WAIPĀ NETWORKS

ASSET MANAGEMENT PLAN

2023

WAIPĀ NETWORKS


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FOREWORD FROM THE CHIEF EXECUTIVE

Welcome to our 2023 asset management plan. The revisions made to this plan reflect the commencement of the next phase in our asset management journey. We have commenced a review of our business to support New Zealand's electricity future and transition to a net zero carbon economy – this review includes our long term plan for delivering electricity to our customers.

This AMP highlights:

- The key issues facing the network;
- Our strategy to address the key issues and the foundation work to further prepare for decarbonisation;
- Our implementation plans to deliver on the strategy and to deliver the required level of performance.

In this plan we have set out the key focus areas for our business and what investments we are making in these areas. This plan does not yet reflect a complete review of our asset management strategy – this will be included in the 2024 AMP after clearly defining our approach to support decarbonisation.

Managing infrastructure assets requires considering a range of factors. Ensuring our services are supporting 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 of our customers are material issues for the business and our industry. The transition to a net carbon zero New Zealand will take time, it is critical that we develop a clear understanding of how best to support our region.

This plan signals a shift in our asset management focus given the continued strong growth we are seeing across our region, the emergence of an ageing asset fleet, and the need to prepare for the energy transformation and the impacts of climate change.

The changes illustrated in this AMP will flow through to the more substantive review planned for the 2024 AMP.

I invite you to read the executive summary to gain insights into how we are approaching the management of the electricity network assets. This may lead you to explore the more detailed content included in the main body of the plan.

Ngā mihi

Sean Horgan
Chief Executive

1. EXECUTIVE SUMMARY

1.1 Where this AMP fits into our asset management journey

We are currently reviewing our business, Waipā Networks Limited (Waipā), including our asset management practices, to ensure that we deliver electricity to our customers in a way that is consistent with how they embrace New Zealand's electricity future.

This Asset Management Plan (AMP) reflects our business' evolution toward a highly electrified, net-zero future. Our executive summary has been revised to highlight the key factors driving investment and performance, the key strategies adopted to ensure the network responds to those factors, and the key programmes and projects supporting the strategy.

We will continue to review all existing programmes and projects to align them to the asset management strategy, which will continue into CY2023. We will incorporate the results of the review into the 2024 AMP. The main body of this AMP has been updated with the latest information, and the sections have generally been aligned with our new structure.

This AMP marks the beginning of the next phase in our asset management journey. The capital expenditure (capex) program proposed in this AMP retains initiatives from the previous AMP with changes primarily relate to short to medium-term issues. The full review of all programmes and projects, including initiatives to support network resilience in light of climate change, will be undertaken in CY2023. We therefore expect changes to medium and long term initiatives, and the associated capex, to be reflected in the 2024 AMP.

1.2 Purpose and structure of this AMP

This AMP communicates Waipā's approach to facilitate the safe and reliable distribution of electricity to customers in our region. We are committed to providing an electricity network that meets the needs of our stakeholders and supports the livelihoods of the people and businesses throughout the regions we serve.

We are seeking to communicate better alignment of our asset management strategy and the needs to our stakeholders - the 2023 AMP commences this work. To better aid this approach, we have organised this executive summary and the AMP 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.

The general sections that existed in the 2022 AMP have been grouped within the Parts mentioned above. The 2024 AMP will include further revisions to organise the content better. A reconciliation of the Information Disclosure requirements is included in the appendices.

Despite the reorganisation, 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 it needs to be).

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 28,000 consumers. We also own the 110kV transmission line from Transpower's Hangatiki GXP to the Te Awamutu GXP. This transmission line was commissioned in 2016 to improve the security of supply to Te Awamutu.

Our network currently services all customers via the 11kV and 400V distribution networks. Over the past decade, the distribution network has been enhanced by adding additional feeders to cater for growth and adding automated line reclosers to improve reliability. This incremental approach has mostly kept pace with growth. However, the continuing network loading increase and forecast growth have reached a tipping point where a 33kV subtransmission network and 33/11kV zone substations are now required. Work on the Cambridge subtransmission network and new zone substation has now commenced, and we envisage a similar shift for the Te Awamutu GXP supply area in the next 5-10 years.

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 beneficiaries, 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. Many other Electricity Distribution Businesses (EDBs) are fully regulated through price-quality regulation.

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 FY2013 as measured by unplanned SAIDI[1]. Unplanned reliability has generally been good and met the target in seven of the last ten years (and as measured by SAIFI[2], reliability met the target in all 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 FY2015, FY2020 and FY2022.

The reliability targets in Figure 1 have evolved over time to ensure that they provided the right incentives for the business[3] in the corresponding periods. From FY2021, our measurement of reliability performance is consistent with fully regulated EDBs and excludes major events like Cyclone Dovi (by normalisation). We have included Dovi in Figure 1 as, while it is excluded from a measurement standard, customers felt its impact.

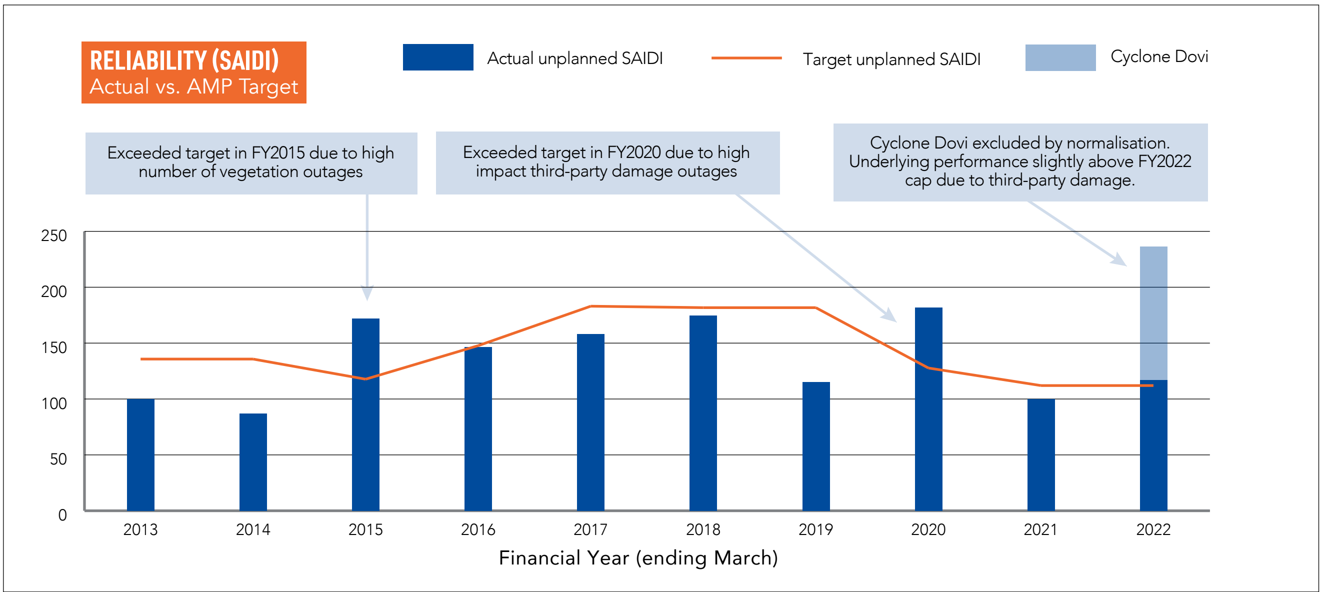

Figure 1: Historical unplanned reliability performance

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[1] *SAIDI 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.*

[2] *SAIFI is a measure of the average number of outages experienced by customers for the year.*

[3] *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.*

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

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

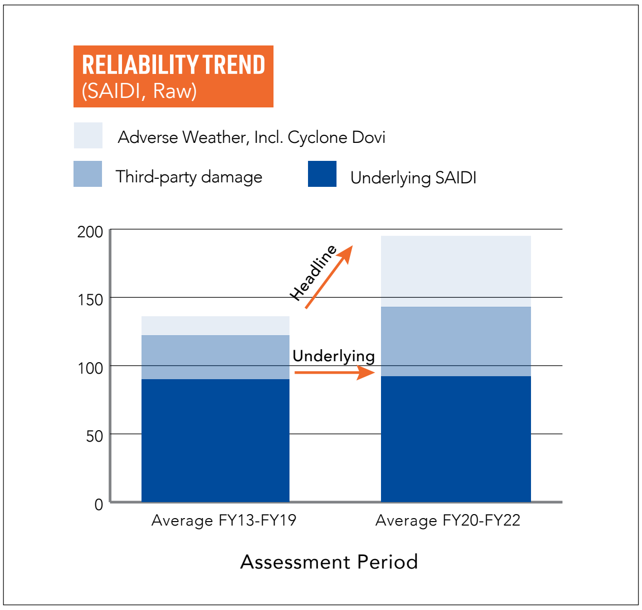

Figure 2: Reliability trend

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

Defective equipment outages have improved across all reliability measures. The analysis indicates that equipment fault rates are all generally trending down, except for crossarms. Crossarms are presently being subject to a more intensive renewal programme.

Vegetation interference continues to be a material cause of outages. Improvements have been made in close-proximity interference, but interference from within the 4m "cut and trim" zone and from outside of the 4m zone continues to be a material issue. Obtaining customer approvals to trim trees (inside and outside of the 4m zone) remains an issue that needs to be resolved as part of our vegetation management strategy.

Delivery of the work programme

Over the past three years, total opex has been within 5% of forecast; however, vegetation spend has been below target due to resource constraints and Covid limitations, while system interruption and emergency expenditure has been above target due to storm events. Planned maintenance and vegetation management expenditure has varied up to 40% in any particular year.

Our network capital expenditure has been behind forecast over the past three years by an average of 24% ($3.3m) p.a. The two key reasons were delays in consenting to the Swayne Road diesel genset (for managing peak demand at Cambridge GXP) and several capital programmes also being delayed as internal resources were constrained during Covid and post Covid there has been a focus on catching up on new connection work.

Our non-network capital spend significantly exceeded the budget in FY2022 ($9.4m vs. $3.3m) due to the purchase of lands for the new Hautapu GXP and land adjacent to Te Awamutu GXP that is being banked for future development.

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

1.5 Customer feedback

We survey our customers annually and regularly engage with key customers and community organisations. The survey is used by several EDBs in the industry and serves as a basis for benchmarking. The results from last year's survey indicate that overall customer satisfaction is 58%, slightly below the peer group average of 62%. We performed well in areas such as value for money and reliability. However, changes are required to improve our image and reputation from a customer perspective. This resulted in a lower satisfaction score in the survey.

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.

In so far as asset management is concerned, the direction outlined in this AMP is consistent with the feedback received.

Looking forward, we have started the journey to enrich the customer engagement framework and tools to enable customers' views to be better incorporated into our planning and asset management objective. This will be a two-way process as we also need to communicate better our future investment programmes and the associated implications to our communities and customers.

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 that is 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 are driving the need for greater maturity in asset management to effectively 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 ICP growth (in relative terms) of any EDB 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 23% to 86 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 local council strategic growth plan.

The need to manage future demand growth due to electrification

Electricity demand growth is expected to accelerate towards the end of the decade due to process heat and transport electrification. Drawing on sources such as Transpower's Te Mauri Hiko report[4], our preliminary view is that demand could increase by 13 MW (15%) over the current demand due to electrification by 2035. This view will be refined once we complete our regional review. 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.

The extent of electrification demand growth, and the availability and firmness of flexibility services, are key areas of uncertainty for the business. Therefore, we are undertaking a regional review in mid-CY2023 that will determine specific regional drivers for growth (such as electrification) as we transition to a net zero economy, consider the implications for both customers and our business, and develop strategic scenarios. The scenarios will inform the development of our future network development strategy.

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 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.

[4] *Transpower, "Whakamana i Te Mauri Hiko – Empowering our Energy Future", March 2020. The demand growth is net of flexibility from EV charge load-shifting and controllable distributed energy resources.*

The age of assets classes

The average age of our network is around 15 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 30% of wood poles, 26% of overhead switches, and 16% of overhead transformers have aged over 45 years.

This is not presently a material issue for the business. However, in the near to medium term, increased asset health deterioration will need to be managed through increasing asset renewals and/or asset 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 CY2022 and Cyclone Gabrielle in early CY2023 both had a very significant impact on our network and customers.

The analysis indicates that for the three years to FY2022, the average annual impact on SAIDI from adverse weather has increased by 270% and averaged 52 SAIDI minutes p.a. over that period. This is a significant increase, and the impact of adverse weather in FY2023 continues this trend.

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.

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

Our asset management maturity is measured yearly, and we are committed to continuously improving our position. We've been pursuing an Asset Management Improvement Plan since FY2019, which targeted achieving an "intermediate" level of maturity over time. This target was appropriate given the historical demands on our business.

However, our outlook is now looking materially different to the past. 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.

5 *This measurement of age reflects the average useful life of EDBs less the average useful remaining derived from RAB divided by RAB depreciation. Waipā's asset base is comparatively young due to the value of the 110kV line that was installed in FY2016 and the value of new distribution assets that was installed as the network expanded to cater for growth in the past decade.*

Summary of Part 2: Strategies to address the key issues

1.7 Revised asset management strategy

Our 2022 AMP described the asset management policy and four broad strategies (covering customer, asset lifecycle, delivery, and enablers). In this AMP, our asset management policy remains unchanged, and our four broad strategies have been replaced with our asset management strategy set out below. The substance of our previous strategy remains intact, but our description has changed. Our strategies are more specific and relatable to our assets. The strategies we used to direct our asset management activities to meet our existing asset management policy and our customer strategy and service standards.

Our asset management strategy has been prepared in response to our key issues and to improve network performance 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. Our six key initiatives will carry over into AMP 2024.

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 and further initiatives will likely be included in the 2024 AMP. 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 is 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. We recognise that it's challenging 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;
- Engage with our 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.

1.9 Performance targets

Customer service (reliability) targets

Reliability comprises of planned and unplanned reliability measures. Figure 3 shows our target unplanned reliability target for FY2023 and the next five years. The graph illustrates the minimal headroom to the target (assuming future performance reflects historical averages. 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.

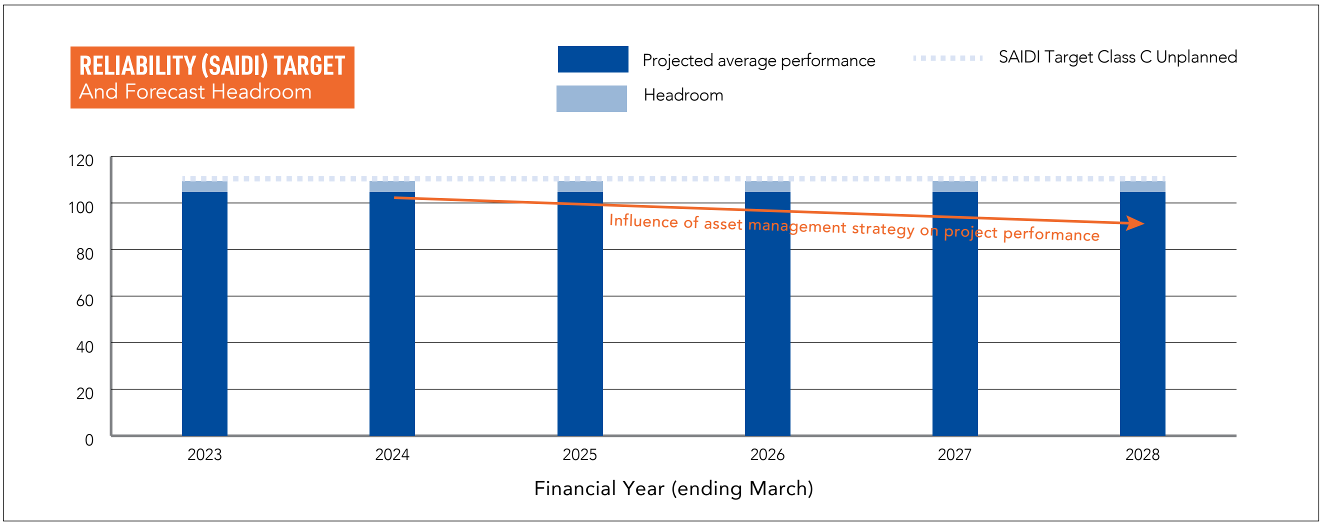

Figure 3: Target Reliability

Unplanned reliability targets exist for both SAIDI and SAIFI. Unplanned SAIFI headroom to target is materially higher (at c.25%) and should improve with the implementation of the 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.

Delivery target

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

The improvement in delivery will be driven through our asset management maturity (AMM) improvement programme, which is discussed in Section 1.11 and Section 7.12.

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

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 are starting to prepare for this role.

Managing infrastructure assets requires considering a range of factors. Ensuring our services are supporting 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 of our customers are material issues for the business and our industry. The transition to a net carbon zero New Zealand will take time, it is critical that we develop a clear understanding of 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 are considering these factors.

Framework

The Energy Trilemma[7] is a well-recognised and useful framework (see Figure 6) when considering the energy transition. We have referenced this framework as it is aligned to the way in which 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 the development of NZ's Energy Strategy.

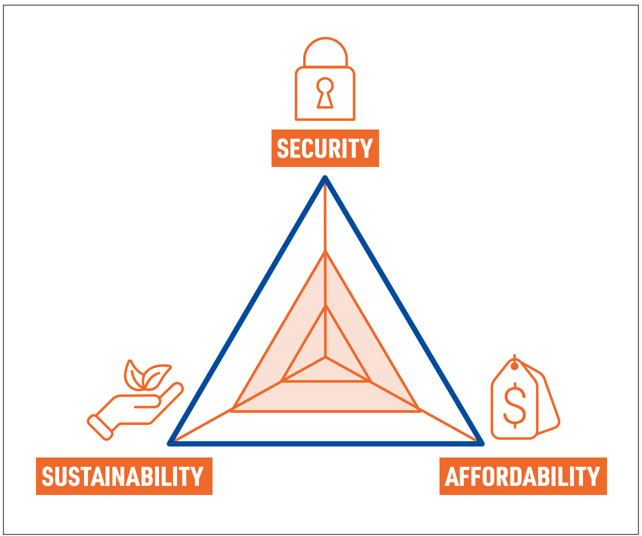

Figure 4: The energy trilemma

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).

How we are considering the factors

Figure 5 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 10-year horizon of this AMP, and is in the following order of consideration:

1. **Sustainability is forecast to improve based on New Zealand's overall direction towards a sustainable and electrified future[8].**

   This will be supported by the asset management initiative discussed in Section 1.7: #1 (regional security) and #2 (energy transformation). This is also supported by our core investment into the network and asset management initiative #5 (asset management) to manage the increasing complexity resulting from the energy transformation.

2. **Security and reliability are expected, by our customers, 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 initiative #1 (regional security), #3 (resilience), and #6 (vegetation). This is also supported by #3 (resilience) to improve the resilience of our network to climate-change-related impacts.

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[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*

3. **Electricity distribution cost is likely to increase, but overall energy affordability should improve – therefore we need to focus on ensuring 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 affordability of energy should improve as a result of electrification[9]. We must ensure that the transition 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.

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

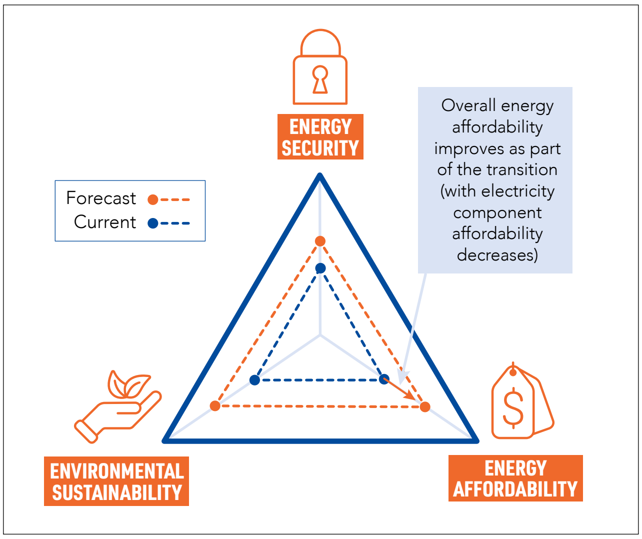


Figure 5: Assessment against the energy trilemma framework

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.

[9] *Assessed by Sapare 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 current state against the AMMAT questions in this AMP, and there has been no material change in the output scores compared to those in the previous 2022 AMP. We are targeting 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 current level of maturity and areas for improvement are shown in Figure 6.

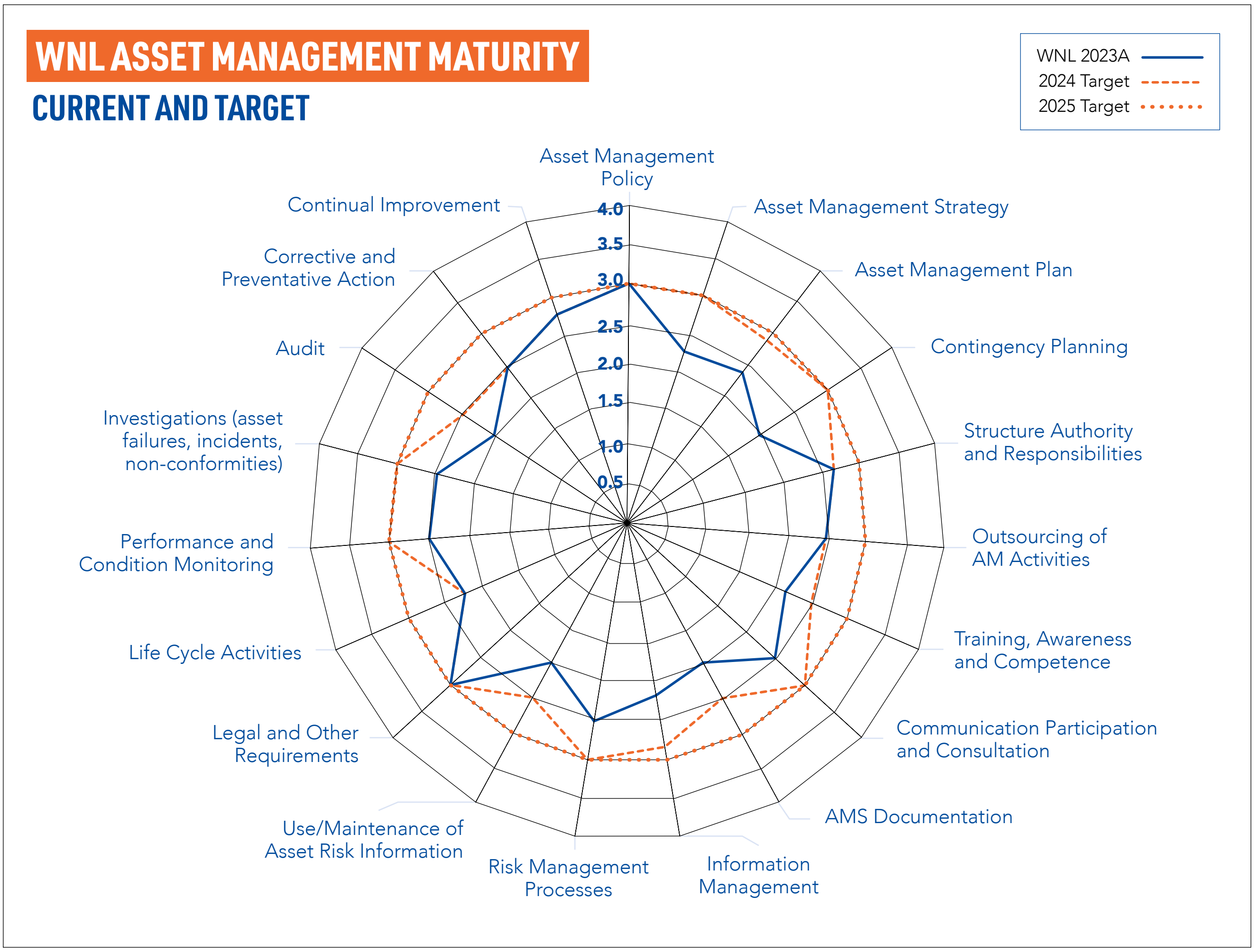


Figure 6: Asset management maturity

During FY2024, our focus areas are:

- Ensuring our asset management strategy is well aligned with our corporate direction.
- Enhancing asset management practices, including risk management, performance and condition monitoring, investigations into asset failures, asset health assessment, and risk-based asset renewal forecasting (with much of this work being visible in our revised asset fleet plans that'll be included in our 2024 AMP).
- The preparation of our 2024 AMP will conclude the review, development, and alignment of programmes and projects against our asset management strategy.
- Information management, in particular, expanding our capture of condition data and validating condition data obtained from the recent pole-top overhead line surveys.

