial energy dependence on electricity). This is okay, provided electricity security and resilience are at the requisite level to minimise the impact of low probability and high consequence events that interrupt supply for days or weeks. Figure 23 portrays the possible electrification scenarios, the extent of decarbonisation, and the expected corresponding network reliability.

		Extent of decarbonisation	
		Low	High
Reliability/resilience	High	Electricity is one of several energy choices for customers. Increased dependance on electricity means customers demand a level of reliability and resilience well above current levels.	Electricity powers almost every aspect of our homes and businesses. Our reliance means we have almost no tolerance for outages/non-supply.
	Low	Electricity is one of several energy choices for customers. Reliability levels haven't changed materially from today as customers are cost conscious. Those who need high reliability do so through in-premise (local) solutions.	Electricity powers almost every aspect of our homes and businesses. Reliability levels haven't changed materially from today as customers are cost conscious. Those who need high reliability do so through in-premise (local) solutions.

Figure 23: High-level scenarios

Insights for regional drivers of electrification

The extent of electrification demand growth and the availability and firmness of flexibility services are key areas of uncertainty for our business. Therefore, we undertook a regional review in mid-CY2023 that assessed regional drivers for growth (such as electrification) and produced a set of Waipā-specific decarbonisation scenarios to refine insights from national-level reports.

The scenarios are not forecasts but pictures of what a net-zero world might look like and the implications for us. Insights from the scenarios will support the development of new demand forecasts.

3.5.3 The age of the asset fleet

Our network is relatively young, and the average age of our network is around 19 years. The asset base is comparatively young due to the value of the Waipā's 110kV line between Hangatiki and Te Awamutu installed in FY2016 and new distribution assets installed as our network expanded to cater for growth in the past decade.

However, based on the analysis in Chapter 11, several asset classes now include a reasonable population of assets over 45 years old. As these asset fleets age, end-of-life drivers will increase, resulting in a deterioration of asset health unless the level of asset renewals increases. For example, around 30% of wood poles, 26% of overhead switches, and 16% of overhead transformers are over 45 years old.

This is not presently a material issue for our business. However, an increase in asset health deterioration needs to be managed through increasing asset renewals and/or asset maintenance.

Ongoing 'business as usual' maintenance and renewal of existing distribution network assets is and will continue to be a significant driver of investment. However, this isn't discussed here as it's not a 'new' driver of investment.

3.5.4 The increasing incidents and impact of adverse weather events

Based on the analysis in Section 4, we have experienced more significant impacts from adverse weather events in recent years, likely signalling an upward trend. Cyclone Dovi in CY2022 and Cyclone Gabrielle in early CY2023 both had a very significant impact on our network and customers.

The increase in SAIDI is driven by the rise in adverse weather outages and an increase in the time taken to restore electricity during the event due to the extent and severity of the events.

3.5.5 The need for greater asset management maturity

Our asset management maturity is measured yearly, and we are committed to continuously improving our position.

We've independently completed a review of our asset management practices following the AMMAT questionnaire in Schedule 13 of the EDB information disclosures. The report on Asset Management Maturity is attached as an appendix to this AMP. There are six assessment areas, each focusing on the way that our organisation manages either its processes or its people:

- Asset strategy and delivery
- Communication and participation
- Competency and training
- Documentation, controls, and reviews
- Structure, capability, and authority; and
- Systems, integration, and information management.

Figure 24 summarises the results of our asset management maturity assessment in 2024. The solid blue line represents observations from the current assessment for us, and the orange plots show industry maturity–the industry average and the industry's 75th percentile.

In the past 12 months, our work has led to good improvements in key areas but didn't achieve our targeted improvement in all areas. The effort required to implement improvements exceeded what was anticipated, and we experienced some resourcing constraints.

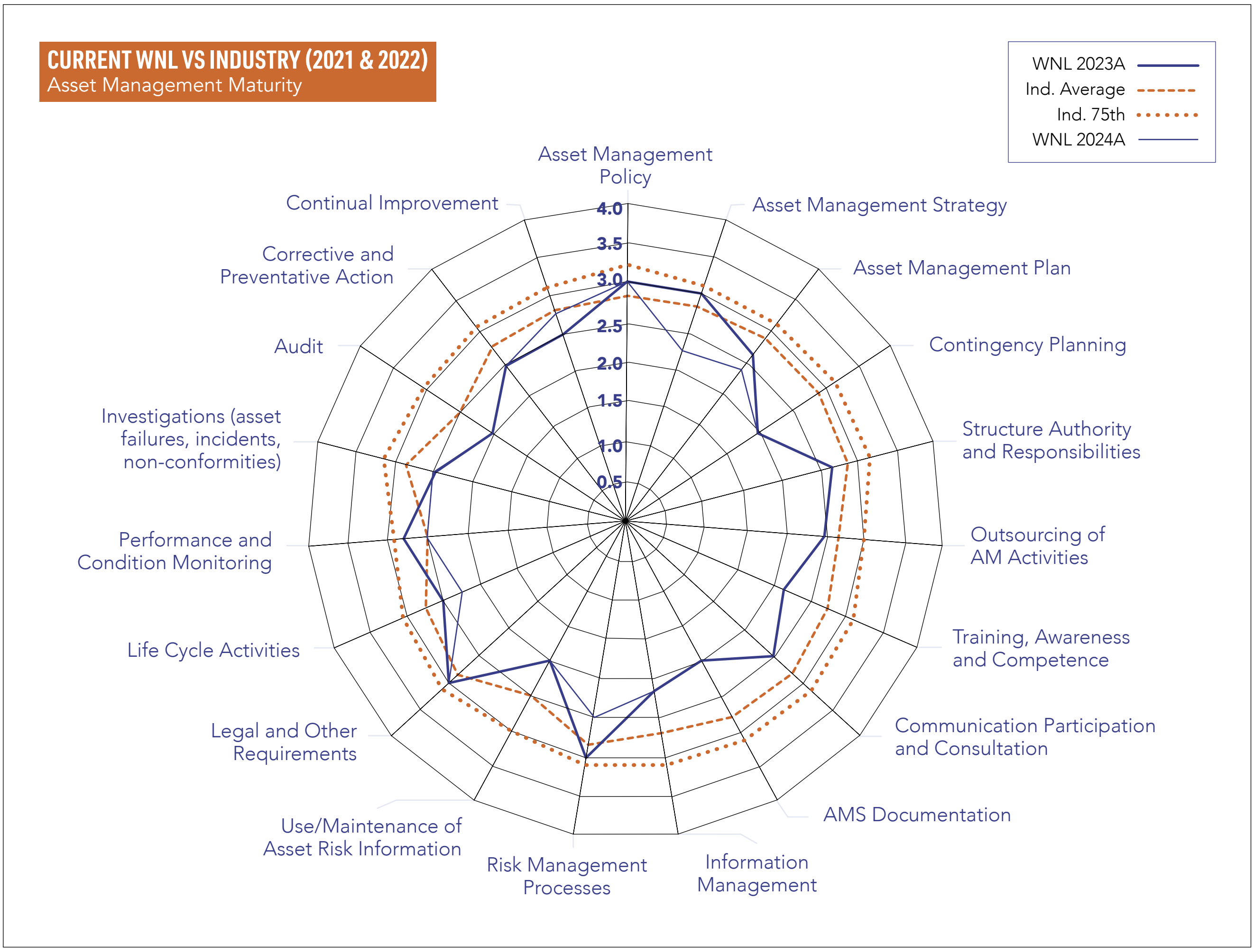


Figure 24: AMMAT summary results

As outlined above (and in the asset management strategy in Section 5), the requirements for our business to have a greater breadth of quality information, undertake more complex modelling and analysis, and operate within a more interconnected and complex electricity sector are rapidly approaching. These demands require us to reach a higher level of asset management maturity over the next two to five years.

4. NETWORK PERFORMANCE

This section presents the network performance results compared to the service level targets and discusses findings and improvement initiatives.

4.1 Introduction

Network performance results provide an avenue to visualise and analyse how Wāipa Networks performed for the year. Our network performance indicators are centred around our asset management strategy and statement of corporate intent (SCI) to ensure we target important and relevant business areas.

These performance indicators are linked to the service levels and targets described in Section 6 and focus on the following categories:

- Network reliability – reflecting overall customer experience,
- Vegetation – separated from reliability, given its impact on network performance,
- Customer satisfaction,
- Asset delivery efficiency, and
- Financial performance

Note: *Some targets below were not set within the FY23 service levels. However, we have outlined some key findings from our internal reviews.*

4.2 Network reliability

4.2.1 Overall network performance (Long term trends)

The following figures provide an overview of our network's performance for the past decade (since FY14). While no significant long-term trends are depicted in the indices, it is evident that major weather events that occurred in Wāipa (Dovi and Gabrielle) over the last two years significantly impacted the network (Reasons for this and our response are highlighted below).

Since FY21, we have adopted the DPP3 methodology of calculating SAIDI and SAIFI. We have set our boundary targets based on Wāipa's operating limits calculated in the same way as for EDBs that fall under the regulated quality path.

The values set are highlighted in Table 7 below and indicate FY22 and FY23 normalised SAIDI and FY23 SAIFI exceeded the target cap.

Given that the reliability analysis indicates that the assets are performing relatively well (see defective equipment Section 4.2.6) and no significant systemic issues are present for the asset types when reflecting on SAIDI, the cause of such large numbers for adverse weather events can only be placed on the network configuration and our operational performance and response times.

Our current network configuration heavily utilises reclosers and network automation to segregate faults and voltage regulators and capacitor banks for power quality; however, as indicated in the network development section, we are outgrowing the 11kV distribution network, and consequently, our reliability is suffering. A high number of consumers per feeder and limited back-feeding capability result in higher consequences for faults.

Through this philosophy, we anticipate that the Cambridge network performance will improve within the AMP period following the commissioning and setup of the Hautapu GXP and subsequent system growth projects highlighted in the network development plans.

Regarding our operational performance, we are reviewing our current resource levels to ensure we have sufficient capacity (during adverse weather events) to address multiple faults. We are also increasing our network visualisation through better GIS information and mapping.

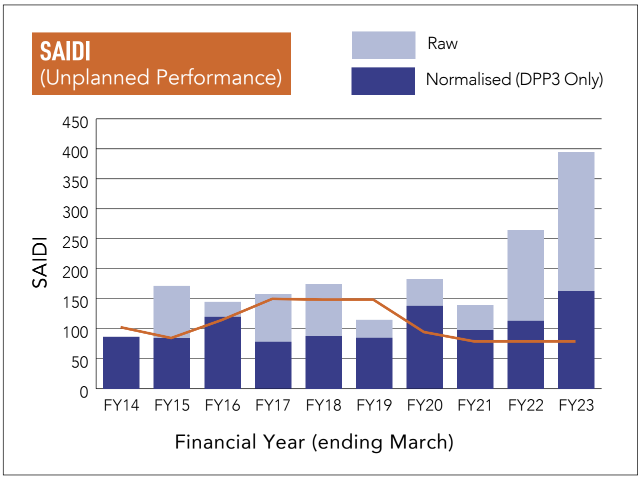


Figure 25: Unplanned SAIDI performance

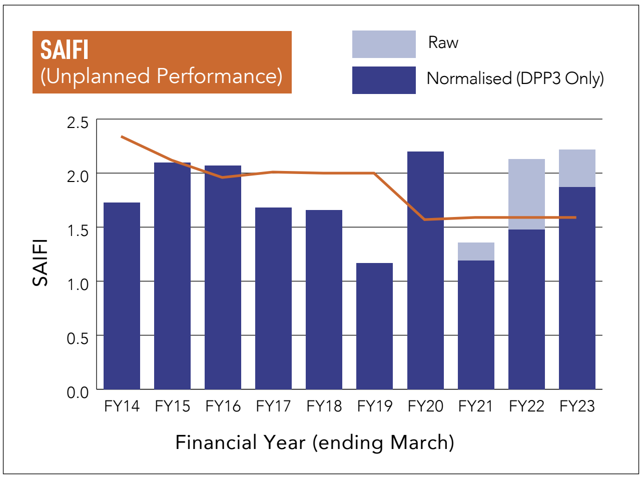


Figure 26: Unplanned SAIFI performance

Our planned SAIDI and SAIFI have varied significantly in recent years and have been affected by several influencing factors. These include:

- **Customer-initiated work**
  - In FY23, there was significant work with regard to customer-initiated work. The capital expenditure was higher for the expenditure category, and resources needed to be diverted to accommodate the capital programme. As mentioned above, we are currently reviewing our internal and external field staff resources with a likelihood that they will increase to assist with the capital and operational programmes projected in the next couple of years.
- **Live-line crews**
  - Wāipa maintains several live-line crews in its field staff. The location and type of work programmed into the annual work plan influence the amount that can be covered by the live-line crew, which effectively has no SAIDI /SAIFI consequence.

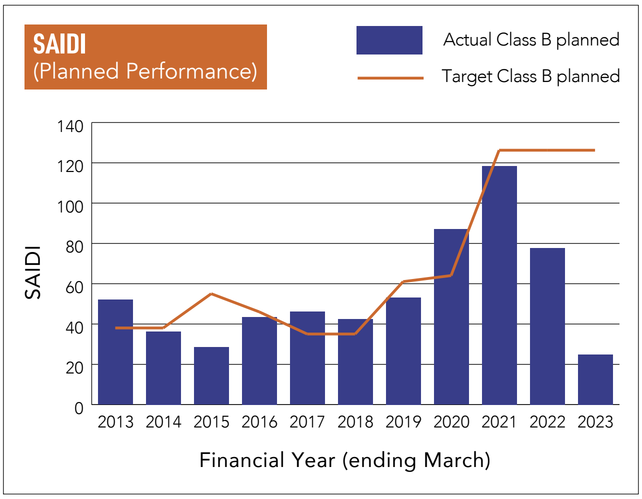


Figure 27: Planned SAIDI performance

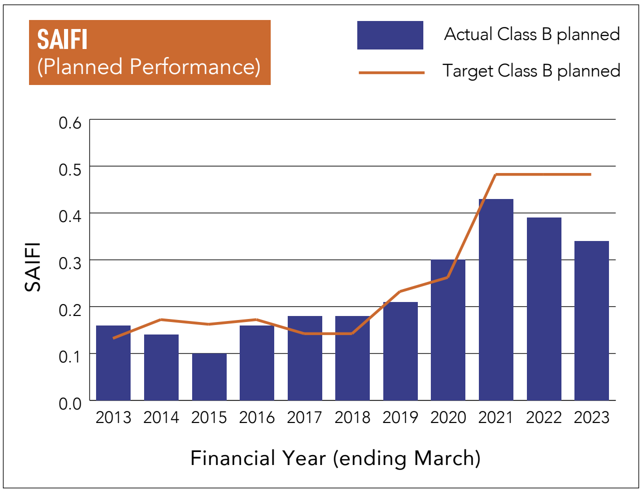


Figure 28: Planned SAIFI performance

4.2.2 Network reliability (FY2023)

FY23 saw Wāipa Networks exceed its reliability cap for SAIDI and SAIFI quality values, including the normalisation values used post-DPP3 process and calculations. However, compared to historical 5-year values (5-year average), performance improved for SAIDI and decreased for SAIFI. We also recorded 2 SAIDI events and one SAIFI event, which were normalised over the annual period and were attributed to a failed switchgear (SAIDI) and cyclone Gabrielle (SAIDI and SAIFI).

Reliability Measure	SAIDI	SAIFI
DPP3 price-quality path cap [18]	109.3	1.73
Historical Average (5yrs) performance	174.6	1.69
Raw Unplanned	404.8	2.09
Normalised Unplanned	168.7	1.87

Table 7: Reliability results (FY23)

[18] *This is used to enable comparison with other EDB performance, but Waipā Networks is not under this price quality regulation.*

4.2.3 Fault cause analysis

A review of the drivers of unplanned outages over the last ten years indicates that Wāipa Networks is primarily affected by defective equipment, vegetation, third-party interference, adverse weather, and unknowns (Refer to Figure 29 and Figure 41).

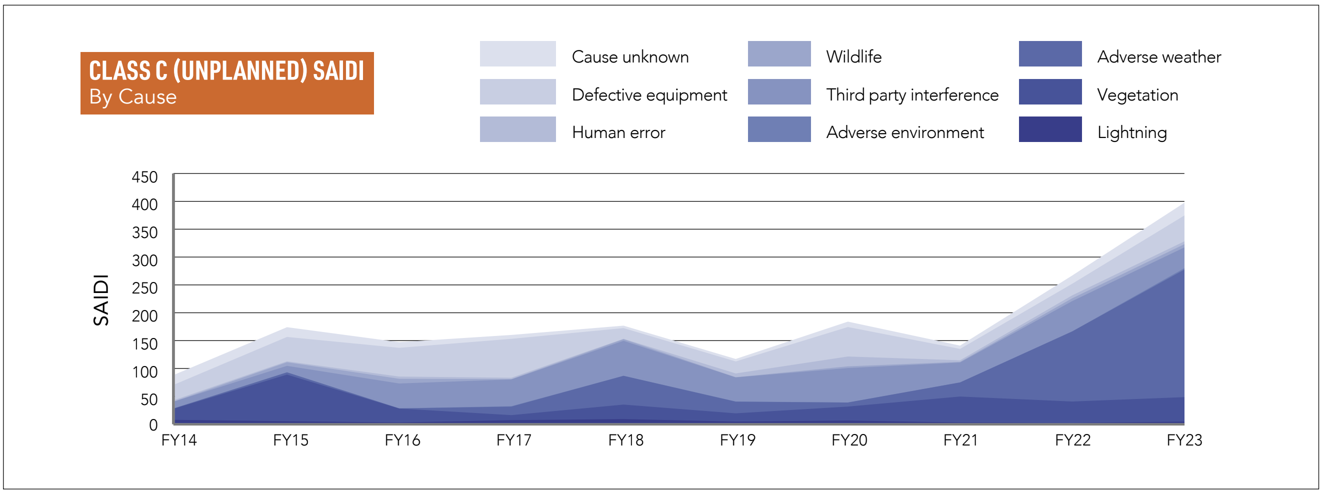


Figure 29: Unplanned SAIDI – by cause

	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23
Lightning	7%	2%	1%	3%	4%	2%	2%	1%	0%	1%
Vegetation	24%	49%	17%	6%	15%	13%	14%	34%	14%	11%
Adverse weather	1%	2%	0%	10%	30%	18%	4%	18%	48%	58%
Adverse environment	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
Third party interference	14%	7%	31%	30%	36%	38%	34%	26%	21%	9%
Wildlife	0%	4%	6%	0%	2%	0%	2%	1%	2%	1%
Human error	3%	1%	3%	2%	0%	6%	10%	2%	2%	1%
Defective equipment	32%	25%	36%	44%	11%	19%	29%	15%	8%	12%
Cause unknown	20%	10%	7%	4%	3%	4%	5%	4%	6%	6%

For FY23, this remained the case.

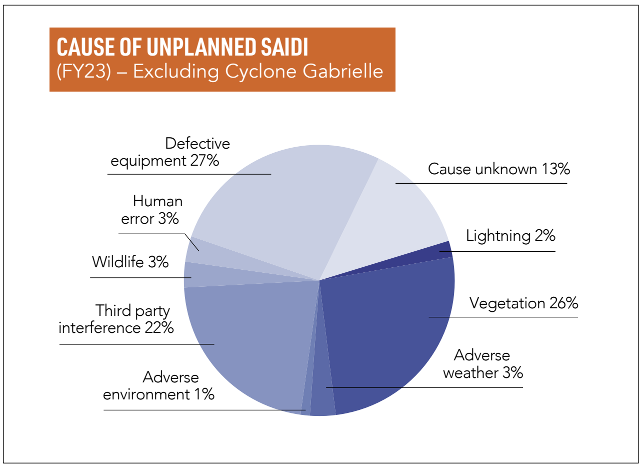


Figure 30: Unplanned SAIDI – FY23 – by cause

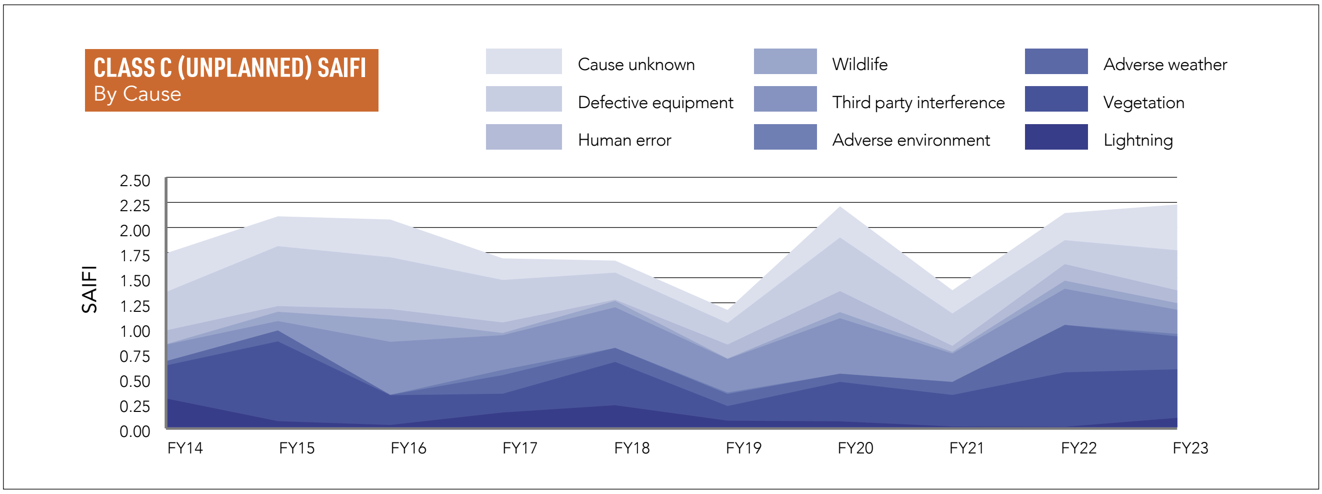


Figure 31: Unplanned SAIFI – by cause

	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23
Lightning	17%	3%	1%	9%	13%	6%	3%	1%	0%	4%
Vegetation	19%	38%	14%	11%	26%	12%	18%	23%	25%	22%
Adverse weather	2%	5%	0%	11%	8%	10%	4%	10%	22%	15%
Adverse environment	0%	0%	0%	3%	0%	1%	0%	0%	0%	1%
Third party interference	10%	4%	26%	21%	24%	29%	25%	21%	17%	11%
Wildlife	0%	4%	11%	1%	4%	0%	3%	1%	4%	3%
Human error	8%	3%	5%	6%	1%	12%	10%	4%	8%	6%
Defective equipment	22%	28%	25%	25%	16%	18%	24%	24%	11%	18%
Cause unknown	22%	14%	18%	13%	7%	11%	14%	17%	13%	21%

For FY23, this remained the case.

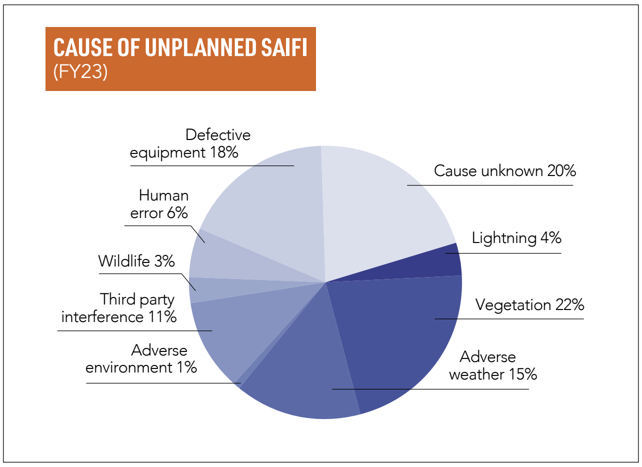


Figure 32: Unplanned SAIFI – FY23 – by cause

Note: *the SAIDI contribution from cyclone Gabrielle was excluded as it put other categories out of proportion.*

4.2.4 General findings (review of fault count and consequence)

A review of the top five fault types (Figure 33 to Figure 38) indicates that:

- Defective Equipment fault types have a high fault count but typically have a low consequence per outage (Proportion gap between Count and SAIDI). The low consequence is largely a result of these outages being typically of shorter duration (I.e., they are easier to repair)
- Cause Unknown faults to have risen in count and SAIDI in the last five years. Our reporting improvements will likely reduce this category in the coming years.
- Third-party interference outages are predominantly Car vs Pole events (Instead of accidental incidents by third-party contractors) and have consistently contributed to unreliability. The count/SAIDI proportion is comparatively quite high, meaning per outage, the consequence is quite high, and the restore period is longer than other causes. This indicates that the damage during these events is extensive, extending the outage time.
- Vegetation fault count and SAIDI have also increased in the past five years. A clear relationship between SAIDI and count indicates that reducing fault count and conducting tree maintenance will have a material effect on reliability.
- Adverse Weather outages have much larger consequences when they happen as a large event (Highlighted by the outages during FY22 and FY23).

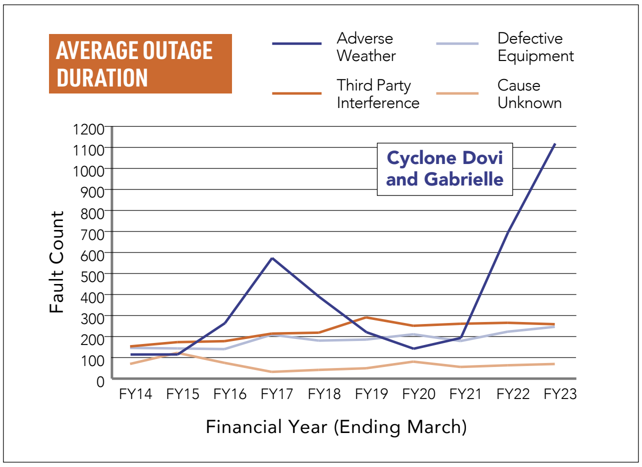


Figure 33: Average outage duration

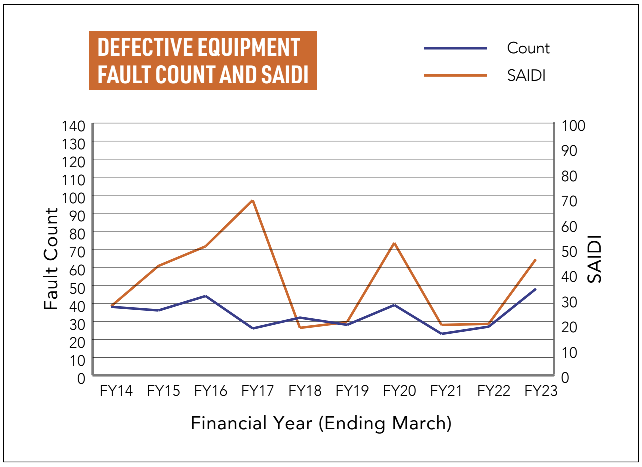


Figure 34: Defective equipment

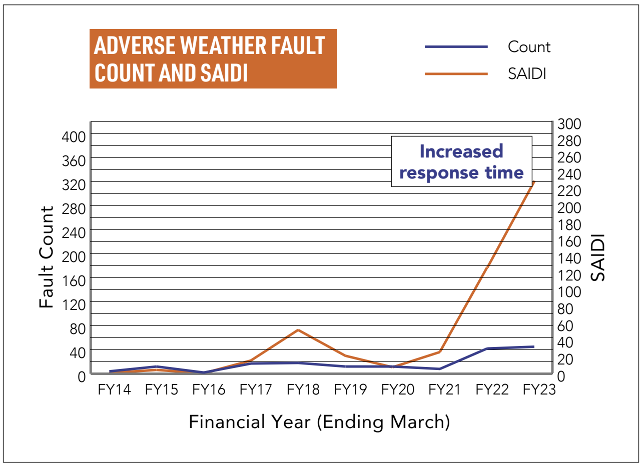


Figure 35: Adverse weather

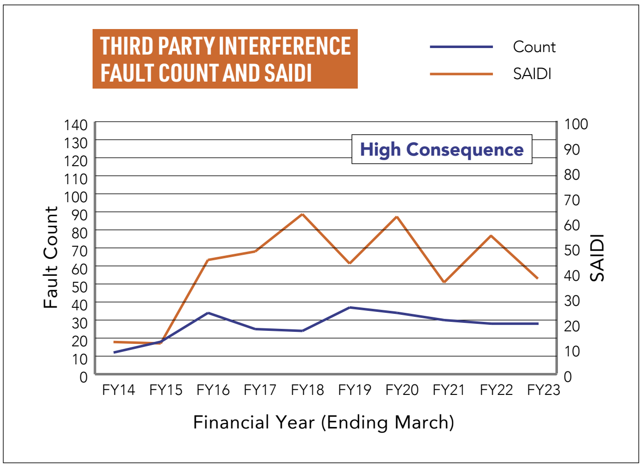


Figure 36: Third-party interference

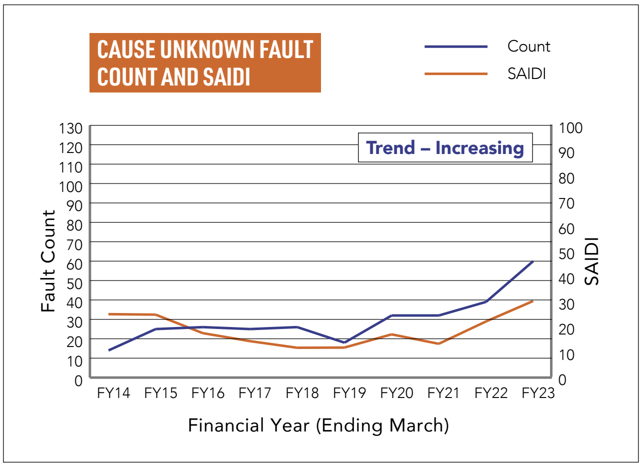


Figure 37: Unknown faults

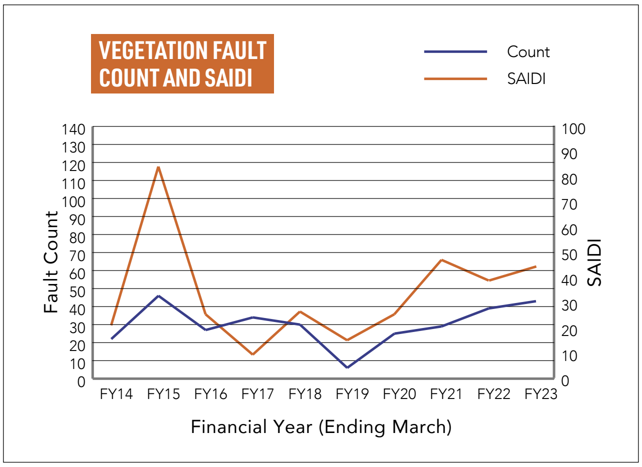


Figure 38: Vegetation fault

4.2.5 Review (adverse weather)

Wāipa is vulnerable to large weather events, particularly events that result in multiple faults coinciding. Resourcing to accommodate these events would increase our field staff and the cost of operating. Therefore, we are currently reviewing our resource requirements based on a forward projection of workload and balancing with predicted customer-initiated works (CIW) and requirements to cover faults. We will engage external contractors and utilise mutual help agreements with other EDBs to provide peak capacity for large irregular events.

We have identified several avenues to increase our resilience in response to adverse weather events, detailed in Chapter 9.4, Resilience Strategy.

4.2.6 Review (defective equipment)

Defective equipment contributed 12% of the unplanned SAIDI and 23% of the unplanned SAIFI. This is an increase in performance for SAIDI and SAIFI compared to the ten-year average values (However, it is skewed by the large contribution from cyclone Gabrielle). The 10-year average values for SAIDI and SAIFI are 23% and 21%, respectively, indicating that this is a material failure type for our overall reliability.

This year we looked at:

- Types of equipment that are failing
- Areas where they are failing (at a feeder level)
- Whether any asset type failures are present (presented within the lifecycle fleet plans)

Comparatively, the component failure count was high in FY23 for cross-arms, conductor/cables, and switchgear.

Fault Count	FY19	FY20	FY21	FY22	Average FY19-22	FY23	FY23 SAIDI	FY23 SAIFI
Insulator/Binder	4	13	3	6	6.5	5	2.41	0.04
X-arm/bracing	5	11	3	1	5.0	9	2.6	0.02
11kV Cond/Cable	6	3	6	8	5.8	16	18.5	0.14
Poles	0	0	0	1	0.3	0	0	0
Fuses	3	1	4	4	3.0	0	0	0
SWGR, ABS, Recloser, RMU	5	7	4	2	4.5	9	17.2	0.16
Surge Arrestor	1	2	1	2	1.5	2	1.2	0.01
Transformer	2	1	2	3	2.0	2	1.8	0.02
2021	1	15	0	12	3	0	23	2
2022	0	9	0	16	32	0	20	0

Table 8: Count of equipment failures by equipment type

We found several feeders that were beginning to show trends of failures for cross-arms and cable, and the switchgear failures were mainly attributed to a single ABS type (note, all defected ABS found eventuated as a fault due to different intervention techniques). We will be targeting these in the future.

One of the biggest findings during the analysis is the need to improve our reporting and data capturing. In 2023, we changed the outage management reporting categories and requirements to capture the cause of unplanned outages better, e.g., we separated cable and conductor and made reporting of the asset number compulsory so faults could be mapped and visualised better.

We will update asset performance targets next year once a full round of data is available for the new asset reporting structure by the end of FY25.

4.2.7 Review (third party interference)

Outages due to third-party interference have consistently and significantly contributed to our network's SAIDI and SAIFI. For FY23, this causal type resulted in 37.29 SAIDI and 0.24 SAIFI, 27% and 11% respectively, of the annual total (excluding cyclone Gabrielle).

This year, we mapped where Car Vs poles occurred using transport data and our database and highlighted the Cambridge and Te Awamutu hotspots. Initial visualisation shows 'hot spots' spread across key areas or routes and have not converged to a finite number of sites that can be easily targeted or addressed cost-effectively. Hence, we are yet to identify or propose dedicated car-vs-poles-related capex initiatives. However, the heatmap has influenced our design choices for certain network development initiatives.

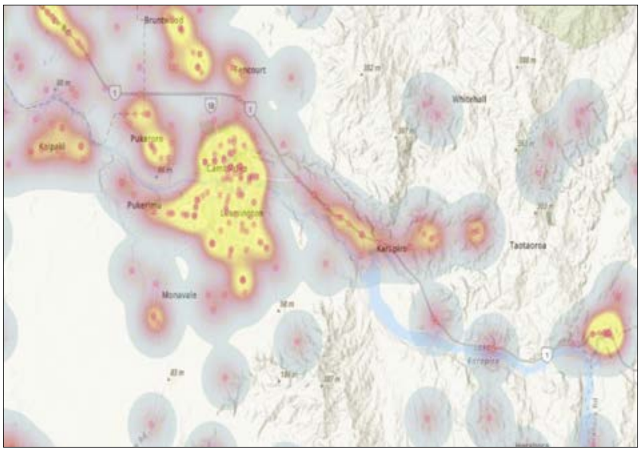


Figure 39: Car-vs-pole heat map – Cambridge

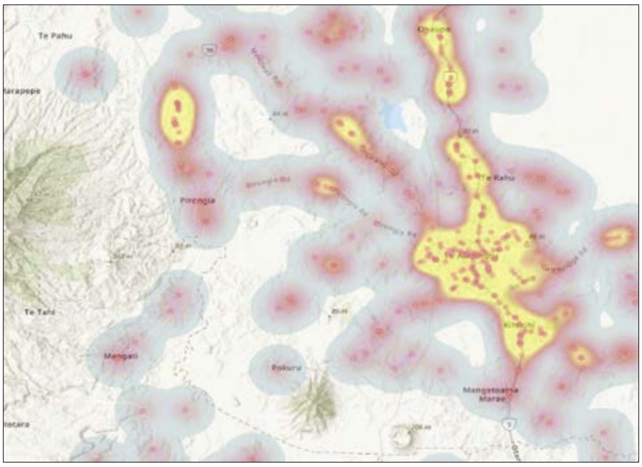


Figure 40: Car-vs-pole heat map – Te Awamutu

4.2.8 Review (vegetation)

The contribution from vegetation-related SAIDI and SAIFI has been highly variable in terms of overall percentage contribution, and the last ten years have contributed, on average, 33.1 SAIDI and 0.391 SAIFI. Compared to our annual target of 109 SAIDI, this is a material contribution to unreliability.

In FY23, vegetation-related outages contributed 43.94 SAIDI (Normalised) and 0.484 SAIFI (Normalised).

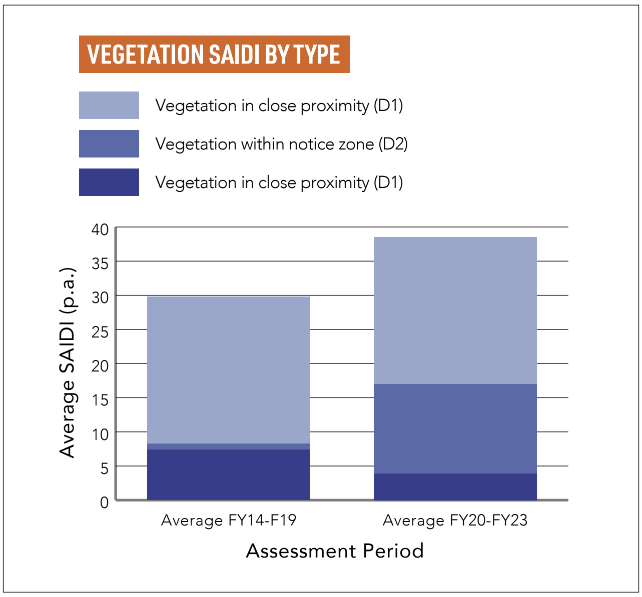


Figure 41: Vegetation faults count

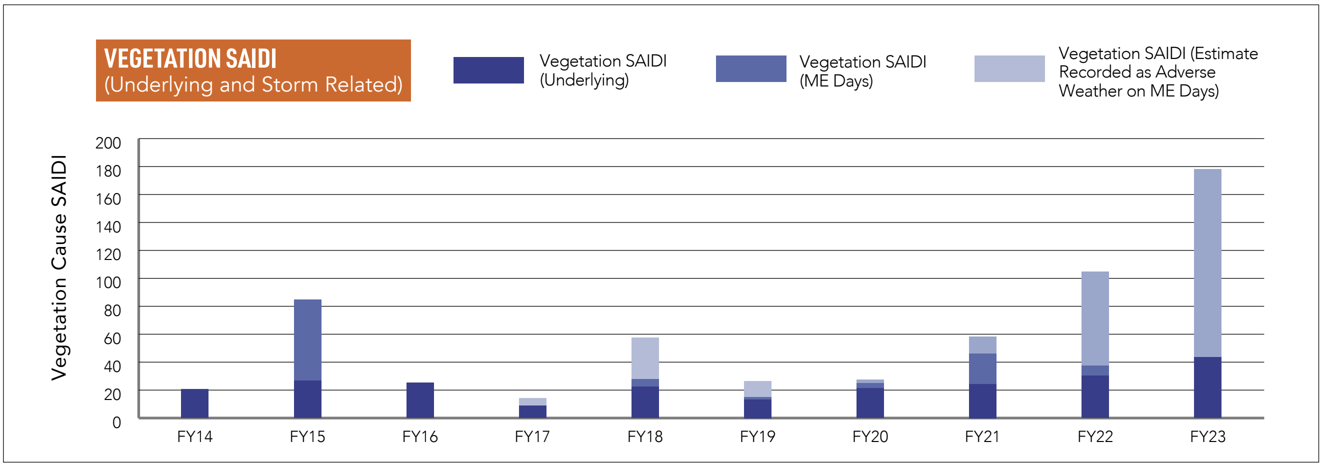


Figure 42: Vegetation faults SAIDI

Some of the key findings from our analysis include:

- A sizeable portion of outages is attributed to vegetation outside the notice zone (D3). These trees are not covered under the tree regulations; however, given their impact, we are looking at trees that fall into this category, i.e. higher-risk trees and trying to work with landowners to minimise the risk (by trimming) or eliminate them by removing them. This method could significantly impact our annual financial expenditure. Therefore, we are only targeting trees that are considered high-risk.
- During adverse weather events, a sizeable proportion of outages are associated with vegetation, as highlighted in the FY22 and FY23 SAIDI figures. Several key areas were affected by cyclone Gabrielle, which caused severe damage and widespread outages in Cambridge. We have introduced a project next year to underground the remaining overhead assets on Lamb St (>40 SAIDI during Gabrielle) and will be continuing this work (undergrounding urban assets) in years to come.
- There is a clear decrease near faults, indicating that our current maintenance regime is working. However, as mentioned above, vegetation outside the notice zone has a high count and contributes to unreliability.
- As highlighted in Chapter 11.21.5, vegetation management, our focus going forward is to take a practical risk-based approach (reflected in both inspection and cut plan), and we will be increasing our inspection frequency to understand better the priority and magnitude of work required. We will monitor this along with the above approach to determine its effectiveness.

4.3 Electricity delivery efficiency

Table 9 shows actual asset delivery performance over the past three years compared to target of <6.5%. Our loss ratio asset delivery KPI was achieved in 2022/23

	Actual 2018/19	Actual 2019/20	Actual 2020/21	Actual 2021/22	Actual 2022/23	FY23	FY23 SAIDI	FY23 SAIFI
Loss Ratio	5.48%	5.40%	4.70%	5.5%	4.8%	5	2.41	0.04

Table 9: Electricity delivery performance

4.4 Customer satisfaction

Our annual customer survey is a key method for engaging with customers. A number of EDBs use survey which serves as a basis for benchmarking[19]. The objectives of the survey are:

- To understand our customers satisfaction and experience when engaging with us
- To identify the key drivers of customer feedback.
- To identify opportunities to enhance customer satisfaction and experience.

Our methodology and measures for surveying customers were changed in 2021 to align with other EDBs and develop a better method for benchmarking across the industry. The survey is conducted via telephone with respondents selected randomly from our customer database to align with key Residential Urban, Residential, Commercial, and Commercial Rural groups. The independent survey covers various operational aspects, focusing on overall satisfaction, reliability, image and reputation, value for money and communication.

For analysis, each customer/ICP is assigned a category from four customer groups:

- Grid Exit Point (Te Awamutu, Cambridge)
- Feeder Type (Urban Te Awamutu, Rural Te Awamutu, Urban Cambridge, Rural Cambridge)
- Tariff Type (Residential, General)
- GXP / Feeder Type has been identified as the key indicator, so quotas are enforced to ensure the survey sample reflects the population mix.

Our survey results are summarised in Table 10. Last year's survey results indicate that overall customer satisfaction is 63%, slightly above the peer group average of 61% and a 5% improvement on our previous year's results. Our measure for image and reputation has improved by 9% this year to 65%, 7% above the group average. We continue to perform well in areas such as value for money and reliability; however, improvements are required in communication and enquiry handling.

Measures	Waipā results	Average benchmark	2023/24 target
Overall satisfaction	63%	61%	62%
Reliability	79%	72%	80%
Image & Reputation	65%	58%	60%
Value for money	56%	49%	55%
Communication	46%	49%	60%
Enquiry Handling	63%	70%	70%

Table 10: Annual customer survey results (2023)

Improvement

Additional surveys to increase our ongoing engagement and measurement of customer experience are being introduced to gather customer feedback after specific interactions and more across broader customer groups to gain wider customer insights. Opportunities to gain regular short-form feedback, such as NPS measures after interactions with our teams, will be implemented to provide a consistent and continuous way to monitor sentiment from our customers and customer experience.

We have started the journey to enrich our customer engagement framework and tools to enable us to incorporate customers' views into our planning and asset management objectives. This will be a two-way process as we also need to communicate better the key trade-offs associated with our future investment programmes (in particular, how the investments impact price).

Continuing to focus on our supply reliability to ensure fewer outages, ongoing improvement to response times, and communication were key priorities identified by customers in our survey.

[19] *Other EDBs using the same survey and participating in the benchmarking include The Lines Company, Top Energy, Counties Energy, Northpower and Network Waitaki.*

4.5 Safety performance

Continual improvement in managing health and safety involves an ongoing review of health and safety practices, systems and documentation, and the outcomes. We track these measures to monitor our safety performance:

- Number of serious harm injuries, and
- Total Reportable Injury Frequency Rate (TNIFR) – a new measure for FY24.

We recorded no reportable incidences in FY23.

Key performance indicator	Actual 2021/22	Actual 2022/23	Comment
Number of serious harm injuries	0	0	Serious harm is defined as a notifiable event under the Health and Safety at Work Act guidelines published by WorkSafe NZ.
Total Reportable Injury Frequency Rate (TRIFR)	-	-	TNIFR is a new measure

Table 11: Health and safety measures

4.6 Financial expenditure

Delivery of our planned and unplanned works is currently measured through financial expenditure, which compares to budgeted values. Figure 43 and Figure 44 show our performance against targets over the last four years.

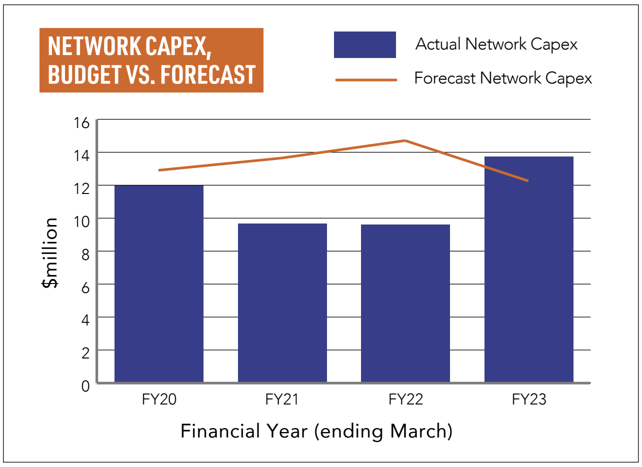


Figure 43: Network Capex

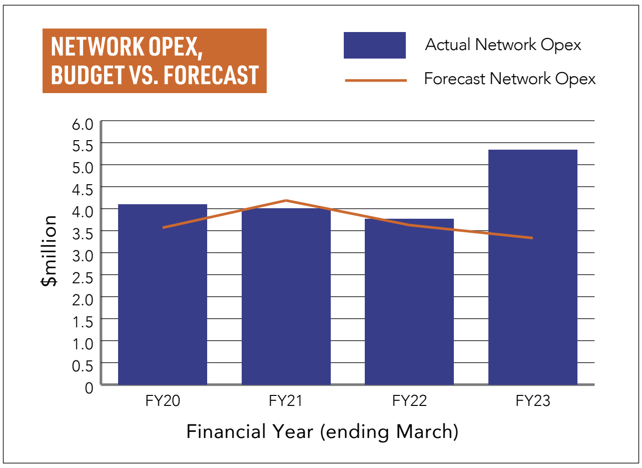


Figure 44: Network Opex

For FY23, we have split the expenditure into the various expenditure categories.

Capex Item	FY2023 Actual ($000)	FY2023 Budget ($000)	Comments on variance
Capex: Customer Connections	8,141	4,218	The budget was overspent due to the large number of sub-divisions and connections. Growth in the Wāipa area was significant, with >500 connection applications. Expenditure was 193% against budget.
Capex: System Growth	2,281	3,322	32% underspent due to delays in gaining easement approval for the 11kV cable upgrade project at Te Awamutu GXP.
Capex: Reliability, Safety and Environment	698	1,525	54% is underspent due to underspending in the voltage regulator structure strengthening project (due to geotechnical issues) and the reprogramming of the remote-control switch/loop automation initiative (due to communication channel capacity constraint).
Capex: Asset Replacement and Renewal	2,102	3,021	The expenditure category is 30% underspent.
Capex: Asset Relocations	492	178	The category is overspent due to relocation work required by the local council and NZTA road redevelopment.
Subtotal – Capex on network assets	**13,713**	**12,264**	**Capex is overspent due to large customer connections in the work programme.**

Table 12: Health and safety measure

Opex Item	FY2023 Actual ($000)	FY2023 Budget ($000)	Comments on variance
Opex: System interruption and Emergency	2,411	994	The category is heavily overspent due to adverse weather events, irrecoverable 3-party incidence costs, and a general increased volume of faults.
Opex: Vegetation Management	1,541	1,034	The category is heavily overspent due to a combination of additional vegetation preventative works to catch up with the previous year's backlogs and the Cyclone Gabrielle response, as well as significant cost escalation in traffic management.
Opex: Routine corrective maintenance and inspections	593	689	The expenditure category is 14% underspent due to less activity associated with field loading checks.
Opex: Asset Replacement and Renewal	801	591	Overspent due to refurbishment of transformers and voltage regulator units.
Opex – Total	**5,346**	**3,308**	**Overall, opex is overspent due to high faults and vegetation management costs.**

Table 13: Health and safety measures

PART 2:

STRATEGIES TO ADDRESS THE KEY ISSUES

WAIPĀ NETWORKS

5. ASSET MANAGEMENT STRATEGY AND PERFORMANCE TARGETS

This section sets out our asset strategies, performance targets, and optimisation and trade-offs that we'll apply to develop our asset management programmes. Our network and customer satisfaction targets are also included in our annual Statement of Corporate Intent (SCI).

Our Asset Management Plan communicates the governance and management framework to describe how we:

- Set service levels for our electricity network that reflect safety, customer, community, and regulatory requirements.
- Understand our network capacity, reliability, power quality, and supply security that is required now and in the future based on our expected service levels.
- Have a robust and transparent process for managing all phases of our network lifecycle from concept to disposal. This includes a systematic process to manage risk.
- Have made adequate provision for funding and resourcing all phases of our network lifecycle for incorporating into our annual and ten-year budgeting cycles.
- Make decisions within systematic and structured frameworks at each level within our business, reducing ad-hoc decisions.
- Continue to improve our knowledge of assets, including location, age, condition, criticality and our network's likely future performance and characteristics as it ages or is required to perform at different levels. Asset management systems and processes will support this.

The AMP also serves to inform our stakeholders of our Company's:

- Policies for investment in construction, maintenance, and retirement of assets.
- Policies for operating the network safely and prudently.
- Security of supply and network reliability targets for different customer segments.
- Areas of asset management where improvements are required.
- Major network developments and enhancements over the next ten years.
- Annual capital and maintenance expenditure forecasts.

This AMP meets the legislative requirements of the Electricity Distribution Disclosure Determination 2012.

5.1 Asset management policy

We're committed to maintaining, operating, and developing our electrical distribution system and supporting management structures to safely, efficiently, and sustainably convey electricity to connected customers.

Our Asset Management Plan is critical to delivering these commitments, and we ensure that through regular review, continuous development, and application of the Asset Management Plan.

5.2 Asset management strategy

5.2.1 Key issues driving strategy

Some of the factors driving change (explored in detail in Section 3.6) are due to the impact of:

- high regional population and industrial growth driving demand growth
- need to manage future demand growth due to electrification
- New technologies that allow customers to participate actively in the electricity market.
- the age of our network fleet and
- increasing incidents and impact of adverse weather events.

We have revised our asset management strategy to address contextual issues and improve network performance. The asset management strategy:

- consists of six initiatives, with key work programmes aligned under each initiative (the work programmes are discussed later in part 3 – the implementation section)
- supports our asset management policy and customer service standards and builds on our work in prior AMPs.
- provides the basis for ongoing engagement with stakeholders and
- will guide the 2024 AMP and our revisions to investment programmes.

Investment decision will be considered against the Energy Trilemma—i.e., trade-offs will need to be made, informed customer engagement outcomes.

5.2.2 Asset management strategy

In this AMP, our asset management policy remains unchanged. Our strategies are used to direct our asset management activities to meet our existing asset management policy, customer strategy, and service standards.

Our asset management strategy has been prepared in response to the key issues and to improve network performance discussed in our prior sections. Our six key initiatives will carry over from AMP 2023.

Initiative	In response to...
1. Improve regional supply security **2.** Develop and implement an energy transformation roadmap to further prepare for decarbonisation	• High population and demand growth • Future demand growth due to electrification • Uncertainty as to the availability of flexibility to manage demand • Customers' future needs and voices
3. Improve the resilience of our network	• The increasing importance of electricity to our customers • Increasing incidents and intensity of adverse weather • Increasing incidents of third-party damage
4. Develop comprehensive fleet plans and renewal forecasts	• Aging of our asset fleet • Increasing requirement for asset renewals
5. Improve asset management maturity	• A need to make quality decisions based on quality data • Increasing business complexity (e.g., managing flexibility)
6. Reduce the impact of vegetation on the network	• Continued material impact of vegetation interference on reliability

Table 14: Our asset management strategy

Pursuing these strategies will require investment in people, systems, and network assets, much of which is already included in this AMP but some of which has yet to be fully considered. The extent and the pace of investment will require optimisation and trade-offs, which we discuss in Section 5.8.

5.2.3 Asset management strategic initiatives

1. **Network capacity and security:** Develop a secure sub-transmission network to support high population and demand growth and future demand growth due to electrification.
   - Prepare a long-term network development plan for both Cambridge and Te Awamutu.
   - Additional GXP capacity of 96MVA by constructing the new Hautapu GXP.
   - Reduction in maximum demand on existing CBG GXP.
   - Subtransmission and new zone substations.
   - Reduction in average feeder ICP-kms; reduce the criticality of individual assets, improving supply security and reliability.

2. **Network transformation:** Develop and implement an energy transformation roadmap to prepare for decarbonisation further.
   - Completed a Waipā region study to define electrification scenarios that inform our demand and expenditure forecast.
   - Implement LV monitoring technology trials in collaboration with Ara Ake and GridSight.

Resilience: Improve the resilience of our network to reduce the impact of increasing incidents and intensity of adverse weather and other major events as the economy increases reliance on electricity. This will lead to:

- a reduction in the asset failures during adverse weather
- a reduction in the vegetation related outage during adverse weather
- a reduction in the fault duration during adverse weather
- an improvement in our RMMAT score to 3 in key areas.

3. **Fleet management:** Develop comprehensive fleet plans and renewal forecasts to better manage our asset fleet. Increasing requirement for asset renewals:
   - prepared condition input data and health data for key asset classes by FY24/25,
   - developed asset fleet plans for key asset classes for the 2024 AMP,
   - asset fleet plans for all other asset classes in the 2025 AMP.

4. **Asset management maturity:** Improve asset management maturity to address the need for quality decisions based on quality data. Improved asset knowledge and asset management practices that:
   - are ready for increasing business complexity,
   - can effectively support investment optimisation and trade-offs.

5. **Reliability:** Reduce the impact of vegetation on our network to address the continued material impact of vegetation interference on reliability.
   - Ensure resources are at a level sufficient for the tasks required,
   - Effective trim and cut program,
   - Efficient inspection and data capture.

5.3 Customer strategy

A customer's direct interaction with our organisation is usually due to an outage or when they want to change their service level–connected capacity and/or supply security. Our customer strategy is to:

- Consult and engage with customers about service standards, network performance, and their views/plans for the macro trends.
- Achieve customer service (reliability) targets.
- Achieve customer satisfaction targets.
- Manage customers' expectations and communicate with them promptly. We recognise that it's difficult to create a positive customer experience when power is out to a community and we rely on the goodwill we create before such events occur.
- Build strong relationships with customers through proactive communication. We know the difficulties in keeping customer satisfaction high during community power outages. Our focus is establishing a positive reputation through consistent, timely interactions, preparing us for any challenges during supply loss.
- Engage with the community through various media on areas of interest such as outages, public safety, and pricing. In addition, we're investing in information systems to improve our ability to manage customer interactions.

We are actively building our customer and stakeholder relationships to deliver better outcomes by continually improving the network performance, costs, and efficiency consistent with our corporate objectives.

5.3.1 Stakeholder engagement

We regularly engage and consult where appropriate with stakeholders to ensure our asset management objectives are aligned with their interests and goals.

We utilise formal and informal stakeholder engagement to develop our asset management objectives. We are a Trust-owned business, and our customers directly elect the Trustees. In turn, the Trustees appoint our directors, approve our annual Statement of Corporate Intent (SCI), and receive our Annual Report and accounts.

Appendix B summarises our key stakeholder group and how we engage with them to formulate business objectives.

5.3.2 Summary of planned customer engagement initiatives

Customer Need or Event	Method of engagement	Desired planning outcome
A new connection to our network or an upgrade of an existing connection	• Network Connection Application and capital contributions processes. Engagement with our team throughout the process. • NPS survey sent after each engagement to measure experience continuously.	• Approvals take network load and growth into consideration. Trends in new connections help plan network income and investment. • Ongoing customer experience measures inform our internal processes and provide insights for network development and customer communication.
Vegetation management	• Processes under the Electricity (Hazards from Trees) Regulations 2003. • Digital and print advertising campaigns across the region targeting proactive vegetation management – 3 times per year. • Identifying customer groups/ network areas more prone to outages from vegetation overgrowth.	• The vegetation management programme addresses all geographic areas according to their specific species growth rates. • Take a proactive vegetation management approach –including directing resources to areas that present the most risk, engaging with tree owners to widen corridors– to reduce network outages due to trees on lines. • Lowering the occurrence of outages caused by trees and vegetation improved customer experience and supply continuity.
Faults	• Customer faults number, call centre and field service engagement.	• Immediate response to resolve the fault. • Faults are individually and collectively analysed to identify medium and long-term investment needs. • Fault data analysis and insights from faults, the Faults team are used to support an understanding of customer group needs, identify key trends, and proactively manage identified recurring issues.
Complaints	• We proactively manage customer concerns and complaints within the Customer & Engagement team to resolve issues quickly. • Use of the customer Disputes Resolution Process when appropriate.	• Registered complaints are analysed for trends. • Service trends are used to assist network investment decisions. • Analysis and insights from customer complaints are used to understand customer group needs, identify key trends, and proactively manage identified recurring issues.
Large Customers	• Individual meetings and correspondence as required to develop a deeper understanding of their current and future needs – informing network development.	• Consideration of larger customers given for key network investments. • Customer insights from direct engagement support customer group profiles and considerations for future large customer needs as the region grows.
Customer Advocacy / Interest Groups	• Public meetings/individual meetings / correspondence as required.	• Consideration of customer advocacy/interest groups given for key network investments. • Identify opportunities and key initiatives where proactive engagement can be undertaken to strengthen our relationship with them and increase understanding of customers.

Customer Need or Event	Method of engagement	Desired planning outcome
Customer Groups (Residential/ Commercial / Urban / Rural)	• Customer Surveys – annual survey as part of wider industry benchmarking and additional shorter surveys to gather intel and feedback on performance and initiatives – utilisation of the NPS methodology. • Community engagement initiatives – increase customer interaction and feedback. • Proactive engagement of customer groups experiencing hardship – including energy hardship and more frequent supply disruption	• Keep a consistent annual performance measure that can be compared via benchmarking to wider industry performance. • Regularly measure customer experiences with us to support understanding of customer needs and enable continuous improvement in customer experience and future network requirements. • Supports understanding of customer needs and network investment requirements. Supports prioritising of asset review and renewal programme.
Local District Councils, Regional Councils & National Regulatory Bodies	• Local Council planning cycles and District Plan updates. • Meetings with Council officers as required for specific projects. • Public meetings/correspondence as required.	• Consideration of local and national regulatory bodies given for key network investments. • Collaborate to understand council initiative impacts on the region and key customer groups. Work more closely to provide consistent messaging and communication to customers.
All	• Public and Stakeholder meetings	• As required: Consultation related to large network development projects that affect all consumers.

Table 15: Customer and stakeholder engagement activities

When they contact us, opportunities to engage with customers are generally related to meeting specific needs such as adding a new connection or upgrading their connection to our network, vegetation management, applying for distributed generation or during a network outage. We also pro-actively consult with customers regarding community and network projects, customer-impact initiatives, and medium/long-term network planning.

5.4 Customer satisfaction targets

This analysis provides the framework for setting customer-oriented performance targets in addition to our wider business objectives. Table 16 shows the Customer-oriented categories and targets. The percentage target figures listed are the results expected to be returned in each category for the respective customer year.

The targets are based on the higher average benchmark score (from other EDBs from the same survey) and our current performance. In the second five years of the period, our performance target ramps up, so we're aiming for performance at the top end of our EDB performance in our current survey by year ten.

Performance Indices	Target 24/25	Target 25/26	Target 26/27	Target 27/28	Target 28/29	Target 29/30	Target 30/31	Target 31/32	Target 32/33	Target 23/34
Overall Satisfaction	62%	67%	72%	75%	78%	80%	82%	84%	86%	86%
Reliability	80%	80%	80%	80%	82%	82%	84%	86%	88%	88%
Image and Reputation	60%	70%	72%	75%	78%	80%	80%	82%	82%	85%
Value for money	55%	55%	55%	55%	56%	59%	62%	65%	68%	68%
Communication	55%	55%	56%	56%	57%	59%	61%	63%	65%	65%
Enquiry handling	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%

Table 16: Customer satisfaction performance targets

We recognise that achieving these satisfaction performance targets depends on continuous improvement and fulfilling our asset management and corporate objectives.

5.5 Service level targets

Our service level targets have been derived from customer engagement, comparative assessment, and a commitment to continuous improvement while recognising the practical limits of a mainly radial network covering urban and rural areas.

Through our SCI, we set other objective targets for network business, including:

- Financial performance.
- Network reliability performance.
- Customer, community, and environment.
- Staff and public safety.

We'll follow our security of supply standards unless the required investment levels are inconsistent with good engineering practice and/or commercial criteria.

- Facilitate the connection of distributed generation, which doesn't compromise the safety, network operation or supply quality to other customers. We may require a distributed generator to pay the economic costs of connection, including reactive power compensation, where these costs are consistent with Part 6 of the Electricity Industry Participation Code.
- Match reliability improvement to specific customer needs – customised reliability setting for key industrial customers,
- for emergency demand management, interrupt the supply to domestic customers before interrupting supply to hospitals, industrial and commercial customers.

5.5.1 Network reliability targets

Providing a reliable network service is a core part of our customer service strategy, and any area that customers require our continued focus. Reliability comprises planned and unplanned reliability measures. Figure 45 shows our target unplanned reliability performance for FY2023 and the next five years. The graph illustrates the minimal headroom to the target (assuming future performance reflects historical averages).

The asset management strategies are intended to improve our projected performance, deliver improved customer service, and increase headroom. Increasing headroom provides a greater allowance for annual volatility due to influences beyond our control. The target performance is based on the methodology applied to regulated EDBs. We'll still be monitoring raw reliability performance (before normalisation for major events) as this is the outturn that customers see.

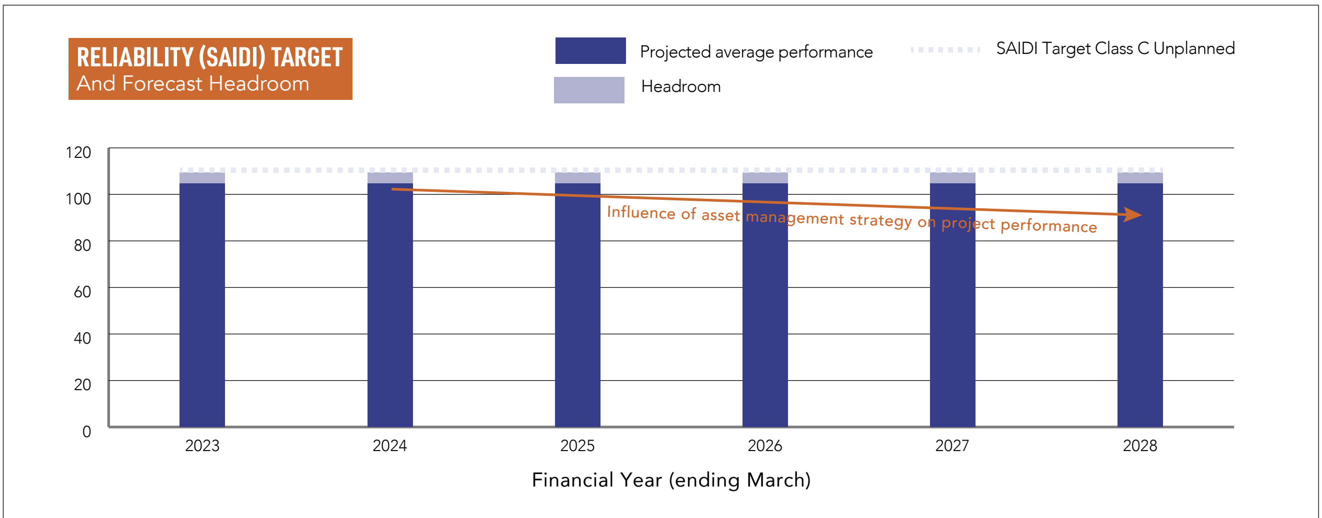


Figure 45: Target Reliability

Unplanned reliability targets exist for both SAIDI and SAIFI. Unplanned SAIFI headroom to target is materially higher (at c.25%) and should improve with implementing our asset management strategies.

Our planned reliability targets increased materially in FY2021, and based on current projections, we have sufficient headroom to cater for forecast planned work activities across both planned SAIDI and SAIFI targets.

SAIDI and SAIFI Targets

From FY21, we've adopted the DDP3 methodology to set performance targets, allowing better comparison and benchmarking against other EDBs subject to price-quality regulation. The DPP3 method sets the planned SAIDI and SAIFI targets at a higher level (three times the historical average) than the previous approach. Higher targets will support a focus on resolving the network defects before they become larger unplanned outages.

Our unplanned targets are capped at the historical ten-year average plus two standard deviations. Targets are normalised to remove huge one-off events. Table 17 shows the targets based on the Commerce Commission's DPP3 approach for reliability targets.

Network Reliability Performance Indices	Target 24/25	Target 25/26	Target 26/27	Target 27/28	Target 28/29	Target 29/30	Target 30/31	Target 31/32	Target 32/33	Target 33/34
SAIDI planned	126.2	126.2	126.2	126.2	126.2	126.2	126.2	126.2	126.2	126.2
SAIFI planned	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
CAIDI planned	261.3	261.3	261.3	261.3	261.3	261.3	261.3	261.3	261.3	261.3
SAIDI unplanned	109.3	109.3	109.3	109.3	109.3	109.3	109.3	109.3	109.3	109.3
SAIFI unplanned	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73
CAIDI unplanned	63.2	63.2	63.2	63.2	63.2	63.2	63.2	63.2	63.2	63.2

Table 17: Our annual reliability targets based on the DPP3 methodology.

5.5.2 Vegetation management performance targets

Establishing performance targets is complex in the absence of reliable historical performance data. We have a reasonable degree of comfort in the underlying vegetation cause SAIDI (this is vegetation SAIDI that does not occur during a major event).

Our target is to reduce underlying vegetation SAIDI by 36% by FY30. Improvement is forecasted to start in FY26 when we should begin to see the benefits of the strategy. Our target for FY24 is the average of the prior three years.

We are seeking an improvement in storm-related vegetation SAIDI. However, given the uncertain historical performance and the highly variable outturn during adverse weather events, it is too early to set a definitive target.

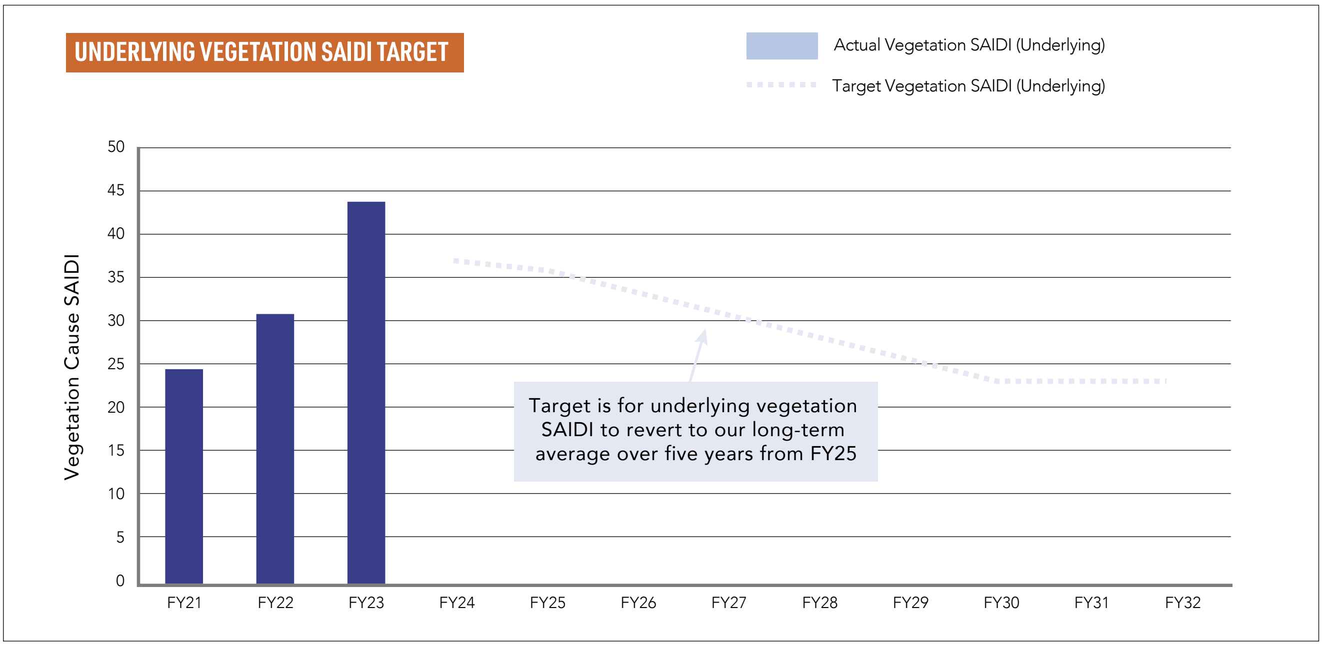


Figure 46: Vegetation SAIDI Target (underlying performance – excluding major weather events)

5.5.3 Electricity delivery efficiency targets

Power quality

Meet statutory and good industry practices for power quality requirements:

- Meet the minimum of statutory levels or agreed terms for supply voltage.
- Endeavour to limit flicker to levels specified by AS/NZS 61000.3.7:2001 by educating and encouraging customers to comply with this standard.

- Endeavour to limit harmonics to levels specified in ECP 36:1993 and AS/NZS 61000.3.2:2013 by educating and encouraging customers to comply with these standards.
- Target an overall power factor greater than or equal to 0.95 lagging at times of high load on our network and require that all ICPs meet this requirement.

Loss Ratio

The loss Ratio measures the ratio of kWh lost on the distribution network to kWh conveyed into our network from the GXPs per year. Lost units differ between metered sales to customers and metered purchases at each Transpower GXP and distributed generation supplied to our network.

Losses are physical losses (heating of distribution assets), unmetered supply and theft. Losses are difficult to measure accurately because all unit sales through retailers' meters need to be read instantaneously at year-end to calculate the difference between conveyed and sold energy. Currently, only Time-of-Use meters in customers' installations can supply the required accuracy for sales data.

The loss ratio target has been reduced from 6.5% to 5.7% to match recent historical performance. Increased levels of smart meter installations appear to reduce losses as smart meters improve reconciliation accuracy.

Table 18 shows our target for the loss ratio. The loss ratio is a factor of the physical aspects of our network equipment and configuration and changes if there is a change in relative utilisation of the parts of our network or a change in network configuration.

Network Reliability Performance Indices	24/25	25/26	26/27	27/28	29/30	30/31
Loss Ratio	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%

Table 18: System losses targets

System losses

System losses are currently of less interest to customers than reliability, although they ultimately impact the cost of supply. This performance measure is largely a direct consequence of design standards and previous decisions on system configuration. The comparative assessment shows this measure to be consistent with expectations given the characteristics of our network.

We use the performance indicator of Loss Ratio to measure network asset delivery efficiency.

Load factor

Load Factor measures the ratio of kWh conveyed per year to the kW maximum demand (MD) multiplied by the number of hours in a year. Improvement in this performance indicator requires minimisation of MDs via a fully functional load management system whilst delivering contracted service levels. Load Factor can also be improved by increasing the kWh conveyed over the distribution network. Because network assets are built to meet maximum demand, a good load factor is essential to obtain economic use of assets.

Load control is used to control maximum demand to:

- Defer capital investment in larger assets.
- Reduce Transpower charges.
- Reduce network losses.

We'll use our load control to minimise the maximum demand of our network as an interim solution to manage peak capacity ahead of network upgrades and to defer capital investment. Its impact on losses is minor. Load Factor is no longer a key performance measure for our network.

5.5.4 Business financial targets

We use the financial performance indicators in Table 19 to measure our financial performance. The targets have been set in the SCI. These targets are consistent with our corporate objectives and are achieved by maintaining sufficient spending to maintain a sustainable business with the effective performance of company functions.

Key performance indicator	Actual 21/22	Target 22/23	Target 23/24	Target 24/25	Target 25/26	How we'll be measured
Return on Total Assets	3.30%	2.11%	3.67%	3.29%	3.47%	Net surplus before interest and tax as a percentage of total assets
Return on Equity	3.73%	1.45%	3.42%	3.63%	3.83 %	Net surplus after tax as a percentage of equity
Discount Policy	$5.4m	$6.4m	$5.1m1	$5.3m[20]	$5.5m[3]	We will report on the discount paid to beneficiary customers during the year.

Table 19: Business efficiency financial targets

[20] *Discounts adjusted for loss rental rebates changes. In prior years, the discount included the loss rental rebates received from Transpower. However, from 1 April 2023, the loss rental rebates will be distributed to the retailer instead of the connected customer. This is our five-year historical average variance.*

5.5.5 Delivery target

We're seeking to maintain maintenance and fault response work delivery within 5% of the financial expenditure target (excluding major weather events) and reduce the planned maintenance and vegetation category variances to 10% over the next two years. We're seeking to improve the delivery of capital works to variances of 15% over the next three years. A higher variance is being allowed in the targets due to the influences of consenting on project timelines.

The improvement in delivery will be driven through our asset management maturity improvement programme.

5.5.6 Asset management maturity improvement targets

We are targeting continued improvements in our asset management maturity over the next two years to ensure our business has the necessary capabilities to deliver on our asset management strategies (asset management strategy #5).

Our focus areas for asset management maturity improvement are:

- Ensuring our asset management strategy is well aligned with our corporate direction supports our asset management policy, customer strategy, and service standards.
- Enhancing asset management practices: we have developed comprehensive asset renewal models, reworked our network development planning, including resilience strategy, and updated our risk management framework,
- Information management and asset management systems improvement, see Section 6.

We have reassessed our asset management maturity in 2024, and we achieved good improvements in key areas but didn't achieve our targeted improvement in all areas. The effort required to implement improvements exceeded what was anticipated, and we experienced some resourcing constraints.

We continue to target improvements in our asset management maturity over the next year to ensure our business has the necessary capabilities to deliver on our asset management strategies (asset management strategy #5). Our current level of maturity and areas for improvement are shown in Figure 47.

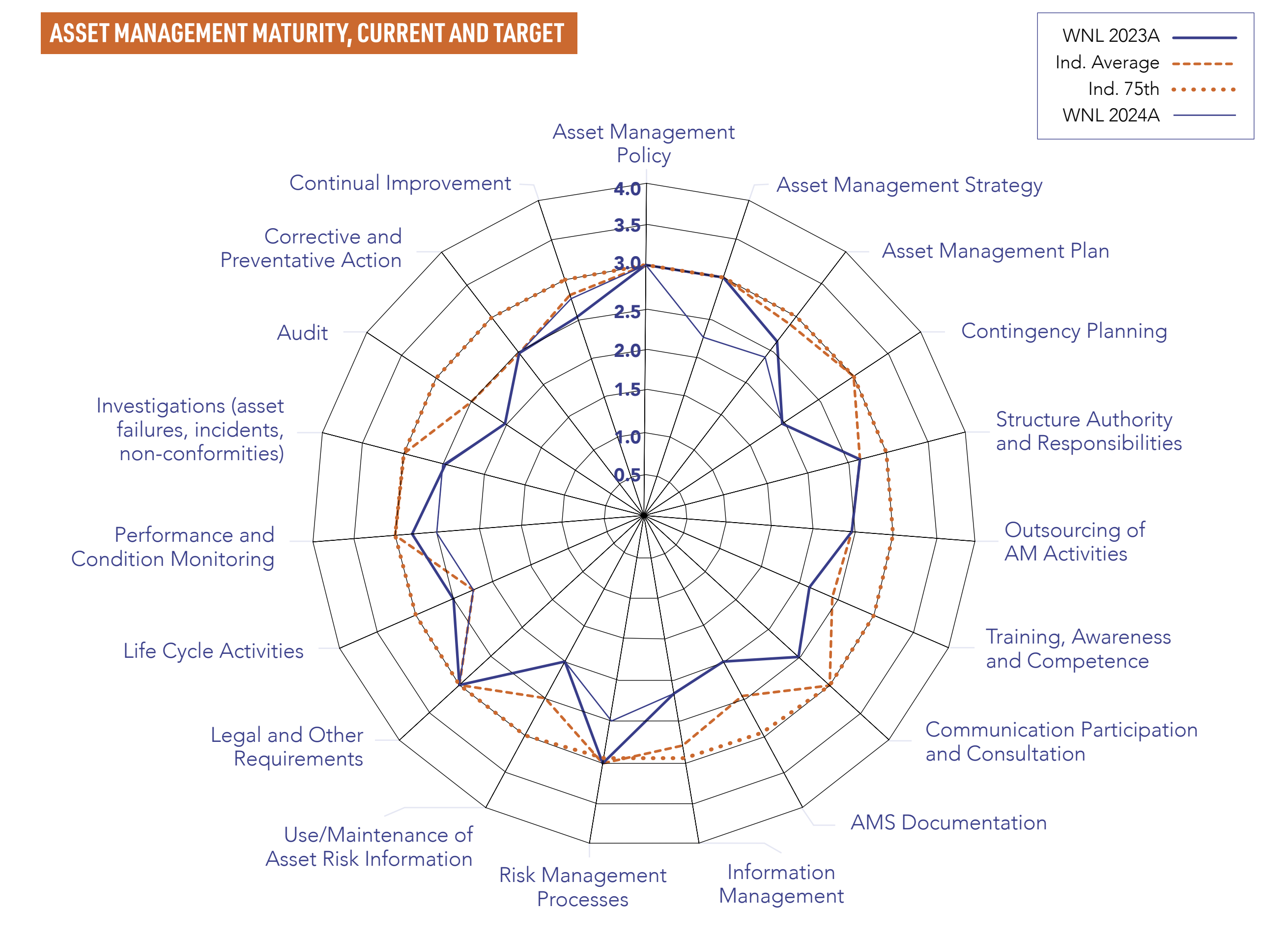


Figure 47: Asset management maturity

We remain committed to our overall goal of an asset management maturity rating of 3. However, our work will extend beyond FY25. We have some resourcing building to do, to achieve all the targeted improvements.

During FY2025, our focus areas will be:

- Continuing to enhance asset management practices, including investigating asset failures and transitioning to risk-based asset renewal forecasting.
- Enhancing our contingency planning work and defining future competency requirements.
- Continuing our work on information management and improving data quality for some asset classes.

5.6 Health and safety

Safety is fundamental to the way we undertake any activity. We prioritise the safety and well-being of our employees, customers, and communities.

Principles that guide our approach to providing excellent Health and Safety outcomes include:

- the operation, maintenance, and improvement of our assets does not harm members of the public,
- all employees and contractors undertake their work in a safe environment using safe work practices,
- physical and mental wellbeing of all staff,
- controls, policies, plans, and competencies are effective for minimising impacts on the environment,
- processes, audit, and review procedures are in place to ensure we consistently achieve high-quality outcomes and
- Continuous improvement.

To support these principles, we have developed robust and comprehensive risk management processes and documentation to address potential hazards and ensure compliance with health, safety, and environmental standards, and these are routinely reviewed and updated.

5.6.1 Public safety management system

Our Public Safety Management System (PSMS) framework is built on policies, procedures, and guidelines relevant to the safe design and management of the assets. The PSMS helps ensure that assets installed in public areas do not pose a risk to public safety.

The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulations 47 and 48 of the Electricity (Safety) Regulations 2010.

Our PSMS system complies with NZS 7901:2008 and is externally audited and centerfield by Telarc. We are looking at transitioning to NZS 7901:2014 in FY25.

5.6.2 Resources

Health and safety critical risk control management

We recognise the importance of identifying and mitigating critical risks to ensure a secure and accident-free work environment. The Health and Safety Critical Risk Control manual outlines the methodologies and protocols for identifying, assessing, and controlling critical operational risks. This empowers our workforce with the knowledge and tools to pro-actively identify potential hazards, implement effective control measures, and maintain a secure workplace.

Health, safety, and environmental risk register

The Health, Safety, and Environmental Risk Register is a comprehensive database of potential risks associated with our activities. This living document continuously evolves as we identify and analyse new hazards, ensuring we stay ahead of emerging threats. Each risk entry includes detailed information about the identified hazard, its potential consequences, and the control measures to mitigate it. This register enables us to prioritise risk management efforts, allocate resources effectively, and maintain transparency throughout the organisation, fostering a culture of safety and vigilance.

Risk assessment in the field

Our guide to Risk Assessment in the Field helps with risk evaluation processes during field operations to ensure our employees are well-prepared to navigate challenges in the field safely and responsibly. It provides a structured approach to efficiently assess and address these risks, including identifying hazards, evaluating the likelihood and severity of potential incidents, and implementing appropriate control measures.

Figure 48: Worksite risk assessment

Safe work method statements

We implement Safe Work Method Statements (SWMS) as a fundamental component of our operational practices to uphold our commitment to a safe and secure work environment.

Standard operating procedures

Operating Procedures (SOPs) govern every aspect of our organisation. The SOPs serve as the best practice guides that ensure the smooth functioning of our company and the safe delivery of services to our valued customers.