Information system development

Supporting the improvement in asset management maturity is our programme to modernise our information systems to enable more effective management of the business and the assets. 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.

A new geographical information system (GIS) containing core asset information was recently completed in FY2023. Other systems that went live over the past two years include the Assura health and safety system, our new Service Management system, and a new billing and ICP management system. A new MagiQ cloud-based finance system will go live in July this year.

Our new health and safety system equips us with access to information and process documentation in the field and facilitates improved safety management and reporting. Our Service Management system will replace our legacy Faults Dispatch system and significantly improve functionality and faults management, particularly during major events such as storms. Our new billing system provides a single platform view, automation of billing processes, and increased security and management of ICP data.

Over the next three years, additional asset management systems are planned for implementation. These will enhance our business's development planning, lifecycle planning and operational capabilities. Our new systems include the following:

- A new network modelling software (DigSILENT) to enable a more efficient, accurate and sophisticated approach to assess network impacts from our revised demand forecasts, outage requests, new loads, and distributed generation applications;
- A replacement SCADA[10] and outage management system (OMS) to improve our network's real-time management and improve outage management, reporting and communication capability. Enhanced field communication is also planned to support the SCADA system;
- Field data mobility and vegetation management systems;
- A drawing management system to manage standard, asset, site, and project design drawings.

Asset information

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

The GIS's LV network information (e.g., conductor type and connectivity) will be reconciled or established. This will provide enabling information for future LV works/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 as our penetration of electric vehicles, solar generation, and batteries increases.

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

Forecast expenditure

Modernising our information system is a significant undertaking. Actual capex amounted to $1.8m across FY2021 and FY2022 and is forecast to be $6.2m across FY2023 to FY2028. Our forecast IT-related capex amounts to 8% of total capex over the next ten years, reflecting the significance of the work.

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

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

1.12 Material network development programmes and projects

Demand Forecasts

System demand is forecast to increase from 90MW in FY2022 to 148 MW in FY2033, which equates to a compounding annual growth rate (CAGR) of 4.6%. This growth is below that included in the FY2022 AMP but remains high.

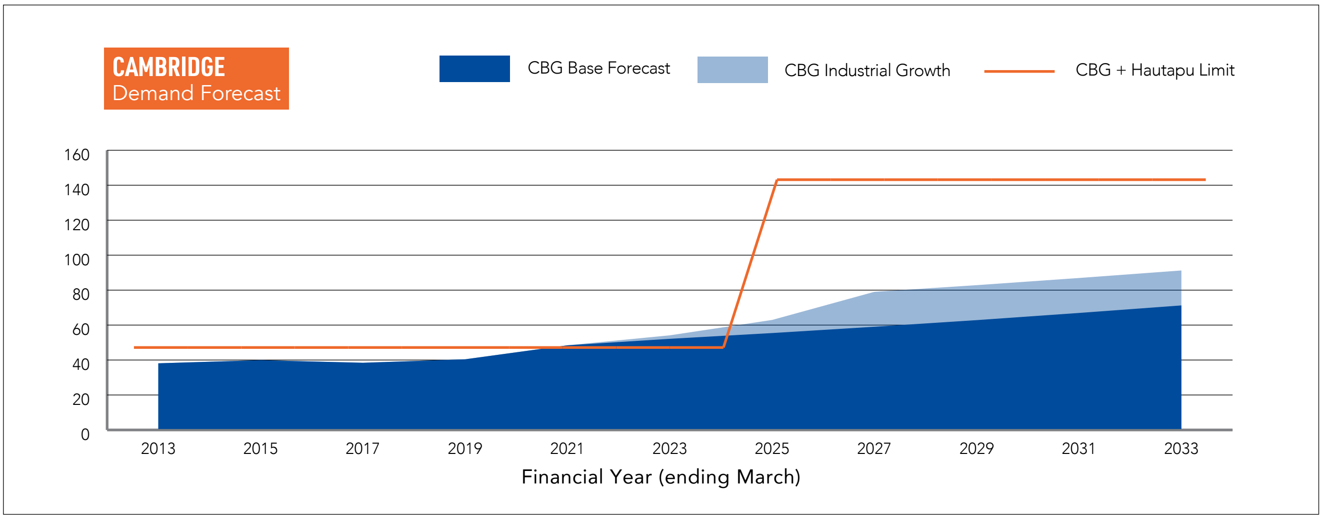


Figure 7: Cambridge demand forecast

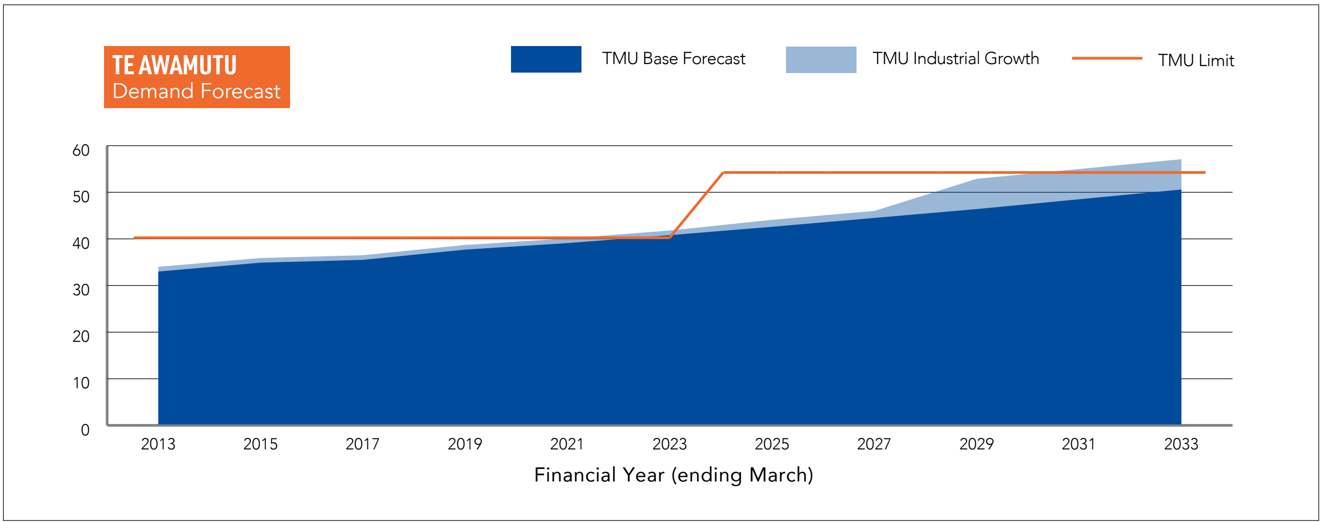


Figure 8: Te Awamutu demand forecast

The forecast demand is driven by a continuation of the strong historical growth in connections (as there are presently no indicators of a decline. Our forecast is aligned with the local council's strategic growth plan and new industrial demand associated with new development in Hautapu, expansion of existing industrial customers, and the likely decommissioning of a co-generation plant at Fonterra's Te Awamutu site in 5-10 years. The new industrial demand amounts to 26.5 MW, 18% of the demand in FY2033. There is some uncertainty around the industrial demand forecasts, as whilst the growth was identified in consultation with customers, it is still subject to various consents and approvals.

Development of an energy transformation roadmap supporting decarbonisation

Our demand forecasts, as shown in Figure 7 and Figure 8, still need to specifically identify the electrification of process heat, residential and commercial gas, or the impact of changes in hot water demand response and controllable distributed energy resources (DERs). Some considerations for EV charging have been included at a moderate level only.

Developing and implementing an energy transformation roadmap supporting New Zealand's decarbonisation is a key strategy for us (asset management strategy #2) and is necessary to support New Zealand's decarbonisation through electrification.

We support distributed generation on our network and continue to have an increasing number of small-capacity distributed generation (mainly solar PV systems) connections each year. The penetration rate for distributed generation is 3.5% in our region, which is significantly higher than the national average of 2.2%.

Electric vehicle ownership in the Waikato region is currently around 0.8%, below the national average of 1.1%.

As detailed in Section 3.6 in the main body of our AMP, electricity demand growth is expected to accelerate towards the end of the decade because of electrification, and the industry is forming a view that flexibility service is part of the solution. Significantly higher demand growth from electrification may risk resulting in shortfalls of flexibility services to shift EV charging to low-demand periods and/or be unable to procure sufficient flexibility services from controllable DERs.

The impact of energy transformation drivers is not expected to be uniform across our network. That is, growth in EVs and general growth in new connections are likely to be significantly greater in Cambridge compared to other parts of our network.

Our development of the energy transformation roadmap is a key focus for our forthcoming year. The purpose of the roadmap is to develop a strategy that is the most cost-effective means of ensuring Waipā's network can meet the needs of customers in a net-zero world. Broadly, this will comprise the following:

- Assessing the potential impacts of our energy transformation (i.e., electrification and decarbonisation) specific to our region.
- Building a new demand forecast model, considering scenarios with/and without access to flexibility services.
- Reviewing the network development plans, information system plans, and opex and capex forecasts considering our new demand forecast scenarios. This will include considering whether there are future projects where alternative non-network options could be viable.
- Improving the visibility of our demand (including LV) to understand the real-time impacts of electrification on our network and enable flexibility to be dispatched to support capacity constraints and/or energy market needs.
- Assess the need for flexibility services and the size required, followed by forming a view on the industry market model for flexibility procurement, assessing the value of flexibility and the extent that flexibility could be a viable (and economical) alternative to network investment.

Inherent in developing the energy transformation roadmap is our strategy, in the immediate term, is to learn and respond to potentially disruptive technologies as a "fast follower". Key focuses will be:

- Monitoring the economics of non-network solutions (compared to the cost of network projects) and avoiding network projects where alternatives offer a lower-cost solution at the same or similar utility.
- Identification and execution of 'no-regret' enabling investments such as network capacity, network information/data and technology readiness, and people capacity/capability, putting ourselves in a position to act fast should we need to.

Work has already commenced in this space where we are:

- Building our new Hautapu GXP, 33kV sub-transmission network and zone substations injecting new capacity to the Cambridge area.
- Working with GridSight, an Australian-based company, to develop a solution to identify and detect solar PV, battery, and EV installations on our network. The GridSight tool will enable the visualisation of LV power quality issues, LV consumption data aggregation and (in the future) network congestions, providing information to understand distribution transformer and circuit loading better. This work is being supported by Ara Ake, New Zealand's future energy centre, as part of their work to develop solutions to help decarbonisation via electrification.
- Commissioning a Waipā region-specific study to assess regional drivers for growth (such as electrification of process heat, transport and gas).
- Further improving our customer engagement to be closer to our customers and community and to better understand their future energy needs and service level (e.g. reliability and resilience), so customers' voices can influence future asset management objectives.
- Upon the go-live of the new state-of-the-art ESRI GSI system, commit to a network data improvement plan, particularly the LV network.

Drivers of network development

The growth in demand is driving an increase in the requirement to augment network capacity, enhance network security, and mitigate future voltage constraints. In this AMP, we have defined the full suite of development planning criteria covering security, capacity, voltage, and reliability across all levels of our network. Our adopted criteria are consistent with industry standards for the size of demand served. Refer to Section 8.2.2 for further details.

Regarding the current and forecast development drivers, Table 2 summarises when constraints are forecast to occur at a transmission and distribution system level. Table 2 indicates emerging capacity, security, and voltage constraints on the network. At a distribution level, 37% of feeders are or are forecast to be constrained due to security or voltage over the next five years, growing to 50% by the end of the AMP forecast period. Our assessment is based on current demand forecasts, and this will be revised to reflect the energy transformation scenarios in the 2024 AMP. A number of feeders also have very high customer numbers, which will require re-balancing over time.

Work is well underway to resolve the current Cambridge GXP constraint, and capacity support will be provided through diesel generation and post-contingency load-shedding until our new GXP and zone substations come online before the end of FY2025.

Capacity constraints were previously reported at Te Awamutu—these were protection system related and have now been resolved by Transpower.

Work is planned from FY2024 to FY2027 to resolve or alleviate the identified feeder security and voltage constraints. Whilst the extent of feeders with current or forecast security and/or voltage constraints appears high, in practice, our expected constraints only emerge during contingency events (in the case of security) or at high load times (in the case of voltage). They can be managed through more aggressive hot water load control or temporary increases to the 11kV bus voltages. These operational controls are only temporary, and the extent of distribution constraints indicates that additional investment at the distribution feeder level is required in the near to medium-term. While new subtransmission solutions are being investigated and will eventually be needed in the longer term to resolve security and voltage constraints (particularly for the Te Awamutu area), distribution solutions such as voltage regulators and capacitor banks are being deployed to address our near-term needs.

The reliability assessment has not indicated any systemic issues on any feeders. However, there are opportunities for continuous improvement by reducing the number of customers on feeders, between controllable switches and reclosers, and/or prioritising renewal or vegetation management on the worst-performing feeder.

Our network development programmes and projects in response to our constraints are shown in Table 2 below.

Network level	Forecast year for capacity constraint	Forecast year for security constraint[11]	Forecast year for voltage constraint	Forecast year for reliability constraint
Transmission/Subtransmission				
Cambridge GXP	Nil[12]	2022	Nil	Nil
Te Awamutu GXP	Nil	2031	Nil	Nil
Distribution feeders				
Cambridge feeders	Nil	1 of 14 feeders is forecast to exceed secure capacity by FY2025, growing to 5 by FY2033	3 of 14 feeders currently have voltage excursions at peak demand	No systemic reliability breaches. Continuous improvement opportunities available
Te Awamutu feeders	2 of 16 feeders exceed total capacity by FY2030	4 of 16 feeders currently exceed secure capacity, growing to 7 by FY2025	6 of 16 feeders now have voltage excursions at peak demand	As above

Table 2: Summary of forecast constraints

Further analysis of the network against our other planning criteria and various solutions (either planned or under consideration) are shown in sections 8.8 to 8.15.

[11] *Demand exceeds capacity at the required level of security*

[12] *Nil means beyond the planning horizon of this AMP*

Network resilience

Building network resilience[13] is an important asset management strategy (#3). As the reliance on electricity increases, the resilience of our electricity network needs to improve to meet future customer needs (with a particular focus on reducing the effect of high-impact and low-probability events that can have a large economic impact).

The resilience work and the regional security strategy (#1) overlap, as network security improvements generally make our network more resilient. Our resilience strategy also encompasses work on climate change adaptation. Our work on adaptation is in its early stages and will include network design standards reviews and environmental hazard assessments. The use of automation to deliver fast restoration of our network after a severe weather event is also part of our resilience initiatives.

Improving resilience is a wide-ranging programme that will be fully scoped, during CY2023 and implemented over the next decade. Some specific work concerning network criticality, network adaptation, segregation and automation, control system disaster recovery and analysis of third-party damage is underway. The 2024 AMP will provide visibility on our resilience maturity and set out the results of our assessments completed and the potential implication of our resilience improvement programme on network expenditure.

Material network development projects

Asset management strategy #1 (regional security) is core to creating our necessary capacity (and security) to support future demand growth. Expanding our subtransmission capacity and number of zone substations allows additional feeders to be installed to augment our distribution network.

This work is underway in the Cambridge area, where transmission capacity upgrade options have been investigated and where our preferred option is a new 220/33kV GXP to the west of Cambridge and a new 33/11kV zone substation at West Cambridge and two new 33/11kV zone substations in the Hautapu industrial area. Agreements have been executed with Transpower for our new GXP, and design work has commenced.

GXP capacity constraints were removed at Te Awamutu during FY2023 by Transpower's protection system upgrade, and our 11kV cable upgrades are progressing to relieve several feeder capacity constraints.

We are implementing a programme to improve the reliability and resilience of distribution feeders. This work includes installing reclosers to segment feeders, automating open feeder points to reduce restoration times, installing dropout fuses on spur lines, and installing loop protection schemes. Loop protection schemes allow faults to be isolated to the smallest possible extent and restore healthy network sections quickly.

Customer connections

Connection growth remains strong, with around 520 new customers expected to connect in FY2024, growing to 600 in FY2028. This high growth aligns with Waipā's long-term growth prospects. The strong connection growth sees the number of new connections increase 50% over the forecast period (compared to the 2022 AMP).

Forecast expenditure

Our material network development projects are shown in Table 3 below. These projects amount to $37.9m over the next ten years and are mostly scheduled for the first five years, representing 37% of our network capex.

Project description	Driver	Timing	Forecast
Transmission/Subtransmission			
Te Awamutu GXP capacity increase: • Removal of GXP protection constraints • 11kV feeder cable upgrade	Security	GXP work is complete Cable upgrade occurring in FY2023-FY2024	$4.0m
Cambridge subtransmission development: • New Hautapu GXP west of Cambridge and a new zone sub at the GXP • A second new zone substations and associated subtransmission • Associated 11kV network integration will include eight new feeders	Security Capacity Voltage	New GXP and associated zone sub due to completion in FY2025 A second zone substation and subtransmission are due for completion in mid FY2026	$25.2m

[13] *Resilience is defined as "the ability of assets, networks, systems, organisations, and people to anticipate, prepare, absorb, adapt to and / or rapidly recover from a disruptive extreme event."*

Project description	Driver	Timing	Forecast
Distribution Feeders			
Cambridge: New voltage regulators on five feeders	Voltage	FY2024-FY2029	$1.2m
Cambridge: Fusing, recloser and loop automation	Reliability	FY2024-FY2033	$2.9m
Te Awamutu: Capacity upgrade on Pirongia feeder	Capacity	FY2024	$0.5m
Te Awamutu: New voltage regulators on five feeders	Voltage	FY2025-FY2029	$1.2m
Te Awamutu: Fusing, recloser and loop automation	Reliability	FY2024-FY2033	$2.9m

Table 3: Summary of major network development projects

Figure 9 summarises our forecast system growth and reliability-related capex. It also indicates our possible direction of travel for capex in the 2024 AMP. In this regard, medium to long-term system growth capex will likely increase as feeder security and voltage solutions are required.

With our current profile, expenditure is higher in the first three years due to the following:

- Cambridge region zone substation and subtransmission network;
- Feeder augmentation in Te Awamutu.

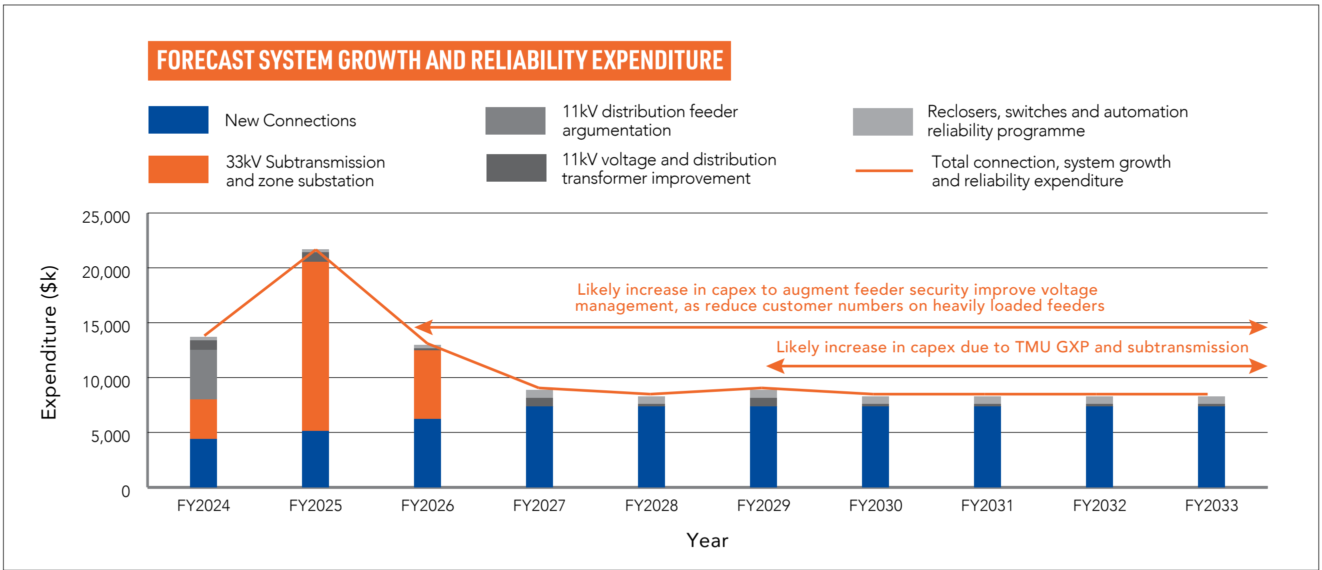


Figure 9: Forecast system growth and reliability expenditure

Following our preparation of new demand forecast scenarios, we'll refresh the constraint analysis, that could reveal our need for additional network development work at the back end of our planning horizon. Any new projects will be identified in the 2024 AMP and incorporated into our wider optimisation review that will be necessary when expenditure forecasts change.

1.13 Material asset lifecycle programmes and projects

Developing a comprehensive fleet plan and renewal forecasts

Given the progressive aging of the network, we are committed to developing comprehensive asset fleet plans for our material asset classes (asset management strategy #4). As mentioned in Section 1.6, we expect to observe more end-of-life drivers over the coming decade. Ensuring we have quality asset condition, asset health, and asset risk information will be important to enable the optimal renewal of our network.

Presently, an asset health assessment is a mix of age and condition-based, with our forecasting of health deterioration predominately based on asset aging. As a first step in revising our fleet plans, assess, we'll assess available asset health assessment and forecasting methodologies and review inspection standards to ensure we capture the correct data on end-of-life drivers. Assessing asset criticality and asset risks will also be a feature of the revised fleet plans in the 2024 AMP. Our renewal forecasts will evolve over the next 2-3 years as new condition information is captured and our forecasting approach evolves.

Asset health assessment

In this AMP, we have updated the existing fleet plans with the most recent age and condition information - providing an improved view before the 2024 AMP.

We have included a health assessment on wooden crossarms. Crossarms are not a specific asset class under the AMP rules, so they're not identified in Schedule 12a. However, crossarms are a significant asset fleet that deteriorates at a different rate to poles. Hence, we manage them separately from the poles they're installed on.

A pole-top helicopter condition survey of most of our rural network was completed in FY2022. We have now commenced a drone-based pole-top asset condition survey for the balance of our network - focusing on the urban area and rural areas inaccessible by helicopter back in FY2022. We have recently completed an independent revalidation of the initial survey results, and our findings will be incorporated into our asset health assessments included in our 2024 AMP.

Figure 10 shows the evolution of our asset health for our material asset classes over the past three AMPs H1 or H2 refer to assets with low health, meaning replacement is required or where end-of-life drivers are present, and there is a high risk of asset failure. The assessed asset health has been changing over the past three years, reflecting the renewal of assets, the use of the most recent asset condition information, and the evolution in the health assessment methodology applied.

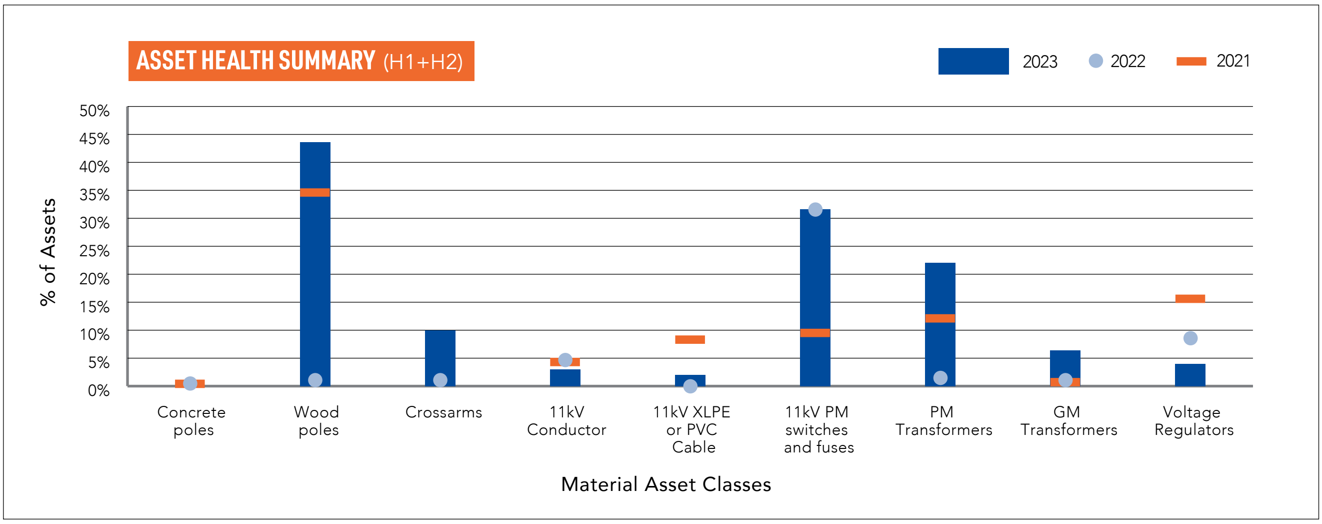


Figure 10: Asset health summary for material asset classes

The asset classes showing a high proportion of low health are wood poles, crossarms, 11kV pole-mounted switches and fuses, and pole-mounted transformers. For most asset classes, there is a view that the quantity of low health assets may have been overstated by either the EEA age-based health assessment, the quality of the age data, or conservatism in the observation-based condition assessment. As noted below, work is underway to improve the quality of the condition data and health assessment. Specific commentary asset classes showing a high proportion of low health are:

- The wood pole fleet is relatively small (less than 1,600 poles), and the health assessment is age-based using the EEA guidelines[14]. The pole-top survey data has not been used for health forecasting this year as wood pole failures almost always occur at or below the groundline. Further work is planned in FY2025 to capture groundline/below ground condition drivers for the wood pole fleet.

[14] *The Electricity Engineers Association (EEA) have produced a guideline to determine asset health based on age data and also based on condition drivers. This is an industry standard guideline.*

- Waipā has both a condition-based data set (covering the majority of the fleet) and an aged-based data set for crossarms. Figure 10 currently shows our aged-based dataset. Our condition-based data currently shows a materially lower quantity of H1 and H2 assets. This work was recently reviewed, and the initial finding suggests there is a greater proportion of H2 health assets than originally surveyed as H4. Following internal validation of the condition-based data, the crossarm fleet health will be updated in the 2024 AMP.
- 11kV pole mount switches and fuses health is derived from age data using the EEA guidelines. Our age data is not completely reliable (as many of these types of assets, especially fuses, do not have an observable manufacture or installation date, so the installation date has been derived from other sources). We have some condition data from the recent pole-top survey (mostly in rural areas), however this does not cover our full fleet. We are validating the pole-top survey data, which may be utilised in future health assessments.
- Pole mount transformer health is derived from age data using the EEA guidelines. We have some condition data from the pole-top survey; however, this does not cover our full fleet. We are validating the pole-top survey data, which may be utilised in future health assessments.

Our fleet plans in Section 10 provide further details on the health of our asset fleet.

Forecast asset renewals

Figure 11 shows the forecast asset renewals vs the current assessment of low-health assets. Our strategy is to replace assets that deteriorate to health grade H1 and H2 if at critical locations. Except for certain asset classes, allowing assets to run to failure is generally not a viable strategy due to safety considerations. Where possible, our renewal work is prioritised based on asset criticality and risk. We plan to bring more formality to the criticality and risk assessment process, which will result in some assets being replaced when they reach H1 health and others being replaced when, or even before, they reach H2 health.

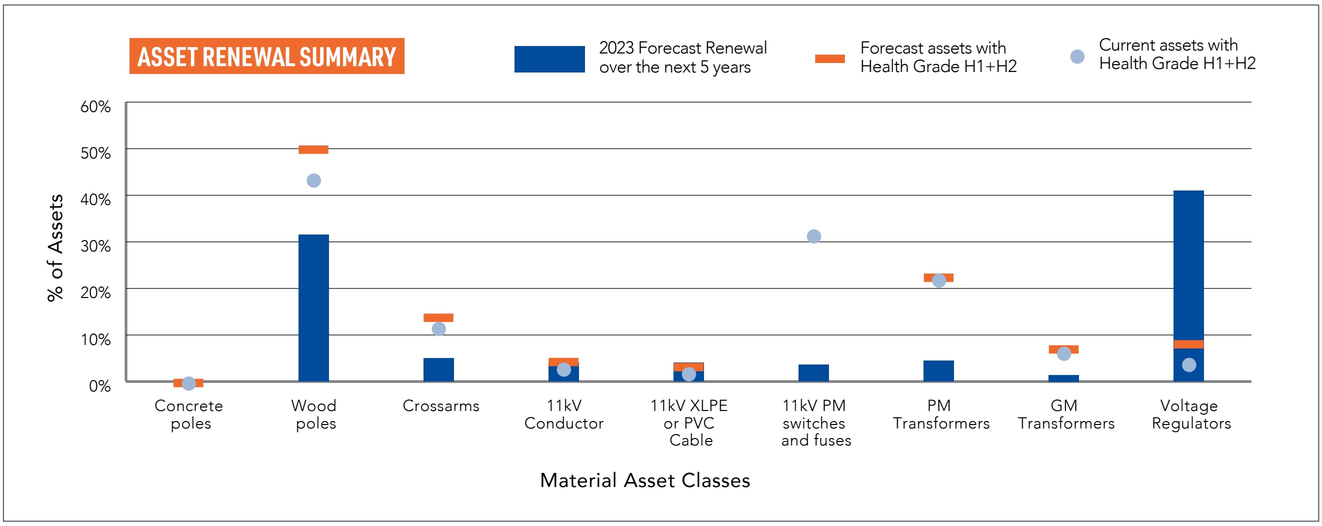


Figure 11: Asset renewal summary for material asset classes

There are some material differences between the forecast asset health and the forecast renewals, which largely relates to a view for some asset classes that the quantity of low-health assets has been overstated. Work is underway to improve the understanding and quality of the health assessment. The reasons for these differences are below:

- Wood pole renewals are below the 5-year forecast for H1 and H2 assets as the renewals are currently scheduled over the next 10-years, rather than 5-years. The wood pole fault rate has been very low, indicating our current age-based forecasting is conservative. The forecast renewals will be refined when ground-line condition data is captured in FY25 and health forecasting transitions to condition-driven;
- Crossarm renewals are below the 5-year forecast for H1 and H2 assets. The forecast renewals are based on replacing all forecast H1 assets over the next 5-years. As mentioned above, the pole-top condition survey results have recently been reviewed and will result in changes to the current quantities of H1, H2 and H3 assets. Upon completion of the internal validation and the development of a risk modelling tool, the 5-year forecast of renewals will be revised and included in our 2024 AMP;
- 11kV pole-mounted switch and fuse renewals have not been adjusted from the 2022 AMP. A 5-year forecast for H1 and H2 has not yet been prepared for this fleet as further work is required to validate the current quantity of H1 and H2 assets, especially for pole-mounted switches. Validating the current condition and developing a more accurate forecast for renewals is a key focus for the current year and will be included in our 2024 AMP; Industry practice for 11kV fuse is to replace at the same time when crossarm, transformer or pole are replaced, while pole-mounted switch should be subjected to a more proactive approach.
- Pole mount and ground mount transformer renewals are below the age-based 5-year forecast for H1 and H2. The forecast renewals are based on the replacement of all forecast H1 assets. H2 assets are not included in the forecast as, based on fault statistics and field observations, age-based forecasting is overestimating low health assets. Notwithstanding the above, industry practice for small rural pole-mount transformers is run to failure (as the failure mode has low safety and environmental risk). Hence the above renewal forecast based on H1 is also considered conservative. Work is

planned to capture condition data in urban areas and move to condition-based forecasting for the full network in our 2024 AMP.

- The replacement of voltage regulators exceeds the condition based 5-year forecast for H1 and H2 assets. The high level of renewal results from replacing the pole structures due to the low seismic ratings and the renewal of voltage regulator controllers.

We consider the differences between the 5-year forecast of H1 and H2, and the 5-year forecast of renewals does not currently increase safety or reliability risk. Whilst our level of renewal may increase in the 2024 AMP from around FY2027 (or earlier based on our modelling work in 2023 to provide a levelled and sustainable long-term renewal programme), we are confident all actual poor-condition assets are being maintained or replaced promptly over the next three years. Our current level of asset failures, our programme to remediate defects found during our recent pole-top survey, and our current inspection programme results support this conclusion.

Asset renewals are not necessarily "like for like". At the time of replacement, consideration is given to using assets with greater inherent reliability or additional functionality (for futureproofing against technology change or work efficiency)

Renewal and safety-related expenditure

Figure 12 summarises the forecast renewal and safety-related capex. It also provides an indicator of the possible direction of travel for capex in the 2024 AMP. In this regard, there may be some changes in allocation between asset classes in the near term, with likely increases in renewal capex towards the back end of the forecast period.

In relation to the current profile, expenditure is higher in the first three years due to the following:

- Additional renewal of priority poles and crossarms identified during the recent pole-top condition survey.
- The replacement of the SCADA system.
- Increased renewal of reclosers and 11kV pole mount switchgear.

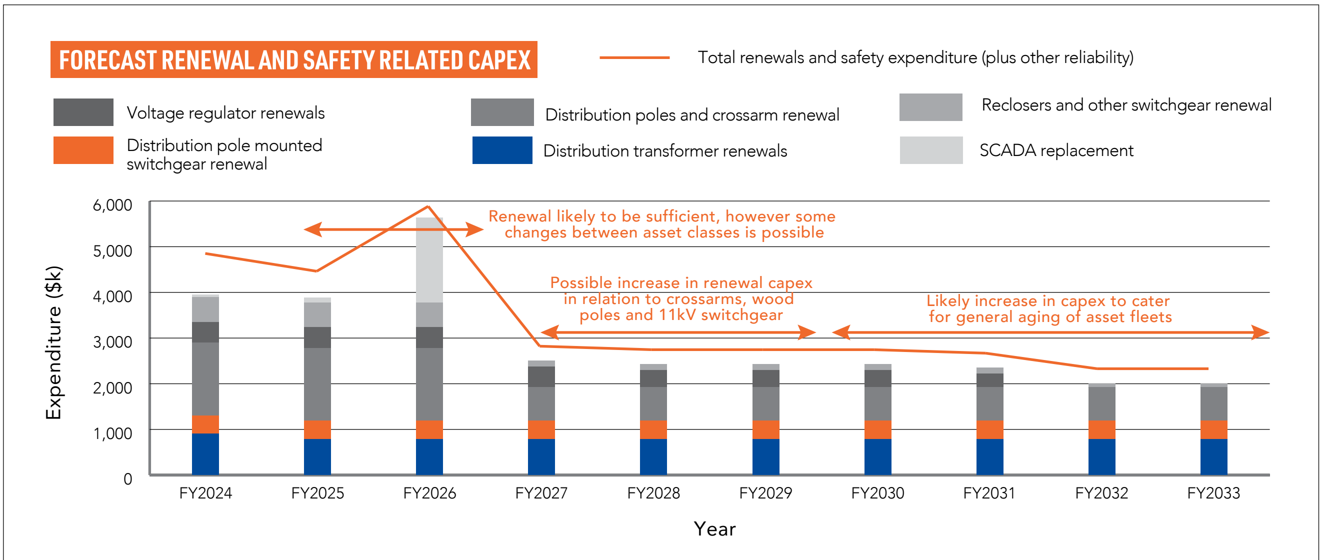


Figure 12: Forecast renewal expenditure

Fault response, maintenance and inspection

In response to the increasing trend in the number of weather related outages and the increasing fault restoration times, we have increased the system interruption and emergency budget by 35% over the next 10-years (compared to our 2022 AMP). Our new forecasts reflect our level of expenditure being incurred in recent years.

Other than the additional inspections mentioned above, material changes concerning corrective and preventative maintenance, inspection and testing programmes have yet to be made. However, given the increase in the number of assets and the progressive ageing of our network, work volumes are expected to increase. As a result, forecast expenditure on routine and corrective maintenance and inspection has increased 4% (compared to the 2022 AMP). Asset replacement and renewal (opex) have increased by 14% (compared to the 2022 AMP) due to a forecast increase in work on transformers, switchgear, and voltage regulators.

Full details on our various programmes are covered in Section 10.16.

Vegetation management

Mitigating vegetation-related outages is a key strategy for our business (asset management strategy #6). We have initiated this strategy as we have observed more vegetation faults than our peers despite increased vegetation management expenditure.

Our vegetation management programme includes systematic inspection and cut programme with tree removal if needed.

Our vegetation strategy seeks to enhance our assessment and management of vegetation to reduce our outage impacts. Our key tactics include the following:

- Developing a tree inspection and tree-cut programme based on criticality, and reliability, targeting high-risk in-zone and fall-zone trees;
- Developing a program that improves private tree owner approval rate for full cuts of trees;
- Developing an inspection tool to better visualise/capture network vegetation issues;
- Increasing vegetation management resources in our region.

To support our strategy, vegetation management expenditure has been increased by 40% over the next ten years (compared to our 2022 AMP).

The implementation plan is being developed over the coming months, and more details and improvement targets will be provided in our 2024 AMP.

1.14 Key asset risks and controls

We use an ISO 31000-compliant risk management system and regularly assess asset risks, risk controls and their effectiveness.

There hasn't been any change to the material risks to our network since our last AMP. Our key network risks continue to be:

- Demand exceeding Cambridge GXP firm capacity exceeded, resulting in a loss of supply.
- Demand exceeding our cable capacity at Te Awamutu GXP, resulting in a loss of supply.
- Vegetation contact with overhead lines resulting in a loss of supply.
- Overloaded customer LV fuse bases (old fuse holders, or additional new customer load) cause pillar fire, localised loss of supply and public safety risk.

Effective controls are in place, or treatments being deployed or planned, for these risks, including:

- Swayne Rd (Cambridge) peak-lopping diesel generation, the construction of our new Hautapu GXP and related subtransmission and zone substation projects.
- Te Awamutu GXP feeder augmentation projects planned for FY2024.
- Creating a longer-term vegetation management strategy from our existing vegetation management schedule and increase in vegetation management expenditure.
- Continuation of our pillar inspection and replacement programme.

We have developed emergency management plans for natural disasters, extreme weather, or cyber-attacks. The recent Cyclone Gabrielle has tested our emergency management plan, and we have gathered learnings across the business for continuous improvements. We have backup systems for the business systems and are planning a disaster recovery facility for the SCADA system to continue operating our business in case of a major incident.

We actively participate in the Waikato Lifeline Utilities Group as the National Emergency Management Agency (NEMA) requires.

1.15 Delivery and deliverability

We have an in-house field service resource, and this will be our preferred option to deliver our 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.

To ensure we have the required capacity and capability to deliver in our AMP timeframe, we have initiated two improvement initiatives:

- Improve our works planning and delivery capability by establishing a Works Planning and Delivery team that will implement the annual works planning process, including scope, design, estimate, plan, and project management work delivery, and
- A review of our inventory management and procurement processes.

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. Cost efficiency is considered throughout project delivery:

- At the design stage: consideration of materials type, total lifecycle costs, standardisation, constructibility, and outage requirements;
- At the procurement stage through competitive tendering and consideration of alternative offerings;
- During construction through benchmarked internal construction costs against external benchmarks.

We embrace an outsourcing approach for special projects (Cambridge GXP re-enforcement and subtransmission projects). The balance of our forecast network capex for the next five years is consistent with the capex delivered in our previous five years. Therefore, we expect to be able to deliver this work programme.

1.16 Network expenditure forecasts

Summary of forecast capex

Figure 13 shows the 2023 AMP forecast capex. 2023 AMP capex has increased by 30% over that included in the 2022 AMP (on a comparable 2023$ basis[15]). The material changes were discussed in the prior sections:

- An increase in forecast customer connection to support the continued high regional connection growth;
- An increase in zone substation and subtransmission project costs;
- An increase in 11kV feeder augmentation work in Te Awamutu;
- Additional prioritised asset renewal following the FY2022 pole-top inspection;
- The inclusion of the SCADA replacement project.
- The removal of the project to monitor distribution transformers via SCADA.

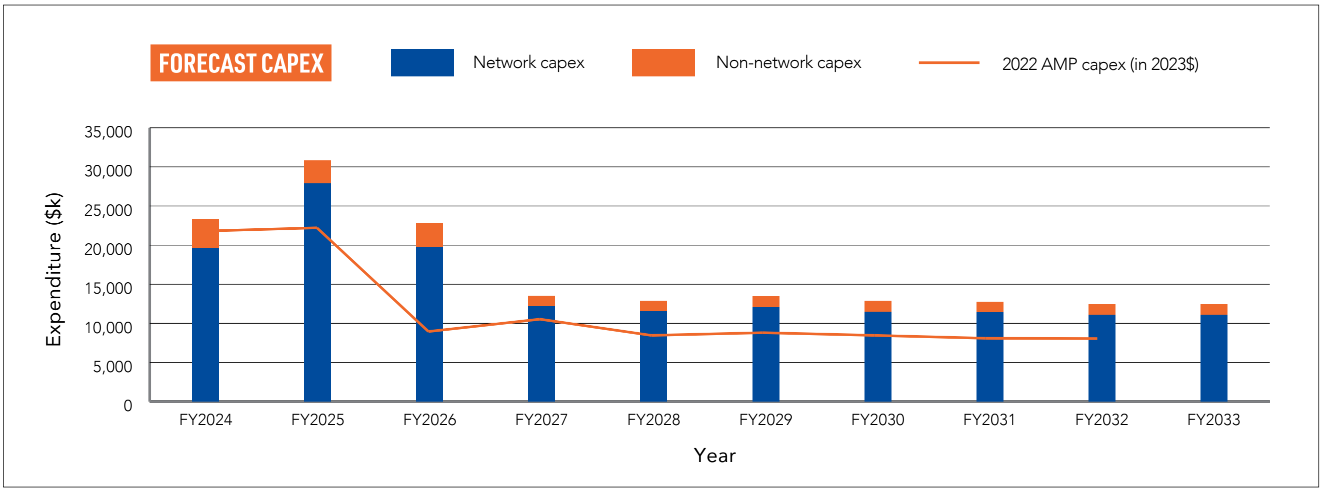


Figure 13: Forecast capex

Summary of forecast opex

Figure 14 shows the 2023 AMP forecast opex. 2023 AMP opex has increased by 30% over that included in the 2022 AMP (on a comparable 2023$ basis). The material changes relate to the following:

- An increase in system interruption and emergency expenditure. Our forecast now reflects the recent cost to attend to and restore faults on our network;
- An increase in vegetation management expenditure to increase the level of vegetation trimming and removal work;
- Removal of transformer monitoring costs.

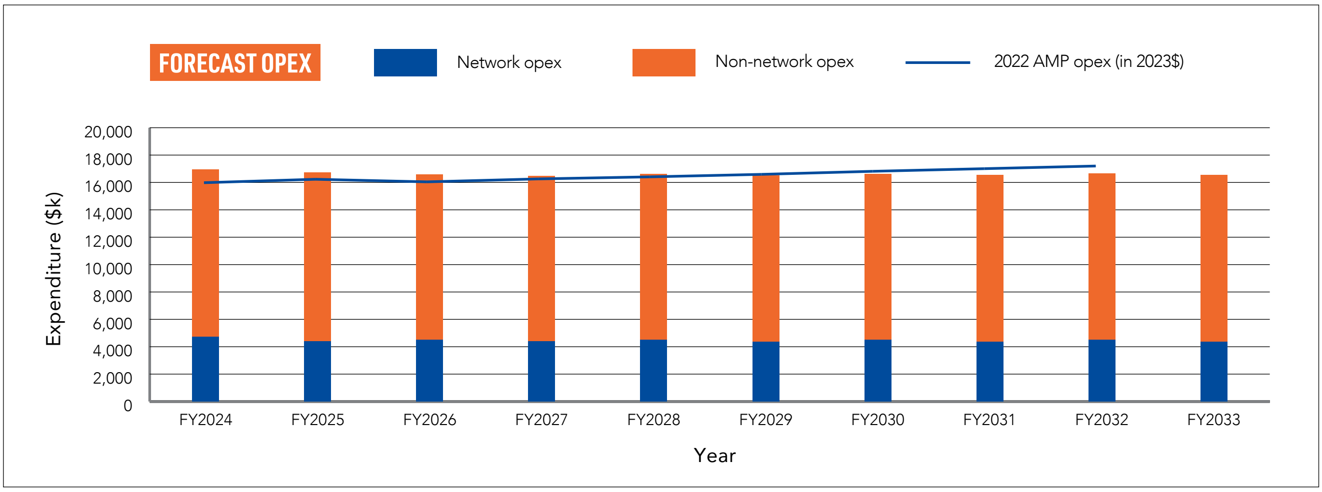


Figure 14: Forecast opex

15 *Based on Sept 2022 inflation figure of 6.23% - Statistic New Zealand*

1.17 Concluding comments

This AMP is the first step in improving our communication on the key issues, asset management strategy, and programmes and projects impacting our network. Further and more significant improvements will be visible in the 2024 AMP.

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. 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. The programmes, projects, and expenditure forecasts over the next three years are sufficient to address the known constraints and issues. Whilst forecast system growth and renewal expenditure will likely increase in the 2024 AMP, the current network risks are known, controls are in place, and/or additional treatments are planned.

There are improvements in asset health data planned for the coming year, and this view (and any changes to future renewal forecasts) will enhance the understanding of the needs of our network. They will ensure that future AMP expenditure forecasts keep pace with the needs of our network.

Our level of performance being delivered from the network has generally been acceptable. This AMP has identified areas for improvement and the programmes that will be implemented to ensure performance standards can continue to be met.

2. BACKGROUND, OBJECTIVES AND RESPONSIBILITIES

2.1 Purpose of this AMP

This AMP describes our approach to meet asset management objectives over the next ten years and beyond. It presents the current state of our network, our understanding of the future expectations of our customers, how we maintain the health of our assets, the new capability we need to develop, and how we've structured and resourced ourselves to deliver our plan.

As we transition from an environment with incremental and fairly certain growth to one of significant growth and change driven by climate change and the need to support decarbonisation, our approach ensures the AMP programmes deliver a network that serves immediate needs and builds foundations for a network that meets the needs of our customers in a future highly electrified world.

2.1.1 Basis of AMP

The AMP documents our asset management intent and the strategies and processes we use to achieve our asset management objectives and target service levels, including investment and operations plans, which inform our annual budgets.

The scope covers a description of assets and their conditions, how our network needs to adapt to change, including any network development required, a description of our total fleet lifecycle management, and our resulting forecast expenditure needed to meet our asset management objectives and service levels.

The Commerce Commission has regulatory oversight of our business 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.