Assura

Assura is a workflow management application we have chosen to capture and manage Health and Safety related events and other information. Section 7.3 describes the system.

5.6.3 Health & Safety Committee

Our Health & Safety Committee (HSC) ensures a safe and secure work environment for everyone associated with our organisation. The primary function of our HSC is to ensure that we focus on measures that prioritise the workforce's wellbeing. The HSC meets monthly to address issues raised by staff or reported through Assura.

5.6.4 Safety targets

We have a set of KPIs that align with our network operator and asset owner responsibilities and will provide a good indication of our safety performance. These include:

Key performance indicator	Target 23/24	Target 24/25	Target 25/26	How we'll be measured
Number of serious harm injuries	0	0	0	No serious harm injuries.
Total Reportable Injury Frequency Rate (TRIFR)	4.1 <4.0	4.1 <4.0	4.1 <4.0	The TRIFR is declining.

Table 20: Health and safety targets

Note: *We will investigate the cause of any injury to mitigate or eliminate future risk.*

Note: *Total Reportable Injuries Frequency Rate (TRIFR) – is a new measure for FY24.*

5.7 Our role towards a sustainable future

We understand we have a key role in enabling our region's transition to a sustainable future through electrification, and we are starting to prepare for this role.

Managing infrastructure assets requires considering a range of factors. Ensuring our services support New Zealand's efforts towards a decarbonised and sustainable future, understanding and delivering the future security and resilience levels expected by our customers, and ensuring a just and fair energy transition for all customers are material issues for the business and our industry. The transition to a net carbon-zero New Zealand will take time; we must clearly understand how best to support our region.

Addressing these factors requires consultation, information, innovation, and good decision-making. This AMP is the first step in explaining how we consider these factors.

5.7.1 Framework

The Energy Trilemma[21] is a well-recognised and useful framework (see Figure 49) when considering the energy transition. We have referenced this framework as it is aligned with how the Central Government (and related agencies, such as the Climate Change Commission, MBIE and Electricity Authority) are considering energy strategy. It is also a core part of the terms of reference for developing NZ's Energy Strategy.

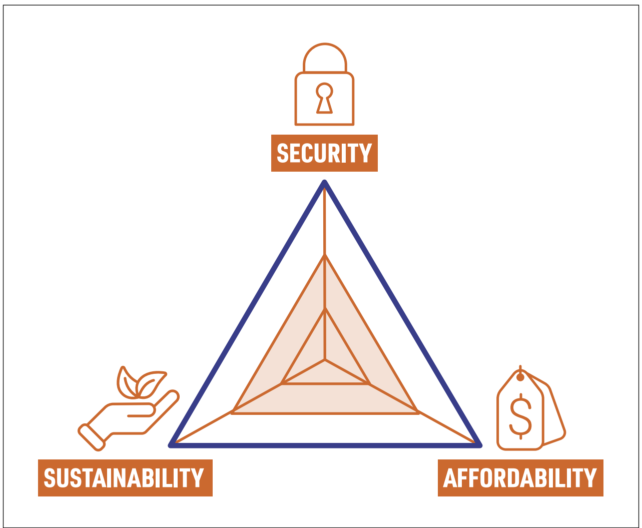


Figure 49: The energy trilemma

In the energy context, the three limbs refer to:

- **Sustainability:** meaning the ability to support New Zealand's energy transformation, minimise emissions, and adapt to climate change.
- **Security:** meaning the ability to meet current and future energy demands reliably, as needed by our customers, including being resilient to external events.
- **Affordability:** meaning the cost of, and access to, energy (of which electricity is an increasingly important component).

[21] *Source: World Energy Council.*

5.7.2 How we are considering the factors

Figure 50 illustrates our initial assessment against the three limbs of the energy trilemma framework. This assessment indicates our current view on the direction of travel over the ten-year horizon of this AMP and is in the following order of consideration:

Sustainability is forecast to improve based on New Zealand's direction towards a sustainable and electrified future[22]**.** This will be supported by the asset management initiative discussed in Section 1.7: #1 (regional security) and #2 (energy transformation). This is also backed by our core investment into the network and asset management initiative #5 (asset management) to manage the increasing complexity from energy transformation.

Our customers expect security and reliability to improve. As dependence on electricity grows, we expect our customers will require a more secure and reliable supply. We will engage with our community to better understand and define our customers service level expectations now and in the future. This is on the back of investments to support asset management initiatives #1 (regional security), #3 (resilience), and #6 (vegetation). This is also backed by #3 (resilience) to improve the resilience of our network to climate-change-related impact.

Electricity distribution costs will likely increase, but overall energy affordability should improve. Therefore, we must ensure a just and fair energy transition for all customers. Improving sustainability and security simultaneously will require considerable investment into the network.

Increasing investment will lead to an increased cost of electricity supply. While the cost of electricity will likely increase, the overall energy affordability should improve because of electrification [23]. We must ensure that transitioning to a net carbon-zero economy is just and fair for all customers. This will include non-asset and/or non-network initiatives to help alleviate energy hardship, targeting those customers who require support.

In summary, we envisage that in the future, customers will experience a lower overall energy cost with an increased electricity component and will also experience a more secure and resilient network.

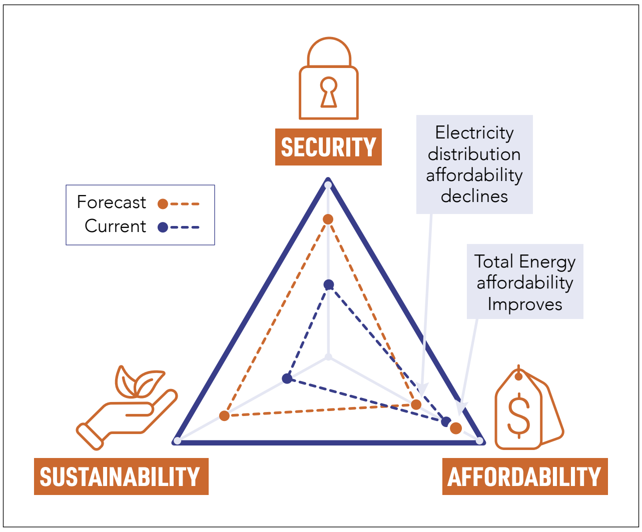


Figure 50: Assessment against the energy trilemma framework

[22] *Report by Boston Consulting Group "Climate Change in New Zealand: The Future is Electric" https://www.bcg.com/publications/2022/climate-change-in-new-zealand*

[23] *Assessed by Sapere in their recent report for the Electricity Networks Association https://www.ena.org.nz/news-and-events/news/total-household-energy-cost-to-reduce-over-time/*

PART 3:

IMPLEMENTATION PLANS TO DELIVER THE STRATEGY AND THE REQUIRED LEVEL OF PERFORMANCE

6. RISK MANAGEMENT

6.1 Introduction

In this section, we describe our risk management process, discuss our exposure to natural hazards, discuss our network and other risks, and describe our contingency plans and preparedness activities to reduce the consequences of events when they occur.

Electricity is a hazard, and the conveyance of electricity has associated health and safety risks. The electricity network is also exposed to risk (from natural and other hazards).

We have initiated a significant strategy (asset management strategy #3) to increase the network's resilience to natural and other hazards. The resilience strategy will reduce the risks associated with high-impact and low-probability events (e.g., failure of a pole carrying multiple circuits or a total loss of GXP) and high-impact and now more frequent events (e.g., major weather events) over time. Refer to Section 9.4 for our resilience strategy.

6.2 Risk management process

To manage risk and to keep exposure within acceptable levels, we have adopted a systemic approach to risk management by following the Australian/New Zealand standards ISO 31000:2019 Risk Management and NZS 7901:2014 Electricity and gas industries – Safety management systems for public safety. Figure 51 shows the risk management process recommended by ISO 31000 and adopted by us.

We have updated our Risk Management Policy and Risk Management Framework in FY2024.

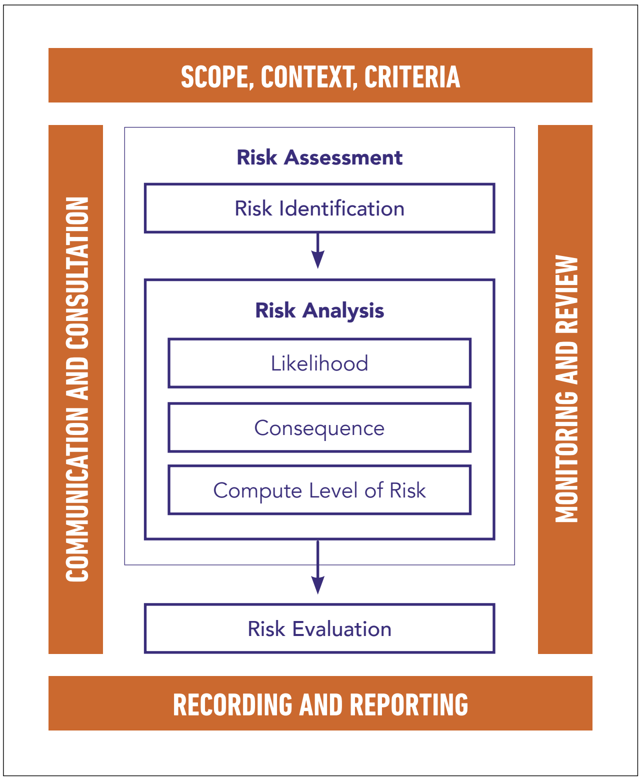


Figure 51: Risk management process

Specifically, we'll:

- Adopt a conservative risk position, especially regarding worker and public safety.
- Regularly review our company risk appetite, policy, and management framework.
- Consider long-term requirements in making network investment decisions. Prudent investment in network capacity may install higher network capacity than needed presently, recognising that under-investment can lead to supply interruption and that the overall economic cost suffered by customers can be markedly greater than the cost of investment taken before it is required.

6.2.1 Risk context

The above process allows for consistent management of risk types affecting us. We use the definition of risk as prescribed by ISO 31000, which is the effect of uncertainty on objectives. When considering our risk and risk management, it's important to place these in relation to our Risk Framework and Risk Appetite, which are linked to our organisation's objectives expressed through our Statement of Corporate Intent.

The risk management process considers risks relative to the operations of our business, broadly grouped into the following risk categories:

- Health and safety, including public safety
- Environmental
- Stakeholder and Community Confidence / Reputation
- Cultural
- Financial (impact on business cash flow)
- Operational (business interruptions)
- Compliance

6.2.2 Risk identification

Our risks are identified by a variety of methods, including:

- On-site checklists before starting work (tailgates).
- Work site reassessments during the day as our work environment changes.
- Regular visual hazard inspections of work areas.
- Analysis of accidents/incidents or near misses.
- Asset condition assessment for the likelihood of asset failure (for which public safety hazards would feature, and potentially other hazards such as loss of supply, financial loss and environmental hazards).
- Defect notification.
- Internal and external feedback.
- External information from specialists.
- Risk workshops and management review.
- External risk reviews and audits.
- Industry information.

6.2.3 Risk analysis

Once risks have been identified, they are analysed to:

- Identify the source and cause of the risk.
- Assess current controls and their effectiveness and identify any gaps.
- Consider how likely the risk is to occur and the impacts (likelihood and consequences).
- Determine the risk rating (likelihood x consequence).

We use the risk criteria and matrix described in Appendix C to analyse risks. This categorises likelihood into five categories (from rare to almost sure) and consequence into five categories (from low to critical). This analysis is performed on the inherent (uncontrolled) risk and then again on the residual (controlled) risk.

Our risk profile is mapped onto a risk matrix, allowing us to identify which risks we need to focus on ("Extreme" and "High").

6.2.4 Risk Evaluation

Once a risk has been analysed, it is then evaluated based on the outcome of the analysis and against the risk assessment criteria to:

- Escalate to the necessary reporting levels.
- Prioritise risks.
- Consider options for managing risks.
- Decide what action is required.
- Identify resources required to manage the risks and allocate responsibilities.

6.2.5 Risk treatment

Risks are treated either through elimination or the application of controls to reduce the risk's likelihood and/or consequences. We seek to put rules in place that will reduce risk tolerably. Ongoing monitoring and review are undertaken to verify that this is being met.

Treatments may avoid, transfer, reduce, remove, modify, or accept the likelihood and/or consequence of risk(s) for non-health and safety-related risks. Non-health and safety risks may be treated in a variety of ways. Some examples of controls include (but are not limited to):

- Changing policies, systems, and processes.
- Changing plant and equipment– redesigning the equipment or construction process.
- Applying new or different technology.
- Training and education, including tailgate sessions.
- Inspections or adjusting the type or nature of inspections.
- Testing.

Under the Health and Safety at Work Act 2015, when determining the appropriate control to manage a health and safety-related risk effectively, and to conform to our health and safety policy, a specified sequence of rules is followed. Our Risk Management Manual and Health and Safety Manual include the health and safety risk management details.

6.2.6 Recording and reporting – risk register

Health, safety, environmental, and corporate/organisational risks (including financial, reputational, business interruption, and regulatory compliance) and risks related to the network and operations are held in a single risk register. A common format, structure and methodology are used, as set out in our Risk Management Manual.

6.2.7 Risk monitoring and review

We have a proactive approach to public safety and safety for our staff, contractors, and customers. Regular surveillance and monitoring relative to safety are undertaken concerning network assets, e.g., ongoing measurement of line heights, inspections of substations, inspections of pillar boxes, and aerial and ground surveillance of lines and vegetation in proximity to our lines. Network inspection criteria and planned maintenance procedures prescribe the standards for network survey activities.

Serious incidents and near misses are investigated following the recognised incident cause analysis method (ICAM) to identify the cause and better enable their prevention in the future.

The importance of lead and lag indicators relative to safety is recognised within our business, emphasising proactivity (informed by lead indicators).

The performance of our network and the effectiveness of work programmes relative to health and safety are regularly reviewed by our senior management, and where appropriate, change is made. These reviews focus on ensuring that the controls in place are effective and efficient. A report is generated and circulated for review and discussion for business-wide risks that fall into the priority categories.

6.2.8 Communication and consultation

Risk evaluation and communication are integrated within our daily operations and processes, including Board meetings, Health and Safety Committee meetings, team meetings, training, visitor and employee induction, inspections, etc., where appropriate specific meetings are held with industry groups.

6.3 Natural hazards

We have reviewed the general exposure of our network to natural hazards, including wind, lightning, floods, land erosion, earthquakes, volcanic eruptions, geothermal activity, and adverse weather. Our general view of the risks from natural hazards is outlined below.

We have further work to do in this area, outlined in Section 9.4 Resilience Strategy.

6.3.1 Wind

Our network is in an area of New Zealand that has one of the lowest recorded average wind speeds. However, seasonal storms with winds blow debris into the 11kV pole lines occasionally. Because of generally low winds, most of the time, trees tend to be weak and easily damaged by stronger winds. Our vegetation management programme is intended to reduce the incidents caused by wind-blown vegetation.

Wind presents a high threat to network assets when significant storms are considered. While the damage caused by wind-borne debris is easily fixed under normal circumstances, a powerful tropical cyclone could result in widespread network damage from downed trees, requiring a long period to reinstate and restore supply. Access to our network is likely to be complicated by wet ground conditions, further complicating supply restoration.

We know the lessons learned during the severe storm that affected Counties Power and Vector in 2018 and the cyclones that affected us directly–cyclone Dovi in 2022 and cyclone Gabrielle in 2023. Our overhead assets stood well from the most recent cyclone events, and out-of-zone trees caused the most damage.

6.3.2 Floods and land erosion

Our network area is subjected to frequent and often heavy rainfalls. There are numerous streams and rivers whose flow paths change over time. The effect of such erosion on network assets is currently minimal, affecting only one or two poles at any time, which are relatively easy to reinstate. However, the effect of such erosions on roads may be prominent in certain parts of the network – mainly the access into the Kawhia area–resulting in an isolated community.

6.3.3 Weather impacts from climate change and increasing resilience requirements

We are already seeing the impact of climate change in terms of the increased frequency of extreme weather events. Also, warmer and wetter environments result in higher vegetation growth rates that can impact the effectiveness of established vegetation management programs.

The impact of climate change in terms of intensification and increased frequency of weather events is expected to increase this risk from wind, floods, and land erosion over time (and this is being considered part of our resilience strategy).

6.3.4 Earthquakes

Transpower has assessed the probability and consequences of earthquakes damaging their assets for all areas in New Zealand and has defined three seismic risk zones: Zone A (high risk), Zone B (medium risk) and Zone C (low risk).

For each seismic risk zone, Transpower developed the following range of seismic risk factors that reflect the financial loading on construction works that'll ensure the integrity of their equipment:

- the seismic risk factor for Zone C (low risk) is 1.00,
- the seismic risk factor range for Zone B (medium risk) is 1.01 to 1.06 and
- the seismic risk factor range for Zone A (high risk) is 1.02 to 1.14, depending on the equipment type.

Our distribution networks are located entirely within a Zone B (medium risk) area. The network assets are predominantly long rural 11kV pole lines. These assets fall into the category defined by Transpower as "Other Plant" and have a seismic risk factor of 1.01.

We consider this an acceptable risk to manage because rural 11kV pole lines are relatively easy and an inexpensive network asset to repair if an earthquake damages. Based on Orion's experience in the Christchurch earthquakes, cable assets will likely be extensively damaged in a severe earthquake, requiring much time and effort to repair, with increased failures and reduced useful life afterwards.

6.3.5 Tsunami

The West Coast Tsunami Risk Study commissioned by Waikato District Council and WEL Networks assessed the risk of network inundation from a tsunami affecting the West Coast. The water level rise at the Aotea Harbour mouth is expected to be like a fast-rising tide, not a "wall of water", so damage and erosion from water inrush are not likely. Our network along Lawton Drive is overhead with pole-mounted transformers and mostly overhead service main entry, so the likelihood of network issues, if inundation occurs, is unlikely.

The water level rise at the Aotea Harbour mouth resulting from the worst-case event is generated from an earthquake on the Puyseger Trench to the south and west of the South Island. The sea level rise at the heads of Aotea Harbour is a maximum of 2.5 metres, but it is attenuated to around 1.5 metres at the Aotea settlement. To gauge the risk to our equipment, the elevation of supply areas was checked using an online mapping application. Areas along Lawton Drive in Aotea are between two and three metres above sea level. Inundation should not result even if the tsunami occurred at high tide unless the event is larger than modelled.

Other tsunami events from the New Hebrides and Tonga-Kermadec trenches would produce a water level rise of 1 to 1.5 metres outside the harbour and 0.5 metres or less inside the harbour, so these aren't expected to pose any risk to our network.

The West Coast tsunami risk study did not cover the Kawhia Harbour. Still, it is assumed that the water level rise at the Kawhia Harbour heads is like the 2.5 metres rise at Aotea for the Puyseger Trench event. In that case, there is a risk to the network supplying Kaora St, Omimiti St and Motutara St on the Kawhia settlement waterfront. Some pad-mounted transformers are in these areas, and the LV reticulation is underground with pillar connections for customers. Hence, some flooding of pillars and pad-mounted transformers may cause supply disruption, requiring isolation until the event is over, then inspection and possibly cleaning or repair before re-livening. Some low-lying areas on Kawhia Road and Kawhia Harbour Road would experience a rise in water level, depending on how much the harbour mouth attenuates the water level rise. However, our network in these areas is overhead distribution, so no supply issues are expected.

Regarding access for fault staff and repair crews, several road sections around Kawhia Harbour and Aotea Harbour are low-lying. They could be affected by rising water levels washing across the road. Depending on the depth, this may delay access, but damage to the road surface is not anticipated.

The impact on our network if this event were to occur is relatively minor. Only a small number of connected customers on these waterfronts would be affected, and it isn't clear if the rising water level will reach our network assets. When the likelihood of the tsunami event is also factored in (the return period for the Puyseger event cannot be determined but is considered very unlikely), the risk posed by the tsunami to our network is not considered significant. No red, orange or yellow tsunami risk zones are produced by the Otorohanga District Council or Waitomo District Council for the Aotea and Kawhia areas. NEMA is doing further work on this, including tsunami risk zones, and this section of the AMP will be updated with that information once it is complete.

6.3.6 Volcanic eruption

There are no known active volcanoes in our distribution area. The Mount Ruapehu eruption in 1995 had no adverse impact on our assets because of the prevailing winds. If volcanic ash had been deposited over the rural 11kV lines, we would have continued operating our distribution networks until there was clear evidence of insulation failure. A water shortage to wash insulators from an ash fall is an expected risk, given that many parties will simultaneously attempt to wash plants and equipment.

6.3.7 Lightning

Our network assets are regularly subjected to lightning strikes. Network assets most affected by lightning are rural 11kV lines on which normal 11kV lightning protection devices are used to localise and minimise lightning damage. Installation of surge arrestors on pole-mounted distribution transformers has been included in the standard design for new installations to protect these assets from lightning.

6.3.8 Geothermal

There is no significant geothermal activity in our reticulation area other than a hot water beach at Kawhia. Therefore, there is no corrosive atmosphere to contaminate the overhead lines or hot ground, gases or liquids constraining cable ratings or corrosive liquids damaging cable insulation and conductors. We conclude that there is minimal risk to our network from geothermal activity.

6.4 Network risk

This section focuses on the network risks category, not support systems or general business risks. Risks are identified, and the inherent (unmitigated) and residual risks are ranked according to the risk matrix. Appropriate controls are listed, and actions are identified.

The following asset categories are considered in our risk management assessment process for Network Risk:

- Overhead line failure and operations.
- Overhead line environment and stakeholders.
- Distribution substations, switchgear, and underground assets.
- Other failures (including SCADA, network connectivity, grid supply etc.).
- Other environments and stakeholders.

The high-focus risks are identified as a selection of the highest-impact risks from the categories above, as detailed in Appendix D. Based on the updated Risk Framework review completed in FY2024, we have reassessed and updated the network risks with the following top-ten risks:

1. Unauthorised/public access to unsecured pillar boxes or unwanted self-tapping screw-cut cable insulation is live (note: no reported incident so far).
2. A major regional storm (tropical cyclone) causes widespread network damage,
3. Sustained (eg >24 hour) loss of supply at GXP /Point of Supply.
4. Earthquake risk to the depot building.
5. Poor or unknown condition of overhead lines/poles causing lines or pole failure and public safety hazards.
6. Assets with unknown age, unable to forecast replacement expenditure.
7. Unlawful or unsafe network (service main/line) connection
8. Long-term planning and investment to enable a resilient and future-enabled network through climate change and decarbonisation are ineffective or too late.
9. Network Security Risk Loss of critical IT systems through Cyber-attack Core operational systems only
10. Cable capacity out of Te Awamutu GXP

Appendix D shows the high-focus risks, risk rankings, risk mitigation initiatives and control measures. Our risk action plans are reviewed periodically, and the actions progress to mitigate the risk impacts.

6.5 Other risks

6.5.1 Pandemic

As an essential service, we must maintain our ability to operate a reliable distribution network during a pandemic. Loss of operating capability would occur if we could not maintain a minimum find fault-and-fix capability of our field crews. This can be due to team members being unable to work due to illness (individual or their dependents), operational control room capability, and availability of equipment and materials due to impacts on our supply chain.

We have maintained a Pandemic Response Plan initially developed in response to the SAARS and avian bird flu incidents internationally and then put the pandemic response into action during the COVID-19 pandemic in 2019 onwards. The experience of implementing a CIMS management structure, allocating field crews into isolated "operating pods", developing contact recording and work crew operating procedures, holding higher equipment stock levels, and moving office workers to remote working was very valuable in terms of the organisation's preparedness for further pandemic disruption.

6.5.2 Cyber attacks

This is discussed in Section 7.2 – Information and Cyber Security.

6.6 Contingency planning and preparedness

6.6.1 Emergency management system

Our Emergency Management System documents procedures for use in the event of major damage to the network and Business Continuity Plans are developed for various significant incident types. It contains information on Transpower, territorial authorities' contact details and other information that may be helpful in times of emergency. Development of our Business Continuity Plans continues with consideration given to various "what-if" scenarios. This prepares our team for multiple scenarios and events.

In 2021, a complete review and update of our Emergency Management System were completed. We have developed Incident and Emergency Management Plans, and the team has been trained to execute the plan under the Coordinated Incident Management framework. Specific Business Continuity Plans are under development for major event scenarios.

6.6.2 Emergency response plans

We operate two relatively simple interconnected radial 11kV, predominately pole line, distribution systems extending from Transpower's Cambridge and Te Awamutu GXPs. Under normal conditions, network operations are initiated through a control room, and work is dispatched through a call centre. In an emergency, we begin our emergency management plans and follow the Coordinated Incident Management principles. The structure assigns roles and responsibilities to enable an effective response to emergency events.

In circumstances where our SCADA and or financial and business computer systems also fail, network information held in printed form will be used by our Fault Staff and Field Supervisors to isolate, repair, and operate the networks safely. During these emergencies, we expect normal telephone services to be disrupted, direct communications with customers will be reduced, and fault identification will require additional line patrols.

6.6.3 Security of supply participant rolling outage plan

We publish a Security of Supply Participant Rolling Outage Plan per the Grid System Operator requirements.

6.6.4 Busbar failure contingency plans

Our busbar contingency plans are internally available and form part of our Business Contingency Plan.

Te Awamutu

In January 2010, we experienced an outage caused by a busbar fault at Transpower's Te Awamutu GXP, which simultaneously occurred while maintenance was being carried out on one of the GXP's transformers. This outage affected half of the Te Awamutu feeders. Power was restored by emergency switching, with the network being placed at risk of damage or overloading by operators needing to make "on the spot" decisions during such a large switching operation. We've developed detailed switching plans for any section of Te Awamutu GXP should there be a similar busbar event.

Cambridge

We've also developed a detailed contingency switching plan for either section of the busbar of the 11kV switchgear at Cambridge.

6.6.5 Business systems contingency

We run our financial and business systems (MagiQ Integrated Data Warehouse) and Windows-based programs hosted on servers locally and utilising external cloud platforms (e.g., for GIS, email, and phone systems).

Our financial and business system (MagiQ) is copied from production servers to a backup server each day and then to an offsite location. If required, backups can be used to restore failed systems or to rebuild systems/servers at alternative locations.

We can recreate the information databases and business functionality after a catastrophic event. Should our Te Awamutu depot be uninhabitable, our business systems can be recreated at the Securecom data centre in Auckland or Hamilton.

6.6.6 Supervisory control and data acquisition system contingency

Our SCADA system comprises a master station and a "hot standby" backup station in our control room at 240 Harrison Drive Te Awamutu and two remote operating terminals in the WEL Networks Control Centre at 114 Maui Street, Te Rapa, Hamilton. WEL networks also run two disaster recovery sites at Avalon Drive and Bryce Street. Both sites are linked via WEL's fibre network, so in the event of COVID or similar events, WEL can operate from these emergency sites to provide full control services in case one control centre goes down. WEL Control has four laptops, enabling the controllers to access SCADA via a secure cloud network.

The SCADA network configuration and operating schematics are backed up each day. The daily backup is held off-site, and we can recreate the SCADA network configuration and operating schematics after a catastrophic event.

Our control room service provider, WEL Networks, runs two disaster recovery sites at Avalon Drive and Bryce Street. Both sites are linked via WEL's fibre network, so in a disaster recovery event, WEL can operate from these emergency sites to provide full control services. In addition, WEL Control also has four laptops, enabling the controllers to access SCADA via a secure cloud network.

We're currently assessing the option for a disaster recovery SCADA control room independent of the Harrison Drive depot to improve the resilience of both voice and data networks.

6.6.7 Communication contingency

We operate our independent radio-telephone system. Should one or more repeaters fail, the system can have short-range point-to-point communications, which will continue functioning. Power restoration will be inherently slow under these circumstances. Most repairs required on the networks would be identified by physically patrolling the pole line feeders.

We participate in the Waikato Lifelines Utilities Group and expect that NEMA, in conjunction with other utility owners and local authorities, will prioritise areas for power restoration.

6.6.8 Coordination

We're an active participant in the Waikato Lifeline Utilities Group as required by the National Emergency Management Agency (NEMA). We coordinate with the local Civil Defence and Emergency Management Centre during major events and emergencies. This ensures that our response and recovery efforts are coordinated with national, regional, and local priorities and other utilities.

6.6.9 Resources

We're experienced at self-managing our network restoration resources during storm conditions and will interact and communicate with NEMA authorities and the public during these events. Our internal crews successfully reinstated our network during the February 2004, April 2011, January 2018, February 2022 (Cyclone Dovi) and February 2023 (Cyclone Gabrielle) storms.

We have sufficient internal field crews and equipment to respond to foreseeable emergencies on the network. We also have agreements with three other local distribution businesses and one contractor to use their field resources. Should the emergency event exceed our internal capabilities, we can call on additional resources outside our region.

We carry sufficient spares in our store to construct several kilometres of pole line. Our store holdings are considered appropriate to respond to foreseeable emergencies on the network. Should these be exceeded, we would call on other local distribution businesses (as mentioned above) to assist.

6.6.10 Exercises

Our emergency management procedures are tested regularly during our response to weather events. We also participate in the Waikato Lifeline Utilities Group and the group's risk assessment exercises.

We also participate in the Grid Emergency Event exercises with Transpower System Operators.

7. ASSET MANAGEMENT SYSTEMS AND DATA

7.1 Introduction

We invest in systems, including non-network assets, to support our core electricity distribution network. These include processes, information, and communication systems. This section describes these systems, the approach we take to ensure these are fit for purpose, and the investment required.

Information systems management includes technology services such as IT infrastructure managed by an in-house Technology team. Technology partners for specific industry expertise, e.g., cyber security, are engaged to assist the Technology team as required. IT-related assets, i.e., hardware and software, are managed on a different lifecycle to Network Assets. Software as a service (SaaS) and hosted infrastructure solutions are used, where appropriate, to reduce maintenance effort and risk.

We recognise the importance of adopting asset management systems to support our business management practices, including working safely and efficiently to provide confidence and transparency to our stakeholders. We have adopted various management practices consistent with recognised standards and best practices. The associated processes are information-driven and generate information requiring comprehensive information management systems and practices.

Our asset management process, see Figure 52, covers activities associated with the management of:

- Existing assets through their life cycle.
- Non-asset solutions to address network issues.
- The creation of new assets.
- Disposal of surplus or end-of-life assets

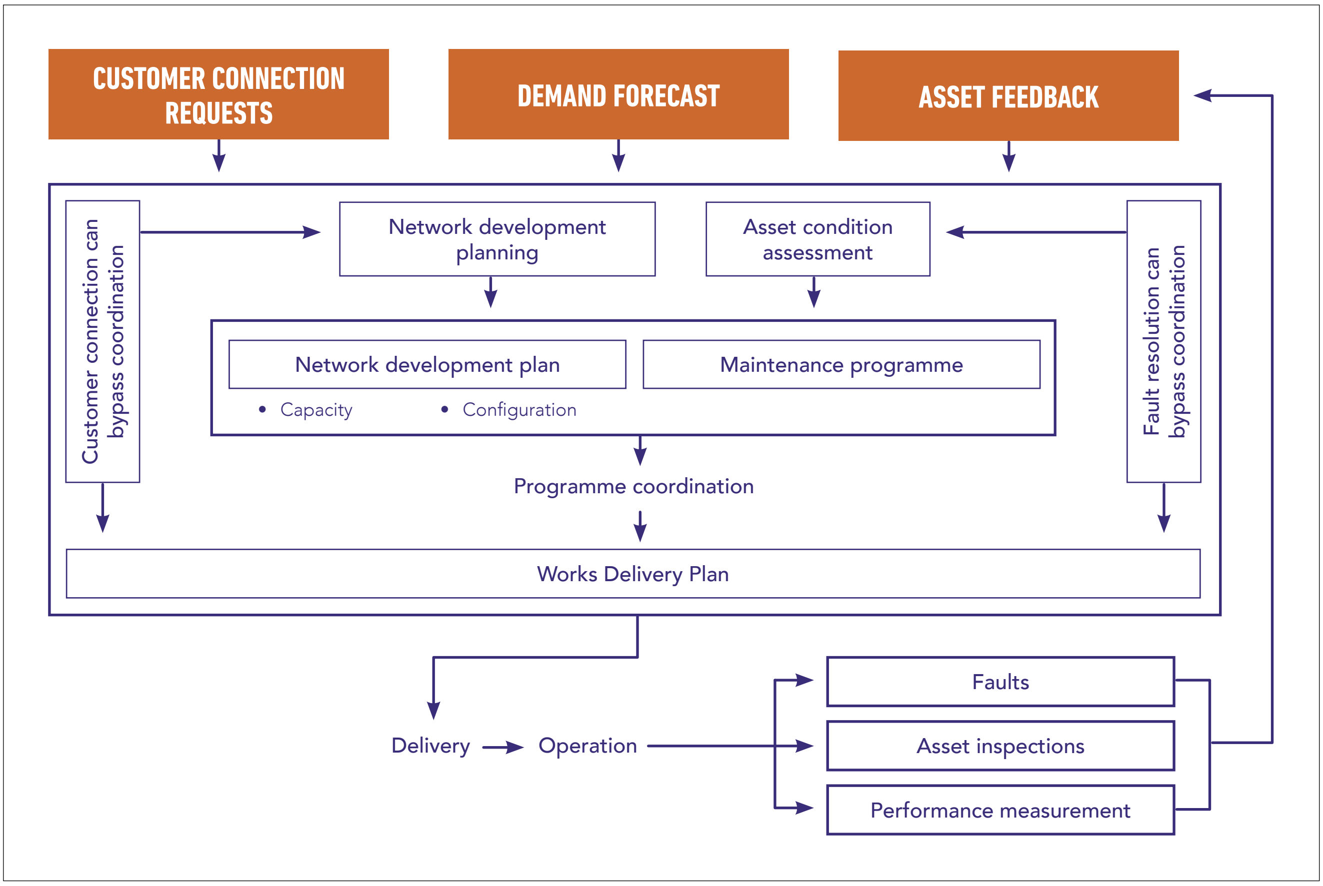


Figure 52: Waipā's asset management process

Our desired outcomes of these asset management activities are:

- Greater asset utility
- Increased asset longevity.
- Improved network performance–reliability and power quality.
- Improved network safety.
- Technically efficient equipment to optimise electrical losses.
- Improved financial performance.
- Business growth.

7.2 Information and cyber security

Increased reliance on connected digital devices increases the potential business impact of cyber-attacks. A cyber security attack on a power utility could affect the physical network, potentially causing equipment overloading or erroneous and/or unintended operations.

The risk of a cyber-attack on our network requires ongoing vigilance. We continue to monitor this risk and are implementing further improvements to the security of the SCADA and business systems.

7.2.1 Status and business response

We are investing more in training, systems and processes that enhance our cyber security posture to reduce the likelihood and impact of a cyber-attack. Enabling the business to respond pro-actively aims to fortify the business's resilience, ensuring minimal disruption to service continuity for our customers during a cyber incident.

Increased security measures that we have implemented to protect against cyber security events include:

- User awareness and training initiatives
- NIST Framework alignment
- Increased security policies across identity/devices
- Realtime monitoring of technology across identity/ hardware
- Threat landscape services
- Proactive Security Operations Centre (SOC)

We are updating our IT Disaster recovery plan to improve our business resilience and return-to-operations processes. Additional controls include external reviews of security controls, remediation of any vulnerabilities, and regular assessments/reporting.

7.3 Asset information systems

We operate asset management information systems to manage our existing assets, plan network development and measure network performance. These comprise systems for operational control and monitoring of network equipment and systems for network analysis and corporate information management. The asset management systems are employed for these functions:

- Asset creation and modification,
- Maintaining asset attributes,
- Operation and control,
- Capital projects – creation and management of project records and information.
- Creation and management of operational tasks and associated information, including planned maintenance tasks,
- Geospatial visualisation of installed assets, and
- Relevant Financial information available for Assets

Table 21 summarises existing asset management information systems that support these functions.

Asset Mgmt. System	Uses	Stored data
ARC	• ICP Management • Service Requests/Faults Management • Outage Notifications and Reporting	• Asset information • Installation Control Point data • Call centre enquiries • Outage data (planned and unplanned) • Financial records and Asset Register (financial and taxation) • Disclosure statistics and information
MagiQ Cloud	Finance and Payroll	• General Ledger • Debtors & Creditors • Purchase orders and invoicing • Stores and inventory management • Project accounting • Payroll
ArcGIS Geographic Information System	Database for asset geospatial information, asset capability attributes	• Asset geographical location data • System schematics and reticulation plans • Owner, road, and property boundary data • Asset data (type, quantity, age, asset value)
Abbey SCADA	Supervisory Control & Data Acquisition – provides network visibility, monitoring, and control functions	• Operational status • Network loading data • Node voltage data • Alarm and fault data • Reliability data
AutoCAD	Engineering design and drafting application	• Construction plans • Design standards
Assura	Health and safety management and reporting system – worksite safety risk management and capture field observations on asset condition	• Worksite safety plans • Work permit (SWMS), • Defects/hazards – reporting and management
DigSILENT Powerfactory Network Modelling Software	Model current and future network performance under steady state and fault conditions and model the impact of proposed system enhancements and future demand	• Network assets physical attributes • Network architecture/connectivity
TVD/Avalanche Outage Communication Platform	An outage communication platform updates customers with known outage information and expected restoration times. This information is sourced from SCADA	• N/A
Avalanche Outage Communication Platform	ArcGIS Survey 123 solution	• Used as a mobile-form solution for capturing/ transmitting asset inspection, condition assessment, and vegetation assessment data from Field Staff

Table 21: Waipā's existing asset management information systems

The systems are described in more detail in Sections 7.3.1 to 7.3.6.

7.3.1 ARC

The ARC system is used for Customer Connection Management, Service Requests and Faults Management, and Outage Notifications and Reporting.

ICP management

The Customer Services Team uses the ICP database for daily operations and to provide source information to the Outage Notifications and Reporting Module. The ICP database contains a complete history of all outages and associated customer comments. ICP data comes from customers, retailers, electrical inspectors, and our processes. The ICP database is continually updated with new and disconnected customer information.

Service and fault management

Customer service requests and fault jobs are managed within the ARC Services module. The Waipā Customer Services team (and after-hours call centre) create, edit, and manage customer requests and faults.

Billing

The Billing module is used to conduct day-to-day billing operations.

Outage notifications and reporting

The Outages module contains details of planned and unplanned outages on the network. The module contains information on the physical network model and can accurately calculate the number of ICPs affected by each outage.

The module contains the functionality to notify retailers of outages as per regulatory requirements (e.g., EIEP5A/5B notifications). Affected ICPs for planned and unplanned outages are sourced from the ICP database. This data enables the calculation of outage statistics for measuring network performance for disclosure purposes and identifying potential network problems.

7.3.2 MagiQ cloud

MagiQ Cloud is the corporate Finance and Payroll System. It is a software-as-a-service solution provided by MagiQ Software.

Financial management functionality

The MagiQ Cloud solution provides the following financial management functions:

- General Ledger
- Creditors and Debtors
- Purchase Orders and Invoicing
- Project Accounting
- Banking transaction processing
- Payroll
- Stores and inventory management
- Asset Register

Quoting database

The Quoting database is a register of work orders within the MagiQ Cloud system and is used to maintain the status of each work order through its lifecycle. Other systems are used to capture the details of each work order (designs, quote details, etc.).

7.3.3 Geographic information system

In 2022, we migrated our as-built location data from a CAD environment to an enterprise GIS platform hosted in Microsoft Azure. Our platform leverages the Esri Utility Network data model and Esri ArcGIS Online cloud platform to enable us to manage our asset information using network connectivity and asset attribute rules.

This allows us to improve the quality and accuracy of our asset data while providing internal and external users access to the data via desktop, web, and mobile devices. We now seamlessly include information from district and national agencies to provide visibility of our assets within local planning rules and cadastral property boundaries.

We are now carrying out asset condition surveys using mobile GIS tools (ArcGIS Survey123), and this informs our asset health assessments that allow us to establish and prioritise our preventive maintenance program.

Additional mobile products have been developed to support the creation of asset identifiers when a discrete asset (such as transformers, RMU, reclosers, air-break switches, etc.) arrives in our asset stores. This removes the need to re-enter asset information when equipment is installed and supports a consistent asset identifier across our GIS, assets, and financial systems.

7.3.4 Assura

This Health and Safety management and reporting system was implemented as part of the field mobility initiative. The system is also available on mobile devices. It enables our field services to manage worksite safety risks and provide field access to digital health and safety system documentation. It provides a framework for identifying and managing hazards, serves as a platform to complete worksite safety plans, captures field observations on asset conditions (defects), and supports management of the work crew and visitor induction (tailgate sign-on). The system benefits include:

- Better access to information resulting in improved operator safety,
- Less time spent on the preparation of printed documentation for site visits and
- Improved confidence in system data.

7.3.5 Network modelling software

We use Digsilent Powerfactory network modelling software to study the impact of increasing demand and new connections on the network. The software is used to model the network electrically, perform load flow analysis, and calculate short circuit current flows that aid electrical network design and effective operational configurations.

7.3.6 Supervisory control and data acquisition system

The SCADA fleet plan is presented in Section 11.19.5, and the SCADA contingency plan is presented in Section 6.6.6.

7.4 Asset information

7.4.1 Asset information

Maintaining and improving asset data is a continuing focus for the business. The development of asset data will assist in making asset management decisions; in particular, further work is required to develop asset condition data, asset health indicators, and network equipment renewal expenditure forecasts.

The new GIS system contains existing geographical data transferred from prior systems. It has also been populated with data from the recent pole-top survey of the overhead network. Additional asset condition data is being captured, stored, and accessed in the GIS. The GIS will provide the base data for the new network modelling software.

The LV network information (e.g., conductor type and connectivity) in the GIS will be reconciled or established. This will provide the enabling information for future LV works/outage management and real-time monitoring for the low-voltage network. The LV network monitoring (including congestion and static/dynamic operating envelope) will become essential as electrification increases the penetration of electric vehicles, solar generation, and batteries.

Asset defect information (that has health and safety implications) is captured via Assura. The data drives corrective work and tracks health and safety measures. The Health and Safety at Work Act, in addition to the focus on field workforce safety, requires information systems to ensure asset maintenance and public safety inspections occur and that any remedial work is completed.

Asset management is dependent on accurate asset data. The quality of our asset quantity, age, and condition data supports our asset management strategy initiative #4, which is to develop comprehensive fleet plans and renewal forecasts.

The storage and management of asset records, including various asset attributes, is fundamental in ensuring appropriate asset management decisions are made. Accurate asset data supports the operations of the assets, maintenance regimes for various asset classes, and the renewal of assets based on factors such as age, condition, and risk.

7.4.2 Asset data

We hold records for electrical assets and non-electrical equipment such as plants, vehicles, office furniture and equipment, and field tools and instruments, all of which are recorded and managed. The assets are separated into distinct classes, such as poles, and then categories, such as concrete or wooden. The attributes held by assets vary by class.

The information we record and manage is based upon the following requirements and purposes:

- **Safety –** knowledge of assets location and condition is imperative in facilitating the safe operation of the network.
- **Reliability –** knowing the types of assets, their location, condition, and their relationship (including connectivity) allows the assets to be managed effectively to assist in minimising failures and network outages.
- **Regulatory –** We must disclose certain information (for example, age, condition, and performance) under specified asset categories.
- **Expenditure –** managing asset records allows for analysis of cost trends and determining internal cost rates and, therefore, the effective planning of maintenance and renewal activities.

The Engineering, Network information and administrative staff manage the Asset information. Field crews record changes to assets (and some asset components in the field) and then pass back the information to our Network Information team to update the asset management system(s) as appropriate.

We review and update our information by adding attributes for various assets, such as when and where they add benefits to the information. We manage relatively high volumes of low-value assets that are geographically dispersed, making invasive inspection techniques uneconomic in most cases. This means the scope for data collection is mostly visual inspection and high-volume aerial survey techniques. Occasionally, we use invasive/non-visual techniques to supplement condition information from visual inspections.

Whilst each asset type has unique attributes, we generally determine the data collected from a framework of failure modes and consequence assessment. For example, spalling on a reinforced concrete pole must be extensive for the pole strength to be affected. However, even a tiny steel exposure within a pre-stressed concrete pole is considered a cause for repair or replacement. Our inspection criteria reflect these different asset-specific risk assessments.

We also utilise information disseminated from organisations such as the Electricity Engineers Aotearoa (EEA) and the Electricity Networks Association (ENA) to identify particular asset types that may exhibit specific failure modes or symptoms, as experienced by other businesses.

While we endeavour to maintain our asset data as complete and correct as possible, general and known data limitations are described below.

7.4.3 Data limitations

General data limitations

General data limitations include:

- **Legacy data.** Our network was established approximately 100 years ago. Data has not always been captured in the manner required by current standards. Records have sometimes been lost during the transfer from one asset system to another. Data may have been compromised or lost, meaning asset records today are not always complete and accurate. Whilst visible assets are known, the installation date (for example) may be unknown for a proportion of assets. We believe we have a good understanding of the asset information that is not complete or accurate. We do not currently have a programme for re-establishing this data as, in most cases, there is no viable way to determine it, or the costs of doing so are prohibitive.

- **Timeliness of inspections.** Due to the rapid expansion of our network, inspection delays can occur. We periodically review our data management systems and processes to evaluate where improvements could be made in data quality and data management that are both useful and cost-effective. Where necessary, we will use a risk-based assessment to mitigate delays.
- The occasional challenge in getting accurate and consistent asset information data following fault events. There is the potential for this information to be overlooked when the primary focus is on the physical works (including making sites safe and restoring supply from outages).

Known data limitations.

Known data limitations include the following:

- **Aerial conductor condition data.** There is no common practical or non-invasive means of assessing conductor conditions other than visual observation (which does not always provide sufficient information). As such, conductor condition is generally assumed based on type, age (where known), location and operational experience. This limitation may result in a risk-based rather than a condition-based renewal of the conductor, where renewal is based on type, age, location (and hence deterioration risk) along with the condition of the supporting poles. The installation age of our low voltage (network) overhead conductor is not detailed in the records. However, this is a common issue for this particular asset class across the whole sector.
- **Underground cable condition.** Condition assessment of cable can only be undertaken through cable testing. However, some types of cable testing can prematurely age cables, and results can be uncertain, so to assess condition alone, cable testing of distribution cables is generally not done. As such, cable renewal is largely based on age, failure consequence, operating history, and type of cable sections.
- **Underground cable location.** Historically, there are cables whose plotted location is less accurate than the current requirements under the Utilities Code. We currently manage the risk through the beforeUdig process, and our cable location service. Further, each time there is need to do work on the cables (e.g., connecting new loads or doing repairs), we take the opportunity to verify and update asset location information.
- **Pole and cross-arm condition.** The condition of cross-arms in rural areas was assessed by the 2021 pole top condition survey, supplemented by inspections during day-to-day operation. The cross-arms in the urban area will be inspected in the FY2024 aerial survey. Timber poles only account for a small proportion of the pole fleet, and an inspection program is planned for FY2025. At present, conservatively assessing poles results in condition-based rather than risk-based replacement. Condition-based replacement is deemed appropriate from a public safety perspective and is in keeping with our approach to prioritising safety.

We monitor industry practice and testing innovations and will review our approach should the situation change.

7.4.4 Network surveys

Network surveys provide comprehensive information on our assets' locations, physical and electrical attributes, and their condition during the survey.

This initial data obtained during the first survey completed in 2006 has been supported by subsequent asset condition surveys and construction, equipment replacement and upgrade records. In 2019, we finished the second asset condition survey on all feeders, and in 2021, we completed the third asset condition survey of overhead and ground-mounted network assets. The 2021 overhead survey included an aerial LiDAR survey and capture of high-resolution pole-top images for accessible rural poles and has added to the overhead asset information available for asset management.

Over the FY24-FY25 period, we are surveying poles not covered by the 2021 survey, mainly in the urban and rural townships and minor rural areas. We continue to find more effective ways of collating and using network condition data and coordinating the survey schedules with equipment inspection programmes for the different asset classes.

7.4.5 Data improvement

We continue to assess data quality, including undertaking field audits and GIS checks and have prepared a data-issues register to track known issues and planned improvements.

In FY24, we also undertook data checks in the new GIS and identified a range of projects that will improve the representation and usability of the data. These projects will achieve the required data quality to support our asset management activities and reduce network risks. The work program will span the next three years, with the priority issues targeted for completion in FY24 and FY25.

The findings from our asset data quality audit support our regulator's information disclosure.

7.5 Asset management documentation

We have a range of documents relating to asset management. These documents include the following:

- **High-level policy documents –** which define how we'll manage our assets.
- **Asset fleet strategies –** asset maintenance, lifecycle management and renewal strategies for various asset groups, from subtransmission cables and power transformers to pole types and LV installations.
- **Network development and reinforcement plans –** providing a long-term plan of forecasted load growth, potential constraints, and mitigation strategies in conjunction with asset renewal and reliability improvement programmes.
- **Technical standards** for procurement, construction, maintenance, and operation of network assets.
- **Network guidelines –** provide directions and procedures on the construction, maintenance and operation of network assets and processes to achieve a desired outcome,
- **Network drawings,**
- **Network instructions –** provide further instructions on constructing, maintaining, and operating network assets and processes and
- **Safety notices.**

Documents, such as policies, specifications, drawings, operations and maintenance standards, and guidelines, follow the structure of the controlled document process, with a formalised review and approval process for new and substantially revised documents.

Generally, controlled documents are intended to be reviewed every three years. However, some documents are subject to more frequent reviews due to their nature or criticality to business function.

7.6 Asset management systems improvement

Through the asset management maturity assessment, we have identified asset management practice areas where there is potential for improvement.

Supporting the improvement in asset management maturity is our programme to modernise our information systems to enable more effective business and asset management. We have developed an Information Systems Strategic Plan (ISSP) with a roadmap for improving and updating systems to provide new integrated features and capabilities. This work commenced in FY2021.

7.6.1 Recent information system improvements

In FY2023, we completed deploying a new geographical information system (GIS) containing core asset information.

Other systems that have gone live over the past two years include:

- Assura health and safety system – The new health and safety system equips our people with access to information and process documentation in the field and facilitates improved safety management and reporting.
- Digsilent – Power systems modelling solution (that replaced ETAP)
- MagicQ Cloud Finance and Payroll system went live in July 2023. This includes Project Accounting functionality.
- ARC Service Management – The Service Management system replaced the legacy Faults Dispatch system and significantly improved functionality and efficient faults management, particularly during major events such as storms.
- ARC Billing and ICP management – the new billing system provides a single platform view, automation of billing processes, and increased security and management of ICP data.
- ARC Outage Notifications and Reporting – the new outage notification and reporting solution utilises the ICP information in the core ARC system and is used to fulfil the regulatory network performance reporting obligations.

7.6.2 Information Systems Strategic Plan (ISSP)

The Information Technology team produces an ISSP reflecting the key IT initiatives required to support and deliver Waipā's overall business strategy. The strategic plan has workstreams that identify and prioritise asset management system enhancements and include a corresponding roadmap.

The Waipā business strategy has three key focus areas.

1. Core network and business support
2. Future network
3. Business growth

Figure 53 shows the current ISSP workstreams under development that support our business strategy. This ISSP is subject to adjustments as it goes through the business approval process.

CUSTOMER AND COMMUNITY ENGAGEMENT STREAM
- Customer journey mapping
- Customer information system/CRM
- Customer engagement system
- Outage notification system

NETWORK STREAM
- SCADA enhancements
- SCADA replacement
- LV network visibility and analytics
- Outage management system

WORKS PLANNING AND DELIVERY STREAM
- Business process mapping
- Works management system

FINANCE AND COMMERCIAL STREAM
- ERP upgrade/replacement

PEOPLE, SAFETY AND WELLBEING STREAM
- HRIS
- Electronic time recording

CORE TECHNOLOGY STREAM
- Information management/EDRMS
- Application and data architecture
- AI and machine learning

Figure 53: Information systems strategic plan overview

7.6.3 Initiatives related to asset management

Further developments to implement an Advanced Distribution Management System (ADMS) will prepare us for the future of distribution network operations with functionality on Distributed Energy Resources (DER) and LV visibility. In FY25, we are plan to:

- implement continual enhancements to the GIS system and data models
  - asset attribute mapping and enhancement
  - asset data migration from the legacy NCS system to the GIS database
- introduce an LV visibility platform for network management, which will provide
  - better visibility of the LV network, enhancing our power quality investigation, solar generation connection assessment and new connection assessment processes.
  - enhanced information for network design planning and improved asset management
  - improved customer service experience, including service turn-around time and safety (e.g., deteriorating neutral issues) and internal process efficiency
- develop the scope for an advanced distribution management system (ADMS) that will integrate the core SCADA with other functions, including the outage management system (OMS), that can interface with future distributed energy resources and/or LV visibility platform. The OMS will provide improved planning and execution of outages, faults dispatch, automated calculation of reliability statistics and improved integration with customer records.

7.6.4 Initiatives related to core enterprise systems

The roadmap includes implementing and enhancing several core business support systems. These include systems/functionality for:

- Works management
- Data and information architecture, management, and workflow (including electronic document and records management).
- A drawings management system to manage standard design drawings, asset and site drawings, and project design drawings (this is closely associated with the records management initiative above).
- Project management.

7.7 Asset information systems forecast expenditure

The forecast investment to maintain and enhance our information systems is significant. The expenditure for the confirmed projects will be $1.77m. This will be refined as the details of the ISSP and the delivery programme are confirmed. The IT-related capex amounts to 4% of total capex over the next ten years, reflecting the significance of the work.

The cost of process improvement work (largely labour costs) is incorporated into our non-network opex forecasts.

8. NETWORK TRANSFORMATION

8.1 Introduction

New Zealand is transitioning in terms of how it produces and uses energy.

Reducing emissions through electrification and increasing renewable generation is critical to New Zealand achieving its net-zero 2050 goal; at the same time, technological advances are also making alternative energy choices economically accessible to customers.

The central pillars of decarbonisation are the electrification of transport and heat (both process and general), expanding the use of distributed energy resources (DERs), increasing the availability and use of flexibility, and 100% renewable electricity[24].

Developing and implementing a network transformation roadmap (the "roadmap") is a key asset management strategy for Waipā (asset management strategy #2). We must ensure that our services support our region's decarbonisation efforts and customer choices to secure a sustainable future in New Zealand.

In this section, we describe what is driving the energy transformation, how these drivers could impact Waipā, the actions we are currently taking, the areas for future work, and how we intend to progress the development of a roadmap over the next 12 to 24 months.

There is significant uncertainty as to the impact of the energy transformation on Waipā Networks. The most critical areas for uncertainty are the pace at which customers will decarbonise their energy use through electrification, how customers will adopt new technology to support their energy needs, how these changes will impact the future demand on the network, and whether we will need to, and be to access demand flexibility effectively and efficiently. How these factors play out could significantly impact the demand on the network, the complexity required to operate the network, and the extent to which we need to invest in new network capacity and organisation capabilities. Achieving clarity on these factors will take time.

Our focus in the short to medium term is to progress "low regret" investments and capability building. That is, we will continue to progress investments that will be utilised (as far as can be reasonably foreseen) across the range of scenarios. At the same time, we will seek to enhance our understanding, crystalise our thoughts and determine our positions in areas we have yet to examine in detail.

Our goal is to make the necessary investments to ensure we deliver the services customers require when they require them whilst having confidence that the investments will not be stranded in the future.

This section addresses the key actions under asset management strategy #2 in the 2023 AMP.

8.2 Drivers of the energy transformation

Multiple drivers for energy transformation exist, including government policy initiatives, regulatory frameworks, technology advancement and cost reduction, and energy customers' choices. However, ultimately, customer actions will result in adopting new technology and changing how the electricity system is used.

From a policy perspective, New Zealand has committed to Net Zero 2050 and set emissions budgets for 2022 to 2035 (the total emissions permitted for the 2022-25, 2026-30 and 2031-35 periods). The budgets require a 17% reduction in emissions and are supported by the emissions reduction plan. The emission reduction plan requires climate action across transport, energy, and building and construction that will impact how our customers use energy. These include:

- Increasing access to electric vehicles and beginning the process of decarbonising heavy transport and freight;
- Supporting businesses to improve energy efficiency and move away from fossil fuels, such as coal, by continuing to roll out the Government Investment in Decarbonising Industry (GIDI) fund;
- Banning new low- and medium-temperature coal boilers and phasing out existing ones;
- Innovation grant programmes and R&D tax incentives to support businesses in undertaking R&D relating to low-emissions technology.[25]

From a regulatory perspective, the Electricity Authority has a work program underway to support the transition to a decarbonised and more decentralised electricity system. The work will ensure the regulatory regime is fit for purpose and will help the adoption of new technologies to assist in transitioning to a low-emissions economy.[26]

[24] *Emissions reduction plan, https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/emissions-reduction-plan/*

[25] *Emissions reduction plan, https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/emissions-reduction-plan/*

[26] *Electricity Authority, "Issues paper: Updating the regulatory settings for distribution networks", December 2022*

Low-emissions energy technology costs are reducing, making them more accessible to customers. In a recent report from Sapere, they conclude that from 2026, all-electric households can expect the total annual electricity cost, including capital costs, to be lower than the combined petrol, gas, and electricity bills (including the relevant capital costs) they would pay otherwise.[27]

New technology continues to advance, and costs are forecast to fall further. The continued reduction in the cost of solar PV installations, batteries, and EVs (and the increasing fossil fuel costs) will increase customers' adoption of these technologies.

Technology that enables the electrification of industrial process heat, the economics of the technology are improving. Presently, heat pumps are suitable for businesses with heat temperature requirements below 100 degrees. Heat pumps can have high co-efficient performance (COP), meaning operating costs are around 45% to 75% of a natural gas or coal boiler. Research currently underway shows that temperatures of industrial heat pumps have the potential to reach above 200°C. This will increase the opportunity for electrification of industrial process heat.

These factors give rise to greater customer choices.

Customers are at the centre of the energy transformation. Some customers are changing how they want to use distribution services. New technologies make alternative ways of generating electricity and storage possible, changing how customers interact with the network. Energy Networks Aotearoa's (ENA) network transformation roadmap [28]portrayed a spectrum of customer behaviours, and we are already seeing some customers becoming living examples:

- At one end, passive customers focus on things other than electricity and rely on the utilities that provide them with energy. The passive customers let the utility decide on their electricity supply. Utilities and third parties assist customers to transition to more renewable electricity use to meet their energy requirements.
- On the other hand, active customers actively engage with their electricity supply, consumption, production, and new technology, and these are referred to as prosumers. Through technology, the prosumer actively decides on, and changes their service level over time based on price. They actively provide demand response from load and batteries for various services in the electricity supply chain and gain cost reductions. Prosumers optimise their usage and on-site distributed generation and sell it across the distribution and transmission network.

Waipā's role is to ensure our services can cater for all types of customers, regardless of where they are on the spectrum.

8.3 Waipā's perspectives

8.3.1 Regional review

In the 2023 AMP, we defined an action to undertake a regional review. This work has been completed and is summarised below.

The regional review identified potential drivers of change within our network and produced Waipā specific growth and change in energy usage pattern scenarios. The scenarios are not forecasts per se but pictures of what a net-zero world might look like and the implications for Waipā. The regional review looked at factors beyond the energy transformation.

The regional review provided a 30-year view, including an overview of the drivers of demand growth. It highlighted the impact of growth in housing to meet population trends, industrial and commercial developments, and the decarbonisation programme. This long-term view provided context to the more detailed 10-year AMP planning forecasts.

The regional review's output will feed into other aspects of our roadmap. However, for this AMP, the output guided the demand forecasts used in the network development section.

8.3.2 View of the Waipā region in 2050

Predicting the exact future state of a region like Waipā in 2050 is challenging and speculative. However, based on general trends and potential developments, we have sketched a view of what the Waipā region might be like in 2050. The regional review considered this future view when forming the demand scenarios.

Population growth and urbanisation

The population of the Waipā region is likely to continue growing, driven by factors such as migration, urbanisation, and economic opportunities. The towns of Te Awamutu and Cambridge are expected to expand (double), with increased residential areas, infrastructure, and services to accommodate the growing population.

Sustainable practices

With growing global awareness of environmental issues, sustainability will play a crucial role in the future. The Waipā region will likely see increased adoption of sustainable farming practices, renewable energy generation, and environmental conservation efforts. The district could become a leader in environmentally friendly initiatives and eco-tourism.

[27] *Sapere, "Total household energy costs", November 2022*

[28] *ENA, "Network Transformation Roadmap", April 2019.*

Technological advancements

Technological advancements are expected to impact various aspects of life by 2050 significantly. The Waipā region will see increased integration of smart technologies, renewable energy systems, and efficient infrastructure. Automation and digitalisation may influence the agricultural sector, improving productivity and sustainability.

Diversification of industries

While agriculture is currently a dominant industry in the Waipā region, economic activities will diversify by 2050. New industries, such as technology, research, and innovation, could attract businesses and foster new job opportunities. The district might become a hub for technology startups or research institutions.

Enhanced connectivity

The transportation and connectivity infrastructure of the Waipā region will improve further, facilitating easier movement within and beyond the district (e.g., the Southern Links project). Upgraded road networks and improved public transportation systems could enhance connectivity with neighbouring regions.

8.3.3 Growth drivers in Waipā region

Baseline customer growth (residential, commercial and industrial)

We expect population and economic growth to lead to new connections growing faster than we have seen over the past decade.

Waipā region is a desired place to live and is well situated for business. In thirty years, the network is forecast to be considerably larger in terms of customers and demand/usage. We forecast the two baseline demand drivers will be:

- **Population growth –** significant population growth due to the desirability of the region as a place to live, improved transport links to main cities leads and proximity to the "golden triangle" (Auckland, Hamilton, Tauranga)
- **New large industrial loads –** proximity to primary industries such as dairy and improved transport links will continue to attract large industrial loads.

Local councils have recognised (and forecasted) significant regional population growth and have identified land use to support residential development. We also expect a densification of residential areas to support population growth.

Farming is changing due to land-use changes and sustainable farming practices. This will change rural electricity consumption. Many of these trends are still developing, and we will continue to monitor long-term land-use changes. We will be looking at the trends in rural land use (from agriculture to horticulture) and farming intensity, and these factors may be considered in future modelling.

Residential and commercial gas conversion

Fossil gas use could transition to a biogas substitute, hydrogen, or to the electricity network. For residential and commercial customers, we expect the transition will be from gas to electricity. Approximately 35% of our residential and commercial customers use fossil gas.

We estimate a gradual growth in conversions until the late 2030s, after which growth is forecast to accelerate to reach the 2050 end state of electricity replacing all gas use. The gas transition has a minimal impact on demand in the 10-year AMP window.

Electrification of transport

Road transport accounts for about 17% of carbon emissions in New Zealand. Reducing emissions by electrifying the vehicle fleet, starting with passenger vehicles, is a focus area in New Zealand. While the current uptake of EVs is relatively low, we expect it to accelerate as EV economics improve.

We expect that the reduced cost of EVs, the expansion of regional charging infrastructure, and the development of smart charging options at home will enable higher EV uptake.

The impact of EVs on electricity demand is highly uncertain. EV demand is subject to how the charging infrastructure structure is used (public infrastructure, residential charging, and large-scale centralised charging of the heavy vehicle fleet), the time of charging (off-peak charging will have little impact, but should it coincide with the early evening demand peak, it will add to total network demand), and whether EV charging is also offered as flexibility. This is the key area that drives differences between the low and high demand scenarios.

Conversion of industrial process heat

Based on our regional review, boilers in diary plants dominate our region's industrial process heat demand.

Industrial process heat conversions involve switching to biomass or biogas as a fuel source, replacing coal or gas-fired boilers with electric boilers or switching to biomass or biogas as a fuel source. Where extensive processes are electrified (e.g., dairy factory boilers), they will likely be directly connected to the transmission grid (due to their size) or use biofuels. However, significant numbers of smaller industrial heat processes are still viable to supply from the distribution network.

Current indications from the major industries in our region are that to reduce carbon emissions, they are more likely to convert their boilers to biomass fuel than electricity. This is partly driven by fuel costs and the limitations of using electricity to effectively drive high-temperature heat processes (as required, for example, for steam boilers).

Distributed Energy Resources (DERs)

DERs, such as residential solar PV and battery, grid-scale solar or wind farms, can deliver energy into the network and enable customers to shift energy usage patterns across the time of the day. We expect this will shift some of the demand from the evening peak to the day as customers take advantage of on-site DERs.

We expect a material increase in active and passive customers installing small-scale solar PV generation and battery installations. The falling cost and increasing efficiency of solar panels and batteries will enable higher DER uptake, which is expected to impact Waipā's network significantly.

Controllable DERs (flexibility)

Controllable DERs can increase or decrease their consumption or generation output in response to control signals. These include diesel generation, batteries, controllable EV chargers, and hot water heating. Intermitting renewable generation (solar and wind) can provide controllable DER when combined with storage. The impact of controllable DER is referred to as flexibility. Flexibility services are already available in different parts of New Zealand; EDBs either access flexibility through a service provider or have started building their capabilities and infrastructures.

We expect an increasing number of active and passive customers with EV chargers, small-scale solar PV installations with batteries, smart appliances and hot water to make these controllable. The falling cost of energy storage and the development of flexibility traders and markets will enable higher controllable DER uptake. The flexibility markets will be enabled by enhanced network monitoring and communication, particularly in the LV space.

Energy efficiency improvements

As technology improves, we expect an improvement in the efficiency of electrical devices. Improving efficiency (e.g., compact fluorescent and LED lighting) has reduced average consumption per customer over the past few decades. Our overall view is that efficiency improvement will continue but will be matched by increased electrical devices. Our modelling excludes continued reduction in average demand and consumption per customer.

8.3.4 Scenario assumptions

We used the output from the regional study to develop a range of demand growth scenarios:

- **Base:** considers only traditional drivers of demand growth – population, economic activity (commercial and industrial development);
- **Low:** assumes low yield in the decarbonisation-driven electrification as some loads convert to non-electric options such as bio-mass, bio-gas and hydrogen (where hydrogen plants are not powered by in-region distribution network);
- **High:** where most loads are converted to electricity.

The material assumptions are summarised in Appendix A.

8.3.5 Growth scenario

Figure 54 to 57 show the demand growth scenarios for Cambridge and Te Awamutu. The forecasts include a 50 MW difference between Cambridge's low and high scenarios and 40 MW for Te Awamutu. This is an indicator of the current uncertainty associated with the energy transformation.

The difference between the high and low forecasts relates largely to population growth, industrial decarbonisation, EV uptake and flexibility (in particular, EV charging load shifting). It is not yet clear how the industry will deploy controllable DERs (in particular demand response), as 66% of the benefits can be attributable to non-distribution sectors of the industry[29]. Given the forecast increase in intermittent renewal generation, flexibility could have a higher value for generation firming.

We have applied a central scenario, the midpoint between the high and low scenarios, for planning purposes. Our planning approach includes testing the relevant low and high scenarios for major projects.

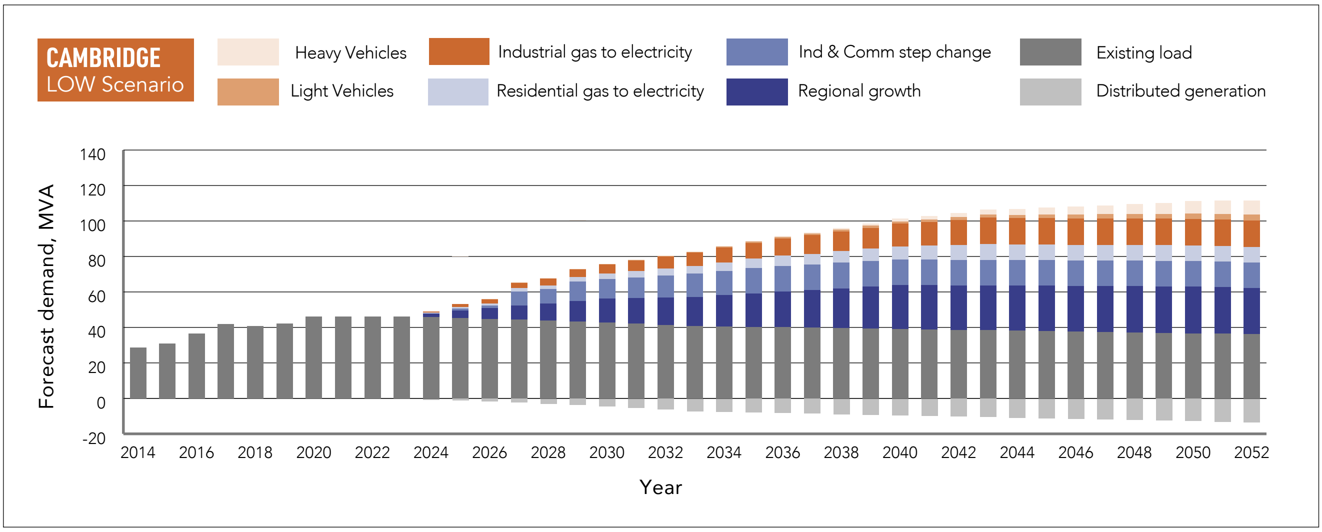


Figure 54: Cambridge low demand scenario

[29] *D. Reeve, T Stevenson & C. Comendant (2021) Cost benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority, Wellington, New Zealand*

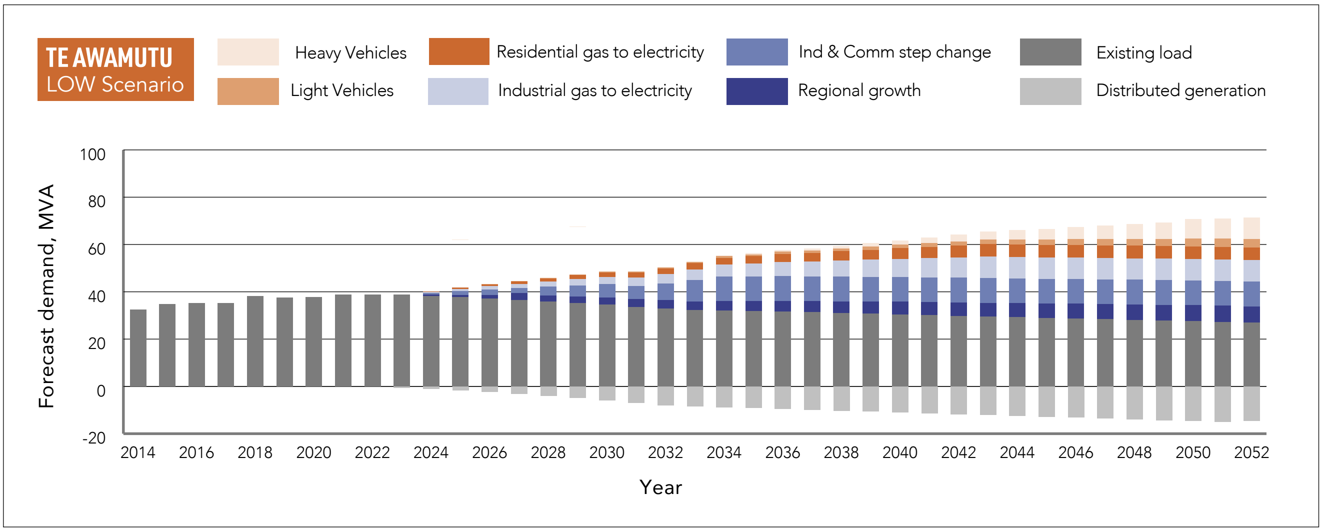


Figure 55: Te Awamutu low demand scenario

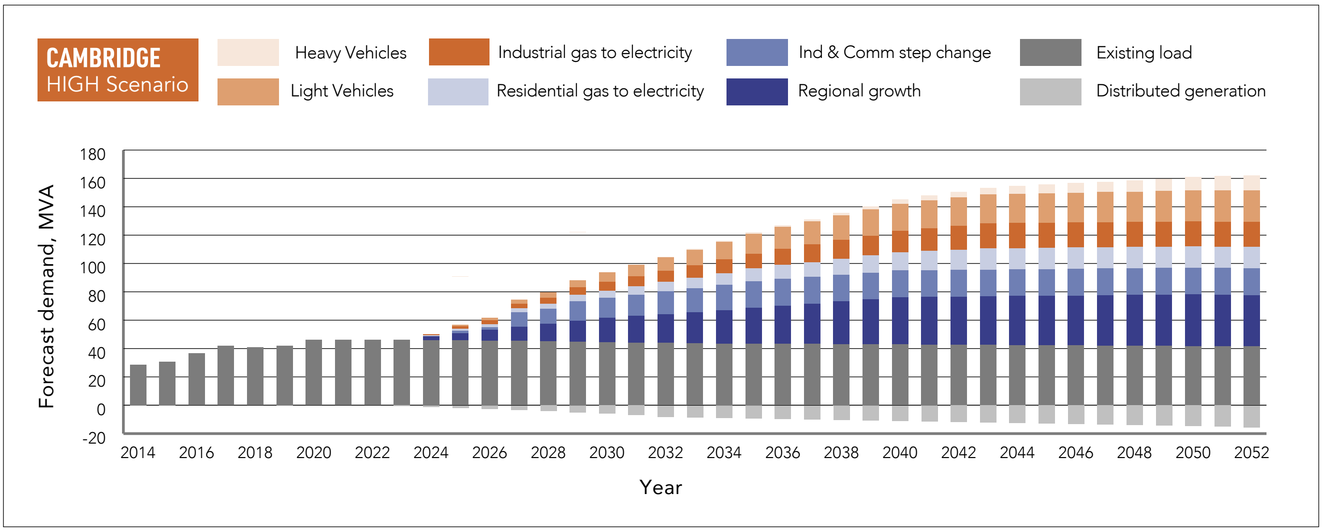


Figure 56: Cambridge high scenario

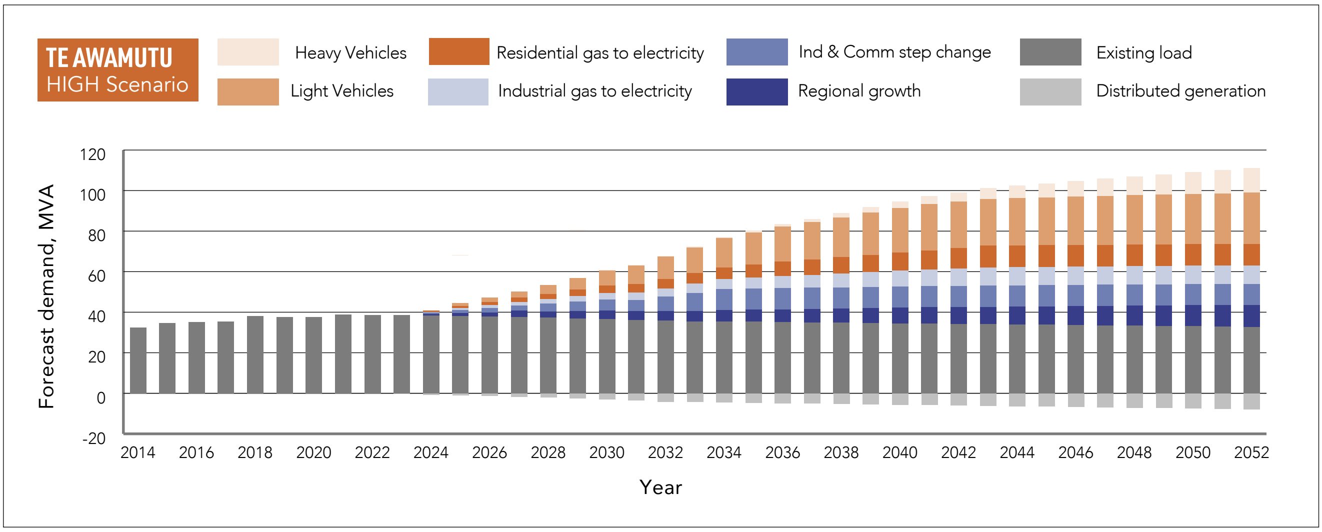


Figure 57: Te Awamutu high scenario

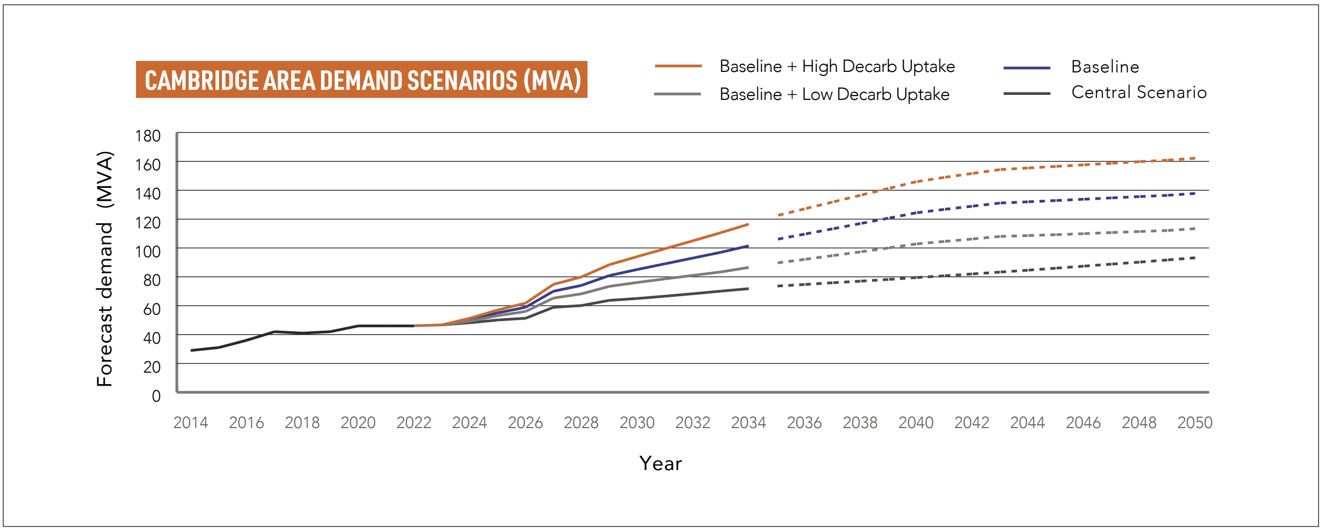


Figure 58: Cambridge scenario comparison

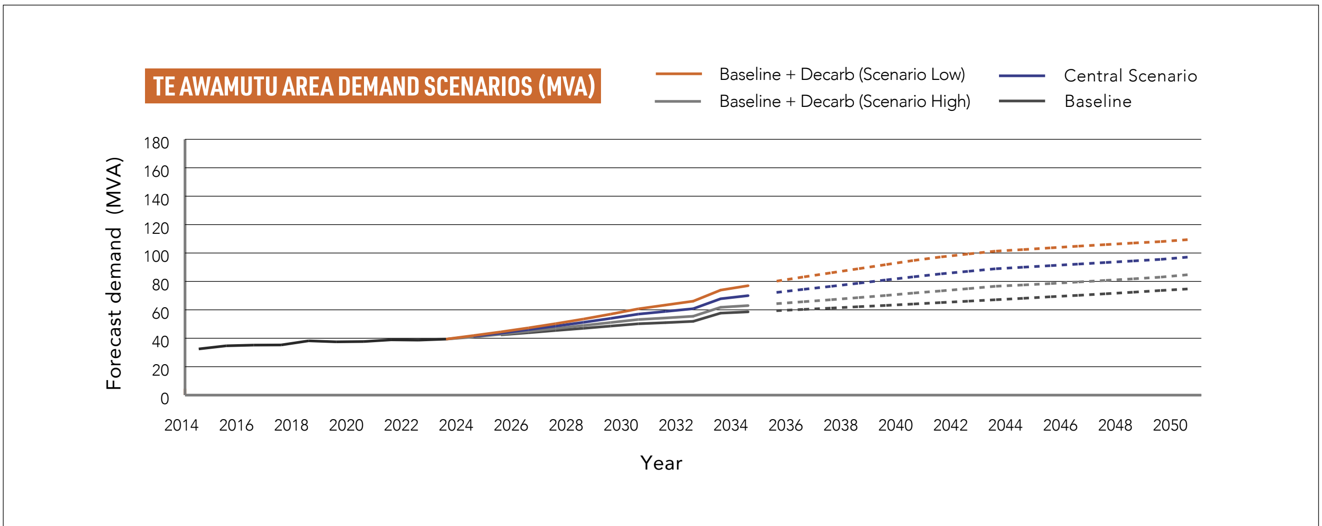


Figure 59: Te Awamutu scenario comparison

8.4 The challenge facing Waipā and distribution businesses

The energy transformation and the specific growth drivers (from the regional review) present a range of challenges for Waipā. These challenges are broadly consistent with those faced by distribution businesses in New Zealand.

These challenges include responding to demand growth, managing two-way power flows, managing the increasing complexity of operating the network, improving resilience, and building capabilities and resources.

Responding to demand growth

Our forecasts predict significant demand growth due to continued population and housing growth, new industrial customers, the electrification of transport, residential and commercial gas, and process heat. Responding to demand growth is particularly challenging for Waipā, where we are at a crossroads in developing the network due to a decade of strong customer growth for a network initially designed to supply a large rural area.

Significant demand growth will require investment in additional network capacity or alternatives. Investment in capacity must be made ahead of the customer need, but not so far ahead that it risks the assets becoming stranded should circumstances change.

Managing two-way power flows

Historically, the distribution network was designed to deliver electricity to customer premises in a one-way power flow. With the growth in customers adopting solar PV generation and batteries, the future network must facilitate two-way power flows. The future network will need to supply electricity from the grid to customers' premises and enable electricity to be distributed from one premise to another.

Networks must support two-way power flows to enable growth in renewable generation and ensure customers benefit from their investments.

Managing increasing complexity

Prosumers will connect new types of devices that allow new ways of using the network. Managing different power flows, ensuring the network operates within voltage capacity and power quality limits, enabling customers to participate in energy and flexibility markets, and accessing flexibility for our network needs will be complex. Additional data from customer meters, LV monitoring, HV monitoring, and flexibility markets will need to be managed and used.

We need to manage this complexity so that customers, energy markets, and we can enjoy the full benefits of new technology.

Improving resilience

The increasing use of electricity to decarbonise transport, industrial process heat, and commercial and domestic gas will increase the reliance on electricity and reduce fuel diversity. In the future, a loss of supply will have more significant community and economic consequences and impact more sectors.

We have developed a resilience strategy to reduce the impact of increasing incidents and intensity of adverse weather and other major events (refer to Section 9.4.3).

Building capabilities and resources

Building capabilities and resources to manage the changing operation of the network and its complexity is a challenge for the sector. Building people skills, business models, processes, tools, and systems to deliver a network appropriate for the future will be a material undertaking for Waipā and the distribution industry. The timing for building capacities must be undertaken before the changes, but not so far ahead that it creates inefficiencies.

8.5 Actions currently underway

We have commenced work supporting our region's energy transformation and future state. Our current focus is on "low regret" investments and activities that we believe will be required across the range of future scenarios outlined in Section 8.3.

The work currently underway is:

- The Cambridge regional capacity and security development programme. This is a significant programme of work involving a new Hautapu GXP in Cambridge, a new Forrest Road Substation, the potential new substation and associated distribution feeder development and integration. This development programme provides network capacity to 2050. The programme was required even if a low scenario occurred. Should the high growth scenario occur, an upgrade pathway has been included in the design;
- Planning for the upgrade to the Te Awamutu regional supply. This involves consideration for GXP and transmission upgrades. We have also commenced work on an options study that considers subtransmission and distribution system architecture to meet future growth needs and provide a foundation to improve reliability and voltage on the distribution system. Optimising the solution across a range of future scenarios is being considered;
- Upgrading our existing radio and communication network to handle more data. This is the first step in creating a platform for an increase in operating and asset data;
- We have commenced planning to replace our SCADA system. The new SCADA systems will provide a technology pathway for advanced distribution management (ADMS) for future LV network management and LV works management and interface with DERs;
- We have commenced work on constraint and solution modelling on the distribution network. This will identify future constraints due to the energy transformation and growth drivers. The focus for FY25 will be assessing network architecture alternatives to serve our future demand. Future work includes assessing hosting capacity, non-network options and how these can influence responsiveness to the transformation and customer service standards;
- Through the Ara Ake Decarbonisation Innovation Challenge[30], we completed a proof-of-value trial of the Gridsight platform to increase the visibility of the LV network.

Further details on these initiatives are provided in Sections 8.7 and 9.

[30] *Electricity Distribution Business (EDB) Challenge, https://www.araake.co.nz/projects/edb-challenge/*

8.6 Development of a network transformation roadmap

We have commenced developing a network transformation roadmap for Waipā. We monitor Government, regulatory, industry and technology developments to ensure our roadmap is consistent with our operating environment.

Our roadmap development aims to ensure that Waipā can support New Zealand's energy transformation and decarbonisation in a manner that presents the least cost to our customers over the long term. The roadmap will ensure that:

- We have the capability, services, and network capacity to allow customers to increase their electricity use to replace fossil fuels;
- We can connect and integrate DERs into the network and allow the owners of DERs to participate in energy markets and flexibility markets;
- We progress "low regret" investments and capability building to ensure our network will be able to deliver the services customers require when they require them and that there is a low risk of future investment stranding;
- We achieve network security and reliability that meets customer expectations.

Community engagement is important and will be part of various activities. It will be essential in terms of services and pricing.

It is intended that the roadmap will provide direction on how we will:

- Build our people and system capabilities to respond to the transition;
- Develop the network and its architecture to meet customers' future needs;
- Monitor the network (in particular, LV) to ensure reliability and security is maintained;
- Develop our business model to engage with customers, other industry players and flexibility markets;
- Develop our prices to influence customer behaviour to reduce peak demand;
- Optimise network investments, including utilising non-network alternatives;
- Develop standards to improve resilience and minimise complexity, network risks and operating costs.

Regulators, the industry, and Waipā need to consider a range of decisions. We discuss some of these in the next section.

We intend to present our network transformation roadmap in the 2025 AMP.

8.7 Direction and considerations for the network transformation roadmap

8.7.1 Assessing industry direction and fit with Waipā's strategy

Our current work on developing our network transformation roadmap has involved assessing industry direction, how this direction fits Waipā's strategy and firming up possible solutions. This work intends to build a roadmap that fits Waipā's long-term strategy. We comment on aspects of the roadmap below.

8.7.2 Building people and system capabilities to respond to the transition

New skills, systems and processes will be required to ensure that the distribution businesses have the services and network capacity to meet future needs. The industry needs new skills in data management, technicians with enhanced IT skills, market management and trading (for flexibility). These new skills come from recognised shortages of line mechanics, cable jointers, substation maintainers and technicians. Developing a plan to build these skills at Waipā is a key focus for the roadmap.

New systems will be required to deliver future services to customers and for distributors to fulfil their role within the electricity supply chain. The new systems will include:

- Meter data management—to enhance the real-time visibility of the LV network;
- Advanced Distribution Management System (ADMS) —A system to optimise the distribution system, manage outages, bring visibility to the LV system and current and forecast constraints, and interface with DERMS;
- Interfaces with Distribution Energy Resource Management System (DERMS)—This is software, and digital information flows that enable the control of controllable DERs and deliver the business processes for selling, contracting with, operating, and paying for controllable DERs;
- Enhanced cyber security—with increased digitisation, ensuring safe and secure connectivity and data management is critical.

System requirements are evolving as regulatory rules are developed and the electricity sector business model evolves. The EA is currently undertaking regulatory setting work, and various research and trials are being undertaken across the industry. There is uncertainty about how this will unfold, and we are currently monitoring industry developments.

How these systems are deployed (e.g. internally or externally) is part of our roadmap development.

8.7.3 Developing the network and its architecture to meet customers' future needs

Our network is currently highly loaded, and we are reviewing the future architecture as part of the Cambridge and Te Awamutu regional development work. The Cambridge architecture is seeing a step-change with the development of a subtransmission network, and this is also being considered for Te Awamutu. We are also reviewing the architecture of the distribution network. The feeders operate in a radial configuration, and there is limited interconnection capability between feeders, with significant use of voltage regulators and reclosers. The network is fully utilised and has reached the limit for getting effective capacity and performance improvement from adding more voltage regulators and reclosers. The network now requires enhancement to supplement the distribution feeders.

Assessing network architecture alternatives and how these can influence responsiveness to the transformation and customer service standards will be a near-term activity on the roadmap.

8.7.4 Monitoring distribution and LV network

Like other distribution businesses, Waipā has traditionally monitored network parameters in real time on primary distribution assets (feeder circuit breakers and reclosers). However, with changing network use patterns, it is necessary to extend network visibility and controllability to cover the entire network.

As customers add more DERs to the network and demand increases due to electrification, new constraints that could be managed flexibly will likely emerge. The industry will need the ability to monitor use patterns and demand at a more granular level than currently to manage the network more effectively and utilise flexibility where practical.

LV monitoring

The extent to which LV monitoring is achieved using meter data or remote devices on the network (or a combination of both) is evolving. Assessing the best approach for Waipā will be part of the roadmap.

Over time, we will need to enhance the distribution network telemetry. This will involve adding new smart sensors and communication to our primary plant, which will be visible via ADMS.

GridSight Innovation and Trial

We are working with Ara Ake on the Gridsight platform. GridSight is an Australian company developing software to increase the visibility of the LV network. The GridSight platform aggregates and analyses smart meter data, helping us to:

- Identify LV power quality issues;
- Assess distribution transformer utilisation and LV phase balancing
- Detect solar PV generation, network-connected batteries and EV chargers on the network

The GridSight system will enhance the visibility required to engage with flexible markets.

This work is in the trial phase and is being supported by Ara Ake as part of their work to develop solutions to help decarbonisation via electrification.

Based on the trial findings, we plan to select and deploy a suitable LV visibility product in FY25 and prepare an LV visibility and management roadmap.

8.7.5 Evolution of our business model to support customers in the transition

Distribution businesses form a critical link between customers and energy markets and can enable greater customer participation in the decarbonisation efforts. A key role for the industry is how DERs will be deployed and optimised to obtain the highest value from them. Optimisation will be essential to improve the use of DERs for flexibility services within network stability constraints. While the term Distribution System Operator (DSO) is nascent and evolving, it is generally considered a key function for optimising DER deployment and managing network stability.[31]

A range of DSO business models are evolving and being considered within the sector—from fully centralised markets and operators to fully decentralised markets and operators.[32]

It is currently clear that we need to develop and operate the distribution network to integrate DERs, support bidirectional power flow, and enable flexibility. This will require us to invest in systems that support open access to the distribution network for a wide range of customers and DERs.

We are closely monitoring the work in this area to ensure that any development work we do (concerning LV monitoring, communication systems, and ADMS) is future-proofed. Our roadmap will outline how we see this evolving and the least-regret investments we plan to make.

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[31] *BSG, "The Future is Electric", October 2022, page 192; Transpower, "Whakamana i Te Mauri Hiko", page 66-68.*

[32] *Transpower, "Whakamana i Te Mauri Hiko", page 67.*

8.7.6 Develop pricing to influence demand response

Waipā has developed a pricing roadmap that sets out the direction for price changes over five years from 2022[33]. As signalled in the pricing roadmap, our pricing will evolve to incorporate demand, capacity options, and products to influence demand response. Our pricing will also evolve to ensure it remains cost-reflective across the various classes of customers and that costs are allocated fairly.

Pricing has a key linkage to our network transformation roadmap.

8.7.7 Optimise network investments, including utilising non-network alternatives

The current direction set by the EA (consistent with other jurisdictions) is that distribution businesses should evaluate non-network alternatives before making significant development investments. We are currently considering network alternatives when developing project proposals. However, this does not extend to a formalised process or request for information/proposal process.

We intend to develop a non-network procurement policy, standards, and evaluation criteria as part of our roadmap. These will define performance standards for non-network alternatives. Initially, this will apply to our large development projects. Where non-network alternatives are deployed or procured, we need to develop processes for monitoring their performance to ensure the benefits procured are delivered. Appendix G2 contains our current policy on non-network solutions.

8.7.8 Develop standards to improve resilience, minimise complexity, network risks and operating costs

Distribution businesses need appropriate standards to control the quality of the connected load, generation, or DERs to manage their impact on the network. Our approach will be to adopt industry-led standards where possible.

We have a process for DG connection but not for other DERs like EV chargers. We are working with industry groups to address the lack of visibility and to improve our ability to monitor DER uptake. One of the proposals is to require customers installing new technology to register their devices with an entity managing a demand management platform to ensure that the installation of the new technology complies with the network's standards for two-way power flows, can be remotely controlled and can participate in flexibility services.

As power flows change, we may experience congestion on parts of the network due to generation. Other distribution businesses have introduced congestion standards, and we will develop standards for managing congestion across competing generators. These will need to complement flexibility markets as they evolve.

We will assess the materials and design standards to enhance our fleet plans to improve resilience to energy transformation (and other hazards). Our review will consider the costs and benefits of incrementally increasing the capacity of current carrying components. This will include assessing the impact on mechanical loadings, fault repair, maintenance, tooling, training, spares, and other downstream implications.

We will provide more details on these initiatives in our roadmap.

8.7.9 Supporting programmes

Our resilience and reliability improvement strategies will support the network transformation roadmap. Given the increasing reliance on electricity, improvements in reliability and resilience will become increasingly important (and failure to do so will undermine electrification and decarbonisation). These initiatives are outlined in Section 9.4 and Section 9.7.

[33] *https://waipanetworks.co.nz/partners/retailers/pricingroadmap/. The roadmap was last revised in 2023.*

9. NETWORK DEVELOPMENT

9.1 Introduction

This section describes the planned development of the network in response to changes in demand, changes in service levels, and current and future network constraints. This section outlines the network development projects implemented over the next ten years. We also outline material projects under consideration that still need to be fully developed.

The previous section summarised our regional review, which is our study into the impacts of decarbonisation on-demand projection and the impact of changing customer energy usage on future service levels. The demand projection work has been completed. This delivered the demand scenarios used as the base for forecasting demand for planning purposes. Based on the above work, we recognise that we face challenges from the ongoing regional (baseload) growth and the emerging decarbonisation (electrification) growth.

The existing distribution network is heavily loaded:

- the loads are near or at their thermal capacity and indicative of the heavy loading,
- high fault levels on the feeders due to the current network configuration and
- many rural feeders have limited backup capability, which will limit the ability to restore power to customers in the event of a component failure.

To maximise investment efficiency for system capacity, we will configure the HV network to address the regional growth challenge and, at the same time, build in margin to address the decarbonisation challenge with relatively small incremental investment. To enable us to achieve that, the next step in our work will be to determine the long-term subtransmission and distribution network architectures that can serve the demand scenarios identified in the previous section, and this is the focus in FY25. These will provide a target to migrate the network towards. The cost of the possible future architecture (including subtransmission, zone substations and distribution) are yet to be quantified and included in the schedule.

Work on the service standards is still progressing; hence, the planning work in this section reflects a continuation of current standards.

We recognise that we need to change how we think, plan, and deliver our network projects to ensure we meet or manage the increase in demand. Our approach is to prioritise the needs of our customers in our decision-making. Further work will include LV management and resilience.

Over the past year, we have worked on understanding our network, improving the tools, systems, and processes we use to visualise what is happening on our network, and building our people capacity and capability to advance capital projects that will secure capacity for the region and customers.

Our current development plans focus on addressing the following:

- **Capacity –** in response to the significant demand growth in Cambridge and surrounding areas, including Hautapu, Leamington, and Tamahere;
- **Reliability –** uplifting network performance;
- **Power quality –** focusing on voltage constraints in rural areas.

We describe our current thinking on addressing the demand growth in the Te Awamutu region, where capacity constraints are predicted in the latter half of the forecast period. The required network solution is expected to have material financial implications, so we must balance customer needs, our required service levels, cost, and the overall vision for the region.

In addition to addressing regional growth, we have planned projects throughout the forecast period to address regulatory compliance and have described our resilience strategy.

The development plan aligns with our asset management strategies, particularly with strategy #1 (Improve regional supply security) and #3 (Improve the resilience of our network).

This section covers:

- How the development plan aligns with the asset management strategy;
- The network planning criteria that trigger development activities;
- An overview of our resilience strategy;
- Network demand forecasts;
- The development to address demand growth and security;
- The development plan to address reliability, quality, regulatory and other drivers;
- A summary of expenditure forecasts.

9.2 Alignment to our asset management strategy

Our updated asset management strategy was first developed and outlined in the 2023 AMP and includes six initiatives that guide our asset management activities. This section describes the linkages between our network development approach and two of the asset management initiatives.

9.2.1 Asset management strategy #1 – improve regional supply security

Before recent investments by Waipā and Transpower, Te Awamutu and Cambridge's demand exceeded the N-1 capacity of the GXP supply transformers, and Te Awamutu relied on a single circuit 110kV line. This situation was unacceptable for our customers and did not support the forecast growth in our region. We have developed a transmission and sub-transmission network investment program to address these issues.

To date, we have completed the following:

- A second 110kV line between Te Awamutu GXP and Hangatiki. This investment responded to several regional planned or unplanned outages due to Transpower's single 110kV lines into Te Awamutu. The line was completed in July 2016 as an alternative supply into Te Awamutu GXP. This second supply lifted Te Awamutu GXP to an N 1 security site, allowing planned or unplanned outages to the incoming 110kV line without a region-wide supply interruption.
- Three 1 MVA diesel generators on the Cambridge 11kV network. These assets were commissioned in 2022 to manage the peak demand within the Cambridge GXP N-1 security limit if a transformer bank fails.
- Removal of the protection constraint in the Te Awamutu GXP, boosting the Te Awamutu GXP N-1 capacity from 40MVA to 53MVA in 2023. This was completed as part of Transpower's protection lifecycle upgrade project.

These three investments have resolved or alleviated GXP capacity issues to date.

However, supply security is forecast to become constrained across the Waikato 110kV transmission system and in the Cambridge and Te Awamutu regions. We are responding to the forecast supply constraints by:

- Building the new Hautapu GXP west of Cambridge;
- Building a new Forrest Zone Substation;
- Building a new zone substation to supply the Hautapu industrial load
- Installing two 33kV cables (initially operated at 11kV) into the south Cambridge area as provision for a third substation in the Cambridge region;
- Working with The Line Company and Transpower to undertake a study on regional 110kV transmission constraints and to develop coordinated solutions;
- We are developing our Te Awamutu sub-transmission solution to address the future capacity, security, and quality of supply constraints in the Te Awamutu area.

We discuss each of these projects later in this Section.

9.2.2 Asset management strategy #3 – improve network resilience

Network resilience refers to the proactive measures taken to prepare for an unpredictable future that could affect the network so that we can supply a basic (minimum) service to our customers when the network has been threatened/ compromised. In the modern context, resilience means[34]:

- The capacity of the network to absorb a shock, recover from disruptions, adapt to changing conditions, and retain essentially the same function as it had before;
- Having the capacity to adapt to those shocks and rapidly recover, even if that means providing services in a new way.

Following the recent cyclone events, resilience has become more critical for all infrastructure providers. We are no exception.

We have considered resilience in our designs for many years. However, given the growing reliance on electricity for energy supply and the increasing prevalence of adverse weather, our approach to planning and design needs to evolve. We have, therefore, increased focus on network resilience. During FY24, we undertook a resilience maturity assessment, which guided the development of our resilience strategy.

Our approach to network resilience has been described in Section 9.4.

[34] DPMC, *"Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system"*, June 2023.

9.3 Network planning criteria

9.3.1 Development planning criteria

Our planning criteria are designed to provide network capacity, maintain supply quality, increase transformers utilisation), reduce system losses, balance capital and operational expenditure, and match the security of supply with customer requirements. Whenever the planning criteria are breached, we trigger network investigations and studies, which may lead to network development projects to prevent constraints from forming on the network. Our assessment of development projects includes consideration of alternatives.

Our first new zone substation will be commissioned in early 2025 and operate at 33kV. This substation marks the beginning of a new chapter for our network development plan, and we have developed specific planning criteria to ensure we plan, design, and build our future network correctly.

Table 22 summarises the key elements of our planning criteria. We will further review these criteria regarding the EEA Security of Supply Guide.

Element	Capacity	Security	Reliability	Voltage	Location
GXP	Load exceeds 100% of normal rating	N-1 using short-term rating	Fault rate above industry standard	Sub-transmission or distribution Voltage depression that cannot be compensated for by the downstream system or causes voltage breach	n/a
Sub-transmission and transmission feeders	Load exceeds 100% of normal rating	N-1 using short-term rating	Fault rate above industry standard	Voltage drop that cannot be compensated for at the substation	The distribution network cannot reasonably supply the load and requires a new substation.
Zone substations	Load (during contingency) exceeds 100% of the nameplate rating over ten consecutive half hours per year.	The load exceeds 100% of N-1 capacity, more than ten consecutive half hours per year.	Fault rate above industry standard	Distribution voltage depression that cannot be compensated for locally.	The substation is not efficiently located to load.
Distribution feeders	The load exceeds 100% of the thermal rating for over ten consecutive half hours per year.	The load exceeds 66% of the thermal rating for over 30 half-hours per year.	The fault rate is above industry standards or identified as a worst-performing feeder[35].	The voltage at the HV terminals of the transformer consistently drops below 10.5kV. Local tap settings cannot compensate for it without causing a high voltage in the LV during the low-load period.	LV configuration cannot reasonably supply the load; therefore, it requires new distribution lines or cables.
Distribution substation	MDI or data logger readings exceed 100% of the nameplate rating.	N/A	Fault rate above industry standard	N/A provided no voltage breach in the Low-voltage system	The substation is not efficiently located to load
Low voltage system	Load exceeds 100% of thermal rating	N/A	Fault rate above industry standards	The voltage at the point of supply consistently drops below 0.94pu or above 1.06pu. Voltage is usually the constraint on LV feeders.	Existing LV circuits do not reach new customers.

Table 22: Network Planning Criteria (Development Triggers)

9.3.2 Asset capacity and planning horizons

We have established standard capacity and planning horizons for each network element to guide our development plan. We have established planning horizons so that upgrading existing capacity and installing new capacity takes a suitably long view of future demand to maximise fixed construction costs (e.g., trenching or building work) and avoids the need for uneconomic near-term reinforcements. We have yet to start applying the long-term network development planning horizons (beyond the 10-year horizon) in earnest and will focus on this in FY25.

[35] *Worst-performing feeder means the feeder lines on an EDB's network that, in respect of the most recent disclosure year, are in the 90th percentile or higher for one or both of the following: (a) feeder SAIDI; and (b) feeder SAIFI.*

In establishing the planning horizons, we have considered the future use of the network. Electricity is an essential service, and reliance on electricity will increase as decarbonisation via electrification increases. For this reason, we see the risk of under-investment that compromises security and capacity (and limits decarbonisation) as higher than the risk of short-term over-investment.

We have defined standard capacities for network elements to guide material and equipment selection and to achieve standardisation, purchasing, and construction efficiencies. The standard capacities and planning horizons outlined in Table 23 reflect the standard cable, conductor, switchgear, and transformers typically available.

Element	Standard Capacity	Planning Horizon	Description
GXP	n/a	30+ years1[36]	We apply a long planning horizon as development can take up to ten years, and the incremental cost of higher capacity at the time of construction is generally low. There is no standard capacity; however, increments will generally be aligned with Transpower's standard transformer sizes.
Sub-transmission feeders	n/a	20-30 years[13]	We apply a long planning horizon due to the long route selection and procurement. The capacity is sized to the number of current and forecast zone substations that must be supplied.
Zone substations	Typical nominal rating is 24 MVA (N-1) for urban or smaller for remote rural areas	20 years[13]	We apply a long planning horizon due to the time required to consent and develop a zone substation. The standard substation capacity is typical in New Zealand for urban and semi-rural substations (increasing the availability of equipment and spares). When capacity is reached, the load is transferred to an adjacent zone substation or a new substation will be developed.
Distribution feeders	4-6 MVA typically for urban feeders, and 2-3MVA for rural feeders	Ten years	We apply a medium planning horizon, and distribution work can typically be completed in 1-2 years. The standard feeder capacity (normal/backfeeding) is typical in New Zealand for urban and semi-rural feeders and is reflective of standard cable and conductor sizes. When capacity is reached, the load is transferred to adjacent feeders or a new feeder or zone substation is developed.
Distribution substation, industrial	Customer-specific	Ten years	A ten-year view of capacity is generally appropriate for industrial customers. Distribution transformers can be incrementally upgraded in most cases.
Distribution substation, commercial	500-1,000 kVA	Ten years	A ten-year view of capacity is generally appropriate for commercial areas—the selected capacity needs to have suitable spare capacity for back-feeding adjacent loads. Distribution transformers can be incrementally upgraded in most cases.
Distribution substation, urban	200-300 kVA	Ten years	A ten-year view of capacity is generally appropriate for residential areas. The selected capacity must have suitable spare capacity for back-feeding adjacent loads in case of a cable fault. Distribution transformers can be incrementally upgraded.
Low voltage, underground	n/a	Ten years	Capacity is based on standard cable size, and LV runs are limited to maintaining voltage and capacity compliance.
Low voltage, overhead	n/a	Ten years	With capacity based on standard conductor sizes, LV runs are limited to maintaining voltage and capacity compliance.
Residential customer demand	3 kVA ADMD (distribution TX level)	n/a	This is the maximum demand of a residential customer used for planning purposes. The diversity is measured at the urban distribution transformer. We will review the ADMD (e.g., at the ICP or LV feeder level) we use for planning as part of our energy transformation work.
Other customer demand	Customer-specific	n/a	These shall be determined in consultation with the developer or customer.

Table 23: Asset Capacity and Planning Horizon

[36] *We are reviewing how we will apply these to our development planning considering that the expected lives of our assets mean we are making decisions on the assets we will have operating in the net zero world, where reliability expectations different from the present day.*

9.3.3 Standardisation of equipment and materials

We have developed Waipā standards for designing and constructing network assets. These standards are based on a safety-by-design that ensures safety is considered at all stages of the equipment lifecycle. This supports compliance with the Electricity (Safety) Regulations 2010 and the Health and Safety at Work Act (2015).

By standardising our designs and assets, we achieve the following benefits:

- Safety from the use of proven construction and maintenance techniques;
- Improved reliability through verified equipment performance;
- Fewer manufacturers and asset types reduce stockholding costs and increase staff familiarity and productivity. We have not yet assessed the impact of such arrangement on competition in our materials supply chain.

To help us develop and update our standards, we subscribe to Powerco's Contract Works and Network Operations standards library. This promotes greater efficiency and standardisation of practices across the industry. The strategies for standardising our assets and designs are summarised in the document attached.

Generally, we only use materials and equipment that meet recognised industry standards approved by our internal standards and policies.

Asset Category	Standardised features	Standardising methods
Distribution and LV Lines	Standard suite of conductors and cables. These are limited to generally available sizes and types.	Our Design Manual. Non-standard types require specific network review and management approval.
Distribution transformers	Pole-mounted transformers are limited to generally available sizes of less than 100kVA, with no customisation. Ground-mounted transformers are limited to generally available sizes, with no customisation.	Our Construction Manual. Non-standard ground-mounted transformers may be required for some industrial customers. These require specific network review and management approval.
Distribution switchgear	Selection is generally from preferred suppliers of off-the-shelf equipment commonly used in New Zealand.	Our preferred suppliers list. Non-standard switchgear may be required for some applications. These require specific network review and management approval.
Poles	New concrete poles are pre-stressed type with standard configuration. Planned pole renewals shall be designed for the site and loadings. The pole type shall be selected from approved manufacturers and standard configurations.	Our Construction Manual. Relevant utility pole standards to apply to new poles.
Other network assets	Generally, procure from preferred (i.e., pre-approved) suppliers.	Our preferred suppliers' list and Design Manual.

Table 24: Asset standardisation

9.3.4 Other purchasing considerations

In addition to the standardisation of assets mentioned above, our purchasing decisions consider the following:

- We only use materials and equipment that meet recognised industry standards approved by our internal standards and policies.
- The total lifecycle costs of assets, taking into account purchasing, operating, useful life, and end-of-life disposal;
- Using recycled materials where practical, considering the total lifecycle costs and risk;
- Using natural products (e.g., timber poles) that are from sustainable and renewable sources;
- The environmental impacts of the creation, operation, and disposal.

9.3.5 Strategies for asset efficiency

We seek to utilise assets efficiently through:

- Establishing planning horizons that are suitable to ensure that assets are sized appropriately for expended demand but not too long that increasing upfront costs and risks the installation of capacity that may not be needed (our planning horizon is discussed in Section 9.3.2);
- Optimising line design to achieve capacity and voltage requirements utilising optimal conductor sizing and pole spacing;
- Considering future increases in demand and minimum power factor requirements when selecting new or replacement distribution transformers;
- Lines pricing/connection fee that incentivises customers to install/request transformers of an appropriate size (this also assists with losses).

9.4 Resilience strategy

9.4.1 Importance of resilience

The increasing use of electricity to decarbonise transport, industrial process heat, and commercial and domestic heating will increase the reliance on electricity and reduce fuel diversity. As a result, in the future, a loss of supply will have more significant community and economic consequences and impact more sectors. Therefore, Waipā's (and the electricity sector's) resilience must be commensurate with its increasing dominance and linkage of electricity supply to economic activity.

9.4.2 Definition of resilience

In the modern context, resilience means[37]:

- The capacity of the network to absorb a shock; recover from disruptions; adapt to changing conditions; and retain essentially the same function as it had before;
- Having the capacity to adapt to those shocks and rapidly recover, even if that means providing services differently.

For the electricity distribution businesses, this means:

- Minimising the potential number of customers interrupted during a major event (generally by way of risk reduction);
- Minimising the duration of the interruptions that occur during a major event (generally by way of readiness and response);
- Communicating with customers and stakeholders so that they can be informed in their decision-making and so that restoration can be effectively coordinated and targeted; allowing us to optimize between what the network can reasonably deliver and how long it may take to recover against what customers can tolerate and what they can do to give them greater control and certainty.
- Recovering to the pre-event state.

9.4.3 Objectives of our resilience strategy

The objective of our resilience strategy is to:

Improve the resilience of our network to reduce the impact within acceptable customers' tolerances, of increasing incidents and intensity of adverse weather and other major events as the economy increases reliance on electricity; while ensuring investment is in the right place.

The outcomes of this strategy will be:

- An improvement in our RMMAT score to 3 in all key areas over three years;
- A reduction in duration of loss of supply to customers during major adverse weather events and other natural hazards (in particular to asset failures and vegetation outages);
- Assessment and adaption to climate change;
- Improved emergency management response and community support.

The regional security strategy (#1) supports the resilience strategy, as network security improvements generally make our network more resilient, and the vegetation management strategy (#6), as vegetation is a key cause of outages during major events.

The resilience strategy supports our network transformation strategy (#2) as greater resilience is required to support electrification.

Whilst our objective focuses on resilience to adverse weather, many of the actions will improve resilience to various natural and other hazards. Our resilience strategy excludes cyber security—however, this is not excluded from a business perspective, and our work on cyber security is addressed in Section 7.2.

9.4.4 Resilience strategy

Improving resilience will take a multi-faceted approach over the next decade. This will be addressed principally through risk reduction, readiness and response activities. To provide a comprehensive view of resilience, our strategy includes new initiatives and existing programmes that enhance resilience.

Our strategy is shown in Figure 60.

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[37] *Department of the Prime Minister and Cabinet "Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system", June 2023.*

COMMUNITY ENGAGEMENT

	STRATEGY ACTION	DESCRIPTION	STATUS
Review	**Conduct a RMMAT assessment**	Assess our resilience maturity and determine improvement activities	Assessment complete
Risk reduction actions	**Undertake a natural hazard risk assessment, including the impacts of climate change**	• Assess the impact of climate change on natural hazards • Assess the vulnerability of the network to natural hazards (wind, seismic, snow/ice, river flooding, coastal inundation, peak rainfall, land stability	To be completed in FY25
	Increase resilience in asset design	Revise design standards to withstand natural hazards	To be commence in FY25
	Increase the physical resilience of critical assets in vulnerable locations	Assess the options to increase the resilience of critical assets that are vulnerable to natural hazards	To be commence in FY25
Response and readiness actions	**Minimise the impact of outages when they occur**	• Reduce outage impact through sectionalisation and automation • Upgrade network to improve back-feed capability (this is covered through our annual work plan and GXP work)	Ongoing programme
	Enhance operational management of major events	Establish a modern SCADA master station and fit-for-purpose control room operating arrangement	Project scoping in FY25
	Improve major event response	• Review of response to storms and implement actions to improve our processes • Develop business continuity and contingency plans • Incident management team training • Enhance mutual aid arrangements	In progress
	Enhance community support	Following Cyclone Gabrielle, the government is looking at increasing support of community resilience. We will support these initiatives	Awaiting government recommendation

IMPROVEMENT IN ASSET RESILIENCE

Figure 60: Resilience strategy

We have commented further on the resilience activities below.

The activities in Sections 9.4.6 to 9.4.8 cover our work on climate change assessment and adaptation.

9.4.5 The outcome of the recent resilience review

Figure 61 shows the results of the independent review of our resilience practices that we recently completed.

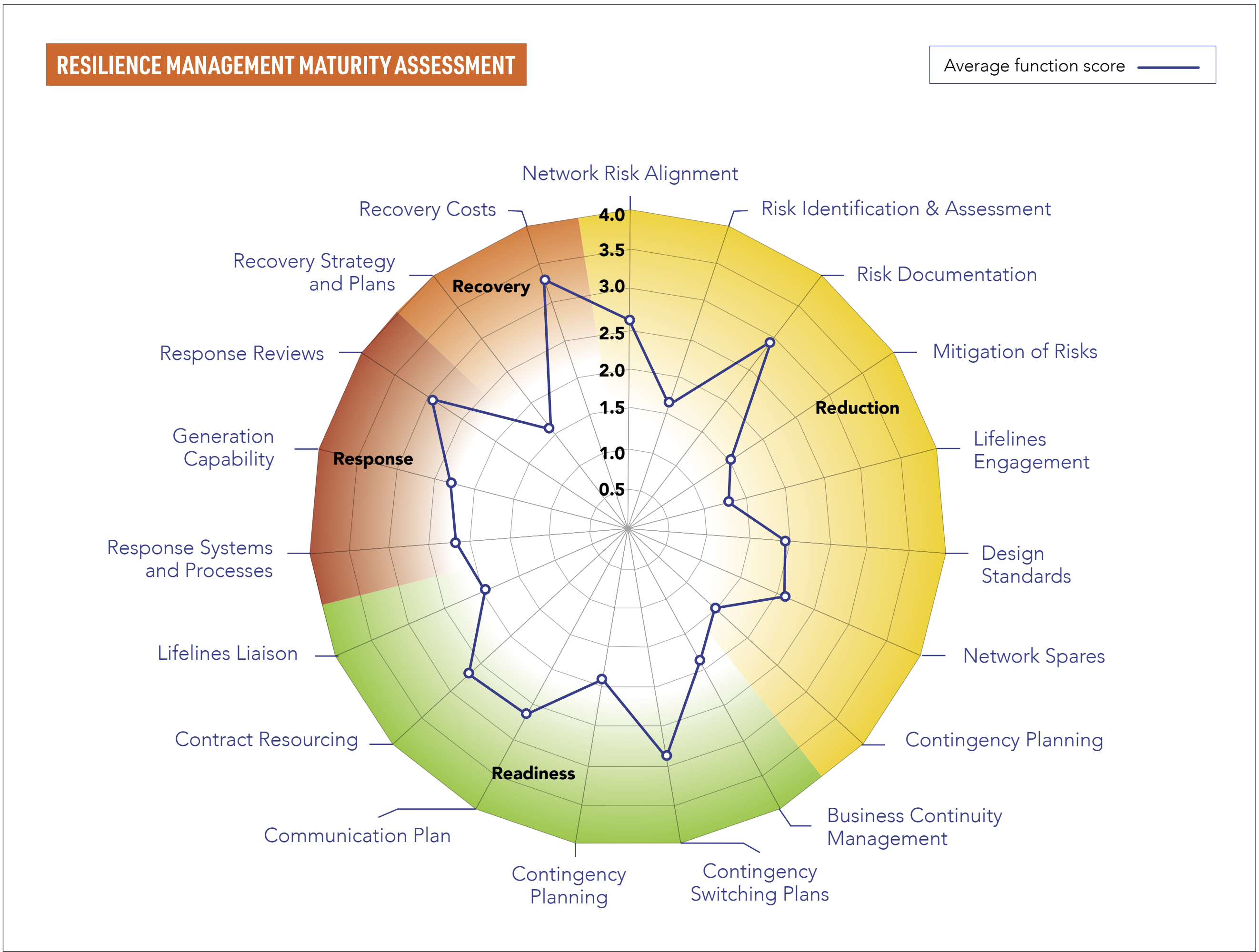


Figure 61: Resilience management maturity assessment – as of FY23

The RMMAT assessed our work on reduction, readiness, response and recovery (the 4Rs of resilience). The key areas for improvement identified in the review were risk assessment and reduction, contingency planning and response systems. The resilience strategy incorporates a range of actions that address these areas. We expect to see material improvements in our RMMAT score by the end of FY26, and our long-term goal is to achieve RMMAT scores of 3 in all key areas.

9.4.6 Natural hazard assessment

We completed an initial broad review of the risks posed by natural hazards. This is presented in Section 6.3.

The risks posed by natural hazards are changing due to climate change. FY25 we will engage capable service providers to do localised future modelling work on our region to provide a comprehensive review of the impact of climate change on natural hazards, particularly wind, river flooding, coastal inundation, rainfall intensity, and land stability. These hazards are most impacted by climate change.

We will then review the network to assess vulnerabilities to those hazards. This will be in two parts:

- Assessing our materials and design standards to determine if they are suitable for future conditions;
- Assessing critical assets to determine if any are vulnerable to natural hazards. This will take a risk-based approach, considering the consequence, return period and the asset's criticality.[38]

[38] *This requires completion of the asset criticality work in GIS. Refer to Section 11.4.2.*

9.4.7 Revision to design standards

Based on the natural hazard assessment outcome, we will revise materials and design standards to improve their resilience. The new design standards are expected to be implemented as new assets are installed or as assets are renewed. Hence, resilience improvements will be incremental.

Work is underway to improve asset resilience as outlined in our distribution structure fleet plan (concerning accelerating the replacement of assets with known weaknesses) (refer to Section 11.10). This includes wood poles, crossarms, and mass-reinforced poles on critical feeders.

Work has also commenced on replacing voltage regulator structures to enhance seismic resilience. Risk assessment has identified the need to improve the strength of many of our current fleet of voltage regulator structures, which are being replaced with structures that comply with current structural standards (refer to Section 9.7.3).

Following the revision of the design standards, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

9.4.8 Increasing the physical resilience of critical assets in vulnerable locations

Based on the natural hazard assessment outcome, there may be areas where assets need to be strengthened, protected or moved to enhance resilience.

Work is already underway to improve the supply's resilience to Kawhia. The Kawhia feeder is one of our worst-performing and susceptible to adverse weather. Our replacement of wood structures with modern concrete/steel structures is being prioritised in this area (refer to Section 11.11.13), and a line deviation is planned to eliminate land stability risks (refer to Section 9.7.3). We are also considering whether Kawhia is an appropriate location for generation support (refer to Section 9.7.6).

Following the completion of the natural hazard assessment, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

Whilst this strategy focuses on natural hazards, resilience is also supported by our work on reducing the impact of third-party damage incidence, outlined in the distribution structure fleet plan (Section 10.11.4).

9.4.9 Minimising the impact of outages where they occur

Reducing outages through sectionalisation, automation and improving back feed capabilities are existing development programmes (refer to Section 9.7.1). These programmes improve reliability and resilience.

The natural hazard assessment results may alter these programmes' priority and targeting.

9.4.10 Enhance operational management of events

The replacement of the SCADA system is required due to end-of-life drivers. The opportunity is being taken to enhance the system's functionality to improve outage and emergency management functionality. Refer to Section 11.9.5.

9.4.11 Improve major event response

The RMMAT review highlighted the need to improve some of our operational processes and practices. We have identified a range of activities that will enhance our response to major events and emergencies, and these include:

- Review of our response to storms. We need to incorporate specific learning from recent events into our contingency plans and operational procedure revisions;
- Develop business continuity and contingency plans. Whilst we have developed a range of contingency plans (refer to Section 6.6), the review identified that these could be further enhanced and additional contingency plans added where needs are identified;
- Incident management team training. We will need to refine our Incident and Emergency Management Plan further and provide further training to the team to execute the plan under the Coordinated Incident Management framework;
- Further formalised mutual add arrangement enables us to increase resources in a major event further.

These process improvements will enhance our response to natural and other major events.

9.4.12 Enhance community support

Following Cyclone Gabrielle, a recommendation by the electricity sector was made to the cyclone recovery task force to develop secure community hubs. Due to our topography, vulnerabilities in the roading networks, and the types of damage that can occur, there will always be some hard-to-restore consumers. For these consumers and communities, having community hubs with a secure standalone supply of electricity and communication will provide support while restoration or alternatives can be brought online. Community hubs will be an important safety net while hazard reduction and other improvements are made.

The outcome of the task force's work and the potential for government funding of community hubs is unclear. We are currently monitoring this work.

9.4.13 Resilience expenditure

Our expenditure forecasts include current programmes and projects that link to resilience. This includes work on seismic strengthening, Kawhia area resilience, segregation and automation and SCADA system. These are already captured under the Asset Renewal and Network Development capex schedules.

After completing the natural hazard assessment (as a network opex) and related work, we expect an increase in our forecast for resilience-related capex expenditure. This increase will be visible in the 2025 and 2026 AMPs.

9.5 Demand forecasts

9.5.1 Introduction

Electricity demand, measured in MVA, is the primary factor determining the network's future needs. Traditionally, demand growth trends were used to derive future demand scenarios. However, given that we are currently in a transition phase where our reliance on electricity is increasing, the trends and growth (or decline) seen in historical demand are no longer relevant in determining future demand scenarios.

Understanding the various factors that impact demand is crucial to optimise investment to efficiently meet customers' future requirements. As we are currently in a transitional phase, getting this right becomes even more critical. Failing to do so could lead to mistimed investment. Investing too early will cause prices to rise unnecessarily or risk of stranded assets should scenarios change, reducing customer satisfaction. On the other hand, investing too late may lead to the need for immediate or unplanned expenditure to address the issue in the short term (which often comes at a higher cost and hidden societal costs like loss of supply to consumers or ongoing costs of energy losses) or not meeting the needs of our customers and communities.

In this section, we have assessed the demand forecast scenarios and have defined appropriate investments to ensure future customer needs can be met and that the investments are appropriately timed and scoped.

9.5.2 Establishing demand forecasts for planning purposes

Future demand is influenced by many factors, such as population growth (driven by land developments), new commercial and industrial load, changes in electricity usage, land usage changes (e.g., diary conversions), and electrification of gas, process heat and transport. We recently completed a regional review, which considered these demand drivers and resulted in regional demand forecast scenarios. A summary of the regional review and the drivers of the demand forecast scenarios is covered in Section 8.

Our demand forecasting process is carried out at a GXP level in the first instance (as outlined in Section 8). To develop feeder demand forecasts, we applied the demand driver defined at a GXP level to each feeder based on the customer composition for that feeder. The arithmetic sum of total feeder demand is higher than the GXP demand forecasts due to the influence of diversity (that is, the feeder peak demand is not all coincident with the GXP demand).

The regional demand forecast scenarios include a baseline (with no decarbonisation) and high- and low-scenario impacts for decarbonisation. There is uncertainty about the actual future demand; we expect the actual outturn between the high and low scenarios. For planning purposes, we have taken the mid-point between high and low as our central case and tested the risks of under-investment (if the high scenario occurs) and over-investment (if the low scenario occurs).

We present the high, low, and central forecasts in Sections 9.5.5 and 9.5.7 below.

9.5.3 Historical demand and customer growth

Electricity demand in Cambridge has been growing faster than in Te Awamutu. Over the past seven years, the maximum demand compounding annual growth rate (CAGR) was 2.9% p.a. for Cambridge and 2.2% for Te Awamutu.

Over the same period, customer connections increased at a CAGR of 1.8% for Cambridge and 1.6% for Te Awamutu. The data indicates that customers in Cambridge have a peakier load profile than those in Te Awamutu.

Figure 62 to Figure 64 show the historical demand and consumer connections.

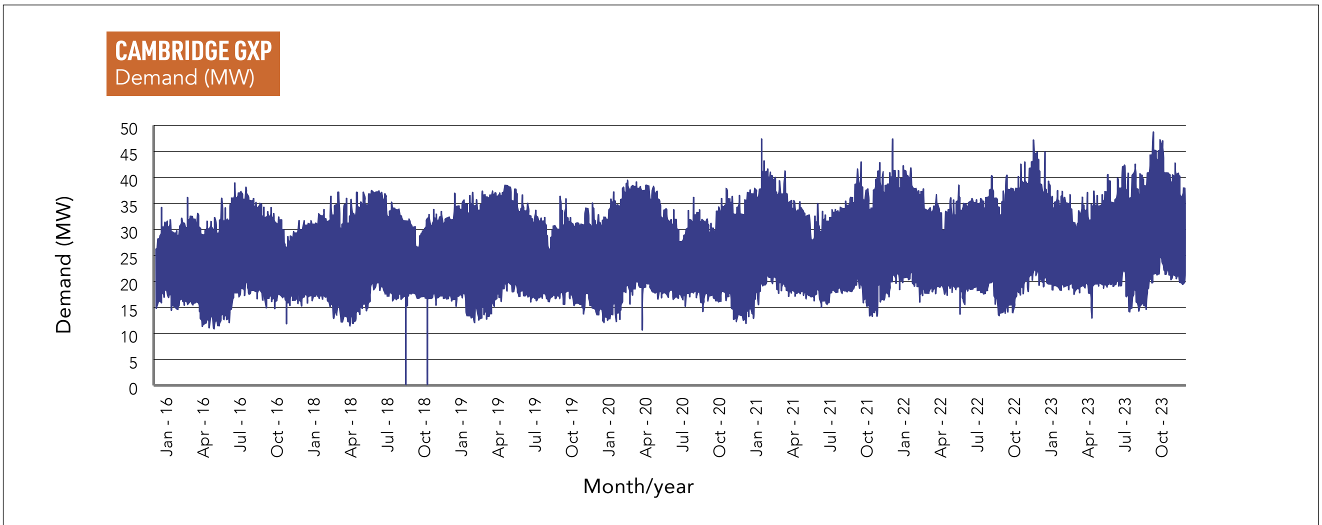


Figure 62: Cambridge GXP demand (MW)

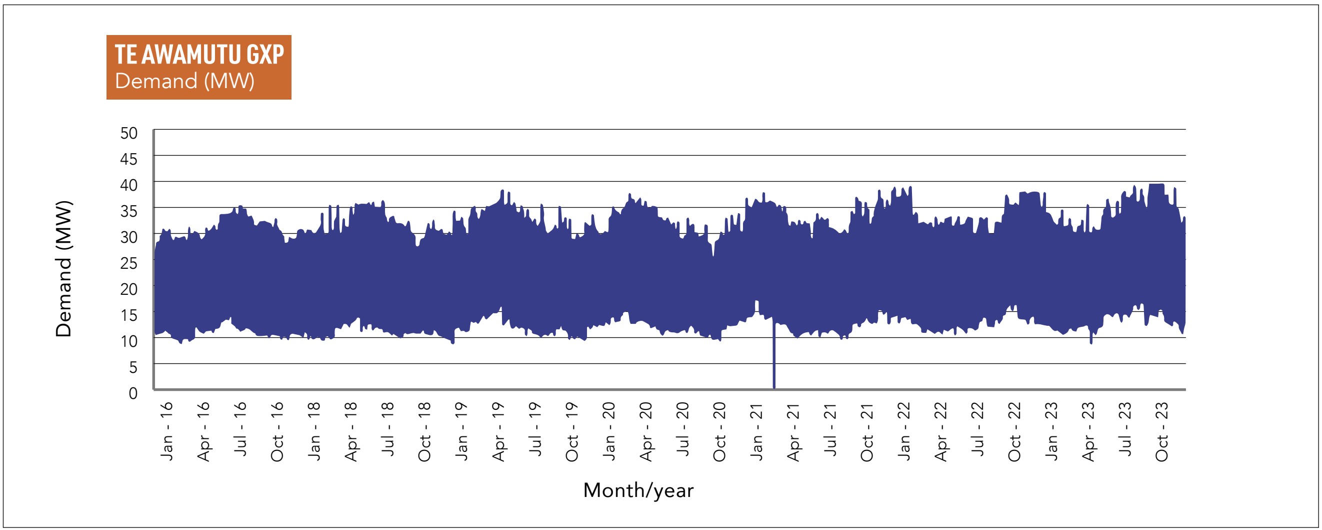


Figure 63: Te Awamutu GXP demand (MW)

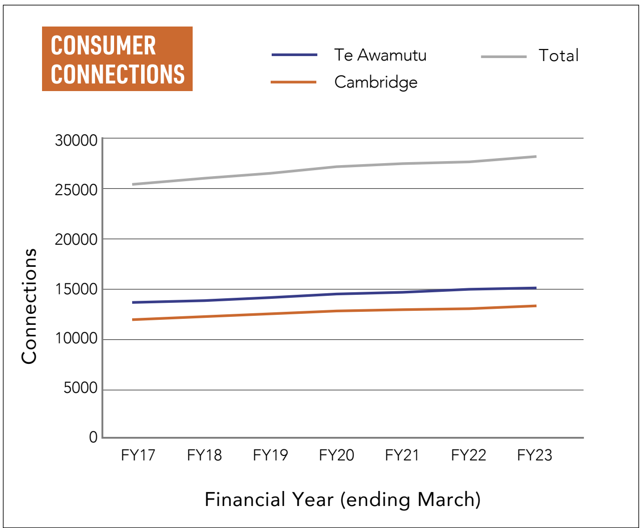


Figure 64: Consumer connections

Note: *The demand for Cambridge excludes the three x 1 MVA diesel generators used to offset peak loads.*

9.5.4 Cambridge area developments and connections driving demand growth

This section outlines known developments and connections proposed in the Cambridge region. We have applied these known factors to the regional demand forecast scenarios from Section 8.

To date, various factors determine the growth in any region, the most significant being residential and industrial growth. Waipā District Council has developed regional growth cells that define the areas and scope of planned land developments. Table 25, Table 26 and Figure 65 outline the growth cells and expected large new connections in the Cambridge region. The tables indicate that the feeder and expected demand increased from these developments and connections. We are confident that the land developments in Table 25 and projects in Table 26 will proceed.

Growth Cell Development	Feeder	Estimated Load and Timing
C1 development – overall density of 12-15 dwellings per ha. The land parcel size is 46ha, with 550 residential connections.	Kaipaki	1.5MW staged as residential connections manifest – developments have started for certain lots.
C2 development – 3MS and St Peters growth and residential developments. There are up to 1,000 connections between now and 2030 and some commercial growth.	Kaipaki	5MW additional demand between now and 2030.
C3 development – Potentially up to 123ha of land conversion	Kaipaki	1.2MW between now and 2030 and an additional 2 MW in the following five years
C4 development – 66ha (approximately 790 dwellings) of residential load forecast between now and 2030.	Monavale	2MW between now and 2030 and also Three waters infrastructure
C5 development – 61 ha of land to be converted to residential housing. Originally scheduled beyond 2035, it is now fast-tracked and set to begin in 2025.	Leamington, Roto-o-rangi, St Kilda	4-5MW connected in stages as residential housing connects, plus community facilities
C7 development	Kaipaki	Growth predicted outside of the forecast period
C8 development – Rezoning 15ha north of Hautapu Rd to industrial zone.	Pencarrow	1.2MW between now and 2030
C9 development	Pencarrow	Growth predicted outside of the forecast period
Northeastern C10 development – 105ha converted to industrial zone	Tamahere	Load use in industrial subdivisions is a lot higher than residential. We have estimated 5~7MW. The council plan indicates development timing beyond 2035. However, we have already received an inquiry in 2023 about the availability of electricity supply.

Table 25: Cambridge area land developments

Major Point loads connections	Feeder	Estimated Load and Timing
Southwestern C10 development – An industrial connection on the APL feeder has indicated significant upgrades to load requirements over the next five years.	New APL zone substation	The initial step load increase of 1MW will occur at the end of 2025. Further 9MW increase in by the end of 2027
Horticultural upgrade and wastewater treatment plant installation.	Monavale	2.5MW in the next three years
Fonterra is constructing a new wastewater treatment plant and has indicated other plans for load increase; however, it has yet to indicate size and timing.	Hautapu A and Hautapu B	2MW in the next two year

Table 26: Cambridge area major new connections

Figure 65: Cambridge growth cells

9.5.5 Cambridge area demand forecasts

The Cambridge regional demand forecasts are presented in Figure 66. They incorporate the significant connections and growth assumptions outlined in the previous section. Cambridge demand is forecast to increase at a CAGR of between 3.3% and 4.7% p.a. by 2050. The central case has a CAGR of 4.1%, which is materially above historical demand growth due to the influence of decarbonisation and is higher than other demand scenarios produced at a national level[39]. This is due to the above-national-average high population and regional growth forecast for Cambridge.

Our central scenario is the mid-point between the low and high scenarios. For the GXP development, our planning horizon is long, and we plan for the GXP capacity to be sufficient to meet the planning criteria for the next 20-30 years.

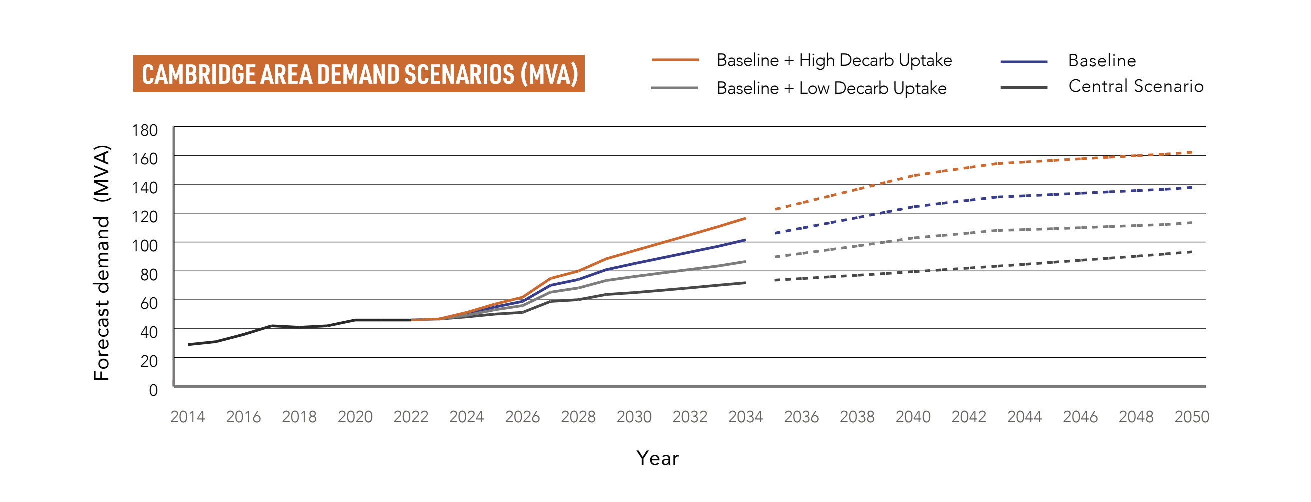


Figure 66: Cambridge area demand forecast

The demand forecasts exclude future major distributed generation connections. Developing a sub-transmission network increases our ability to host new large-distributed generators. We are unaware of any potential new distributed generator connections within the Cambridge area.

[39] *The Future is Electric, BCG 2023, https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf*

Whakamana i Te Mauri Hiko, Transpower 2020, https://static.transpower.co.nz/public/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf?VersionId=FljQmfxCk6MZ9mlvpNws63xFEBXwhX7f

9.5.6 Te Awamutu area developments and connections driving demand growth

This section outlines known developments and connections proposed in the Te Awamutu region. We have applied these known factors to the regional demand forecast scenarios from Section 8.

Waipā District Council has developed regional growth cells that define the areas and scope of planned land developments. Table 27 outlines the growth cells and forecasts new, large growth projects in the Te Awamutu region. We have indicated the feeder and expected demand increase from these developments.

Growth Cell Development	Feeder	Estimated Load and Timing
The Waikeria prison is expanding to allow additional space and beds. Our network capacity for this and a second step increase has already been constructed and is contracted to the Department of Corrections on a use-it-or-lose basis for ten years.	Waikeria	This development has no urgency, and the load increase is estimated at 1-2MVA over the next three years.
Fonterra has indicated that the 5/7.5MVA generation scheme may reach economic life within the 10-year planning period.	Fonterra A and Fonterra B	5MVA step change in load at the GXP. There is no timing confirmation, but it is a significant step in load for the TMU GXP. We are monitoring this closely. We have assumed that it will be decommissioned in 2033 for planning purposes.
T1 and T2 growth cell development include the Frontier Estate subdivision, Kotare Height subdivision, and Te Awamutu Country Club retirement village. Note: The second half of the T1 growth cell is on hold – 39 hectares of residential land development, enough room to provide 444 new houses	Pirongia	The total transformer capacity is 4.2MVA; however, the ADMD is likely significantly lower due to the load type. Between 1-5 years.
Bond Rd Development PGG Wrightson inquired about a possible load increase for their site on Bond Rd due to process heat conversion.	Pukeatua	Note: Early indications only. Roughly 3MVA.
T8 growth cell, 46 hectares of residential development, enough room to provide 564 new houses. The first development in T8 has been completed, and sections will be available shortly. Other developments will be coming online soon.	Kihikihi	Up to 1.5MVA in the next three years.
The T12 growth cell has 11 hectares of residential development, enough room to provide 132 new houses. The development has been completed, and demand will slowly grow as houses are built.	Te Awamutu West	Up to 0.5MVA as load connects.
Other growth cells are planned further out beyond 2030.		

Table 27: Te Awamutu area land developments and demand growth

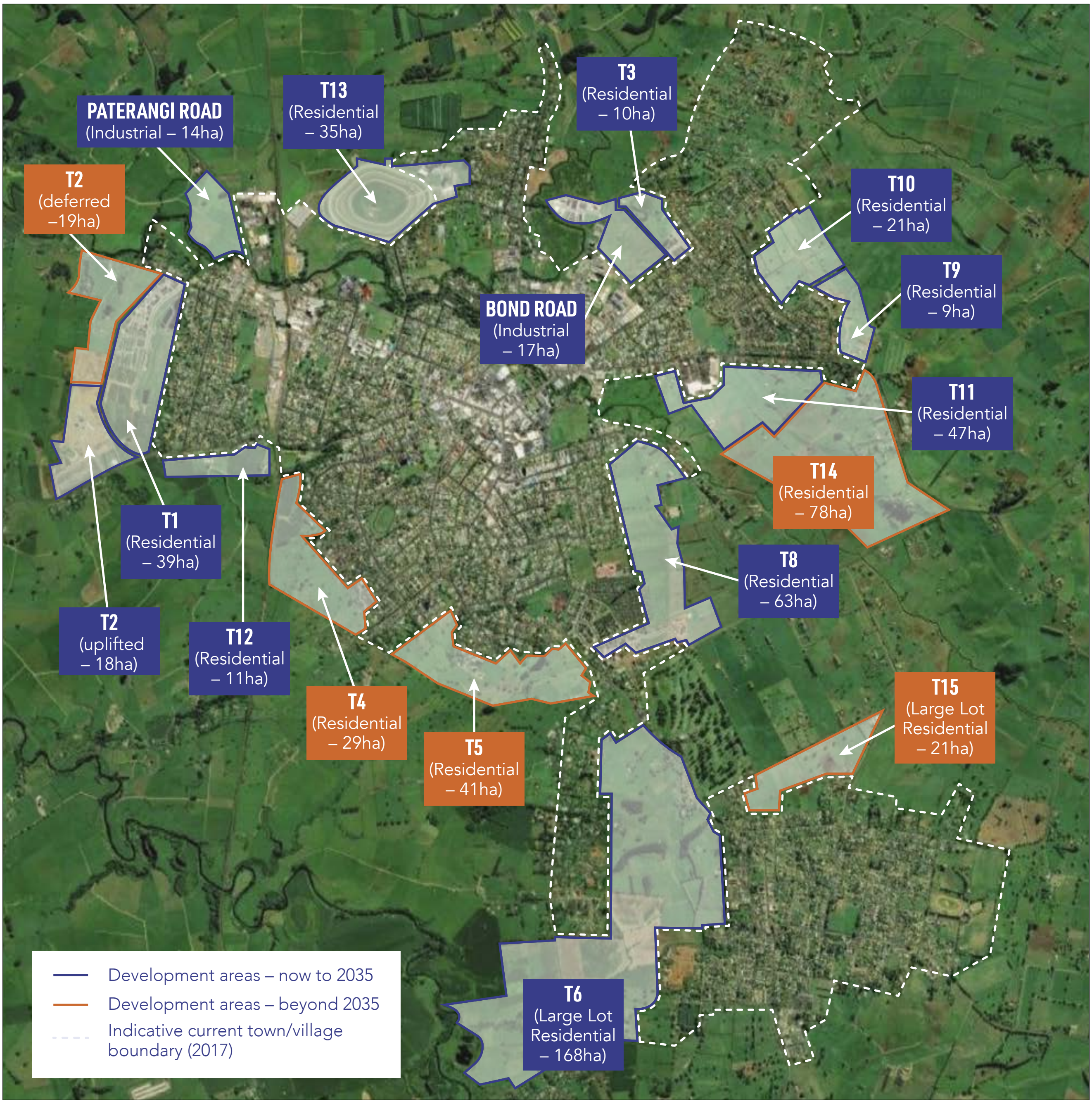


Figure 67: Te Awamutu growth cell map

9.5.7 Te Awamutu area demand forecasts

Te Awamutu regional demand forecasts are presented in Figure 68. They incorporate the significant connections and growth assumptions outlined in the previous section. The forecasts include the end-of-life decommissioning of Fonterra's 5MVA generator in 2033. The decommissioning of this unit will materially affect the GXP load. We will continue engaging with Fonterra to ensure any updates concerning the generator are known and accounted for.

Like historical demand, Te Awamutu's future growth is increasing but slower than in Cambridge. Te Awamutu's demand is forecast to grow at a CAGR of between 2.9% and 3.9% p.a. by 2050. The central case has a CAGR of 3.4%, which is materially above historical demand growth due to the influence of decarbonisation.

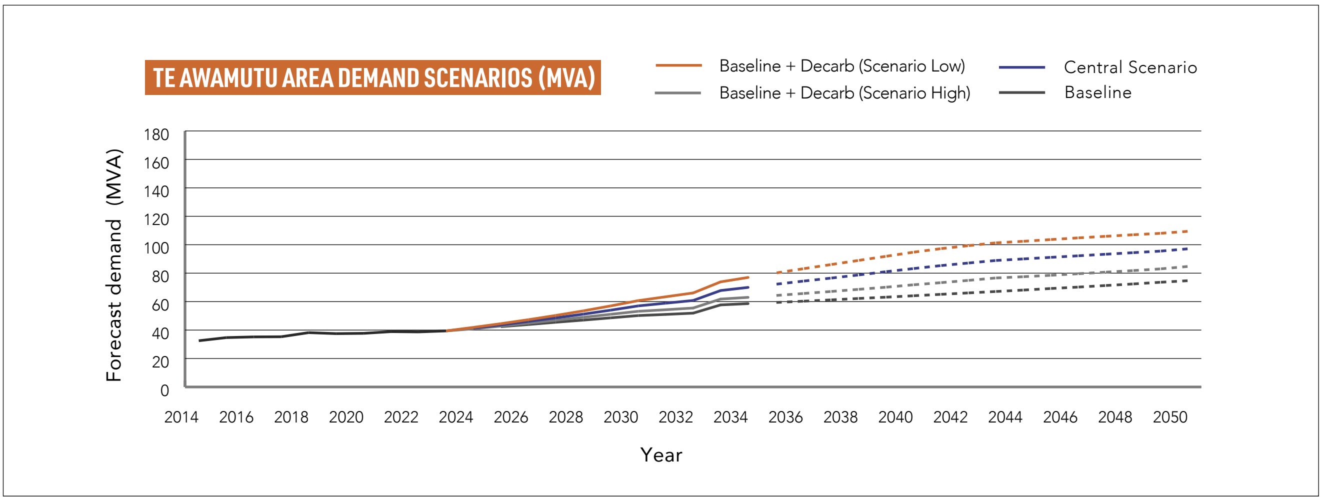


Figure 68: Te Awamutu demand forecasts

9.6 Development plan to address demand growth and security

This section describes projects to address demand growth and security at the regional and distribution levels.

Our 11kV feeders take supply directly from the Cambridge GXP and Te Awamutu GXP without subtransmission. And our forecast demand has outgrown this arrangement. We have commenced a review of the network architecture to identify the optimum network configuration to serve the expected load growth. The future architecture will include the sub-transmission we are currently developing for the Cambridge region.

9.6.1 Cambridge regional capacity and security developments

Constraint

As shown in Figure 69, demand exceeded firm (N-1) security criteria in FY23 for the Cambridge region. The 3 MVA generators will support network security until the new Hautapu GXP is commissioned. The graph shows the total planned capacity (including the new Hautapu GXP build underway). The N-1 capacity is the combined Cambridge GXP (47MVA) and the new Hautapu GXP (96MVA).

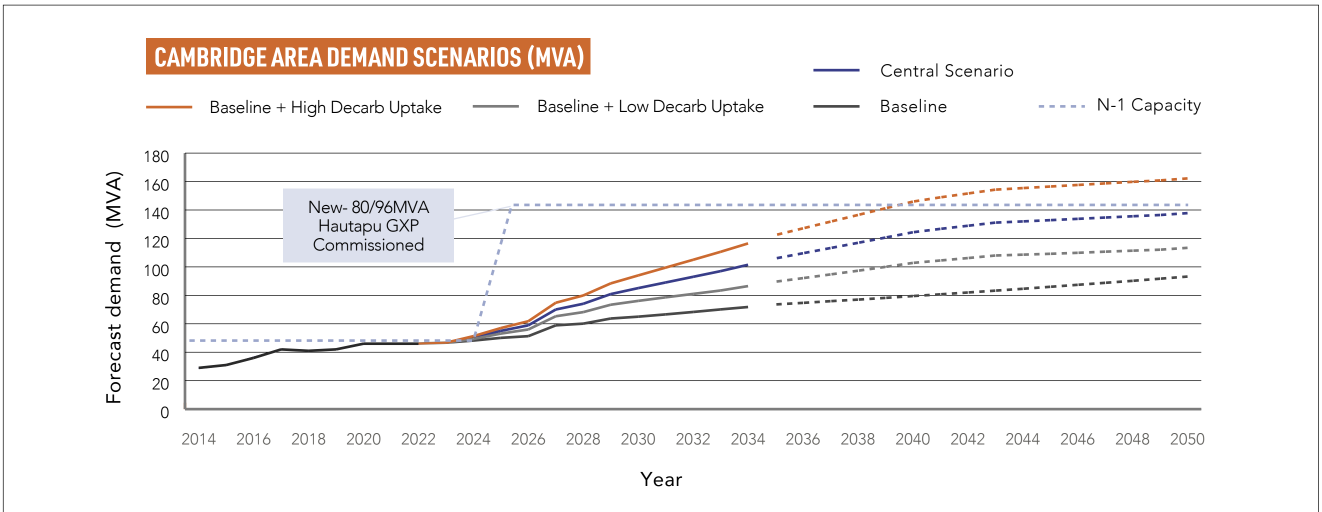


Figure 69: Cambridge demand and capacity

We describe the solution below. This covers the overall solution, the projects in progress, the projects planned, and further project concepts under consideration.

Solution (overall)

The overall solution to the regional constraint is:

- A new Hautapu GXP in Cambridge. This project is committed and in delivery;
- A new Forrest Substation (connected to the new Hautapu GXP) to supply existing and new load to the west of the existing Cambridge GXP;
- A potential new substation connected to the new Hautapu GXP to supply industrial load at Hautapu with timing dependent on the rate of development of the C8, C9 and C10 growth cells;
- Installing two 33kV cables (initially operated at 11kV) to supply significant subdivision activities in the Leamington area and as provision for sub-transmission circuits to a future third zone substation in the Leamington area.

Solution (projects in progress)

Project	Description
New Hautapu GXP	The new Transpower Hautapu GXP will provide significant capacity for the Cambridge region and will provide the foundations for the new 33kV sub-transmission network. The new GXP is underway, and commissioning is expected at the end of FY25. Transpower will install 2 x 80/96MVA transformers at the GXP, providing a n-1 capacity of 96 MVA (firm post contingency rating). The new GXP will be supplied from the 220kV Otahuhu-Whakamaru circuit, diversifying supply away from the 110kV system. We expect to transfer an initial 10 MVA from the existing GXP to the new GXP, removing the capacity and security constraint at the existing Cambridge GXP. The existing Swayne Rd 3MVA diesel generator will no longer be required and will be considered for redeployment. The regional capacity supports our central case over the 30-year planning horizon. **Expenditure forecast** **A New Investment Contract between Waipā and Transpower funds this Transpower project.**
Forrest Rd Substation	The new Forrest Rd substation commenced in FY23, concurrent with the new Hautapu GXP development. We have progressed with major material acquisitions, substation design, and site establishment. The project is on track for commissioning in early 2025. This substation is adjacent to the new Hautapu GXP and consists of two 16/24MVA ONAF transformers, a 33kV, and an 11kV switchboard. The new substation will release the current 11kV n-1 capacity and security constraint at the existing GXP and provide feeder capacity to support growth to around FY32. At that time, a new substation will be needed; refer to our discussion on the new Leamington substation under Solution (under consideration). **Expenditure forecast** **FY25 expenditure = $9m** **FY26 expenditure = $265k**

Table 28: Cambridge regional capacity and security development – projects in progress

Solutions (projects planned)

Project	Issue	Proposed solution	Options considered
Bardowie Substation (Includes 33k cable, land purchase and substation build)	Significant industrial load growth is forecast in the Wāipa District council's C8 (Hautapu industrial park) and the adjacent C10 growth cell. The load growth is expected to exceed the capacity of the existing 11kV feeders.	Install 33kV cables from the 33kV switchboard at the Forrest Rd substation. Purchase land in the Hautapu area for a new substation. Build a new substation (Bardowie). Expenditure includes land acquisition, 33kV cable, and the building of a substation. The construction of the substation and associated works are dependent upon suitable commercial arrangements being reached with the customer. **Expenditure forecast** **Budget: $13.3m** **Schedule: FY25 – FY28**	• Do nothing. • Upgrade 11kV feeder capacity.

Table 29: Cambridge regional capacity and security development – projects planned

Solutions (under consideration)

Project	Description
Leamington Substation	The capacity increase from the new Forrest Rd substation is sufficient to support near-term growth in the Leamington region. We plan to install two 33kV-rated cables, initially operated at 11kV and connected to the Forrest Rd substation, to offload the Roto-o-rangi and Leamington feeders (refer to 9.6.2). With the C5 growth cell developments and other cell growth in adjacent areas, a new substation in the Leamington area is likely warranted. We will monitor this growth and consider our options and timing for establishing a substation.

Table 30: Cambridge regional capacity and security development – projects under consideration

Managing demand forecasting risk

Should the high demand scenario eventuate, regional firm capacity will be exceeded by around 2040, and 166 MVA will be required at the end of the 30-year planning horizon. This will necessitate an incremental upgrade of the GXP transformers to 140 MVA (ONAF) in the late 2030s. The new 33kV switchboard is already rated for 140 MVA, and Transpower 220/33 transformer foundations are also rated for 120/140MVA units. Hence, the upgrade costs will be incremental.

In the event of the low scenario, the total GXP capacity can support demand growth into 2060. The incremental cost for the under-utilized 25 MVA capacity that the current design affords (over that required for the low scenario) is insignificant.

We consider that the new GXP sizing for the central scenario is appropriate. In particular, the under-investment risks are acceptable.

9.6.2 Cambridge distribution capacity and security developments

Constraints

We have defined a range of capacity and security projects to address a range of distribution constraints in the Cambridge region; the details are in Appendix E. The constraints include:

- The inability to transfer load to the new Forrest substation due to the current rural nature of the network, hence interconnectivity issues;
- The number of customers and load on some Cambridge feeders is too high, which increases the consequences of outages, no ability to cater for ongoing regional growth, and limits the ability to back feed in contingency situations (i.e., limits security);
- The load density for some western Cambridge feeders is too large for the dimensions of the feeder, which creates voltage regulation issues and limits the ability to back feed in contingency situations.

We describe the solution below. This covers the overall solution, the projects in progress, the projects planned, and further project concepts under consideration.

Solution (overall)

As an extension of Regional Capacity and Security Developments projects in Section 9.6.1, the overall solution is to develop the 11kV network to:

- Facilitating the transfer of load to the west of the Cambridge GXP to the new Hautapu GXP;
- Transfer customers, load and feeder section from the congested western and southern Cambridge feeders to new feeders from the Forrest substation.

Adding feeders (as outlined below) will offload significant loads from the existing Cambridge GXP and resolve the GXP security issue.

The solution will increase network resilience by reducing the number of ICPs per feeder and providing additional interconnections to facilitate backfeeding in contingency situations.

This work is achieved through the project outlined below.

Solutions (projects in progress)

Currently, there are no projects in progress.

Solutions (projects planned)

Project	Issue	Proposed solution	Options considered
Forrest Substation 11kV Integration plan	The Forrest Road substation is situated west of the current Cambridge GXP and away from the mainline feeders. To connect to the existing distribution network, the substation must utilise four of the six 11kV feeder circuit breakers assigned for the new substation.	The substation's location allows four new feeders to interconnect with existing feeders in the western Cambridge area. The new feeders will transfer load from the existing Pencarrow, Tamahere, Kaipaki, and Monavale feeders, thus freeing them up to cater to the growing demand in the CBG township and the new C10 growth cell. This is a complex project, as the existing infrastructure needs to maintain connectivity until the substation is operational. This project involves running 11kV cables for the four new feeders. The other two 11kV feeders will be used to run two circuits down into Leamington (as mentioned in the Leamington 33kV cable project below). **Budget: $2.35m** **Schedule: FY25-FY26** The final connection to the substation will be in FY26. We aim to complete the bulk of the work before the substation commissioning is ready for connection.	We completed a detailed study of all options, and the proposed solution was the most appropriate to achieve a cost-effective load transfer.
Feeder 1 (New) Tamahere reinforcement	The 11kV circuits from the Forrest Rd Substation connect to the existing Tamahere feeder. Reinforcement of the downstream conductor is required to allow for alternate power flow and supply the anticipated approved load increase in the area.	The project will resolve constraints on the Tamahere feeder. The 11kV network will be upgraded to enable alternate power flow. Minimal work is required for this feeder as the conductor capacity is high. The existing voltage regulator will be relocated due to the changes in feeder demand and voltage drop. This expenditure is from the voltage improvement programme. **Budget: $120k** **Schedule: FY25**	Variations in the selection of mainline circuits and open points.

Project	Issue	Proposed solution	Options considered
Feeder 2 (New) Pencarrow reinforcement	The 11kV circuits from the Forrest Rd Substation connect to the existing Pencarrow feeder. Reinforcement of the downstream conductor is required to allow for alternate power flow and supply the anticipated approved load increase in the area.	This project will resolve constraints on the Pencarrow feeder. The 11kV network capacity will be upgraded to allow for alternate power flow. Several RMUs required connection to adjacent feeders. Additional work will be undertaken to select the optimal location of the voltage regulator and reclosers. This expenditure is from the voltage improvement programme and the reliability improvement programme. **Budget: $850k** **Schedule: FY25**	Variations in the selection of mainline circuits and open points.
Feeder 3 (New) CBG West reinforcement	The 11kV circuits from the Forrest Rd Substation connect to the existing Kaipaki feeder. Reinforcement of the downstream conductor is required to allow for alternate power flow and supply the anticipated approved load increase in the area.	The 11kV network capacity will be upgraded to allow for alternate power flow. Some conductor upgrades were fast-tracked in FY24 to offset delays in other projects. This feeder will supply the new 3MS and St Peter development. **Budget: $800k** **Schedule: FY25-26**	Variations in the selection of mainline circuits and open points.
Feeder 4 (New) Kaipaki reinforcement	The 11kV circuits from Forrest Rd Substation also connect to the existing Kaipaki feeder and pick up some of the Monavale feeder load. Reinforcement of the downstream conductor is required to allow for alternate power flow and supply the anticipated approved load increase in the area.	The 11kV network capacity will be upgraded to allow for alternate power flow. Some conductor upgrades were fast-tracked to FY24 to offset delays in other projects. This feeder will extend into the existing Monavale feeder and pick up some commercial load and the new wastewater treatment plant. **Budget: 200k** **Schedule: FY25**	Variations in the selection of mainline circuits and open points.
Feeder 5 & 6 **11kV Link from Forrest Rd to Leamington C5 (33kV Rated Cable)**	Leamington and Roto-o-rangi feeders are currently capacity and voltage-constrained, with high customer numbers. New feeders in the area are required to alleviate the above issues and enable the new C5 development (~1,700 lots) starting in 2026.	This project involves running two 33kV cables (initially operating at 11kV) from the Forrest Rd substation to the Leamington area and transferring load. This project will resolve the constraints on the Leamington and Roto-o-Rangi feeder and provide capacity for the new C5 growth. We are monitoring the progress of this development in case we need to advance this by one year. A substation in the Leamington area is likely in the future; however, operating this 33kV cable at 11kV will defer the need for a substation, and the timing will be further investigated (refer to projects under consideration). **Budget: $7m** **Schedule: FY26 – FY27**	• Do Nothing • Install voltage regulators • Build substation earlier
Pukerimu Lane conductor upgrade	A new wastewater treatment plant and an increased load on an existing commercial connection will significantly increase the load requirements on a tap-off line. The existing conductor is not sufficient to supply in terms of capacity and volt drop.	Upgrade the poles and conductors on Pukerimu lane, which supplies the new connections, and rearrange the feeder layout to supply it from Forrest Rd Substation. **Budget: $250k** **Schedule: FY25**	• Do Nothing

Table 31: Cambridge distribution capacity and security development – projects planned

Managing demand forecasting risk

The demand forecasting risk is not a material issue for the distribution network as the planning horizon is shorter, at ten years, solutions are sized based on standard capacities, and solutions can be advanced or deferred more easily.

9.6.3 Te Awamutu regional capacity and security developments

Constraint

As shown in Figure 70, demand is forecast to exceed firm (N-1) security criteria in FY30-FY31 for the Te Awamutu region.

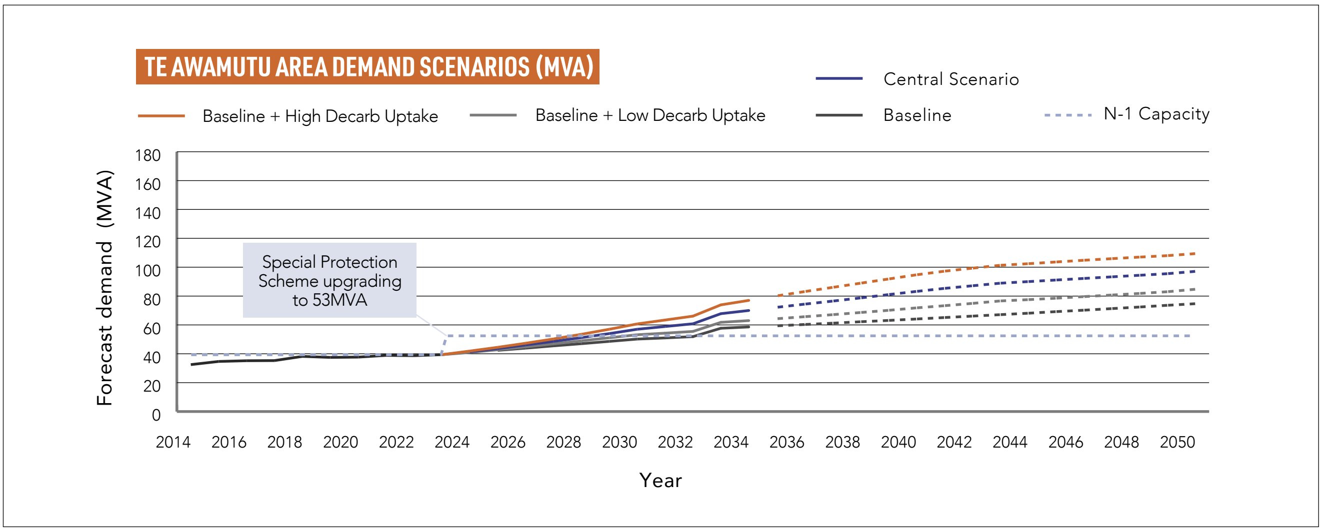


Figure 70: Te Awamutu demand and capacity

The issues for the Te Awamutu region are complex and extend from the regional transmission system, GXP, to the distribution network. The issues are:

- **Regional 110kV transmission network N-1 security breach:** See the detail section below that explains why it is important for us and the sub-transmission development.
- **Te Awamutu GXP N-1 firm capacity is exceeded around FY30-FY31:** Residential growth, and land developments, mean the Te Awamutu GXP load will breach its N-1 capacity between CY29 to CY30.

  Early decommissioning of the Fonterra 5MVA co-generation plant (currently assumed occur about FY34) could advance the breach– this is the biggest uncertainty.

- **Te Awamutu is characterised by long 11kV feeders which have a range of capacity, security, reliability and power quality constraints:** Some customers in the Te Awamutu region are experiencing power quality issues, more frequent outages, extended restoration periods, and connection capacity constraints (when compared to Cambridge). Supporting planned and unplanned outages has become operationally challenging due to limited backfeeding capability and thermal and voltage constraints. In addition, the feeder configuration in Te Awamutu is not designed to support regional growth and security performance in terms of backfeeding ability.

Constraint (Waikato regional 110kV transmission network N-1 security breach in more detail)

Supply security is forecast to become constrained at GXPs connected to the 110kV system in the wider Waikato region. Transpower's annual planning Report[40] indicates various constraints on the 110kV network supplying the Te Awamutu GXP, specifically:

- The Karapiro-Te Awamutu circuit may overload for an outage of the Hangatiki Te Awamutu circuit (regardless of the Karapiro generation output), and
- Outages on the Karapiro-Te Awamutu circuit may overload the Arapuni-Hangatiki circuits.

Transmission overloading means Waipā will be forced to disconnect customers or invest in the generation to alleviate the constraints (under certain transmission contingency situations). In contrast, these are Transpower assets; the cost of alternatives or upgrading falls to those who benefit from the investments (which is Waipā and possibly The Lines Company).

This year, we collaborated with The Lines Company and Transpower to define the current and future constraints and develop high-level solutions to benefit all stakeholders connected to the Waikato 110kV transmission network.

The section below describes the proposed high-level solution to the constraints mentioned above being examined by Transpower.