Disclosure of this AMP complies with the requirements of Section 2.6 and Attachment A of the Commerce Commission's Electricity Distribution Information Disclosure (ID) Determination 2012. Our practice is to prepare and disclose a full AMP or AMP update each year to assist with our asset management improvement path and provide 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 2023 AMP are:

- Safety: Provide a safe environment for the public and staff by embedding safety considerations in network design, equipment choice, and operations
- Customer and stakeholders: Improve understanding of what our customers and stakeholders value most to ensure their needs are reflected in our plans and strategies.
- Assets: Maximise asset utility while minimising total cost and network performance that meets service level targets
- Capability: Continuous improvement of our asset knowledge, and asset management processes and systems, to deliver performance and efficiency improvements

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

2.1.3 Period covered

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

Our CEO and Board of Directors approved the AMP and the document will be signed on 18 April 2023. 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 are managing the network. Our key stakeholders are:

- Our owner, the Waipā Network Trust, represents our wider customers.
- The public within our region.
- Mana whenua within our network area.
- Our customers take supply from our approximately 28,033 installation connection points (ICPs) to whom we deliver electricity (some of whom receive supply at 11kV).
- Generators who are directly connected and embedded within our network and produce electricity for use by others.
- The electricity retailers who operate over our network.
- The territorial authorities, Waka Kotahi (NZTA), and other government agencies whom we engage with.
- Our team and contractors who work in or on our network or work on connections to our network.

The interests of these and other stakeholders are assessed through stakeholder 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

While the 2024 AMP will describe how we align our asset management strategy and performance targets to the interests of our stakeholders, this 2023 AMP commences this work. To better aid this approach, we've organised this executive summary and the AMP 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.

The general sections that existed in the 2022 AMP have been grouped within the Parts mentioned above. The 2024 AMP will include further revisions to organise the content better. A reconciliation of the Information Disclosure requirements is included 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);
- That our business is efficient (so that the distribution prices are no higher than they need to be).

2.3 Accountabilities and responsibilities for asset management

2.3.1 Responsibilities

Our Network Assets team determines 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 Head of Network is responsible for disclosure of the AMP and associated schedules, and together with the Asset Strategy Manager completes the AMMAT assessment. Other areas of our business are consulted as required.
- Our Network Information Specialists are responsible for managing records of network assets.
- The AMP is prepared by our Asset Strategy Manager, reviewed by our Head of Network, recommended for approval by our Chief Executive, and approved and certified by our Directors.

Management and Company Directors review the AMP to consider whether the AMP accurately reflects our Strategic direction, the current SCI, and forecast performance and expenditure. Once the AMP is approved, the following stages occur:

- Specific approval of major projects is tabled at appropriate Board meetings for our Directors' evaluation and appropriate approval.
- Our Head of 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 Head of Finance and Commercial is responsible for collating the budgets, reporting expenditures, and compiling information disclosure schedules.

Our Chief Information Officer is responsible for corporate business systems, and IT functions within our business.

Our Head of People, Safety & Wellbeing 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.

Figure 15 shows our organisation chart depicting responsibilities for asset management planning and disclosure from our Board of Directors, Executive Management to Operational functions.

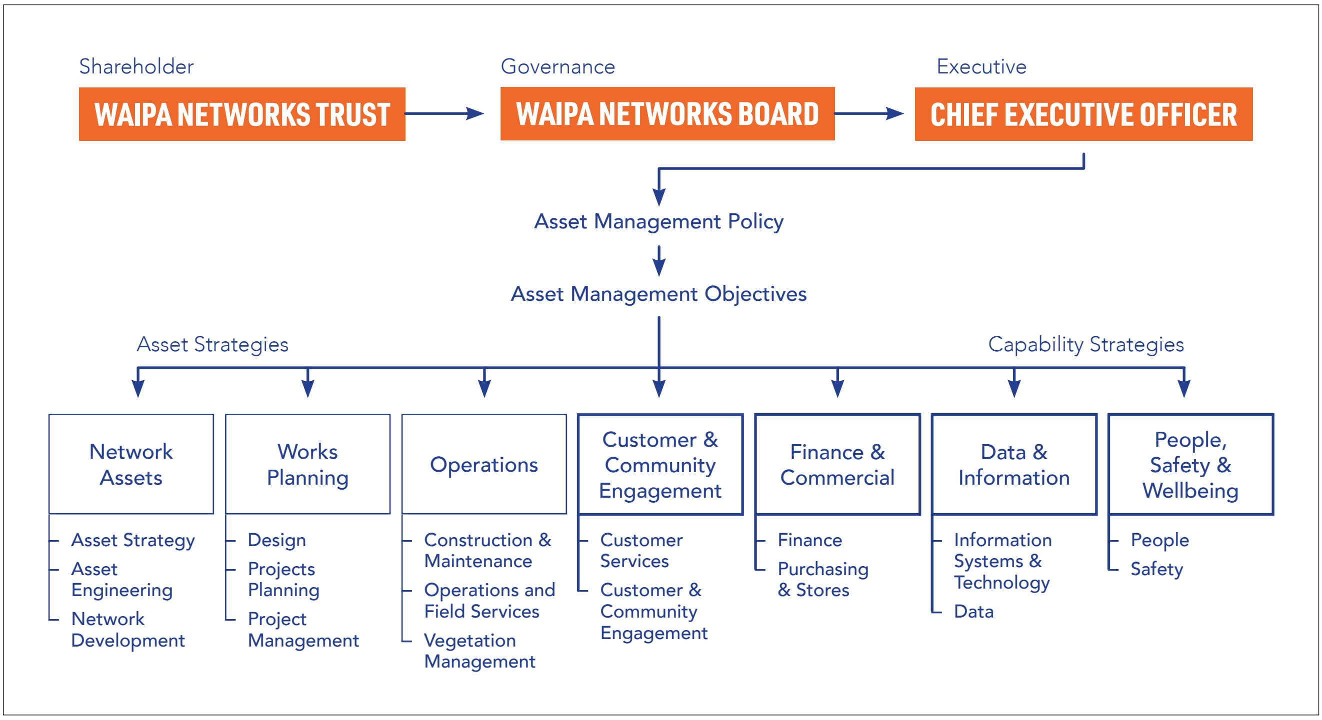


Figure 15: Our ownership, governance, and operational responsibilities

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. We contract external service providers when the workload exceeds the capacity of internal resources and will:

- Identify the 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 such as 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.
- Conduct a regular review of our works management and delivery processes to ensure deliverability and enhance operational efficiency.

2.4 Communication and participation processes

Our asset management practices are communicated internally to staff and externally to other stakeholders through our policies, standards, and this AMP. Table 4 summarises the processes and systems that support communication and participation.

Processes/ systems/ plans within 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 a number of policies and procedures relating to asset management held and available through the intranet.	Waipā's team participate in periodic reviews of Policy/Procedures. Senior management have oversight of 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 on a periodic basis. The external Public Safety Management System audit is undertaken on relevant parts of the system annually.
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, inhouse Contracting department, external Consultants engaged by Waipā. Network Design Manual made 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 are used to specify processes and procedures relating to the maintenance of assets on Waipā's network. This includes inspection requirements and frequency.	The document is communicated to relevant team members by the Network Development and Engineering Manager.	In-house management of the maintenance standards by Waipā's Network Development and Engineering Manager.
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 also, as appropriate.	Internal design team, in-house Contracting department, external Contractors engaged by Waipā. Waipā will instruct external contractors as part of the procurement process that works are to be undertaken in accordance with applicable elements of Waipā's manual.	The Manual is reviewed and updated internally on an as-needed basis.
Other relevant industry Standards	Designs should be undertaken in accordance with relevant industry best practice (i.e., following current applicable standards). Examples of this are the construction of new switch room buildings, or foundations supporting sub-transmission poles in soft ground. Consultant engineers engaged by Waipā are required to undertake design in accordance with 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 applicable 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 and updated and signed off by the Board.

Table 4: Summary of communication 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 available on our website. This document identifies our mission and 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 and 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.
- **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** that ensure 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 and are updated as and when revisions come into effect.

Our senior management regularly reviews our legislative compliance via a company-wide assessment using Comply with. 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 inadvertent 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 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 actions and considerations are consistent with our objective of environmentally friendly and sustainable operation.

PART 1:

THE KEY ISSUES FACING THE NETWORK

3. NETWORK OVERVIEW

This section summarises our network and the region it operates 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 28,033 customers (ICPs) on behalf of 15 energy retailers. Our position is to operate the distribution function in the electricity supply industry, shown as D and E in Figure 16.

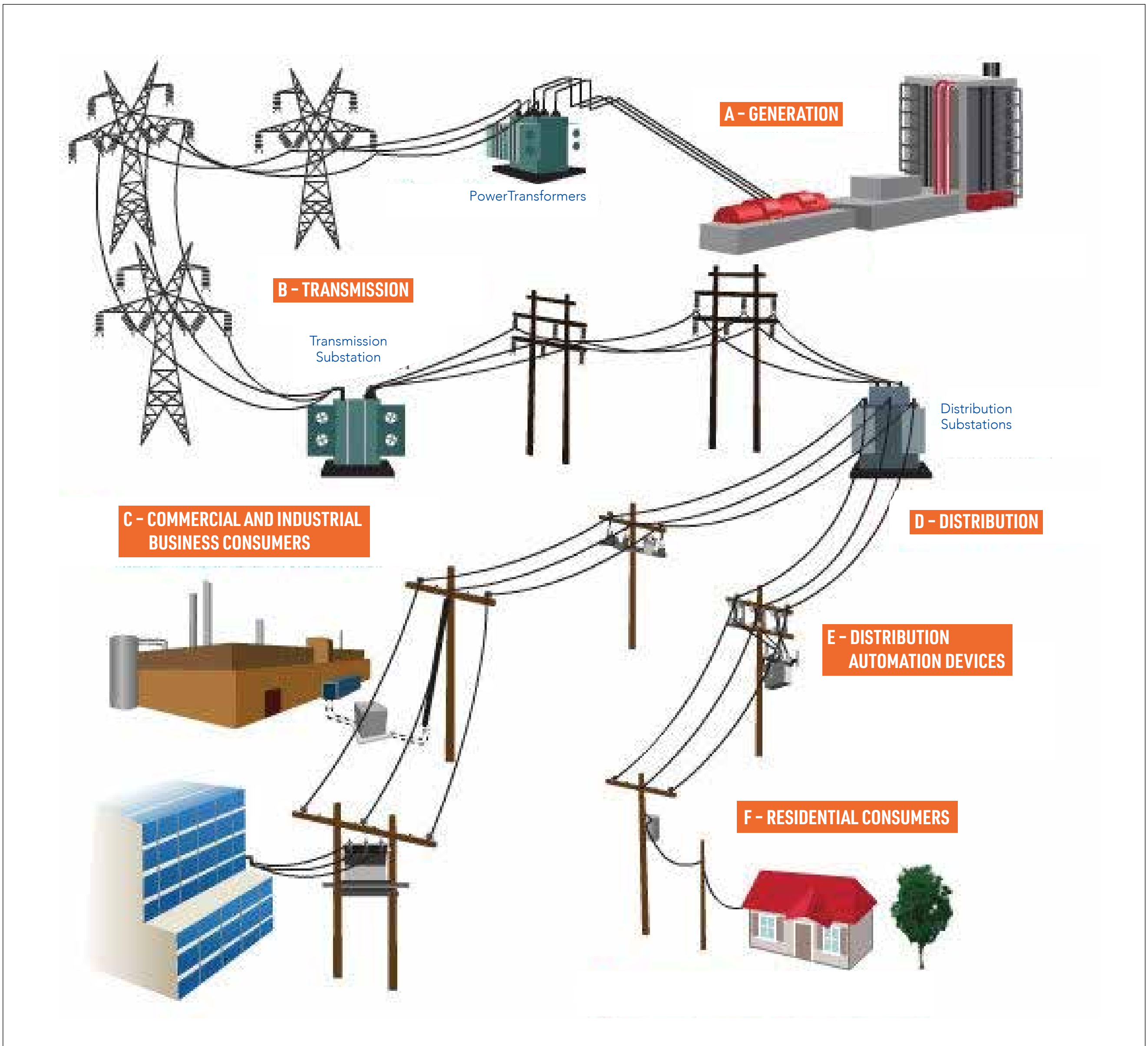


Figure 16: Illustration of the New Zealand electrical supply industry

3.2 Region and context

Our network covers the Waipā area in the Waikato and King Country region 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 17. Our distribution system covers 1,865 square kilometres.

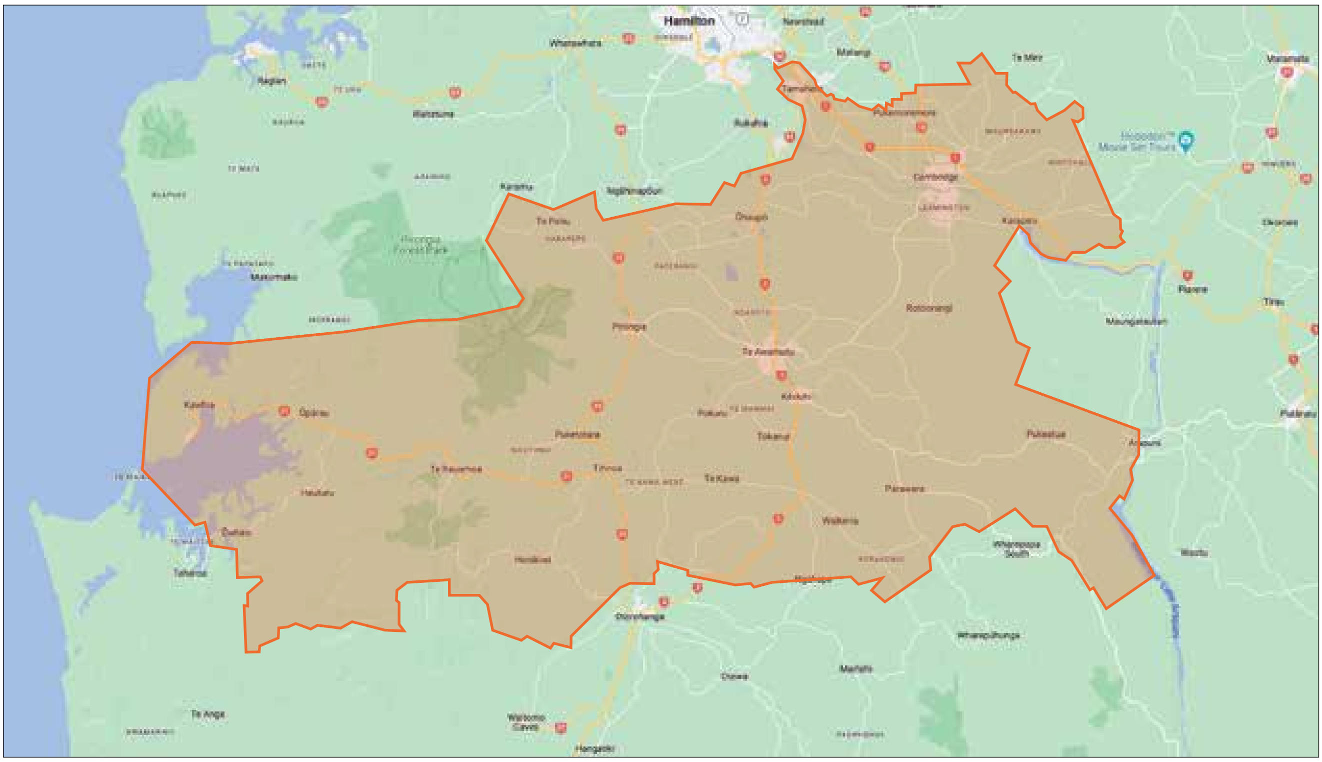


Figure 17: Network supply area overview

3.2.1 Supply area characteristics

In the urban and suburban areas of Cambridge, Leamington, Te Awamutu, Hairini, Kihikihi, Ohaupo, Pirongia and Kawhia, our distribution assets are generally located within the road reserve. 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 relatively 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 difficult 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.

3.2.3.1 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.

3.2.3.2 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, like during the 2011 Christchurch earthquake.

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.

3.3 Customers and network demand

3.3.1 Customer overview

Our network supports approximately 28,000 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.

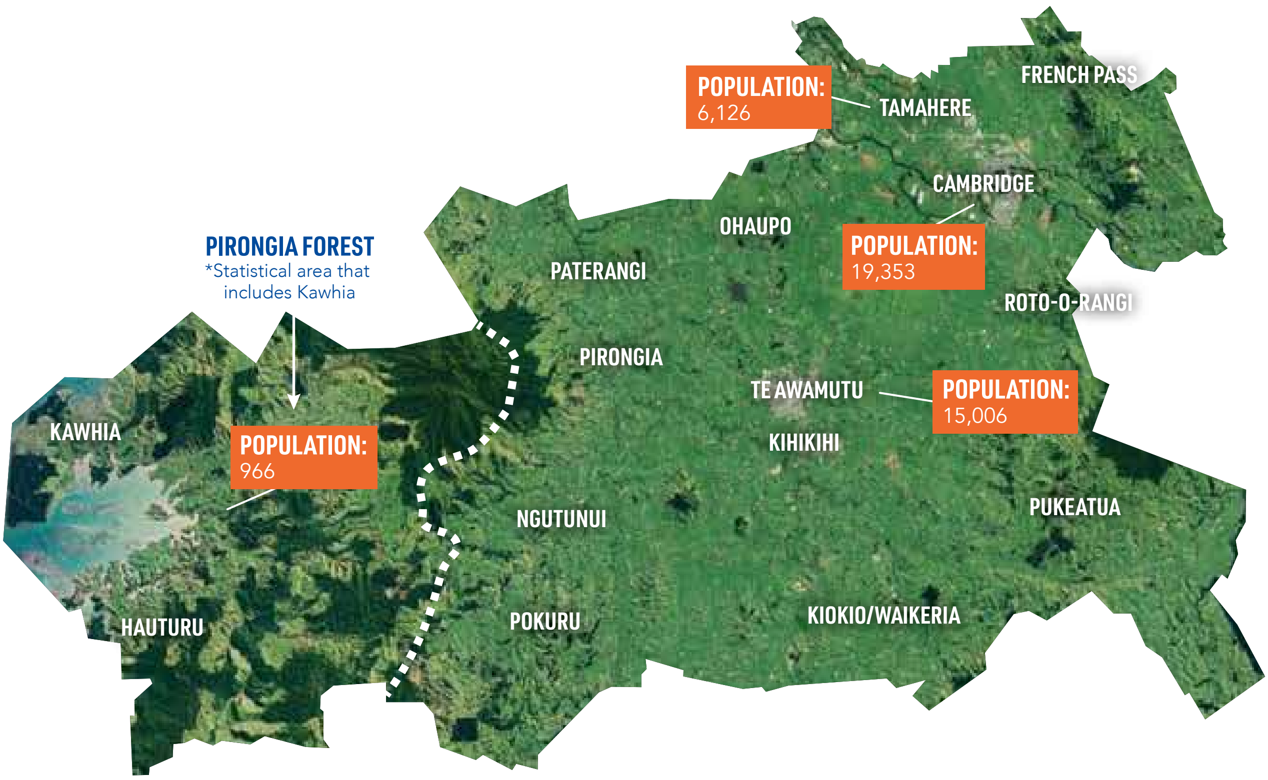
Our customers range from residential to large industrial, and our region is one of the fastest growing in New Zealand relative to size. Approx. 19% of our ICPs are from business customers, with 46% from the dairy and agriculture sector.

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 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 18: Population distribution in the network supply area

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[16]

Waipā District (which comprises most of Waipā's network area) had a resident population of about 60,500 people, a 1.2% average annual increase in 2022.

Waikato region has had a historic ten-year gross domestic product (GDP) growth of 11%. However, economic wellbeing is not uniform across our network. There is a marked difference in affordability between areas, for example, Cambridge vs Kawhia.

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.

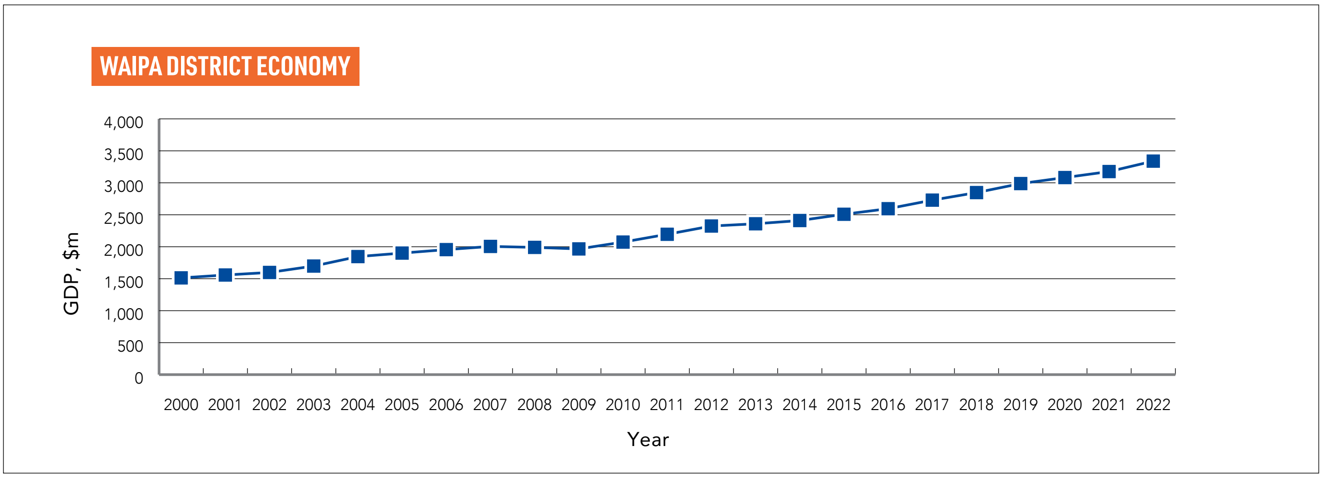


Figure 19: Waipā District Gross Domestic Product (February 2023)

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 currently drive the growth in manufacturing.
- 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 5 shows the impact of these issues on our electricity distribution business. Low probability outcomes are considered and addressed within our risk management framework.

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

Issue	Impact
Shifts in market demand for milk	There is 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 5: 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:

- **Domestic:** Heat pumps are expected to become more common for domestic space heating and will likely be used as air conditioners in the summer.
- **Industrial:** Climate change targets related to the decarbonisation of industrial process heat 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.
- **Transport:** Charging electric vehicles (EVs) is becoming more prevalent. EV take-up is expected to be gradual within this planning period.

A discussion on the expected impact of the decarbonisation-driven initiatives and possible response is presented in Section 3.5.2.

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 6 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 6: 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 20, which shows a winter-peaking network.

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 FY2021/22, the network delivered 420GWh of electricity to approximately 28,033 connected customers. The maximum coincident (instantaneous) system demand was 81MW, with a load factor of 52%.

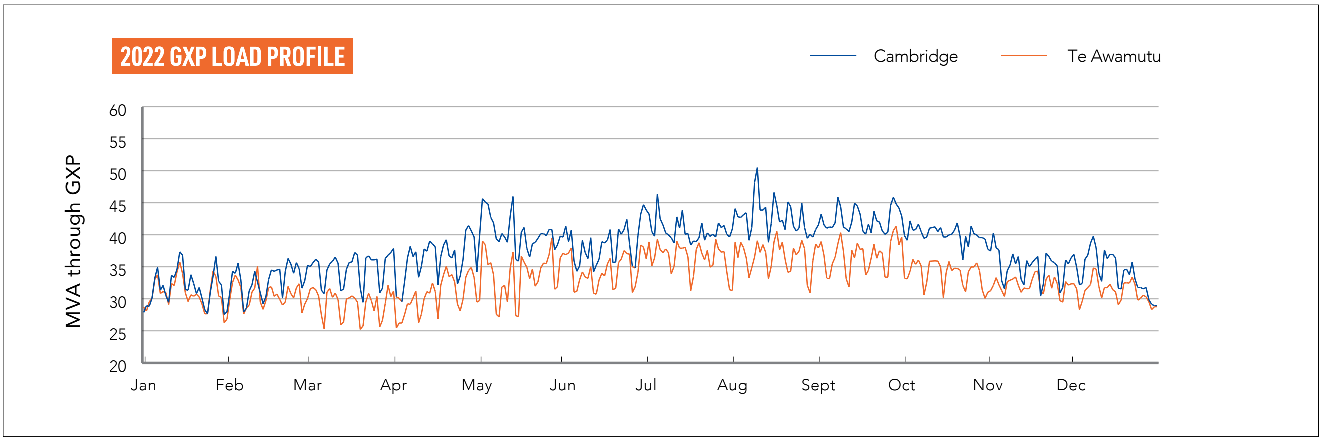
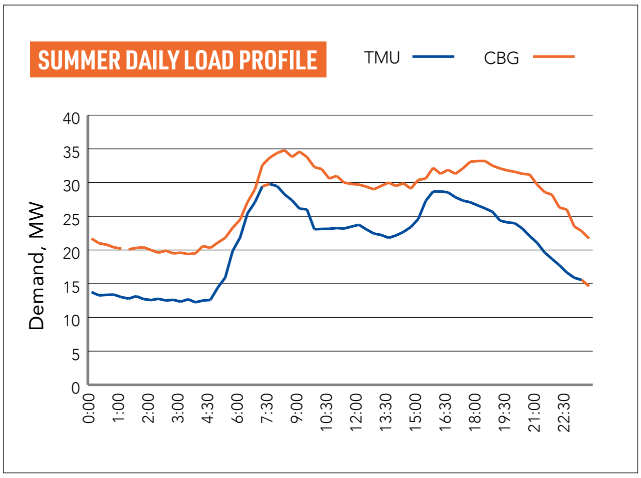


Figure 20: Our seasonal load profile (MVA)

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 then again at night as in Figure 21. 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.



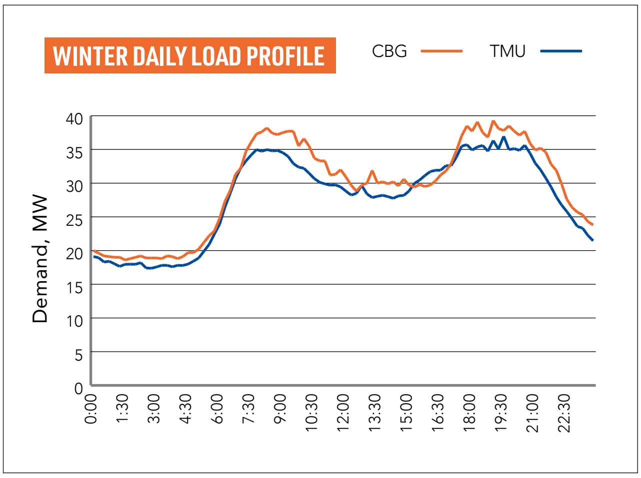


Figure 21: Daily GXP load profile

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 22 shows the geographic view of the 29 11kV feeders supplied by the two GXPs of Cambridge and Te Awamutu. Appendix A shows our 11kV feeder attributes as of 31 March 2022.

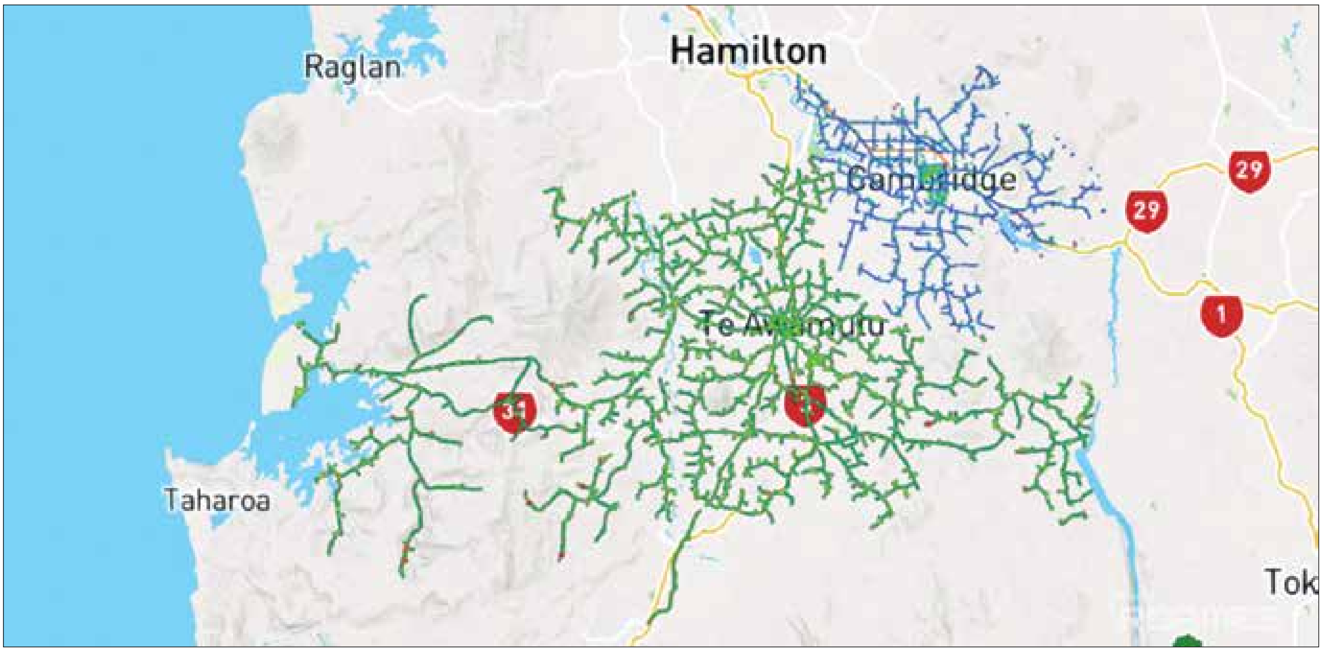


Figure 22: Extent of our network

Our assets extend to the 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 7 presents a summary of our major asset groups.

Type	Quantity	Average remaining age[17]	RAB value $000
110kV transmission lines	36 km	49 years	20,003
Distribution and LV lines	1,740 km	26 years	30,438
Distribution and LV cables	515 km	27 years	25,088
Distribution transformers	3,762	27 years	32,675
Distribution switchgear	5703	21 years	19,761
Other network assets	-	21 years	6,279
Non-network assets	-	16 years	11,166
Total			145,410

Table 7: Our major asset classes (RAB values from 2022 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 feeder 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.

[17] *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 also predominately 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 1,395km.

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 legacy distribution substations are predominately pole-mounted transformers (up to 200kVA on two pole structures or up to 100kVA on single pole structures) and pad-mount substations (up to 1,500 kVA) in urban and suburban areas and industrial applications. We are at the end phase of removing all two pole transformer structures.

Newly commissioned substations are either pad mounted (typically 50kVA up to 1,500kVA), or pole mounted up to 100kVA as permitted by District Council Plan requirements.

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

Our distribution system comprises (as of 31 March 2022):

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

3.4.5.1 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.

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.

3.4.5.2 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 single-circuit 110kV transmission line from Hangatiki owned by us.

Te Awamutu also 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 will complete 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. There are twelve 11kV circuit breakers supplying urban and rural feeders and two 11kV circuit breakers supplying the Fonterra dairy factory site in Te Awamutu.

3.4.6 Distributed generation on customer premises

Customer interest is expected to grow as distributed generation (DG) systems' affordability 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 144 new distributed generation installations in 2022, adding 1.7 MVA installed capacity. Figure 23 and Figure 24 show 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.

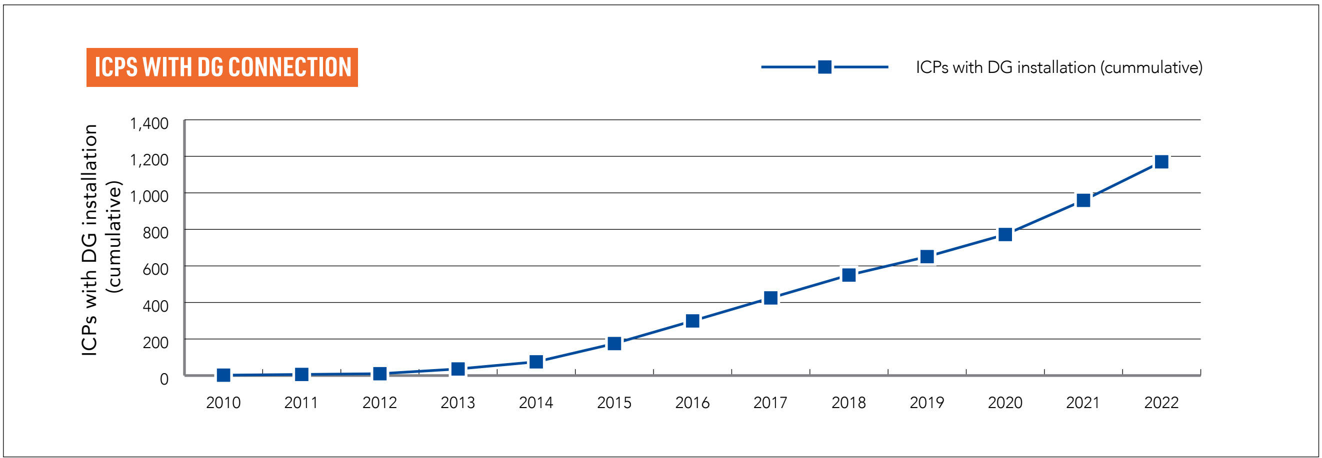


Figure 23: ICPs with DG installation (cumulative)

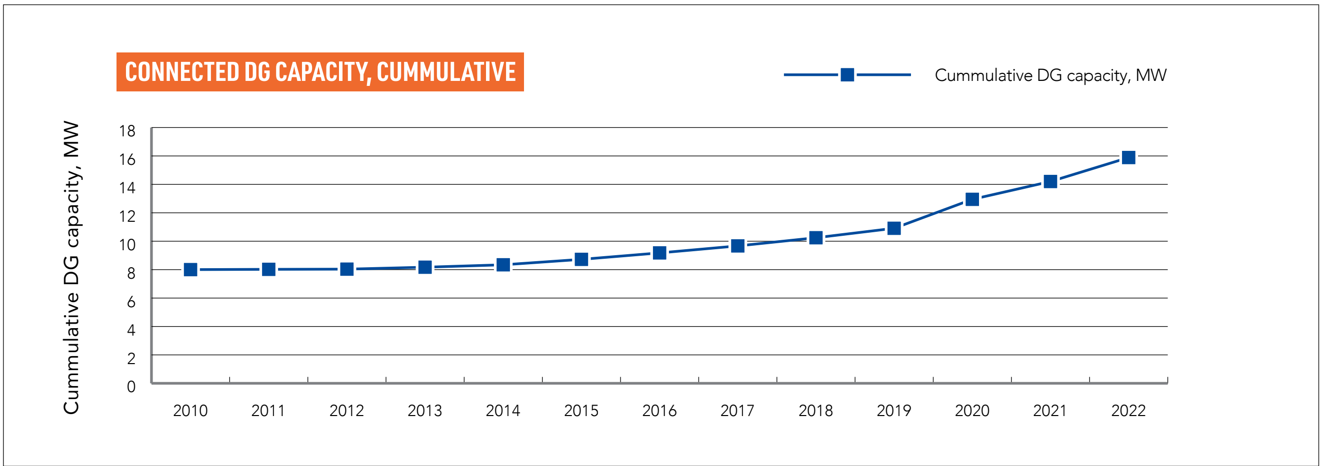


Figure 24: DG connected capacity (cumulative MW)

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. Whether underground cable is more appropriate than overhead conductor considers factors such as surrounding land use, safety, and public amenity.

Distribution substations step down the voltage from 11kV to 400V/230V in locations appropriate to service customers' needs, and local council District Plan requirements.

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 837km. 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 area 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 streetlights. We're using ripple control systems to help manage GXP peak demand and transmission changes 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 consist 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 have 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 will be considerably larger in terms of 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 23% to 86 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).[18]

3.5.2 Impacts from regional growth and energy transformation

New Zealand's path to a carbon zero future is driven by the displacement of fossil fuel energy with 100% renewable electricity. Us and other 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 and 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.

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.

3.5.2.1 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. Drawing from sources like Transpower's Te Mauri Hiko report, the initial view[19] is that demand could increase by 13 MW (15%) over the current demand due to electrification by 2035. Figure 25 shows the potential impact on our network demand based on the Te Mauri Hiko accelerated electrification, if apportioned to us based on ICP numbers. This view will be refined once we complete our regional review.

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.

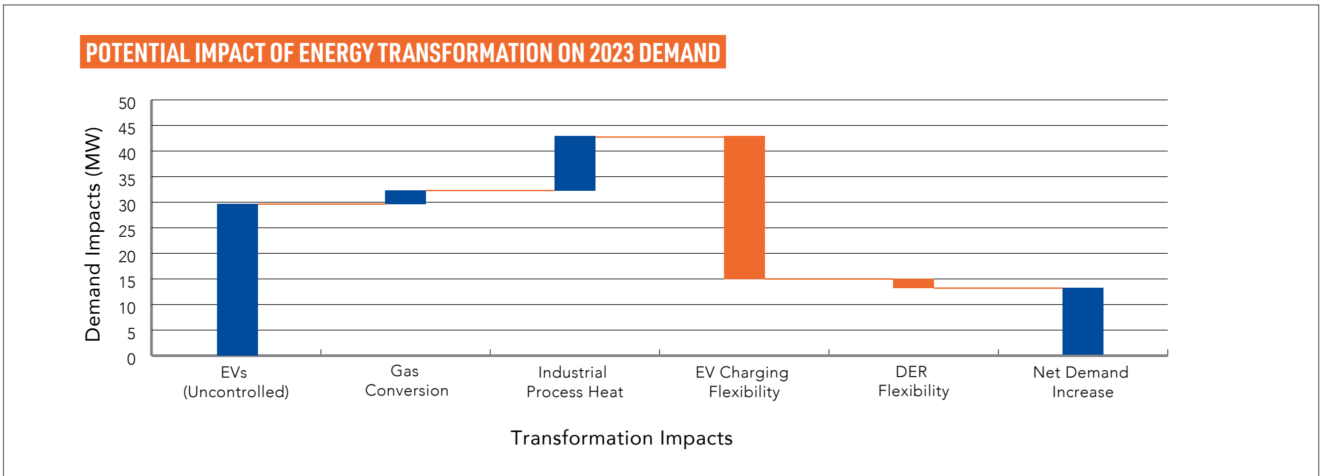


Figure 25: Potential impact of energy transformation forecast to 2035 based on Te Mauri Hiko [20]

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

[19] *Whakamana i Te Mauri Hiko - Empowering our Energy Future | Transpower. The demand growth is net of flexibility from EV charge load-shifting and controllable distributed energy resources.*

[20] *In 2035, EVs are expected to make up 37% of the vehicle fleet, with roughly two vehicles per household, equating to an EV ICP penetration rate of 73%. This equates to roughly 23,500 EVs in the region in 2035. Transpower's view is that the EV ADMD is 0.061 kW/EV controlled and 1.26 kW/EV uncontrolled, controlled EV ADMD increases to 0.18 kW/ICP by 2050. This analysis excludes current hot water flexibility and any improvement in household flexibility from smart appliances.*

3.5.2.2 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).

3.5.2.3 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 26 shows possible electrification scenarios, decarbonisation's extent, and 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 26: High-level scenarios

3.5.2.4 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 are undertaking a regional review in mid-CY2023 that will assess regional drivers for growth (such as electrification) and produce 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 15 years[21]. The asset base is comparatively young due to the value of the HTI-TMU 110kV line installed in FY2016 and new distribution assets installed as our network expanded to cater for growth in the past decade.

Based on the analysis in Chapter 10, however, 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 have aged over 45 years.

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.

[21] *This age measurement reflects the average useful life of EDB's assets less the average useful remaining derived from RAB divided by RAB depreciation.*

3.5.4 The increasing incidents and impact of adverse weather events

Based on the analysis in Section 4.1, 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, and there is no material change compared to the 2022 AMP. 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 27 summarises the results of our asset management maturity assessment in 2023. 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.

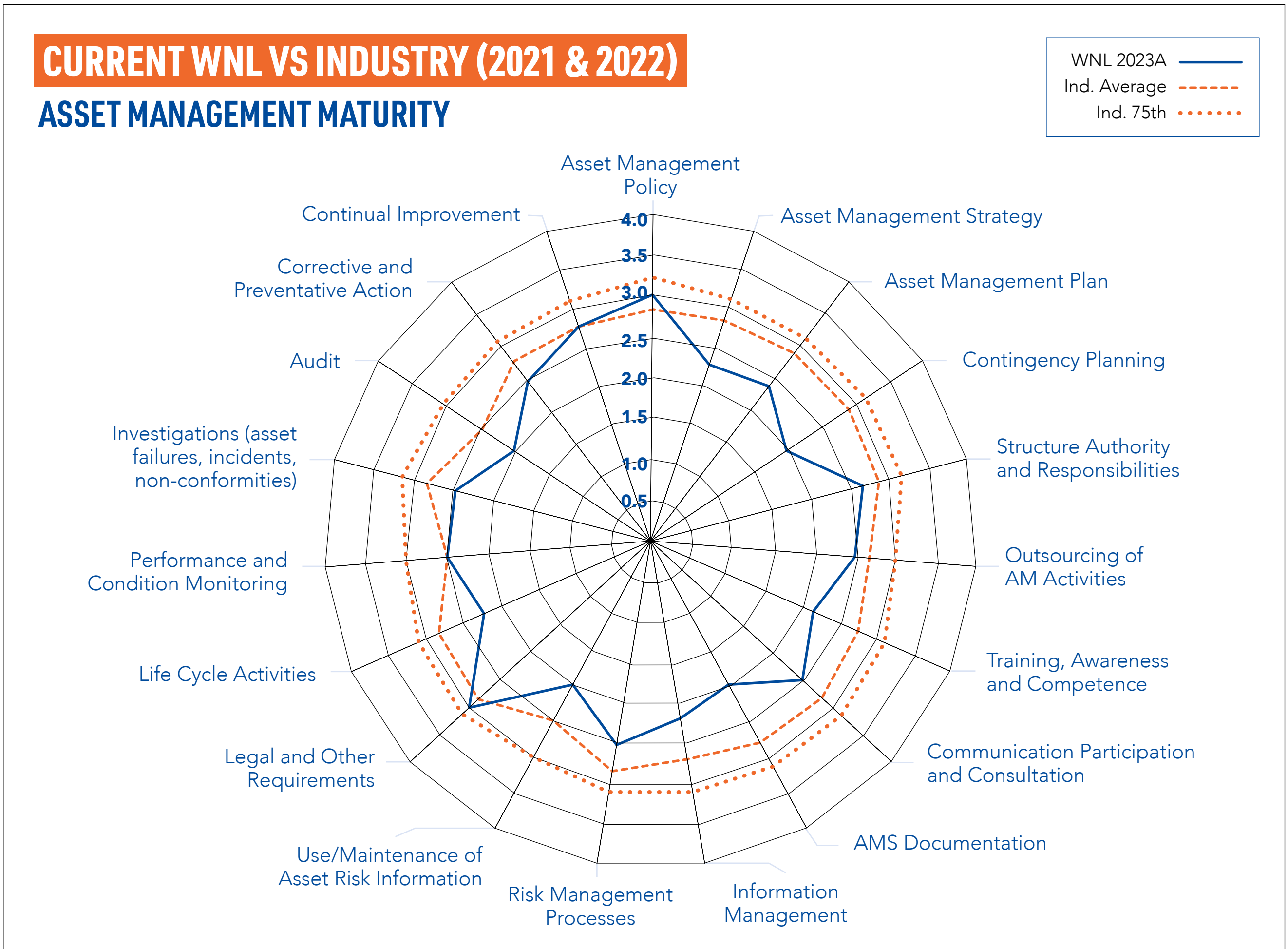


Figure 27: AMMAT summary results

We've been pursuing an Asset Management Improvement Plan since FY2019, which targeted achieving an "intermediate" level of maturity over time. This target was appropriate given the historical demands on our business.

However, our outlook is now looking materially different to the past. As outlined above (and in the asset management strategy in 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.

4. NETWORK PERFORMANCE AND SERVICE LEVELS

This section discusses the performance of our network and business against measures covering network reliability, quality of supply, cost performance, losses and asset utilisation, and customer engagement and satisfaction.

Customer engagement includes planned focus group engagements, particularly with key stakeholders, and through annual satisfaction surveys of customers. Customer satisfaction surveys provide feedback on our network reliability and fault response performance.

The section also provides an assessment of relative performance against other businesses. The comparative performance analysis has been completed based on several metrics, with our business compared to the whole industry and a selection of distribution businesses of a comparable medium size and mixed urban and rural coverage area.

This performance analysis concludes that:

- To achieve the set reliability targets, we need to maintain our vegetation management programme as this significantly impacts faults. Tree Regulations allow us only to cut or trim a tree when it is within the prescribed growth limit zone, which can limit the degree of proactive tree management. Therefore, to support a higher level of reliability, we need to balance engagement with tree owners and multiple visits.
- We're entering a period requiring increasing replacement of aging assets, especially wooden cross arms. The aerial survey of our network and the upcoming risk-based asset renewal modelling will assist in quantifying and prioritising our replacement programme.
- Further analysis of reliability initiatives is planned to identify avenues for greater use of automation and technology to improve network restoration times.
- No change in strategy is required to achieve other performance targets, such as managing line losses and asset utilisation.

4.1 Network reliability performance

Network supply reliability is a key input in developing the asset management strategy. This section provides a review of how our network performed against the key measures.

4.1.1 Network unplanned interruptions

Figure 28 and Figure 29 show our historical SAIDI and SAIFI performance (the 2021 and 2022 figures have been normalised based on DPP3). Unplanned reliability has generally been good and met the target in seven of the last ten years (and as measured by SAIFI, reliability met the target in all 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 FY2015, FY2020 and FY2022[22].

The reliability targets in Figure 28 and Figure 29 have evolved over time to ensure that they provided the right incentives for the business in the corresponding periods. For FY2013-15 the targets were set internally to reflect improvement over historical averages. From FY2016-20, the cap was set at one standard deviation from the prior 5-year average. From FY2021, the cap was set based on the DPP3 methodology consistent with fully regulated EDBs and excludes major events like Cyclone Dovi (by normalisation). The historical targets are as disclosed in the relevant year's AMP Schedule 12d.

We exceeded SAIDI target in FY2015 due to a higher number of vegetation outages and in FY2020 due to third-party damages. The value for FY2020 excludes the impact of cyclone Dovi.

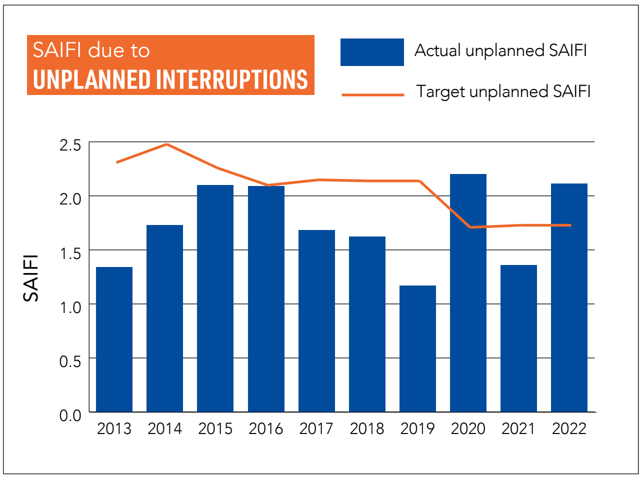


Figure 28: Unplanned SAIFI

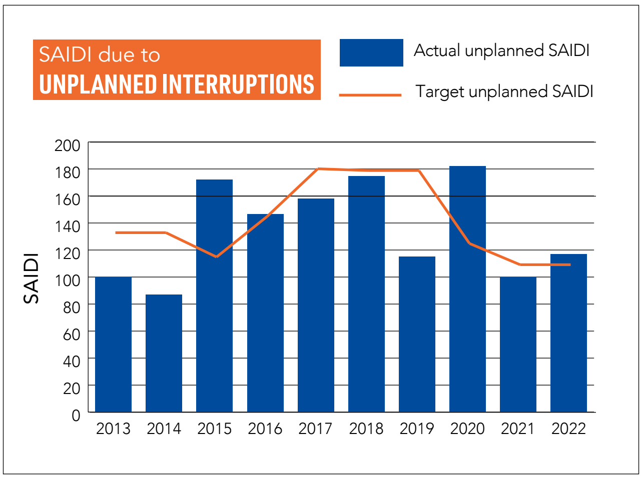


Figure 29 - Unplanned SAIDI[23]

Continued work to increase network automation, including the automation of isolation points, is expected to improve our unplanned SAIDI and SAIFI performance in the medium term through faster isolation of faulted parts of our network and faster supply restoration.