[40] *Refer to Transpower's Annual Planning Report for more information regarding the issues, constraints, and solution options being proposed by Transpower – Transmission Planning | Transpower.*

Solution (Waikato regional 110kV Transmission and supply, under consideration)

The capacity (and constraints) of the Waikato 110kV transmission system influence the solutions available for increasing capacity at Te Awamutu. We are working with Transpower through the options analysis to alleviate the constraints. Progress to date (Dec 2023) has generated the following high-level options for further evaluation:

Option	Description
Upgrading the capacity of existing assets	Upgrading supply transformers at existing GXPs (upgrade Te Awamutu GXP supply transformers to 110/33kV, various 110kV transmission circuits including Karapiro-Te Awamutu, and the 220/110kV interconnecting transformer at Hamilton GXP).
Installing a new 220/33kV grid exit point	Building a new 220/33kV GXP to take some load from Hangatiki and Te Awamutu. The 220kV supply will come from the Huntly-Taumarunui line, which traverses the Te Awamutu area;
New 220/110kV interconnection	Building a new 220/110kV interconnection near the Otorohanga area where the 220kV Huntly-Taumarunui and the 110kV Hangatiki-Te Awamutu circuit cross.

Table 32: Te Awamutu area transmission development options

All options require considerable investment that will ultimately pass back to local distribution networks, including us, and we must ensure that any investment is best for Waipā's customers. As highlighted in Table 32, a solution is likely required in the six to ten-year window.

Considering the significant lead time for transmission and sub-transmission project development, we must continue with the momentum of the work and ensure Transpower delivers the transmission part of the solution, and we will be able to deliver the distribution part of the solution timely.

The next step of the works in FY25 broadly includes the following steps:

- Transpower generate high-level cost bands for the above options,
- The Lines Company and Waipā Networks to assess each of the transmission options, generate respective sub-transmission and distribution network upgrade options and budget estimates, and
- Transpower will synthesise the total combined costs (EDB plus Transpower) and recommend a final option, demonstrating to the regulators that the overall cost is optimised.

This region-wide issue impacts The Lines Company and us, and we are all working with Transpower to develop a regional Waikato solution. We will report on progress in resolving this constraint in the 2025 AMP.

Solution (Te Awamutu regional and distribution supply, under consideration)

We have commenced work on an options study that considers subtransmission and distribution system architecture to meet future growth needs and provide a foundation to improve reliability and voltage on the distribution system. This work is still in the early stages and the cost of the possible future architecture are yet to be quantified, and therefore not yet included in the forecast expenditure schedule.

We have developed and tested the high and low demand scenarios and seek to optimise around our central case (while testing the risks concerning the high and low scenarios). Figure 71 illustrates the high-level concepts that we developed in 2023. These concepts will be reviewed and refined against Transpower's updates in 2024.

While there is currently no generation application in the Transpower Connection Queueing system, there is a possible transmission-connected (100MW+) solar farm development in the region near the 220kV line. We seek to engage with potential solar farm investors as an opportunity for a combined Grid Exit Point / Grid Injection Point in the region to share the transmission development costs.

We will include our preferred likely solution in the 2025 AMP, depending on the progress from other stakeholders.

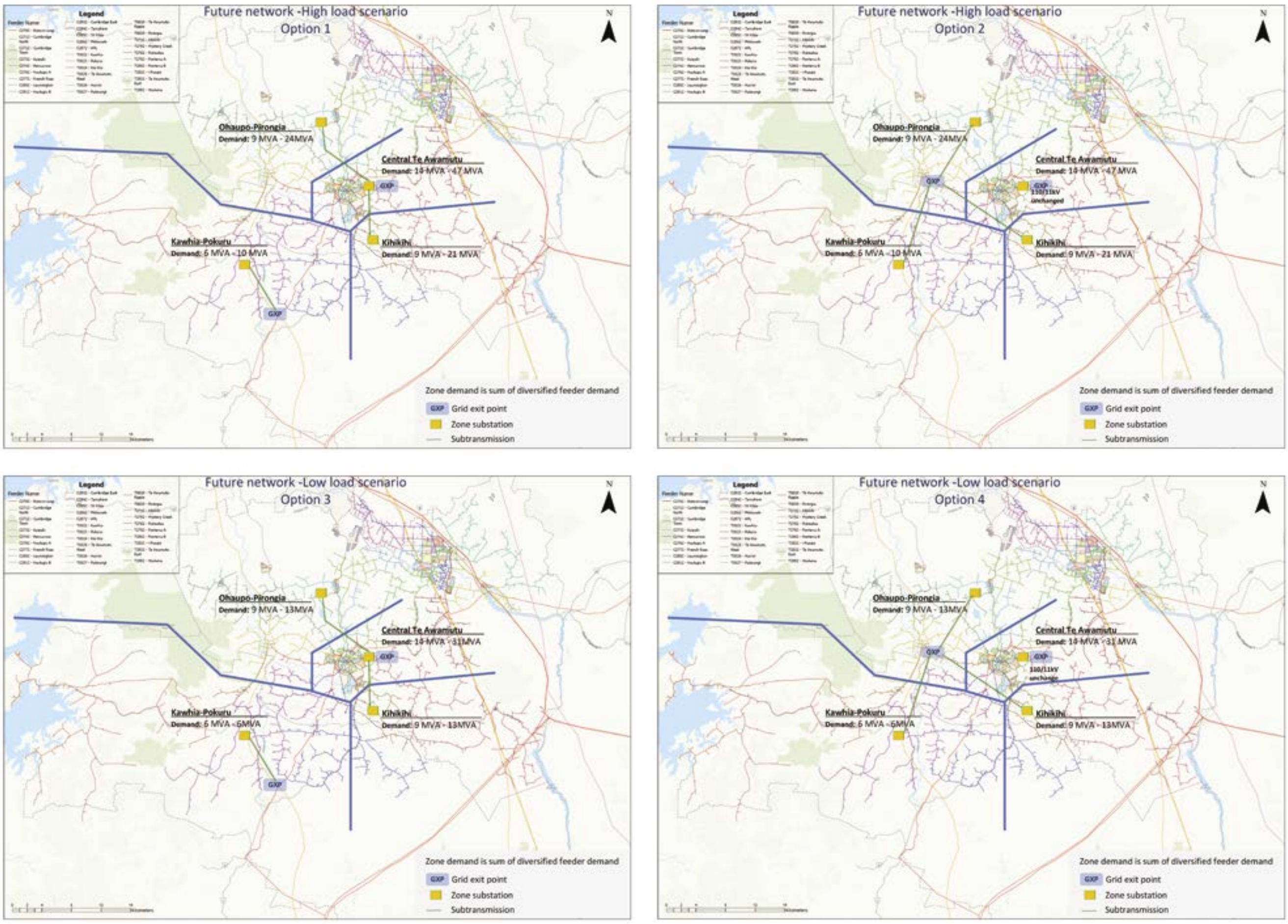


Figure 71: Te Awamutu sub-transmission options under investigation

Managing demand forecasting risk

We have not yet assessed forecasting risk. This will be discussed when our preferred solution is developed.

Our contingency is to work with Fonterra to keep the 5MW co-generation unit running, as this will advance the GXP security breach significantly (but will not resolve the wider feeder reliability and voltage issues).

Overview of Issue

We have undertaken high-level reviews indicating current and emerging capacity and security constraints; see Appendix E for details. We will define specific constraints (and solutions) as we complete the load flow modelling of the network at the feeder level.

9.6.4 General distribution capacity developments

Solutions (projects in progress)

Project	Issue	Proposed solution	Options considered
Te Awamutu PILC Cable Upgrade (Continued	11kV CU 160mm2 PILC cables from the TMU GXP are constrained and present security of supply risk in case of a cable fault. The cables are bundled together, and a failure on one could affect others.	Upgrade the 11kV cables to 400mm Cu cables. This project is a carry over from FY23. Easements within a reserve took longer than anticipated. The remaining cost is for cable purchase and installation. **Budget: $3.6m FY25** **Schedule: FY24-FY25**	• Do nothing • Utilise spare breakers to offload demand from existing cables (Doesn't mitigate the risk of failure of existing cable)

Table 33: Other distribution capacity development projects (projects in progress)

Solutions (planned projects)

Project	Issue	Proposed solution	Options considered
Distribution transformer upgrade	Distribution transformers breach their capacity or security triggers due to incremental load growth (e.g. from Customer Initiated Works)	Upgrade the existing transformer or install additional transformers to sectionalise the network. The budget is provisional and will respond to distribution transformer constraints (we identify these constraints from MDI and logger readings at distribution transformer sites). **Budget: $3.5m** **Schedule: FY25-FY34**	• Do nothing • Utilise spare breakers to offload demand from existing cables (Doesn't mitigate the risk of failure of existing cable)
11kV Conductor upgrade	11kV conductors breach their capacity or security triggers due to incremental load growth (e.g. from Customer Initiated Works)	Upgrade the conductor in various locations as required. The provisional budget will respond to projects defined from our 11kV modelling work. **Budget: $2.8m** **Schedule: FY28-FY34**	• Do Nothing • Rearrange feeders to offload demand.
11kV Cable upgrade	11kV cable breaches their capacity or security triggers due to incremental load growth (e.g. from Customer Initiated Works)	Upgrade the cables in various locations as required. The provisional budget will respond to projects defined from our 11kV modelling work. **Budget: $2.8m** **Schedule: FY28-FY34**	• Do Nothing • Rearrange feeders to offload demand.

Table 34: Other distribution capacity development projects (planned projects)

9.7 Development plan to address other drivers

This section outlines our development plan that responds to other planning criteria and drivers. These projects respond to the following:

- Reliability improvement opportunities on the distribution network;
- Voltage constraints on the distribution network;
- Our resilience strategy;
- Regulatory requirements;
- Constraints with our communication system;
- Other matters.

9.7.1 Reliability improvement projects

Overview of issue

Our overhead network covers rural and semi-rural areas. As land use changed over the preceding decades, the customer density has increased. Faults on rural feeders now impact a larger number of customers. Response time to these faults is also longer than for urban networks.

As outlined in Section 5.5, we have very little headroom against our reliability targets (assuming future performance reflects historical averages), and we breached our target in FY23 (after normalisation for major events). Hence, we need to improve the reliability performance of our network continually.

There are opportunities for continuous improvement by reducing the number of customers between controllable switches and reclosers and prioritising renewal and vegetation management on the worst-performing feeder (discussed in the relevant fleet plans in Section 11).

The reliability review (refer to Section 4.1) made a specific recommendation concerning car vs pole incidents. The first area to address has been identified for remediation.

Solutions (overview)

We are implementing a program to improve the reliability. This work includes installing reclosers to segment feeders (without introducing longer fault clearance time), upgrading non-automated ABS/LBS to automated LBS at key switching points and open points to reduce restoration times and installing dropout fuses on spur lines.

Using reclosers, sectionalisers, and fuses helps us respond to unplanned faults as quickly as possible and helps reduce the number of consumers impacted. Comparisons to other EDBs show that we have a high ratio of reclosers per line length compared to other EDBs, as shown in Figure 72. Additional automation of remote switchgear is currently constrained until the communication network upgrade is completed (refer to Section 9.7.5).

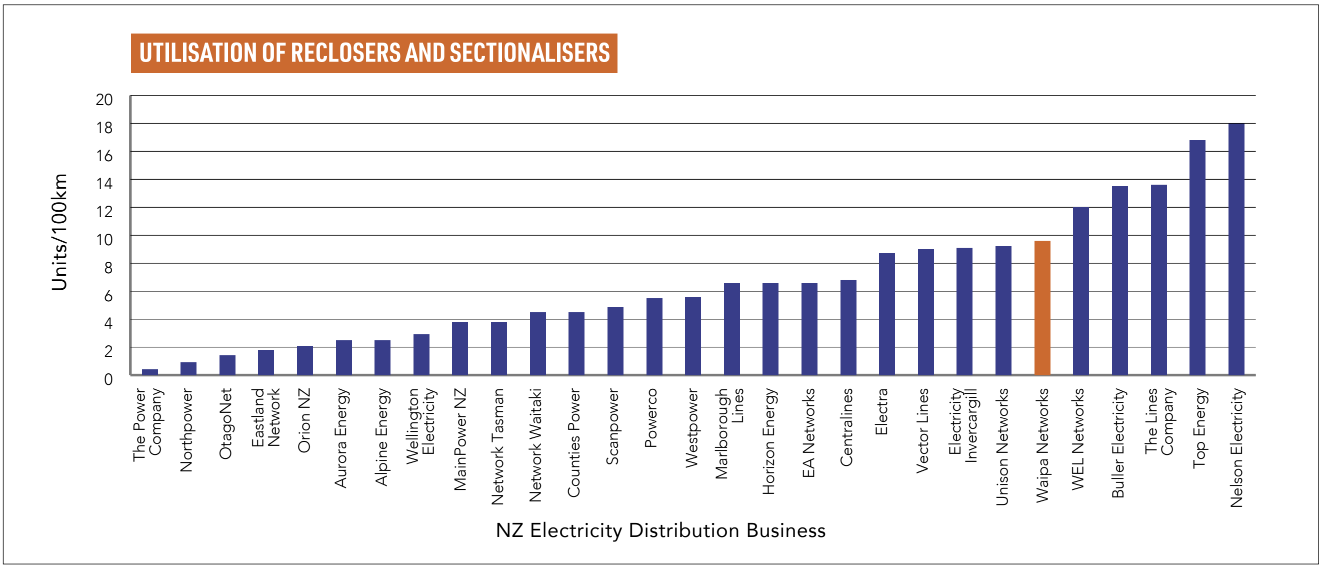


Figure 72: Recloser utilisation (from 2023 AMP)

The new zone substations will provide a foundation to add additional feeders over time, reducing the number of customers and length of feeders. This will further reduce the impact of a feeder fault.

Solutions (planned projects)

Project	Issue	Proposed solution	Options considered
Te Rahu Rd and SH3 intersection	Multiple third-party interference events on the corner pole. Over three incidents in the last five years.	Underground the intersection. Install an RMU and underground cable across the state highway. Remove 2 x ENTEC ABSs. **Budget: $120k (RSE, Quality)** **Schedule: FY26**	• Do nothing • Shift the pole
11kV automation recloser/ sectionaliser additions	11kV lines need further sectionalisation to reduce the impact of unplanned outages.	Install 2 x additional NOJA reclosers or ENTEC LBS/ sectionaliser per annum following the communication upgrade. **Budget: $720k (RSE, Quality)** **Schedule: FY26-FY34**	• Do nothing
Install remote control switches.	Long outage periods due to limited automation.	Automate switch sites. Expenditure is delayed until the communication network is installed. **Budget: $1.6m (RSE, Quality)** **Schedule FY26-FY34**	• Do nothing

Table 35: Development projects to address reliability issues

9.7.2 Voltage improvements projects

Overview of Issue

We have undertaken high-level reviews indicating current and emerging voltage constraints on rural feeders. We will define specific constraints (and solutions) as we complete the load-flow modelling of the network at a detail feeder level.

Solutions (planned projects)

Project	Issue	Proposed solution	Options considered
Te Awamutu PILC Cable Upgrade (Continued	11kV CU 160mm2 PILC cables from the TMU GXP are constrained and present security of supply risk in case of a cable fault. The cables are bundled together, and a failure on one could affect others.	Upgrade the 11kV cables to 400mm Cu cables. This project is a carry over from FY23. Easements within a reserve took longer than anticipated. The remaining cost is for cable purchase and installation. **Budget: $3.6m FY25** **Schedule: FY24-FY25**	• Do nothing • Utilise spare breakers to offload demand from existing cables (Doesn't mitigate the risk of failure of existing cable)

Table 36: Development projects to address voltage constraints

9.7.3 Projects to improve resilience

Overview of driver

The resilience strategy is set out in Section 9.4. The first development projects linked to this strategy have been defined, addressing some known issues.

Solutions (planned projects)

Project	Issue	Proposed solution	Options considered
Underground Lamb St	85% of the street has been converted to underground. The remaining 15% was severely hit by vegetation during cyclone Gabrielle, causing a significant SAIDI impact.	Underground the remaining section of Lamb St. Install 2 x RMUs to supply the remaining transformers on the section of the line. **Budget: $400k (RSE, Other)** **Schedule: FY25**	• Do nothing • Shift the pole
Kawhia line deviation	Sections of the line are at risk of collapsing into the nearby river. Some line sections supply the Kawhia township. Risk is not immediate.	Deviate the line away from the river. **Budget: $300k (RSE, Other)** **Schedule: FY25-FY26**	• Do nothing
Seismic strengthening of voltage regulator sites.	Some VR structures and their foundation do not meet our current standards for seismic strength.	Upgrade structures to coincide with VR renewal and maintenance program under Asset Lifecycle. Civil design to propose a solution. **Budget: $1.6m (RSE, Other)** **Schedule: FY25 – FY34**	• Do nothing

Table 37: Development projects to support the resilience strategy

Note: We had one two-pole transformer structure left in the network at the time of AMP writing. This type of structure is considered a hazard due to the nature of the pole construction. The structure is planned for replacement in March 2024. Replacing this unit removes a public and network safety risk for Waipā.

9.7.4 Projects in response to regulatory requirements

Overview of issue

We have a range of regulatory obligations. Managing compliance with these obligations is an ongoing activity for Waipā.

Solutions (planned projects)

Project	Issue	Proposed solution	Options considered
Mutu St and Ohaupo Rd OH circuit clearance issue	11kV and 400V lines traverse above a building, and clearances are within ECP34 requirements. Note: this is a multi-circuit line	Underground all circuits, including the LV. Circuits are located on SH3 and in a busy area for vehicles and the public. Two feeders (Hairini and Kihikihi) are connected to this section, so an additional benefit is reducing the risk of significant outages through third-party interference. **Budget: $780k** **Schedule: FY25 (RSE, Other)**	• Do nothing • Increase the height of the poles to increase the clearance distance.
Low road crossing improvements	Low road crossings (either at or below ECP compliance) must be resolved. Our focus is to improve clearances on major transport routes.	Specific projects are identified from the defect notices (via line inspection, vehicle damage, and high-load escorts) and other project works. **Budget: $950k** **Schedule: FY25-FY34 (RSE, Other)**	
Automatic Underfrequency Load Shedding	The new requirements for distributors are to have a 4-stage AUFLS scheme with high-resolution event recording to better stage and record load disconnection. Transpower has indicated they are moving away from having their equipment responsible for load disconnection. All of Wāipa's current 11kV feeders are owned and operated by Transpower, giving us a unique problem to solve in terms of implementing the AUFLS scheme	Install 2 x AUFLS relays at Te Awamutu and Cambridge grid exit points. The relays will utilise an inter-trip scheme where our relays will monitor the frequency and send a trip signal to Transpower's feeder relays (When required) **Budget: $160k** **Schedule: FY25**	• Alternate relay suppliers • Alternate wiring design

Table 38: Legislative and regulatory development projects

9.7.5 Projects that respond to other drivers

In this section, we outline development projects that relate to other network assets. These projects respond to various constraints and drivers on the network.

Project	Issue	Proposed solution	Options considered
Communications (Voice and SCADA radio) upgrade	The existing radio communications network is overloaded—too many sites per channel, creating congestion and long poll periods on SCADA.	Upgrade the repeater links to Microwave links. Digitise the voice network and upgrade all existing radios to digital. Create the platform for SCADA integration. Work includes: • establishing a new repeater site and easement, • upgrading existing sites, • installing new microwave links, and • backup power supplies. This project will allow us to communicate with the new substations and the additional communication devices we have planned for the network. The design considerations for this project are included in the fleet plan (refer to Section 11.19.3). **Budget: $1.8m** **Schedule: FY25-FY33**	• Do nothing • We assessed various repeater sites; however, microwave links require a line of sight. • Alternate communication frequencies
Network Access Lock Upgrade	Our existing lock system uses a master key, which hasn't been carefully controlled since its inception. This poses a significant security risk to Wāipa because the master key can be copied.	Upgrade the lock system to the digitally coded lock and key system and replace the existing one. We have estimated that approximately 2800 locks require replacing. **Budget: $400k** **Schedule: FY25**	• Status quo

Table 39: Other network asset development projects

9.7.6 Future generator usage

Overview of issue

Three 1MVA diesel generators were installed in Swayne Rd Cambridge in 2022 to manage the peak demand on the Cambridge network (so that the GXP security was not breached). The land lease for the installation runs out in FY29; however, once the new Hautapu GXP and Forrest zone substation are commissioned in early 2025, the generators will no longer be required post-2024 winter.

There are some emerging constraints and issues that the generators could support. These include:

- Offset demand at the Te Awamutu GXP to avoid a breach of GXP security;
- Improve security and reliability at several locations on the 11kV network;
- Increase supply reliability to Kawhia as part of the resilience strategy.
- Increase voltage performance at certain locations on the 11kV networks.

Solution (under consideration)

We are currently exploring potential options for using these generators once they are no longer needed for their original purpose.

9.8 Expenditure forecasts

Below is a summary of the development plan for capital projects. Further commentary is provided in Section 12 (including comparators to the 2023 AMP).

System Growth Projects	Type	FY25	FY26	FY27	FY28	FY29	FY30-34
Forrest Zone Substation	Project	9,000	265				
Forrest 11kV Feeder Integration Plan	Project	2,350					
New Forrest Feeder 1 (Tamahere) augmentation	Project	120					
New Forrest Feeder 2 (Pencarrow) augmentation	Project	850					
New Forrest Feeder 3 (Cambridge West) augmentation	Project	200	600				
New Forrest Feeder 4 (Kaipaki) augmentation	Project	200					
11kV cable project (Forrest Rd – Leamington)	Project		3,500	3,500			
33kV cable project (Forrest Rd – Bardowie)	Project		100	1,700	1,600		
Bardowie Substation – land purchase	Project			1,100			
Bardowie Substation	Project	193	535	3,210	4,815		
Te Awamutu feeder cable upgrade	Project	3,600					
Communication network upgrade	Project	700	325	130	130	104	416
11kV Conductor upgrade	Provisional				400	400	2,000
11kV Cable upgrade	Provisional				400	400	2,000
Distribution Transformer upgrade	Provisional	350	350	350	350	350	1,750
Pukerimu Lane conductor upgrade	Project	250					
Total of System Growth		**17,813**	**5,675**	**9,990**	**7,695**	**1,254**	**6,166**

Table 40: System Growth Expenditure

Note: *Real FY24 $000*

Reliability, Safety, and Environmental Projects	Type	FY25	FY26	FY27	FY28	FY29	FY30-34
Quality of Supply							
Voltage regulator (Upgrades or new)	Project	250	500	250	500	250	2,000
Underground Lamb St	Project	400					
11kV automation additions (2x new sites)	Provisional		80	80	80	80	400
LV voltage complaints	Provisional	130	130	130	130	130	650
Install remote control switches and automation (coincide with ABS ARR)	Provisional	-	182	182	182	182	910
Install HV fuses on spur and service lines, and resolve grouped fusing	Provisional	10	10	10	10	10	50
	Sub-Total	*790*	*903*	*652*	*902*	*652*	*4,010*
Legislative and regulatory							
AUFLS scheme and relay install (TMU)	Project	80					
AUFLS scheme and relay install (CBG)	Project	80					
Mutu St – Te Rahu Rd underground project	Project	780					
Improve low crossings on major transport routes	Provisional	50	100	100	100	100	500
	Sub-Total	*940*	*100*	*100*	*100*	*100*	*500*
Other							
Te Rahu Rd/SH3 intersection underground project	Project		120				
Kawhia line deviation	Project	150	150				
Seismic strengthening of voltage regulator structures	Provisional	160	160	160	160	160	800
Network Access Lock upgrade	Project	400					
	Sub-total	*710*	*430*	*160*	*160*	*160*	*800*
Total of Reliability, Safety and Environmental Projects		**2,440**	**1,433**	**912**	**1,162**	**912**	**5,310**

Table 41: Reliability, Safety and Environmental Expenditure

Note: *Real FY24 $000*

10. CUSTOMER WORKS

This chapter outlines our approach to customer-initiated work and how related expenditure is forecasted. Customer-initiated work includes new connections, upgrading existing connections, and relocating distribution assets.

New connections or changing existing connections initiated by customers impact our long-term network planning and development. The process used to connect new customers is tailored to ensure the fast, efficient, and cost-effective connection of new electricity customers to our network while ensuring integration with network development and fleet management plans.

10.1 New connections

10.1.1 Overview of customer connections

We connect approximately 600 new residential, commercial, and industrial electricity customers to our distribution network every year. The five-year average growth in new connections has been about 13%; we expect the same growth rate to continue.

Depending on the size or number of the new connections, the ability to supply the new connections may require investment to extend our distribution network to meet the required capacity.

The new customer connection may occasionally require an upgrade of near-end-of-life network assets. We will then consider whether our assets are effectively being replaced and may contribute to the costs of the new equipment.

The quantity and timing of customer-initiated developments, including subdivisions, are driven by the developers of each site. Recently, customer-driven activity has increased in the Cambridge and Te Awamutu areas, reflected in the forecasts in this AMP.

10.1.2 Connection process

Our practice for connecting new customers and customer-initiated network alterations follows a process that includes the following:

- Assessing the proposed load's impact on the network – capacity and voltage. The level of detail depends on the connection size; the engineering team assesses larger connections to determine if upstream upgrades are needed before the design team confirms the installation arrangements, access requirements and customer contribution.
- Common issues include:
  - timing to align equipment sourcing with long lead times from suppliers and the iterative process involving initial customer enquiry. Waipā responds with connection requirements when the customer confirms their needs. To overcome the challenges, we ensure that our equipment stock is at a level that covers these uncertainties.
  - Data availability, where needed to confirm existing loading, can sometimes impact the time to assess new connections. We expect this will largely be resolved as we adopt new technologies for LV network visibility.
- With the requirements confirmed, we create the ICP for new connections and carry out the physical connection (our in-house field service team does the construction to complete the requested connection/network alteration), then forward the information to the customer's retailer.

Residential customers

Residential customers requiring a new connection will often hire an electrician who will make an application to us on their behalf. The electrician will submit the proposed connection specifications and design and notify us of any special requirements, such as the need for an easement. This will be reviewed and approved, provided our distribution assets have sufficient capacity. Upon approval, our contracting division will plan and perform the installation.

Larger commercial customers

Larger commercial customers, subdivision developers, and others will often contact us directly to discuss connection requirements or will work with engineering consultancies to develop suitably sized distribution systems for their proposed works. Connections of this size will often involve relatively significant infrastructure development, network extension or asset renewal. We work with these larger entities to facilitate the connection of large loads in a standardised and efficient manner.

Where asset replacement is required, we will review the connection on a case-by-case basis to determine the contribution level, if any, that we will provide. It is beneficial for us to work with developers during the connection process as it allows upgrading assets approaching the end of life or near their capacity rating.

Our customer connection process and capital contributions policy are set out in further detail on our website.

10.1.3 Minimising costs to consumers

Using standard design and construction ensures the network will maintain acceptable reliability and safety with the extensions and alterations and helps minimise customer costs.

Where we can, we install equipment, ensuring that the configuration allows for future upgrades/alterations considering the area growth profile, ensuring work common to different projects is done once.

We consider the quotation fee part of the customer contribution and apply it to offset some project costs.

10.1.4 Planning and managing communication with customers

We maintain a web portal that allows customers or their representatives to submit applications for new connections or alterations to existing connections. Our interaction with the customer starts from acknowledging receipt of the application and confirming customer requirements to continual updates on the progress. The updates include when we expect the customer input to proceed with the application, such as when they need to pay connection fees. We also engage with customers through workshops, community events, and local agencies. These additional initiatives allow us to discuss broader changes to our processes and pricing and support customers with their requirements.

10.1.5 Major customer projects

Kiokio / Waikeria

The 600-bed Waikeria Prison upgrade is under construction. This has required significant network reinforcement to create capacity for the additional 2 MVA load, with the potential to expand to 4 MVA in future.

The network upgrade is complete, with the Waikeria and Kiokio feeders split and additional capacity added. We are yet to see the step increase in load from the customer due to project progress.

Other

Other proposed major customer connection projects, where we have not yet received a specific connection application, are discussed in Section 9.8, Growth/Demand Projections.

10.2 Asset relocations

This section outlines our approach to relocating distribution assets when required by external stakeholders, such as landowners district councils or Waka Kotahi/NZTA. It includes an overview of typical drivers of asset relocation, managing the relocation works and how they are funded.

10.2.1 Overview of asset relocations

Electricity distribution assets often require relocation due to the development of the surrounding environment or infrastructure where they are installed. This is typically due to the activities of other utility owners operating in our network, e.g., replacing water pipes, telecommunications circuits, roading activities, or land development for farming, commercial activities, or urban development.

Working with our stakeholders requiring asset relocations allows us to upgrade segments of our network or replace aged assets at a reduced cost.

In most circumstances, we receive contributions from our external stakeholders requesting the relocation of assets, reducing the amount of our investment in these projects.

In most asset relocations resulting from road works, we bear costs, often in materials per required legislation. We consider other projects on a "case by case" basis. Our capital contributions policy is set out on our website.

Expenditure is capitalised where replaced assets are approaching the end of life and can be renewed or upgraded during the asset relocation. Otherwise, relocation of the same individual asset is considered an operational expenditure.

Where major works are required for asset relocation, such as major roading and other infrastructure projects, we will include the project in the annual capital expenditure plan to resource the project. Projects of a smaller scope where our contribution (if needed) can be accommodated in the general asset relocation allowance are incorporated into the work plan for the current year.

10.2.2 Asset relocation projects

When writing this AMP, one committed asset relocation project was proposed for the planning period: the Silverwood and Lamb Street undergrounding project.

10.3 Expenditure forecast

The ability to forecast precise works relating to customer-initiated works is relatively complex as it relies on external factors and can also be influenced by shorter-term economic turbulence. Currently, forecasting is reliant on the following factors:

- Trending expenditure information from recent years,
- Residential development forecasting from major developers and WDC planning,
- Understanding the current economy driving local commercial development and other environmental factors.

Over the planning period, capital expenditure forecasting is based on the following assumptions:

- New residential development in the Te Awamutu and Cambridge areas will continue at an approximate rate as seen over recent years, i.e., approximately 2% per annum ICP growth.
- Existing residential loads
  - A general steadying in load through the installation of energy-efficient lighting and heating in residential applications slows the need to increase the capacity of distribution assets.
  - It is noted, though, that if the widespread uptake of electric vehicles occurs, this may increase demand in some localised areas.
- Commercial development will continue at or around current rates.
- Asset relocations: We will assume a trend in line with historical expenditure.

From the above, we currently adopt the following approach for forecasting Customer Initiative Works:

- For the shorter-term forecast, it is difficult to be accurate as it can be heavily influenced by economic turbulence.
- For the medium-longer term forecast, we expect the current growth trend will continue. Growth rate to date, and our Regional Study supports this continuation of growth in both industrial/commercial and residential sectors.
- Based on the above, we adopt the past 5-year average to set the 10-year average for the AMP period.

Table 42 shows forecast expenditure for customer-initiated works over the next ten years.

Customer-initiated works	Type	FY25	FY26	FY27	FY28	FY29	FY30-34
Disconnector Switchgear Additions	Provision	19	19	19	19	19	97
General Relays Additions	Provision	28	28	28	28	28	139
Dropout Fuse Switchgear Additions	Provision	67	67	67	67	67	334
Ring Main Unit Switchgear Additions	Provision	207	207	207	207	207	1,036
Transformer & Sub Additions	Provision	1,707	1,707	1,707	1,707	1,707	8,535
General Extensions	Provision	3,483	3,483	3,483	3,483	3,483	17,417
Total		**5,511**	**5,511**	**5,511**	**5,511**	**5,511**	**27,557**

Table 42: Customer-initiated works forecast

Note: Real FY24 $000

Relocations	Type	FY25	FY26	FY27	FY28	FY29	FY30-34
Relocations	Provision	231	231	231	231	231	1,155
Total		**231**	**231**	**231**	**231**	**231**	**1,155**

Table 43: Relocation forecast

Note: Real FY24 $000

11. ASSET LIFECYCLE MANAGEMENT

11.1 Introduction

Asset lifecycle management describes the steps within an asset's lifespan and ensures that an asset (or asset fleet) delivers the required performance at the least overall lifecycle cost. The principal aims of our lifecycle management include:

- To manage the risk to staff, customers and the public.
- To achieve our service levels and meet customer expectations.
- To comply with our environmental policy.
- To minimise the total cost of ownership and maximise the efficiency of our operations.
- To satisfy legislative requirements.

Much of the existing network was developed in the 1970s and 1980s. The presence of end-of-life (EOL) drivers in these assets is increasing and has required us to increase our focus on forecasting and managing EOL issues.

Historically, we have used a mixture of asset age and observations from planned and defect-driven inspections to inform asset renewal plans. We have commenced the transition from this age and inspection-based approach to an asset health, criticality, and risk approach to inform our asset renewal plans. Over the past 12 months, we have improved our assessment and forecasting of asset health, and revised asset health forecasting has been included for all our material asset classes. We are still transitioning, as the field capture of condition data (that aligns with our revised approach) is in progress and will take several years to complete.

Our asset renewals are forecasted based on asset health (with prioritisation based on criticality considered at the project definition stage). Over the next 24 months, we intend to transition to a comprehensive risk-based approach using improved health forecasting and asset criticality. Hence, our fleet plans, renewal forecasts and expenditure forecasts may evolve further in subsequent AMPs.

The recent improvements and planned improvements align with Asset Management Strategy #4 (develop comprehensive fleet plans and renewal forecasts) and #5 (improve asset management maturity).

In this section, we cover:

- Alignment to our asset management strategy.
- Lifecycle management.
- Asset health, criticality and risk.
- Improvements to our fleet plans included in this AMP.
- Fleet strategies that apply to all our material asset classes.
- Summary of material changes to the health of the fleet and our renewal plans.
- Fleet plans; and
- Asset renewal and network maintenance expenditure forecasts.

11.2 Alignment to our asset management strategy

In the 2023 AMP, we revised our asset management strategy, and three strategic initiatives now guide our lifecycle management. These are:

- #3 Resilience: Improve the resilience of our network to reduce the impact of increasing incidents, the intensity of adverse weather, and rising incidents of third-party damage on the network. As far as lifecycle management is concerned, the resilience strategy is influencing the design standards and approach for the replacement of assets—that is, a progressive improvement in asset resilience as the network is renewed.
- #4 Fleet management: Develop comprehensive fleet plans and renewal forecasts to better manage our asset fleet. The outcome of this strategy can be seen in the improvement we have made (and plan to make) concerning our asset health, criticality and risk approach, the development of fleet strategies, and the revised fleet plans presented later in this section.
- #5 Asset management maturity: Improve asset management maturity to address the need for quality decisions based on quality data. Regarding lifecycle management, this strategy drives the improvement in inspection standards and the availability and use of condition data in the fleet plans.

11.3 Lifecycle management

11.3.1 Stages in an asset's lifecycle

We consider our network assets within a lifecycle framework from design and procurement through installation, commissioning, operation, maintenance, renewal, and disposal.

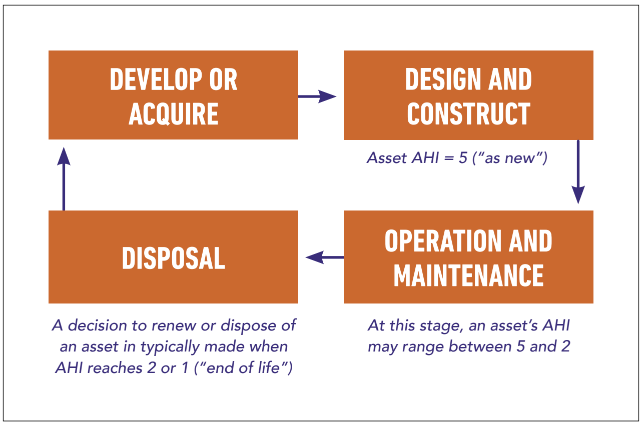


Figure 73: Asset lifecycle management

The goal of lifecycle management is to maximise the utility of the assets while minimising total cost over its life. Paying more upfront may be more cost-effective if this reduces the total operating costs over the asset's lifetime. Practical examples include:

- Distribution transformers in salt-prone areas have galvanised tanks and longer insulators.
- Selection of pole-mounted switchgear with stainless steel tanks for extended life.
- Selection of enclosed load break switches over open air break switches for extended life, lower maintenance, and improved reliability.

The lifecycle stages are described below.

11.3.2 Develop or acquire

This phase covers creating an asset by identifying the initial need, assessing options, and preparing the conceptual designs. We cover this phase in the Network Development and Customer Works sections.

11.3.3 Design and construct

This phase covers detailed design, procurement, construction and project management, and commissioning of new assets. This is a crucial phase in the asset lifecycle where risk can be designed out, and reliability, resilience and "smarts" can be designed in. Several asset management strategies influence this phase of the asset's lifecycle.

11.3.4 Operate, monitor, and maintain

Condition monitoring

Monitoring the assets (inspection or testing-based condition assessments) is a major input to determine the health of the assets and provide us with the information needed to assess safety risks and reliability issues.

The type and frequency of inspection or testing are influenced by many factors, including public safety, the criticality of the asset, network reliability, the risk of failure, the consequence of failure, the cost of the inspection or testing, and the time it takes for an asset to deteriorate from H2 to H1. These factors can be fleet-specific, and as a result, we have adopted a range of techniques, and these are outlined in the fleet plans.

Condition-based and routine maintenance

We undertake condition-based and routine maintenance on the assets. The output informs condition-based maintenance of the condition monitoring. For some assets, we also undertake routine (time or operation-based) where it is impossible to accurately identify condition triggers or where routine maintenance is needed to maintain the asset's utility. Where possible, we prefer condition-based maintenance over routine maintenance.

Corrective maintenance

Corrective maintenance typically occurs in response to a defect notice (and some defect notices will result in the replacement of an asset). Corrective maintenance may occur immediately upon identification of the defect, or it may be scheduled within a short period (days to a few months).

Fault repairs and response

We have a faults response team on duty 24/7 to resolve equipment failures leading to loss of supply to customers or posing immediate safety risks requiring emergency shutdown. If the Faults team cannot fix the issue within the limits according to our response targets for the service area, the problem is escalated to the Construction team for resolution.

11.3.5 Renew or dispose

This phase involves deciding when to renew or dispose of the assets.

Asset renewal

A range of factors are considered in determining whether an asset is renewed. These include:

- **Safety –** an asset may be renewed when the risk to staff, customers, or the public is too high per our risk framework.
- **Asset health, asset criticality, and asset risk –** our current approach for deciding whether to renew or dispose of an asset is based on asset health. That is, the decision to renew an asset is considered when the asset's health declines to a point when the risk of failure is too high. This is typically before the asset reaches an asset health of H1. A few asset classes, such as some pole-mounted transformers, may be replaced on failure, depending on their criticality/consequence of failure.

Asset criticality is presently considered based on the judgement of our asset planners. We intend to evolve our asset renewal process based on asset risk by incorporating asset criticality. The combination of health and criticality provides a consolidated view of asset risk. Our approach is discussed in the next section.

- **Asset type risk –** an asset may be renewed where a specific issue exists with the material, construction, operation, or other issues for a particular type or manufacturer.
- **Construction efficiency –** we may replace assets ahead of health needs where there are advantages of doing so through economies of scale, for example, in undertaking whole line section renewal where most (but not all) poles and components in the line section are assessed in poor health. Such a strategy is economically efficient due to the one-off project and site set-up costs, especially in rural and remote locations, and the avoided cost of multiple customer interruptions.
- **Overall workforce efficiency –** we may seek to spread as evenly as possible renewal expenditure over several years to ensure that we maintain overall work levels to maximise the efficiency of field crews, allow an orderly ramping up (to allow training or recruitment to take place), or ramp down work levels.

Our fleet strategy and renewal methodology in the fleet plans describe our asset renewal decision process and related criteria.

Asset disposal

We dispose of assets when there is no longer a need for its service on the network (e.g., when the load served has disconnected) or when alternative connections make the assets obsolete. Disposal is preferred to renewal for assets providing temporary solutions (such as generators) when a permanent network solution has been implemented.

11.4 Asset health, criticality, and risk

11.4.1 Asset health

We have adopted the EEA asset health indices (AHI) for asset health[41]. The AHI measures an asset's lifecycle stage and fitness to continue safe, compliant, cost-effective service. All fleet plans include an asset health assessment for all fleet assets.

Identifying EOL drivers for an asset can be complex as multiple factors often drive a decision to replace or dispose of it. For example, the decision to replace an asset may be due to one or more of the following factors:

- **Physical condition –** is in-service deterioration present that diminishes the capability or reliability of the asset to an intolerable level?
- **Functionality –** does the asset meet current and future requirements for functionality and capacity?
- **Operating economics –** are the operating economics of the asset viable? Is utilising a new asset or a different solution to meet the need less costly?
- **Compliance –** does the asset comply with current legislation, codes of practice, standards, or good practice?

The AHI scores are shown in Table 44.

AHI category	Serviceability Criteria	Suggested rectification interval
H5	**As New** The asset is in a new condition	No EOL drivers for replacement
H4	**Asset serviceable** Normal deterioration occurs that does not impact the utility of the asset	No EOL drivers for replacement
H3	**Onset of unreliability** The asset is in a serviceable condition but showing deterioration. EOL drivers for replacement are first becoming evident, and there is an increasing asset-related risk	EOL drivers are present, but replacement is not yet required. Reinspection is necessary within a reasonable period. The asset may be included in a replacement programme for economic reasons.
H2	**Elevated risk** EOL drivers for replacement are present, and there are high asset-related risks. Assets with EOL condition drivers may be left in service on a risk-assessed basis. The probability of failure is at maximum tolerable levels.	EOL drivers for replacement are present, and the asset should be scheduled for replacement within an appropriate period (considering risk and criticality).
H1	**End of Life** The asset has reached end-of-life. Significant EOL drivers that are likely to lead to failure are present. The probability of failure is higher than would normally be tolerated for an asset in service. This includes Amber and Green defects.	Replacement or retirement is recommended, typically within six months, consistent with the risk.

Table 44: Waipā's AHI scores with definitions

[41] *EEA Asset Health Indicator (AHI) Guidelines 2019*

11.4.2 Asset criticality

Our asset renewal planning considers criticality when determining specific projects and project priorities. This consideration is based on the judgement of our asset planners, who considered the factors mentioned below. We intend to adopt the EEA asset criticality indicator (ACI), as shown in Table 45[42].

AHI category	Criticality
C4	**Minor:** Credible CoF is broadly tolerable and run to failure may be a valid strategy
C3	**Typical:** Asset failure would cause some disruption and inconvenience, but systems are already in place to anticipate and manage the outcomes
C2	**Elevated:** Asset failure would cause significant harm to people, assets, the business, or the environment. The consequences are tolerable but should be avoided or mitigated if it is practicable to do so
C1	**Extreme:** The credible consequences of failure would be intolerable

Table 45: Waipā's asset criticality levels (as per the EEA ACI)

Our initial approach will be to assign asset criticality at feeder and feeder-section levels. All assets within the feeder or section will be given the same ACI. Once an initial criticality assessment is completed, we will fine-tune the assessment to include an evaluation of the factors of criticality mentioned below.

Assessing asset criticality is multi-dimensional. We plan to apply the dimensions included in the EEA asset criticality guide. The impact of an asset will determine asset criticality:

- **Public safety** – the harm to the public that might arise due to the failure of an asset.
- **Personnel safety** – the harm to personnel that might arise due to the failure of an asset.
- **Service levels** – the economic impact of a supply failure on customers and community.
- **Direct Cost** – substantial repair cost and/or secondary damage resulting from asset failure.
- **Environmental** – the harm of a failure on the environment.

11.4.3 Asset risk

We intend to adopt an overall risk approach consistent with the EEA asset criticality guide. Asset criticality will be used with asset health to define a risk-based approach for asset renewals, inspection and maintenance, and renewal programmes.

The risk matrix is shown in Figure 74 below.

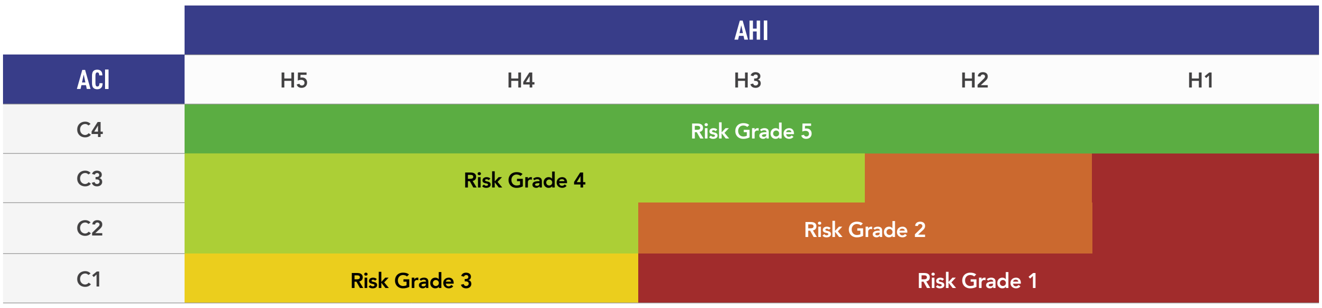


Figure 74: Asset risk matrix

[42] *EEA Asset Criticality Guide 2019*

The risk reporting matrix contains five risk-grade zones. Each zone represents a combination of health and criticality indicators within which the intervention response is likely to be broadly similar. Definitions of the risk grades are shown in Table 46.

Risk category	Criticality	Driver for replacement
R5	**Risk Grade 5:** Low relative consequences of failure	There is no specific driver for replacement. Replacement would be based on efficiency or cost considerations.
R4	**Risk Grade 4:** Typical asset, in useful life phase	There is no specific driver for replacement. Replacement would be justified on efficiency or cost-benefit considerations.
R3	**Risk Grade 3:** Healthy but highly critical assets	There is no specific driver for replacement; however, monitoring and maintenance of the asset is required to avoid or manage the transition to R2.
R2	**Risk Grade 2:** A combination of criticality and health indicates elevated risk	Drivers for replacement are present, and the asset should be scheduled for replacement within an appropriate period
R1	**Risk Grade 1:** A combination of high consequences of failure and reduced health indicates high risk	Replacement or retirement is recommended, typically within six months, consistent with the risk

Table 46: Waipā's asset risk grades (as per the EEA guide)

We have not yet completed our work on asset criticality and asset risk. We expect our fleet plans to transition to risk-based forecasting over the next two years. Given the current aging of the network, we are comfortable that this period does not present any undue risk.

11.5 Improvements to our fleet plans included in this AMP

11.5.1 Improvements to our asset fleet plans

As Section 3.5.3 mentioned, we expect to observe more EOL condition drivers over the coming decade. Ensuring we have quality asset condition, asset health, and asset risk information will be essential to enable the optimal renewal of our network. Consistent with asset management strategy #4 (develop comprehensive fleet plans and renewal forecasts), we have developed comprehensive asset fleet plans for our material asset classes.

11.5.2 Improvements to asset condition data

We are revising our inspection standards to ensure they capture information on the EOL drivers for the assets. This information is needed to assess the health of the assets more accurately.

Most of our EOL condition inputs in this AMP were obtained from prior inspections (including Fugro's helicopter-based pole-top inspection from early CY21). We spent time validating the Fugro pole-top survey data over the past 12 months and have used this data in our health assessments. The validation included interpreting the data into a format consistent with the EEA standard that can be used in asset health models. As we progressively inspect the network, the old inspection data will be superseded by new inspections (to the latest EEA-aligned standard).

For FY24 and FY25, we have planned and budgeted additional drone-based inspections (mainly urban and rural townships and some rural areas where the helicopter could not fly over) to provide further condition data for the overhead asset fleets. Other work is planned in FY2025 to capture groundline/below-ground condition drivers for the wood pole fleet. The FY24 inspections are still progressing (at the time of writing) and will used in the health assessments included in the 2025 AMP.

The table below shows the status of the development of new inspection standards and the capture of EOL condition drivers for each material asset class.

Asset fleet	AHI-aligned inspection standard developed	% of assets with condition data to the old standard	% of assets with condition data to AHI standard	Target date for completion of inspections to AHI standard
Subtransmission structures and conductor	Yes	n/a	n/a	FY26[43]
Distribution structures	Due early FY25	70%	n/a	Starting from FY25
Distribution crossarms	Due early FY25	47%	n/a	Starting from FY25
Distribution overhead conductor	Due early FY25	n/a	n/a	n/a
Pole-mounted transformers	Yes	Yes	0%	Started in FY24
Voltage regulators	Yes	35%	0%	FY25
Reclosers and sectionalisers	Yes	n/a[4]	16%	FY25
Overhead switches	Due early FY25	1%	0%	Starting from FY25
Distribution cables	n/a	n/a	n/a	n/a
Ground-mounted transformers	Yes	n/a[21]	67%	FY25
Ring-main units	Yes	n/a[44]	28%	FY25

Table 47: Status of inspection standards and data capture to the new standards as of June 2023

11.5.3 Improvements to our asset health assessment and health forecasting

Our asset health assessment continues to be a mix of age and condition-based.

Over the last 12 months, we considered whether we would adopt the DNO Common Asset Indices methodology or the EEA AHI methodology. We have adopted the EEA AHI approach as this was the best fit for Waipā assets (as the DNO methodology did not incorporate several of our material asset classes). We have developed a new EEA AHI-based health assessment and forecasting model that forecasts asset health over the next ten years. Our revised health assessment and forecasting model allows for age- or condition-based assessments. Where condition-based assessments are undertaken, the model allows for up to ten EOL drivers (ten allows for new drivers to be added without the need to revise the model) to be assessed per asset class.

Where no asset condition data exists, the health assessment continues to be age-based, consistent with the EEA AHI guide.

The EEA AHI methodology does not include a condition-based health forecasting tool, so one was developed. Our methodology forecasts the decline in asset health by applying an exponential decay curve to the current condition-based asset health. The change in the health of a distribution asset is modelled exponentially, as it is assumed that the processes involved as the asset deteriorates (e.g., corrosion, oil oxidation, insulation breakdown, etc.) are accelerated by the products of the deterioration process (this is consistent with condition-based health forecasting used in the DNO methodology).

The decay in health is modelled over the asset's maximum practical life (MPL). Different decay curves are applied where assets in the same fleet have different MPLs due to asset-type or material-type differences. Figure 75 shows the comparison between the exponential and age-based approaches (noting that the shape of the EEA "curve" will change given the onset of unreliability (OOU)[45]). Figure 76 shows the decay in asset health for H3 and H2 assets. In this example, the impact of using an exponential decay curve shortens the forecast time an asset takes to deteriorate from H3 to H2 and from H2 to H1 than would be the case for an asset with an OOU of 20 and MPL of 40. The exponential decay rates would be like a linear decay where the OOU was 26 years, and the MPL was 40.

[43] The first condition assessment for the subtransmission assets will occur at 10 years after commissioning.

[44] Only condition data captured using the new standards was used in the health assessments. Condition data captured under old standards exists but was not used.

[45] Onset of unreliability (OOU) is the nominal age at which replacement drivers first become evident within a population. Approximately defined as the age where 5% of assets would be retired for end-of-life reasons (excluding capacity-related reasons). The onset of unreliability (OOU) corresponds to an AHI of 3.

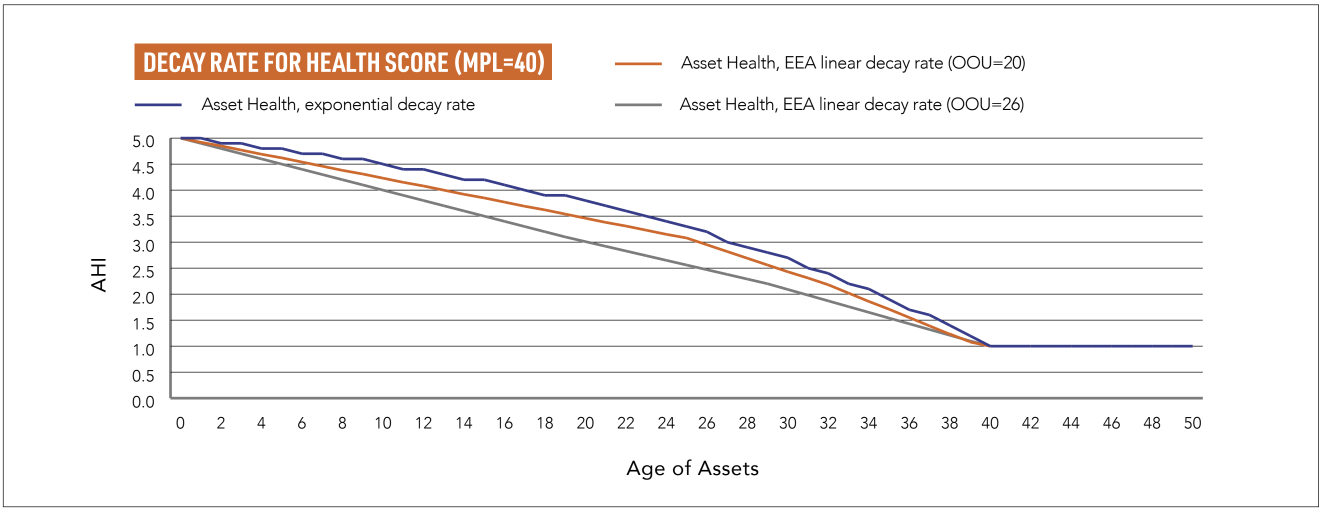


Figure 75: Exponential and EEA (linear) health decay

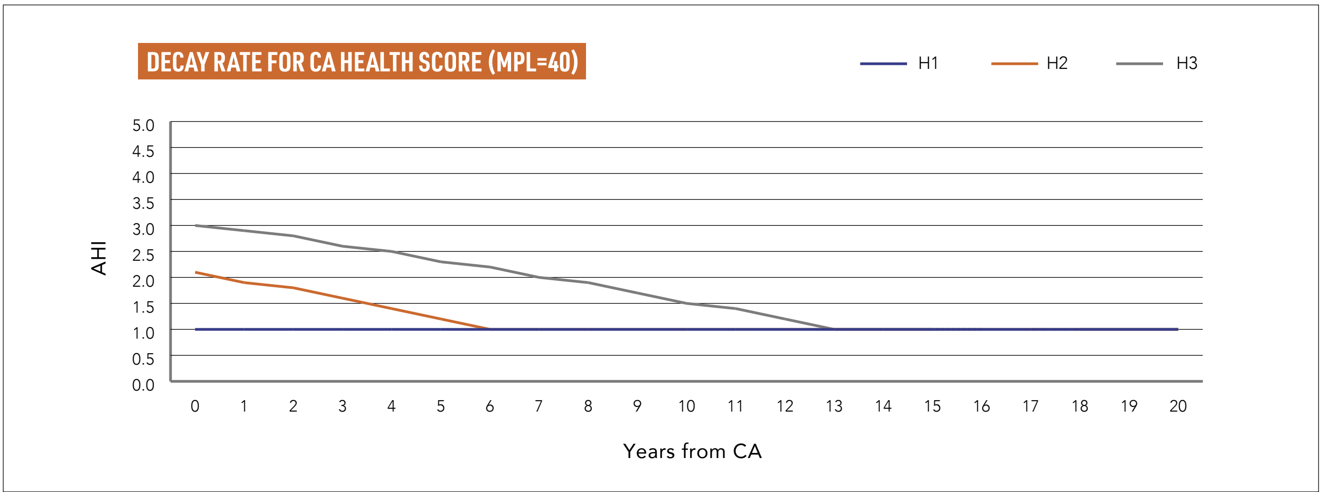


Figure 76: Exponential decay rates for AHI H3 and H2

We have also assessed asset condition and survival statistics and adjusted the standard EEA OOU and MPLs to incorporate Waipā-specific life expectancies where possible[46]. Life expectancies are also modified due to the impact of asset refurbishment. Presently, Waipā does not retain survival statistics on its assets; hence, our ability to assess asset survival to alter MPLs has been minimal. Improvements to maintaining asset data will enable survival statistics to be evaluated.

The new model enables line-of-sight between current asset health (either age or condition-driven), 5/10-year forecast asset health, 5/10-year asset renewal forecasts, and 5/10-year expenditure forecasts. The models will significantly simplify renewal forecasting in future years, and the accuracy will improve as our condition data improves and Waipā-specific life expectancies are included.

[46] *As we only have limited survival data (dating back to 2013) we can only assess different OOU's for relatively new assets that were not subject to significant replacements programmes prior to 2013.*

11.5.4 How condition data is being used and improved

Table 48 below shows the extent to which we are currently using condition-based health assessments

Asset fleet	% of the fleet with condition-based asset health	% of forecast H1 and H2 assets that are condition-based	Target date for completion of condition-based health assessments and renewal forecasting
Subtransmission conductor and structures	n/a	n/a	FY26
Distribution structures	70%	23%	FY25-FY30
Distribution crossarms	47%	54%	FY25-FY30
Distribution overhead conductor	0%	0%	n/a
Pole-mounted transformers	83%	47%	FY25-FY30
Voltage regulators	35%	67%	FY25
Reclosers and sectionalisers	16%	88%	FY25
Overhead switches	1%	5%	FY25-FY30
Distribution cables	0%	0%	n/a
Ground-mounted transformers	67%4	35%	FY25
Ring-main units	28%4	0%	FY25

Table 48: Status of condition-based health assessment and renewal forecasting as of June 2023

11.5.5 How we are forecasting asset renewals and determining specific renewal projects

Table 49 below illustrates how we forecast asset renewals and determine specific renewal projects. Our approach differs for each fleet depending on the quality of the condition data, age data, the mode of failure, and the expected repair or replacement times. These are discussed further in the fleet plans. As mentioned above, a risk-based approach is being introduced over the next 24 months.

Asset fleet	Asset renewal forecasting	Determining specific renewal projects
Subtransmission conductor and structures	Condition-based asset health (from FY26)	Health-based, prioritised by criticality
Distribution structures	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Distribution crossarms	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Distribution overhead conductor	Age-based asset health	Reliability-based in the short-medium term
Pole-mounted transformers	Combination of age and condition-based asset health	Urban units – Health-based Rural units Failure and defect-based
Voltage regulators	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Reclosers and sectionalisers	Combination of technological obsolescence, age, and condition-based asset health	Health-based, prioritised by criticality
Overhead switches	Mostly age and type-issue asset health	Health-based for ABSs and enclosed switches Failure and defect-based dropout fuses and links
Distribution cables	Age-based asset health	Reliability-based in the short-medium term
Ground-mounted transformers	Combination of age and condition-based asset health	Health-based, prioritised by criticality
Ring-main units	Combination of age and condition-based asset health	Health-based, prioritised by criticality

Table 49: Current approach for forecasting asset renewal and specific renewal projects

11.6 Fleet strategies applying across all material asset classes

Several fleet strategies apply to all our material asset classes. To avoid duplication, we describe these in detail in Table 50 and make summary-level references to them in the fleet plans.

The first three fleet strategies align with asset management strategies #4 (develop comprehensive fleet plans and renewal forecasts) and #5 (improve asset management maturity).

Strategy	Description	Outcome
Enhance inspection standards and data.	• Develop new inspection standards to capture EOL condition drivers to support asset health assessment • Capture condition data for the remaining assets in the next two years for ground-mounted assets and five years for overhead asset fleets • Build inspection resources and capabilities to have a prioritised and continuous flow of inspections	• Condition data (aligned to EEA AHI standard) available for >95% of assets
Enhance asset health assessment and forecasting	• Implement new outage codes to capture fault causes better • Capture and analyse asset survival statistics to determine Waipā specific MPLs • Analyse asset condition data to determine Waipā specific OOUs	• Increase asset condition data accuracy score • Increase in condition-based forecasting to >95%
Implement risk-based renewal forecasting	• Develop an asset criticality and risk model to assist with developing replacement programmes	• Improve the quality of our asset health and renewal forecasting
Enhance renewal project selection and prioritisation.	• Develop asset health, risk, and reliability/fault maps to enhance the definition of project work packs and prioritisation	• Improved optimisation of work plans and project timing
Understand and reduce fleet risks	• Assess asset fleet for safety risks or type risks • Include safety risk and type risk as inputs into asset health assessments • Enhance the quality of risk controls and treatments for asset fleets	• Reduce reliability and safety risks

Table 50: Common fleet strategy

11.7 Summary of material changes to the health of the fleets and our renewal plans

Figure 77 and Figure 78 show the evolution of our asset health assessment and renewal forecasts for our material asset classes in this AMP. H1 or H2 refer to assets with low health, meaning replacement is required or where EOL drivers are present, and there is a high risk of asset failure.

Figure 5 shows the material changes in the asset health since the 2023 AMP. These include:

- A reduction in low-health wood poles due to the ongoing asset renewal programme (which has a material impact due to the small fleet).
- A reduction in low health crossarms due to the continuing asset renewal programme and the use of condition data (where over half of the H1 and H2 crossarms were derived from condition data).
- A reduction in low-health pole-mounted transformers due to the use of condition data (where nearly half of the H1 and H2 crossarms were derived from condition data).
- An increase in low-health voltage regulators and reclosers reflects the use of condition data for these fleets.
- A material reduction in low health overhead switches due to the revised health forecasting methodology. The extent of low health assets is likely to be understated as the health of this fleet is largely age-based, and 40% of the fleet has unknown ages.

The asset classes showing a high proportion of low health are wood poles, crossarms, pole-mounted transformers and voltage regulators. Specific commentary asset classes showing a high proportion of low health are:

- The wood pole fleet is small (at 1,300 poles) and is currently subject to an intensive renewal programme targeting the renewal of all low-health poles over the next five years. This strategy has resulted in an increase in forecast renewals over the 2023 AMP.
- The crossarm fleet is material and is subject to an intensive renewal programme targeting the renewal of all low-health poles over the next ten years. This strategy has resulted in an increase in forecast renewals over the 2023 AMP.
- For pole-mounted transformers, the renewals are forecast to replace 150% of H1 assets over the next five years. This is consistent with the failure and defect-driven replacement strategy due to the relatively low risk of failure associated with these assets.
- The forecast renewal of voltage regulators has reduced from that forecast in the 2023 AMP due to better condition-driven health forecasts. This renewal forecast excludes the replacement of voltage regulators for seismic strengthening.
- The forecast renewal of overhead switches has increased over the 2023 AMP. The renewals are currently above the forecast level of H1 and H2 assets due to the uncertainty associated with this asset class. Most of the assets due for replacement are ABSs. Replacement of dropout fuses and links will be a failure or defect-driven replacement.

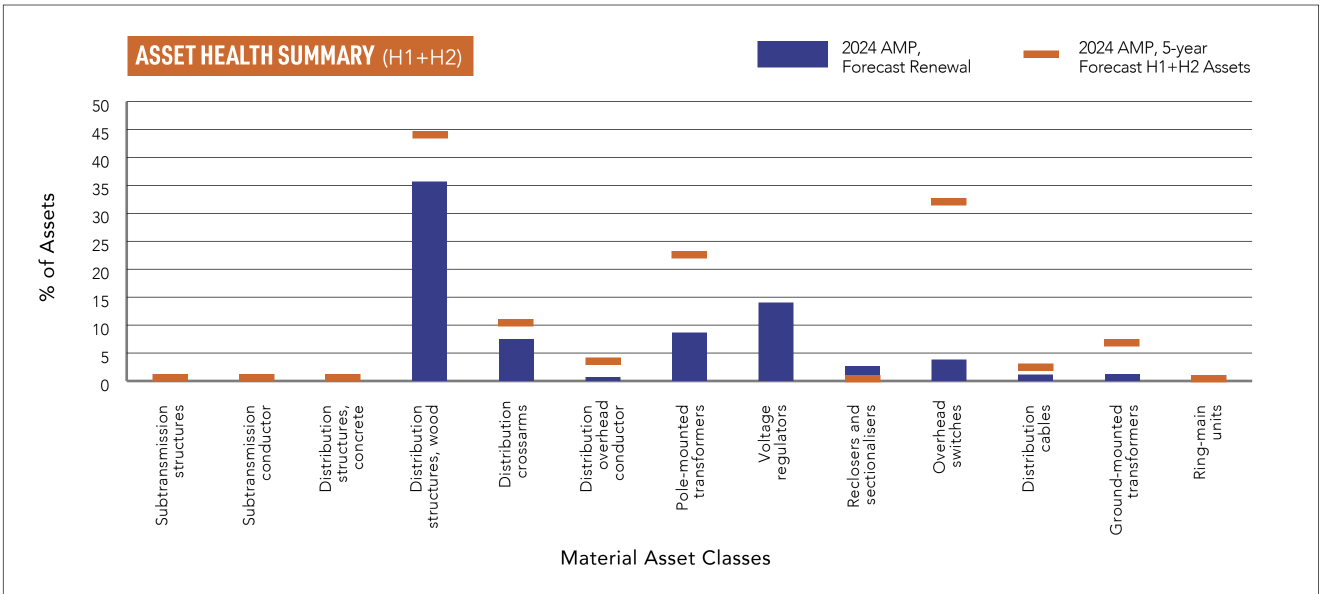


Figure 77: Asset health summary for material asset classes

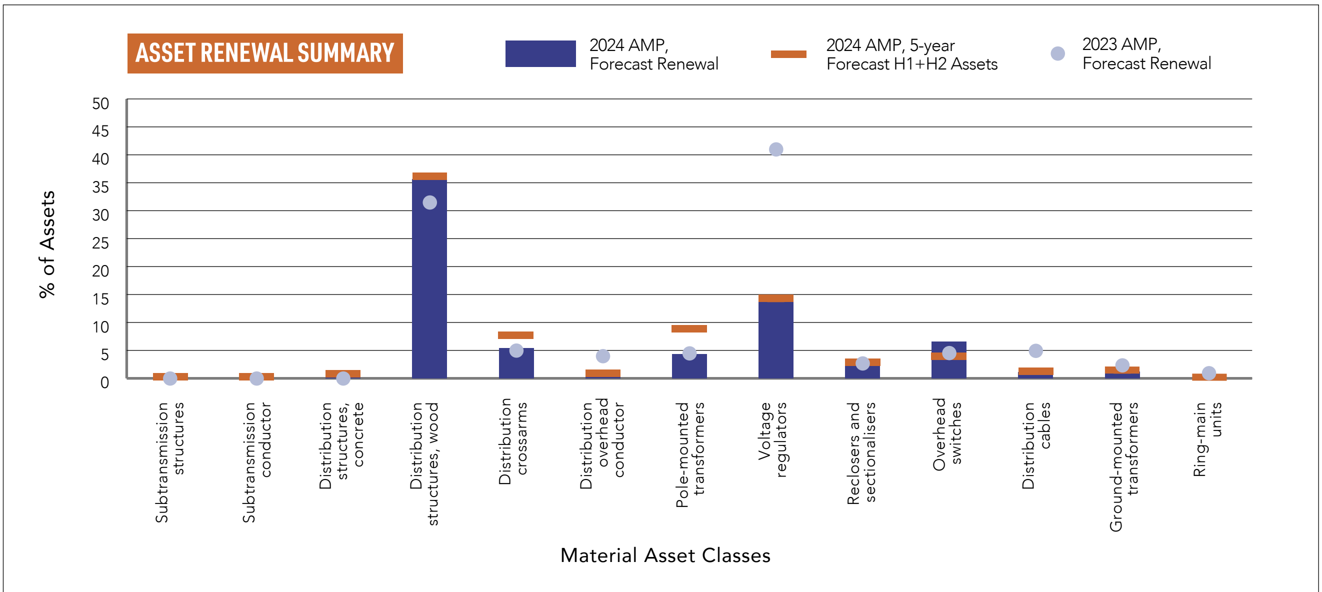


Figure 78: Asset renewal summary for material asset classes

11.8 Asset fleet plans

Table 51 shows the material asset classes for Waipā. Fleet plans for each of these material asset classes are included in this AMP.

Asset fleet	Asset Classes (Commerce Commission definitions)	Unit	Quantity
Subtransmission conductor and structures	Concrete / Steel Structures (110kV only)	No.	190
	Subtransmission OH 110kV+ Conductor	Km	33
Distribution structures and crossarms	Concrete / Steel Structures (excluding 110kV)	No.	20,999
	Wood poles	No.	1,300
	Crossarms [47]	No.	45,348
Distribution and LV overhead conductor	Distribution OH Open Wire Conductor	Km	1,245
	LV OH Conductor	Km	500
Pole-mounted transformers	Pole Mounted Transformers	No.	2,777
Voltage regulators	Voltage Regulators	No.	57
Reclosers and sectionalisers	3.3/6.6/11/22kV CB (pole mounted) – reclosers and sectionalisers	No.	116
Overhead switches (ABS, enclosed LBS, links, fuses)	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4,411
Distribution and LV cables	Distribution UG XLPE or PVC	Km	160
	Distribution UG PILC	Km	0.1
	LV UG Cable	Km	378
Ground-mounted transformers	Ground Mounted Transformers	No.	916
Ring-main units	3.3/6.6/11/22kV RMU	No.	136

Table 51: Material asset fleets

We have included summary-level fleet plans concerning our other asset classes. These cover:

- LV OH/UG streetlighting circuits.
- OH/UG consumer connections.
- Protection relays.
- SCADA and communication equipment.
- Load control plants.
- Load control relays.

Our fleet plans also consider relevant environmental factors, e.g., keeping trees clear of overhead lines. A significant part of the maintenance budget is allocated to vegetation control. Hence, we have included a summary of our vegetation management strategy in this section.

[47] *Not a Commerce Commission asset class. This includes all voltages.*

11.9 110kV Subtransmission structures and conductor

11.9.1 Fleet overview

We own the 110kV line from Transpower's Hangatiki GXP to the Te Awamutu GXP. This line was commissioned in 2016. The purpose of the line is to improve the security of supply to Te Awamutu.

The new subtransmission line consists of 175 steel poles, is less than ten years old and 15 concrete poles for the short section from Te Awamutu GXP to Factory Road. We have not yet undertaken a comprehensive condition assessment, which will occur in FY26. We will expand this fleet plan following the condition assessment.

There are a range of failure modes for concrete poles, steel poles and conductors. We discuss the failure modes for concrete poles and conductors in the relevant distribution fleet plans. Concerning steel poles (which are only used on the subtransmission system), failure is driven by corrosion of the pole and fixing. The corrosion is observable through visual inspection, and the deterioration rate (which depends on environmental conditions) is slow, meaning we can be confident that failure between inspections is improbable.

We have good-quality data on the age and attributes of this fleet.

11.9.2 Fleet performance

There have been no faults on the 110kV line since its commissioning. There are presently no concerns with the fleet's performance.

11.9.3 Fleet risks

Table 52 highlights the material risks associated with the 110kV subtransmission fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Third-party interference (car vs pole) damages overhead lines, causing outages and potential contact with live wires.	• Given the criticality of this line, a car vs. pole incident could limit security into Te Awamutu while the structure is repaired. • Injury to members of the public	• Public safety • Network performance	The poles have been located away from the busy roadway or with setbacks, and structures are protected if necessary.
Failure of 110kV above 11kV could cause fatal over-voltages on the 11kV and LV systems.	• Injury to members of the public	• Public safety	The 110kV line is inspected and maintained to Transpower standard. The health of subcomponents will be kept to H3, given the high criticality and risk.
Outages to multiple 11kV feeders may be required to maintain some 110kV subcomponents or assets.	• This could result in significant customer outages	• Network performance	A review of the maintainability of complex structures is planned. Undergrounding of multi-circuit 11kV circuits is also linked to our Resilience Strategy.
Damage from vegetation	• Network performance	• Network performance	The 110kV line is inspected and maintained to Transpower standard. It is patrolled annually, including detection and action for any vegetation issues.

Table 52: Fleet risks

Given the modern design of the 110kV line. The risks from adverse weather and adverse environmental factors were mitigated through the design process.

11.9.4 Fleet strategy

The key objective for this fleet is to convey power and maintain n-1 security into the Te Awamutu GXP while maintaining public safety and avoiding asset failures.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 53.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in Section 11.6)	• Implement risk-based renewal forecasting (including all subcomponents)	Improve the quality of our asset health and renewal forecasting
Maintain the asset and subcomponents at H3	• Carry out annual patrol • Condition assessed at ten-year intervals and maintain the asset to Transpower standards (see below) • Maintain the assets and components at H3 • Maintain or replace subcomponents at or before they transition to H2	No H1 or H2 assets or subcomponents
Review the maintainability of complex structures.	• A project will be initiated over the next three years to determine solutions to maintain the 110kV components above the 11kV circuits	Optimal maintenance procedures
Timely replacement of defects	• Given the potentially high consequence of failure, defect replacements shall occur promptly	No failure of a subcomponent of the assets with defect notices

Table 53: Fleet strategy

11.9.5 Design and construct

The new 110kV lines comprise galvanised steel poles, steel post-arms, insulators, and aluminium conductors. 17 existing concrete poles were incorporated into the line route.

The line was designed per AS/NZS 7000:2010 Overhead Line Design, AS/NZS 1170 Structural Actions, Transpower line design standards TP.DL 12.01 – Structure Loadings, TP.DL 12.02 – Structures Spacing and Distances, and NZECP34:2001 for electrical clearances.

The line and support structures were designed with a 50-year design life; however, the asset should achieve a 100-year service life if the various subcomponents are suitably maintained.

The 110kV pole also supports some 11kV circuits below the 110kV (up to three in some cases) at certain locations. This will impact the future maintainability of the line (as it is not permitted to work above live lines) if the 11kV circuits cannot be readily isolated. Detailed maintenance procedures will be required as we approach the first round of maintenance on the steelwork, insulators, jumpers and fixings.

11.9.6 Monitoring

A maintenance manual was developed as part of the initial construction project. The 110kV subtransmission line will be monitored using specialised transmission contractors to Transpower standards. Northpower (a Transpower contractor in the Waikato region) has been contracted to undertake patrols, inspections, and maintenance.

Table 54 describes our current fleet monitoring approach:

Monitoring Type	Description	Frequency
Line patrols	• Assess safety, structural integrity, structural damage, public safety risk, and operational risks • Identify defects that are expected to deteriorate to below H3 within the next year • Assess vegetation encroachment, animal interactions, and incompatible corridor use	Annually
Condition assessment	• Condition assessments monitor the condition of structures, foundations, conductors, and hardware. The assessment produces a score for various components on a scale from 100 (new) to 20 (replacement or decommissioning criteria) to 1 (where failure is likely under everyday conditions). • It applies a consistent approach to assessing line components and allows extrapolation of the assessed condition into the future.	At year 10, then at intervals based on the asset condition after that

Table 54: Fleet monitoring

11.9.7 Maintaining

A maintenance manual was developed as part of the initial construction project. The 110kV subtransmission line will be maintained using specialised transmission contractors and to Transpower standards.

Monitoring Type	Description	Frequency
Preventive maintenance	• Preventative maintenance will be carried out as specified in the Transpower maintenance standards	As required
Condition-based maintenance	• Detail maintenance plans will be developed after each condition assessment to maintain the asset and subcomponents to achieve the intended service live and retain them to H3	As required
Defect repairs	• Defect repairs will be completed in response to line patrols and condition assessments. Defects are compiled in our defect management system, and a rating is applied based on urgency.	Defect notice

Table 55: Fleet maintenance

11.9.8 Renewal

Our fleet renewal approach is shown in Table 56.

Decision	Description
Renewal forecasting	• The forecast of asset renewals is as described in the fleet strategy.
Maintenance forecasting	• To be developed in FY26 following the first condition assessment
Determining specific renewal projects	• Specific renewal projects are identified from the health assessment • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by criticality. The highest priority will be replacing transformers in critical locations
Assessing alternatives	• In normal circumstances, no other options are assessed • The exception is where the transformer replacement resulted from a car vs pole incident. If historical data on car vs pole incidents indicate the transformer is in a high-risk area, we will consider relocating the transformer
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 56: Fleet renewal forecasting

Material spares

We currently hold spare conductors and components, including insulators and line hardware. The spares are considered sufficient to cover all reasonable likely events.

The 110kV steel poles are designed for each location and are not interchangeable, and we currently do not hold spares. We must order replacements from the supplier (estimated supply time is 12 weeks from overseas manufacturing). We will seek Transpower's assistance with spare concrete poles as either a replacement for the concrete pole line section or as temporary replacements for steel pole section towers.

11.9.9 Population and age

The population and age of the 110kV subtransmission structures and conductor fleet are shown in Figure 79 and Figure 80. The graphs indicate no assets are near OOU[48]. The OOU for the structure and conductor are similar.

Our current data shows the concrete poles in the 26-35 age bracket being mass-reinforced. The team will review the exact pole type and update the record accordingly. All existing conductors were replaced when the new line was commissioned.

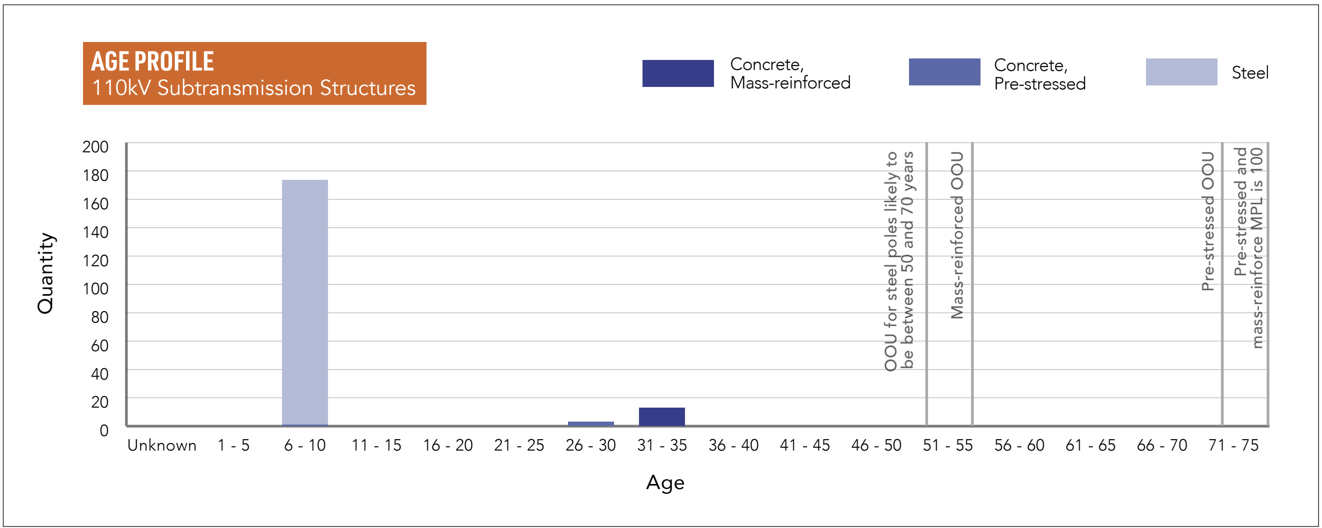


Figure 79: Age profile (110kV structures)

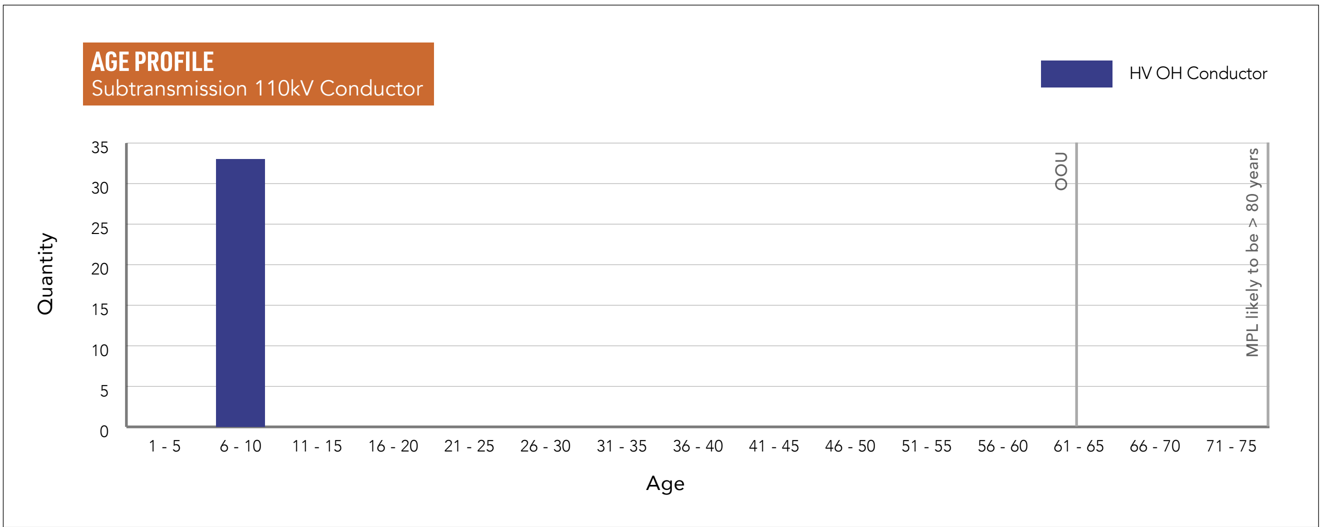


Figure 80: Age profile (110kV conductor)

[48] *Our initial view is that OOU is somewhere between 50-70 years, with a service life of up to 100 years if properly maintained. For our initial modelling, we have set this at 100 years. The OOU for AAAC conductors is 60 years.*

11.9.10 Asset health

Figure 81 and Figure 82 show the health assessment for 110kV subtransmission structures and conductor fleet. It is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

No low-health assets or subcomponents are forecast over the next ten years.

The forecasting is all age-based.