Due to factors outside our control, we have experienced a deterioration in headline reliability (as reflected in Figure 28 and Figure 29), and Figure 30 shows the trend in the causes of deteriorating reliability. The primary causes of the deterioration in "headline" SAIDI were due to adverse weather and third-party damage to the network. Regarding adverse weather, Cyclone Dovi was the material contributor (and we discuss this in more detail in the key issues section below).

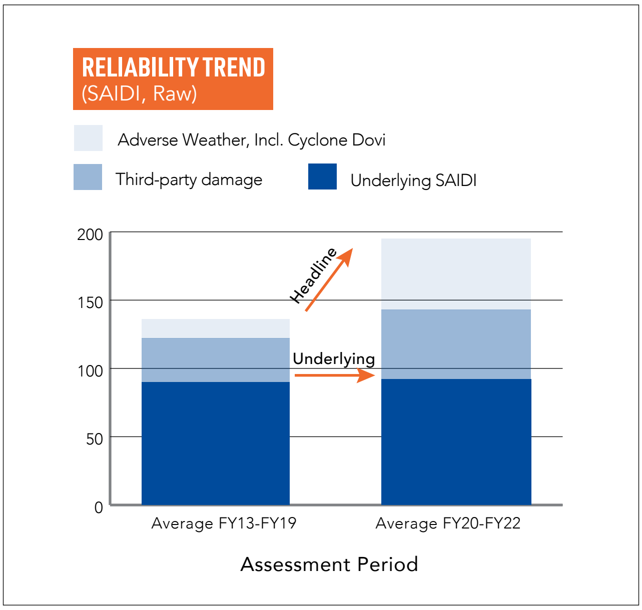


Figure 30: Reliability Trend (SAIDI, RAW)

[22] *FY2015 was due to high number of vegetation outages. FY2020 was due to high impact third-party damage outages. Impact from Cyclone Dovi in FY2022 has been normalised, and the underlying performance is slightly above target due to third party damage.*

[23] *Impact from cyclone Dovi in 2022 is excluded by normalisation – 114 SAIDI minutes for the single event.*

4.1.2 Network planned interruptions

Planned outages have exceeded the target for four out of the last ten years. The higher planned outage reflects the specifics of the work programme in those years. Figure 31 and Figure 32 show the ten-year trend for SAIDI and SAIFI respectively.

In the coming years, relatively high levels of planned outages for asset renewal are expected as we increase our maintenance programmes. The increased activity on our network is expected to utilise the margin between our current performance and target for planned SAIDI and SAIFI. Increased outages for network renewal are expected to continue for the entire ten-year period of this AMP.

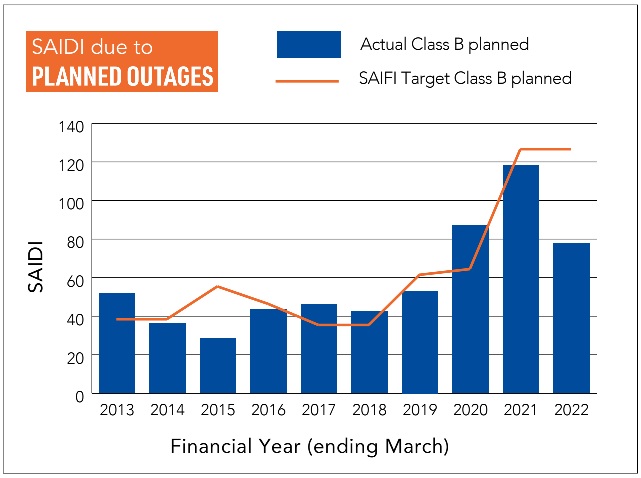


Figure 31: Planned SAIDI

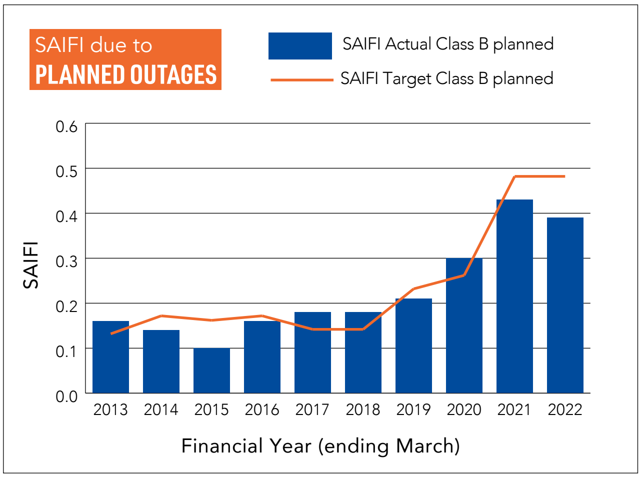


Figure 32: Planned SAIFI

4.1.3 Fault cause analysis

This section presents the trends in extended-duration interruptions longer than three hours. Deteriorating trends in extended-duration interruptions can indicate changes to restoration practices, declining network asset health in general, or a reduction in available post-contingency network capacity.

Figure 33 illustrates the growing trends in interruptions with durations greater than three hours, and Figure 34 the Opex expenditure for service interruptions for corresponding periods – noting the impact by Cyclone Dovi in 2022. Service interruption and emergency budgets have been increased accordingly.

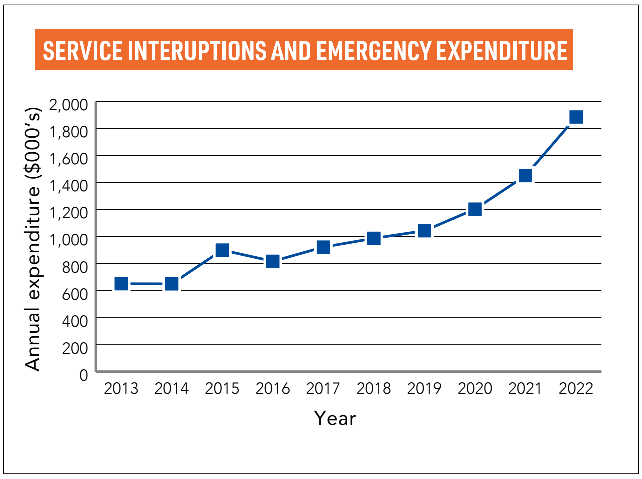


Figure 33: Service Interruption and emergency expenditure ($000's)

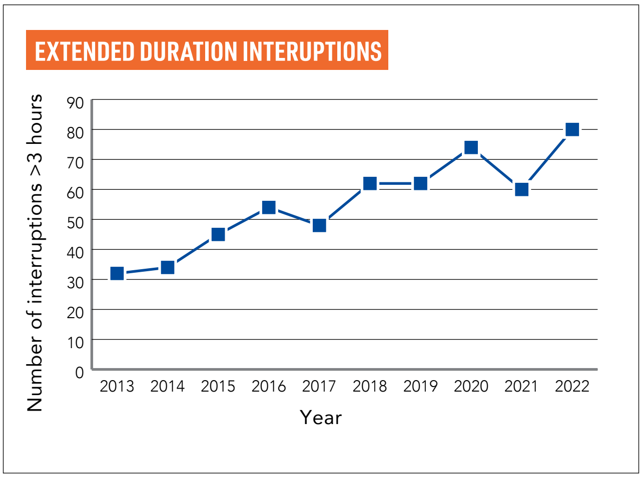


Figure 34: Number of interruptions over three hours

The data in Table 8 provides a breakdown of the causes of extended unplanned outages (over three hours).

	Lightning	Vegetation	Human Error	Equipment Failure	Adverse Weather	Adverse Environment	Third-Party Interference	Wildlife	Unknown
2013		7	0	5	1	0	13	4	2
2014	4	4	1	13	1	0	8	0	3
2015	1	18	1	12	2	0	9	2	2
2016	1	7	1	19	0	0	22	1	3
2017	3	7	1	12	5	2	18	1	0
2018	5	14	1	13	7	0	21	1	0
2019	1	9	1	13	6	0	31	0	1
2020	1	12	5	22	4	0	25	2	3
2021	1	15	0	12	3	0	23	2	4
2022	0	9	0	16	32	0	20	0	3

Table 8: Unplanned outages > 3 hours duration by cause

The following sections detail the main drivers of long duration outages that show an increase over the ten years and contain our works and initiatives to date as a continuation of previous AMP. As part of our Asset Management improvement journey, many of the initiatives below will also be further supported by our refined Asset Management Strategies detailed in section 5.2.

4.1.3.1 Third-party interference

Third-party interference is largely car versus pole incidents. Such incidents are generally random events where preventative measures such as barriers or undergrounding are often not cost-effective.

We have a process of geographically mapping all car versus pole incidents and identifying repeat pole strikes for review. The review considers if the location is inherently hazardous and if remedial measures would be justified.

The increase in third-party damage reflects the increase in economic activity, population, and vehicle-km travelled through the region.

Repeated pole strikes on a section of State Highway 39 led to the line being relocated further from the road. In most cases, however, the pole strike was a random event, and often relocations or barriers cannot be easily justified. Figure 35 shows (as blue dots) the repeat car versus pole incidents on our network since 2006.

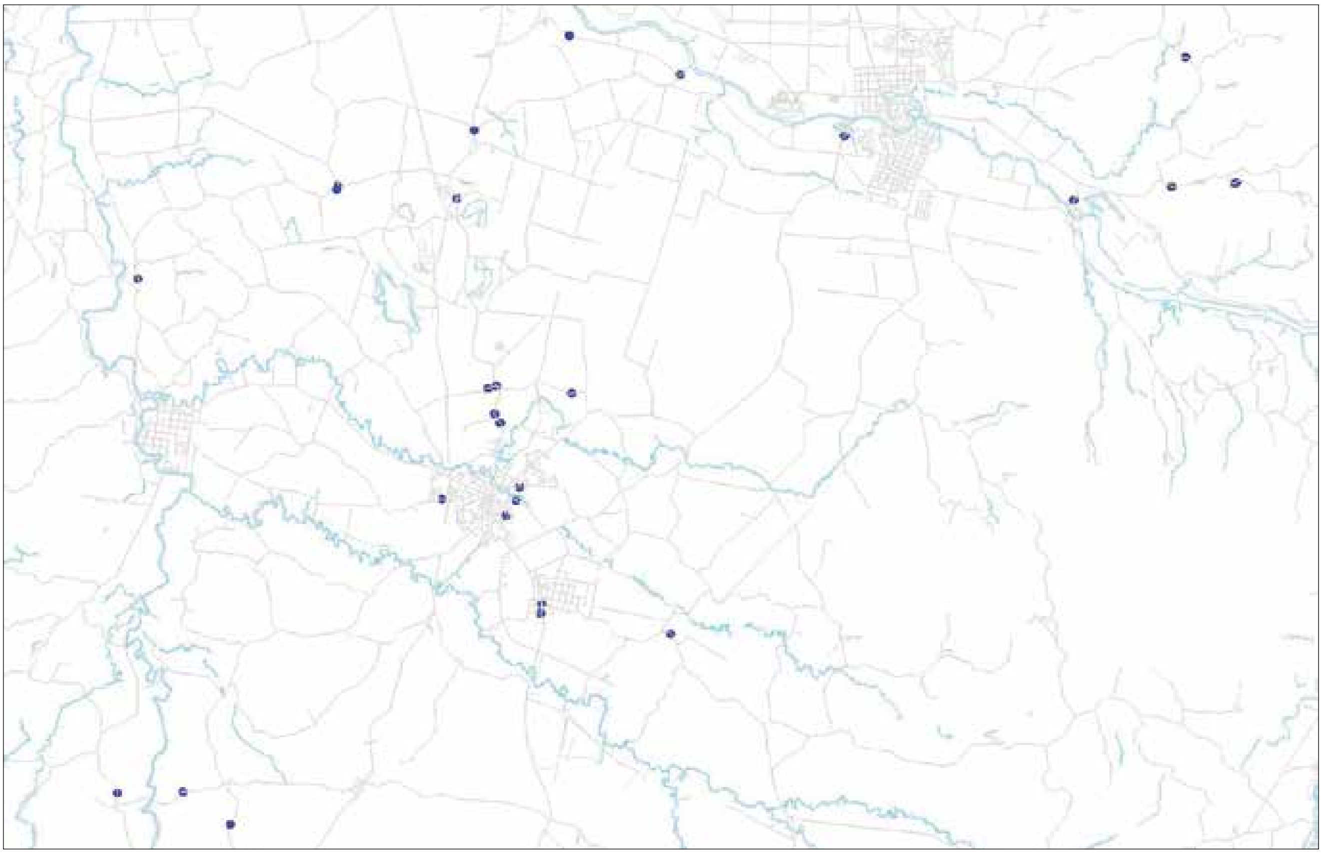


Figure 35: Repeat car vs. pole incidents map

Current initiatives: In December 2021, Orbica completed a geospatial risk analysis of car versus pole incidents on our network. This considered the Waka Kotahi 20-year crash statistics, road characteristics such as width, posted speed, elevation changes and the location of poles in relation to the road corridor. The data provided a granular analysis of car versus pole incidents risk for all the road corridors in our network and all pole locations. This allows potential accident and public safety risk hotspots to be identified and mitigations such as network relocation, roadside barriers or other roading interventions to be considered. The analysis provides a structured and analytical approach to determining vehicle versus pole incidents risk and allows interventions to be prioritised.

Planned initiatives: Further analysis of the risk of car vs. pole incidences that combines NZTA accident data and risk factors related to road configuration and posted speed limits with pole location data. This may provide more information on locations where proactive interventions to prevent car versus pole incidents may be justified, for example, reducing the number of circuits on a pole to reduce the impact on our network. We'll discuss opportunities for improvement with the local district councils and Waka Kotahi to improve public safety to benefit our community and the reliability of our network for customers.

4.1.3.2 Defective Equipment

Our analysis summarised in the 2022 AMP concluded that there was no clear pattern of a particular class of equipment causing more long-duration outages. Hence our updated defective equipment analysis now covers all unplanned outages with performance change compared across two periods.

Defective equipment causing outages is presented in Table 9 and Table 10 for the period FY14-FY19 compared to the period FY20-FY22. Defective equipment outages have improved across all reliability measures. The updated analysis indicates that equipment fault rates are all generally trending down, except for crossarms.

Crossarm will be subject to more intensive renewal starting from FY23-24, as the fleet comprises mainly wood crossarms with signs of the endoflifedrivers due to age.

Defect Equipment	Average FY14- F19	Average FY20-FY22	% Change
Interruptions	34	30	-13%
SAIDI	39	31	-20%
SAIFI	0.40	0.36	-8%
CAIDI	99	83	-16%

Table 9: Defective equipment unplanned outages impact

Asset type	Unit	Average FY14-F19	Average FY20-FY22	% Change
Insulator / Binder	Per 10,000 units	1.3	1.1	-13%
LV Fuse	Per 10,000 units	0.1	0.1	-10%
Crossarm, arm Brace	Per 10,000 units	1.5	2.2	49%
11kV Conductor / Cable	Per 100km	0.5	0.4	-16%
Pole, stay pole, stay wire	Per 10,000 units	0.2	0.1	-2%
Fuses, Switchgear, ABS, Reclosers	Per 10,000 units	18.3	13.6	-26%
Transformer	Per 10,000 units	10.7	5.6	-48%

Table 10: Defective equipment unplanned outages per unit

Current initiatives: We're continuing with the programme of network asset condition surveys and resolving the defects that arise from the inspections. We have a prioritised list of network defects arising from our asset inspections. We're increasing our budget to spend more on resolving defects in the coming years to address the list and reduce network risk.

Planned initiatives: We continue to monitor trends in network faults due to defective equipment to identify potential equipment-type issues. We adjust our renewal, replacement, or maintenance programmes to address the issue if a trend is identified.

The 2021 helicopter-based overhead assets survey mainly covered rural assets. In 2022, the team completed independent validation of the results, and the AMP is introducing a transitional budget to address the prioritised low health index assets.

In 2023 we'll be carrying out drone-based overhead asset condition surveys to the remaining part of our network to identify defective equipment and prioritise rectification. The survey outcome will enable more targeted remedial actions for our wider network.

At the same time, we are starting the work on risk-based asset renewal modelling journey in 2023 that will assist us in establishing a levelled and sustainable asset renewal budget. This will be further addressed by our refined asset management strategies as detailed in section 5.2.

4.1.3.3 Vegetation

Long-duration outages are typically out-of-zone trees falling onto our lines. These are difficult to control as they require trimming trees from the D1 and D2 growth limit zones under the Tree Regulations.

Vegetation interference continues to be a material cause of outages. Improvements have been made in close-proximity interference, but interference from within the "cut and trim" zone and from outside of the zone continues to be a material issue. Obtaining customer approvals to trim trees (inside and outside of the 4m zone) remains an issue that needs to be resolved as part of our vegetation management strategy.

Further details on our vegetation-related initiatives are supported by our refined asset management strategies covered in section 5.2, and are documented in Section

4.1.3.4 Adverse weather

The analysis indicates that for the three years to FY2022, the average annual impact on SAIDI from adverse weather has increased by 270% and averaged 52 SAIDI minutes p.a. over that period. This is a significant increase, and the impact of adverse weather in FY2023 continues this trend.

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 are driving an increase in SAIDI. Cyclone Dovi was the material contributor.

We've 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.

This AMP contains a suit of initiatives that will contribute toward improving the network's performance and our response towards major weather events, such as:

- Capex projects to upgrade our communications network and network automation to improve fault sensing, isolations, and restoration.
- Capex projects to replace our SCADA system (including an outage management system) to improve our network operation visibility and response.
- Developing a vegetation management strategy to reduce the impact from vegetation related extended outages during storm events.
- Increasing our Opex for vegetation management and service interruptions.

This will be further supported by our refined Asset Management Strategies detailed in section 5.2.

4.2 Asset delivery efficiency

Table 11 shows actual asset delivery performance over the past three years compared to the Statement of Corporate Intent target of <6.5% set for 2019/20. Our loss ratio asset delivery KPI was achieved in 2021/22.

	Actual 2018/19	Actual 2019/20	Actual 2020/21	Actual 2021/22
Loss Ratio	5.48%	5.40%	4.70%	5.5%

Table 11: Asset delivery performance

4.3 Customer satisfaction

Our annual customer survey is a key method for engaging with customers. The survey is also used by other EDBs in the industry and serves as a basis for benchmarking[24]. The key 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 groupings of; Residential Urban, Residential Rural, Commercial Urban and Commercial Rural. 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 5. The results from last year's survey indicate that overall customer satisfaction is 58%, slightly below the peer group average of 62%. We're performing well in areas such as value for money and reliability. However, our overall satisfaction is below the average benchmark score, and improvements are required in image, reputation, and communication.

Target	Waipā results	Average benchmark	Proposed target
Overall satisfaction	58%	62%	62%
Reliability	78%	74%	80%
Image & Reputation	55%	55%	60%
Value for money	54%	49%	55%
Communication	46%	51%	60%
Enquiry Handling	74%	74%	75%

Table 12: Annual customer survey results (2022)

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

Improvement

We recognise that achieving these satisfaction performance targets depends upon fulfilling our asset management and corporate objectives and seeking continuous improvement in our security and reliability targets.

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[25] 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 customers' views to be better incorporated into our planning and asset management objective. 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 both price and service.).

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.

4.4 Delivery of the work programme

Over the past three years, total opex has been within 5% of forecast; however, vegetation spend has been below target due to resource constraints and Covid limitations, while system interruption and emergency expenditure has been above target due to storm events. Planned maintenance and vegetation management expenditure has varied up to 40% in any particular year.

Our network capital expenditure has been behind forecast over the past three years by an average of 24% ($3.3m) p.a. Table 13 shows the actual expenditure for the financial year to March 2022 compared to the spending projected in the AMP budget for the FY2021/22 year. This shows an overall outcome of a 27% below-forecast expenditure comprising a 35% underspend on network capital and a 5% above-forecast expenditure on direct opex. The two key reasons were delays in consenting to the Swayne Road diesel genset (for managing peak demand at Cambridge GXP) and several capital programmes were also delayed as internal resources were constrained during Covid and post Covid and there has been a focus on catching up on new connection work.

Given the forecast increase in opex and capex over the next ten years, improving work plan delivery is a focus for our business, see Section 11.5.

Item	Actual FY2021/22 ($000)	Budget for RY2022 ($000)	Variance as % of forecast
Capex: Customer Connection	4,061	3,738	9%
Capex: System Growth	1,826	5,701	-68%
Capex: Quality of Supply	49	1,298	-96%
Capex: Other Reliability, Safety and Environment	1,069	1,321	-19%
Capex: Asset Replacement and Renewal	2,455	2,656	1%
Capex: Asset Relocations	153	178	-14%
Subtotal - Capex on network assets	**9,613**	**14,717**	**-35%**
Opex: Service interruptions and emergencies	1,885	1,003	88%
Opex: Vegetation management	768	1,031	-26%
Opex: Routine and corrective maintenance and inspection	646	1,049	-38%
Opex: Asset replacement and renewal	470	519	-9%
Subtotal - Opex on network assets	**3,769**	**3,602**	**5%**
Total direct expenditure on our distribution network	**13,382**	**18,319**	**-27%**

Table 13: Summary of FY2019/20 expenditure vs forecast

Our non-network capital spend significantly exceeded the budget in FY2022 ($9.4m vs. $3.3m) due to the purchase of land for the new Hautapu GXP and land adjacent to Te Awamutu GXP for future development.

[25] *Net Promoter Score (NPS) measures the loyalty of a company's customer base from customers answering the question "How likely are you to recommend this company to a friend or colleague?"*

4.5 Comparative performance

The section also provides an assessment of relative performance against other businesses. The comparative performance analysis has been completed based on several metrics, with our business compared to the whole industry and a selection of distribution businesses of a comparable medium size and mixed urban and rural coverage area.[26]

4.5.1 Comparative cost performance

The comparison of the relative costs considers the level of reliability and the reasonableness of capital and maintenance expenditure. Figure 36 shows the total network opex (actual vs forecast) for our business (coloured dots) and comparable EDBs (the black circles) over a period of five years. The red circle is the FY2022 performance for our business, and the blue circles represent our historical performance. We have had lower operating costs than the industry trend (the dashed line). However, our costs are increasing, similar to general industry trend.

Our lower opex means we can review cost-quality trade-offs, e.g., restoration efficiencies and link to asset condition. Proactive asset replacement will improve customer reliability as equipment failures that require the replacement of the complete asset instead a small component will likely increase restoration time.

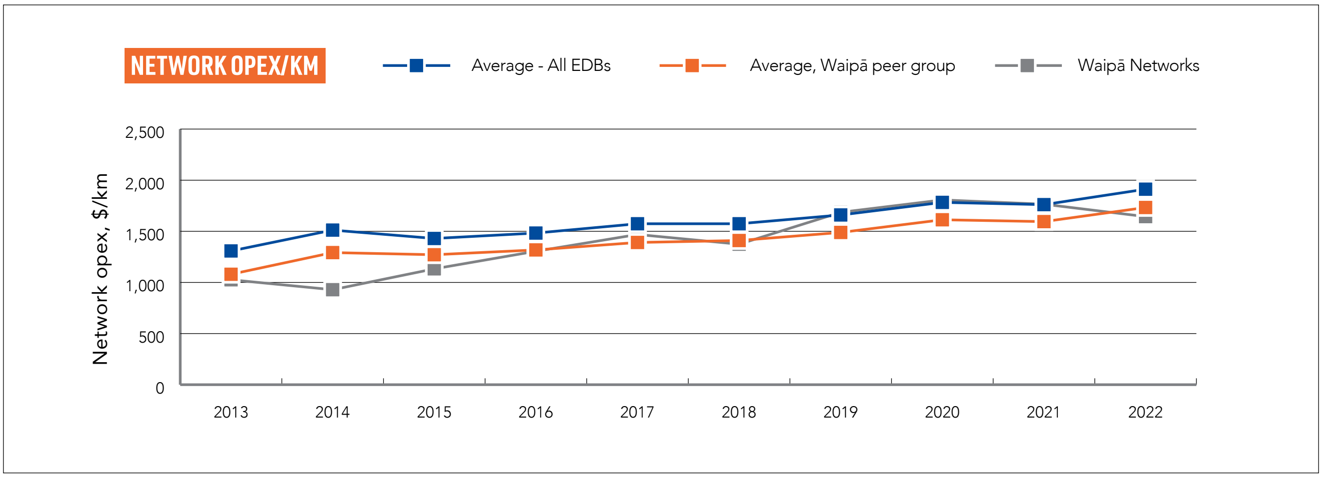


Figure 36: Network Opex/km

4.5.2 SAIFI comparative performance

Figure 37 and Figure 38 show the causes of faults over the past five years for comparable EDBs and for Waipa. The SAIFI trend in Figure 39 is in line with the industry cohort. Variations from year to year are related to weather.

We have higher vegetation and third-party faults than our cohort (Figure 37) and have increased vegetation maintenance expenditure to address the level of related faults. In proportion, we have a lower level of defective equipment faults, indicating our assets are in a reasonable condition compared to our cohort.

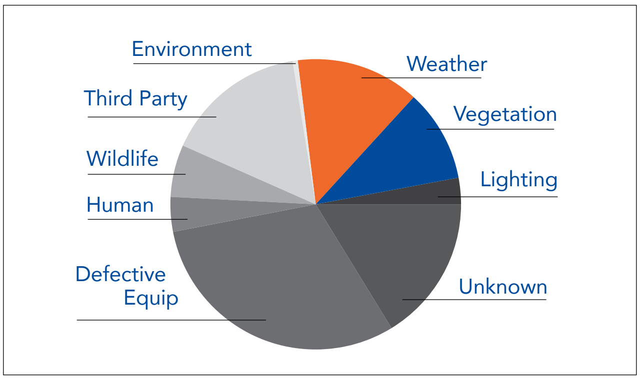


Figure 37: Outage causes for comparable EDBs (five-year average)

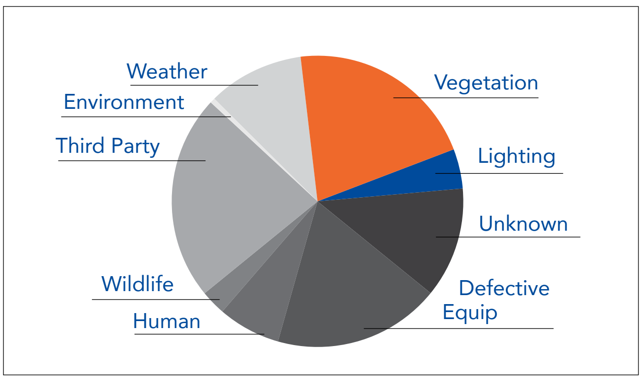


Figure 38: Outage causes for Waipā (five-year average)

[26] *Comparable EDBs by size and mix of customers (medium size/mixed customer) cohort includes: Alpine Energy, Counties Power, Electra, EA Networks, Horizon Energy Distribution, Mainpower New Zealand, Marlborough Lines, Network Tasman, Network Waitaki, Northpower, Powerco, Unison Networks, Waipā Networks, and WEL Networks.*

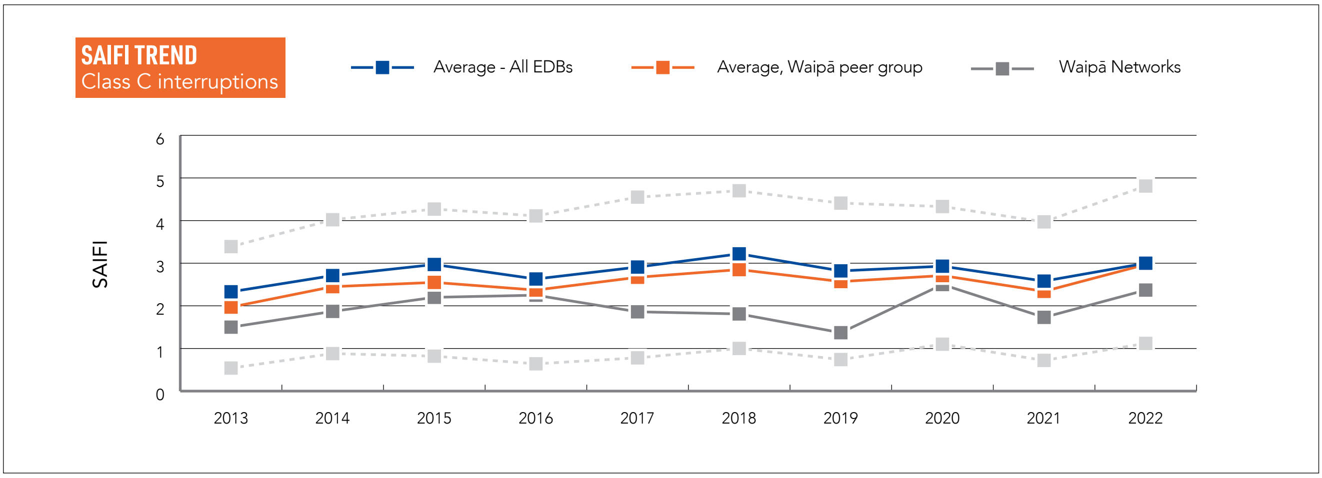


Figure 39: Our SAIFI trend

4.5.3 Network interruptions – number of faults

The number of faults on a network indicates the effectiveness of the maintenance and replacement processes. Figure 40 shows that for our overhead network, the group of comparable EDBs has steadily increased faults over time while we have had a steady trend over recent years. This indicates the effectiveness and adequacy of our maintenance and renewal undertakings to date.

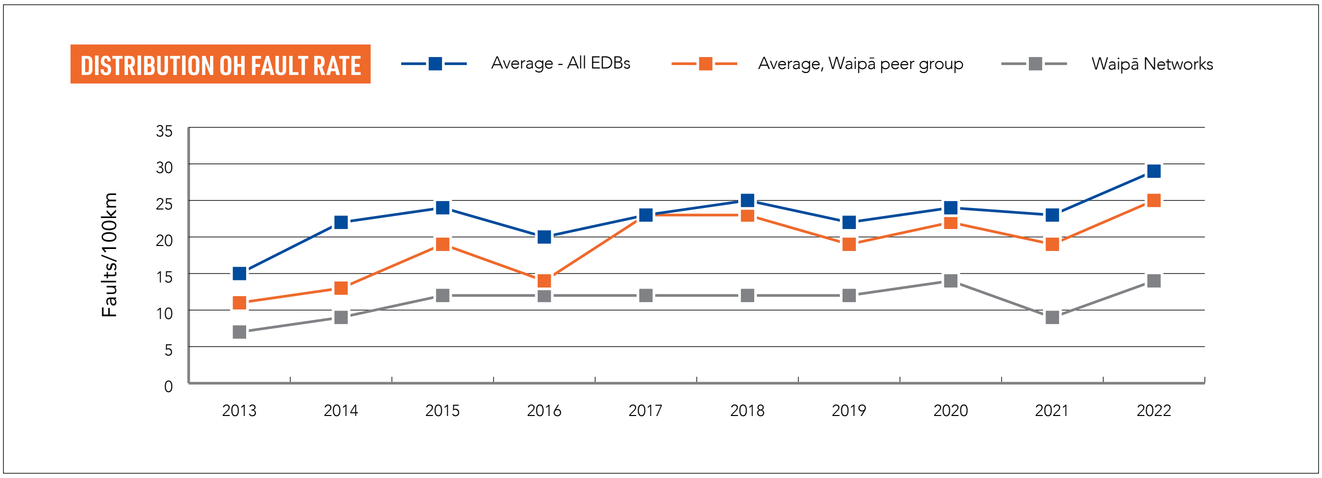


Figure 40: Fault rate trend for overhead assets

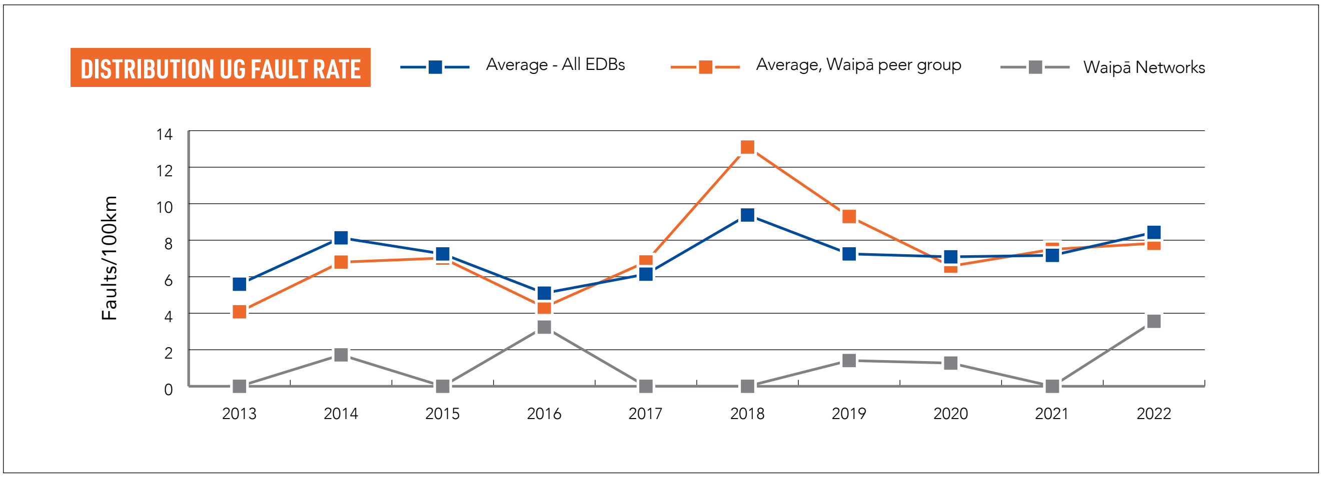


Figure 41: Fault rate trend for underground/ground-mounted assets

4.5.4 Revenue

The Net Revenue per ICP chart (net of Transpower charges) shows we (EDB26) have lower line charges per customer than comparable distribution businesses. This is partly due to our network's simple 11kV distribution architecture compared to networks with sub-transmission networks.

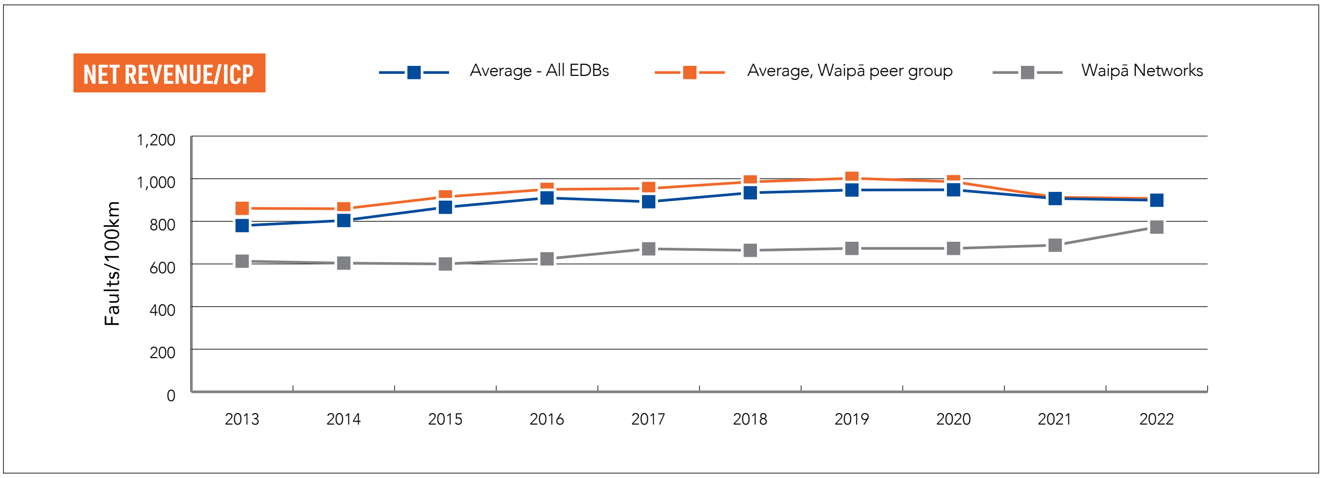


Figure 42: Net revenue per ICP (corrected to CPI)

PART 2:

STRATEGIES TO ADDRESS THE KEY ISSUES

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).

5.1 Asset management policy

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

Our Asset Management Plan is a critical document to deliver to these commitments and is regularly reviewed and updated. 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 security of supply that is required both 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.
- Has made adequate provision for funding and resourcing all phases of our network lifecycle for incorporating into our annual and ten-year budgeting cycles.
- Makes 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.

5.2 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 actively participate 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 in response to the contextual issues, and to 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 services 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.
- Optimisation of investments will be considered against the Energy Trilemma—i.e., trade-offs will need to be made, aided by more informed customer engagement.

5.2.2 Revised asset management strategy

The 2022 AMP described the asset management policy and four broad strategies (covering customer, asset lifecycle, delivery, and enablers). In this AMP, our asset management policy remains unchanged, and our four broad strategies have been replaced with our asset management strategy set out below.

The substance of our previous strategy remains intact, but the description has changed. Our strategies are more specific and relatable to our assets. 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 into AMP 2024.

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 subtransmission network to support high population and demand growth and future demand growth due to electrification.
   - Additional GXP capacity of 100MVA by constructing the new Hautapu GXP.
   - Reduction in maximum demand on existing CBG GXP
   - 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 further prepare for decarbonisation.
   - Complete a Waipā region focussed study to define electrification scenarios and inform demand and expenditure forecast.
   - Implement LV monitoring technology trials in collaboration with Ara Ake
   - Develop a pilot for operating flexibility services in collaboration with GridSight.
3. **Resilience:** Improve the resilience of our network to reduce the impact on the network of increasing incidents and intensity of adverse weather and increasing incidents of third-party damage as the economy increases reliance on electricity. This will lead to a reduction in the:
   - Asset failures during adverse weather
   - Vegetation related outage during adverse weather, and
   - Fault duration during adverse weather.
4. **Fleet management:** Develop comprehensive fleet plans and renewal forecasts to better manage our asset fleet. Increasing requirement for asset renewals:
   - Condition input data and health data prepared for key asset classes by FY24/25
   - Asset fleet plans for key asset classes in the 2024 AMP
   - Asset fleet plans for all other asset classes in the 2025 AMP
5. **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.
6. **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 experience with our organisation is often because of an outage or when they want to change their service level. 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.
- Where possible, 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 rely on the goodwill we create before such events occur.
- 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 intend to build on our relationship with our customers and other stakeholders to deliver better outcomes by continually improving the network performance, costs, and efficiency consistent with our corporate objectives.

Stakeholder engagement

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

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.

We provide a copy of our AMP to the following stakeholders on an annual basis to consult and gain feedback:

- Waipā District Council
- Waikato District Council
- Ōtorohanga District Council
- Waitomo District Council
- Waikato Regional Council
- Fonterra
- Architectural Profiles Limited (APL)
- Aotearoa Developments
- Major subdivision developers
- Transpower
- National Emergency Management Agency

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

5.3.1 Summary of planned customer engagement initiatives

Table 15 provides an overview of the drivers for customer and stakeholder engagement, the we take and the desired outcomes.

Customer Need or Event	Method of engagement	Desired planning outcome
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 Regulations 2003. Digital and print advertising campaigns across the region targeting proactive vegetation management- 3 x 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 approach to manage vegetation 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. Analysis and insights from faults 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.

Customer Need or Event	Method of engagement	Desired planning outcome
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 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 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: Engagement drivers, processes and outcomes

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 proactively 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 when compared to other benchmark EDBs by year ten.

Performance Indices	Target 2023/24	Target 2024/25	Target 2025/26	Target 2026/27	Target 2027/28	Target 2028/29	Target 2029/30	Target 2030/31	Target 2031/32	Target 2032/33
Overall Satisfaction	62%	70%	70%	70%	73%	76%	79%	82%	86%	86%
Reliability	80%	78%	78%	78%	80%	82%	84%	86%	88%	88%
Image and Reputation	60%	60%	60%	60%	63%	67%	71%	75%	79%	79%
Value for money	55%	54%	54%	54%	56%	59%	62%	65%	68%	68%
Communication	60%	56%	56%	56%	57%	59%	61%	63%	65%	65%

Table 16: Customer satisfaction performance targets

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

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. We will:

- 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 purposes of 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 43 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.

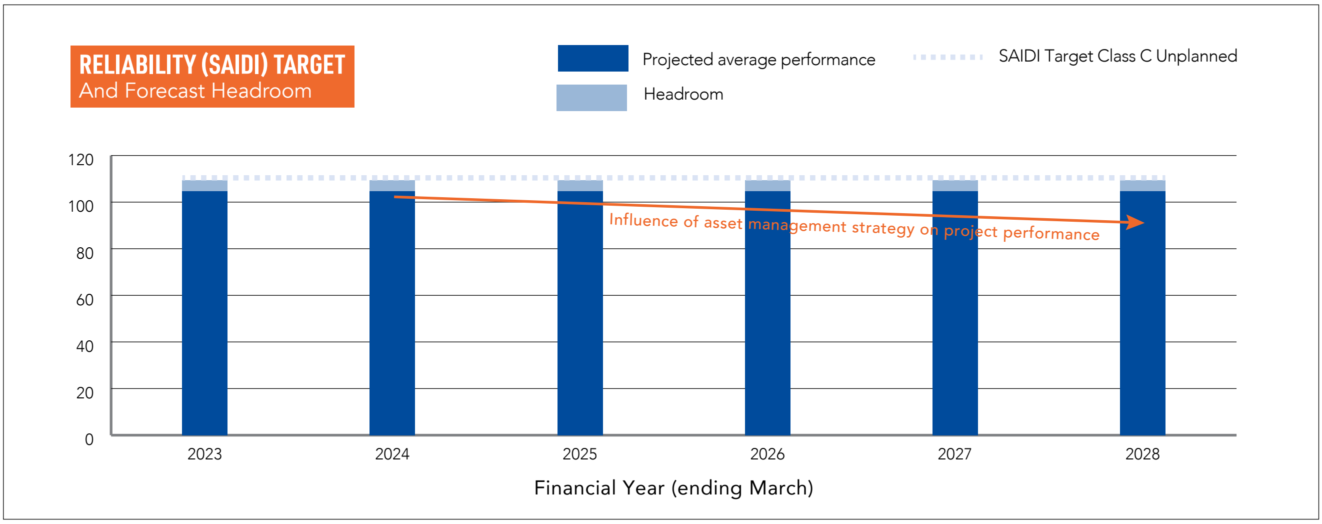


Figure 43: Target Reliability

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.

5.5.1.1 SAIDI and SAIFI targets

From FY21, we've adopted the DDP3 methodology to set performance targets, allowing better comparison with, 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 for planned interruptions 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. The historical performance data used to set the targets has been 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 2023/24	Target 2024/25	Target 2025/26	Target 2026/27	Target 2027/28	Target 2028/29	Target 2029/30	Target 2030/31	Target 2031/32	Target 2032/33
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 Asset delivery efficiency targets

5.5.2.1 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.

5.5.2.2 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 are the difference between metered sales to customers and metered purchases at each Transpower GXP plus 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.

	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Loss Ratio	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%	<5.7%

Table 18: System losses targets

5.5.2.3 System losses

System losses are currently of less interest to customers than reliability, although they ultimately impact the cost of supply. To a large extent, this performance measure is 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.

5.5.2.4 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 MD, a good load factor is essential to obtain economic use of assets.

Load control is used to control MDs to:

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

We'll use our load control to minimise the MD 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.

5.5.3 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	Target 2021/22	Actual 2021/22	Target 2022/23	Target 2023/24	Target 2024/25	How we'll be measured
Return on Total Assets	3.81%	3.30%	3%	3%	2.50%	Net surplus before interest and tax as a percentage of total assets
Return on Equity	4.60%	3.73%	2.60%	3.20%	2.80%	Net surplus after tax as a percentage of equity
Discount Policy	$5.15m	$5.4m	$5.3m	$5.5m	$5.7m	We will report on the discount paid to beneficiary customers during the year.

Table 19: Business efficiency financial targets

5.5.4 Delivery target

We're seeking to maintain delivery of maintenance and fault response work within 5% of the target (excluding major weather events) and reduce the planned maintenance and vegetation category variances of less than 10% over the next two years. We're seeking to improve the delivery of capital works to variances of less than15% over the next three years. A higher variance is being targeted due to the influences of consenting on project timelines.

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

5.5.5 Asset management maturity improvement targets

We are targeting 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). Figure 44 shows our current level of maturity and areas for improvement with targets for the next three years.

During FY2024, our focus areas for asset management maturity improvement are:

- Ensuring our asset management strategy is well aligned with our corporate direction.
- Enhancing asset management practices, including risk management,
- The preparation of our 2024 AMP will consolidate the final review, development, and alignment of programmes and projects against our asset management strategy.
- Information management and asset management systems improvement, see Section 7.12.