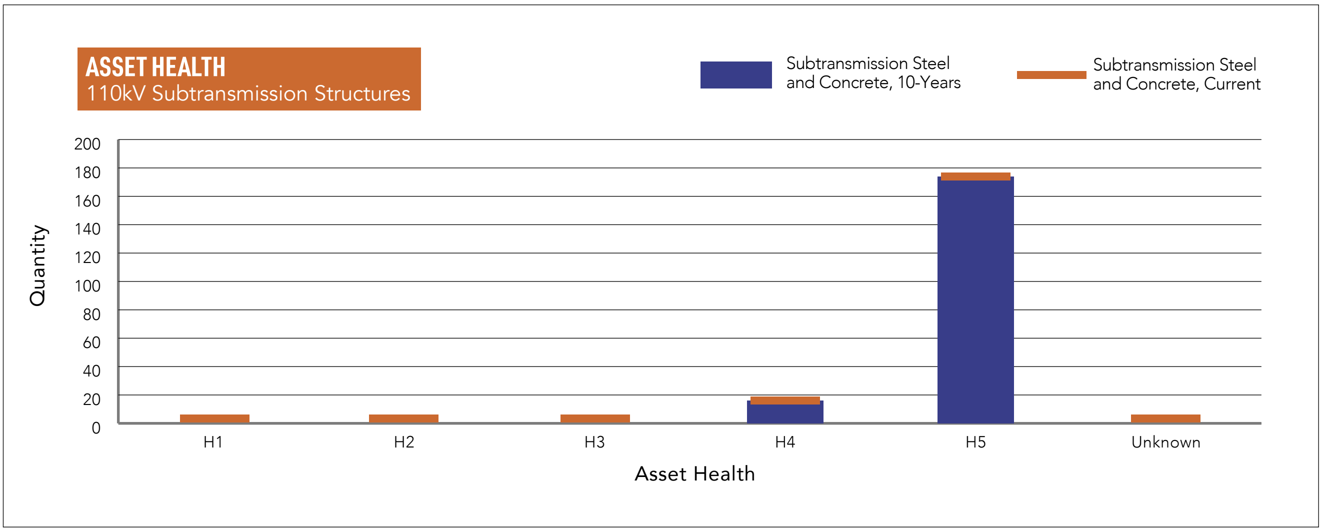


Figure 81: Current and forecast asset health (110kV structures)

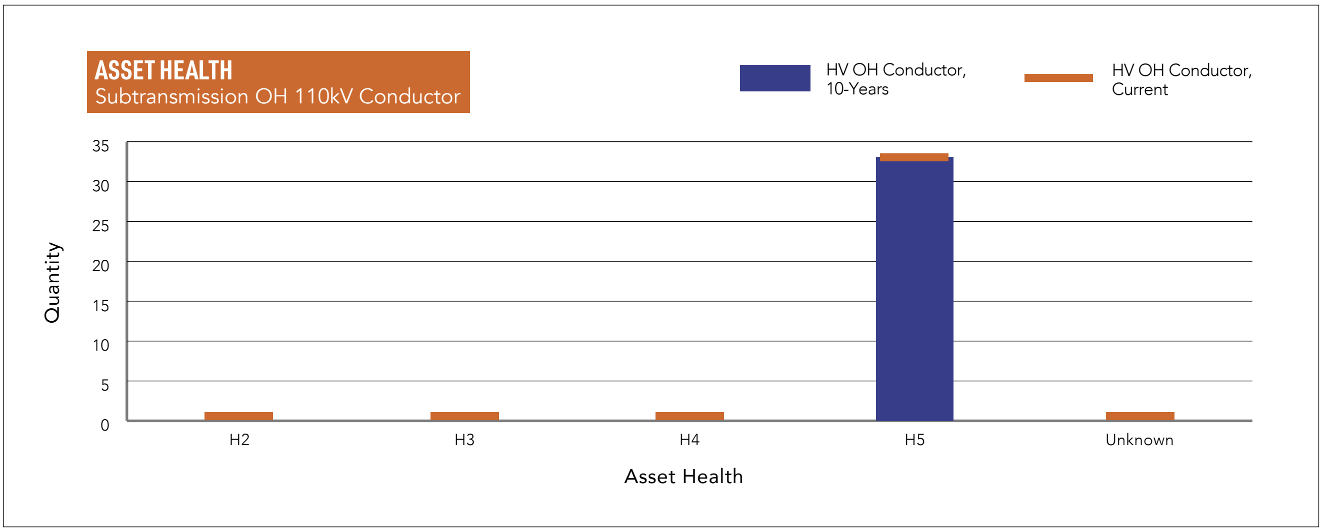


Figure 82: Current and forecast asset health (110kV conductor)

11.9.11 Asset replacements

There are no asset or subcomponent replacements forecast over the next ten years.

11.9.12 Expenditure forecast

No renewal expenditure on the asset or subcomponent is forecast over the next ten years.

The line is patrolled annually, and any asset, componentry defects and vegetation issues are addressed accordingly, given the criticality. We have not developed a replacement forecast for this asset. This will need to be prepared following the first condition assessment in FY26.

There is currently no specific maintenance provision in the network opex forecast, so some increase in maintenance will occur following the plan's development. The increase is not likely to be material for the next ten years.

11.10 Distribution structures (pole and crossarm) fleet plan

11.10.1 Fleet overview

Overhead lines make up 85% of Wāipa's distribution total circuit length. Overhead lines include pole structures (covered in this fleet plan) and conductors (covered in the next fleet plan). Overhead lines are our most significant asset fleet by quantity and the largest by value. This section excludes the 110kV subtransmission structures covered in Section 11.9.

Overhead lines are the network's backbone and provide the means to distribute electricity safely and securely to consumers' homes and businesses. Overhead lines are a cost-effective way of conveying electricity and are generally easy to repair. Development plans could alter some of how structures are replaced. For example, if an overbuilt subtransmission circuit is needed, standard distribution poles could be replaced with taller poles.

Most existing poles (>93%) are concrete of various types (Busck, Stresscrete heavy/light, Window, Brown Brother heavy/light, Bill Young, etc.). Wooden poles are predominantly softwood poles with small patches of Hardwoods remaining in isolated areas.

As indicated by the age profile (refer to Figure 83 and Figure 84), in the 1970s and 1980s, concrete poles were being used for new construction and to replace wood poles. Using concrete poles has benefited reliability as concrete pole failures are rare.

There is a range of failure modes for poles and crossarms. For pre-stressed concrete poles, cracking can lead to water ingress and corrosion of the pre-stressed tendons, resulting in loss of strength and unexpected failure when the load is applied. For mass-reinforced poles, corrosion of the internal reinforcing can occur if water penetrates through cracks. Corrosion of the reinforcing can lead to spalling (loss of concrete cover), further accelerating the corrosion; however, the loss of strength is generally gradual. This deterioration typically occurs slowly and is observable through our detailed inspections.

For wood poles, pole-top rot or ground-line rot are the primary drivers of loss of strength that can lead to failure. Rotting is also the primary failure mode for wood crossarms. Pole-top rot is observable from our pole-top visual inspections; however, detection of ground-line rot requires close inspection and minor excavation. This is undertaken as a separate inspection.

Concrete poles and wooden crossarms have different MPLs. While concrete poles generally remain in serviceable condition, their associated crossarms show the presence of EOL condition drivers (e.g. rot). This mismatch led to a change in approach in 2018 when we commenced using steel crossarms instead of hardwood crossarms. While the initial cost is marginally higher for steel, it increases the overall lifespan of the structure (by aligning pole and crossarm MPLs), increases the structure's mechanical strength, and improves the overall resilience of the structure[49].

We consider the data we used for pole and crossarm replacements robust. 70% of poles and 47% of crossarms have condition data. The remainder of the assets have good age data. Pole and crossarm condition data were sourced from the overhead inspections completed in early FY22. We spent time validating the data over the past 12 months, and the results indicated the presence of some low-health crossarms. In response, we accelerated the replacement of crossarms in FY23.

In FY24, we commenced inspecting the remaining urban assets with aerial drones, and the program will finish in FY25. This work is ongoing, and the results will be incorporated into our health assessment for the 2024 AMP.

There is a large quantity of privately owned poles connected to Wāipa's network whose performance affects the networks. There is a large quantity of privately owned poles connected to our network. We will work with the owners of private lines to clarify their obligations as asset owners, and offer services for the inspection and maintenance of those assets.

11.10.2 Fleet performance

Poles are generally located where the public can access them and, therefore, need to be installed and designed correctly to ensure public safety. There are no recorded public safety events due to unassisted pole failures.

Regarding reliability, we have only three recorded pole faults over the past five years, which indicates a pole fault rate of 0.3 faults per 10,000 units per year, excluding adverse weather events (i.e. it is an unassisted fault rate). For crossarms, the unassisted fault rate is around 1.3 faults per 10,000 units per year. We look at industry data to establish suitable maximum thresholds for unassisted pole and crossarm fault rates. From our data, the performance of poles and crossarms is good.

[49] *Refer WNL's Asset Management strategy Initiative #3*

11.10.3 Fleet risks

Table 57 highlights the predominant risks posed to the pole fleet, its impact, and our response. The responses to the risk also feature in our fleet strategy.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Third-party interference (Car vs Pole) damages overhead lines, causing outages and potential contact with live wires.	Car vs pole outages accounted for an average of 25% of unplanned SAIDI over the past five years—injury to members of the public.	• Public safety • Network performance	Our fleet strategy includes a mitigation plan.
Adverse environments, such as peat, swamps, or waterway eroding foundations, causing poles to lean or fall	Poles are leaning, causing clearance issues.	• Public safety, as clearances of lines can reduce to unsafe levels	When an issue is identified, remediation is actioned through our defects process, which may include groundline reinforcement or pole relocation
Major weather events, e.g. cyclones) can result in wind speeds above older (pre-2000) design limits, causing damage or failure of the pole or crossarm. **The fleet performed well over the 2022 cyclone Dovi and 2023 cyclone Gabrielle events, with minimal unassisted failures.**	Adverse weather outages accounted for 48% of unplanned SAIDI for FY22 and 58% for FY23.[50]	• Network performance.	New structures are designed to current standards that can withstand higher wind loadings. Use material such as steel crossarms to increase mechanical ratings. Appropriate stock holdings that can support asset replacements during major weather events
Damage from vegetation	Vegetation outages contributed between 11% and 14% to unplanned SAIDI for FY22 and FY23.	• Network performance	A vegetation management strategy has been developed (refer to Section 11.19)
Undetected rotting of larch poles causing pole failures. Industry experience suggests that Larch poles tend to rot from the inside with little visual indications of weakening. The rot could result in unassisted pole failures.	This is a known asset-type issue that requires further investigation.	• Public safety, due to unassisted pole failures • Network performance	We consider this risk to be low as we have no reported issues. However, we are undertaking a wood pole groundline survey in FY25 (included in our fleet strategy)
The strength of some early mass-reinforced poles may be below their current mechanical loading.	The scope of the issue has yet to be determined; however, current information on failures does not indicate any recent issues.	• Public safety, due to unassisted pole failures • Network performance	This issue will be further invested, including testing to confirm the strength of older mass-reinforced poles as a first step. (or draw from peer EDBs testing results)
Unknown condition of private poles that could result in unassisted failures	Customers may be unaware of their responsibilities or the condition of their poles.	• Public safety, due to unassisted pole failures	This is an emerging risk, and we are developing a response strategy.
Asset component failure on poles carrying multi-circuit line sections could cause outages on multiple feeders.	Loss of supply to many customers with a longer time to restore	• Network performance	Acoustic survey for multi-circuit line sections to detect developing issues. Progressively remove multi-circuit setup from the network where the opportunity arises under Resilience, Growth or Renewal programmes.

Table 57: Fleet risks

[50] *Waipā has historically included vegetation outages as part of adverse weather during major events. The SAIDI data excludes normalisation for major events.*

11.10.4 Fleet strategy

The key objectives for this fleet are to manage the growing presence of end of life condition drivers and to improve resilience as assets are replaced incrementally.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the 10-year strategy for this fleet is shown in Table 58.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in Section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation • Understand and reduce fleet risk	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Eliminate all H1 poles and crossarms	• Ensure all H1 poles and crossarms (which include red-tagged poles[51]) are replaced before failure • Ensure all H2 poles and crossarms are replaced before they become H1	• Zero H1 poles and crossarms by the end of FY26
Eliminate all low-strength wood poles	• Replace all low-strength wood poles (following the below-ground inspection) within 4-years	• Zero low-strength wood poles by the end of FY28
Improve the reliability of the worst-performing feeders	• The initial focus of the pole and crossarm renewal is on the worst-performing feeders	• Improve the reliability of the worst-performing feeders
Vegetation strategy	• Refer to Section 11.19	• Reduction in vegetation-related outages
Minimise private pole safety risks	• Consult with the industry (as this is a common issue) and leverage learnings from others. • Develop a plan and process for the management of private poles (and capture additional data if needed).	• Minimise public safety risks SFARP
Reduce the incidents of car vs poles	• Develop a plan to mitigate car vs pole incidents. This will include the analysis of car vs pole data and developing solutions such as undergrounding, relocation or installing barriers	• Minimise the impact of third-party incidences on the network performance
Enhance fleet resilience (refer to Section 9.4)	• Replace H2 wood crossarms with steel on critical feeders • Proactively replace H2 wood poles in critical feeders • Proactively identify and replace mass-reinforced poles under heavy loading (e.g., stayed, angle pole) in critical feeder sections • Ensure all pole renewals are designed to NZS7000 • Ensure all foundations are assessed for pole renewals • Investigate raising the wind-speed design limits (to future-proof current design) • Following the recent cyclones, the stock levels are being reviewed	• Increase the mechanical strength of the structure • Potential increase in stock levels

Table 58: Fleet strategy

[51] *Red tag poles are defined as poles which are unsafe to climb and cannot support the mechanical weight they are supporting. Recommended replacement time is within three months.*

11.10.5 Design and construct

Wāipa designs new and replaced poles to the AS/NZS 7000 standard, which specifies the clearance requirements, seismic, wind and snow design parameters, and safety factors applicable to overhead line design. The standard defines a "security level" that sets design parameters for the safety and utility requirements of the line. We apply the highest "level 3" requirement for all main lines and "level 2" for remote spur lines. This approach ensures the highest level of utility is applied to the core network and that remote areas, where few customers are connected, have a fit-for-purpose design.

Our current standard is to use prestressed concrete poles. These have higher mechanical strength and a higher OOU than other mass-reinforced concrete poles.

We have developed standard construction drawings and bill of materials for most typical pole and line configurations. These drawings were prepared with representatives from across the organisation to ensure they work in design, regulation, and practicality.

11.10.6 Monitoring

Capturing condition data for overhead assets (poles, crossarms, conductor[52] and pole-mounted fuses, switches, links and ABSs) generally occurs as part of a single inspection. The exceptions are voltage regulators, reclosers and enclosed switches, which have a separate inspection routine (refer to the recloser fleet plan for details).

We undertook a baseline aerial inspection of the rural network in FY22, which was extended to the urban overhead network in FY24 and FY25.

Monitoring Type	Description	Frequency
Detailed line inspection	• Our baseline inspection have been aerial using helicopters in rural areas and drones in urban areas. The future detailed inspections are likely to be ground-based and will utilise the new inspection standard and will capture asset attribute data as required • The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the pole, crossarms, insulators, stays, jumpers, binders, terminations, other accessories attached to the poles, and foreign interference • Defect notices are raised where priority repair or replacement is required	5 Yearly
Acoustic survey for multi-circuit line sections	• Carry out acoustic surveys for multi-circuit line sections to detect emerging failures early	2 Yearly
Below-ground inspection	• We plan to undertake a below-ground inspection to capture additional condition data for wood poles. The additional EOL condition drivers will include the extent of rot and decay (and the diameter lost) • An assessment will then be made of the residual pole strength and health • Defect notices are raised where priority repair or replacement is required	One-off in FY25-26
Line patrol	• A drive-by patrol of the line and visual inspection at sites of concern. • Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required	As required in response to fault issues or reliability trends

Table 59: Describes our current fleet monitoring approach

[52] *Near to the pole only.*

11.10.7 Maintaining

There are three maintenance activities that we undertake to ensure that poles are fit for purpose and can maximise their economic life; these are:

Monitoring Type	Description	Frequency
Concrete repair	• Patching concrete that has been hit/damaged or where corrosion has exposed reinforcing steel	Defect notification
Relocation or realignment	• Relocating or realigning poles that are on a lean due to ground conditions (peat soil or soil erosion near waterways), high winds, broken stays, etc.	Defect notification
Subcomponent replacement	• Replacement of components (insulators, binders, jumpers, stays, etc.) • Identification of one component defect will typically result in all subcomponents being replaced to avoid further subcomponent defects being identified (as they will be typically of the same age)	Defect notification

Table 60: Fleet maintenance

Note: *Wāipa considers the replacement of crossarms to be a capital expenditure, and this work is included in the renewal section below.*

11.10.8 Renewal

Our fleet renewal approach is shown in Table 61. Considerations for future proofing are done when we have confirmed the renewal needs at the works optimisation stage (which includes investments triggered by different drivers).

Decision	Description
Renewal forecasting	• The forecast of asset renewals is as described in the fleet strategy
Determining specific renewal projects	• Specific renewal projects are identified from the health assessment and are grouped by location and feeder • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by criticality, worst-performing feeder, and reliability trends. The highest priority will be replacing poles with compromised strength in critical locations that could present a public safety risk
Assessing alternatives	Alternatives to like-for-like replacements are considered on a case-by-case basis and include: • **Undergrounding:** This is considered if a line is in a high-density area or clearances cannot be maintained based on the contour of the land • **Relocating:** If historical data on car vs. pole incidents indicate the pole is in a high-risk area, we will consider relocation or undergrounding to reduce or remove the risk • **Design:** We will determine whether a like-for-like replacement is appropriate for the current situation and ensure that current design standards are met • **Opex/capex trade-off:** Due to the high site establishment cost associated with line work, we tend to proceed with asset replacements rather than repairs (except as mentioned in the maintenance section) A cost/benefit analysis will be completed as part of the assessment.
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset • Where possible, defects are combined into a single work-pack to maximise the work undertaken in a single network outage

Table 61: Fleet renewal forecasting

Material spares

Poles and crossarms are common assets that are exposed to adverse weather events. We hold sufficient stock to cover any reasonable situation which may arise. We increase our stock holding when supplier delivery is constrained and lead times are extended.

11.10.9 Population and age – poles

The population and age of our pole fleet assets are shown in Figure 83 and Figure 84. These graphs indicate that:

- For concrete poles, 10% of mass-reinforced poles are above OOU.[53] This is an age where signs of deterioration and the associated risks are growing. No concrete poles have reached MPL.
- For wood poles, 80% of hardwood and 99% of softwood poles are at or above OOU.[54] The number of hardwood poles beyond OOU reflects the age profile of that fleet, whereas, for softwood poles, it reflects a low EEA guideline OOU of 15 years. Our condition data suggests that the softwood pole OOU may be too low for our fleet, as we are only seeing condition issues emerge at around 25 years (albeit the current sample size is small, and we are yet to complete the below-ground survey). However, only 1% of softwood poles have reached MPL.
- We assessed a Waipā specific MPL for hardwood poles at 70 years based on our survival statistics.[55]

The data suggests that, based on age, EOL condition drivers are emerging for the mass-reinforced concrete and wood fleets. This is generally consistent with the recent condition survey.

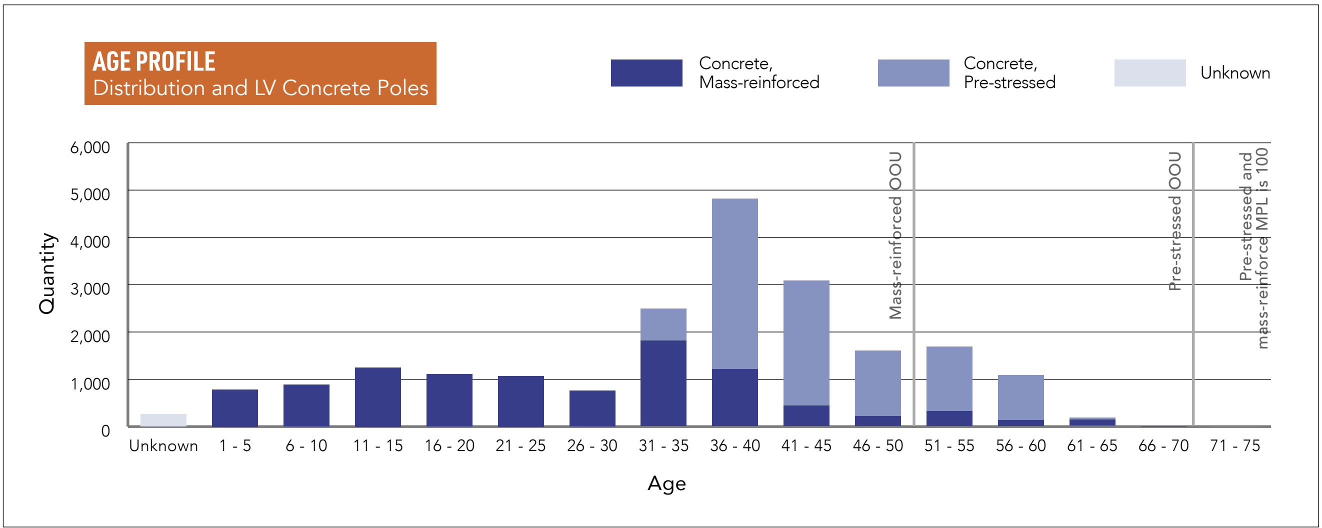


Figure 83: Age profile – concrete poles

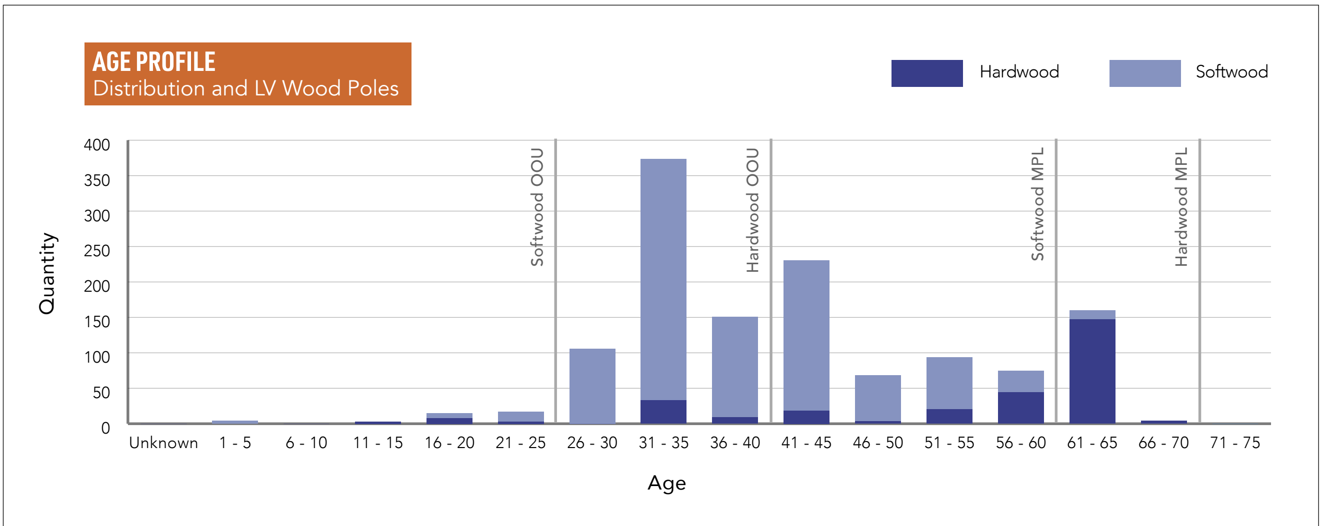


Figure 84: Age profile – wooden poles

[53] *Mass-reinforced concrete poles have an OOU of 55 years and pre-stressed have an OOU of 70 years. MPL for all concrete poles is 100 years.*

[54] *Softwood and hardwood poles have an OOU of 15 and 40 years respectively, based on the EEA guide.*

[55] *MPL is defined as the age at which 95% of the poles could be expected to have been replaced. We increased the MPL of hardwood poles from 60 to 70 years based on survival statistics. This was based on disclosure data, which showed that 94% of 1950s poles (average age 68 years) have survived since 2013, and 79% of 1960s poles (average age 64 years) have survived since 2013. Whilst we don't have data prior to 2013, our understanding is that there has not been any extensive renewal programme prior to 2013; hence, the current data suggests that well more than 5% of the assesses are surviving beyond the 60-year MPL defined in the EEA standards. Management's view is that an MPL of 70 is reasonable for our fleet. This equates to assets being generally replaced between 60 and 70 years*

11.10.10 Asset health assessment – poles

The health assessment for poles is shown in Figure 85 and Figure 86, and is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.

The data used for pole health forecasting is robust, with 70% of poles being condition-based. The remainder of the assets have good age data.

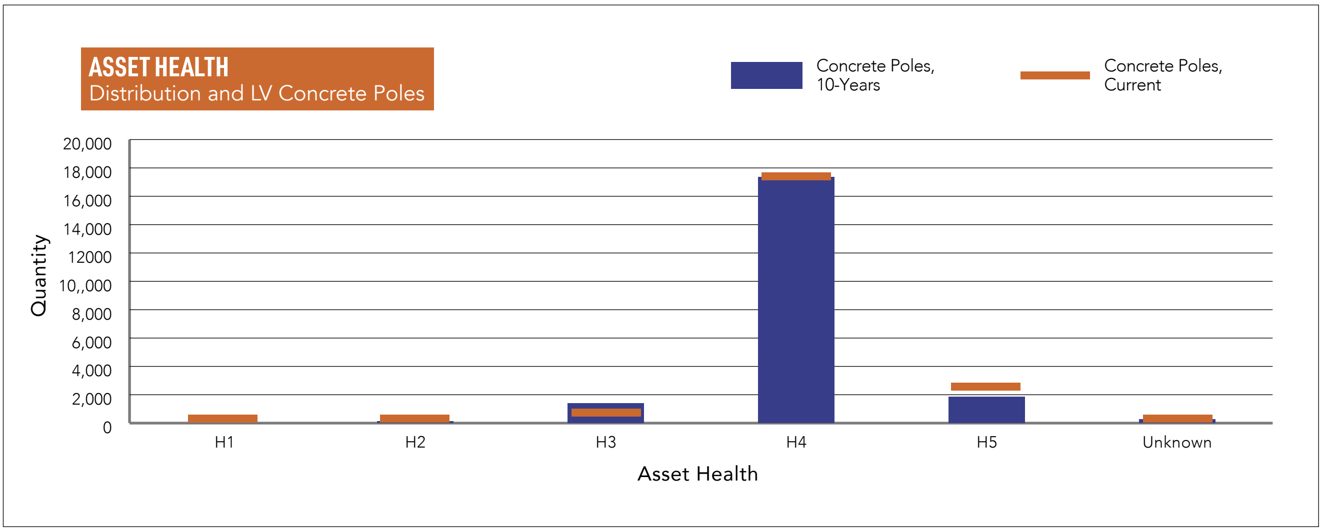


Figure 85: AHI concrete poles

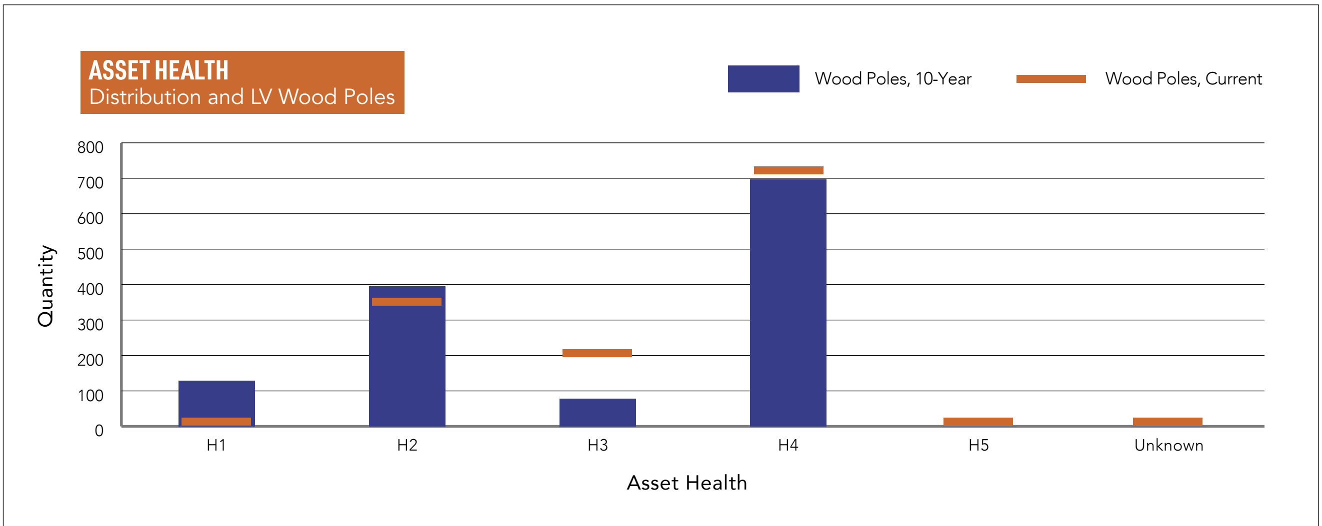


Figure 86: AHI wood poles

Table 62 shows the current and forecast quantities for low-health poles over the next ten years. There is a significant population of wood poles (mostly softwood) that meet the criteria for renewals and a small number of mass-reinforced concrete poles. Most low-health wood poles are forecast based on age, which suggests there could be some movement in this forecast when the data from the urban pole-top survey and ground-line inspection are included in FY25.

All low-health concrete poles are condition-based, which gives us confidence in the forecasts. Most of these are mass-reinforced concrete poles. Due to the slow deterioration rate for concrete poles, there is no increase in the number of low-health poles over the forecast period (but there is a significant increase in H3 poles).

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
Concrete Poles	20,999	135	135	0.6%
Wood Poles	1,300	360	525	40%
Total	22,299	495	660	3.0%

Table 62: Current and forecast asset health

The forecast quantity for low-health concrete poles is higher, and the wood poles are lower than in the 2023 AMP forecast. The change in forecast reflects the use of condition data (after its review) and the improvements in health forecasting methodology.

11.10.11 Population and age – crossarms

The population and age of our crossarm fleet assets are shown in Figure 87. Most of the age data is derived from the pole, with only around 5% relating to the crossarm. The graph indicates that around 37% of hardwood crossarms are above OOU but only around 1.5% above MPL. The data suggests that, based on age, EOL condition drivers are emerging, which is consistent with the recent condition survey.

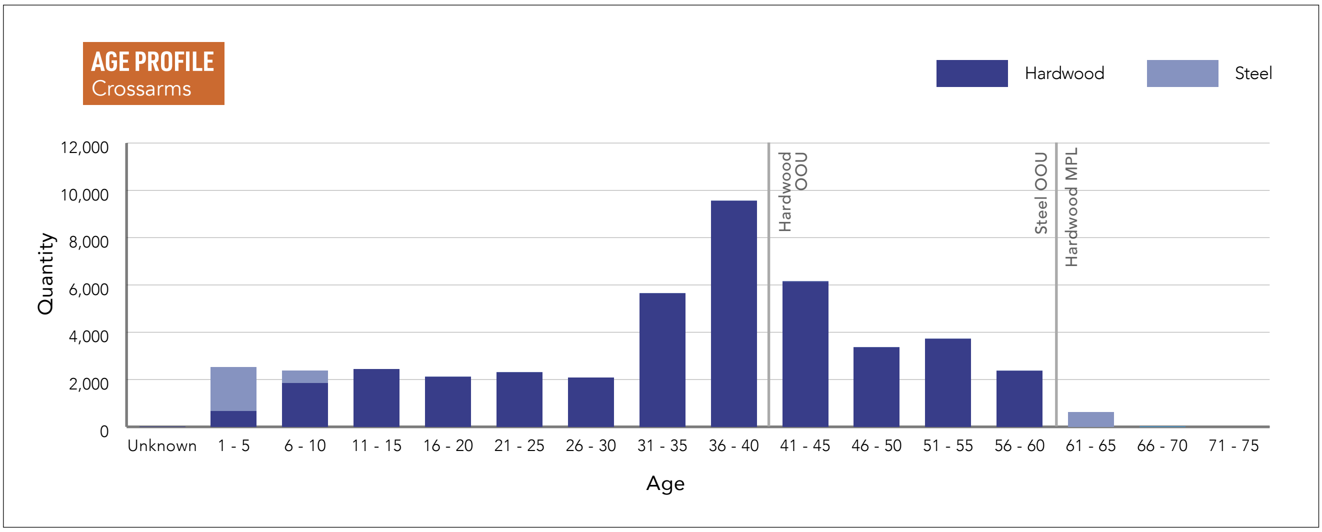


Figure 87: Age profile – crossarms

11.10.12 Asset health assessment – crossarms

The health assessment for crossarms shown in Figure 88 is based on the EEA asset health guide, including the health forecasting mentioned in Section 10.5.3.

The data used for pole health forecasting is robust, with 47% of crossarm being condition-based. The remainder of the assets are age-based, using primarily pole age.

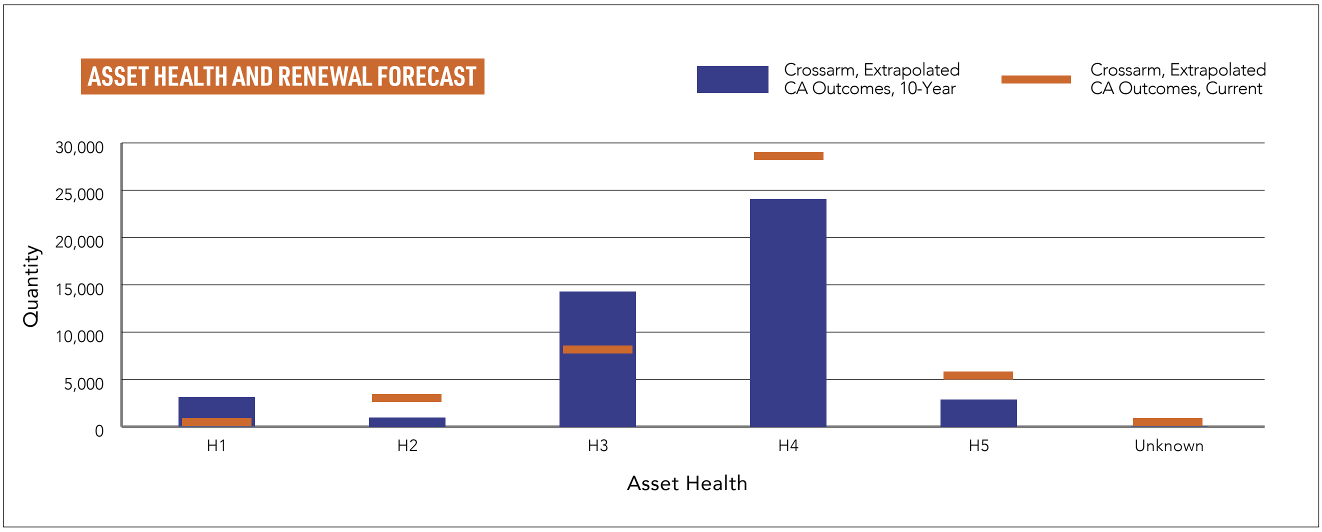


Figure 88: AHI – crossarms

Table 63 shows the current and forecast quantities for low-health crossarms over the next ten years. Around 9% of the fleet (all hardwood) meets the criteria for renewal. Concerning low health crossarms, 47% are assessed based on condition. For the remainder, we have applied the observed deterioration rate (i.e., rotting rate) to the age data; we expect the same rotting level in the observed and non-observed fleet.

Whilst the headline H1 & H2 assets increase by 1,000 over the next ten years, the population of H1 crossarms increases materially (to over 3,100)—further reinforcing emerging EOL issues.

The forecast quantities for low-health crossarms are lower than were forecast in the 2023 AMP. The change in forecast reflects the use of condition data (after its review) and the improvements in health forecasting methodology.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
Crossarm	45,348	3,007	4,091	9%

Table 63: Current and forecast asset health

11.10.13 Replacement programme

Consistent with our renewal strategy, we are forecasting the replacement of all H1 and H2 poles over the next ten years (as shown in Table 64). The annual renewal rate is sufficient to replace all H1 poles by FY26 and to keep pace with the health deterioration, so new H1 poles should be minimal.

Crossarm renewals have been set at 120% of the forecast low-health assets. A consistent replacement rate has been applied over the 10-year forecast period. The renewal rate is slightly behind the forecast H1+H2 assets for the first five years and slightly ahead for the second five years. The higher renewal rate accounts for the uncertainty in the data, which will be refined as new condition data is collected.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
Concrete Poles	135	135
Wood Poles	525	525
Crossarms	4,091	4,909

Table 64: Asset renewal forecast

In FY23 and FY24, crossarm replacements were targeted on the worst-performing feeders (e.g. Kawhia, Pukeatua, Kiokio and Paterangi). This has addressed most of the urgent defect and condition issues. There are a few locations on the worst-performing feeders to address in FY25. We expect the urban pole-top inspection results to shape the health assessments in the 2025 AMP and the renewal projects in the latter part of FY25 and FY26.

Wood pole replacements are concentrated on critical feeders (in response to the resilience strategy) and the LV network (where the population of low-health poles is the highest).

Concrete pole replacements, mainly for mass-reinforced poles, will be concentrated on critical feeders (in response to the resilience strategy) at locations closer to the substation and/or with high loading.

In future reviews of the fleet plan, the targeting of the replacements may change following the completion of the urban aerial inspection and the ground-line inspection of wood poles.

11.10.14 Expenditure forecast

Table 65 shows the forecast expenditure for this fleet. The forecast expenditure is $7.9m (150%) higher than we forecasted in the 2023 AMP for the FY25 to FY29 period. This is due to the higher forecast renewals in this plan.

The renewal provision for "other drivers" accounts for storm and vehicle damage.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
Concrete pole renewal	Planned	ARR	-	-	540	540	540	-
Wood Pole renewal	Planned	ARR	1,116	1,116	1,116	1,116	1,104	720
Crossarm renewal	Planned	ARR	1,288	1,288	1,288	1,288	1,288	6,440
Pole replacement, other drivers	Unplanned	ARR	147	147	147	147	147	735
Crossarm replacement, other drivers	Unplanned	ARR	50	50	50	50	50	250
Total	-	-	**2,601**	**2,601**	**3,141**	**3,141**	**3,129**	**8,145**

Table 65: Forecast Expenditure

FY24 Real $000

11.11 Distribution and LV overhead conductor fleet plan

11.11.1 Fleet overview

This fleet plan excludes the 110kV subtransmission and street-lighting conductor.

Overhead lines comprise 89% of Wāipa's distribution circuit length and 57% of LV circuit length. Overhead lines include pole structures (covered in the previous fleet plan) and conductors (covered in this fleet plan).

This fleet plan includes 11kV and LV conductors, as shown in Table 66.

Asset Type	Quantity
11kV conductor	1,245 km
LV conductor	500 km

Table 66: Conductor fleet circuit length

Conductors need to have good conductivity (to minimise losses and voltage drop on long feeders), good strength (to optimise span lengths and withstand wind and mechanical loads), minimal weight (to optimise the strength of the poles needed), and resistance to wear (to minimise the risk of failure from movements due to wind forces over many years). There are around 22 different conductor specifications on the network. Each conductor type has its unique properties and differences in OOU and MPL. Table 67 summarises the 22 different conductor specifications on the network into broad categories

Asset Type	Approximate % of the fleet	Attributes
All Aluminium Conductor (AAC)	1%	AAC uses high-purity aluminium, giving it good conductivity, minimal weight, and low strength. This limits the span lengths.
Aluminium Conductor Steel Reinforced (ASCR)	11%	ACSR has an inner core of solid or stranded steel and one or more outer layers of aluminium strands. This gives it high strength at a modest weight. ASCR is commonly used in rural areas where long spans make construction efficient. The steel core can be either greased or non-greased. The greased steel cores increase the OOU and MPL of the conductor.
All Aluminium Alloy Conductor (AAAC)	1%	AAAC uses aluminium alloy, which gives it greater tensile strength than AAC and is significantly lighter than ACSR. AAAC also has good conducting properties. This type of conductor is now commonly used.
Copper	53%	Hardened copper was used early in the development of distribution networks. It is highly conductive with good strength and weight but is expensive.
Steel	<1%	Steel is very strong and was used for long spans on remote spur lines. Only small steel conductors (often No.8 wire) were used, so they were light but had poor conductivity. Steel is no longer used. The team will validate this data.
AAC Covered	<1%	In many LV applications, the conductor is covered in PVC to provide a layer of insulation. AAC was typically used as span lengths are shorter in LV applications because of its good conductivity. The team will validate this data – whether any are used for HV application.
Unknown	34%	We have significant conductors of unknown type. It is challenging to determine conductor types from ground-based visual inspections. We suspect the unknown type was introduced during the NCS to GIS migration. We will go through a discovery and recovery process in FY25.

Table 67: Conductor type

There are a range of failure modes for conductors. These can be incremental, where the health decays over time, or more acute, where failure is caused by foreign interference (e.g. vegetation). The incremental failure includes a reduction in strength from the effect of movement and wear, a reduction in strength due to heat-cycling, weakening due to corrosion, and the failure of bindings, terminations and joints (due to any of the reasons mentioned above). The location and environment can significantly impact the rate of deterioration.

Capturing condition inputs is complex and requires close proximity inspection or the analysis of samples; hence, our health forecasting is age-based for this fleet. Specific renewal projects are driven by failure and reliability data and detailed inspections, which give the best indication of asset health (in the absence of sampling). The challenge is reacting quickly to reliability trends to avoid impacting customers.

11.11.2 Fleet performance

Overhead lines are generally located where the public can access them; therefore, conductor failures can have public safety implications. There are no recorded public safety events due to conductor failures.

We do not have detailed failure data on conductors (and they are currently grouped with cable). However, we have identified some specific areas (Pukeatua, Ohaupo and Cambridge East) that require further investigation to determine the cause of recent conductor or cable faults. These investigations may drive specific renewal projects. Other than the identified areas, we do not have any concerns with the fleet performance.

Recent changes to the fault recording system will provide additional data to enable fault trends to be analysed going forward.

11.11.3 Fleet risks

Table 68 highlights the predominant risks posed to the conductor fleet, its impact, and our response. The responses to the risk also feature in our fleet strategy or other strategies and programmes in this AMP

.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Damage from vegetation	Vegetation outages contributed between 11% and 14% to unplanned SAIDI for FY22 and FY23.	Network performance	A vegetation management strategy has been developed (refer to Section 11.19)
Conductor failure leads to electrocution risk for people and livestock, either directly from the conductor or indirectly through the livening of fences or structures.	Electrocution or electric shock Loss of livestock Network outages	Public safety Network performance	Electrical protection at zone substations, reclosers, spur line fuses, and LV fuses (in the case of LV conductor) operating to isolate the line when faults occur. Prompt response to reliability trends, fault trends and defects to replace poor health conductors
Conductor failures lead to fires that impact forestry plantations, crops, and buildings.	Loss of property	Network performance	As above Fire mitigation policy also prohibits auto reclosing when a "high fire risk" is declared.
Vehicles or machinery contacting live conductors risk electrocution and equipment damage.	Electrocution or electric shock Damage to equipment Network outages	Public safety Network performance	Electrical protection, as mentioned above We have a public safety campaign to raise awareness of risks around live lines. Identifying low and high-risk conductors during detailed inspections and raising or undergrounding the line Using a permit procedure for working near live lines
Members of the public working near live conductors risking electrocution	Electrocution or electric shock Network outages	Public safety Network performance	We have a public safety campaign to raise awareness of risks around live lines. Using a permit procedure for working near live lines
Third-party interference (Car vs Pole) damages overhead lines, causing outages and potential contact with live wires.	Third-party interference (Car vs Pole) damages overhead lines, causing outages and potential contact with live wires. Car vs pole outages accounted for an average of 25% of unplanned SAIDI over the past five years and trended toward 45% for FY25 at the time of preparing this AMP. Injury to members of the public	Public safety Network performance	Our fleet strategy includes a mitigation plan

Table 68: Fleet risks

11.11.4 Fleet strategy

The key objective for this fleet is to convey electricity to consumers reliably and efficiently while managing public safety risks through prompt identification and remediation of low-health assets.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year strategy for this fleet is shown in Table 69.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in Section 11)	• Enhance inspection standards and apply them to our current network surveys to provide baseline asset condition data (Note: this is a key strategy for this fleet to improve our health forecasting) • Enhance asset health assessment and forecasting (Note: this is a key strategy for this fleet as we are relying on improvement fault and reliability analysis to identify low health assets and drive the renewal projects) • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation • Understand and reduce fleet risk	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Assess new condition assessment techniques.	• We will monitor industry development concerning conductor condition assessments. These will be adopted where practical to do so	• Improved condition assessment, more accurate health forecasting, and more proactive health-based renewals
Undertake conductor inspections and risk mitigations in areas with high risk of failure.	• Undertake a study to identify areas where conductor failures are at higher risk. This will include assessing reliability trends, fault trends, and environmental factors (high crosswind and coastal conditions) • Undertake detailed inspections of conductor joints, jumpers and terminations to assess EOL drivers and the health of the conductors • Consider renewal or remediation options (e.g. rebinding, vibration dampeners, etc) to reduce risk	• Replacement of low-health and high-risk conductors
Vegetation strategy	• Refer to Section 11.21.5	• Reduction in vegetation-related outages
Maintain conductor clearances and remove high-risk road crossings	• We have a specific program to maintain line clearances and remove high-risk road crossings. Refer to Section 9.7.4	• Reduce vehicle and machinery damage to conductors • Minimise public safety risks SFARP
Public safety campaign to raise awareness of risks around live lines	• Annual social media campaign as part of our Public Safety Management System and its KPI	• Minimise public safety risks SFARP
Reduce impact on network performance of car vs pole incidents	• Develop a mitigation plan following the analysis. Refer to the Distribution Structures Fleet Plan	• Minimise the impact of third-party incidences on the network performance.

Table 69: Fleet strategy

11.11.5 Design and construct

Conductor selection and design are integrated into the line design process, which complies with the AS/NZS 7000 standard. The standard specifies the clearance requirements, seismic, wind and snow design parameters, and safety factors applicable to overhead line design.

As a general guide, our standard conductor specifications are:

- Primarily AAAC conductor – some AAC used on LV;
- ACSR where required for long spans in rural areas (typically based on mechanical loading);

Special consideration is given to unique circumstances, for example, the use of covered conductors in locations susceptible to windborne debris.

11.11.6 Monitoring

We undertook a baseline aerial inspection of the rural network in FY22, which was extended to the urban overhead network in FY24 and FY25. These inspections identified issues concerning conductor bindings, terminations, jumpers and any near-pole conductor issues. Defect notices were raised when repairs were necessary. The data was not in a format to derive any EOL condition drivers for the conductor. The inspection standard is being revised next year, which may provide condition data that will be used to direct more detailed conductor inspections.

Table 70 describes our current fleet monitoring approach:

Monitoring type	Description	Frequency
Detailed line inspection	• This inspection provides some data on conductor binders and terminations, but its holistic nature may not reveal the specific condition. Refer to the Distribution Structures Fleet Plan for further details	5 Yearly
Detailed conductor inspection	• This detailed inspection focuses on joints, binders, terminations, and near-pole conductors. This inspection will assess EOL drivers concerning wear damage, evidence of internal corrosion in ACSR (birdnesting), wear damage on binders and broken conductor strands. • Conductor samples may be taken if needed • Defect notices are raised where priority repair or replacement is required	As required by the conductor risk assessment
Line patrol	• A drive-by patrol of the line and visual inspection at sites of concern. • Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required	As required in response to fault issues, reliability trends or criticality.

Table 70: Fleet monitoring

11.11.7 Maintaining

There are no specific maintenance servicing routines for conductors. We may undertake reactive binder and joint replacements when this is identified from inspections.

11.11.8 Renewal

Our fleet renewal approach is shown in Table 71.

Monitoring type	Description
Renewal forecasting	• The forecast of asset renewals is to replace all current and forecast H1 and H2 assets over the next ten years
Determining specific renewal projects	• Renewal projects are determined from reliability trends, fault trends and environmental assessments. These assessments direct more detailed inspections that define the specific renewal projects • The assessments are prioritised by criticality and worst-performing feeder
Assessing alternatives	• Alternatives to like-for-like replacements are considered on a case-by-case basis and include: • Undergrounding: This is considered if a line is in a high-density area or clearances cannot be maintained based on the contour of the land • Design: We will determine whether a like-for-like replacement is appropriate for the current situation, ensure that current design standards are met, and assess concurrent conductor capacity upgrade opportunities. • A cost/benefit analysis will be completed as part of the assessment.
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset • Where possible, defects are combined into a single work-pack to maximise the work undertaken in a single network outage

Table 71: Fleet renewal forecasting

Material spares

A conductor is a common asset that is exposed to adverse weather events. We hold sufficient stock to cover reasonable situations, i.e., a range of conductor sizes to cover fault repairs, and we have supply arrangements for replenishment of spare stock and new developments.

11.11.9 Population and age

The population and age of our pole fleet assets are shown in Figure 89. The age data has been derived from a mix of conductor manufacture date, installation date, and the age of poles on the relevant line segment. The data between years 1 to 30 is not considered reliable as most of the conductors in this age range have a default age of 2019. The combined default and unknown age assets are 49% of the fleet.

Assessing and improving conductor age data is an important improvement project that will commence in FY25.

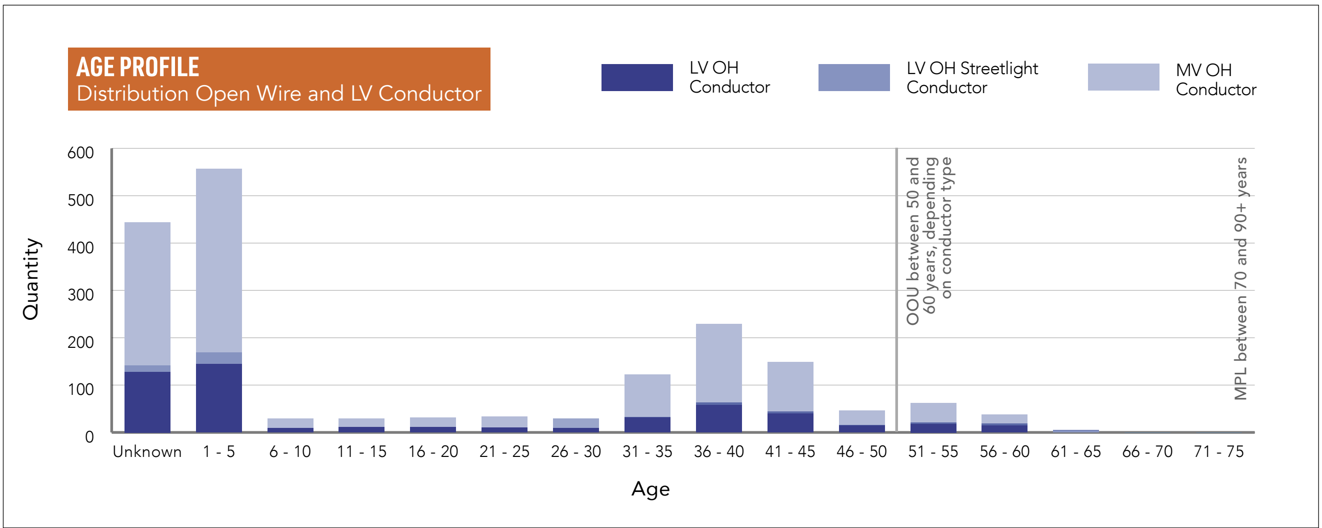


Figure 89: Age profile (km)

11.11.10 Asset health assessment

The health assessment for 11kV and LV conductors is shown in Figure 90 and Figure 91. The assessment is age-based using the EEA asset health guide, including the health forecasting discussed in Section 11.5. As noted above, the age data is unreliable, particularly for assets likely to be in the H3 to H5 health grades. The health forecasting for grades H1 and H2 is indicative only. Our health forecasting will improve following the data improvements.

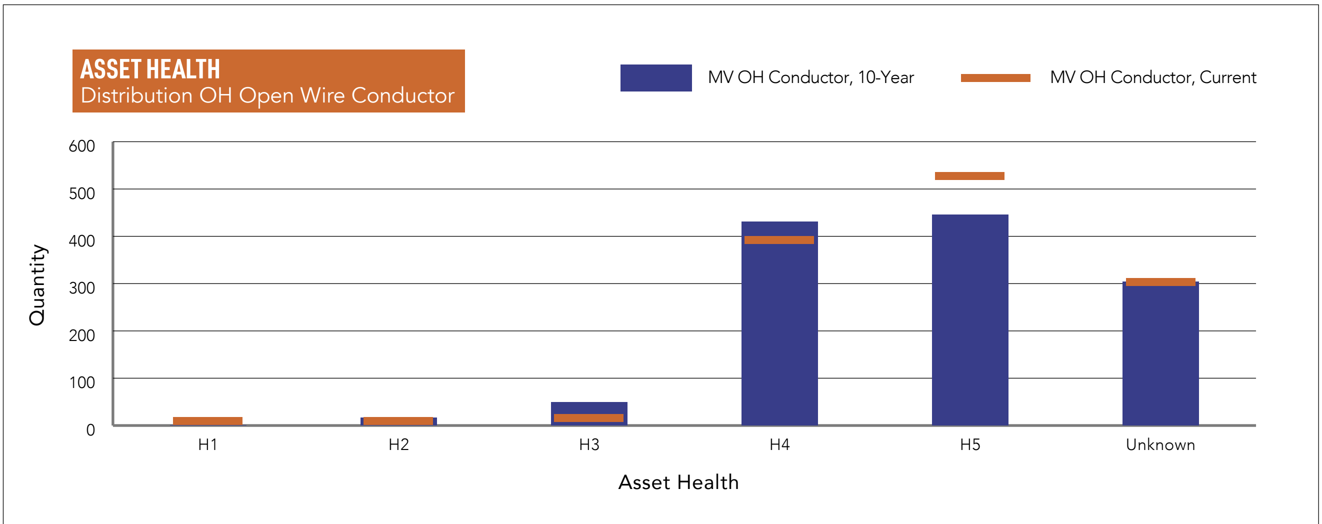


Figure 90: AHI, 11kV conductor (km)

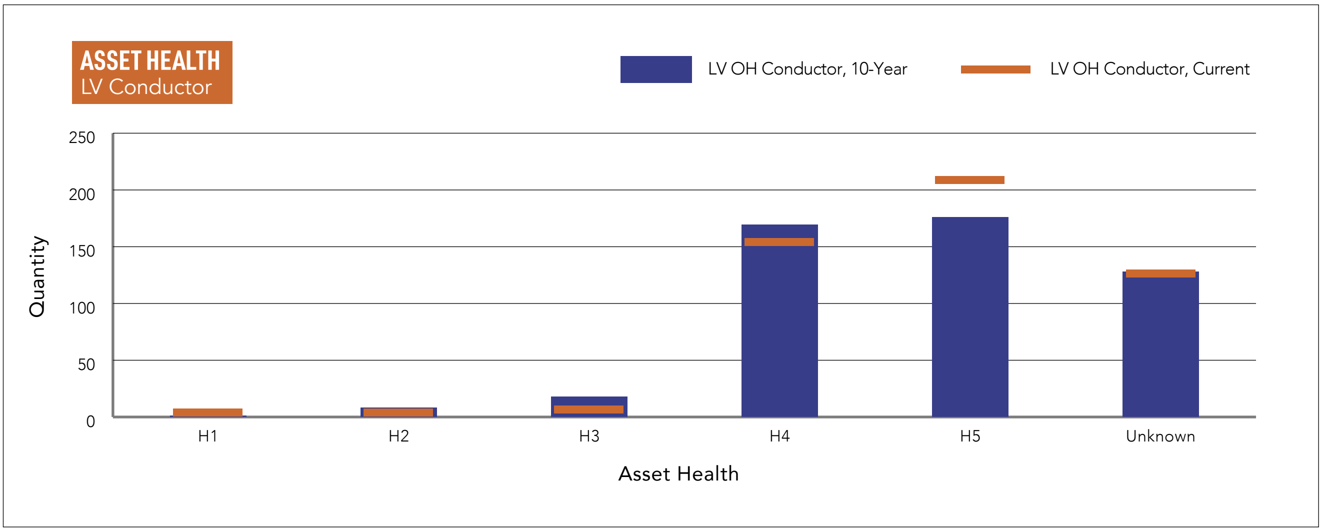


Figure 91: AHI, LV conductor (km)

Table 72 shows our current estimates of assets that will reach health grade H1 and H2 over the next ten years.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
11kV conductor	1,245	0.3	17.2	1.4%
LV conductor	500	1.1	9.1	1.8%

Table 72: Current and forecast asset health (circuit km)

Note: *Quantities are in km of circuit length.*

11.11.11 Replacement programme

We have estimated the quantity of assets for renewal over the next ten years (as shown in Table 73). The forecast conductor replacements are below the estimated H1 and H2 assets as we do not have any specific projects defined for the next 18 months and have removed renewal estimates for that period. The replacement conductor type and size choice will consider other drivers, such as future capacity requirements/network configuration.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
11kV conductor	17.2	16.7
LV conductor	9.1	8.5

Table 73: Asset renewal forecast

Note: *Quantities are in km.*

11.11.12 Expenditure forecast

Table 74 shows the forecast expenditure for this fleet. The renewal provision for "other drivers" accounts for storm and vehicle damage.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
11kV conductor replacement	Planned	ARR	-	150	300	300	405	1,350
LV conductor replacement	Planned	ARR	-	30	60	60	60	300
Conductor replacement, other drivers	Unplanned	ARR	17	17	17	17	17	86
Total	**-**	**ARR**	**17**	**197**	**377**	**377**	**482**	**1,736**

Table 74: Forecast Capital Expenditure

FY24 Real $000

11.12 Distribution pole-mounted transformers

11.12.1 Fleet overview

The purpose of distribution transformers is to convert the electricity supply from the distribution voltage (11kV) to low voltage (400V/230V) suitable for supply to residential, commercial and rural customers. A secondary purpose is isolating the low voltage network from the common mode voltage changes that can occur during distribution network faults.

Pole-mounted distribution transformers have a capacity of up to 100kVA and are in rural and semi-rural areas. If the transformer fails, it generally impacts a few customers and can be replaced quickly. We hold spare transformers in stock in the event of failure.

Table 75 summarises the population of pole-mounted distribution transformers by kVA rating. Approximately 91% are 50kVA or smaller.

Capacity	Quantity	% of total	Typical usage
≤ 15kVA	484	17%	Supplying 1-2 rural customers
> 15 and ≤ 30kVA	872	31%	Supplying 2-3 rural customers or a small farm
>30 and ≤ 50kVA	1165	43%	Supplying 3-5 rural customers or a small farm
>50 and ≤ 100kVA	252	9%	Supplying a small cluster of rural customers, a large farm, or an urban area
>100kVA	4	0.1%	Supply urban areas
Total	**2,777**	**100%**	

Table 75: Pole-mounted distribution transformer population by kVA rating

We have good-quality data on the age and attributes of this fleet. 100% of the assets have a date of manufacture, and only a handful of assets have missing transformer manufacturers. Asset condition data was captured in 2021 for 83% of the fleet and was used in our health assessment.

11.12.2 Fleet performance

We have very few failures on this fleet (outside of adverse weather events), averaging two faults per year since FY19, equating to an unassisted failure rate of 5.4 faults/10k units. There are presently no concerns with the fleet's performance.

11.12.3 Fleet risks

Table 76 highlights the material risks associated with the pole-mounted transformer fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Damage or failure of the structure that supports the transformer	Damage or failure of the structure could result in an outage and injury to members of the public	Public safety Network performance	Refer to the Distribution Structures (Poles and Structures) fleet plan
Wide-spread damage to transformers during lightning events	Lightening surges can damage multiple transformers, resulting in an outage for many customers	Network performance	Waipā region does not presently encounter significant lightning events. Lightning arrestors were not currently fitted to existing pole-mounted transformers but are now pre-fitted with new ones from FY24.
Damage to transformers during major weather events	Adverse weather outages accounted for 48% of the overall SAIDI for FY22 and 58% for FY23[56].	Network performance	Appropriate stock holdings that can support asset replacements during major weather events
Oil leaks that could cause environmental damage	Environmental damage	Environmental damage	The assets are inspected five yearly, and assets with oil leaks are replaced. We have oil spill kits, and our field crews are trained to handle oil spills should a leak occur.
The earthing system is damaged, compromising electrical protection and risking fatal voltages.	Proper earthing is critical to the multiple-earthed neutral (MEN) system in New Zealand.	Public safety Regulatory breach	The earth is inspected and tested every five years.
Transformer phase overloading due to load imbalance (caused by load changes post-installation)	Damage to the transformer and loss of supply to customers.	Network performance	Check load balance following voltage complaints of transformer damage due to overload and load rebalancing where needed.

Table 76: Fleet risks

11.12.4 Fleet strategy

The key objective for this fleet is to convey electricity to and from consumers with reliable voltage transformation by the timely replacement of defects and failures to ensure customer service levels are maintained.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 77.

[56] *Waipā has historically included vegetation outages as part of adverse weather during major events. The SAIDI data excludes normalisation for major events.*

Monitoring type	Description	Frequency
Common fleet strategies (refer Table 50 in section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting. (For small pole-mounted transformers where a run-to-failure strategy is more appropriate, asset health is considered if other work is happening in the vicinity.) • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Remove all large two-pole structures	• Undertake a programme to remove all two-pole transformer structures	• All eliminated by the end of FY24
Timely replacement of defects and failures	• For pole-mounted transformers, given the generally low consequence of failure, our strategy is to replace them when material defects are reported or at failure	• Replacement occurs within mandated customer response and restoration times
Enhance fleet resilience (refer to Section 9.4)	• New pole-mounted transformers are limited to 100kVA and below, with standard designs detailing pole and foundation requirements • Maintain stock holding to ensure it is sufficient for major weather events	• Increase the mechanic strength of the structures supporting the fleet • Restoration of supply is not impacted by stock holding during major events
Reduce the incidents of car vs poles	• Concerning the structure, refer to the Distribution Structures (Poles and Structures) fleet plan	• Minimise the impact of third-party incidences on the network performance.
Enhance fleet resilience		

Table 77: Fleet strategy

11.12.5 Design and construct

The standard pole structure and foundations design complies with the AS7000, and the transformers design complies with the AS/NZS/IEC 60076 series. The design for these assets considers seismic resilience, as noted in the fleet strategy.

Due to exposure to environmental conditions, distribution transformers in salt-prone areas have galvanised tanks and longer insulators. The increased initial cost of galvanised tanks provides a lower lifecycle cost than more regular replacements of steel tank transformers.

Waipā has standard designs prepared for pole-mounted transformer structures.

We have standardised the size and type of transformers to enable us to hold efficient spares for major events.

11.12.6 Monitoring

Pole-mounted transformers are inspected, and their earthing systems are tested, separate from the detailed line inspection. Table 78 describes our current fleet monitoring approach:

Monitoring type	Description	Frequency
Detailed inspection	• The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, oil leaks, insulators, mounting, earthing and accessories. Note: the fuse condition is captured as a separate asset. • Defect notices are raised where priority repair or replacement is required	• 5 Yearly
Earth testing	• Measure the resistance of earthing connections • Visual inspection of the earthing system • Note: the MEN earthing on the overhead LV system is also inspected and tested.	• 5 Yearly
Line patrol	• A drive-by patrol of the line and visual inspection at sites of concern. • Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required	• As required in response to fault issues, reliability trends, or criticality

Table 78: Fleet monitoring

11.12.7 Maintaining

There are no specific maintenance routines for pole-mounted distribution transformers. However, earthing systems are maintained to achieve the same MPL as the transformer. If an existing transformer is recovered from the field, say replaced for capacity reasons, it is serviced and added to spare stock.

11.12.8 Renewal

Our fleet renewal approach is shown in Table 79.

Monitoring type	Description
Renewal forecasting	• The forecast of asset renewals is based on replacing all H1 assets over the forecast period. • Pole-mount transformer renewals respond to defect notices or asset failures. Asset failures and significant defects are consistent with a health grade of H1 • This approach is adopted due to the low consequence of failure for this fleet as few customers are impacted, and replacement can be achieved quickly
Determining specific renewal projects	• No specific renewal projects are determined (other than the exception mentioned below)
Assessing alternatives	• In normal circumstances, no other options are assessed • The exception is where the transformer replacement resulted from a car vs pole incident. If historical data on car vs pole incidents indicate the transformer is in a high-risk area, we will consider relocating the transformer as a planned project
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 79: Fleet renewal forecasting

Material Spares

Pole-mounted transformers are common assets that are exposed to adverse weather events. We hold stock sufficient to cover any reasonable situation, i.e., a range of transformer sizes to cover fault repairs, and we have supply arrangements for replenishment of spare stock and new developments. We increase our stock holding when supplier delivery is constrained and lead times are extended.

11.12.9 Population and age

The population and age of our pole-mounted transformer fleet is shown in Figure 92. The graph indicates that 54% of the fleet is above OOU, but no assets are at MPL.[57]. Our condition data suggests that the OOU could be too low for our fleet as we do not see condition issues arise until around 30 years.

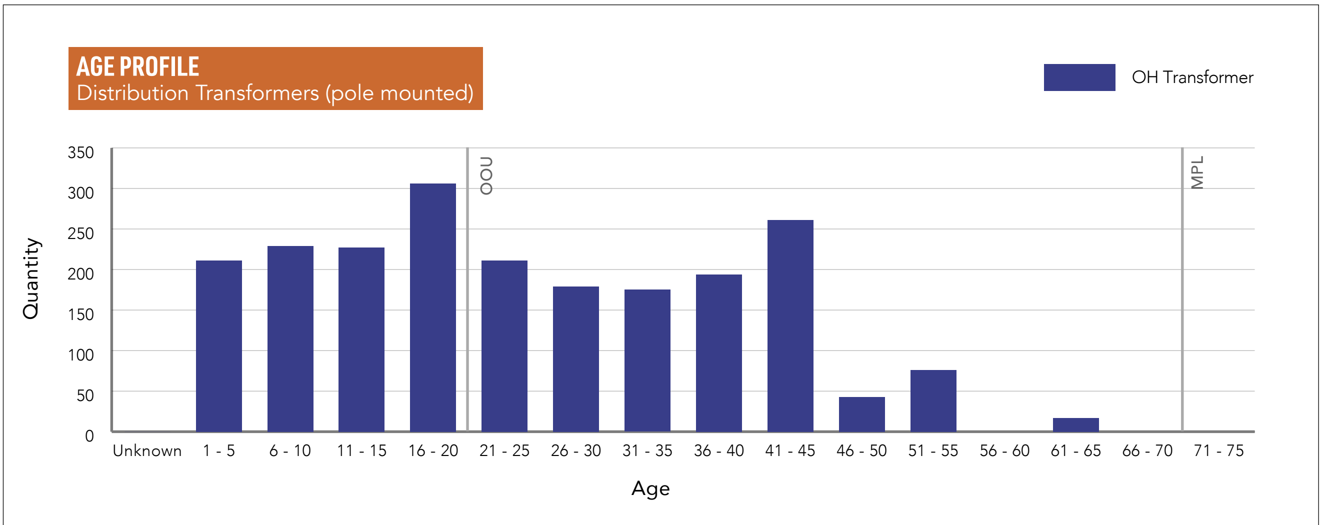


Figure 92: Age profile

[57] *Pole-mounted transformers have an OOU of 20 years and an MPL of 70 years.*

11.12.10 Asset health

The health assessment for pole-mounted distribution transformers is shown in Figure 93. The assessment is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

The data used for pole-mounted transformer health forecasting is robust, with 83% being condition-based. The remainder of the assets have good age data. The deterioration of pole-mounted transformers is relatively gradual, consistent with the long MPL for this fleet.

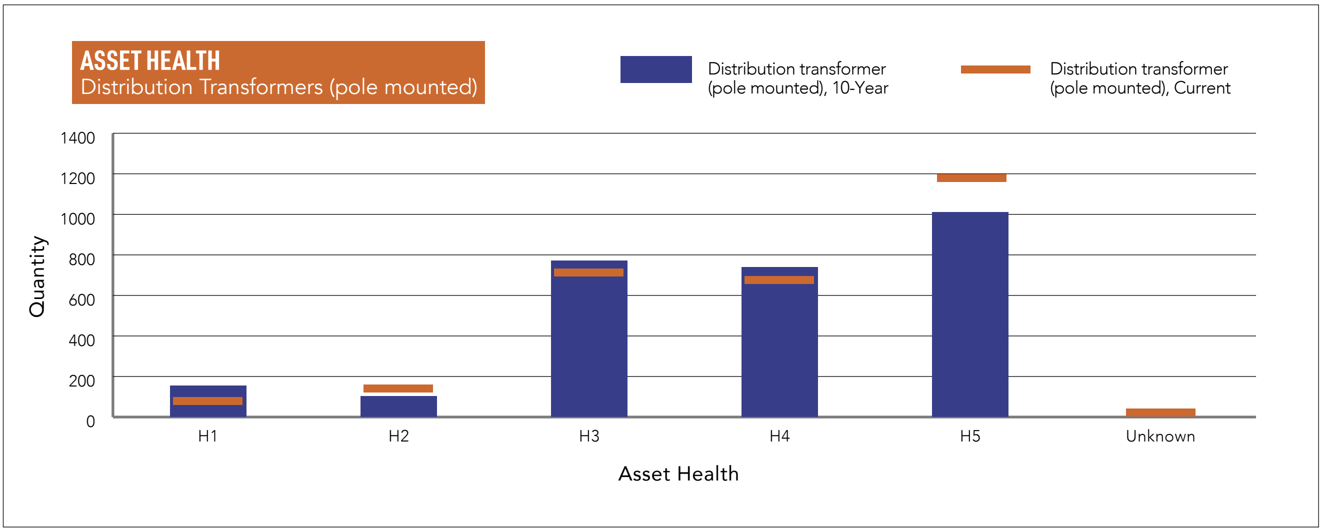


Figure 93: Current and Forecast Asset Health

Table 80 shows the current and forecast numbers for low-health pole-mounted transformers over the next ten years. Nearly half of low-health transformers are forecast based on condition. The extent of low-health assets would double if the forecasting were solely age-based, indicating that the deterioration rate we see is lower than that implied by age-based forecasting. Hence, it's likely that the addition of new condition data will improve the fleet's health profile.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
11kV conductor	1,245	0.3	17.2	1.4%
LV conductor	500	1.1	9.1	1.8%

Table 80: Current and Forecast Asset Health

The forecast for low-health pole-mounted transformers is materially lower than in the 2023 AMP forecast. The change in forecast reflects the use of condition data and the improvements in health forecasting methodology.

11.12.11 Asset replacements

Consistent with our renewal strategy, we forecast 150 H1 pole-mounted transformers to be replaced over the next ten years (as shown in Table 81). We set the renewal rate above the quantity of forecast H1 assets, reflecting the level of historical replacements (including the storm and other damage). The renewals are unplanned (defect and failure-driven); hence, actual renewals may differ.

The choice of replacement transformer size will consider other drivers, such as future capacity requirements.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
Pole-mounted transformers	154	240

Table 81: Asset Renewal Forecast

11.12.12 Expenditure forecast

Table 82 shows the forecast expenditure for this fleet. The forecast expenditure is slightly higher than in the 2023 AMP for FY25 to FY29. The renewal provision for "other drivers" accounts for car vs poles and storm damage. This estimate is based on historical averages.

The cost forecasts include the cost of associated dropout fuses.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
Pole-mounted transformer, defect and failure renewals	Unplanned	ARR	240	240	240	240	240	1,200
Pole-mounted transformer, storm and damage replacement	Unplanned	ARR	160	160	160	160	160	800
Total	-	-	**400**	**400**	**400**	**400**	**400**	**2,000**

Table 82: Forecast Expenditure

FY24 Real $000

11.13 Distribution voltage regulators

11.13.1 Fleet overview

We apply voltage regulators on the network to improve the voltage along rural feeders to maintain the voltage within regulatory limits. Voltage drop is the limiting factor on rural feeders, and voltage regulators are a cost-effective way to increase the feeder's capacity by extending the feeder's voltage reach.

Waipā uses voltage regulators extensively on its network. They have supported the load growth in rural areas as land use has changed and energy density has increased.

Voltage Regulators are typically rated at 100, 200 or 300 amps at 11kV and are installed mainly in a closed delta (3 tanks) with some sites in an open delta (2 tanks) configuration. The closed delta configuration is preferred for new sites with heavy loading as it is less prone to voltage fluctuations during operation and can achieve a higher current rating. The open delta configuration is preferred for end-of-line locations with no backfeeding need. Single-phase controllers per tank, or one multi-phase controller, at each site, monitor the current and voltage and control the voltage. The controller is connected to the SCADA system.

About 40% of our 11kV voltage regulators are on two-pole structures; the rest are on four-pole structures. Most old two-pole structures are not compliant with current seismic standards and are being proactively replaced.

In response to asset condition, we commenced proactive replacement and refurbishment of voltage regulators in FY24.

We have good-quality data on the age and attributes of this fleet. All assets have a known date of manufacture. Asset condition data is being captured during the most recent inspection rounds.

Note: *The asset quantities in this fleet relate to the number of single-phase voltage regulator "cans" or "tanks", where there can be two or three tanks per site.*

11.13.2 Fleet performance

Operational issues due to controller and tap-changer failures have occurred. The controllers are progressively replaced due to age, ant infestation or condition.

Our tap changer maintenance program started in FY23. We generally coincide the tank swapping (for workshop de-tank maintenance) with the pole structure seismic strengthening works (Section 9.7.3). There is a potential backlog in this workstream, and we continue to improve our visibility and delivery of this workstream in our FY25.

11.13.3 Fleet risks

Table 83 highlights the material risks associated with the voltage regulator fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Third-party interference (Car vs Pole) damages the structure and regulators, causing outages and potential contact with live wires	Regulator and structure damage could result in a large outage and injury to members of the public	Public safety Network performance	Old structures are being replaced, and relocation or protection is being considered for high-risk sites.
Oil leaks that could cause environmental damage	Environmental damage	Environmental damage	The assets are inspected three yearly, and assets with oil leaks are replaced.
The strength of older structures is below current design standards (for seismic hazards)	The structures may fail in a seismic event, causing a loss of supply to customers and risk to the public.	Public safety Network performance	Older structures are being proactively replaced

Table 83: Fleet risks

11.13.4 Fleet strategy

The key objective for this fleet is to improve the regulation of voltage on distribution feeders and improve the overall health of the fleet by increasing the seismic rating of structures.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 84.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Eliminate all H1 assets by the end of FY29	• Ensure all H1 voltage regulators are replaced before failure • Ensure all H2 voltage regulators are replaced before they become H1	• Zero H1 voltage regulators by FY29
Enhance fleet resilience (refer to Section 9.4)	• Replace or remediate all structures that are below current seismic ratings • Consider flooding and geotechnical hazards (Peat soil) in the new site and structure design	• Improved asset resilience
Timely replacement of defects	• For voltage regulators, given the potentially high consequence of failure, defect replacements shall occur promptly	• No failure of assets with defect notices

Table 84: Fleet strategy

11.13.5 Design and construct

We have standardised the selection of voltage regulator cans and a single controller type to aid with the management of spares and ensure consistent interfaces for field operators. The voltage regulators designs comply with the AS/NZS/IEC 60076 standard series. The voltage regulator structures are designed to structural design standards (NZS 1170 series), and the. The design for these assets considers seismic and wind resilience in the structural design standards. Flooding and geotechnical hazards are considered during site selection.

Given the physical size of these assets, a specific geotech design is prepared for each site.

11.13.6 Monitoring

Table 85 describes our current fleet monitoring approach:

Monitoring type	Description	Frequency
Patrol and inspection	• Include the condition of the external tank, oil leaks, controllers • Inspect and check the controller, battery, and site signal strength. • Carry out pest control and battery replacement as required	Annually
Detailed inspection	• The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, oil leaks, controllers • Oil dielectric strength, acidity and moisture testing • Tap-changer operational checks	3 Yearly
Insulation testing	• Winding insulation testing	12 Yearly
Operational monitoring	• SCADA monitors the operation of the voltage regulators. This alerts the operator of any operational issues.	-

Table 85: Fleet Monitoring

11.13.7 Maintaining

Voltage regulator maintenance is shown in Table 86.

Monitoring type	Description	Frequency
Routine maintenance	• Bug and pest control to prevent damage to controllers and electronics. • Radio signal strength checks • Battery condition checks	Annually
Preventive maintenance	• Preventive maintenance is undertaken as per manufacturer recommendations • Tap-changer and internal mechanism replacement	Tap-changer counter time-based
Condition-driven maintenance	• Maintenance is carried out in response to the inspection and testing. This may include additional testing, spot repairs to the cans, replacement of fitting, or control box replacement.	As required

Table 86: Fleet Maintenance

11.13.8 Renewal

Our fleet renewal approach is shown in Table 87.

Decision	Description
Renewal forecasting	• The forecast of asset renewals is set out in the fleet strategy.
Determining specific renewal projects	• Specific renewal projects are identified from the health assessment • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by criticality. The highest priority will be replacing voltage regulators in critical locations
Assessing alternatives	• In some circumstances, evaluate the effectiveness of using switched capacitor banks or STACOM if a power-factor mainly causes the feeder voltage issue • The exception is if historical data on car vs pole incidents indicate the voltage regulator is in a high-risk area, we will consider relocating the voltage regulator
Defect repair and replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 87: Fleet Renewal Forecasting

Material Spares

We hold stock sufficient to cover defect and damage replacements.

11.13.9 Population and age

The population and age of our voltage regulator fleet is shown in Figure 94. The graph indicates that 31% of the original (non-refurbished) fleet is above a Waipā specific OOU, but no assets are at MPL[58].

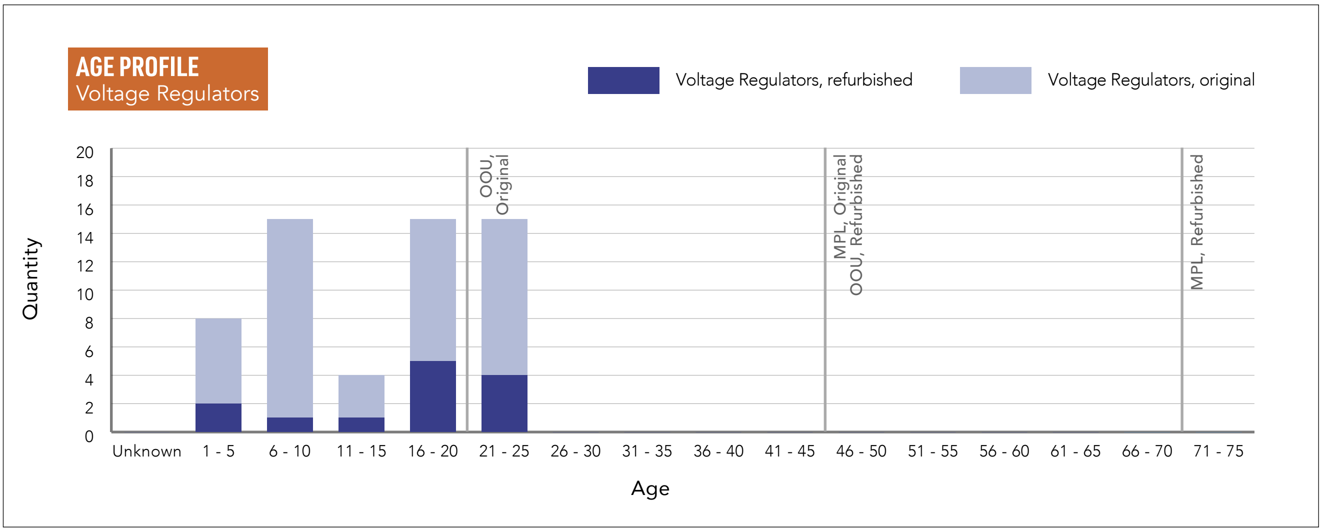


Figure 94: Age profile

11.13.10 Asset health

The health assessment for voltage regulators is shown in Figure 95 and is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

For voltage regulators, 35% of the assets have condition data, and the remainder have good age data. The condition assessments were conducted in 2023 and indicate that the tank and control box condition is worse than age-based forecasting implied. We will investigate the cause of the deterioration and assess whether maintenance practice changes are required.

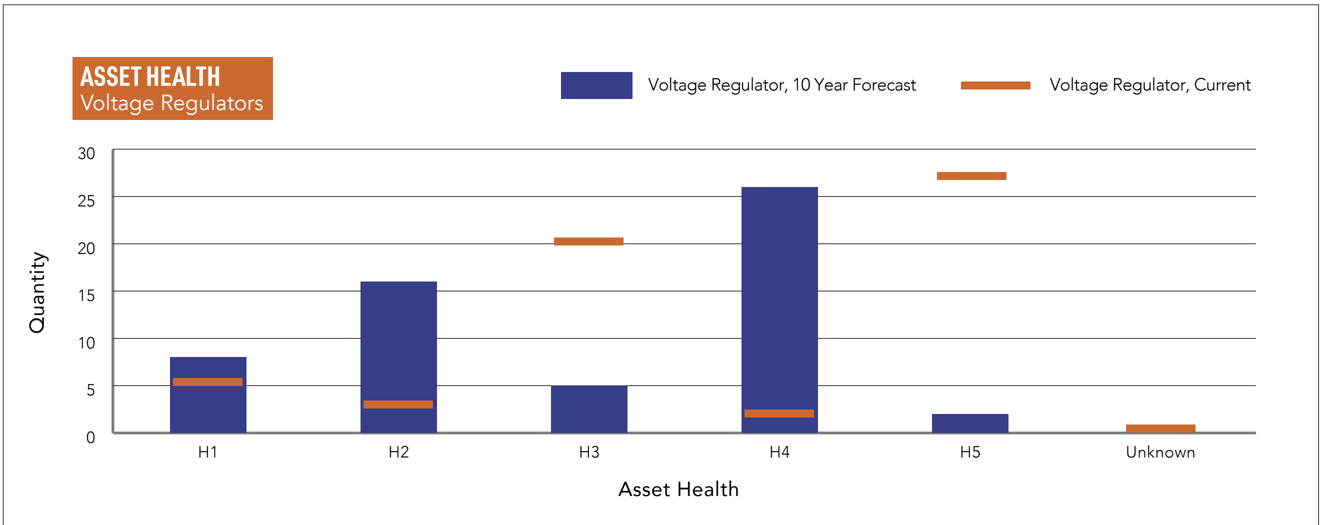


Figure 95: Current and forecast asset health

Table 88 shows the current and forecast for low-health voltage regulators over the next ten years. 67% of low-health voltage regulators are forecast based on condition, and the rest are based on age.

The low-grade structures are based on an initial assessment, which indicates the structures do not meet current seismic standards.

[58] *Voltage regulators have a OOU of 20 years and an MPL of 45 years. This is extended to an OOU of 45 year and a MPL of 70 years after refurbishment of the cans.*

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
Voltage regulators	57	8	24	42%
Structures	21	20	20	95%

Table 88: Current and Forecast Asset Health

The forecast for low-health voltage regulators is the same as in the 2023 AMP forecast. Structure renewals were also included in the 2023 AMP.

11.13.11 Asset replacements

Consistent with our renewal strategy, we are forecasting the replacement of all H1 and H2 voltage regulators over the next ten years (as shown in Table 89). The annual renewal rate is higher in the first five years to address the H1 assets and is sufficient to replace all H2 assets before deteriorating to H1.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
Voltage regulators	24	24
Structures	20	20

Table 89: Asset renewal forecast

11.13.12 Expenditure forecast

Table 90 shows the forecast expenditure for this fleet. Concerning the voltage regulator renewal, the forecast expenditure is $770k higher than in the 2023 AMP for FY25 to FY29. For structures, the forecast expenditure is $670k lower than the 2023 AMP over the same period. The changes are due to revisions in project costs.

The controllers are being upgraded as the voltage regulators are refurbished.

Note that "Structure Replacements" is specified in the Network Development Section 9.7.3 and is also shown here for information.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
Voltage regulator, renewals	Planned	ARR	374	374	374	187	187	2,990
Structure replacements	Planned	RSE-other	160	160	160	160	160	800
Total	-	-	**534**	**534**	**534**	**347**	**347**	**3,790**

Table 90: Forecast expenditure

FY24 Real $000

11.14 Distribution reclosers and sectionalisers

11.14.1 Fleet overview

The purpose of reclosers and sectionalisers is to reduce the number of customers impacted by outages when an outage occurs. They operate along the feeder to isolate only the faulted section of the line, leaving the rest of the feeder in service.

Waipā uses reclosers and sectionalisers extensively on its network. There are 114 reclosers and two sectionalisers in the fleet.

We are progressively replacing the control and communication system on the fleet as the control and communication units are aging (as they last around half that of the recloser) and are approaching technical obsolescence.

We have good-quality data on the age and attributes of this fleet. Any missing data is being captured during inspections. All assets have a known date of manufacture. Asset condition data (to the new standard) is presently being captured and will be completed in time for the 2025 AMP.

11.14.2 Fleet performance

We have experienced increased operational issues with some of our older reclosers and RC-01 controllers. We are addressing the performance of the recloser units through inspection and maintenance, and the performance of the controllers is being addressed through the controller and recloser replacement programme.

11.14.3 Fleet risks

Table 91 highlights the material risks associated with the reclosers and sectionalisers fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Damage or failure of the structure supporting the recloser	Damage or failure of the structure could result in an outage and injury to members of the public	Public safety Network performance	Refer to the Distribution Structures (Poles and Structures) fleet plan
Third-party interference (Car vs Pole) damages the structure and recloser, causing outages and potential contact with live wires	Recloser and structure damage could result in a large outage and injury to members of the public	Public safety Network performance	Relocation or protection is being considered for high-risk sites
Control and communication systems reach technological obsolescence and become incompatible with SCADA.	Reclosers fail to operate, increasing the number of customers impacted by an outage.	Network performance	Replace batteries. Upgrading the control and communication systems
Non-discrimination of protection when three or four reclosers are installed on a single feeder	Incorrect reclosers operation, increasing the number of customers impacted by an outage	Network performance	Review reclosers' placement and protection settings to ensure they can operate correctly.

Table 91: Fleet risks

11.14.4 Fleet strategy

The key objective for this fleet is to maintain high operational performance to ensure the reclosers operate reliably.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 92.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting
Eliminate all H1 assets by the end of FY29	• Ensure all H1 reclosers and sectionalisers are replaced before failure • Ensure all H2 reclosers and sectionalisers are replaced before they become H1 • Replace the last oil unit with a modern equivalent	• Zero H1 reclosers and sectionalisers by FY29
Enhance operational performance	• Inspect the controllers, carry out pest controls and replace defective batteries by the end of FY24. • Replace all older RC-01 controllers by the end of FY34 • Catch-up on all 10-yearly maintenance • Calibrate all CTs as part of 10-yearly maintenance • Confirm protection discrimination when there are multiple reclosers on the feeder	• Improve operational reliability
Reduce the incidents of car vs poles	• Concerning the structure, refer to the Distribution Structures (Poles and Structures) fleet plan	• Refer to the Distribution Structures (Poles and Structures) fleet plan
Enhance fleet resilience		

Table 92: Fleet strategy

11.14.5 Design and construct

Reclosers and sectionaliser structures are designed to AS/NZS 7000 and the structural design standards (NZS 1170 series). The design for these assets considers the following:

- seismic and wind resilience in the structural design standards. Flooding and geotechnical hazards are considered during site selection.
- capacity to suit application point, regulation range, uni-/bi-directional capability, and firmware.

Waipā has standard designs for pole-mounted recloser structures.

11.14.6 Monitoring

Table 93 describes our current fleet monitoring approach:

Monitoring type	Description	Frequency
Patrol and inspection	• Inspect and check the controller, battery, and site signal strength. • Carry out pest control and battery replacement as required	Annually
Detailed inspection	• The detailed inspection captures the EOL condition drivers, which include the condition of the recloser/sectionaliser unit, control box, associated fuses and switches, structure, etc. • Operational and communication checks	3 Yearly
Operational monitoring	• The operation of the reclosers and sectionalisers is monitored by SCADA. This alerts you of any operational issues.	-

Table 93: Fleet monitoring

11.14.7 Maintaining

The maintenance of reclosers and sectionalisers is shown in Table 94.

Monitoring type	Description	Frequency
Preventive maintenance, oil sectionaliser	• The last oil unit is planned for replacement; hence, there is no further planned maintenance activity	n/a
Routine maintenance, vacuum and SF6 reclosers	• Bug and pest control to prevent damage to controllers and electronics. • Radio signal strength checks • Battery condition checks	Annually
Preventative maintenance, vacuum and SF6 reclosers	• Preventive maintenance on the operating mechanism is undertaken as per manufacturer recommendations • Thermal scan to check the integrity of load-carrying components • Calibration of CTs • Battery replacement	Ten years
Condition-driven maintenance	• Maintenance is carried out in response to the inspection and testing. This may include maintenance on the unit, replacement of the controller, RTU, antenna, battery, or other components	As required

Table 94: Fleet maintenance

We currently have a backlog of maintenance on the fleet as many reclosers were installed between 2010 and 2015, and these are now due for their first ten yearly maintenance. This work is underway and should be completed by the end of FY26.

11.14.8 Renewal

Our fleet renewal forecasting approach is shown in Table 95.

Monitoring type	Description
Renewal forecasting	• The forecast of asset renewals is as per the fleet strategy.
Determining specific renewal projects	• Specific renewal projects are identified from the health assessment and known controller-type issues • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by the criticality of the feeder
Assessing alternatives	• In normal circumstances, no other options are assessed • The exception is if historical data on vehicle accidents indicate the reclosers and sectionalisers are in a high-risk area, we will consider relocating the reclosers and sectionalisers
Defect repair and replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 95: Fleet Renewal Forecasting

Material spares

We hold stock sufficient to cover defect and damage replacements.

11.14.9 Population and age

The population and age of our reclosers and sectionalisers fleet is shown in Figure 96. The graph indicates that two assets are above OOU, but none are at MPL[59]. The age profile reflects the large reliability improvement initiative utilising reclosers over the last twenty years.

The outlier in the Age 36-40 group is an oil KF sectionaliser.

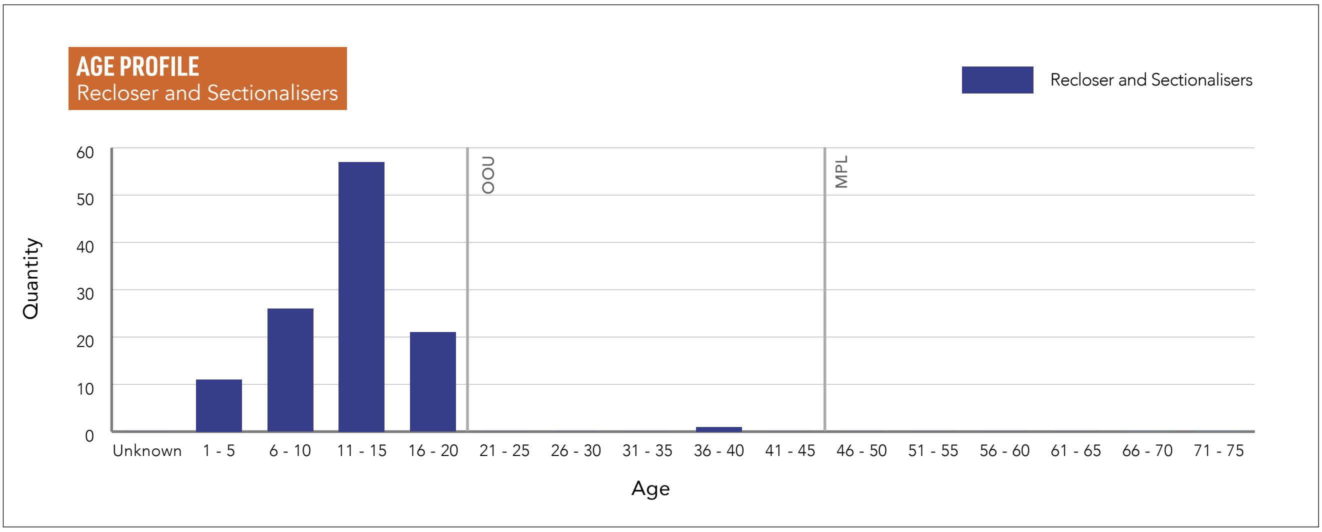


Figure 96: Age profile

11.14.10 Asset health

The health assessment for reclosers and sectionalisers is shown in Figure 97 and is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

For reclosers and sectionalisers, 16% of the assets have condition data, and the remainder have good age data. The condition assessments (to the new standard) are in progress, and health forecasting should be completed for the 2025 AMP. The known issue with the RC-01 controllers will be fully incorporated into the asset health assessment in the 2025 AMP.

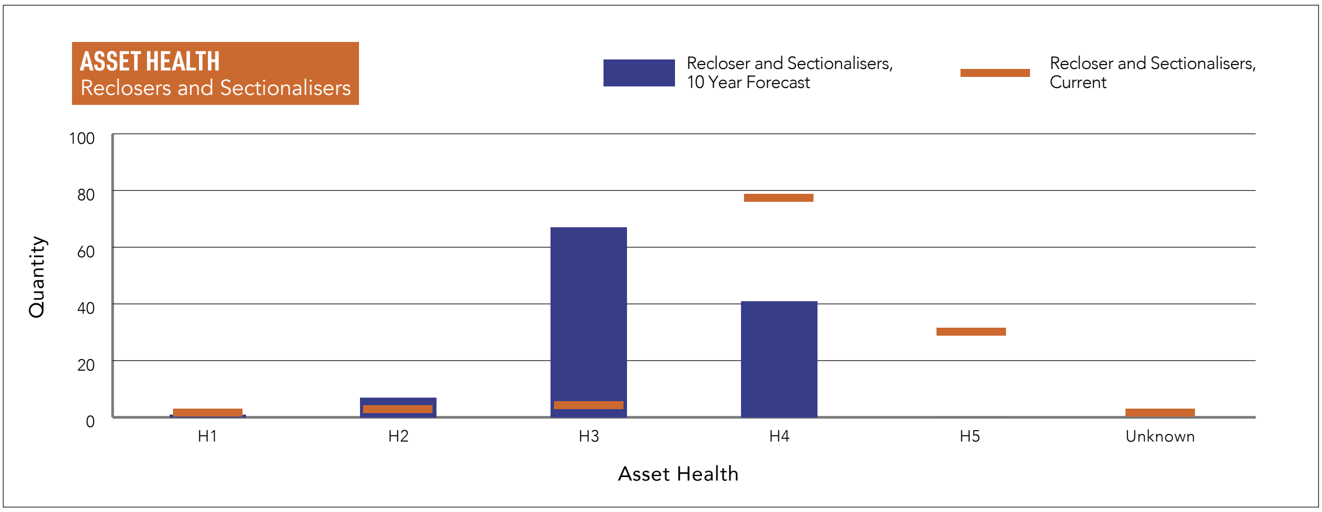


Figure 97: Current and forecast asset health

Table 96 shows the current and forecast for low-health reclosers and sectionalisers over the next ten years. Seven of the eight reclosers and sectionalisers forecast for replacement are based on condition, and one is age-based.

[59] *Reclosers and sectionalisers have a OOU of 20 years and an MPL of 45 years.*

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
Reclosers and sectionalisers	116	3	8	7%

Table 96: Current and forecast asset health

The forecast for low-health reclosers and sectionalisers has reduced materially from the 2023 AMP.

11.14.11 Asset replacements

Consistent with our renewal strategy, we are forecasting the replacement of all H1 and H2 reclosers and sectionalisers over the next ten years (as shown in Table 97). No assets should deteriorate to H1 over the forecast period. For FY25, we plan on replacing the current H1 and H2 reclosers (refer to Table 96), with replacements continuing annually to maintain good health for the fleet.

All older RC-01 controllers will be replaced by the end of FY34.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
Reclosers and sectionalisers	8	8
Control boxes	50	50

Table 97: Asset renewal forecast

11.14.12 Expenditure forecast

Table 98 shows the forecast expenditure for this fleet. Concerning the reclosers and sectionalisers renewal, the forecast expenditure is $800k lower than in the 2023 AMP for FY25 to FY29. The number of reclosers forecast for renewal reflects our current view of the fleet's health.

The controller replacements have been phased over ten years (rather than the next two as included in the 2023 AMP) to fit resourcing requirements and the increase in near-term maintenance requirements.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
Voltage regulator, renewals	Planned	ARR	374	374	374	187	187	2,990
Structure replacements	Planned	RSE-other	160	160	160	160	160	800
Total	-	-	**534**	**534**	**534**	**347**	**347**	**3,790**

Table 98: Forecast capital expenditure

FY24 Real $000

11.15 Distribution overhead switches

11.15.1 Fleet overview

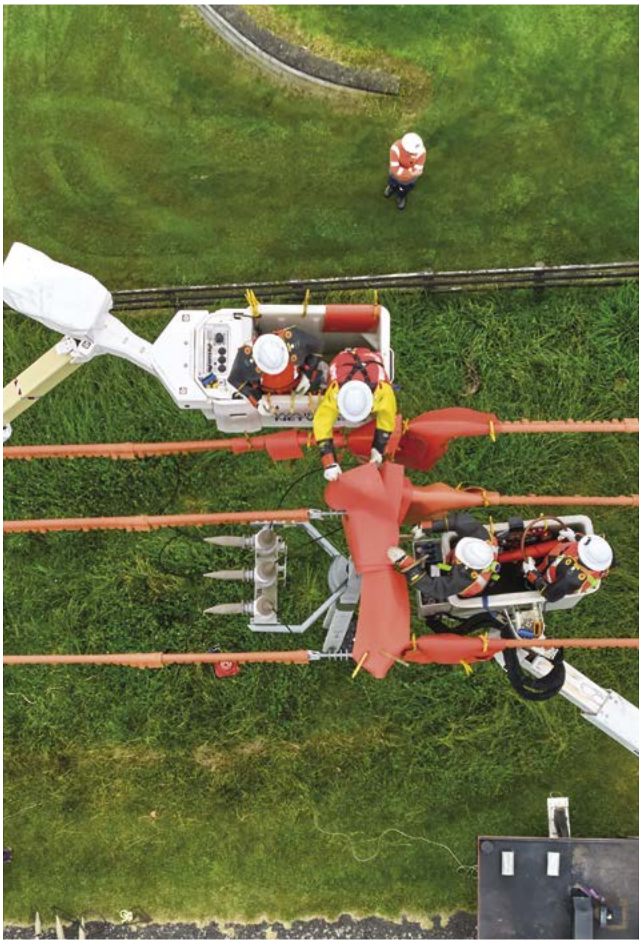
The purpose of overhead switches is to provide the ability to switch, isolate and protect the overhead distribution network. This fleet has four asset types, as shown in Table 99.

Asset Type	Quantity	Description
Air break switch (ABS)	443	Pole-top switches that can be operated under load to switch and isolate parts of the overhead network, either operated by handles or by hot stick
Enclosed load break switch (LBS)	155	An enclosed switch using vacuum or SF_6 insulation can be operated under load to switch and isolate parts of the overhead network. Automation of the switch is also possible.
Drop out fuse (fuses)	3,601	These expulsion fuses protect a line section, usually a spur line, a pole-mounted distribution transformer, or a cable section. They can be used to isolate lines under small loads.
Links	192	These are dropout links that can be used to isolate line equipment.
Total	4,411	

Table 99: Overhead switch asset types

We do not have good data on all the assets in this fleet. We have missing asset age data on 40% of the fleet; most of this relates to fuses, links and some ABSs. We intend to do further work to improve the data quality for ABSs over the next two years. Data quality on age for fuses and links will be difficult to improve; hence, we will rely on condition data for these asset types.

The failure modes for these assets are generally driven by corrosion, wear, misalignment of components, and arc damage that occurs during operation. These failure modes can usually be observed during our inspection. Hence, for this fleet, condition-based health forecasting is appropriate.



11.15.2 Fleet performance

We do not have good data on faults by each asset type for this fleet (as all switchgear faults are combined) due to how historical outages were recorded. The number of unassisted faults has averaged 5.4 per year since FY19.[60] This fault rate represented around 11 faults/10k units/year across all asset types.[61] Recent changes to the fault recording system will provide additional data to enable fault trends to be analysed in more detail from now on.

We are also finding a higher number of ABS with a seized operating mechanism and inoperable during planned or unplanned switching. These failures are currently reported through our defect process.

[60] *This excludes faults on switches during adverse weather events.*

[61] *This also includes RMUs, reclosers and sectionalisers.*

11.15.3 Fleet risks

Table 100 highlights the material risks associated with the overhead switch fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Failure of the equipment to operate (either open or close) disrupts switching operations and causes risk to staff.	An inability to isolate or liven parts of the network. In these situations, the outage duration for some customers may be extended by the repair time. Failure of the switch can also endanger staff operating the switch	• Staff safety • Network performance	• Inspection and replacement of the switch. • We have documented operational steps when a defective switch is found. • No further installation of certain ABS types and LBS is preferred for new switch installation.
Certain ABS base mounting channels are prone to premature severe rusting at the bolting points. **We are finding certain types of ABS are prone to such issue**	The switch becomes insecure and may endanger staff operating the switch or the public	• Staff safety • Public safety • Network performance	• Inspection and replacement of the switch. • No further installation of certain ABS types and LBS is preferred for new switch installation.
Public gain access to the switch operating mechanism	Injury to members of the public	• Public safety	• The operating handle is locked. • Inspections of public safety measures. • Upgrading the network access lock system. • New switch type will be hot stick operated.
Failure of the earthing of the switch and handle	Injury to staff or members of the public	• Staff safety • Public safety	• The operating handle is locked. • Inspections of public safety measures. • Upgrading the network access lock system. • New switch type will be hot stick operated.
Damage or failure of the structure supporting the switch	Damage or failure of the structure could result in a large outage and injury to members of the public	• Public safety • Network performance	• Refer to the Distribution Structures Fleet Plan
Control and communication systems reach technological obsolescence and become incompatible with SCADA.	Controlled switches fail to operate, increasing the number of customers impacted by an outage.	• Network performance	• Replace batteries. • Upgrading the control and communication systems

Table 100: Fleet risks

11.15.4 Fleet strategy

The key objective for this fleet is to maintain high operational performance for work isolation, network re-configuration, and ensure public safety.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 3. The fleet strategy differs by switch type. For ABSs and enclosed LBS, the strategy is proactively replacing these assets based on our health assessment and field inspection findings.

For fuses and links, where the replacement is generally more straightforward (and health data is currently less reliable), we will replace these assets when defects are identified, concurrent to other asset replacements (e.g., pole mount transformer, cross arms), or the asset is non-operational. We will be looking to change the fleet strategy to be more proactive as our health data improves with condition information.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in section 11)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing
Eliminate all H1 ABSs and enclosed LBSs by the end of FY29	• Ensure all H1 assets are replaced before failure • Ensure all H2 assets are replaced before they become H1	• Zero H1 ABSs and Enclosed LBSs by the end of FY29
Timely replacement of defects	• For ABSs and enclosed LBSs, given the potential consequence of failure, defect replacements shall occur promptly	• No failure of assets with defect notices
Enhance operational performance (automated LBS only)	• Inspect the controllers, carry out pest controls and replace defective batteries by the end of FY24. • Catch-up on all 10-yearly maintenance	• Improve operational reliability
Improve the reliability of the worst-performing feeders	• The initial focus of the planned switch renewal is on the worst-performing feeders	• Improve the reliability of the worst-performing feeders
Timely replacement of defects and failures for fuses and links	• For fuses and links, given the generally low consequence of failure, our strategy is to replace them when defects are reported or when non-operational	• Replacement occurs within mandated customer response and restoration times
Reduce the use of ABS and adopt enclosed LBS as the preferred switch	• ABS is more prone to failure; hence, minimise the use of ABS and use enclosed LBS for most locations.	• Improve performance reliability of the overall ABS/LBS asset types
Reduce the incidents of car vs poles	• Refer to the Distribution Structures (Poles and Structures) fleet plan for the switch support structure	• Refer to the Distribution Structures (Poles and Structures) fleet plan
Enhance fleet resilience		

Table 101: Fleet strategy

11.15.5 Design and construct

Waipā has standard designs prepared for all pole-mounted overhead switches. All equipment is purchased to the relevant industry standards. Refer to the Distribution Structures (Poles and Structures) fleet plan for structure design standards.

Due to the less reliable nature of ABS, we intend to reduce the use of ABS and have implemented the following design approach:

- Minimise the use of ABS to the following applications only
    - Bypass switch for reclosers and voltage regulators

      We are evaluating the need for a bypass switch for reclosers and the feasibility of using enclosed LBS for voltage regulator
    - Ganged switch to mitigate ferro resonance risk when operating expulsion dropout fuse (EDO) that supplies long transformer cable
    - Emergency like-for-like replacement
    - Other situations where an enclosed LBS is not economical due to other extensive changes required, as judged and approved on a case-by-case basis
- Work with peer EDB to select a reliable ABS for the above applications.
- Use automated enclosed LBS for critical switching points
- Use enclosed LBS for all other applications in general

We have standardised the size and type of overhead switches to enable us to hold efficient spares for major events.

11.15.6 Monitoring

Table 102 describes our current fleet monitoring approach:

Monitoring Type	Description	Frequency
Detailed inspection	• Condition data is captured during the detailed line inspections or pole-mounted transformer inspections (refer to the Distribution Structures (Poles and Structures) fleet plan and the pole-mounted distribution transformer fleet plan) • The detailed inspection captures the EOL condition drivers, which (under the new standard) will include the condition of the switch and operating mechanism • Defect notices are raised where priority repair or replacement is required	5 Yearly
Line patrol	• A drive-by patrol of the line and visual inspection at sites of concern. • Minor repairs may be performed, or defect notices are raised where priority repair or replacement is required	As required in response to fault issues or reliability trends
Patrol and inspection (for automated LBS)	• Inspect and check the controller, battery, and site signal strength. • Carry out pest control and battery replacement as required	Annually
Operational monitoring (for automated LBS)	• We monitor the operation of the controlled switches through SCADA. This alerts the operator of any operational issues.	As required

Table 102: Fleet monitoring

11.15.7 Maintaining

There are no specific maintenance routines for links and dropout fuses. ABSs and enclosed LBSs are maintained as described in Table 103.

Monitoring Type	Description	Frequency
Routine inspection and earth testing	• Visual inspections of a switch, including contacts and pantographs (for ABSs) • Thermal scan to check the integrity of load-carrying components • Visual inspection of the earthing system and measurement of resistance of earthing connections	5 Yearly
Routine maintenance (automated LBS)	• Bug and pest control to prevent damage to controllers and electronics. • Radio signal strength checks • Battery condition checks	Annually
Preventative maintenance (automated LBS)	• Preventive maintenance on the operating mechanism is undertaken as per manufacturer recommendations • Thermal scan to check the integrity of load-carrying components • Calibration of CTs • Battery replacement	Ten years

Table 103: Fleet maintenance

11.15.8 Renewal

Our fleet renewal approach is shown in Table 104.

Decision	Description
Renewal forecasting (ABSs and enclosed LBSs)	• As per the fleet strategy
Determining specific renewal projects (ABSs and enclosed LBSs)	• Specific renewal projects are identified from the health assessment • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by the criticality of the feeder
Assessing alternatives (ABSs and enclosed LBSs)	• For ABS and enclosed LBS renewal, the team will assess whether the switch is needed at all at its current location (i.e., whether it is a duplicated device for removal or it shall be better located) and whether it should be upgraded to an automated enclosed LBS in conjunction with "11kV automation recloser/sectionaliser Additions" under Section 9.7.1. • One exception is where the overhead switch replacement resulted from vehicle damage. If historical data on vehicle crashes indicate the overhead switch is in a high-risk area, we will consider relocating the overhead switch as a planned project
Renewal forecasting (fuses and links)	• The forecast of asset renewals is based on continuing historical replacement rates. • This approach is adopted due to the low consequence of failure for this fleet as few customers are impacted, and replacement can be achieved quickly
Determining specific renewal projects (fuses and links)	• No specific renewal projects are defined for these asset types
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 104: Fleet renewal forecasting

Material spares

Overhead switches are common assets exposed to adverse weather events and vehicle damage. We hold stock sufficient to cover any reasonable situation. We hold stock adequate to support the unplanned replacements for dropout fuses and links.

11.15.9 Population and age

The population and age of our overhead switch fleet is shown in Figure 98. The graph indicates that 60% of the fleet is above OOU or has an unknown age.[62] There are no enclosed LBSs above MPL and 5% of ABSs above MPL. The data for dropout fuses and links isn't sufficiently reliable to assess the assets at our above MPL.

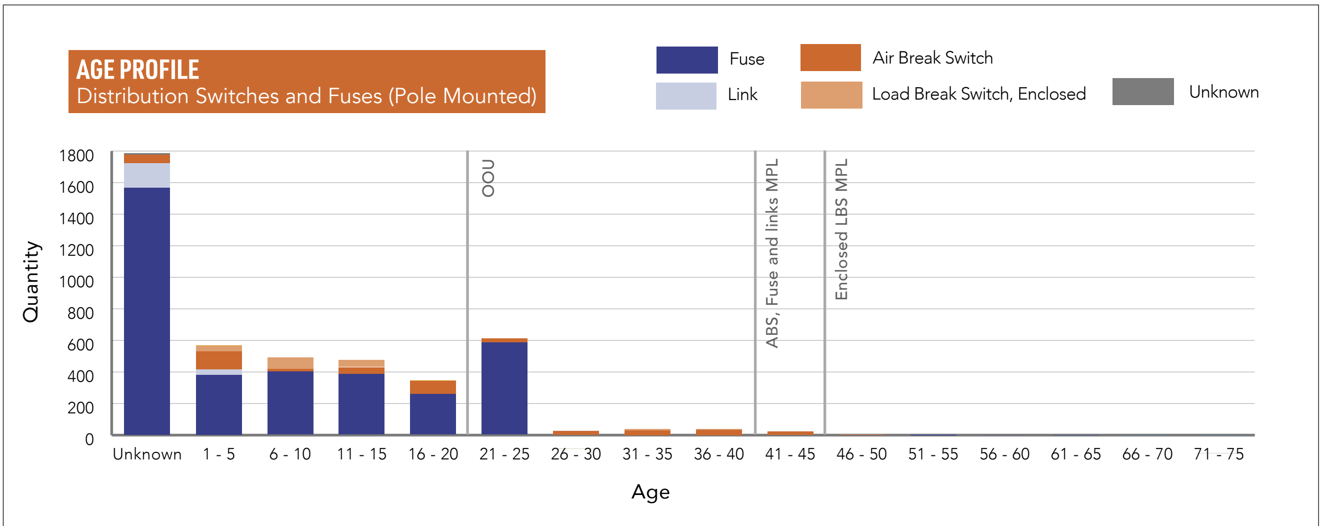


Figure 98: Age profile

62 ABSs, dropout fuses and links have an OOU of 20 years and an MPL of 40 years. Enclosed LBSs have an OOU of 20 years and an MPL of 45 years.

11.15.10 Asset health

The health assessment for overhead switches is shown in Figure 99 to Figure 100. The assessment is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

The health forecasting for ABSs and enclosed LBSs was predominantly age-based (less than 10% was based on condition). For ABSs, 46% of the age data reflected the installation date, another 40% was derived from the pole age, and the remainder is unknown. For the enclosed LBSs, we have the installation dates for all but two units. Hence, the age-based forecasting is robust. We intend to use condition data for health forecasting, so the assessment accuracy for these assets will improve over the next few AMPs.

We have 57% of the assets with an installation date for dropout fuses, and for links, this is 18%. Our current health forecasting is not reliable. It is not practical to improve the age dataset (as this data cannot be obtained from our visual inspections); hence, our health and forecasting for these assets will only improve as we get condition data. Improvements can be expected over the next five years.

Figure 99: Current and forecast asset health (ABSs)

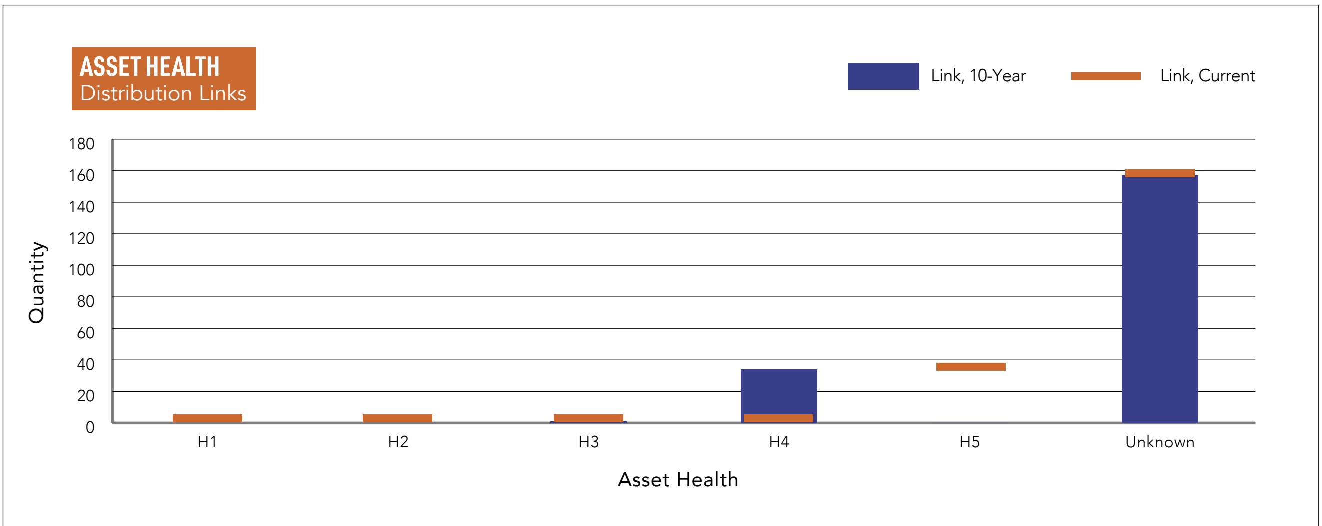


Figure 100: Current and forecast asset health (Links)

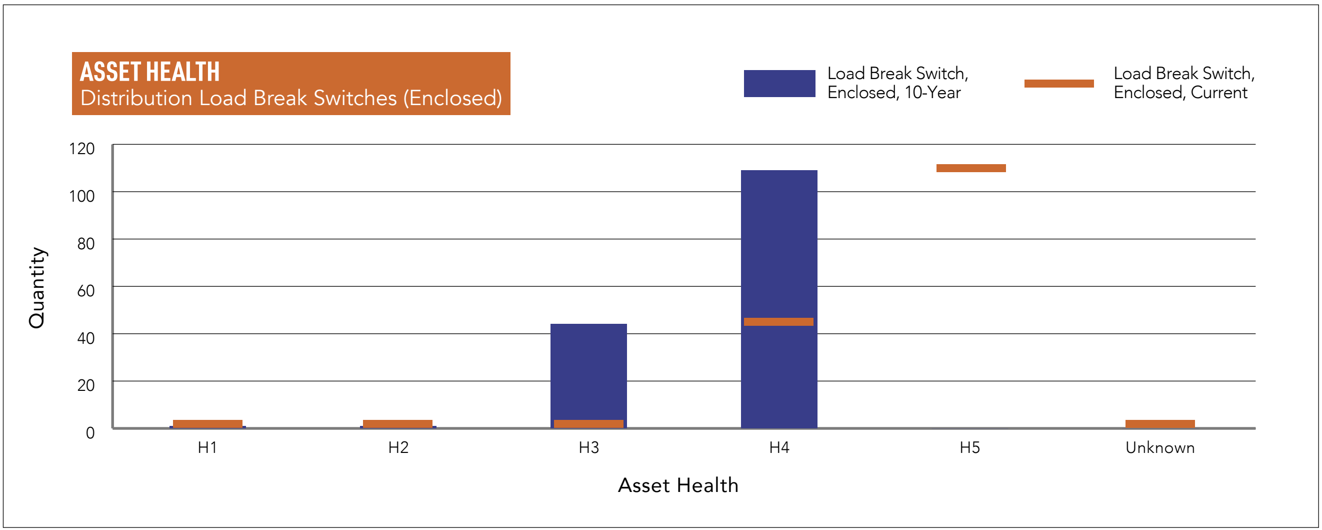


Figure 101: Current and forecast asset health (Enclosed LBS)

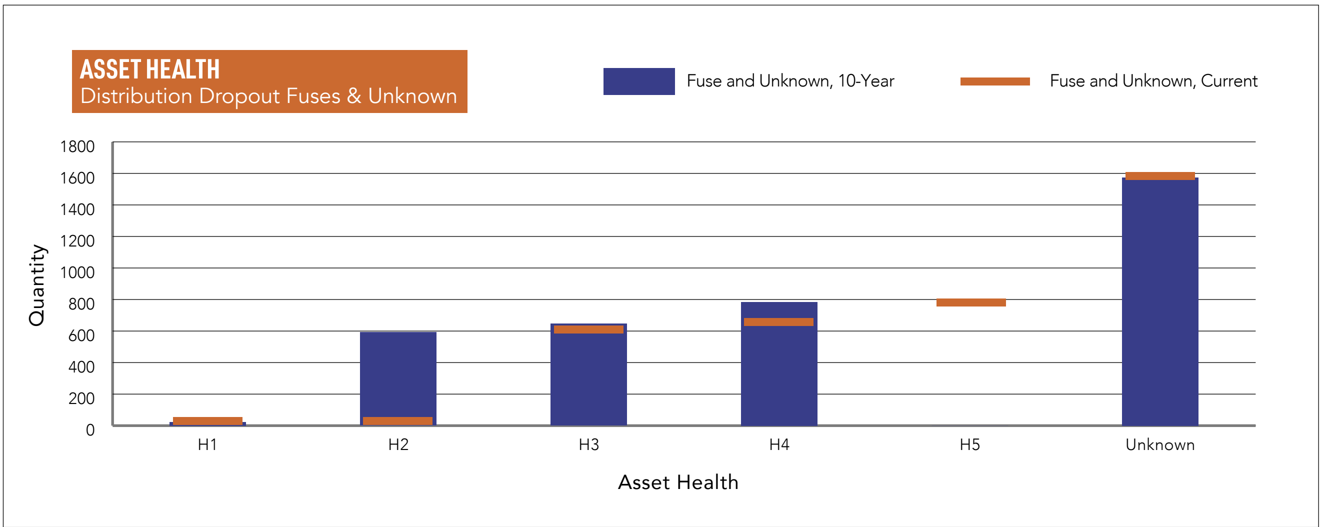


Figure 102: Current and Forecast Asset Health (Dropout Fuses and Unknown)

Table 105 shows the current and forecast for low-health overhead switches over the next ten years. For ABSs and enclosed switches, health forecasting is considered reasonable. The dropout fuses, and links data is not regarded as accurate and is not used for renewal forecasting.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
ABS	443	119	168	38%
Enclosed LBS	155	1	2	1%

Table 105: Current and forecast asset health (ABSs and enclosed LBSs)

Type	Quantity	Grade H1 (Current)	Grade H1 (+10yrs)	% of Fleet at Grade H1 (+10yrs)
Dropout fuse	3,601	Not accurate	Not accurate	Not accurate
Links	192	"	"	"

Table 106: Current and forecast asset health (dropout fuses and links)

11.15.11 Asset replacements

For ABSs and enclosed LBSs, we forecast to replace all H1 and H2 assets over the next ten years (as shown in Table 107). The renewal rate is sufficient to eliminate all H1 enclosed LBSs by the end of FY29. However, we are forecasting a constant ABS replacement rate over the next ten years (rather than frontloading this to the FY25 to FY29 period), which means all H1 ABSs will be eliminated by FY31. A flattened replacement rate better fits our resourcing, and we do not consider the two-year delay in eliminating H1 ABSs will create material risk as we will be prioritising renewal in areas with high criticality.

The revised health assessment has resulted in fewer low-health ABSs than the 2023 AMP.

We forecast a renewal rate consistent with historical replacement rates for dropout fuses and links. Our forecasts are higher than the 2023 AMP. The renewals are unplanned (defect and failure-driven); hence, actual renewals may differ.

Type	Grade H1 (+10yrs)	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
ABS	-	168	168
Enclosed LBS	-	2	2
Dropout fuse	Not accurate	-	350
Link	"	-	20

Table 107: Asset Renewal Forecast

11.15.12 Expenditure forecast

Table 108 shows the forecast expenditure for this fleet. The forecast expenditure is higher than in the 2023 AMP for FY25 to FY29 due to the increase in dropout fuse replacements. The renewal provision for "other drivers" accounts for storm and vehicle damage.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
ABS renewal	Planned	ARR	336	336	336	336	336	1,680
Enclosed LBS renewal	Planned	ARR	-	-	-	-	40	40
Link replacements	Unplanned	ARR	4	4	4	4	4	20
Dropout fuse replacements	Unplanned	ARR	70	70	70	70	70	350
Unplanned replacements (all types), other drivers	Unplanned Unplanned	ARR	103	103	103	103	103	514
Total	**-**	**ARR**	**513**	**513**	**513**	**513**	**553**	**2,604**

Table 108: Forecast Expenditure

FY24 Real $000

11.16 Distribution and LV cable fleet plan

11.16.1 Fleet overview

Note: This fleet plan excludes streetlight cables.

Underground cables comprise 11% of Wāipa's distribution circuit length and 43% of the LV circuit length. This fleet plan includes 11kV and LV cables, as shown in Table 109.

Asset Type	Quantity
11kV cable	160 km
LV cable	378 km

Table 109: Cable fleet circuit length

Cables need to have good insulating properties (as they are buried in the ground and may contact other objects that must not become live), good conductivity (to minimise losses and associated heating), and resistance to deterioration of the insulation and conductor (as they are expensive to replace): the insulation type and type of construction results in different OOU and MPL. However, we need more detailed data on specific cable types (other than basic insulation types). Table 110 summarises the types of cables currently used on the network.

Cable and insulation type	Approximate % of the fleet	Attributes
11kV XLPE	100%	Cross-linked polyethene is used as the insulation medium around the cable cores for these cables. PVC separates the cores and outer protection of aluminium sheaths or steel wire armour with a final sheath of PVC.
11kV PILC	0.01%	PILC uses oil-impregnated paper insulation. A lead sheath protects the cable cores and insulation. A lead sheath encases the cable, and a further outer sheath of tar-impregnated fibre material, PVC, or polyethylene. PILC cables have been used for over 100 years and typically have a long MPL. XLPE cables are favoured over PILC. The last of our PILC cables will be replaced in FY25 as part of the Te Awamutu GXP 11kV feeder cable upgrade project.
400V PVC	100%	These cables use XLPE insulation and an outer protective sheath of PVC.

Table 110: Cable type

There are a range of failure modes for cables. These can be incremental, where the health decays over time, or more acute, where failure is caused by foreign interference (e.g. digger excavation).

Early generation XLPE cables were prone to insulation deterioration and pre-mature failure due to water treeing.

Other failure modes may be due to aluminium screening and the brittling of PVC sheaths (known as the 'red rubber sheathing' cable, mainly in the Cambridge network) associated with the older XLPE cables. These issues can cause water ingress, insulation deterioration, or other safety issues.

We believe we have many HV cables of the 'red rubber sheathing' type or early generation.

11.16.2 Fleet performance

We do not have detailed failure data on cables (and they are currently grouped with conductors).

Based on operational observations, we experienced several failures over the years associated with the 'red rubber sheath' 11kV cable associated with the brittling of PVC sheaths (an older type of cable).

Recent changes to the fault recording system will provide additional data to enable fault trends to be analysed going forward.

11.16.3 Fleet risks

Table 111 highlights the predominant risk posed to the cable fleet, its impact, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Excavation machinery contacting live cables risking electrocution and equipment damage.	• Electrocution or electric shock • Damage to equipment • Network outages	• Public safety • Network performance	• Warning tape and protection are fitted above the cables. 11kV cables have steel protective screening. • Electrical protection isolates the cable in the event of a fault. • We have a public safety campaign to raise awareness of risks around digging in the road reserve. • Provide cable locate service to 3rd party, provide a mark-up, and issue a closed work permit.
The early generation 11kV XLPE cable, particularly the 'red rubber sheath' cable, have a high failure rate.	• Network outages	• Network performance	• Reactive renewal when such a cable is identified through other projects. • Review historical asset data to check for data improvement opportunities.

Table 111: Fleet risks

11.16.4 Fleet strategy

The key objective for this fleet is to convey electricity to consumers reliably and efficiently while building our data on the cable fleet to understand asset health and promptly identify and resolve any low-health assets.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year strategy for this fleet is shown in Table 112.

Strategy	Description	Outcome
Capture fleet data	• Assess internal records to build data on cables • Update GIS accordingly	• Increase in data accuracy scores for asset register and age profile
Common fleet strategies (refer Table 50 in section 11)	• Enhance asset health assessment and forecasting (Note: this is a key strategy for this fleet as we are relying on the improvement of fault and reliability analysis to identify low health assets and drive the renewal projects) • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation • Understand and reduce fleet risk	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Assess new condition assessment techniques.	• We will monitor industry development concerning cable condition assessments. These will be adopted where practical to do so.	• Improved condition assessment, more accurate health forecasting, and more proactive health-based renewals
Public safety campaign to raise awareness for "Dial before you dig."	• Newspaper adverts, Social media campaigns, community events and target group (e.g., emergency services, excavators, etc.) presentations as part of our Public Safety Management System and its KPI	• Minimise public safety risks SFARP
Renew early generation / 'red rubber sheath' 11kV XLPE cables	• Reactive renewal when such a cable is identified through other projects.	• Progressively replace the older cable, improve overall fleet performance

Table 112: Fleet strategy

11.16.5 Design and construct

Cable selection and design are integrated into the line design process. We have a standard suite of cable sizes for each voltage.

As part of our network transformation roadmap, we will review cable sizes to ensure they remain appropriate for our future needs (refer to Section 8.7.11).

11.16.6 Monitoring

Proactive cable monitoring is limited to 11kV terminations. Cable testing occurs if fault and reliability trends indicate potential deterioration of the cable.

Monitoring type	Description	Frequency
Inspection and testing of 11kV cable terminations	• Partial discharge and acoustic diagnostic testing of cable terminations in switchgear occurs as part of switchgear testing, • Acoustic and visual inspection of the live termination in the distribution transformer HV compartment under a specific Standard Operating Procedure	Three yearly
	• Overhead cable terminations are inspected as part of the detailed overhead line inspections	Five yearly
11kV Cable testing	• We do insulation on cable runs to assess the condition of a cable length where we have concerns about the cable's performance	Ad hoc
400V cable	• We do insulation testing on cable runs to assess the condition of a cable length where we have concerns about the cable's performance	Ad hoc

Table 113: Fleet monitoring

11.16.7 Maintaining

There are no specific maintenance routines for cables. We will replace termination and joints if these show signs of deterioration after inspection or testing.

11.16.8 Renewal

Our fleet renewal approach is shown in Table 114.

Decision	Description
Renewal forecasting	• The forecast of asset renewals is to replace all current and forecast H1 and H2 assets over the next ten years
Determining specific renewal projects	• Renewal projects are determined from reliability trends and fault trends. These assessments direct more detailed testing to determine if renewal is required • The assessments are prioritised by criticality and worst-performing feeder
Assessing alternatives	• For cables, the only alternative to like-for-like replacement relates to cable size. We may consider installing a larger cable size
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset. This mainly applied to 11kV terminations.

Table 114: Fleet renewal forecasting

Material spares

Cable is a common asset. We hold termination and joint spares and a reasonable amount of 11kV and 400V cables sufficient to support fault situations.

11.16.9 Population and age

The population and age of our pole fleet assets are shown in Figure 103. Due to the high number of unknown assets, the data is not considered reliable.

Assessing and improving cable age data is an important improvement project that will commence in FY25.

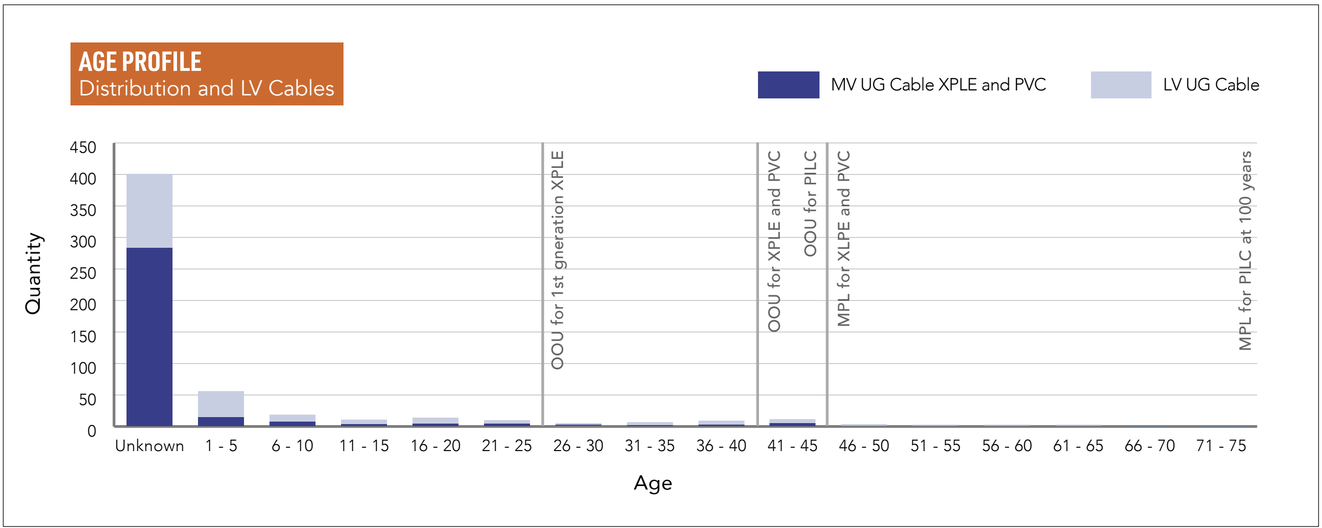


Figure 103: Age profile (km)

11.16.10 Asset health assessment

The health assessment for LV and 11kV cables is shown in Figure 104 and Figure 105. The assessment is age-based using the EEA asset health guide, including the health forecasting discussed in Section 11.5. As noted above, the age data is unreliable and should only be taken as a rough guide. The health forecasting for grades H1 and H2 is indicative only. Our health forecasting will improve following the data improvements.

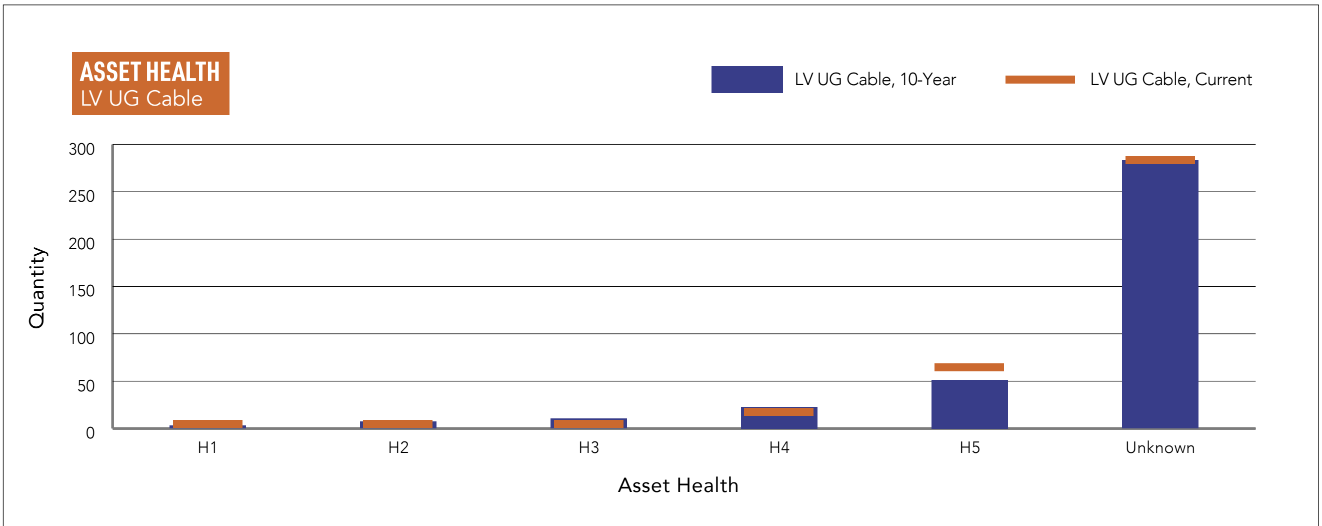


Figure 104: AHI, LV UG cable (km)

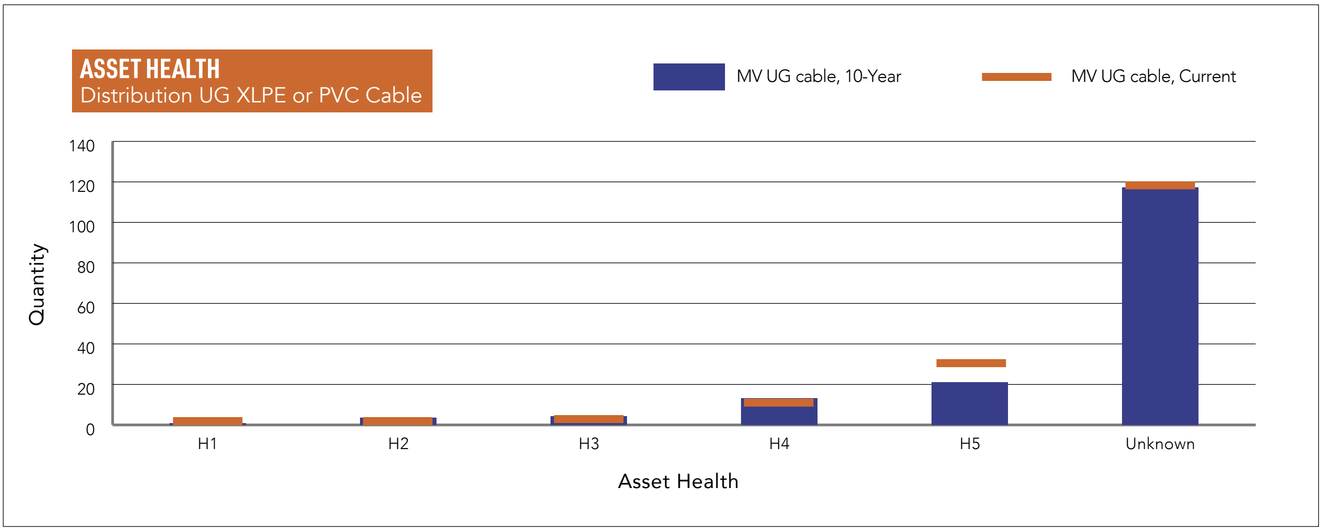


Figure 105: AHI, MV UG cable (km)

Table 115 shows our current estimates of assets that will reach health grade H1 and H2 over the next ten years. This assessment is not considered to be reliable.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
11kV cable	160	0.9	4.4	2.8%
LV cable	378	2.9	10.2	2.7%

Table 115: Current and forecast asset health (circuit km)

Note: *Quantities are in km of circuit length.*

11.16.11 Replacement programme

We have estimated the quantity of assets for renewal over the next ten years (as shown in Table 116). The forecast cable replacements are a provision only. We have not defined specific projects for the next 12 months and have removed renewal estimates the 12 months.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
11kV cable	4.4	0.7
LV cable	10.2	9.0

Table 116: Asset renewal forecast (circuit km)

Note: *Quantities are in km.*

11.16.12 Expenditure forecast

Table 117 shows the forecast expenditure for this fleet.

We have included a provision replacement budget to reactively replace the early generation XLPE cables when they are identified during other project works and unplanned renewal for LV cables.

We have not included a provision for third-party damage repairs as these are difficult to forecast (and the net impact will be minimal as customer contributions are required for repairs).

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
11kV cable replacement	Planned	ARR	-	-	-	-	140	-
11kV cable replacement (reactive identification)	Planned	ARR	100	100	100	100	100	500
LV cable replacement	Planned	ARR	-	80	80	80	80	400
Cable replacement	Unplanned	ARR	5	5	5	5	5	25
Total	**-**	**ARR**	**105**	**185**	**185**	**185**	**325**	**925**

Table 117: Forecast capital expenditure

FY24 Real $000

11.17 Distribution ground-mounted transformers

11.17.1 Fleet overview

The purpose of distribution transformers is to convert the electricity supply from the distribution voltage (11kV) to low voltage (400V/230V) suitable for supply to residential, commercial and rural customers.

Ground-mounted distribution transformers have a capacity from 50kVA to over 1,500kVA. We hold spare transformers in stock for the standard sizes. These are generally located in the berm, and the transformers on industrial or commercial premises are covered by easement or contract.

Transformers are upgraded as required to meet load growth.

Table 118 summarises the population of ground-mounted distribution transformers by kVA rating.

Rating	Quantity	% of total	Typical usage
< 100kVA	136	15%	Mainly 50kVA supplying a few rural lifestyle customers in the urban fringe.
= 100kVA	230	25%	Supplying small urban areas or commercial customers
150 to 200 kVA	291	32%	Supplying urban areas or commercial customers
300 kV	154	17%	Supplying commercial or industrial customers
500kVA	59	6%	Supplying industrial customers
>500kVA	24	3%	Supplying industrial customers
Unknown	21	2%	unknown
Total	**916**	**100%**	

Table 118: Ground-mounted distribution transformer population by kVA rating

We have good-quality data on the age and attributes of this fleet. 98% of the assets have a date of manufacture. Asset condition data is being captured during the most recent inspection rounds.

11.17.2 Fleet performance

Ground-mounted transformers are often located where the public can access them and, therefore, need to be designed and secured to ensure public safety. There are no recorded public safety events concerning these assets.

Apart from one known 1.5MVA transformer failure due to a tap changer, there have been very few incidents of ground-mounted transformer failures. There are presently no concerns with the fleet's performance.

11.17.3 Fleet risks

Table 119 highlights the material risks associated with the ground-mounted transformer fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Third-party interference (Car vs Transformer) that damages the asset, causing outages and potential contact with live parts	Transformer damage could result in a large outage and injury to members of the public	• Public safety • Network performance	• Our fleet strategy includes a mitigation plan.
Public gain access to live parts through poorly secured or damaged locks and doors	Injury to members of the public	• Public safety	• Doors are securely fixed and locked, and live parts are screened internally. • Large urban transformers are inspected annually to ensure that public safety measures are maintained. • An upgrade to the locking system upgrade is planned.
Oil leaks that could cause environmental damage	Environmental damage	• Environmental damage	• The assets are inspected annually, and assets with oil leaks are replaced. • We have oil spill kits, and our field crews are trained to handle oil spills should a leak occur.
The earthing system is damaged, compromising electrical protection and risking fatal voltages.	Proper earthing is critical to the multiple-earthed neutral (MEN) system in New Zealand.	• Public safety • Regulatory breach	• The earth is inspected and tested every five years.
Unforeseen demand growth occurs, which causes overloading and damage to transformers.	Transformer failure could result in a large outage.	• Network performance	• Five yearly monitoring of transformer load. • We are investigating an LV visibility solution.
Sub-optimal transformer tap setting leading the high or low voltages at the LV network	Poor supplier voltage will affect customers' appliances and equipment and limit their ability to connect Distributed Energy Resources like electric vehicles and solar generators.	• Public safety • Network performance • Regulatory breach	• Potential voltage issues due to network growth and backfeed are studied. • The low Voltage Complaint process addresses voltage issues. • We are investigating LV visibility solutions to enable proactive action.

Table 119: Fleet risks

11.17.4 Fleet strategy

The key objective for this fleet is to ensure voltage compliance and public safety and to avoid asset failures.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 120.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting • Improved optimisation of work plans and project timing • Reduce reliability and safety risks
Eliminate all H1 transformers by the end of FY26	• Ensure all H1 transformers are replaced before failure • Ensure all H2 transformers are replaced before they become H1	• Zero H1 transformers
Ensure the security of the assets	• Annual public safety inspection	• Zero public safety incidents
Maintain critical spare	• Consider geotechnical and flooding hazards in the new site and structure design • Stock critical spares. Review the spares required for industrial customers and include appropriate spares	• Critical spares of the right size and type are available for unplanned renewal
Timely replacement of defects	• For ground-mounted transformers, given the potentially high consequence of failure, defect replacements shall occur promptly	• No failure of assets with defect notices
Assess third-party damage risk	• Undertake a review of vehicle crashes to determine if there are any high-risk sites	• Consider protection or relocation for high-risk sites.
Enhance fleet resilience (refer to Section 9.4)	• The design for new sites will take into consideration flooding and geotechnical hazards (seismic and wind are already covered in the design standards)	• Resilience to natural hazards

Table 120: Fleet strategy

11.17.5 Design and construct

The transformer foundations are designed to structural design standards (NZS 1170 series), and the transformers are designed to AS/NZS/IEC 60076 series. The transformer design standards include a capitalised loss calculation to ensure new transformers are efficient over their lifecycle. The design for these assets considers seismic in the structural design standards. Flooding and geotechnical hazards are considered during site selection.

Waipā has standard designs prepared for general ground-mounted transformers, including its LV frame. Currently, we do not own any transformers with LV circuit breakers.

Special design requirements are in place for new transformer sites:

- In the circumstances of the overhead network supplying a ground mount transformer via a long cable (exceeding 200m), our design rules require a 3-phase switch to be installed in series with the drop-out fuse. Based on operating experience, there are no known farro-resonance concerns to our network.
- For industrial or commercial sites with large, dedicated transformers supplying dedicated industrial or commercial consumers, our current design rules require a protection device on the transformer LV. We have standardised ganged fuse LV frame designs for transformers up to 1.5MVA. Special dispensation may be considered, and we would require the customer to meet the additional requirements under the NSZ3000 (e.g., mechanical protection) as an 'unprotected main'.

11.17.6 Monitoring

Ground-mounted transformers are inspected, and their earthing systems are tested, separate from the detailed line inspection. Table 121 describes our current fleet monitoring approach:

Monitoring type	Description	Frequency
Safety inspection	• Inspection of security, locks, doors and other public safety hazards for transformers located within urban areas.	Annually
Detailed inspection	• The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, oil leaks, HV panel, LV panel, locks, doors, and earthing connections. • Reading of LV MDIs • Defect notices are raised where priority repair or replacement is required	5 Yearly
Earth testing	• Measure the resistance of earthing connections • Visual inspection of the earth connection	5 Yearly
Special industrial sites	• Transformers supplying major industrial sites may be subjected to additional inspection and tests based on site-specific requirements and commercial arrangements with the owner, including but not limited to the following: • Detailed inspection as detailed above. • Dissolve gas analysis.	As agreed with the Customer

Table 121: Fleet monitoring

11.17.7 Maintaining

There are no specific maintenance routines for ground-mounted distribution transformers. However, earthing systems are maintained to achieve the same MPL as the transformer.

General distribution transformers that are swapped out due to capacity or corrosion are taken to the workshop for paint and testing before being put back on the network. Large industrial units are sent to service providers for more detailed maintenance.

11.17.8 Renewal

Our fleet renewal approach is shown in Table 122.

Decision	Description
Renewal forecasting	• The forecast of asset renewals is as per the fleet strategy
Determining specific renewal projects	• Specific renewal projects are identified from the health assessment • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by criticality. The highest priority will be replacing transformers in critical locations
Assessing alternatives	• In normal circumstances, no other options are assessed • The exception is where the transformer replacement resulted from a car vs pole incident. If historical data on vehicle crashes indicate the transformer is in a high-risk area, we will consider relocating the transformer
Defect replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 122: Fleet renewal forecasting

Material spares

We hold stock sufficient to cover standard sizes and configurations for normal usage if a defect replacement is required. We increase our stock holding when supplier delivery is constrained and lead times are extended. We are in the process of reviewing the need for spares of large size and non-std configuration mainly.

11.17.9 Population and age

The population and age of our ground-mounted transformer fleet assets is shown in Figure 106. The graph indicates that 10% of the fleet is above a Waipā specific OOU, but no assets are at MPL.[63] Our condition and asset replacement data suggest that the OOU for Waipā is around 30 years, above the EEA standard for this asset type of OOU of 20 years (refer to Figure 107).

[63] *Ground-mounted transformers have a Waipā OOU of 30 years and an MPL of 70 years.*

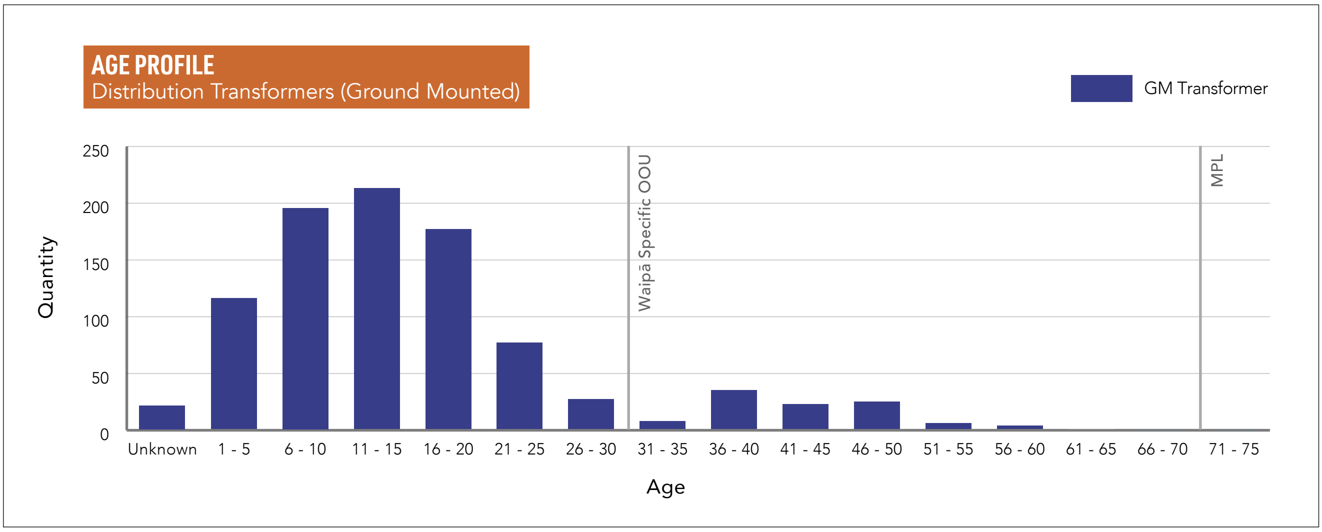


Figure 106: Age profile

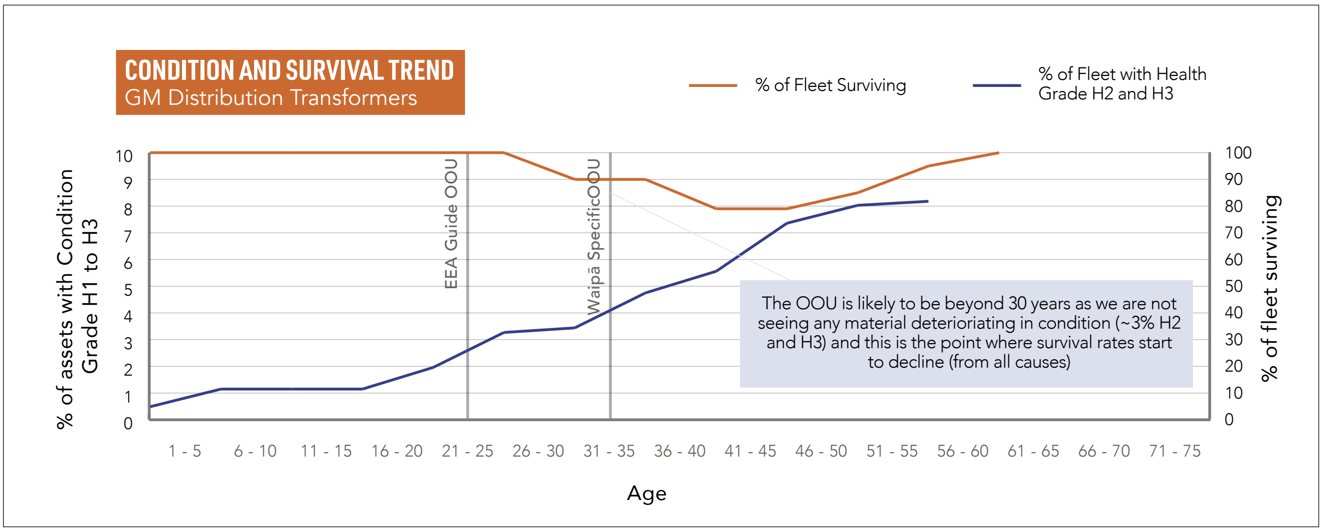


Figure 107: Assessment of Waipā specific OOU

11.17.10 Asset health

The health assessment for ground-mounted distribution transformers is shown in Figure 108 and is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3.

The data used for ground-mounted transformer health forecasting is robust, with 67% being condition-based. The remainder of the assets have good age data. The deterioration of ground-mounted transformers is relatively gradual, consistent with the long MPL for this fleet.

There are currently no assets with a health grade of H1.

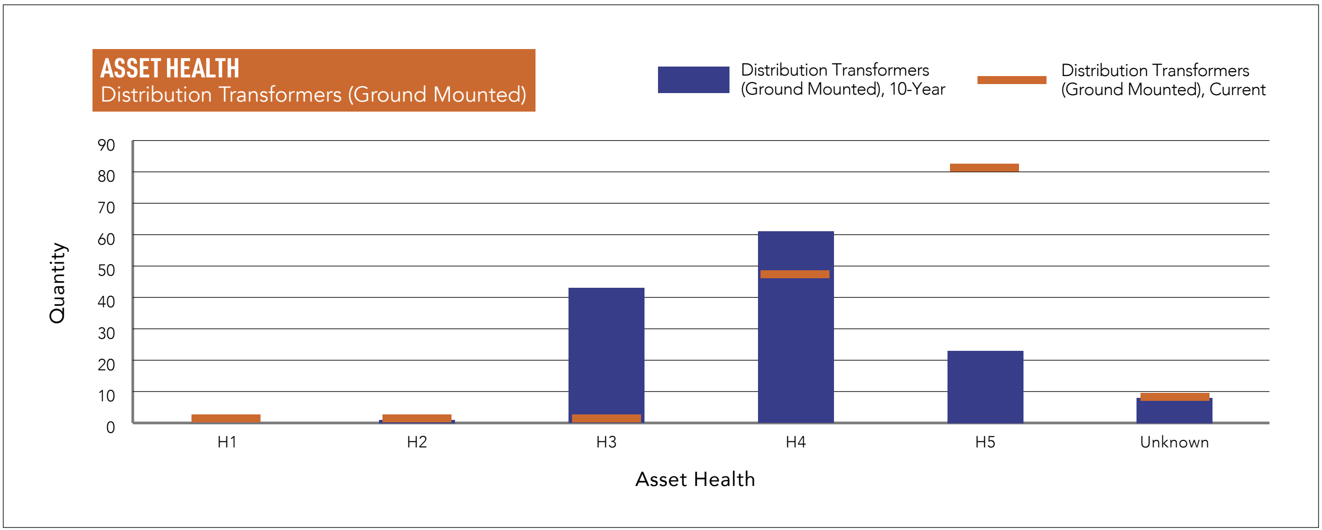


Figure 108: Current and forecast asset health

Table 123 shows the current and forecast low-health ground-mounted transformers over the next ten years. 23% of low-health transformers are forecast based on condition, and the rest are based on age. The extent of low-health assets would increase by 70% if the forecasting was solely age-based, indicating that the actual deterioration rate is lower than that implied by age-based forecasting. Hence, it's likely that the addition of new condition data will improve the fleet's health profile.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
11kV cable	160	0.9	4.4	2.8%
LV cable	378	2.9	10.2	2.7%

Table 123: Current and forecast asset health

The forecast for low-health ground-mounted transformers is materially lower than in the 2023 AMP forecast. The change in forecast reflects the use of condition data and the improvements in health forecasting methodology.

11.17.11 Asset replacements

Consistent with our renewal strategy, we are forecasting the replacement of all H1 and H2 ground-mounted transformers over the next ten years (as shown in Table 124). The annual renewal rate is sufficient to replace all H2 assets before deteriorating to H1.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
11kV cable	4.4	0.7
LV cable	10.2	9.0

Table 124: Asset renewal forecast

11.17.12 Expenditure forecast

Table 125 shows the forecast expenditure for this fleet. The forecast expenditure is slightly higher than in the 2023 AMP for FY25 to FY29. The renewal provision for "other drivers" accounts for damage to the asset from other drivers (e.g. weather events or third-party damage). The provision for transformer replacements for load upgrades is included in the development plan.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
Ground-mounted transformer, renewals	Planned	ARR	130	130	130	130	195	910
Ground-mounted transformer, other drivers	Unplanned	ARR	64	64	64	64	64	322
Total	-	-	**194**	**194**	**194**	**194**	**259**	**1,232**

Table 125: Forecast capital expenditure

FY24 Real $000

11.18 Distribution ring main units (RMUs)

This fleet has no old assets, and no renewals are forecast for the next ten years. This is the same as the 2023 AMP.

We have included a change to our inspections as part of this fleet plan. Since the key fleet objective is public safety, we have included an annual public safety inspection (e.g., security, locks, damage). This is consistent with other EDBs.

11.18.1 Fleet overview

Our fleet of ring main units (RMUs) provides switching points for the underground cable network. Almost all the RMUs are in the urban, commercial and industrial areas. They are primarily installed in the road reserve with significant public exposure.

We currently have over 130 RMUs in service. The fleet is relatively young as all old oil-filled RMUs were replaced due to potential fire risk. The following are the types of RMU installed in the network:

- Schneider 11kV RingMaster RMU – air/SF6 insulated;
- Entec 11kV Halo RMU – solid insulation;
- ABB 11kV Safelink and Safelink2 – SF6 insulated;
- ABB 11kV SafeRing / SafePlus – SF6 insulated;
- Siemens 11kV 8DJH RMU – SF6 insulated with insulated elbow termination.

All RMUs are currently 11kV units only. We will introduce the first 33kV Siemens unit for the new 33kV ripple plant in the Forrest Zone substation.

We have good-quality data on the age and attributes of this fleet. 94% of RMUs have a known date of manufacture. Asset condition data (to the new standard) is presently being captured and will be completed in time for the 2025 AMP.

11.18.2 Fleet performance

Failures and operational issues are rare, but the impacts on customers can be significant when they do occur. FY23, an RMU failure on the Cambridge East feeder caused 11.84 SAIDI minutes. We are also experiencing RMU damages due to cable termination failure, mainly triggered by moisture-caused partial discharges and flashovers within the cable compartment for certain types of RMU. Due to the intrinsic safety design of the RMU, the faults are well contained within the RMU.

11.18.3 Fleet risks

Table 126 highlights the material risks associated with the RMU fleet, their impact on stakeholders, and our response.

Risk	Stakeholder Impact	Stakeholder Linkage	Our response
Third-party interference (Car vs RMU) that damages the asset, causing outages and potential contact with live parts	• RMU damage could result in a large outage and injury to members of the public	• Public safety • Network performance	• Refer to the fleet strategy
The public gain access to the switch controls through poorly secured or damaged locks and covers	• Unauthorised operation of the switch resulting in switch damage, customer outages, and potential injury to members of the public	• Network performance • Public safety	• The covers are securely fixed and locked. • RMUs are inspected annually to ensure that public safety measures are maintained. • An upgrade to the locking system upgrade is planned.
Cable termination for ABB RMU is susceptible to condensation-triggered partial discharge, hence failure.	• Cable termination failure could result in a large outage.	• Network performance *Note: The RMU is arc containment rated for safety.*	• A partial discharge test has been included in the standard maintenance procedure.
ABB SafeLink RMUs manufactured in certain years are prone to have the switch over-travel when operating, phase making contact to earth, resulting in an internal fault	• RMU switch over-travel could result in an internal fault and a large outage	• Network performance • Staff safety *Note: The RMU is arc containment rated for safety.*	• We follow the manufacturer's instructions and operate such RMU with the Manufacturer's proprietary overtravel arrest device.
According to the latest industry update, ENTEC Halo RMU has recorded internal failures, which typically occur during switching upon re-livening *Note: we have three units in the network*	• RMU internal faults will result in a large outage and expose staff to hazards.	• Network performance • Staff safety	• Temporary operating restrictions on the earth switches have been imposed according to the manufacturer's recommendation.

Table 126: Fleet risks

Oil-filled ground-mounted switchgear presents fire and operational risks. Fire could result from an in-service failure or the internal mechanism's failure during switching. This is an industry-wide issue; most EDBs are progressively replacing their oil-filled switchgear. Waipā has completed the replacement of its oil-filled switchgear to remove this risk.

11.18.4 Fleet strategy

The key objective for this fleet is to maintain high operational performance for work isolation, network re-configuration, and ensure public safety.

To address the fleet performance, risks, and other issues mentioned in the preceding sections, the ten-year fleet strategy is shown in Table 127.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting • Implement risk-based renewal forecasting	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting
Avoid any H1 assets	• Ensure all H2 RMUs are replaced before they become H1	• Zero H1 RMUs
Ensure the security of the assets	• Annual public safety inspection	• Zero public safety incidents
Ensure operational performance	• Complete the required inspections and maintenance on the assets • For RMUs, given the potentially high consequence of failure, defect replacements shall occur promptly	• Inspection and maintenance completed as per schedule • No failure of assets with defect notices
Assess third-party damage risk	• Design and position RMU away from busy roadways and corners. • Undertake a review of vehicle crashes to determine if there are any high-risk sites	• Consider protection or relocation for high-risk sites.
Enhance fleet resilience (refer to Section 9.4)	• Consider geotechnical and flooding hazards in the new site and structure design	• Improved asset resilience

Table 127: Fleet strategy

11.18.5 Design and construct

The RMU foundations are designed to structural design standards (NZS 1170 series), and RMUs are designed to AS/NZS 60265. The design for these assets considers seismic in the structural design standards. Flooding and geotechnical hazards are considered during site selection.

Waipā has standard designs prepared for RMU sites.

11.18.6 Monitoring

Table 128 describes our current fleet monitoring approach:

Monitoring type	Description	Frequency
Safety inspection	• Inspection of security, locks, covers, doors and other public safety hazards for units located in towns or populated / special locations • Inspection of insulating gas levels	Annually
Detailed inspection and testing	• The detailed inspection captures the EOL condition drivers, which (under the new standard) include the condition of the external tank, operating mechanism, locks, doors, and earthing connections • Partial discharge and acoustic diagnostic tests • Measure the resistance of earthing connections • Visual inspection of the earth connection • Defect notices are raised where priority repair or replacement is required	3 Yearly

Table 128: Fleet monitoring

11.18.7 Maintaining

The maintenance of RMUs is shown in Table 129.

Monitoring type	Description	Frequency
Preventative maintenance	• All units are SF6 insulated. All components within the SF6 insulated tank are maintenance-free for the unit's life expectancy. • Gas top-up is not expected during the lifecycle. Gas levels are readjusted in response to inspection if technically and economically acceptable. Unit is red tagged and operating temporarily ceased until maintenance is completed (May be replaced – dependant on leakage rate)	As required
Condition-driven maintenance	• Maintenance is carried out in response to the inspection and testing. This may include maintenance on the unit • Damage to panels (or restrictions from opening panels) repaired or remedied as required	As required

Table 129: Fleet maintenance

11.18.8 Renewal

Our fleet renewal forecasting approach is shown in Table 130.

Decision	Description
Renewal forecasting	The forecast of asset renewals is to: • Ensure there are no H1 assets • Replace all H2 assets before they become H1 • Replace all current and forecast H1 and H2 assets over the next ten years
Determining specific renewal projects	• Specific renewal projects are identified from the health assessment • Site inspections are undertaken to confirm the scope and design for the renewal • The renewal projects are prioritised by the criticality of the feeder
Assessing alternatives	• In normal circumstances, no other options are assessed • The exception is if historical data on vehicle crashes indicate the RMUs are in a high-risk area, we will consider relocating the RMUs or adding protection
Defect repair and replacement	• Defects are compiled in our defect management system, and a rating is applied based on urgency. The urgency rating considers the criticality of the asset.

Table 130: Fleet Renewal Forecasting

Material spares

We hold stock sufficient to cover defect and damage replacements. We are looking at rationalising the models and quantities we hold for emergency spares.

11.18.9 Population and age

The population and age of our RMU fleet is shown in Figure 109. The graph indicates that one asset is above OOU, but none are at MPL.[64] The age profile reflects the initiative to replace oil-filled switchgear over the last twenty years. Age data on the eight unknown age assets will be captured as part of the current inspections.

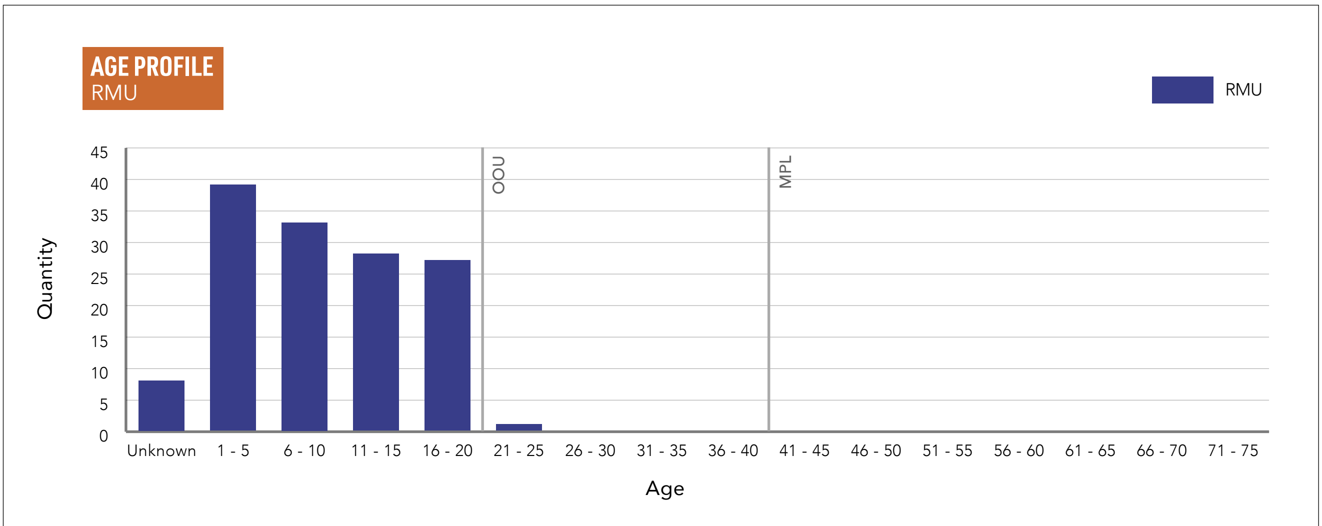


Figure 109: Age profile

[64] *RMUs have a OOU of 20 years and an MPL of 40 years.*

11.18.10 Asset health

The health assessment for RMUs is shown in Figure 110 and is based on the EEA asset health guide, including the health forecasting discussed in Section 11.5.3. For RMUs, 28% of the assets have condition data.

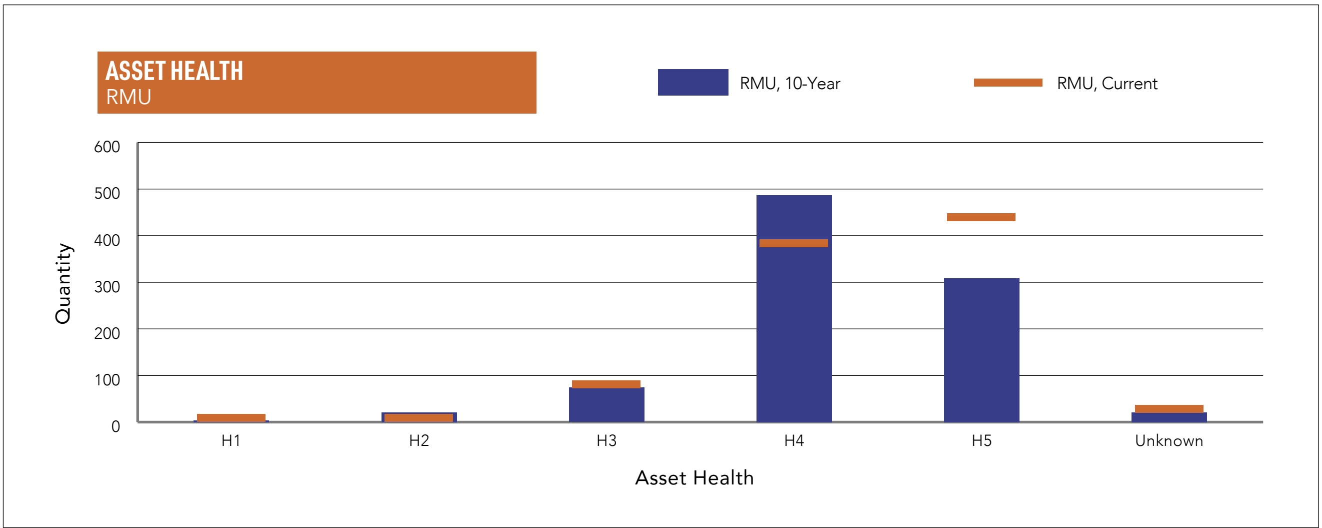


Figure 110: Current and forecast asset health

Table 131 shows the current and forecast for low-health RMUs over the next ten years. One RMU is forecast to transition into H2 health towards the end of the forecast period.

Type	Quantity	Grade H1 & H2 (Current)	Grade H1 & H2 (+10yrs)	% of Fleet at Grade H1 & H2 (+10yrs)
RMUs	128	0	1	<1%

Table 131: Current and forecast asset health

11.18.11 Asset replacements

We have not forecast any RMU replacements over the next ten years (see Table 132). The one RMU that transitions to H2 occurs at the end of the forecast period and will be replaced beyond the ten years, well before it transitions to H1.

Type	Grade H1 & H2 (+10yrs)	10yr Forecast Replacements
RMUs	1	0

Table 132: Asset renewal forecast

11.18.12 Expenditure forecast

There is no expenditure forecast for the planned renewal of RMUs. Damage to RMUs is rare; however, we recently experienced some failures due to cable termination failures. We have since performed a network-wide RMU Partial Discharge survey and have proactively mitigated sites with high Partial Discharge readings.

To be prudent, we have assumed one failure every two years in our budget. We may remove this allowance as we get comfortable with the ongoing results of the partial discharge testing.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
RMUs, defect and failure renewals	Unplanned	ARR	27	27	27	27	27	135

11.19 Secondary systems and other assets

Secondary systems include protection, communication and control systems and are critical to operating a safe and reliable electricity network. The useful life of equipment that makes up secondary systems is generally shorter than that of primary assets, as most are electronic and software-driven. Fast technological changes and a commitment to continually improve the network's performance to meet reliability requirements also drive the need to renew the fleet at shorter intervals than primary equipment.

11.19.1 Fleet strategy

The key objectives for secondary systems are to:

- Ensure the network fails-to-safe
- Remote operations execute correctly
- Reduce network costs by minimising equipment damage and increasing remote operation and control
- Replace assets before they become technically obsolete

The general 10-year strategy for secondary systems is shown in Table 133.

Strategy	Description	Outcome
Common fleet strategies (refer Table 50 in section 11.6)	• Enhance inspection standards and data • Enhance asset health assessment and forecasting (including incorporating technological obsolescence in the health assessments, as this is a key driver for replacement for the secondary fleet) • Implement risk-based renewal forecasting • Enhance renewal project selection and prioritisation	• Increase in asset condition data accuracy score • Increase in condition-based forecasting to >95% • Improve the quality of our asset health and renewal forecasting
Eliminate all H1 assets	• Ensure all H1 assets are replaced before failure • Ensure all H2 assets are replaced before they become H1	• The target will be set as data improves

Table 133: Fleet strategy

11.19.2 Protection relays

Overview of fleet

Protection relays ensure the safe and correct operation of the electrical network. They detect network faults and isolate the faulted equipment to prevent harm to the public and staff and prevent damage within consumer installations or network assets. Waipā takes 11kV supplies directly from Transpower-owned 11kV circuit breakers. Hence, our protection relay fleet is limited and includes the following:

- Protection relays within recloser/sectionaliser controllers;
- Automatic Under Frequency Load Shedding (AUFLS) relays installed at the two GXPs (currently owned by Transpower). These are programmed to trip feeders if the system frequency drops below specific set points, as the System Operator requires.

The types and quantity of our protection fleet will expand as we commission our subtransmission network and new zone substations, and we will develop this chapter further in 2025 AMP.

New regulatory requirements require us to transition to a 4-block AUFLS scheme. We will install our AUFLS relays at the two new GXPs in FY25 (refer to Section 9.7.4).

Monitoring and maintaining

Protection relays within recloser/sectionaliser controllers are covered in the respective recloser/sectionaliser live cycle chapters.

The AUFLS relays are monitored and maintained by Transpower.

Renewal

No renewals are planned for this fleet.

11.19.3 Load control system and relays

Fleet overview

We operate a ripple control system for managing peak demand (via control of consumers' hot water) and to control council street lighting. We have two ripple injection plants at the existing GXPs. We also own all the ripple relays installed at the consumer's premises.

The ripple plant at Cambridge GXP has two supply connections, one off each 11kV bus section, so it can still be operated in the event of a half switchboard outage.

Historically, the Te Awamutu ripple plant has a single supply connection on one side of the bus (meaning loss of ripple control if the bus section or the feeder is out of service). We implemented a project in 2023 to provide a second connection to a second feeder from a different bus section.

We are installing a third ripple plant (33kV unit) for the new Hautapu GXP and the Forrest Zone Substation project.

Condition, performance, and risks

The ripple plant and control system are in good condition, as they are inspected, serviced and tested annually. The ripple converters are five years old, and the coupling cells (transformer, capacity, and inductor) are 17 years old (TMU) and 23 years old (CBG).

Failure of the ripple plant could risk exceeding the GXP security level, failing to meet the System Operator's load-shedding request under the Grid Emergency Situation, and requiring us to control street-lighting manually.

Design and construct

No design changes are planned.

Operate and maintain

Our service agreement with Landis and Gyr provides annual condition monitoring and access to a contingency spare replacement converter panel, capacity cell, and other strategic spares. We also hold spares for the converter controllers interfacing with the SCADA system.

This enables major faults to be rectified within 48 hours, provided the failure is not catastrophic or involves the primary reactor or capacitor plant.

Regular inspection and testing of the ripple injection system assets ensure continued and reliable operation. The preventive maintenance schedule includes yearly onsite testing and physical inspection of the ripple plant. To comply with the Electricity Participation Code 2010, we have a 10-year inspection and recertification of ripple relays.

We also offer the ripple to the reserve market through an external service provider.

Renew or dispose

Currently, there are no plans to renew or change the ripple control within the period of this plan. However, the energy transition and the development of flexibility markets will likely result in a shift from ripple control to consumer/market-based control.

The future abandonment of the system requires further consideration as we approach end-of-life. We may need to replace the existing ripple plant coupling capacitors as soon as they reach the typical service life (per the manufacturer's advice). This project is under consideration.

11.19.4 Communication systems

Fleet overview

The communications network carries our SCADA data and voice systems. Data is used for the SCADA system to monitor and control automated devices. In contrast, voice channels are used for voice communication between the field staff and the control room to operate or switch network devices.

Our communications network consists of data systems and physical infrastructure, including fibre optic circuits, UHF point-to-point digital radios, microwave point-to-point digital radios, point-to-multipoint UHF repeaters and cellular/ADSL circuits.

There is an increasing number of automated devices on the network, and the requirements for voice and data are exceeding the capability of the older analogue channels.

Condition, performance, and risks

Some repeater channels have exceeded the maximum recommended RTUs per line, impacting overall SCADA system performance.

The existing SCADA cannot be expanded significantly because it is constrained by the bandwidth between our depot and the repeater sites and also between repeater sites. In the interim, it may be possible to install additional SCADA repeaters to alleviate the constraint (by reducing the number of RTUs per line and enabling more devices to be connected). However, the SCADA system speed will not be improved by these measures.

Design and construct

Limitations with analogue systems highlight the need for a digital solution. Key design considerations for communications system upgrade are:

- **Capacity –** new higher capacity equipment that can handle more channels, connect more devices, and increase the number of repeater sites;
- **Current functionality –** this supports a digital solution, which is the current functional standard;
- **Reliability –** ring topology to provide multiple paths for redundancy;
- **Quality/grade of service –** a digital solution delivers this.

Operate and maintain

Yearly visual inspection is completed for radios, switches, and antennas at automated devices and radio sites.

Renew or dispose

Upgrading of the current system is planned. Refer to Section 9.7.5.

11.19.5 Supervisory Control and Data Acquisition (SCADA)

System overview

SCADA and communications assets provide network visibility and remote control, allowing safe and efficient operation of the network. We contract our network control function to WEL Networks, which operates the SCADA system on our behalf.

The SCADA system also manages the ripple injection plants at Cambridge and Te Awamutu to control the load over peak times at GXP or feeders.

Our SCADA system comprises a master station, a "hot standby" backup station in our control room, and two remote operating terminals in the WEL Networks Control Centre. We have contingency plans for SCADA (refer to Section 6.6.6).

The SCADA central server communicates with remote terminal units (RTUs) over UHF and VHF radio communications. The RTUs provide the interface with network equipment such as recloser control systems.

The data collected includes feeder currents, voltages, real and reactive power, power factor and switch states. This information is used to inform operations, maintenance programs, network development planning, and to measure network performance.

Our current standard communications protocol for RTUs converts relays DNP protocol into the proprietary ABBEY protocol over analogue UHG and VHF carrier, then into the SCADA hub. DNP is not fully utilised directly due to radio network bandwidth limitations, and this constraint will be resolved as we complete the Communication system upgrade.

Condition, performance, and risks

The performance of the SCADA system depends on the overall configuration of the constituent elements:

- **Communication –** media (fibre, radio) and RTUs: This is currently constrained. Refer to Section 11.19.4.
- **Hardware –** SCADA front end and central server/ master station;
- **Software –** SCADA operating system, applications, and operator interface.

The key risk for the SCADA system is the loss of network visibility and control. A significant source of risk is a cyber-attack on the SCADA system, where a party gains control of devices or blocks our access to the network devices. Cyber security is discussed in Section 7.2.

The system's useful life depends on the availability of support, and we have an ongoing support arrangement for an existing system. The current Abbey SCADA system is reaching end-of-life due to technical obsolescence. The current system cannot support the development of advanced functionality that will be required in the future.

Operate and maintain

The SCADA system is continuously monitored through self-checking and third-party monitoring systems. The communications network is part of this monitoring system and alerts operators to communication failures or overloaded communications networks.

We currently hold limited spares for critical SCADA hub devices, with support from supplier.

Renewal

The SCADA system now requires renewal due to technology obsolescence risk. We have support available until it is replaced over the next two years. New SCADA systems have better functionality to enhance operational efficiency and manage switching and outage restoration. The new SCADA systems also offer a technology pathway for advanced distribution management (ADMS) for future LV network management, LV works management and interface with DER.

During FY25, we will evaluate the mainstream SCADA and ADMS systems deployed in NZ and select a product suite that best fits Waipā's needs. Availability of technical support, user group support, and the deployment speed (of ADMS modules) will be key considerations.

In late FY24 we commenced our discovery work to identify a suitable solution in addition to the confirmation of direction for of our control room capabilities.

Expenditure forecast

Table 134 shows the forecast expenditure for this fleet.

Description	Type	Category	FY25	FY26	FY27	FY28	FY29	Total FY30-34
SCADA Replacement	Planned	ARR	500	1,000	-	-	-	-

Table 134: Forecast Expenditure

11.20 Generation

11.20.1 Fleet overview

We maintain a small fleet of generators to support critical network parts during outages and provide supply security before delivering permanent network solutions. The existing generator sets are:

- **Swayne Road:** 3x 1MVA (fixed)
- **Te Awamutu depot:** 1x 275kVA (portable), 1x 200kVA (fixed)
- The three generator units at Swayne Road are operated to manage Cambridge GXP winter peak demand before Hautapu GXP is commissioned.
- The generators only operate during network peak load hours, generally during winter cold snap days, to manage network demand within Cambridge GXP n-1 capacity of 47MVA. Hence, in 2023 winter, they have only been operated for <10 days.
- With the commissioning of the new Hautapu GXP in early 2025, we expect the Swayne Rd generator will be operated for the 2024 winter and then redeployed.
- We are looking into redeploying them to the other part of the network to improve network reliability and resilience.

There is one fixed generator providing backup support to our Te Awamutu depot. The other is a portable unit deployed on parts of the network during outages to reduce the impact of outages on customers.

11.20.2 Fleet strategy

The generator fleet is deployed as a short-term solution to network problems on demand. Therefore, the generator sets need to be serviceable when required to run.

11.20.3 Operate and maintain

The maintenance routine includes inspection and service according to manufacturer specifications and routine operational tests to ensure the generators will run when needed.

These assets are not part of the standard network assets, so their maintenance is outsourced, commonly as part of the supply contract.

11.20.4 Renew and dispose

The need for generator sets is reviewed when the asset is nearing the end of life based on service agent advice or when it is no longer needed for its original primary function, e.g., when a permanent network solution has been implemented.

Because of the short lifespan of this asset category, disposal, sale, or re-deployment is preferred to renewal.

The Swayne Road 3x 1MVA (fixed) generators were only commissioned in 2023, and we are looking into the redeployment options to support distribution reliability or resilience issues as per Section 9.7.6.

11.21 Systems operation and network support

System operations and network support comprise our functions directly supporting electricity network operations. This covers a range of activities on the network to support the operation and maintenance part of the asset lifecycle management. These include:

- Network operations
- Network interruptions
- Fault response, maintenance and inspection
- Vegetation management

11.21.1 Network operations

Our network uses its SCADA system to carry out centralised network operations through outsourced control room services a service. The control room services cover network monitoring, switching, permitting and access control.

11.21.2 Network interruptions

Planned interruptions notification

Consumers are currently notified of planned interruptions using the following methods:

1. An email to impacted consumers' retailers providing a minimum of ten working days' notice, who then notify consumers directly.
2. Website notification before planned interruptions aligned with notifications to retailers of ten working days. An additional notification on the day of the outage as the outage reaches 'active' statuses via the Waipā Networks website.
3. A letterbox card is also distributed to customers where a planned interruption is required within ten working days for retailer notification.

Unplanned interruptions

Consumers are notified of unplanned interruptions using the following methods:

1. An email of the impacted area is sent to all retailers, the Waipā Networks customers and call centres (including after hours). This email is sent via the outage notification communication system and is manually generated. Retailers are then able to notify consumers of the unplanned outage.
2. Website notification at the time of the unplanned interruption on the Waipā Networks website.

Changes to processes and communications

Waipā Networks will shortly be transitioning to a new platform to manage several services, including notification of planned and unplanned interruptions to retailers. Once transitioned, this notification will automatically be system-generated for planned interruptions rather than manual and will be aligned with the minimum ten working day timeframe. Unplanned disruption will also be generated from the new platform to retailers once an interruption is logged.

11.21.3 Voltage quality

Voltage monitoring

Voltage is critical to our network as we have long 11kV distribution feeders. For the 11kV (HV) feeders, we have remotely controllable devices connected to our SCADA system, such as reclosers and voltage regulators, providing real-time voltage measurement.

However, we traditionally have not had permanent voltage monitoring for low-voltage networks and rely on customer feedback, after which we install portable dataloggers to confirm any issues. We now have transformer LV monitoring devices on a few select distribution transformers. We recently initiated a project that provides visibility of the low voltage network via the GridSight platform (still at the proof of value stage) using data from smart revenue meters at customer premises.

Addressing non-compliance

As the load on the network increases, feeder loading can exceed what the initial design allowed, potentially resulting in voltage non-compliance. Regular feeder quality performance reviews through field monitoring and network modelling confirm potential voltage issues. We address voltage non-compliance at both HV and LV levels through:

HV:

- Installing automatic voltage regulators,
- Installing capacitor banks,
- upgrading conductor and/or
- reconfiguring the feeders.

LV:

- reconfiguration of the LV network,
- transformer upgrades,
- upgrading conductor and/or
- adjusting transformer tap changers.

Responding to low voltage issues raised by stakeholders

When customers notify us of voltage issues, we respond to it as a fault, at the same level as a 'no power' report, and we follow these steps:

- Technical verification that includes engineering assessment of network layout for the affected stakeholder(s), field verification of the desktop assessment through data logging, transformer tap position check, verifying installed conductors and possible alternate LV arrangements.
- This step identifies possible reasons for the non-compliance and confirms whether the issue is on the network or customer side.
- Where the issue is due to the network, our engineering teams determine an appropriate solution, and the field services team deploys the solution.
- Verifying the solution's effectiveness through onsite measurements and with the affected stakeholders.
- If there is a repeat notice from the same customer, we classify it as a complaint and raise the priority for resolution.

Communication with affected customers

We keep the customer informed of progress throughout the resolution process and aim to resolve customer complaints within 20 working days. Should there be a requirement to exceed this timeframe, we will communicate this and the reasons to the customer and work to resolve the complaint as soon as possible.

Improvement initiatives

Initiatives that will improve our practices and network voltage performance include:

- network architecture changes such as introducing subtransmission, driven mainly by capacity needs, improve network voltage performance by shortening distribution feeders and introducing another stage for voltage control.
- our voltage management programme considers forecast load at the distribution feeder level and proactively deploys voltage management solutions, such as voltage regulators, capacitors, and conductor upgrades. Our current practice for the low-voltage network is to respond to issues as they arise.
- updating our design standards to allow for the change in customer density and usage profiles.
- extending the coverage of LV monitoring based on the smart meter data aggregation method will enable us to proactively improve voltage performance at low voltage levels.

11.21.4 Fault response, maintenance, and inspection

This function delivers the field switching operations and restoration following outages, network inspection and defect resolution.

In response to the increasing trend in weather-related outages and fault restoration times, we increased the system interruption and emergency budget by 35% over the next ten years in the 2023 AMP. We have increased the forecast by a further 30% (in real$) in this AMP due to the continued increase in the cost of fault response.

The new forecasts reflect the level of expenditure being incurred in recent years. We have developed and documented all the additional inspection and maintenance activities in the comprehensive fleet plans in this AMP.

Inspection

Field inspections carry out defect identification on key ground-mounted equipment, including transformers, ring main units, reclosers and voltage regulators, using inspection guides and inspection record forms.

In 2024 AMP, we have refreshed our inspection and maintenance regime as documented in our comprehensive fleet plan per asset classes in this 2024 AMP submission.

The opex has increased accordingly.

Maintenance

Maintenance practices

In 2024 AMP, we have refreshed our inspection and maintenance regime, as documented in our comprehensive fleet plan per asset classes in this 2024 AMP submission.

The opex has increased accordingly.

Live-line techniques

Live line work maintains supply to sensitive customers and avoids widespread disruption of shutdowns on customers in general. Live line techniques are selected where this approach is more efficient and may avoid disrupting supply to customers.

Safety is a key consideration in choosing whether to use live-live techniques. To ensure that safety is maintained in all cases, we have a risk assessment tool to evaluate the justification for live line work over de-energised work. This justification process follows the EEA guidelines and industry best practices.

De-energised work

The current approach to de-energised work is to cluster planned work that requires a shutdown into modules and complete all work within a single module shutdown if resources allow. This minimises SAIDI and customer inconvenience.

11.21.5 Vegetation management

Overview

Vegetation is one of the significant causes of outages on the network. Parts of our network pass through dense vegetation and forested areas, exposing the network to faults from branch contact and tree fall, particularly during storm events. Moreover, faster vegetation growth rate due to summer/spring growth seasons getting warmer and wetter, quickly erodes the established clearances. Overgrown trees and other vegetation near power lines can lead to outages, fires, and safety hazards.

Vegetation management is necessary to ensure supply reliability by preventing line interference and providing access to network assets and public safety by reducing the risk of fire or a broken conductor falling on the ground. We undertake routine inspections of our network to identify areas where vegetation has the potential to (or already is) breach the minimum specified legislative distances.

Inspections include frequent assessment of the network to establish where vegetation is encroaching (or approaching encroachment of) overhead lines. It also includes liaising with landowners regarding subsequent first-cut costs associated with physical trimming or felling of vegetation we bear.

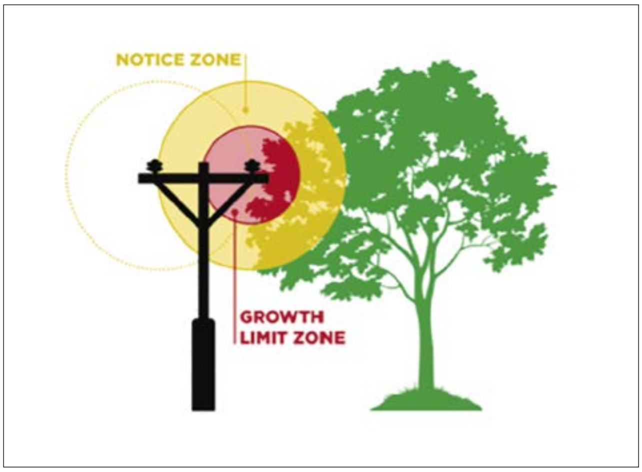


Figure 111: Vegetation management zones

Tree regulations

The Electricity (Hazards from Trees) Regulations 2003 specifies minimum distances that vegetation must be clear from overhead power lines, "growth limit zone," with distances varying depending on voltage and conductor span length. The regulations also require electricity distribution networks to advertise suitable safety information to vegetation owners in appropriate publications and contact those owners whose vegetation is approaching or exceeding the specified minimum distances.

While these zones provide clearance from interference from branches (although greater clearance would be useful), they are inadequate to manage tree fall risk and interference during storm events, where greater separation is needed.

We can request the tree owner to trim or remove vegetation once it infringes on the notice zone and enforce trimming when it encroaches on the growth limit zone (using a prescribed process that can take some time to complete). However, in high-growth areas, the trees quickly exceed the limits after trimming, requiring frequent return visits. Under the regulations, we have no mandate to remove a small tree from under a line but must wait until it encroaches the notice zone before acting.

The regulations also require EDBs to advertise suitable safety information to tree owners in appropriate publications and contact owners whose vegetation reaches the notice zone. Tree owners can take ongoing responsibility for maintaining vegetation outside the minimum distance(s) or granting the network owner approval to keep the vegetation outside the minimum distance by appropriate trimming or removal. The notice and trim process must be repeated for every individual tree on a property.

The tree legislation requires EDBs to offer tree owners a first free cut. The landowner must then meet the cost of resulting cuts, which has resulted in an increasing number of trees being declared "no interest" by landowners on the second cut. At that point, we prefer to completely remove the tree to avoid future issues rather than trimming the tree.

Risks from vegetation

Vegetation presents two primary risks to us in achieving our business objectives. These are public safety risks and reliability risks.

- Public safety risk: Vegetation owners may put themselves at risk by carrying out the vegetation trimming or felling work themselves. This puts the vegetation owners at risk of electrocution or may elevate the fire risk due to arcing between live power lines and the trees being worked on. Vegetation close to lines presents a risk for vegetation contact if a child climbs the tree.
- Reliability risk: Vegetation outages comprised 19% of our SAIDI over the past five years. Failure to properly manage vegetation will increase the risk that we will not achieve our reliability target, leading to more outages and time without electricity supply for our customers.
- We sometimes encounter vegetation that impedes field staff access to our equipment. This can delay operations and power restoration, where the vegetation needs to be cleared first to enable access to the equipment. The issue is presently managed reactively.

Objective and strategy for vegetation management

Mitigating vegetation-related outages is one of our key strategies (asset management strategy #6).

Our vegetation management strategy aims to identify and address vegetation growth issues before they become safety hazards or impact network reliability, i.e.:

- Vegetation interference does not increase public safety risk;
- Vegetation interference has minimal impact on the network performance both in normal and in adverse weather;
- Expenditure on vegetation management is efficient;
- We comply with our regulatory obligations.

We currently do not proactively manage all trees in the fall zones (apart from known critical spots in the network as observed from recent cyclone events – under Asset Management Strategy #3 – Resilience). Our future position and strategy will be established once the Tree Regulation review is complete.

In FY24, the team reviewed our vegetation management approach and strategy. The new strategy has four key initiatives, each responding to the drivers above.

Initiative	Purpose
Establish regular baseline measurements of vegetation in the line corridor	• Identify all trees in the line corridor that could present a risk and link these to the relevant tree owner through a combination of annual and 3-yearly inspection cycles, depending on the location of the network • Capture accurate data on vegetation outages and control activities • Implement a practical vegetation management system
Implement a practical risk-based vegetation control programme	• Determine the risk posed by all vegetation sites in the line corridors • Determine a risk-prioritised vegetation management work programme • Develop an inspection and cut programme based on criticality and reliability, targeting high-risk in-zone and fall-zone trees
Increase community engagement	• Use customer engagement to enhance full cuts, tree-owner payments, and vegetation control beyond the growth limit zone.
Continuous improvement	• Develop an understanding of the long-term work and expenditure requirements • To progress our vegetation management to industry best practice • Increase vegetation management resources in the region.

Table 135: Vegetation management initiatives

Risk-based Vegetation management practices

Previously, the planned inspection and cut/trim for feeders were in the same cycle. Under our new approach starting from late FY24, the two types of activities ('intelligence gathering' vs 'plan and act') are now de-coupled.

Our vegetation management practices include the following four key elements, reflecting our progression in FY24.

Inspection

We undertake routine inspections of our network to identify areas where vegetation has the potential to (or already is) breach the minimum specified legislative distances. The inspections combine a rotational survey and reactive trimming of vegetation hot spots. The inspections are undertaken by vehicle and foot.

Historically, we inspected feeders (and trim) on a five-year rotation. However, given tree growth rates, that return period was too long to maintain clearance from the growth limit zone. This cycle reduced the interval to three years for the whole network based on the team's experience.

In FY24, as an outcome of our review of vegetation management practice, we adopted the following practical risk-based (currently considering network impact only) inspection approach, given that our network is relatively small:

- Annual inspection for lines to the second reclosers from the GXP. These lines are close to the GXP. Hence, a vegetation event will result in a large SAIDI impact; hence, we inspect them more often.
- For the rest of the network.
    - Generally, a 3-year inspection cycle continues the current management cycle. The adequacy of this

interval will be reviewed at the end of FY25 to consider whether this interval should be further reduced.

- Targeted more frequent inspection for known problematic feeders, for example, Kawhia feeder, where a fault (including vegetation) will require a longer duration to identify and clear due to its challenging terrain, resulting in a higher SAIDI, and

- We also conduct reactive inspection post repetitive reclosing or feeder tripping.
- Further opportunities under consideration include Helicopter-based vegetation inspection – which will make it possible to shorten the inspection cycle for most of the network from 3-year to 1 or 2-year intervals.

Recording

Records of vegetation that present a risk to our network are managed similarly to an asset through a record with attribute data and specific location details assigned to it. Liaison with the vegetation owners then occurs as appropriate. Work packs are designed and compiled where applicable to allow our team or external contractors to undertake the corresponding vegetation control work.

In FY24, leveraging our GIS system, the team now adopted the Survey123 App as the new digital survey platform for asset and vegetation inspection. This new app lets the team record and collect vegetation issues digitally – removing all paper-based inspection forms and improving overall administration efficiency and backend work management.

Further opportunities the team is looking into include:

- Visualization of inspection results and problematic sites on the maps.
- Continue refining the content of the inspection and record form to better support risk and time urgency-based works planning and enable a direct printout of the land-owner liaison form.

Vegetation control work plan and tactics

The subsequent cut/trim work will be planned based on inspection results.

- Based on our in-cycle and reactive inspection findings. We are starting a risk-based approach – primarily informed by observations, consideration of public safety risk and network performance (impact of outages), and urgency to act.
- Aim for a higher tree fell rate over trim rate. Our recent review shows that our internal vegetation management team achieved a fall rate of 85%, and we will continue to maintain this high fall rate through good stakeholder engagement.

Resourcing and stakeholder engagement

We have directed our efforts to manage the risk of vegetation interference by, where possible, obtaining greater clearances (including full removal) than those provided by the legislation with the cooperation of vegetation owners. Obtaining greater clearances than the minimum values specified in legislation reduces the potential for network damage, reduces the frequency of return visits and enhances the safety of landowners.

In FY24, we have recruited a dedicated Scoping and Liaison officer to support the above inspection and stakeholder engagement activities.

FY25 will be the first full year that we adopt this new approach. A performance review will be conducted at the end of FY25 to guide our continuous improvement.

11.22 Systems operation and network support (non-network)

This covers a range of management activities of the network, including:

- Policy, standard and manuals development and management.
- Outage recording and data management.
- Asset data management, business support and management of IT systems.
- Asset management planning, engineering design, project technical support, procurement, contract, and inventory management (excludes capitalised project costs).
- Health and safety, environmental and quality management.
- Training.
- Creation and management of existing easements.
- Vehicle operation management and maintenance.
- Consumer enquiries, records, and other activities.

It also covers related network support expenses, such as professional advice, engineering reviews, quality assurance, and network running costs.

11.23 Business support (non-network)

This covers corporate activities, including:

- Chief executive and director costs, legal services, non-engineering/technical consulting services.
- Commercial activities include pricing, billing, revenue collection, and marketing/sponsorship.
- Compliance-related activities (finance and regulation).
- HR and non-operational training.
- Property management.
- Support services such as IT, secretarial, etc.

11.24 Vehicle fleet

11.24.1 Description

We own and manage a vehicle fleet to support the business. Vehicles are essential assets that enable our activities to meet our asset management objectives. Our vehicle fleet as of March 2023 includes the following:

- 28 utility vehicles (utes).
- 13 trucks (including crane, bucket and tipper trucks).
- 10 light vehicles (cars and SUVs).
- 2 forklifts.
- 3 diggers/trenchers.
- 12 other (chippers, trailers etc).
- 1 cable jointing van.

When procuring vehicles, we consider safety, environmental impacts such as fuel efficiency (and consider electric or electric/hybrid motors if appropriate), and operational requirements (i.e., suitability for intended use).

11.24.2 Management

Records of our vehicles are maintained in the financial management system, the Smartrak fleet management system, the GPS tracking system, and spreadsheets. Vehicles are split into various classes and categories, and relevant attributes are recorded against each vehicle. The records allow easy visibility and tracking of when maintenance activities are required against each vehicle.

Our vehicles are regularly maintained to ensure operational effectiveness and to minimise the potential for component failure, which could contribute to poor performance and/or lower reliability.

Our utility vehicles (especially for fault response) travel the greatest distances. These vehicles are typically replaced between three and six years, depending on the make and model, distance travelled, and performance. Older fault vehicles are cascaded down the fleet to lower mileage roles to maximise utility from the asset before disposal. Other vehicles are replaced on a case-by-case basis.

We completed a comprehensive fleet review in FY24. We have prioritised key recommendations for action from FY25.

11.25 Buildings and land

11.25.1 Overview

We own and maintain non-network property and buildings, including Te Awamutu's main office building and depot. This houses engineering, network, financial, commercial, and corporate services staff and contracting business staff, including management, supervisors, engineers, design estimators, fault crew, and administrative support.

The depot includes an electrical workshop, store warehouse, plant and vehicle sheds, hazardous goods store, and the yard housing materials and equipment.

We have also purchased the land for the upcoming Hautapu GXP and Forrest Zone Substation development, and land adjacent to Te Awamutu GXP.

11.25.2 Development

Operations are being constrained by space due to equipment for renewal and expansion works (e.g., reclosers, voltage regulators and distribution transformers). There is insufficient bunded area for the storage of transformers.

We are evaluating the feasibility of a second depot in the Cambridge area, allowing more storage space, reducing staff commuting time, and improving field operational efficiencies.

The ground and building inspection and maintenance costs associated with the new Hautapu GXP/Forrest Zone Substation are yet to be established and will be included in the 2025 AMP.

11.26 Asset lifecycle management expenditure forecasts

11.26.1 Capital expenditure

Routine inspection and defect survey outcomes mainly drive the pre-2024 AMP replacement volumes and associated forecast expenditure.

Our new 2024 AMP now takes a health-based forecasting approach, which better quantifies future renewal needs, ensuring the network's safety, reliability, and sustainability. On this basis, we see an increase in renewal capex in the 2024 AMP submission.

Due to the current data quality limitation (e.g., conductor and cables), as explained in each asset lifecycle plan, we expect to quantify better and revise the forecast for certain asset classes as the data improves.

Below is a summary of the fleet plan's asset replacement and renewal expenditures. Section 12 provides further commentary (including comparators to the 2023 AMP).

Asset Replacement and Renewal	Type	FY25	FY26	FY27	FY28	FY29	FY30-34
Concrete poles/steel structure	Provision	147	147	687	687	687	735
Wood poles	Provision	1,116	1,116	1,116	1,116	1,104	720
Crossarms	Provision	1,338	1,338	1,338	1,338	1,338	6,690
Distribution OH Conductor	Provision	17	167	317	317	422	1,436
LV OH Conductor	Provision	-	30	60	60	60	300
Pole Mounted Transformer	Provision	400	400	400	400	400	2,000
Overhead Switches (ABS, Enclosed LBS, Fuse, Link)	Provision	513	513	513	513	553	2,605
Voltage regulators	Provision	374	374	374	187	187	2,990
Reclosers and sectionalisers	Provision	200	130	130	130	130	650
Distribution UG XLPE or PVC	Provision	100	100	100	100	240	500
Ground Mounted Transformer	Provision	194	194	194	194	259	1,232
RMU	Provision	27	27	27	27	27	135
LV UG Cable	Provision	5	85	85	85	85	425
LV OH/UG Streetlight circuit	Provision	-	-	-	-	14	-
OH/UG consumer service connections	Provision	273	273	273	273	273	1,364
SCADA replacement	Project	500	1,000	-	-	-	-
Total		**5,204**	**5,894**	**5,614**	**5,427**	**5,779**	**21,782**

Table 136: Asset replacement and renewal expenditure

Note: Real FY24 $000

11.26.2 Operational expenditure

Table 2 shows the operational forecast expenditure for managing the asset fleet over the next ten years. Service interruptions and emergency maintenance can only be forecast and reported at a system level.

Several key changes to the network Opex have been made due to the following changes or new activities. A comparison is in Section 12.3.1.

- Escalating costs in responding to faults.
- While we do not see a material increase in fault rate, faults are generally take longer to resolve, reflecting the complexity of the faults we respond to, including labour and traffic management costs.
- Increase costs associated with vegetation management activities.
- This includes additional patrol and customer liaison activities and a significant increase in traffic management costs.
- Increase cost in planned asset inspection and maintenance activity based on our new fleet plan
  - Annual Public Health and Safety checks for ground mount assets in the urban area starting FY25
  - Annual field automation equipment inspection, battery maintenance and pest control starting FY25
  - One-off timber pole ground line inspection in FY25/26
  - 5-yearly condition inspection for all distribution overhead structures (i.e. Pole and cross arms) starting FY25
  - 10-yearly condition inspection for 110 kV line at ten-year, with the first round in FY27
  - 10-yearly recloser/sectionaliser maintenance, including CT/VT calibration starting in FY25.
  - Additional preventative maintenance requirements for voltage regulator, including oil sample checks and intrusive maintenance.
- No material change in Asset replacement and renewal.
- Refer to 12.3 for commentary on non-network opex.

Operational Expenditure Forecast	FY25	FY26	FY27	FY28	FY29	FY30-34
Service interruption and emergencies	1,838	1,838	1,838	1,838	1,838	9,190
Vegetation management	2,027	1,879	1,879	1,894	1,879	9,410
Routine and corrective maintenance and inspection	941	1,190	1,154	1,139	1,121	5,600
Asset replacement and renewal	813	842	702	799	767	3,870
Sub-total – Network OPEX	**5,619**	**5,749**	**5,573**	**5,670**	**5,605**	**28,070**
System operations and network support	5,353	5,358	5,358	5,358	5,358	26,789
Business Support	5,831	5,831	5,831	5,831	5,831	29,156
Sub-total – Non-Network OPEX	**11,184**	**11,189**	**11,189**	**11,189**	**11,189**	**55,945**
Total OPEX	**16,803**	**16,938**	**16,762**	**16,859**	**16,794**	**84,015**

Table 137: Operational expenditure

12. EXPENDITURE FORECAST AND CAPACITY TO DELIVER

12.1 Assumptions on cost inflators

We continue to see significant cost pressures in our network opex and capex activities. These pressures are particularly noticeable in materials, labour, and traffic management.

Our assessment of the inflation in network opex and capex activities from FY2023 to FY2024 is 7% and 6%, respectively. This was calculated from a representative sample of materials, average field personnel salary increases, the increase in plant costs, and the increase in traffic management costs. The differences between capex and opex inflation are due to the mix of labour and materials. Our observed cost escalation is higher than the PPI for the same period of 4%[65].

This is an average increase (opex and capex activities are 7% and 6%, respectively), and the extent of cost increases differed by work type. Hence, we reviewed all our unit cost estimates used in our asset replacement and renewal programmes and most system growth projects. The average increase was applied to a relatively small number (by value) of programmes and projects where costs were not reviewed.

We used the average inflation estimate to compare the 2023 and 2024 AMP. The expenditure forecast graphs in this section contain the following information:

- The dark blue bar and light blue bar combined show the project expenditure in 2024 AMP constant dollar
    - A dark blue bar that shows the 2024 AMP project expenditure if discounted back to 2023 AMP dollar in constant dollar
    - The light blue bar indicates the inflationary impact on project delivery unit costs between September 2023 and September 2024, when the expenditure forecasts were prepared.
- The grey dotted line indicates the expenditure profile in the constant dollar as per the AMP2023 disclosure

With Schedule 11a and 11b, where we escalated constant prices to nominal dollars, we applied CPI as forecast by Westpac for FY25 to FY28, then applied 2% p.a. post FY28, the middle of the Reserve Bank inflation policy range.

Unless specified otherwise, all dollar figures disclosed in this AMP are in constant dollars (thousands) as of September 2023.

[65] *This is the PPI capital goods for energy generation, transmission, and distribution works. For Sep 2022-2023 https://www.stats.govt.nz/information-releases/business-price-indexes-december-2023-quarter/*

12.2 Capex

12.2.1 Network capex summary

Table 138 summarises the AMP2024 10-year capex by category over the next ten years compared to the 2023 AMP (in comparable, constant prices).

Network Capital Expenditure (10-year total)	AMP2023 ($)	AMP2024 ($) with inflation impact discounted	Changes ($k)	Change (%)
Consumer connection	67,223	51,508	-15,715	-23%
System growth	37,155	45,414	8,259	22%
Asset replacement and renewal	29,693	46,451	16,758	56%
Asset relocations	1,890	2,159	269	14%
Reliability, safety and environment:				
Quality of supply	1,755	7,396	5,641*	321%*
Legislative and regulatory	–	1,720	1,720*	n/a*
Other reliability, safety and environment	10,180	2,262	-7,918*	-78%*
Total reliability, safety and environment	11,935	11,378	-557	-5%
Expenditure on network assets	*147,896*	*156,910*	*9,014*	*6%*
Expenditure on non-network assets	*19,403*	*20,280*	*877*	*5%*
Expenditure on assets	**167,299**	**177,190**	**9,891**	**6%**

* *Changes in the categorisations of certain projects have also affected the comparison.*

Table 138: Comparison between FY24 and FY25 10-year total Capex forecast

Figure 112 shows the forecast capex for the period FY25 to FY34. The ten-year forecast table is provided in Appendix F.

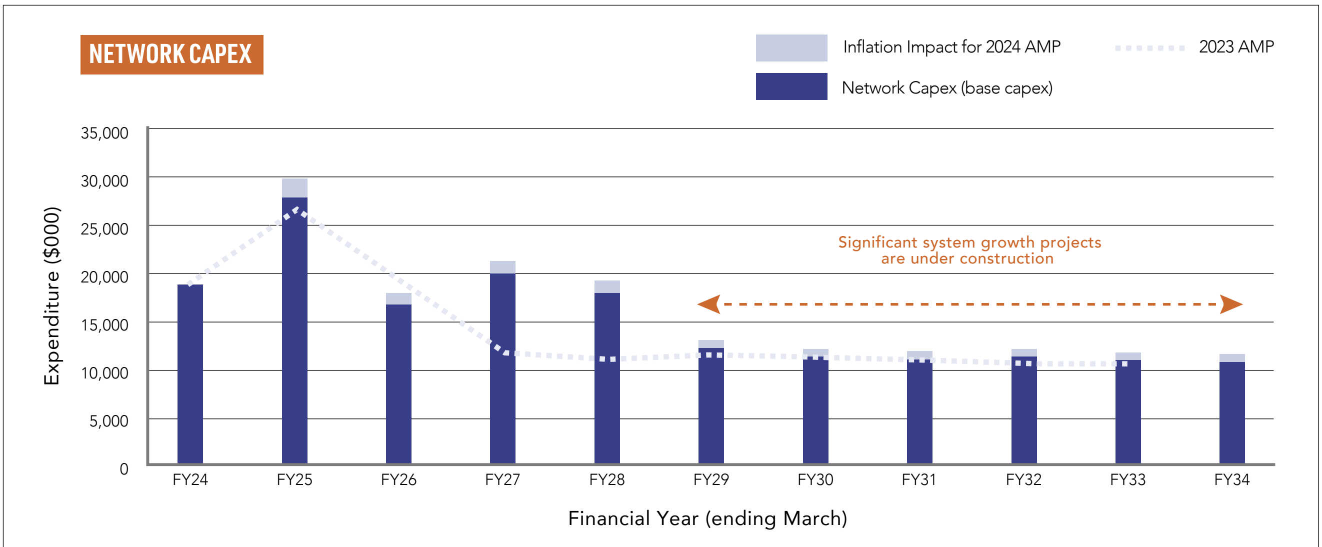


Figure 112: Summary of forecast capex ($k)

It is worth highlighting that several significant system growth-related projects are still under consideration. The expenditure forecast in this AMP does not yet include the cost of the possible projects that have not yet been confirmed.

The network capex has increased by $17.1m (12%) over the next ten years compared to the 2023 AMP (in comparable, constant prices), specifically $15.3m (16%) in the next five-year period, i.e., from FY25 to FY29. The change is principally driven by:

- A reduction in customer connection due to a change in the budget forecast method;
- The 11kV integration plan, new feeder downstream augmentation plans associated with the new Forrest Road substation in the Cambridge region;
- An increase in wood pole and crossarm renewal;
- Ongoing 11kV cable and conductor upgrades to mitigate capacity and voltage constraints.

12.2.2 Customer connection

Customer connection capex has decreased by $8.2m (23%) over the FY25 to FY29 period compared to the 2023 AMP (refer to Figure 113). Customer connection capex is inherently volatile and is dependent (to a large degree) on the progress of land developers. We have experienced strong connection growth in recent years and are forecasting this to continue. Our customer connection capex forecast reflects the five-year historical average connection capex. Our target capital contribution from customers and developers for this work is 78%.

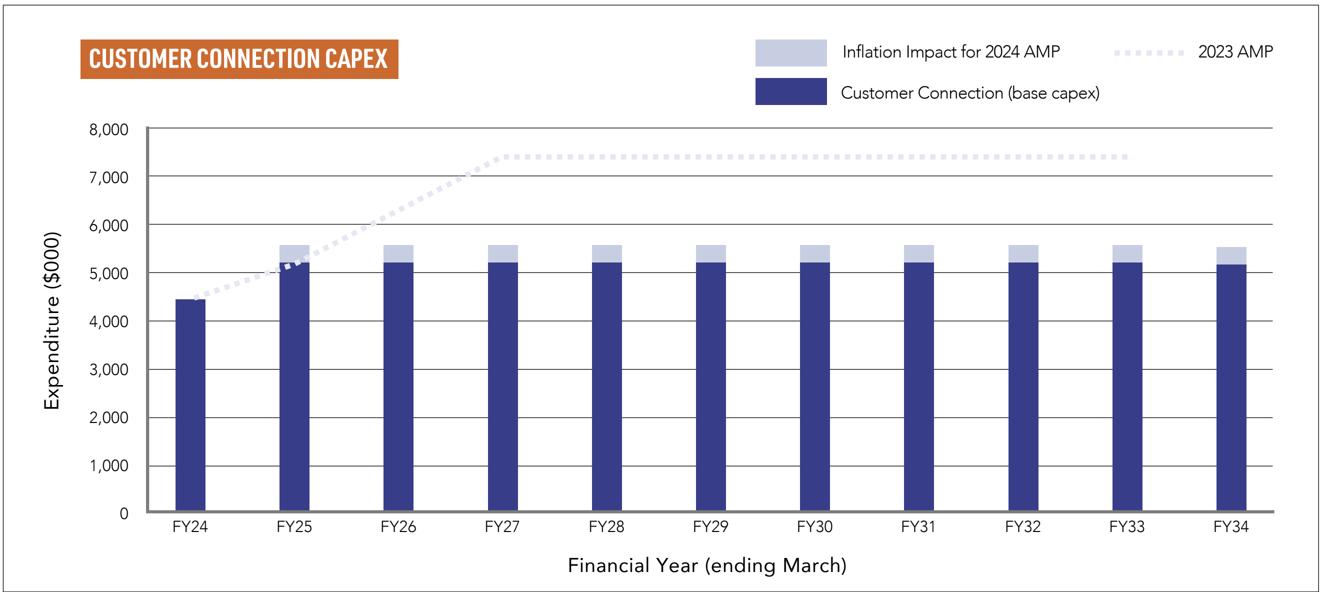


Figure 113: Customer connection capex ($k)

12.2.3 System growth

System growth capex has increased by $13.9 m (49%) over FY25 to FY29 and by $3.6m (253%) from FY30 compared to the 2023 AMP (refer to Figure 114). The increase is driven by:

- The full scope of the 11kV integration plan for the new Forrest Zone Substation (which is a $2.3m work programme) to split the existing rural network and create new feeders;
- Feeder capacity upgrades on the Tamahere, Cambridge West, and Kaipaki feeders to cater for the power flow change (as a result of Forrest Zone Substation) and new significant loads increase on these feeders;
- The installation of 33kV tie-cables ($7m), initially operating at 11kV, from Forrest Zone Substation to the Leamington area to resolve existing feeder congestions and the upcoming major load increase. We anticipate a new Leamington substation will eventually be required, and the project and timing are under further consideration.
- A provision to upgrade the capacity of 11kV feeder conductors/cables in response to voltage and capacity constraints.

The increases were partially offset by reduced costs for the zone substations (mainly relating to the completed work in FY24 for Forrest Rd Zone Substation) and the voltage quality improvements program being transferred to the quality of supply category.

The system growth capex in FY29-34 remains low, as major development needs are still being evaluated. Several potential and significant longer-term initiatives, such as the Te Awamutu area GXP upgrade and subtransmission development plan and future Leamington Substation, are listed as "under consideration" and have not been included in the CAPEX schedule until further substantiated.

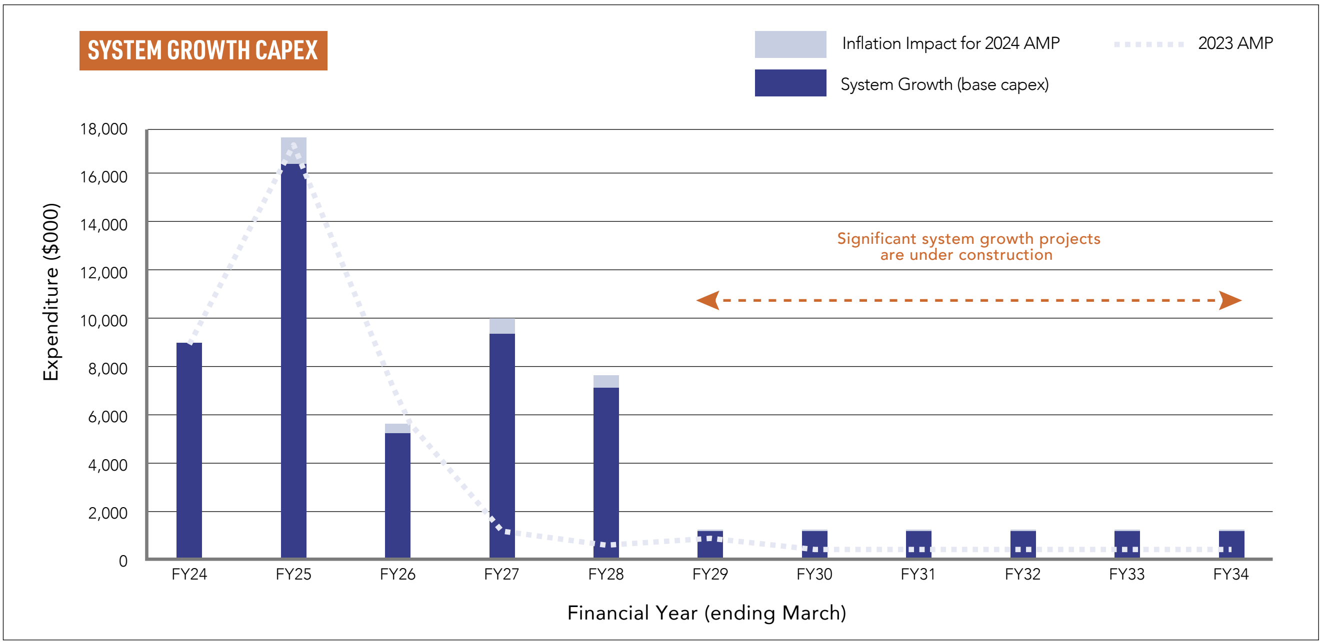


Figure 114: System growth capex ($k)

12.2.4 Asset replacement and renewal

Our asset replacement and renewal capex forecasts have evolved since the 2023 AMP due to our new health forecasting methodology and the use of more extensive condition data. We have seen a positive increase in the renewal forecasts driven by asset condition (rather than age). This increases our confidence in the five-year forecasts; however, new condition data will be incorporated each year so that these forecasts will evolve in subsequent AMPs. We expect renewal capex to increase as we go through our inspection cycles over the next 5-7 years when end-of-life condition drivers are likely to grow.

Asset replacement and renewal capex over the next five years (FY25 to FY29) has increased by $9.9m (55%) and by $4.4m (44%) from FY30 compared to the 2023 AMP (refer to Figure 115). The increase is driven by:

- An increase in pole and crossarm renewals;
- An increase in voltage regulator renewals;
- An increase in cable renewals (concerning the red-rubber sheathed cables).

Lower renewal requirements for distribution transformers partially offset these increases.

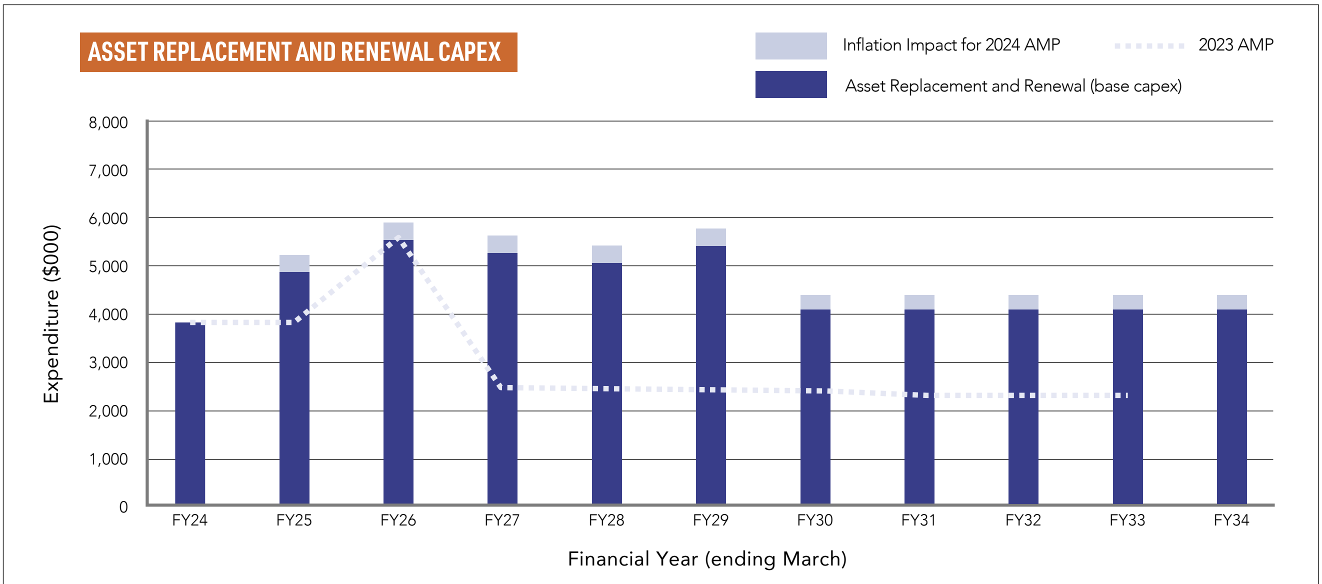


Figure 115: Asset replacement and renewal capex ($k)

12.2.5 Asset relocation

Asset relocation capex has increased slightly ($114k) over the FY25 to FY29 period compared to the 2023 AMP (refer to Figure 116). Asset relocation capex is volatile and depends on the NZ Transport Agency and Council roading programmes. Given the difficulty of forming a robust forward view, the asset relocation capex forecast reflects the five-year historical average. Capital contributions to this work have historically averaged 88%, and we forecast this to continue.

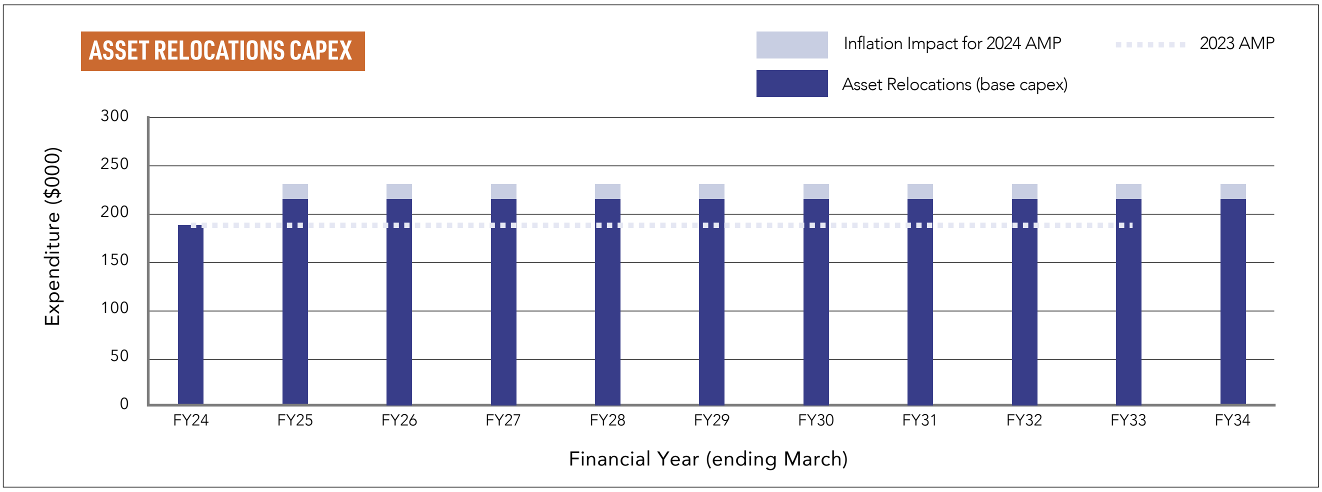


Figure 116: Asset relocation capex ($k)

12.2.6 Reliability, safety and environmental

The overall change to the "total Reliability, Safety and Environmental" is an 5% reduction. The completion of the Natural Hazards Assessment planned for FY25 will help us identifying resilience projects to address network risks triggered by climate change. We expect the expenditures will change.

Some projects and programmes have moved across the three reliability, safety and environmental capex sub-categories.

The key changes are explained in the following sections.

Reliability, safety and environmental – the quality of supply

Overall, there has been a $3.4m (497%) increase over the FY25 to FY29 period and a $2.6m (549%) increase from FY30 compared to the 2023 AMP, mainly due to the transfer of projects from "Other Reliability" to "Quality of Supply".

With the quality of supply capex (refer to Figure 117), the change is driven by:

- The transfer of the voltage improvement programme from system growth and an increase in the programme's scope due to the known voltage issues. Voltage is considered a quality of supply issue;
- Reduction in remote-controlled switches and loop automation programme, as this initiative will now coincide with increased spending in the ASB renewal program.

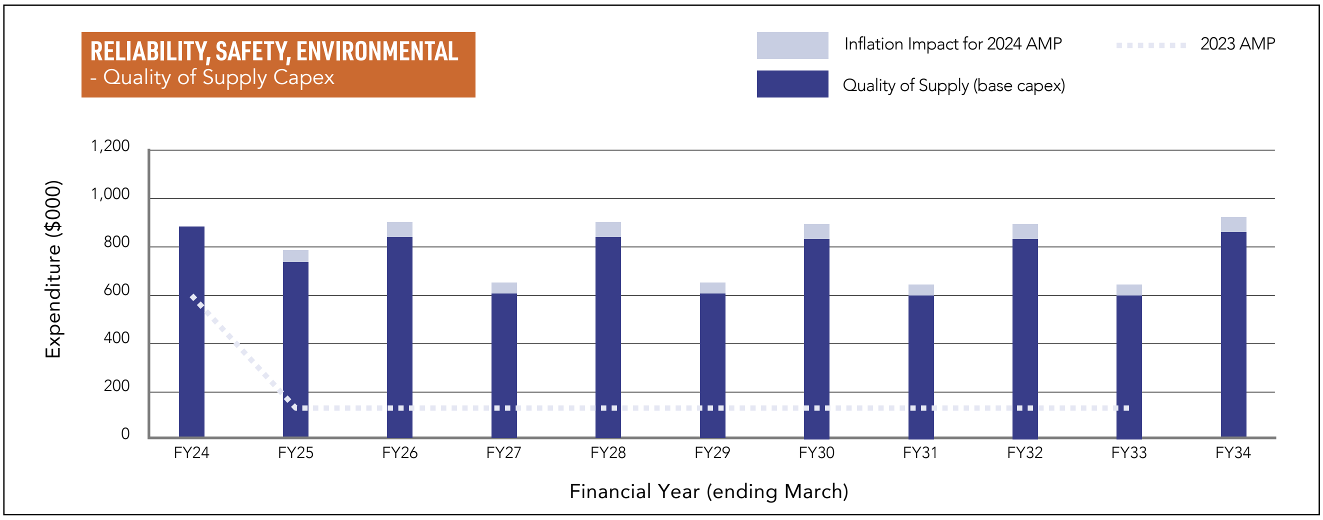


Figure 117: Reliability, safety and environmental – quality of supply capex ($k)

Reliability, safety and environmental – legislative and regulatory

The legislative and regulatory capex is driven by electricity code compliance (upgrading automatic under-frequency load shedding relays) and the remediation of line clearances. The significant spending in FY25 (refer to Figure 118) principle relates to the underground section of a line on Mutu St—Te Rahu Rd due to clearance issues. Mitigating risks from the multi-circuit overhead lines improves network resilience.

There was no other forecast for legislative and regulatory capex. The programmes in this category have previously remediated overhead conductor road crossings with low ground clearance.

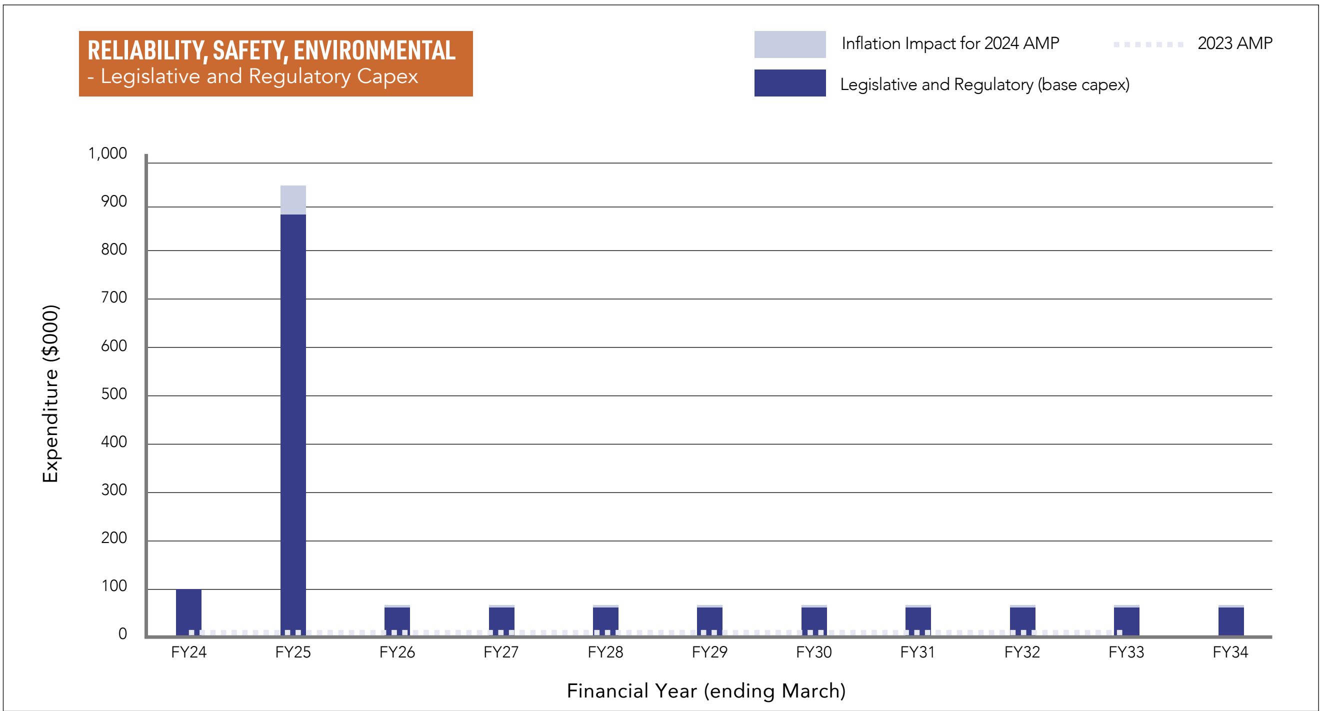


Figure 118: Reliability, safety and environmental – legislative and regulatory capex ($k)

Reliability, safety and environmental – other

The category includes the replacement of network access locks and seismic and environment-related resilience work. The difference from the 2023 AMP relates to the reclassification of several programmes.

This category will also include any capex projects to improve network resilience, which will be identified and evaluated after our Natural Hazards Assessment in FY25.

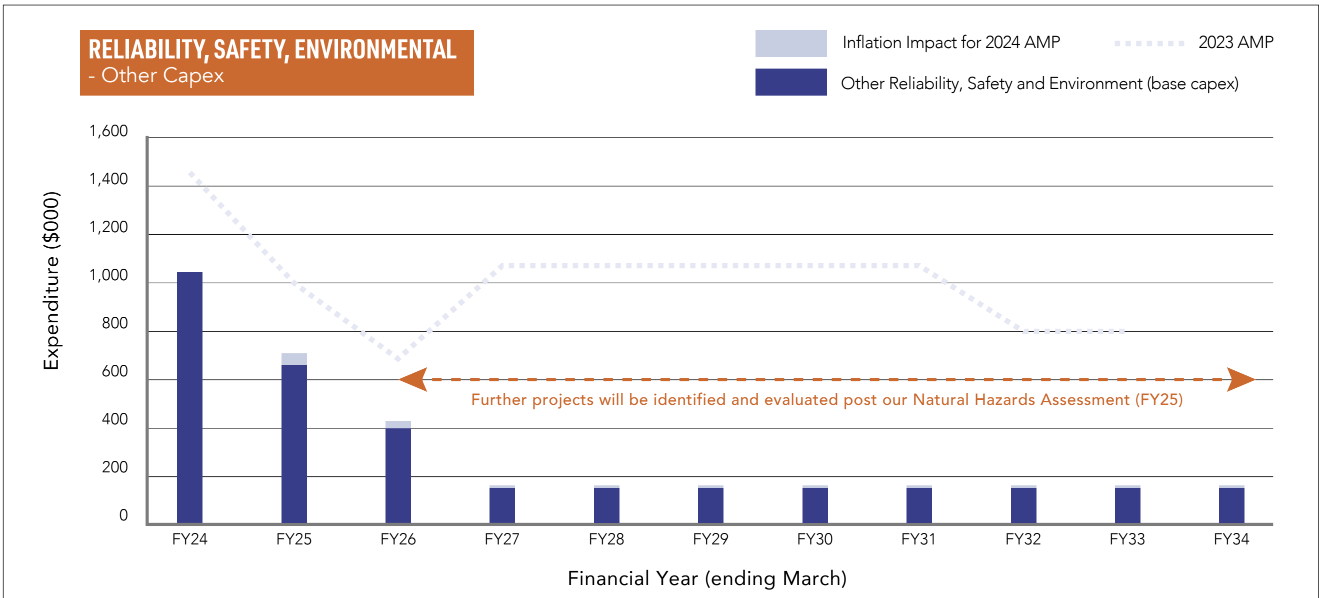


Figure 119: Reliability, safety and environmental – other capex ($k)

12.2.7 Non-network asset

Non-network expenditure covers:

- Office furniture and equipment purchases
- Computer software and equipment
- Land and buildings
- Motor vehicles, fleet and plant purchases
- Information network systems
- Asset data (including data generated from programmes like drone-based survey), and
- atypical projects.

Expenditure on non-network assets has marginally increased from AMP 2023 (1%).

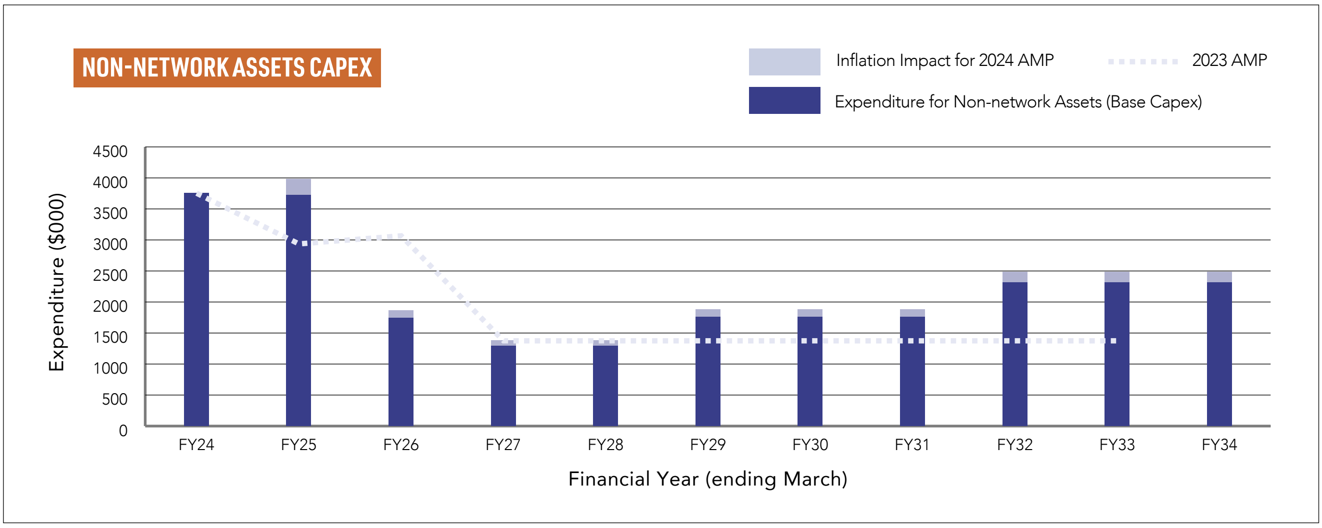


Figure 120: Reliability, safety and environmental – other capex ($k)

12.3 Opex

Figure 9 shows the forecast Opex for the period FY25 to FY34. The ten-year forecast table is provided in Appendix F.

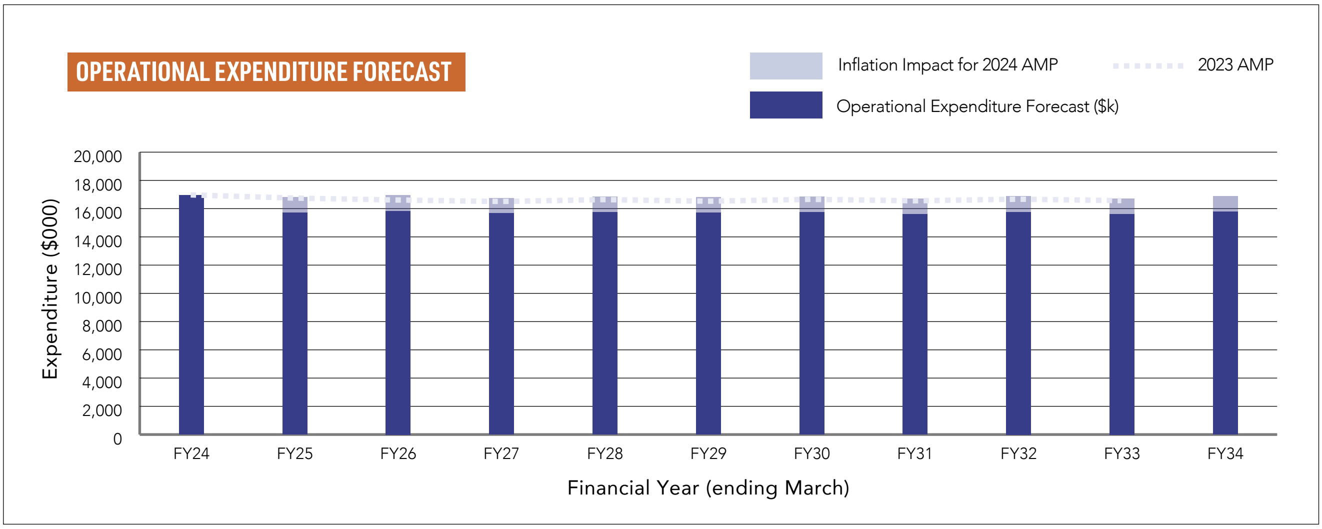


Figure 121: Operating expenditure ($k)

Movements in operational expenditure between AMP2023 and AMP2024 by category are shown in Table 139.

Operational Expenditure Forecast	AMP2023 ($)	AMP2024 ($) with inflation impact discounted	Changes ($k)	Change (%)
Service interruption and emergencies	14,260	17,178	2,918	20%
Vegetation management	15,323	17,727	2,404	16%
Routine and corrective maintenance and inspection	7,775	10,416	2,641	34%
Asset replacement and renewal	7,241	7,283	42	1%
Sub-total – Network OPEX	*44,599*	*52,604*	*8,005*	*18%*
System operations and network support	36,016	50,067	17,556	49%
Business support	85,570	54,498	-27,257	-32%
Sub-total – Non-Network OPEX	*121,586*	*104,565*	*-9,701*	*-8%*
Total OPEX	**166,185**	**157,169**	**1,986**	**1%**

Table 139: Comparison between FY24 and FY25 10-year total opex forecast

Table 139 shows that network opex has increased by $8m (18%) over the ten years compared to the 2023 AMP (in comparable constant prices), principally driven by the following as detailed in Section 11.26.

- Escalating costs in responding to faults (including labour and services such as traffic management), reflecting historical performance (excluding storms);
- Increase in vegetation management activities, including the additional patroller and increased traffic management costs;
- Increase cost in planned asset inspection and maintenance activity;
- No material change in asset replacement and renewal.

The above network opex has not included any additional maintenance activities associated with the new asset classes [66]introduced by our new Forrest Substation. The maintenance requirements will be better defined in FY25 and reflected in the opex schedule in the 2025 AMP submission.

The non-network opex budget has reduced (-8%) over the ten years compared to the 2023 AMP (in comparable constant prices), mainly driven by the following:

- **System operation and network support:** the significant increase is due to the additional resourcing need (e.g. Engineers and field crews).
- **Business Support:** Due to prior year variances between actual and forecast, we reviewed our calculation of the forecast. The revised forecast reflects the best estimate going forward on that basis.

12.4 Capex/opex trade-off

Capex/opex trade-offs are part of our development and lifecycle (renewal) planning processes. With development planning, the option analysis assesses viable alternatives, some of which may be opex-related. We expect that the viability of opex options will increase as the flexibility market evolves. With lifecycle planning, the option to maintain an asset (as an alternative to replacement) is considered when developing our fleet plans. In principle, we generally seek to maintain assets for as long as this is economical while continuing to deliver the same level of service from the asset.

[66] *New asset classes include (but not limited to) 33kV and 11kV switchboards, power transformers, substation grade protection relay and communication equipment, and substation building and civil structures.*

12.5 Capacity to deliver

12.5.1 Delivery approach

As part of our approach to asset management, we are committed to retaining our current field services staff for fault restoration, inspections, maintenance, and capital work. Our in-house delivery resource will be our preferred option for delivering the standard volumetric works in our AMP.

Our in-house delivery resource consists of approximately 50 staff and includes a vegetation management team, faults team, four-line crews, and cable and electrical fitter resources. Our Works Planning and Delivery Team supports the delivery of work in the field by providing dedicated and integrated resources to scope, design, estimate, plan, and project manage our work delivery.

We also use contracted external resources where our staff do not have the required skill sets, where resources are inadequate, or where it is more cost-effective to do so. A current example where we have used external resources is the Cambridge GXP reinforcement programme via the new 220/33kV GXP and our sub-transmission investment. We have engaged Ergo to design the solution, Edison Consulting to provide project management support and external service providers will be used to provide electrical and civil services to complete the build. These providers are being sourced through an RFP process. Another example of outsourcing is our network inspection programme, supplemented by a high-resolution aerial photo survey undertaken by a helicopter or drone.

In 2023, we introduced the following new processes: the Annual Work Plan (Annual Work Plan), Project Definition Documents (PDD), workflow and delivery monitoring and control and resource forecasting to improve our overall planning and delivery end-to-end process.

12.5.2 Annual works plan

The Network Team publishes our Annual Work Plan at the beginning of each calendar year. The purpose of this document is to provide an annual job list to the Works Planning and Field Delivery teams to ensure that sufficient design and construction resources are secured to meet the forecast workload for the year. The main benefits from the Annual Work Plan include:

- The ability for schedulers, project managers and designers to get sufficient visibility of upcoming projects;
- The ability to identify and order long lead-in items for the year ahead;
- Early allocation of projects that are outside our normal operating parameters to external providers;
- Ensuring there are enough resources to deliver the forecasted workload.
- Clarity across team members with budgeted expenditures and workload throughout the year.

The Annual Work Plan also captures all projects planned for the upcoming year. Project details are captured in the Project Definition Documents.

12.5.3 Project definition documents

Project Definition Documents (PDDs) define the scope of work for a network project. We introduced this new process in the 2024 AMP production cycle to support the more complex nature of the projects to come and the outsourcing evaluation to support delivery.

The PDD contains a high-level description of the project, scope of works, current and proposed network configurations, high-level commissioning approach, key materials, and a budget. It also documents the technical review and approval process, supporting the overall AMP financial approval process.

During the development of the PDD, a project is also optimised to minimise network outages whilst maximising resource utilisation. Long-lead procurement items and external resource needs are also identified. Following approval of the PDD, associated budgets, resource planning for detailed design and project construction are used to produce a high-level project delivery timeline.

12.5.4 Monitoring and control

The Annual Work Plan is developed and reviewed at the commencement of the calendar year. Once the Plan is finalised, the work's delivery is monitored and continuously managed through the Fortnightly and Quarterly Forward Work Planning Meetings.

The Fortnightly Forward Work Planning Meeting ensures that:

- Work specified in the Annual Work Plan is delivered annually and on budget.
- Work requested from customers is delivered on time and meets customer expectations.
- That the trade-off and timing between the delivery of defects, asset renewals, network projects, and customer work is proactively managed.
- That plant and equipment, material and resourcing requirements are proactively managed and planned.
- That schedule utilisation achieves the KPI targets set by the Business (Currently 80% fulfilment over 12 weeks)

A Quarterly Forward Work Planning Meeting is also held to undertake a financial reforecast to assess recent delivery performance, future resource (both internal and external) requirements and the overall deliverability of the remaining Annual Work Plan.

12.5.5 Annual resource forecast

As part of the Annual Work Plan process, we also undertake a resource estimation forecast for the work planned for the year ahead. This forecast uses a unit rate approach to approximate the number of Field staff hours required to deliver the work allocated. This means we can determine the variance between the total work hours available of our workforce and the total hours of committed work. This estimation is undertaken at the year's specific project and asset category level.

Figure 122 shows that for the coming year, an estimated 27,500 internal field staff hours are available. This includes the assumption that we will move to four-line crews at the start of the new financial year and that there will be a 5% productivity increase in field delivery. Given this cap, several Quality of Supply and Legislative and Regulatory Projects will need to be outsourced as we do not have enough capacity to deliver internally. Ongoing work to replace voltage regulators will also continue to be outsourced.

Based on the resource hour estimate and our in-house/outsource decision criteria as per Section 12.5.1, the majority of System Growth Projects are being outsourced for design, project management, and delivery services through competitive tenders (e.g., the Forest Zone Substation Project and the Te Awamutu Cable Upgrade Project) due to the specialties, complexity, or scale of the works being beyond our current internal team's capability. This capability gap will be addressed as the new assets enter the operation and maintenance phase.

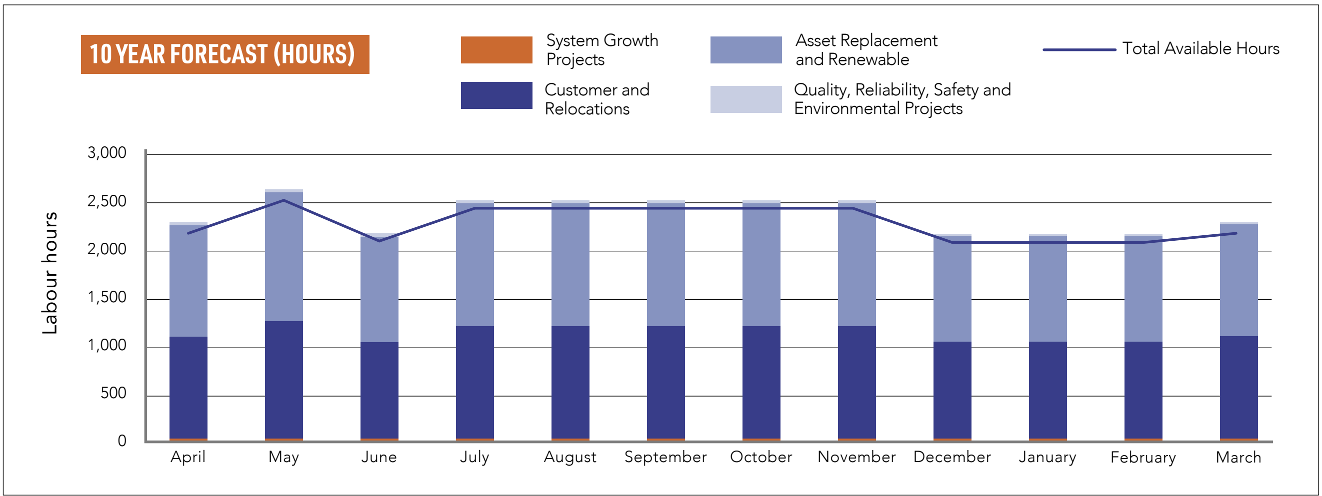


Figure 122: Annual resource forecast for capital projects

12.5.6 Long-term resource forecast

We completed a ten-year resource forecast as part of the Annual Work Plan process. This model uses a similar approach to the annual resource forecast model, but the forecasts are undertaken at the cost category level, not at the project or asset category level. Two key assumptions have been made in undertaking this forecasting.

As the System Growth (Section 12.2.3) outlines, there is significant forecast spending from FY25 to FY28. Most projects included in this expenditure category will be outsourced through competitive tenders because we do not have the internal capacity or competencies to undertake this work. The project scope will include arrangements for quality checks of specific parts of the builds to ensure long-term quality performance. These projects have been excluded from the 10-year resource estimation model.

Secondly, as the sections on customer connections and asset relocation (Sections 12.2.2 & 12.2.5) outline, the expenditure forecasts for customers and relocation have been extrapolated using the historical five-year average. This is a judgment call, given the volatile nature of the activity. However, we believe consistency with our demand forecasts is an appropriate approach. This means that 10-year resource estimation for customer and relocation work is also based on simple extrapolation.

Figure 123 below shows the 10-year labour forecast for system growth (standard volumetric 11kV conductor and distribution transformer upgrades only from FY26, with non-standard projects outsourced), customer and relocation, asset replacement and renewals, quality, reliability, safety, and environmental projects.

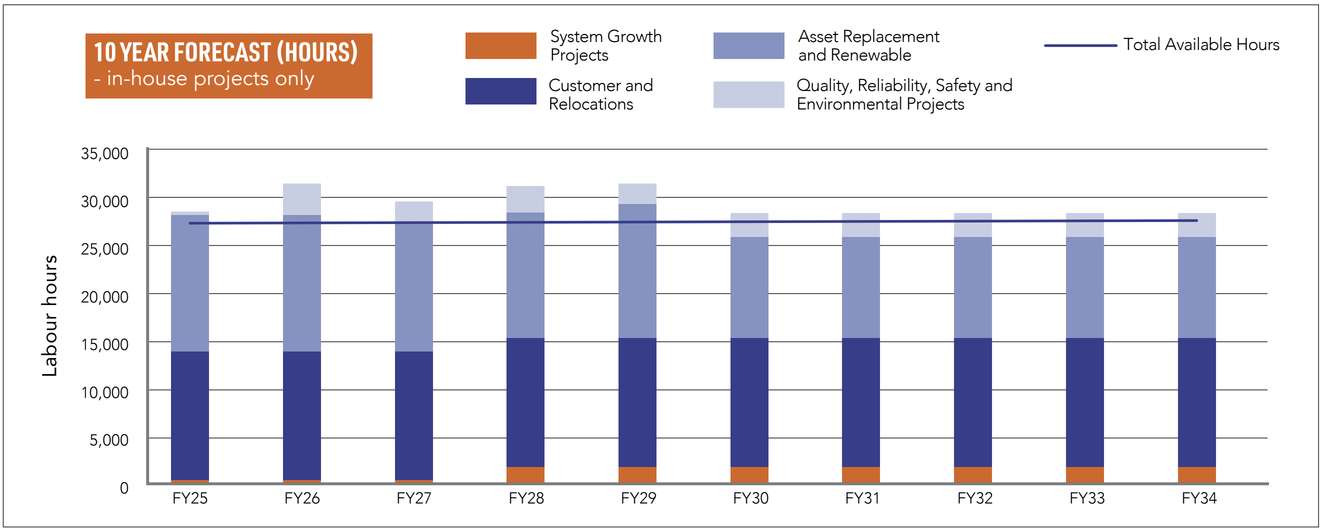


Figure 123: Asset Management Plan Resource

The model shows that from FY26 to FY29, there is an internal resource shortfall of approximately 5,000 hours a year to deliver the current AMP capital expenditure. This shortfall could be reduced by introducing a 6th Line Team internally or outsourcing the 5,000 hours per year to an external provider.

A key uncertainty is customer-initiated work (CIW), which can be volatile.

A decision will be made in FY25 on how to address the above-stated shortfall and uncertainties and put a plan in place for implementation by FY26.

APPENDICES

WAIPĀ NETWORKS

APPENDIX A – ASSUMPTIONS

A.1 General assumptions

Area	Assumption	Sources of uncertainty	The possible impact of uncertainty
Resilience	No major disasters or widespread systemic problems will occur – requiring significant expenditure (both opex and capex) in a relatively short timeframe for repair.	While contingency planning and emergency response plans are in place, it is difficult to predict the timing, extent, and location of events with any great degree of certainty.	Extensive damage to a significant proportion of our network requires significant expenditure (both opex and capex) in a relatively short timeframe.
Local authority developments	There are no significant changes to a local authority (i.e., Wāipa's District Council (WDC)) long-term plan.	WDC may alter existing plans. This may allow an opportunity for cost-sharing. For example, if road widening or renewal of underground services occurs, we can renew electrical infrastructure (or underground overhead sections) simultaneously.	Inclusion of as-yet unplanned activities by us. Missed opportunities to benefit from coordinating development with local area works.
Demand and Consumption	There are no significant changes to forecast load demand. No major new unknown loads or new generation sources connect to our network.	A step change in district population growth or load demand from industry growth. Inability to accurately predict future growth, which others control, changes in economic opportunities for various industries.	Additional or reduction in forecast growth expenditure, changes in transmission prices. It may require an upgrade and/or modification(s) to our network depending on the nature and scale of new load(s) or generation. In addition to growth expenditure above forecast.
Quality targets	Customers remain satisfied with current reliability and resulting costs.	Customers may change preferences – i.e., accept less reliability for lower line charges. The uncertainty here is knowing customers' future preferences.	Less revenue, which in turn would result in less expenditure. Ultimately, this would result in a less reliable network.
Inflation	The rates used for the expenditure forecast are based on the midpoint of the RBNZ's target inflation range.	Inflation is managed by the monetary policy of the Reserve Bank of New Zealand (RBNZ). While RBNZ aims to keep inflation near the 2% target midpoint, this could vary.	Should inflation vary from the assumed value, forecast amounts may increase or decrease, causing inaccuracies in forecast expenditure amounts (either over or under depending on actual vs assumed price inflator allowed for). Further details are presented in the expenditure forecasts section.
Constant price escalation to nominal dollars	CPI was applied to escalate constant prices to nominal dollars in Schedule 11a and 11b, based on Westpac's forecast for FY25 to FY28.	Westpac forecasts are based on their observations of price movements, which could vary due to unseen factors.	Variations in the forecast value may increase or decrease, causing inaccuracies in forecast expenditure amounts. Further details are presented in the expenditure forecasts section.
Regulatory environment	No significant changes to the regulatory regime and requirements.	The shift in Government changes the regulatory nature/requirements of EDBs.	Plan revision may be required to adhere to any changes in regulatory requirements.
Capital Expenditure – Customer Driven	The capital expenditure proposed for customer-initiated projects will remain within forecast levels.	Overall, the customer market in the residential sector is steady, though building consents show an increase Our ability to recover upstream costs for larger investments or uneconomic supplies.	Investment levels may increase or decrease in response to changes in demand for new customer connections.

Area	Assumption	Sources of uncertainty	The possible impact of uncertainty
Capital Expenditure – Network Driven	The capital expenditure proposed for asset replacement and renewal will continue at forecast levels, which assume a steady operating state.	The overall condition and rate of aging of network assets are fairly known and steady. No step change in expenditure is expected, except the transitional spending included in the plan to cater for deferred maintenance.	Investment levels may increase or decrease in response to changes in known asset conditions and possible increased requirements for asset replacement or catastrophic plant failure requiring a high one-off cost.
Operational Expenditure – Routine Inspection and Maintenance	The inspection and maintenance expenditure proposed will remain within forecast levels.	The inspection programmes are based on maintenance standards. The routine of inspection and servicing programmes is not likely to change significantly.	Any material change to the annual maintenance programme or associated costs may increase or decrease the Opex costs related to inspection and maintenance.
Operational Expenditure – Reactive Maintenance	The reactive maintenance expenditure proposed will remain within forecast levels for the next year.	Impact of third-party and weather-driven reactive maintenance driven by factors not in our control. Aging assets may lead to higher levels of reactive maintenance required.	A change in network equipment failure rate could lead to an increase in reactive maintenance requirements and costs.
Technology development	The uptake rate of new technologies (e.g., EVs, PV and battery storage).	The rate of uptake of new technologies is largely unknown at this stage.	The widespread charging of EVs on our network has the potential to provide a source of revenue that currently does not exist, albeit that investment may be required. The widespread installation of distributed generation (mostly PV) can have two principal effects. (i) A reduction in delivered energy to ICPs where all the output is consumed within the premises and (ii) if large numbers of customers sought to inject power into our network, the power injection would need to be managed to prevent voltage problems. In the event of generation injection from some ICPs, our network will be required to deliver the power to other ICPs. Introducing cost-reflective line charges will likely dampen enthusiasm for PV, as line charges relate to installed network capacity, not delivered energy. A significant reduction in the cost of battery storage could increase the benefit of PV installations. However, introducing capacity charges for all ICPs may constrain further development of PV installations.
Public Safety	Compliance with requirements for public safety management will not adversely impact the existing network assets in the public domain.	Implementing a safety management system, Assura, and promoting a culture of incident reporting and safety awareness.	Assets in the public domain may require higher than average rates of replacement or increased level of isolation from the public, leading to higher costs or reallocation of work programmes.
Transmission Pricing	The transmission pricing methodologies will remain unchanged, and the transmission pass-through pricing will stay in place.	Transmission pricing is regulated as a pass-through cost, and we expect this to remain as a pass-through cost, with the net effect on the business remaining the same.	Changes to the methods of transmission pricing may lead to increased expenditure as grid alternative options become more attractive in a non-pass-through environment.
Transmission Network	The transmission grid and grid exit point connections will remain unchanged from the agreed projects.	Our network developments drive changes to grid exit points, and planned major transmission developments will be signalled well before delivery.	A change to the configuration or capability of the transmission system could lead to a requirement for increased levels of investment in the network to provide alternative capacity or security.

Table 140: General assumptions

A.2 Energy transformation demand growth scenarios assumptions

Table 141 summarises the material assumptions for demand growth scenarios.

Driver	Base (i.e., no change in energy usage pattern)	Low scenario	High scenario
Population-driven regional growth	The continued growth of the Waipā population is faster than historical trends, resulting in demand growth of between 32-95% by 2050 Commercial demand growth of 51% by 2050	80% of forecast regional growth is realised	100% of forecast regional growth eventuates
Residential and commercial gas-to-electricity conversion	No conversion from gas to electricity	Gas usage is expected to decline gradually but will still be present in some form (biofuels and hydrogen) by 2050. 50% of all gas usage covers electricity	High-efficiency electricity heat is the most economical solution and dominates the market. 100% of gas usage converts to electricity.
Light passenger vehicle electrification	No further uptake of EVs	75% of the fleet will be electrified by 2050, the balance fuelled by alternative fuels. Most light vehicle charging occurs at homes	100% electrified by 2040. Most light vehicle charging is expected to occur at homes.
Commercial/ heavy vehicle electrification	No further uptake of EVs	Light commercial and some short-haul heavier vehicles are electrified using centralised charging stations. Heavy vehicles convert to hydrogen. Light and heavy electric vehicle charging is fully controlled to avoid peak times.	Light commercial vehicles are electrified using centralised charging stations. Heavy vehicles are electrified using centralised charging stations. Light and heavy electric vehicle charging is uncontrolled and impacts peak demand.
Industrial process heat electrification	No conversion to electricity	Natural gas and LPG are substituted mainly by biomass and biogas	Light commercial and some short-haul heavier vehicles are electrified using centralised charging stations Natural gas and LPG are substituted mainly by biomass and biogas for large industrial customers
Distributed generation (DERs)	The current adoption rate continues (see Section 3.46) No grid-scale distributed generation	The current adoption rate continues (see Section 3.46) No grid-scale distributed generation	The current adoption rate continues New grid-scale distributed generation
Controllable DERs	Technology changes do not change network use patterns	No additional flexibility beyond existing hot water control (which transfers to the flexibility market) and the EV charging assumption	No additional flexibility beyond existing hot water control (which transfers to the flexibility market) and the EV charging assumption
Energy efficiency	No net change	No net change	No net change

Table 141: Energy transformation demand growth scenarios material assumptions

APPENDIX B – STAKEHOLDERS AND STAKEHOLDER INTERESTS

We define our stakeholders as any person or class of persons that:

- Has a financial interest in our business (equity or debt).
- Pays money to us (either directly or through an intermediary) for delivering service levels.
- Is physically connected to our network.
- Uses our network for conveying electricity.
- Has an interest in land on which our assets are located.
- Has an interest in land that provides access to our assets.
- Supplies us with goods or services.
- Is affected by our network's existence, nature, or condition (especially if it's unsafe).
- Has a statutory obligation to perform an activity concerning our network's existence or operation, such as request disclosure data, regulate prices, investigate accidents, investigate consumer complaints, operate infrastructure dependent on our network, prepare for and manage emergencies, include infrastructure plans in a District Plan, protect archaeological and Wahi Tapu sites, etc.
- Has an interest in the safety of our network.
- Is employed by us.

Stakeholders and nature of interest

Table 142 highlights our key internal and external stakeholder groups and the nature of their relationships with us.

Stakeholders	Relationship / Interface	Nature of Interest
General electricity customers	Beneficiaries of Waipā Networks Trust Independent surveys Consultation meetings Daily direct and indirect feedback	Fault services, Network reliability Quality of supply, Controlled supply New connections, Safety disconnects. Service requests, Bi-annual discount Cost of supply
Large electricity customers **Fonterra** **Architectural Products Limited (APL)** **Department of Corrections** **Aotearoa Developments** **Winstone Aggregates** **Major subdivision developers**	Conveyance agreements, where applicable Ad-hoc meetings	Future demand plans, Network capacity, Network reliability, Quality of supply, Cost of supply
Waipā Networks Trust	Shareholder Six monthly meetings	Return on investment. Bi-annual discount Sustainable business Responsible corporate behaviour KPIs
Electricity Retailers	Interposed use-of-system agreements Ad-hoc meetings	Line charges and methodology Line losses, Revenue protection Billing accuracy and timeliness Retailer services Quality of supply and reliability
Waipā, Otorohanga, Waikato & Waitomo District Councils, Waikato Regional Council	Utility service provider Road requirements Regular meetings RMA / Planning	District & Regional planning Traffic management Utility services locations Co-ordinated street openings

Stakeholders	Relationship / Interface	Nature of Interest
Waka Kotahi/NZTA, KiwiRail	Road user requirements Rail asset owner requirements Correspondence, ad-hoc meetings	Traffic management Street lighting Utility services locations Electrical interference & safety clearances
Other utility operators	Road user requirements Ad-hoc meetings	Utility services locations
Transpower	Transmission Pricing Agreement Customer Investment Contracts Quarterly meetings System Operator regarding the operation of HTI-TMU 110kV line	Capacity, reliability and maintenance of grid transmission and connection assets, including HTI-TMU 110kV line. Security of transmission lines Code compliance at the GXP interface
Electricity Authority **Commerce Commission** **MBIE** **Auditor General** **Inland Revenue**	Electricity Distribution Business Legal operating framework Ad-hoc meetings, discussions, and correspondence	Information Disclosure compliance Threshold compliance Compliant business practices Submissions on proposals
Industry Suppliers	Goods & services provider	Products and services
Iwi	Network developments and resource consenting applications in our network area via meetings as required	Tangata whenua consultation regarding resource consents, network developments and works affecting wai tapu. Network service to iwi constituents.
Waipā Employees	In house Company workforce	Zero injuries Healthy employment environment Remuneration Individual training plans Personal growth opportunities
Contractors	Working on our assets or for customers on assets that connect to our network	They providing services and access our network for connections, inspections etc.
Utility Disputes	Customer complaints	Customer complaints
Chorus	Shared use of Assets	Attachment of copper and fibre cables to our poles. Attachment of electricity lines to Chorus network poles.
National Emergency Management Agency	Lifeline utility emergency preparedness Waikato Lifeline Utility Group meetings	Emergency preparedness and risk management related to maintaining electricity supply during natural disasters.

Table 142: Our key internal and external stakeholders

Managing stakeholder interest

Stakeholders	How we engage
Waipā Networks Trust	• Providing feedback and approval of the SCI. • Regular meetings between our Directors and the Waipā Networks Trustees.
Banks	• Regular meetings between the banks and our staff. • Adherence to our Treasury policy.
Customers	• Direct and regular discussions with large industrial customers. • Customer experience surveys • Customer focus groups • Regular communication via digital and print channels, including social media, websites, advertising, media stories, and direct communication. Community engagement projects such as energy assessments and community sponsorships • Public disclosure documents

Stakeholders	How we engage
District Councils	• Consultation regarding Council development plans and long-term planning. • Engagement regarding AMP and network development
Energy Retailers	• Annual consultation with retailers, regular contact, and discussion.
Mass-market Representative Groups	• Informal contact with group representatives.
Industry Representative Groups	• Informal contact with group representatives. • WorkSafe website. • Safety bulletins from the Electricity Engineers Association. • Exchange and contribution towards industry best practices.
Employees and Contractors	• Regular communication via digital and in-person channels, including newsletters, emails and employee and contractor briefings.
Suppliers of Goods and Services	• Regular supply meetings. • Written communication.
Public (as distinct from Customers)	• Informal talk and contact. • Feedback from public meetings. • Regular communication via digital and print channels, including social media, websites, advertising, media stories, and direct communication. • Community engagement projects such as energy assessments and community sponsorships
Landowners	• Individual discussions as required.
Councils (as regulators)	• Formally, as necessary, to discuss issues such as assets on Council land.
Iwi	• Formally, informally, and as required.
Waka Kotahi, Kiwirail	• Formally and as required.
MBIE	• Regular bulletins on various matters. • Release of discussion papers. • Analysis of submissions on discussion papers.
Energy Safety/WorkSafe	• Regulations and codes of practice. • WorkSafe website. • Audits of our activities. • Audit reports from other EDBs.
Commerce Commission	• Regular bulletins on various matters. • Release of discussion papers and direct communications. • Analysis of submissions on discussion papers. • Conferences following the submission process.
Electricity Authority	• Weekly update. • Release of discussion papers. • Briefing sessions. • Analysis of submissions on discussion papers. • Conferences following the submission process. • Information on the Electricity Authority's website.
Utilities Disputes	• Reviewing their decisions regarding other EDBs. • Assistance with any complaint investigations.

Table 143: Key stakeholder groups

APPENDIX C – RISK FRAMEWORK

This risk management matrix is described in Section 6.1 Risk Management Framework.

Risk consequence categories

	CONSEQUENCE					
	No Appetite for	Low	Minor	Moderate	Major	Severe
People/ Health and Safety	Unsafe work practices which would cause harm to our employees, sub-contractors, customers or the public. Trading off health and safety outcomes for any other objectives. Material exposure to key operational personnel risk or the lack of succession plans for executive and key roles.	First Aid	Medical Treatment Lost Time Injury	Serious Harm Injury Notifiable injury	Permanent Disability	Single or Multiple Fatalities
Environmental	Risks that may cause a major environmental breach.	On site Environmental released – contained within site	On site Environmental released – not contained within site No permanent effects	Off-site environmental release with minor detrimental effects Recovery up to 1 year	Offsite environmental release with detrimental effects Recovery 1-2 years	Offsite environmental release with detrimental effects Recovery 2+ years
Stakeholder and Community Confidence / Reputation	Risks that affect our reputation with influential stakeholders. Unethical behaviour or putting our staff in a position where they may be forced into unethical behaviour. Risks that may result in customers without power for more than 24 hours.	Isolated adverse local media reference Public complaints	Repeated adverse local media coverage	Sustained adverse local and national media reference	Sustained adverse local and national media reference	Irrevocable damage to reputation
Cultural	Risks that may cause irreparable damage to key cultural stakeholder relationships.	Minor offence caused to individual relationship (eg customer). No negative public perception issues created	Lack of understanding of key cultural aspects requiring formal apology by a member of the Senior Leadership Team	Breach of trust with cultural stakeholders requiring Chief Executive or Board response	Significant breach of trust with cultural stakeholders	Irreparable damage to key cultural stakeholder relationships
Financial (impact on business cashflows)	Risks that cause a sustained level of underperformance in our core business which impacts the strength of our balance sheet or achievement of budgets and SCI targets. Risks that affect our ability to raise debt on reasonable terms or invest in our network. Material risks on investments that are outside of our core competency to manage (e.g. our core competencies exist in investments in infrastructure, electrical contracting etc).	Loss less than $75,000	Medium Financial loss $75,000 to $200,000	High Financial loss $200,000 to $750,000	High Financial loss $750,000 to $2,000,000	High Financial Loss greater than $2,000,000
Operational	Risks that would put our network business at risk. Risks that impact the ability of the network to meet demand or respond to growth. Risks that result in underinvestment in the network and the network health suffers as a result.	Limited Interruption	Significant interruption to less than 20% of the Company's operations	Significant interruption to between 20-50% of the Company's operations	Significant interruption to more than 50% of the Company's operations	Company-wide inability to continue normal business operations
Compliance	Risks that may cause a significant regulatory or statutory breach which may impact our exempt regulatory status or expose the company to significant regulatory penalty.	Regulator notification not required	Regulator notification not required	Regulator notification may not be required	Regulator notification required – self reported breach	Regulator notification required / notified breach or investigation

Likelihood categories

Likelihood	Probability % in next year	Probability Description
Almost certain	95%+	The risk event will probably occur in most circumstances (e.g. will happen immediately or within a short period of time). Expected to occur regularly under normal circumstances
Likely	50-95%	The risk event could occur at some time (e.g. Will probably happen within the next year but is not a persistent issue). Expected to occur at some time
Possible	10-50%	The risk event could occur at some time (e.g. reasonable expectation that event will happen within a 5 year period). Distinct possibility it may happen.
Unlikely	2-10%	The risk event could occur at some time (e.g. may occur within a 10 year timeframe). Not likely to occur in normal circumstances
Rare	>2%	This risk event may occur only in exceptional circumstances (e.g. Highly unlikely to happen within 10 year time frame). Could happen but probably never will.

Combination risk matrix table

			CONSEQUENCE				
			Low – 1	Minor – 2	Moderate – 3	Major – 4	Severe – 5
LIKELIHOOD	Almost Certain	5	5 Medium	10 High	15 Extreme	20 Extreme	25 Extreme
	Likely	4	4 Low	8 Medium	12 High	16 Extreme	20 Extreme
	Possible	3	3 Low	6 Medium	9 Medium	12 High	15 Extreme
	Unlikely	2	2 Low	4 Low	6 Medium	8 Medium	10 High
	Rare	1	1 Low	2 Low	3 Low	4 Low	5 Medium

Risk escalation / decision making

Operational / Low	Operational and Compliance / Medium	Strategic / High	Governance / Extreme
Risk managed through routing management/internal control procedures.	Risk to be reported to relevant manager. May require additional risk treatment actions.	Risk to be reported to the Chief Executive Officer and Senior Leadership Team to approve and monitor risk treatment actions	Risk to be reported to the Board to approve and monitor risk treatment actions.

APPENDIX D – NETWORK HIGH-FOCUS RISKS

The following table summarises our updated network's high-focus risks based on the Risk Management Framework revised in FY2024 (Refer to Appendix C).

Risk	Inherent Risk	Residual Risk	Level of Control	Current Actions
Unauthorised/public access to unsecured pillar boxes or unwanted self-tapping screws cut cable insulation and are live (note – no incidence found yet).	Extreme 15	High 10	Improving	The pillar inspection program is underway, with Cambridge town completed and Te Awamutu town started in FY24. Continue with the pillar replacements program.
Major regional storm (tropical cyclone) causes widespread network damage,	High 12	High 12	Improving	Review major storm contingency planning and business continuity planning. Improve network visibility through access to Control Room ADMS and upgrade the existing comms and SCADA system.
Sustained (e.g., >24 hours) loss of supply at GXP/Point of Supply	High 12	High 12	Improving	An emergency response plan will be developed with Transpower within 12 months. The new Hautapu GXP and the reconfiguration of the Cambridge network (e.g., sub-transmission development) will significantly reduce the risk for the Cambridge area. An network architecture review for the Te Awamutu network will be conducted in 2024.
Earthquake risk to the depot building	High 10	High 10	Further controls needed	The depot is constructed according to the pre-2010 Code, but performance under the latest earthquake risk and current code has not been assessed. As part of the depot building fit out review process, assess building performance against the current code and assess collateral damage to depot and systems.
Poor or unknown condition overhead lines/poles causing lines or pole failure and public safety hazards.	High 12	Medium 9	Improving	A rural helicopter-based survey was completed in 2022, and an urban drone-based survey is progressing in FY24. Priority issues are being addressed by the Defect process, with an additional renewal budget started from AMP 2023. Other pole-top equipment is already being inspected as part of the routine earth inspection. A one-off wood pole inspection program is being planned for FY25. AMP 2024 also incorporates an increase in inspection resources. Our new works planning and delivery process support our capacity to deliver.
Assets with unknown age, unable to forecast replacement expenditure	High 12	Medium 9	Improving	Asset data audit highlighted areas for improvement. Some 'quick win' fixing will be implemented in FY25. One-off timber pole inspection and urban drone survey. Improving our digital inspection process.
Unlawful or unsafe network (service main/line) connection	High 12	Medium 9	Improving	Put a formal system, process and recording system for these instances in place. Aerial Survey data has greatly increased the volume of defective service mains identified; these are being worked through.
Long-term planning and investment to enable a resilient and future-enabled network through climate change and decarbonisation are ineffective or too late.	High 12	Medium 8	Improving	Our Network Transformation strategy addresses this risk. We are 'building the HV big' to address regional growth and electrification challenges simultaneously with incremental investment. We are also developing a strategy for LV visibility and management and LV data capture.
Network Security Risk Loss of critical IT systems through Cyber-attack Core operational systems only	High 12	Medium 8	Improving	ISSP Developed and being implemented. Specific sections on managing risk, in particular Cyber and single point of failure risk.
Cable capacity out of Te Awamutu GXP	High 12	Medium 8	Improving	AMP project to replace TMU cables. Construction project to be mobilised in FY25. Feeder connectivity also altered, allowing backfeeding.
A fire started by overhead lines, auto reclose or field activities.	High 12	Medium 8	Effective	We have implemented a fire risk mitigation strategy during high fire risk seasons, including disabling auto recloses and additional field awareness and mitigation measures.
Legacy-designed poles cause risk of failure and H&S risk (if climbed)	High 12	Medium 8	Further controls needed	The number of poles at risk is currently unknown. However, pole failures due to under design are rare, indicating historical practice and pole condition are acceptable. The urban OH asset drone survey was completed in FY24. A pole climbing SOP will be developed in FY25, and a one-off timber pole inspection will occur in FY25-26.

APPENDIX E – FEEDER CAPACITY, SECURITY, AND VOLTAGE CONSTRAINT ANALYSIS

As of 31st March 2023, it is subject to change due to ongoing projects.

GXP	Feeder Name	ID	Feeder Type	Capacity	Capacity (Based on cable rating)	66% Capacity	Feeder MD FY23	99th Percentile
* Cambridge Grid Exit Point								
CBG	Roto-o-Rangi	2702	Predominantly Residential	400	300mm Ali	264	307	187
CBG	Cambridge North	2712	Predominantly Residential	400	300mm Ali	264	137	121
CBG	Cambridge Town	2722	Predominantly Residential, some commercial	400	300mm Ali	264	302	251
CBG	Kaipaki	2732	Predominantly Residential, some agricultural	400	300mm Ali	264	184	149
CBG	Pencarrow	2742	Predominantly Residential	400	300mm Ali	264	259	217
CBG	Hautapu A	2762	Industrial	632	2 x 300mm Ali	417	370	339
CBG	French Pass	2772	Predominantly Residential, some agricultural	400	300mm Ali	264	221	185
CBG	Leamington	2802	Predominantly Residential	400	300mm Ali	264	227	162
CBG	Hautapu B	2812	Industrial	632	2 x 300mm Ali	417	259	242
CBG	Cambridge East	2832	Predominantly Residential	400	300mm Ali	264	241	203
CBG	Tamahere	2842	Predominantly Residential	400	300mm Ali	264	193	122
CBG	St Kilda	2852	Predominantly Residential	400	300mm Ali	264	164	142
CBG	Monavale	2862	Predominantly Residential	400	300mm Ali	264	281	201
CBG	APL	2872	Industrial	400	300mm Ali	264	182	141
* Te Awamutu Grid Exit Point								
TMU	Kawhia	22	Predominantly rural residential	295	160mm PILC	195	200	145
TMU	TA West	24	Predominantly Residential	295	160mm PILC	195	299	219
TMU	Pirongia	25	Predominantly Residential	295	160mm PILC	195	197	175
TMU	Hairini	26	Predominantly Residential	295	160mm PILC	195	307	191
TMU	Paterangi	27	Predominantly Residential	295	160mm PILC	195	216	188
TMU	TA Load Cell	28	-	402	300mm Ali	265	0	0
TMU	Kiokio	2732	Predominantly Residential	402	300mm Ali	265	241	199
TMU	Kihikihi	2742	Predominantly Residential	295	160mm PILC	195	209	178
TMU	Mystery Creek	2752	Predominantly Residential	295	160mm PILC	195	103	88
TMU	Pukeatua	2762	Predominantly Residential	402	300mm Ali	265	238	205
TMU	TA Fonterra A	2782	Industrial	800	2 x 300mm Ali	528	305	262
TMU	TA Fonterra B	2802	Industrial	800	2 x 300mm Ali	528	273	182
TMU	Ohaupo	2822	Predominantly Residential	402	300mm Ali	265	238	160
TMU	TA East	2832	Predominantly Residential	295	160mm PILC	195	301	237
TMU	Pokuru	2842	Predominantly Residential	295	160mm PILC	195	242	201
TMU	Waikeria	2852	A mixture of commercial and residential	402	300mm Ali	265	187	158

	% of Overall Capacity	% Of 66% Capacity	FY expected to exceed 66% Capacity	FY expected to exceed 100% Capacity	Existing Voltage Problems	Constraint addressed through:
	77%	116%	Beyond planning period	Beyond planning period	N	
	34%	52%	Beyond planning period	Beyond planning period	N	
	76%	114%	**FY25**	Beyond planning period	N	New GXP FY25/26
	46%	70%	Beyond planning period	Beyond planning period	N	
	65%	98%	**FY30**	Beyond planning period	**Y**	New GXP FY25/26
	59%	89%	Growth by step change	Beyond planning period	N	
	55%	84%	Beyond planning period	Beyond planning period	N	
	57%	86%	Beyond planning period	Beyond planning period	N	
	41%	62%	Growth by step change	Beyond planning period	N	
	60%	91%	**FY32**	Beyond planning period	N	
	48%	73%	Beyond planning period	Beyond planning period	**Y**	VREG FY25
	41%	62%	Beyond planning period	Beyond planning period	**Y**	VREG FY25
	70%	106%	**FY32**	Beyond planning period	N	
	46%	69%	Beyond planning period	Beyond planning period	N	
	68%	103%	Beyond planning period	Beyond planning period	N	
	101%	154%	**FY23**	Beyond planning period	N	Feeder Cable Upgrade FY25
	67%	101%	**FY29**	Beyond planning period	**Y**	Feeder Cable Upgrade FY25 & Vreg install Fy25
	104%	158%	**FY23**	Beyond planning period	N	Feeder Cable Upgrade FY25
	73%	111%	**FY25**	Beyond planning period	**Y**	Feeder Cable Upgrade FY25
	0%	0%	Beyond planning period	Beyond planning period	N	
	60%	91%	Beyond planning period	Beyond planning period	N	
	71%	107%	**FY28**	Beyond planning period	**Y**	Feeder Cable Upgrade FY25
	35%	53%	Beyond planning period	Beyond planning period	**Y**	Offload onto the CBG feeder
	59%	90%	Beyond planning period	Beyond planning period	N	
	38%	58%	Growth by step change	Beyond planning period	N	
	34%	52%	Growth by step change	Beyond planning period	N	
	59%	90%	Beyond planning period	Beyond planning period	N	
	102%	155%	**FY23**	Beyond planning period	N	Feeder Cable Upgrade FY25
	82%	124%	**FY23**	Beyond planning period	**Y**	Feeder Cable Upgrade FY25 and (Vreg and Cap bank FY25)
	47%	70%	Beyond planning period	Beyond planning period	N	

APPENDIX F – EXPENDITURE FORECASTS

F.1 Capital expenditure

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Ten year total
Consumer connection	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	**55,114**
System growth	17,813	5,675	9,990	7,695	1,254	1,254	1,254	1,254	1,254	1,150	**48,593**
Asset replacement and renewal	5,204	5,894	5,614	5,427	5,779	4,379	4,378	4,378	4,378	4,268	**49,703**
Asset relocations	231	231	231	231	231	231	231	231	231	231	**2,310**
Reliability, safety and environment:											
Quality of supply	791	903	653	903	653	903	653	903	653	903	**7,914**
Legislative and regulatory	940	100	100	100	100	100	100	100	100	100	**1,840**
Other reliability, safety and environment	710	430	160	160	160	160	160	160	160	160	**2,420**
Total reliability, safety and environment	**2,441**	**1,433**	**913**	**1,163**	**913**	**1,163**	**913**	**1,163**	**913**	**1,163**	**12,174**
Expenditure on network assets	**31,201**	**18,744**	**22,259**	**20,027**	**13,688**	**12,538**	**12,287**	**12,537**	**12,287**	**12,323**	**167,894**
Expenditure on non-network assets	3,986	1,866	1,381	1,381	1,881	1,881	1,881	2,481	2,481	2,481	**21,700**
Expenditure on assets	**35,187**	**20,610**	**23,640**	**21,408**	**15,569**	**14,419**	**14,168**	**15,018**	**14,768**	**14,804**	**189,594**

F.2 Operational expenditure

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Ten year total
Service interruption and emergencies	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	**18,380**
Vegetation management	2,027	1,879	1,879	1,894	1,879	1,879	1,879	1,879	1,894	1,879	**18,968**
Routine and corrective maintenance and inspection	941	1,190	1,154	1,139	1,121	1,126	1,101	1,126	1,101	1,146	**11,145**
Asset replacement and renewal	813	842	702	799	767	827	694	834	694	821	**7,793**
Network Opex	5,619	5,749	5,573	5,670	5,605	5,670	5,512	5,677	5,527	5,684	**56,286**
System operations and network support	5,353	5,358	5,358	5,358	5,358	5,358	5,358	5,358	5,358	5,358	**53 ,572**
Business Support	5,831	5,831	5,831	5,831	5,831	5,831	5,831	5,831	5,831	5,831	**58,313**
Non-network Opex	**11,184**	**11,189**	**11,189**	**11,189**	**11,189**	**11,189**	**11,189**	**11,189**	**11,189**	**11,189**	**111,885**
Operational Expenditure	**16,803**	**16,938**	**16,762**	**16,859**	**16,794**	**16,859**	**16,701**	**16,866**	**16,716**	**16,873**	**168,171**

APPENDIX G – DISTRIBUTED GENERATION, NON-NETWORK ALTERNATIVES, AND INNOVATION PRACTICES

G.1 Policies on distributed generation

We welcome enquiries from customers and other interested parties regarding the commercial and technical viability of various distributed generation (coal/diesel, micro-hydro, wind and photo-voltaic, etc.) proposals.

Our connection policy[67] requires distributed generators to contribute to any network enhancements needed to eliminate any network issues caused by the distributed generator.

The application process and a description of the consenting, associated legislation, and technical requirements for distributed generation are available on our website.

In summary, our requirements for new generators are:

- Operators must ensure their generator operates safely and doesn't adversely affect our network or any other network customers.
- Generators must not produce voltages or harmonics outside regulatory limits, interfere with network protection systems or inject fault currents above network capabilities.
- Generator owners must protect against over and under frequency, overcurrent, phase-to-phase, and phase-to-earth faults.
- Generators must comply with all relevant regulations, standards, and codes of practice.
- Applicants who reduce the net reactive power supplied to our network by Transpower will be encouraged. In contrast, those who require excessive additional reactive power support will be declined or required to supply power factor correction.
- Generators must be tested fully before connection.
- Connected generators will be disconnected in emergencies if the generator has failed to pay any fees or charges, if there is a change or increase in distributed generation without our prior consent, or if the generator fails to have an electricity retailer.
- Standard fees apply for applications and inspections.

Most of our distributed generation installations have been downstream of the customer's metering point and generally photovoltaic applications. Given the low penetration levels of data, this type of distributed generation has had little effect on our network. Still, high voltage issues on LV feeders have been observed, and this remains a potential issue with increasing penetration.

G.2 Policies on non-network solutions

Non-network solutions enable our network to deliver more services and/or improve existing services without augmenting our network. These include embedded generation, network-initiated load control, demand-side management solutions, and network reconfigurations.

The electricity distribution model has been relatively unchanged for many decades. However, the industry is now seeing the increasing availability of alternative technologies, mainly through small-scale distributed generation and battery storage. Using non-network solutions, where appropriate and economical, can offset investment in standard network assets such as poles and wires.

Non-network solutions such as energy-efficient lighting and heat pumps may reduce customers' demand and energy consumption within their installations. We use our load control system to reduce maximum demand on our network and effectively move the load to low load periods. This has the effect of deferring the need for demand-driven network investments.

To address network constraints, we encourage all forms of non-network solutions that can be provided at an economically competitive price and are practical alternatives to conventional network augmentation. The tendering approach for market-provided non-network solutions will be considered when opportunities are identified.

Operation

We recognise that the scale of individual installations for non-network solutions may not be able to deliver effective network support; therefore, we will consider a portfolio approach to utilising the available non-network solutions.

Line pricing incentives

We offer incentives for non-network solutions through pricing tariffs, e.g., the controlled load, day/night and 8-hour supply kWh line pricing to all retailers to encourage customers to reduce network MD at peak times. From 2021, a new pricing structure has been implemented to provide for peak, shoulder, and night periods as a pricing signal to reflect the impact on our demand network at different times of the day.

[67] *WNL-Distributed-Generation-Policy_v3-intrnt.pdf (waipanetworks.co.nz)*

Customer advice

Our website (Info for Customers/Energy Efficiency) contains suggestions for customers to save power without adversely impacting their lifestyle.

Embedded generation

We will consider using non-network solutions such as diesel generation to reduce network MD and delay conventional network capital expenditure where it is prudent and economical to do so.

Remote area power supplies

Remote Area Power Supplies (RAPS) are essentially an alternative electricity supply from a standalone generation system instead of a network connection. A RAPS system typically uses a combination of solar generation, battery storage and diesel backup to provide supply.

There are a small number of instances where RAPS may provide immediate benefit by minimising economic losses, typically at sites characterised by:

- Extreme remoteness resulting in increased line and vegetation maintenance costs.
- Extremely low customer count per km of line requiring renewal.
- Poor asset health drives a case for short-term renewal.

We don't currently have plans for any significant investment in RAPS within the next five years.

Network adaption

Ultimately, the role of network services may change from a traditional full lines service to provisioning firm capacity, fault current and frequency regulation support for micro-networks. The greatest risk for us may not be mastering the technology involved but rather the ability to properly reflect our long-run and marginal costs for our services.

In addition, the cost of acquiring/implementing non-network solutions needs to be balanced with the need for cost-reflective network prices, as signalled by the Electricity Authority.

G.3 Innovation practices

Our innovation strategy is to be fast followers instead of early adopters; therefore. The main issue from a strategy perspective is that the future uptake rates for new technologies are uncertain, with no trends yet to build on. We are mindful of this and will continue to monitor developments closely.

The current focus of our innovation includes exploring options to improve network visibility, extend the use of existing ICP data, and build a platform for flexibility services.

Decisions on innovations and measurement of success

Innovation brings change to our practices, so to ensure effective adoption, we follow these stages to discover and explore innovation opportunities:

1. **Discovery:** activities that enable discovering innovation opportunities and available options. These include participation in industry forums such as the Ara Ake, EEA, ENA, EDB peer-group interactions, Government agency events, vendor presentations, etc., which inform our innovation decisions.
2. **Persuasion:** ascertaining the potential value of adopting innovation and achieving buy-in. At this stage, we carry out trials as proof of concept and proof of value to confirm the innovation's features, including the data we can collect and how to interpret findings, identify critical risks, and act on them.
3. **Decision:** determining whether we will adopt the innovation or not. We are informed by the observations from the persuasion stage: successful proof of concept, including deliverability and cost-benefit.
4. **Implementation:** putting the innovation into practice. Our general approach is staged implementation (small steps), as there can still be a degree of uncertainty surrounding the outcomes of the innovation and whether to keep it as opposed to reverting to old practices. This stage includes training to ensure the effective embedding of the innovation.

   In addition, factors driving the uptake of new technologies will likely result in a need for evolving asset management practices. However, plans can be adapted as the technology is established and its effects become more certain. We will continue to monitor new technologies and consider how our network can best be managed to give maximum benefit to all stakeholders.

5. **Confirmation:** evaluation to verify whether expected benefits are being realised based on:
   - **Strategic Alignment:** strategic fit and impact, synergy with existing knowledge/systems/practices, proprietary position, and the potential for wider application (even commercialisation).
   - **Financial Impact:** return on investment (can be difficult to measure for innovation), time to implement.
   - **Technical Feasibility:** resource availability, external support, complexity.
   - **Value Proposition:** impact on stakeholders, business service transformation.

Collaboration and learning from others

The pace at which we adopt innovation relies partly on the progress and lessons learnt from others, including the progress of industry working groups.

We follow the work of a national industry group considering the potential impact of new disruptive technologies and how network assets will be operated and managed. Technologies becoming increasingly available and affordable are expected to impact our network. These include distributed generation (photo-voltaic, in particular), wind and electric vehicles, and storage batteries to a lesser extent.

We will monitor this rapidly developing area and review our position on battery storage, demand side management and associated infrastructure during this planning period. We are also learning from other distribution network approaches to tendering for non-network solutions, which can provide access to more economic demand management. For example, battery installations can become more economically feasible if the operator can obtain multiple revenue streams from sources other than network demand management, reducing the cost burden to our network for this service.

APPENDIX H – INVESTMENT SELECTION AND APPROVAL PROCESS

H.1 Overview

We follow a structured investment selection and approval process that ensures investments selected for implementation meet our asset management goals and support delivery efficiency. Figure 123 shows the stages of our investment approval process.

Various drivers determine the need for network investment, including customer requests, load growth, examination of existing constraints or limitations within our network, and asset condition.

This process enables consistent decisions that balance risk, service levels, and expenditure. It is used to determine and justify expenditures on network development, asset replacements and refurbishments, maintenance activities, and customer-initiated work.

The level of analysis of issues and opportunities is commensurate with their complexity, level of expenditure, and timing. Complex, expensive, and imminent needs receive more rigour than those that are simple, inexpensive, or more distant in the future.

Figure 124: Investment selection and approval process

H.2 Need identification

A need is a clearly defined problem and/or opportunity that impacts how we operate the network. Identifying the need includes establishing a need date (i.e., the date at which a solution must be in place) and the planning lead time (i.e., the time required to complete the investment selection and approval and complete the delivery).

A need can include problems with a common set of solutions. The need is recognised when:

- One or more planning criteria are breached,
- Request for new load connection or asset relocation from a customer,
- Asset condition meets criteria for replacement or renewal,
- Safety non-compliance, and
- Projects are identified under other business strategies or programmes.

H.3 Solution options identification

This stage explores a range of options to meet the need. This is also an opportunity to explore innovative ideas, including emerging technologies and new approaches for delivery and operation. Options to address the need are assessed.

Engineers typically develop network options using various tools, such as load flow modelling software, local knowledge (and experience), and sourcing information from others. For long-term issues, an incremental scope build-up would be usual as more knowledge on the issues and solution options are developed. When the project scope has been updated, the solution must pass through the assessment, prioritisation, and approval stages.

- Where an asset fleet strategy prescribes a sole option, other options are not considered.
- Non-network alternatives are also considered when practical to do so.
- A do-nothing option representing the status quo is always considered.

H.4 Options assessment

The outcome of this step is the selection of a preferred solution. The various solution options are assessed based on multiple criteria. The level of analysis depends on the size and risk of the projects. The solution or combination of options best meets the needs is selected.

An option assessment accounts for the following:

- all lifecycle costs to deliver, maintain, operate, and dispose of the relevant assets,
- cost of residual risk associated with the option,
- benefit including risk mitigation or opportunity value, provided by the option,
- maximum net benefit that the option and the associated need date can provide,
- changes in the net benefit (including any changes in risk) when the need date is delayed or advanced (e.g., growth appears faster or load decommissioned earlier than forecast),
- sensitivity analysis where two options have the same net benefit.

Some of the options may not be technically feasible or economical. Where possible, options are analysed and pre-determined and then documented in the relevant asset class lifecycle strategy.

The option with the highest net benefit, subject to sensitivity analysis, is selected as the solution. Solutions to security issues will be economically tested where the cost is high or the security benefit provided is modest. The cost/benefit assessment also provides a framework for managing conflicting stakeholder expectations and interests.

H.5 Prioritisation and approval

This step ranks projects and presents them for approval. We prioritise projects on:

- Need dates to ensure assets are commissioned on time,
- Alignment with long-term network development plan,
- Risk reduction–the extent to which the project eliminates or minimises network, health and safety, and business risks,
- Ease of coordination with other projects, which supports work integration and
- Service level improvement
- Where solutions are based on a risk assessment (other than asset capacity or condition), further prioritisation is undertaken based on the magnitude of the net benefits, with the solutions with the highest net benefit being prioritised first. Where available, criticality is also utilised to prioritise solutions.
- Approval to proceed with the project is sought via the delegated authority process. For large projects, a business case is required.

H.6 Delivery

A works delivery plan is developed to ensure efficient solutions delivery. This plan includes accounting for funding and deliverability constraints. If all solutions cannot be delivered by the need date, they are re-phased based on their priority.

Nearer to the time, a concept design report is prepared in which implementation options are considered and selected, and revised expenditure estimates are presented for approval. Following this, the detailed design and material purchases are made.

We periodically review how we manage work activities for maximum efficiency and what spare inventories we need. Progress on the works programme is tracked continuously (both in the active implementation phase and planned projects) to ensure that expenditure is within budget limits and planned projects are still relevant.

We do monthly reviews to manage the status of Capital projects and capitalise or expense costs when and where appropriate.

Stakeholder engagement to support the delivery is planned for and coordinated following our stakeholder engagement strategy. After identifying options, plans for stakeholder engagement–customers, landowners, councils, and iwi, broader project communications–can be enacted. When the preferred option is chosen, further engagement may be undertaken with landowners and the community on the proposed works.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APPENDIX I – ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012 REFERENCE TABLE

Information disclosure requirements 2012 clause			AMP section
3.1	A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant		**1**
3.2	Details of the background and objectives of the **EDB**'s asset management and planning processes		**2**
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	**2.1, 2.4, 2.5**
	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	
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		**2.1.3**
3.5	The date that it was approved by the directors		
3.6	A description of stakeholder interests (owners, **consumers** etc) which identifies important stakeholders and indicates:		**Appendix B**
	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	
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including:		**2.2**
	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	
3.8	All significant assumptions		**Appendix A**
	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.	
3.9	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		**Appendix A**
3.10	An overview of asset management strategy and delivery		**5.2**
3.11	An overview of systems and information management data		**7.1 – 7.8**

Information disclosure requirements 2012 clause	AMP section
3.11.1 To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the **AMP** should describe: **a.** The processes used to identify asset management data requirements that cover the whole of life cycle of the assets; **b.** 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; **c.** The systems and controls to ensure the quality and accuracy of asset management information; **d.** The extent to which these systems, processes and controls are integrated;	**11.5**
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	**7.10**
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.	**11.9 – 11.25, 9.6, 4**
3.14 An overview of asset management documentation, controls and review processes	**7.11**
3.15 An overview of communication and participation processes	**2.4**
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	**12.1 – 12.3**
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.	**2.2**
Assets covered	
4. The **AMP** must provide details of the assets covered, including: **4.1** **a** high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including: 4.1.1 The region(s) covered 4.1.2 Identification of large **consumers** that have a significant impact on network operations or asset management priorities 4.1.3 Description of the load characteristics for different parts of the **network** 4.1.4 Peak demand and total energy delivered in the previous year, broken down by **sub-network,** if any.	**3.1, 3.2, 3.3**
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; and 4.2.6 An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	**3.4, 3.5**
4.3 If **sub-network**s exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network.**	**N/A**
Network assets by category	

Information disclosure requirements 2012 clause	AMP section
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; and 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.	**11.8, 11.9 – 11.19**
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; and 4.5.11 Other generation plant owned by the **EDB**.	**11.9 – 11.20**
Service levels	
5. The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	**5.4 – 5.5**
6. Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**.	**5.5**
7. Performance indicators for which targets have been defined in clause 5 above should also include: **7.1** **Consumer** oriented indicators that preferably differentiate between different consumer types; **7.2** Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	**5.4**
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.	**5.4 – 5.5**
9. Targets should be compared to historic values where available to provide context and scale to the reader.	**4.2, 4.3, 4.5**
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	**5**
Network development planning	
11. **AMP**s must provide a detailed description of **network** development plans, including: **11.1** A description of the planning criteria and assumptions for **network** development;	**9.3**
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;	**9.3.1**
11.3 A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs;	**9.3.3**
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.	**9.3.3**

Information disclosure requirements 2012 clause		AMP section
11.5	A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	**9.3.5 – 9.3.6**
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**.	**9.3.2**
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.	**9.3.7**
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**; and 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.	**9.5**
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.	**9.6**
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); and 11.10.3 An overview of the material projects being considered for the remainder of the **AMP planning period**.	**9.6**
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.	**Appendix G1**
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; and 11.12.2 The potential for non-network solutions to address **network** problems or constraints.	**Appendix G2**
Lifecycle asset management planning (maintenance and renewal)		
12.	The **AMP** must provide a detailed description of the lifecycle asset management processes, including:	**11**
12.1	The key drivers for maintenance planning and assumptions;	
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; and 12.2.3 Budgets for maintenance activities broken down by asset category for the **AMP planning period**.	**11.1 – 11.25**

Information disclosure requirements 2012 clause	AMP section
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); and 12.3.5 An overview of other work being considered for the remainder of the **AMP planning period**.	**11.1 – 11.25**
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.	**11.9 – 11.25**
Non-network development, maintenance and renewal	
13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including: **13.1** A description of non-network assets;	**7.3 – 7.9**
13.2 Development, maintenance and renewal policies that cover them;	**7.12**
13.3 A description of material capital expenditure projects (where known) planned for the next five years;	**7.13**
13.4 A description of material maintenance and renewal projects (where known) planned for the next five years.	
Risk management	
14. AMPs must provide details of risk policies, assessment, and mitigation, including: **14.1** Methods, details and conclusions of risk analysis;	**6.2**
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;	**6.2 – 6.5, 9.4**
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 14.2;	**6.2**
14.4 Details of emergency response and contingency plans.	**6.6**
Evaluation of performance	
15. AMPs must provide details of performance measurement, evaluation, and improvement, including: **15.1** A review of progress against plan, both physical and financial;	**5.4 – 5.6**
15.2 An evaluation and comparison of actual service level performance against targeted performance;	**4.2 – 4.6**
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the **EDB**'s asset management and planning processes.	**3.5**
15.4 An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation.	**3.5, 5.2**
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;	**11.5**
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the **AMP** plans.	**2.3**
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.	**11.21**

Information disclosure requirements 2012 clause			AMP section
Voltage quality			
17.2	A description of the EDB's practices for monitoring voltage, including:		**11.21**
	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;	
	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:		**5.3**
	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.	
Practices for connecting new consumers and altering existing connections.			
17.4	A description of the EDB's practices for connecting consumers, including:		**10.1**
	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	A description of the following:		**9.3, 9.5**
	17.5.1	How the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: **e.** How the EDB measures the scale and impact of new demand, generation, or storage capacity; **f.** How the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; **g.** How the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	
	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:		**Appendix G3**
	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.	

APPENDIX J – SCHEDULES

Schedule	Schedule name
11a	Report on forecast capital expenditure
11b	Report on forecast operational expenditure
12a	Report on asset condition
12b	Report on forecast capacity
12c	Report on forecast network demand
12d	Report forecast interruptions and duration
13	Report on asset management maturity

Company Name	Waipa Networks Limited
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges.

Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

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h 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			31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	4,418	5,657	5,776	5,883	6,003	6,123	6,245	6,370	6,497	6,627	6,760
11		System growth	9,179	18,282	5,948	10,664	8,381	1,393	1,421	1,449	1,478	1,508	1,411
12		Asset replacement and renewal	3,791	5,342	6,178	5,993	5,911	6,421	4,962	5,061	5,162	5,265	5,236
13		Asset relocations	189	237	242	247	252	257	262	267	272	278	283
14		Reliability, safety and environment:											
15		Quality of supply	886	812	946	697	983	725	1,023	754	1,064	785	1,107
16		Legislative and regulatory	97	965	105	107	109	111	113	116	118	120	123
17		Other reliability, safety and environment	1,042	729	451	171	174	178	181	185	189	192	196
18		**Total reliability, safety and environment**	2,025	2,505	1,501	974	1,266	1,014	1,317	1,055	1,371	1,097	1,426
19		**Expenditure on network assets**	19,602	32,023	19,645	23,761	21,813	15,207	14,207	14,202	14,781	14,776	15,115
20		Expenditure on non-network assets	3,756	4,091	1,956	1,474	1,504	2,090	2,131	2,174	2,925	2,983	3,043
21		**Expenditure on assets**	23,358	36,114	21,601	25,235	23,317	17,297	16,339	16,376	17,706	17,759	18,158
22													
23	*plus*	Cost of financing	-	636	634	663	411	369	338	338	338	339	331
24	*less*	Value of capital contributions	3,530	4,531	4,959	7,920	8,301	4,904	5,002	5,102	5,204	5,308	5,414
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	19,828	32,219	17,275	17,978	15,427	12,762	11,674	11,612	12,840	12,790	13,075
28													
29		Assets commissioned	16,340	29,121	21,011	17,802	16,065	13,428	11,946	11,627	12,533	12,802	13,003

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31			31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
32			**$000 (in constant prices)**										
33		Consumer connection	4,418	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511
34		System growth	9,179	17,813	5,675	9,990	7,695	1,254	1,254	1,254	1,254	1,254	1,150
35		Asset replacement and renewal	3,791	5,204	5,894	5,614	5,427	5,779	4,379	4,378	4,378	4,378	4,268
36		Asset relocations	189	231	231	231	231	231	231	231	231	231	231
37		Reliability, safety and environment:											
38		Quality of supply	886	791	903	653	903	653	903	653	903	653	903
39		Legislative and regulatory	97	940	100	100	100	100	100	100	100	100	100
40		Other reliability, safety and environment	1,042	710	430	160	160	160	160	160	160	160	160
41		**Total reliability, safety and environment**	2,025	2,441	1,433	913	1,163	913	1,163	913	1,163	913	1,163
42		**Expenditure on network assets**	19,602	31,201	18,744	22,259	20,027	13,688	12,538	12,287	12,537	12,287	12,323
43		Expenditure on non-network assets	3,756	3,986	1,866	1,381	1,381	1,881	1,881	1,881	2,481	2,481	2,481
44		**Expenditure on assets**	23,358	35,187	20,610	23,640	21,408	15,569	14,419	14,168	15,018	14,768	14,804
45													
46		**Subcomponents of expenditure on assets (where known)** **EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
47		Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48		Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
49		Research and development	-	-	-	-	-	-	-	-	-	-	-
50		Cybersecurity (Commission only)	-	-	-	-	-	-	-	-	-	-	-
51													

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
53			31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
54		**Difference between nominal and constant price forecasts**	**$000**										
55		Consumer connection	-	145	265	372	491	611	734	859	986	1,116	1,249
56		System growth	-	469	273	674	686	139	167	195	224	254	261
57		Asset replacement and renewal	-	137	283	379	484	641	583	682	783	887	967

Company Name	Waipa Networks Limited
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges.
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h ref												
58	Asset relocations	-	6	11	16	21	26	31	36	41	47	52
59	Reliability, safety and environment:											
60	Quality of supply	-	21	43	44	80	72	120	102	162	132	204
61	Legislative and regulatory	-	25	5	7	9	11	13	16	18	20	23
62	Other reliability, safety and environment	-	19	21	11	14	18	21	25	29	32	36
63	**Total reliability, safety and environment**	-	64	69	62	104	101	155	142	208	185	263
64	**Expenditure on network assets**	-	822	901	1,501	1,785	1,518	1,669	1,915	2,243	2,488	2,792
65	Expenditure on non-network assets	-	105	90	93	123	209	250	293	444	502	562
66	**Expenditure on assets**	-	927	991	1,594	1,909	1,727	1,920	2,208	2,687	2,991	3,354

67

68 **Commentary on options and considerations made in the assessment of forecast expenditure**

69 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

70
71

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
73	**11a(ii): Consumer Connection**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
74	*Consumer types defined by EDB**	**$000 (in constant prices)**										
75	Residential and commercial connections	4,418	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511
76	Industrial connections	-	-	-	-	-	-	-	-	-	-	-
77												
78												
79												
80	**include additional rows if needed*											
81	**Consumer connection expenditure**	4,418	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511	5,511
82	*less* Capital contributions funding consumer connection	3,435	4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299
83	**Consumer connection less capital contributions**	983	1,212	1,212	1,212	1,212	1,212	1,212	1,212	1,212	1,212	1,212
84	**11a(iii): System Growth**											
85	Subtransmission	-	-	100	1,700	1,600	-	-	-	-	-	-
86	Zone substations	3,588	9,193	800	4,310	4,815	-	-	-	-	-	-
87	Distribution and LV lines	-	250	-	-	400	400	400	400	400	400	400
88	Distribution and LV cables	4,519	7,320	4,100	3,500	400	400	400	400	400	400	400
89	Distribution substations and transformers	228	350	350	350	350	350	350	350	350	350	350
90	Distribution switchgear	649	-	-	-	-	-	-	-	-	-	-
91	Other network assets	195	700	325	130	130	104	104	104	104	104	-
92	**System growth expenditure**	9,179	17,813	5,675	9,990	7,695	1,254	1,254	1,254	1,254	1,254	1,150
93	*less* Capital contributions funding system growth	-	-	318	3,005	3,208	-	-	-	-	-	-
94	**System growth less capital contributions**	9,179	17,813	5,358	6,985	4,488	1,254	1,254	1,254	1,254	1,254	1,150

95

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
97		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
98	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**										
99	Subtransmission	-	-	-	-	-	-	-	-	-	-	-
100	Zone substations	-	-	-	-	-	-	-	-	-	-	-
101	Distribution and LV lines	-	2,618	2,798	3,518	3,518	3,625	2,006	2,006	2,006	2,006	1,856
102	Distribution and LV cables	-	378	458	458	458	598	458	458	458	458	458
103	Distribution substations and transformers	787	968	968	968	781	846	1,245	1,244	1,244	1,244	1,244
104	Distribution switchgear	1,105	740	670	670	670	710	670	670	670	670	710
105	Other network assets	1,899	500	1,000	-	-	-	-	-	-	-	-
106	**Asset replacement and renewal expenditure**	3,791	5,204	5,894	5,614	5,427	5,779	4,379	4,378	4,378	4,378	4,268
107	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
108	**Asset replacement and renewal less capital contributions**	3,791	5,204	5,894	5,614	5,427	5,779	4,379	4,378	4,378	4,378	4,268

109

Company Name	Waipa Networks Limited
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges.
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h ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
111			31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
112	**11a(v): Asset Relocations**												
113	*Project or programme**		$000 (in constant prices)										
114	NZTA and Council asset relocations		189	231	231	231	231	231	231	231	231	231	231
115													
116													
117													
118													
119	*include additional rows if needed*												
120	All other project or programmes - asset relocations												
121	**Asset relocations expenditure**		189	231	231	231	231	231	231	231	231	231	231
122	Capital contributions funding asset relocations	*less*	95										
123	**Asset relocations less capital contributions**		94	231	231	231	231	231	231	231	231	231	231
124													

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
126			31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
127	**11a(vi): Quality of Supply**												
128	*Project or programme**		$000 (in constant prices)										
129	Network automation (quality improvement) programme		301	-	262	262	262	262	262	262	262	262	262
130	Other quality improvement programme			400	-	-	-	-	-	-	-	-	-
	Network protection programme			11	11	11	11	11	11	11	11	11	11
	Network reconfiguration and extension programme			-	-	-	-	-	-	-	-	-	-
	Distribution voltage improvement programme			250	500	250	500	250	500	250	500	250	500
131	Generator and non-network security support			-	-	-	-	-	-	-	-	-	-
132	LV voltage and quality improvement programme		130	130	130	130	130	130	130	130	130	130	130
133	Kihikihi Grey St and Oliver St 11kV network extension		455										
134	*include additional rows if needed*												
135	All other projects or programmes - quality of supply		-	-	-	-	-	-	-	-	-	-	-
136	**Quality of supply expenditure**		886	791	903	653	903	653	903	653	903	653	903
137	Capital contributions funding quality of supply	*less*	-	-	-	-	-	-	-	-	-	-	-
138	**Quality of supply less capital contributions**		886	791	903	653	903	653	903	653	903	653	903
139													

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
141			31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
142	**11a(vii): Legislative and Regulatory**												
143	*Project or programme**		$000 (in constant prices)										
144	Electricity code compliance programme		-	160	-	-	-	-	-	-	-	-	-
145	Line clearance improvement programme		97	780	100	100	100	100	100	100	100	100	100
146			-										
147			-										
148			-										
149	*include additional rows if needed*												
150	All other projects or programmes - legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
151	**Legislative and regulatory expenditure**		97	940	100	100	100	100	100	100	100	100	100
152	Capital contributions funding legislative and regulatory	*less*	-	-	-	-	-	-	-	-	-	-	-
153	**Legislative and regulatory less capital contributions**		97	940	100	100	100	100	100	100	100	100	100
154													
155			CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges.
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h ref		31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
156	**11a(viii): Other Reliability, Safety and Environ**											
157	*Project or programme**	$000 (in constant prices)										
158	Seismic resilience programme	-	160	160	160	160	160	160	160	160	160	160
	Replace Two Pole Transformers and Sub Structures	117										
	Seismic strengthening of Voltage Regulator structures	295										
159	Weather and environmental resilience programme	-	150	150	-	-	-	-	-	-	-	-
	Other resilience programme	-	-	120	-	-	-	-	-	-	-	-
	Safety improvement programme	-	-	-	-	-	-	-	-	-	-	-
	Distribution environmental improvement programe	-	-	-	-	-	-	-	-	-	-	-
160	Soundproofing Cambridge Ripple Plant Building	130										
160	High Resolution Photo Survey	500										
163	**include additional rows if needed*											
164	All other projects or programmes - other reliability, safety and environment	-	400	-	-	-	-	-	-	-	-	-
165	**Other reliability, safety and environment expenditure**	1,042	710	430	160	160	160	160	160	160	160	160
166	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
167	**Other reliability, safety and environment less capital contributions**	1,042	710	430	160	160	160	160	160	160	160	160
168												

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
170		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
171	**11a(ix): Non-Network Assets**											
172	**Routine expenditure**											
173	*Project or programme**	$000 (in constant prices)										
174	Office furniture and equipment purchases	1,395	304	4	4	4	4	4	4	4	4	4
175	Computer software and equipment	58	447	147	147	147	147	147	147	147	147	147
176	Land and buildings	1,892	560	60	60	60	60	60	60	60	60	60
177	Motor vehicles, fleet and plant purchases	411	2,675	1,655	1,170	1,170	1,670	1,670	1,670	2,270	2,270	2,270
178	Computer software and equipment - network systems	-	-	-	-	-	-	-	-	-	-	-
179	**include additional rows if needed*											
180	All other projects or programmes - routine expenditure	-	-	-	-	-	-	-	-	-	-	-
181	**Routine expenditure**	3,756	3,986	1,866	1,381	1,381	1,881	1,881	1,881	2,481	2,481	2,481
182	**Atypical expenditure**											
183	*Project or programme**											
184												
185												
186												
187												
188												
189	**include additional rows if needed*											
190	All other projects or programmes - atypical expenditure	-	-	-	-	-	-	-	-	-	-	-
191	**Atypical expenditure**	-	-	-	-	-	-	-	-	-	-	-
192												
193	**Expenditure on non-network assets**	3,756	3,986	1,866	1,381	1,381	1,881	1,881	1,881	2,481	2,481	2,481
194												

Company Name	Waipa Networks Limited
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

sch ref

	CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
Operational Expenditure Forecast	$000 (in nominal dollars)										
Service interruptions and emergencies	1,426	1,886	1,926	1,962	2,002	2,042	2,083	2,124	2,167	2,210	2,254
Vegetation management	1,532	2,080	1,969	2,006	2,063	2,087	2,129	2,172	2,215	2,278	2,305
Routine and corrective maintenance and inspection	788	966	1,247	1,232	1,241	1,245	1,276	1,273	1,327	1,324	1,406
Asset replacement and renewal	961	834	882	749	870	852	937	802	983	835	1,007
Network Opex	4,707	5,767	6,025	5,949	6,175	6,227	6,425	6,371	6,693	6,646	6,972
System operations and network support	3,682	5,494	5,615	5,719	5,835	5,952	6,071	6,193	6,316	6,443	6,572
Business support	8,557	5,985	6,112	6,225	6,351	6,478	6,608	6,740	6,875	7,012	7,152
Non-network opex	12,239	11,479	11,727	11,944	12,186	12,430	12,679	12,932	13,191	13,455	13,724
Operational expenditure	16,946	17,246	17,752	17,892	18,362	18,657	19,104	19,303	19,884	20,101	20,696

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
	$000 (in constant prices)										
Service interruptions and emergencies	1,426	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838
Vegetation management	1,532	2,027	1,879	1,879	1,894	1,879	1,879	1,879	1,879	1,894	1,879
Routine and corrective maintenance and inspection	788	941	1,190	1,154	1,139	1,121	1,126	1,101	1,126	1,101	1,146
Asset replacement and renewal	961	813	842	702	799	767	827	694	834	694	821
Network Opex	4,707	5,619	5,749	5,573	5,670	5,605	5,670	5,512	5,677	5,527	5,684
System operations and network support	3,682	5,353	5,358	5,358	5,358	5,358	5,358	5,358	5,358	5,358	5,358
Business support	8,557	5,831	5,831	5,831	5,831	5,831	5,831	5,831	5,831	5,831	5,831
Non-network opex	12,239	11,184	11,189	11,189	11,189	11,189	11,189	11,189	11,189	11,189	11,189
Operational expenditure	16,946	16,803	16,938	16,762	16,859	16,794	16,859	16,701	16,866	16,716	16,873

Subcomponents of operational expenditure (where known)

**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

	CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Insurance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cybersecurity (Commission only)	78	78	78	78	78	78	78	78	78	78	78

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

	CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
Difference between nominal and real forecasts	$000										
Service interruptions and emergencies	-	48	88	124	164	204	245	286	329	372	416
Vegetation management	-	53	90	127	169	208	250	293	336	384	426
Routine and corrective maintenance and inspection	-	25	57	78	102	124	150	172	201	223	260
Asset replacement and renewal	-	21	40	47	71	85	110	108	149	141	186
Network Opex	-	148	276	376	505	622	755	859	1,016	1,119	1,288
System operations and network support	-	141	258	361	478	594	713	835	959	1,085	1,214
Business support	-	154	280	393	520	647	776	909	1,043	1,181	1,321
Non-network opex	-	295	538	755	997	1,241	1,490	1,743	2,002	2,266	2,535
Operational expenditure	-	443	814	1,130	1,503	1,863	2,245	2,602	3,018	3,385	3,823

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.

Company Name: **Waipa Networks Limited**

AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	1%	3%	83%	13%	-	3	1%
11	All	Overhead Line	Wood poles	No.	1%	27%	16%	56%	0%	-	3	40%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km							N/A	
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km					100%	-	4	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km							N/A	
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
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.							N/A	
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.							N/A	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.							N/A	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.							N/A	
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.							N/A	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.							N/A	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

			Company Name	Waipa Networks Limited
			AMP Planning Period	1 April 2024 – 31 March 2034

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.							N/A	
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	0.0%	1.4%	31.8%	42.5%	24.4%	2	1.0%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.2%	0.4%	2.2%	6.2%	17.9%	73.2%	1	1.4%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	87.2%	12.8%	-	1	-
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	2.6%	4.3%	67.2%	25.9%	-	3	3.4%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.5%	1.7%	14.6%	18.4%	23.6%	40.2%	1	3.1%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	0.7%	33.8%	59.6%	5.9%	3	0.7%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.5%	4.9%	25.9%	24.2%	42.5%	-	3	4.3%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0.4%	7.8%	42.1%	47.4%	2.3%	3	1.4%
53	HV	Distribution Transformer	Voltage regulators	No.	8.8%	5.3%	35.1%	3.5%	47.4%	-	3	21.1%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	-	0.2%	1.6%	30.6%	42.0%	25.6%	2	2.0%
56	LV	LV Cable	LV UG Cable	km	0.3%	0.4%	1.9%	4.6%	17.8%	74.9%	1	1.4%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	0.1%	0.9%	12.1%	23.4%	63.4%	1	-
58	LV	Connections	OH/UG consumer service connections	No.	19.0%	18.6%	18.9%	17.2%	26.3%	-	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	-	72.0%	28.0%	-	2	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.0%	-	-	-	3	2.0%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.0%		4	-
62	All	Load Control	Centralised plant	Lot	-	-	100.0%	-	-	-	4	-
63	All	Load Control	Relays	No.	0.3%	1.6%	46.8%	39.6%	11.7%	-	1	2.0%
64	All	Civils	Cable Tunnels	km							N/A	

Company Name: **Waipa Networks Limited**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Transpower GXP Cambridge	49	47	N-1	-	105%	143	57%	No constraint within +5 years	Firm capacity is currently being exceeded for short durations during the winter periods. Causes are large step change in industrial load in 2020 and incremental base load growth through residential developments. Transpower's transformers have a short term overload rating of 45/47MVA (Summer/Winter) which will assist with sustained peak demands until 2024. A special protection scheme installed in May 2020 avoids cascade tripping of supply transformers. Waipa Networks has installed 2.7MW of peaking generation to manage peak demand and a new 2 x 96 MVA (80MVA nominal) 220/33kV GXP for the Cambridge area is expected to be completed 2025.
10	Transpower GXP Te Awamutu	39	41	N-1	-	96%	54	100%	No constraint within +5 years	Firm capacity is currently being exceeded, however the period is minimal <1%. Transpower will upgrade transformer protectionthat will in FY24 that will raise the transformer N-1 capacity to 52/54 MVA. This will ensure capacity is adequate for at least the next five years.
11						-			[Select one]	
12						-			[Select one]	
13						-			[Select one]	
14						-			[Select one]	
15						-			[Select one]	
16						-			[Select one]	
17						-			[Select one]	
18						-			[Select one]	
19						-			[Select one]	
20						-			[Select one]	
21						-			[Select one]	
22						-			[Select one]	
23						-			[Select one]	
24						-			[Select one]	
25						-			[Select one]	
26						-			[Select one]	
27						-			[Select one]	
28						-			[Select one]	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Waipa Networks Limited**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
11	*Consumer types defined by EDB**							
12	Residential		555	570	586	601	616	632
13	General		80	80	80	80	79	79
14	Unmetered		-	-	-	-	-	-
15	11kV		-	-	-	-	-	-
16								
17	**Connections total**		635	650	665	681	696	711
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		211	228	245	261	278	295
21	Capacity of distributed generation installed in year (MVA)		2	2	2	2	2	3
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
25	GXP demand		89	99	105	119	125	135
26	*plus* Distributed generation output at HV and above		-	-	-	-	-	-
27	**Maximum coincident system demand**		89	99	105	119	125	135
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		89	99	105	119	125	135
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		460	512	545	615	650	700
32	*less* Electricity exports to GXPs		-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation		1	1	1	1	1	1
34	*less* Net electricity supplied to (from) other EDBs		1	1	1	1	1	1
35	**Electricity entering system for supply to ICPs**		460	512	544	615	650	700
36	*less* Total energy delivered to ICPs		412	459	492	537	629	665
37	**Losses**		48	52	52	78	21	36
38								
39	**Load factor**		59%	59%	59%	59%	59%	59%
40	**Loss ratio**		10.4%	10.2%	9.6%	12.8%	3.3%	5.1%

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**Waipa Networks Limited**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	126.2	126.2	126.2	126.2	126.2	126.2
12	Class C (unplanned interruptions on the network)	109.3	109.3	109.3	109.3	109.3	109.3
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.48	0.48	0.48	0.48	0.48	0.48
15	Class C (unplanned interruptions on the network)	1.73	1.73	1.73	1.73	1.73	1.73

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	**Based on PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The Asset Management Policy was authorised by the CEO and defines the key principles and approach to asset management at Waipa Networks, and is used as reference when preparing the Asset Management Plan. A copy of this policy is available for visitors, on the Company intranet, and on the company website for other stakeholders, interested parties and Commerce Commission.	The Head of Network Asset and the Asset Strategy Manager were responsible for completing this question assessment, referring questions as required to other representatives in the organisation.	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	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	The organisation has an asset management framework that ensures alignment between the asset management strategy and all the key elements of the framework that include the Asset Mgmt policy from which the strategy and objectives are based, with a pathway for input from customers and stakeholders, and feedback loops to consider performance against service level targets. Ref., AMP section 6	The Asset strategies are now explicitly discussed as they relate to organisation strategies.	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	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	Assets are categorised in classes that consider type and function with asset class specific lifecycle mgmt. strategies and plans. Approach to asset lifecycle management is presented in the AMP (section 6.11) and summaries of the fleet lifecycle mgmt. plans in AMP section 9.	Further improvements to fleet management are planned, through progressive production of fleet asset management plans.	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	Asset lifecycle management plans are under development for each class of primary assets aligned to asset management objectives and strategies.	Progress in asset health indicators has been made through aerial surveys and condition assessment of overhead assets to complement data from direct inspections. Further work is planned.	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	**Waipa Networks Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	**Based on PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2.5	The plan is communicated to most of those responsible for delivery to a level of detail appropriate to their participation or business interests in the delivery of the plan. The Network Asset Manager delegates appropriate Sections of the AMP works program to appropriate planning and engineering staff and supervisors for implementation assigning responsibility for implementation of the Asset Management Plan. The Network Asset Manager reports at Board Meetings on progress on delivery against the Asset Management Plan.	An Asset Strategy Manager has been appointed to focus on asset management improvement and the collation of the annual AMP update. Annual programmes of work (capital projects or maintenance programmes) are communicated to the Operations team for completion.	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?	2.5	The asset management plan documents responsibilities for the delivery actions, and appropriate detail is provided to enable delivery of these actions, Ref. AMP section 6.4. Roles and responsibilities of individuals and organisational departments are defined.	Additional resources are being recruited to enable further documentation of processes and complete engineering tasks. Action plans for Asset Management Improvement Plan (AMIP) projects have been developed.	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)	2.5	The plans consider availability of resources. In-house contracting division completes most of the maintenance, vegetation management and replacement and minor upgrades on our network on a cost basis. Waipa utilises external resources as necessary to manage the peak workload and major network development projects. The Company holds monthly Operational Meetings for all Supervisors to co-ordinate implementation of the Asset Management Plan.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	Waipā's Emergency Management System documents procedures for use in the event of major damage to the network. These plans get tested in simulated major event situations. During emergencies, where control room and call centre functions may be disrupted or overloaded, network operations and fault dispatch functions can be performed by the administrative staff and field crews.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Management has appointed appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s). AMP Sec 6.4 Accountabilities and Responsibilities for Asset Management.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.5	A process exists for determining what resources are required for asset management activities. Waipa has its own contracting division which enables it to manage and retain key staff with the ability to control the size of the workforce available to ensure the work plan can be delivered. See AMP section 11.5		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.5	Communication of the asset management requirements is through annual AMP disclosures, and the company holds monthly Operational Meetings for all Supervisors to co-ordinate implementation of the Asset Management Plan. A monthly Network Management report is prepared by the Network Asset Manager for operational and asset management staff to review progress against asset management KPIs and programmes of work.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.5	Waipa outsources a number of asset management activities, such as Control Room Services, Call Care for customer enquiry and dispatch services(Refer AMP Sec 6.4 Resourcing Asset Management). All outsourced services have contracts which include performance KPI's to ensure efficient and cost-effective delivery of these activities. Construction Manual and network standards used to ensure contracted works are constructed to appropriate standard.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.5	Role descriptions are in place for all staff required to conduct asset management functions, and that these roles are filled with appropriately qualified personnel. The company's Training Matrix and Individual Personal Development Plans are used to increase skills of current staff and engaging additional staff for long term needs or contractors for short term.		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	The Company Training Matrix and Individual Personal Development Plans are used to identify maintain and increase skills of current staff. However, an Asset Management competency framework has not been developed to guide training requirements.		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	Waipa monitors and ensures that contractors and staff have, and maintain their competencies. Well trained staff are engaged as Design Planners to prepare and manage job packs, review quality, and conduct inspections. As per our Heath, Safety and Environmental requirements all contractors are inducted to work on our network. The Company assesses the competence of service providers under its direct control by observing the quality of the work performed and checking if any industry competencies that are required for the work, are held by the staff doing the work. Competencies for fault staff to operate on the network are defined and new fault staff are assessed and signed off.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2.5	Role descriptions are in place for all staff required to conduct asset management functions, and that these roles are filled with appropriately qualified personnel. The company's Training Matrix and Individual Personal Development Plans are used to increase skills of current staff and engaging additional staff for long term needs or contractors for short term.		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	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The Company Training Matrix and Individual Personal Development Plans are used to identify maintain and increase skills of current staff. However, an Asset Management competency framework has not been developed to guide training requirements.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	Waipa monitors and ensures that contractors and staff have, and maintain their competencies. Well trained staff are engaged as Design Planners to prepare and manage job packs, review quality, and conduct inspections. As per our Heath, Safety and Environmental requirements all contractors are inducted to work on our network. The Company assesses the competence of service providers under its direct control by observing the quality of the work performed and checking if any industry competencies that are required for the work, are held by the staff doing the work. Competencies for fault staff to operate on the network are defined and new fault staff are assessed and signed off.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2.5	Refer AMP Sec 6.3 Systems and Information Management. The Network Information Officer populates the Asset Equipment Data Bases and inputs are audited for errors and irregularities. The Network Asset Manager and Network Information Specialists request improvements that are designed and implemented by IT and the Operations Committee offers feedback in this iterative process. External audit is completed on information disclosure reporting to ensure that information reported out of the systems is accurate.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Asset Management Information system requirements were fully reviewed during development of the business case to implement GIS ensuring that they meet Asset Management needs. The Network Asset Manager and Network Information Specialist specify improvements that are designed and implemented by IT, and the Operations Committee offers feedback.		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	The organisation has an integrated risk management system compliant with ISO31000 documented in the Risk Management Manual, and uses the Company Risk Register to track and communicate identified risks. This provides a structured and robust framework to managing risk, which is applied to all business activities. Section 6.10 of the AMP provides an overview of the organisation's Risk Management framework.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Outputs from risk assessments are fed back into standards, procedures and training through the actions resulting from various meetings and other communications. The linkages from the risk management system to key plans is evolving, and the organisation is in the process ensuring that outputs of risk assessment are consistently included in developing requirements for resources and training. The Company Training Matrix and Individual Personal Development Plans are used to increase skills of current staff.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements. Waipa Networks uses ComplyWith web enabled software to assess compliance with legislative and regulatory requirements. This produces a six-monthly declaration of compliance that is reported to the Board. The AMP communicates how the organisation translates its legal and other requirements into asset management programmes, and performance targets.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.5	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. AMP Section 8 Network development summarises the process for establishing new assets. Waipa's asset selection policy is to use only tried and proven products. When new modern equivalent assets are considered, their performance and lifecycle cost are evaluated by Waipa's Engineering team including consultation with Operations before they are installed on the network. Use of the Design Manual and Construction		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.5	There are inspection and maintenance programmes for underground assets and the organisation is putting in place process(es) and procedure(s) that include asset risk modelling to manage and control the implementation of asset management plan(s) during this life cycle phase. Remedial actions derived from the prioritisation of defects and condition observed from inspections. These plans are reviewed and optimised on an annual basis. Safety and Quality audits are conducted on a sample basis to monitor performance of works. Progress against AMP targets is tracked and		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.8	The Company monitors network performance and reports monthly on SAIDI, SAIFI, planned and unplanned outage numbers and causes of faults. Section 5 of the AMP summarises the overall network performance against targets, and section 9 Lifecycle Management covers the asset class performance and the outcome of inspection and condition assessment. Waipa regularly reviews asset health ratings of assets based on the AHI's guideline published by the EEA. This is informed by results of the inspection and maintenance programmes conducted at frequencies and according to procedures detailed in maintenance standards for each asset class. In addition, Waipa is developing asset risk		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.5	The organisation has defined the appropriate responsibilities and authorities for managing asset-related failures, incidents and nonconformities. Incidents and emergency situations are managed by the Control Room Operators and the Field Services Manager and Duty Supervisors are authorised and responsible for assigning staff to respond to incidences. Contracts with third parties describe responsibilities and performance measures. The Network Asset Manager is responsible for investigating all network asset failures and performance of the network. The Public Safety Management System and the Health, Safety and Environmental Manual ensure Identification and Control of Significant Hazards which are included in the Company Hazard Register. Duty Supervisors and Health, Safety & Wellbeing Manager respond immediately to safety incidents, and the Health, Safety & Wellbeing Manager ensures investigation of the incidents is completed.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation is reviewing its audit procedure(s) that include a yearly audit of its asset management functions, but they do not yet cover all the appropriate asset-related activities. Examples of audit of asset management functions include: Field supervisor sample and inspect 20% of completed work sites and sign off all as-built drawings. Asset inspection data is checked at data entry into the asset database. For network wide surveys the results are verified independent assessor, e.g., Northpower regrading a sample of the aerial survey.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.5	Field observations on asset risk are captured into Assura (the H&S system) with a workflow that ensures visibility of the issue and the resolution process. Investigation for significant unplanned outages and equipment failure are done using ICAM system for root cause analysis.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.5	Continuous improvement is recognised as beneficial, however it has just been started, and there initiatives informed by the asset management maturity assessment covering some of the asset drivers. Improvement initiative includes formally documenting the investment approval process. Opex/capex trade-off is considered business case development for investment with optioneering that considers non-network vs network solutions, and whole of life cost.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.5	The organisation participates in industry forums (that include ENA, EEA) to share and, or identify 'new' to sector asset management practices. New equipment is evaluated on a cost, quality and general life cycle performance. Pilots to trial new equipment and gain experience with new technology are used in some cases before a wholesale adoption is contemplated.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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Asset Management Standard Applied	**Based on PAS 55**

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.

APPENDIX K

Schedule 17: Certification for year – beginning disclosures

Clause 2.9.1 of Section 2.9

We, Jonathan Anthony KAY and Jonathan Guy Scott CAMERON, being directors of Waipā Networks Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a. The following attached information of Waipā Networks Limited prepared for the purposes of clause 2.4.1, clause 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution 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 Waipā Networks' corporate vision and strategy and are documented in retained records.

Jonathan Anthony Kay

Jonathan Guy Scott Cameron

31 March 2024


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THANK YOU!

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