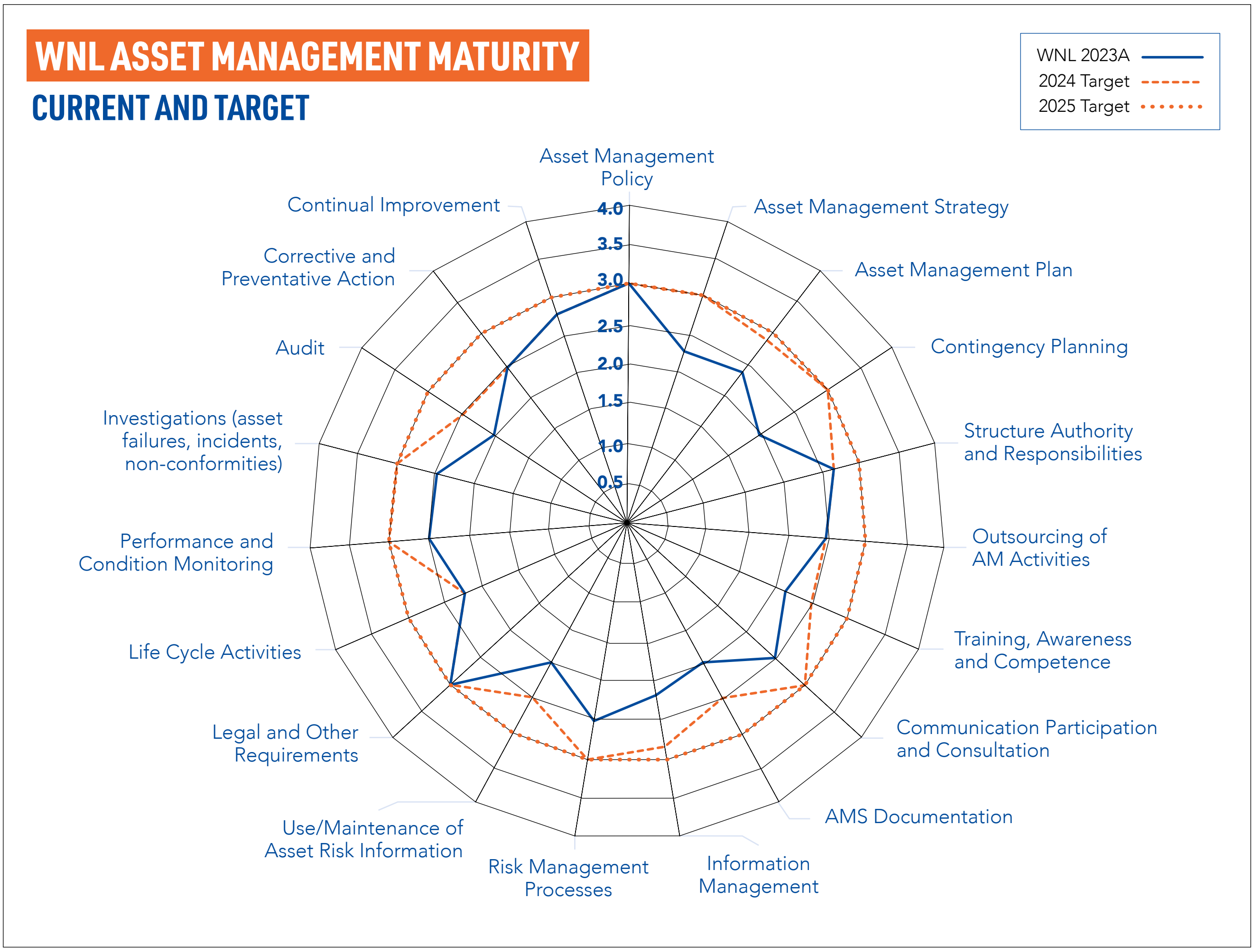


Figure 44: Asset management maturity

5.6 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 are supporting 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 of our customers are material issues for the business and our industry. The transition to a net carbon zero New Zealand will take time, it is critical that we develop a clear understanding of 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 are considering these factors.

5.6.1 Framework

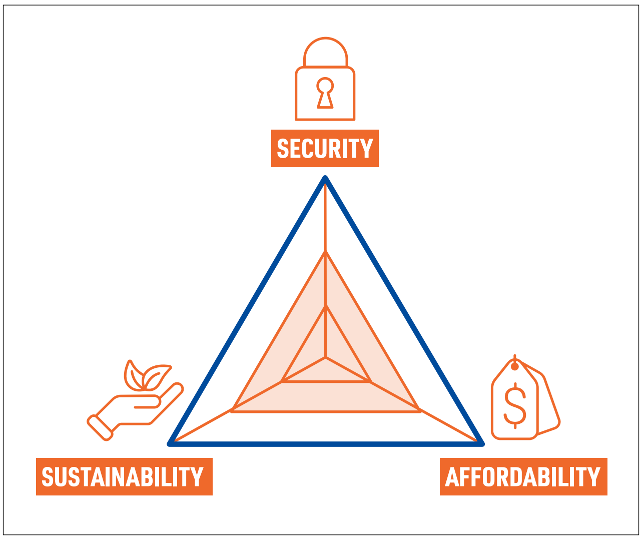


Figure 45: Assessment against the energy trilemma framework

The Energy Trilemma[27] is a well-recognised and useful framework (see Figure 45) when considering the energy transition. We have referenced this framework as it is aligned to the way in which 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 the development of NZ's Energy Strategy.

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).

5.6.2 How we are considering the factors

Figure 46 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 overall direction towards a sustainable and electrified future[28].** This will be supported by the asset management initiative discussed in Section 1.7: #1 (regional security) and #2 (energy transformation). This is also supported by our core investment into the network and asset management initiative #5 (asset management) to manage the increasing complexity resulting from the energy transformation.
- **Security and reliability are expected, by our customers, 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 supported by #3 (resilience) to improve the resilience of our network to climate-change-related impact.
- **Electricity distribution cost is likely to increase, but overall energy affordability should improve.** We therefore we need to focus on ensuring 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 affordability of energy should improve because of electrification[29]. We must ensure that the transition 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.

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

  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.

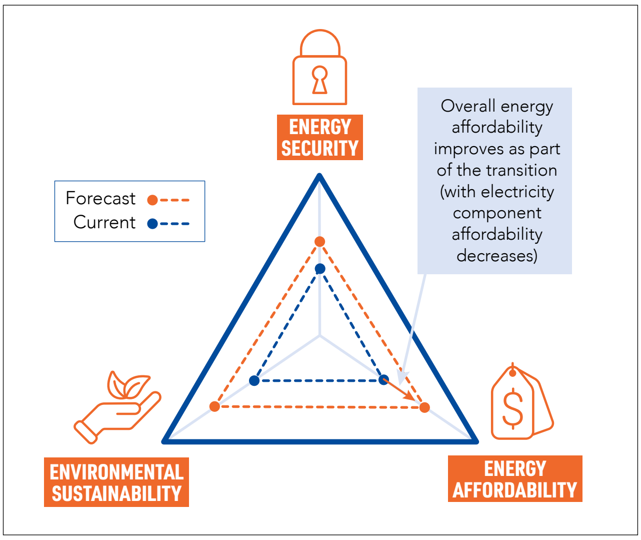


Figure 46: The energy trilemma

[27] *Source: World Energy Council.*

[28] *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*

[29] *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

Risks can be variable in their nature and scale. The conveyance of electricity (our core function) involves significant health and safety hazards, and the associated risks must be mitigated. We are also exposed to many business-related and other forms of risk.

6.1 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 47 shows the risk management process recommended by ISO 31000 and adopted by us.

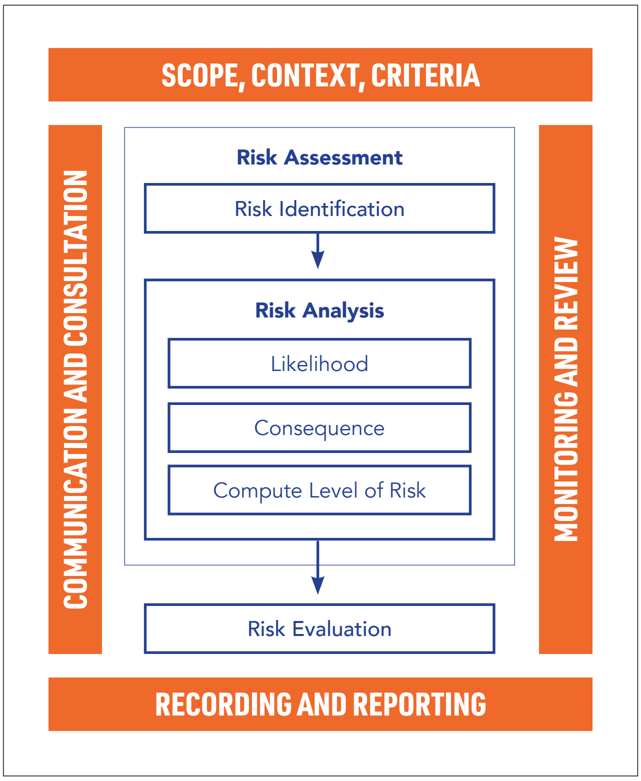


Figure 47: Risk management process

Specifically, we'll:

- Adopt a conservative risk position, especially regarding worker and public safety.
- Regularly review our company risk appetite and use the prevailing standard ISO 31000:2019.
- 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.

6.1.1 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 corporate objectives expressed through our Vision and Mission statements and our Statement of Corporate Intent.

The risk management process considers risks relative to the operations of our business, which are broadly grouped into the following risk category types:

- Health and safety, including public safety.
- Quality
- Environmental
- Financial
- Reputational
- Business interruption; and
- Regulatory compliance.

6.1.2 Risk identification

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

- On-site checklists before starting work (tailgates).
- Re-assessments during the day as our work environment changes.
- Regular visual hazard inspections of work areas.
- Analysis of accidents/incidents or near misses.
- Internal and external feedback.
- Condition assessment of our network to identify public safety risks.
- External information from specialists.
- Risk workshops and management review.
- External risk reviews.
- Industry information.

6.1.3 Risk analysis

Once risks have been identified, they're 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 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 the matrix described in Appendix C, which allows us to identify which risks we need to focus on (e.g., risks that fall into the High (Red) and Serious (Amber) categories).

6.1.4 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.

6.1.5 Risk treatment

Risks are treated either through elimination or the application of controls to reduce the risk's likelihood and/or consequences. Ongoing monitoring and review are undertaken to verify that this is being met.

For non-health & safety-related risks, treatments may avoid, transfer, reduce, remove, modify, or accept the likelihood and/or consequence of risk(s). Non-health & 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.
- Redesign.
- New or different technology.
- Training and education.
- Inspections or increased inspection frequency.
- Testing.
- Insurance.

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

6.1.6 Recording and reporting – Risk register

Health, safety, and environmental and corporate/organisational risks (including financial, reputational, business interruption and regulatory compliance risks) 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.

6.1.7 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 in respect of 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) procedure to identify the cause and better enable their prevention in the future.

The importance of both lead and lag indicators relative to safety is recognised within our business with an emphasis on proactivity (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.

6.1.8 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, e.g., with Fonterra.

6.2 Natural Hazard Risk Management Assessment

We're an active participant in the Waikato Lifeline Utilities Group as required by the National Emergency Management Agency (NEMA). Through consultation with other group members, we have assessed the potential physical threats to our network assets posed by naturally occurring hazards of wind, lightning, floods, land erosion, earthquakes, volcanic eruptions, geothermal activity and adverse weather. The methods used to assess the risk of each natural hazard are listed in respective sections below.

6.2.1 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 from time to time. 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 learnt during the severe storm that affected Counties Power and Vector in 2018 and cyclone Dovi in 2021. The impact of climate change in terms of intensification and increased frequency of weather events is expected to increase this risk over time.

6.2.2 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.

6.2.3 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 minimal, affecting only one or two poles at any time, which are relatively easy to reinstate. We are a member of the Waikato Lifeline Utilities Group. By participating in the group's risk assessment exercise, we assessed that floods and land erosion have not been major threats to our network. However, the impact of climate change in terms of intensification and increased frequency of weather events is expected to increase this risk over time.

6.2.4 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 post-event because rural 11kV pole lines are relatively easy and an inexpensive network asset to repair if an earthquake causes damage. Based on the experience of Orion in the Christchurch earthquakes, cable assets are likely to be extensively damaged in a severe earthquake, requiring a lot of time and effort to repair, with increased failures and reduced useful life after that. This is a lower risk on our network due to the percentage of underground assets.

6.2.5 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've 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.

6.2.6 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 is 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. There are some pad-mounted transformers 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 water level rise, 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 was 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 water level rise 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 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.

6.2.7 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.

6.2.8 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 findfault-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.

6.2.9 Weather impacts from climate change and increasing resilience requirements

We're already seeing the impact of climate change in terms of the increased frequency of extreme weather events. Also, warmer and wetter environment results in higher vegetation growth rates that can impact the effectiveness of established vegetation management programmes.

Increased electrification to support the decarbonisation of the economy will likely lead to increased dependency on electricity, and customers will be less tolerant of a loss of supply. Service levels will likely need to increase from current levels. Our future network will need to be more resilient and deliver reliability levels consistent with the future expectations of customers.

6.3 Network Risk

Network related 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.
- Other failures and operations (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. There hasn't been any change to the material risks to our network since our last AMP. Our key network risks continue to be:

- Demand exceeding Cambridge GXP firm capacity exceeded, resulting in a loss of supply.
- Demand exceeding our cable capacity at Te Awamutu GXP, resulting in a loss of supply.
- Vegetation contact with overhead lines resulting in a loss of supply.
- Overloaded customer LV fuse bases (old fuse holders, or additional new customer load) cause pillar fire, localised loss of supply and public safety risk.

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

6.3.1 Risk mitigation initiatives

Aside from the ongoing surveillance and monitoring of our network and operations, risk mitigation projects in this AMP include:

- Cambridge GXP re-enforcement via new 220/33kV GXP and our sub-transmission investment. Use of diesel generation at Swayne Rd (Cambridge) for peak-lopping as a non-network capacity support to manage Cambridge GXP peak loading in the interim.
- Te Awamutu GXP feeder cable capacity is limited by thermal constraints addressed by the replacement project planned for FY2024.
- Te Awamutu ripple plant ring main unit to provide alternative supply to mitigate switchboard failure risk.
- Te Awamutu GXP capacity and distribution network constraints, potential projects or non-network solutions being confirmed via development planning studies.
- Network inspection programme delay addressed by LiDAR and high-resolution photo aerial survey.
- Vegetation management programme to address priority areas identified through the LiDAR survey and creating a longer-term vegetation management strategy and increasing vegetation management expenditure.
- Additional voltage regulator and capacitor installations to manage 11kV network back feed capacity.
- Staged replacement of our two-pole distribution substations following a review of seismic safety and in consideration of both our asset condition and risk priority with the last site scheduled for completion in FY2024.
- Continuation of our pillar inspection and replacement programme.
- SCADA disaster recovery facility to increase resilience and single points of failure at Harrison Drive depot.
- Upgrade of the existing analogue-based communication network to a digital network via Microwave ring will provide resilience and high bandwidth to enable a safer, more secure, and more reliable voice and data network.

6.4 Contingency planning

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 which 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.

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 the control room, and work is dispatched through a call centre. System switch status is recorded on a single-line computer mimic diagram. Under extraordinary conditions, the control room and call centre functions may be disrupted and overloaded. During these emergencies, our administrative staff and field crews will need to perform network operations and fault dispatch functions.

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 will be disrupted, and direct communications with customers will be reduced due to the abnormal nature of the operation.

We operate our independent radiotelephone 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.

6.4.1 Emergency response capability

During significant storm events, Cyclone Drena in 1997 and the "weather bomb" of June 2002, we contracted external resources to help repair the network. We built our internal field crews and successfully reinstated our network during the February 2004, April 2011, January 2018, and February 2022 (Cyclone Dovi), February 2023 (Cyclone Gabrielle) storms. We have also liaised with three other local Electricity Distribution Businesses and one contractor to use their field resources if required.

We carry sufficient spares in our store to construct several kilometres of pole line.

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. In 2021, a complete review and update of our Emergency Management System were completed. We have developed the 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.

6.4.2 Security of supply participant rolling outage plan

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

6.4.3 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 simultaneously occurring 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 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.

6.4.4 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).

MagiQ is copied from production servers onto a backup server each day which is then copied 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.

6.4.5 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 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 is prepared to operate from these emergency sites to provide full control services in case one control centre goes down. WEL Control also has four laptops enabling the controllers to access SCADA via a secure cloud network.

Our SCADA network configuration and operating schematics are copied onto our administration servers and backup servers daily. A daily backup of SCADA network configuration and operating schematics information is held off-site, and we can recreate the SCADA network configuration and operating schematics after a catastrophic event.

We're currently investigating a purpose-built disaster recovery SCADA control room with a fibre or microwave-based communication interface independent of the Harrison Drive depot to improve the resilience of both voice and data networks.

7. ASSET MANAGEMENT SYSTEMS AND IMPROVEMENT

7.1 Introduction

We invest in support systems, including non-network assets to support our core electricity distribution network. These include information and communication systems. This section describes these systems, the approach we take to ensure these are fit for purpose and the associated 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. Softwareasaservice (SaaS) and hosted infrastructure solutions are used, when appropriate, to lower costs and reduce risk.

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

Our asset management process, see Figure 48, 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

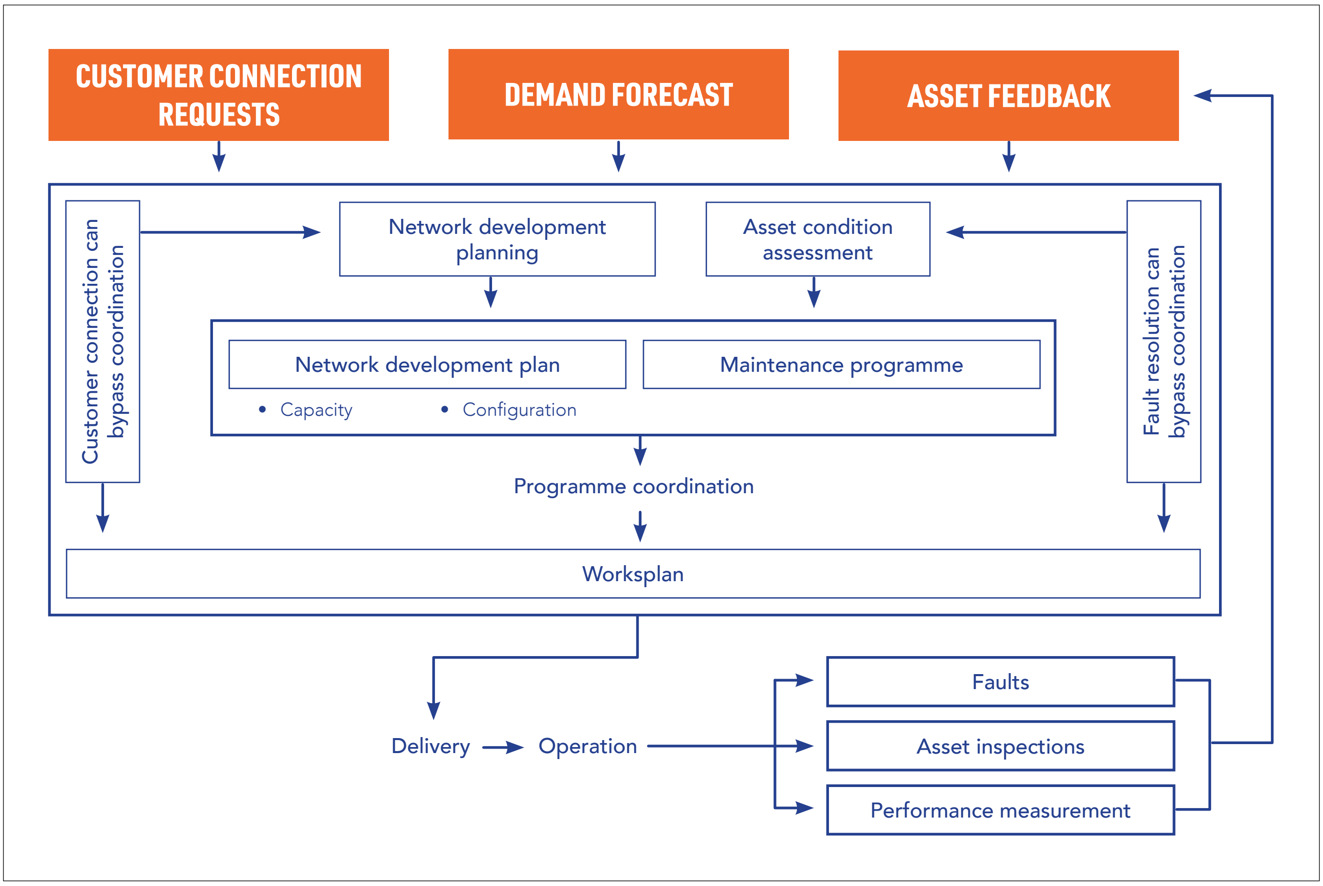


Figure 48: Waipā's asset management process

Our desired outcomes of these asset management activities are:

- Increased asset longevity.
- Improved network reliability.
- Improved network safety.
- Improved power quality.
- Technically efficient equipment to optimise electrical losses.
- Improved financial performance.
- Business growth; and
- To deliver a service that customers want.

7.2 Information security

Increased reliance on connected digital devices increases vulnerability to 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 improvement to the security levels of the SCADA system.

Status and business response

We are investing more in training, systems and processes that enhance cyber security monitoring and protection with the goal of reducing the likelihood and impact of a cyber-attack. This will reduce any impact on the continuity of service to our customers and help ensure our business is prepared and resilient when under attack.

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

- User awareness
- Increased security policies across identity/devices
- Realtime monitoring of technology across identity/hardware.

We are developing a full IT Disaster recovery plan to reduce reliance on the corporate network.

Our risk assessment process (discussed in chapter 6) identified cyber-security as having moderate consequences. Additional controls put in place include external review of security, remediation of any vulnerabilities, and regular monthly and quarterly audits.

7.3 Asset information systems

We operate asset management systems to manage our existing assets, plan network development and measure network performance. These comprise of 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
- Integration with our financial system.

Improvements in asset management systems to improve integration and reduce the need for staff intervention to integrate between data sources is required. Section 7.15 on Support Systems provides more information on our information system development roadmap, the Information Systems Strategic Plan (ISSP).

Table 20 shows a summary of existing asset management information systems that support these functions.

Asset Mgmt. System	Uses	Stored data
NCS	Enterprise database for • Financial applications and transactions (General Ledger, Creditors Ledger, Debtors Ledger, Banking Transaction processing, Payroll, Human Resources, Stores, Purchase Orders) • Customer information management • Planned outage notification • Works management	• 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	Integrated Data Warehouse	Backup copies of all data in NCS
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 to capture field observations on asset condition	Worksite safety plans, work permit (SWMS), defects/hazards*
MATLAB Network Data Management System	Network operational data extraction from SCADA: • Network loading • Node voltages and switch states	N/A
ETAP 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
Avalanche Outage Communication Platform	Communication Platform to update customers with known outage information and expected restoration times. This information is sourced from SCADA	N/A

Table 20: Waipā's existing asset management information systems

The systems are described in more detail in section 7.4 to 7.9

7.4 NCS

NCS is our enterprise database containing several modules that hold most of our asset and corporate information. The modules include:

7.4.1 Asset equipment database

Our Asset Equipment Database contains physical, electrical, location and valuation information on substations, transformers, switchgear, voltage regulators and sites. This Asset information is used for network design, asset valuation and disclosure.

7.4.2 Asset condition database

The asset condition surveys collect asset condition data, which is used as basis for asset health assessment. This information is recorded in the Asset condition database and is used to establish and prioritise our preventive maintenance program.

7.4.3 Outage database

Contains details of shutdowns that include switching instruction sheets for planned outages (that identify areas of the network affected), shutdown advertising notices, and the actual switching times for the outages. For unplanned outages the details are recorded by the Network Operator and checked by the engineering team then captured in the Outage database.

Customer numbers for both planned and unplanned outages are sourced from the ICP database. This data enables the calculation outage statistics for measuring network performance for disclosure purposes and to identify potential problems on the network.

7.4.4 ICP database

The ICP database is used by the Call Centre for daily operations and to provide information to the Outage database for the calculation of network reliability performance. The ICP database contains a complete history of all outages and associated customer comments.

ICP data comes from the customer, retailers, electrical inspectors, and our processes. The ICP database is continually updated with new and disconnected customer information.

7.4.5 Call centre database

We have contracted our call answering and dispatch activities to a remotely located Call Centre that relies on the ICP Database information for its operation. The Call Centre logs all incoming and outgoing dispatch calls in the Call Centre database.

7.4.6 Financial systems

We have the following financial applications with operational data stored in NCS:

- General Ledger
- Creditors Ledger
- Debtors Ledger
- Banking transaction processing
- Payroll
- Human Resources
- Stores and inventory management
- Purchase Orders, and
- Asset Register (financial and taxation)

7.4.7 Q (quote) database

The Q database serves as the works management system for creating work orders, cost estimation, stores/inventory integration, and workflow management.

7.5 MagiQ integrated data warehouse

The key function of the data warehouse is to provide a single repository for all data which is held in enterprise operational databases. All the databases archived in the data warehouse can be accessed through a web browser.

7.6 Geographic information system

In 2022 we implemented a Geographic Information System (GIS) in ESRI ArcView with the data format following the Utility Network Common Information Model (UN CIM). The UN CIM data structure allows compatible systems to access the same network model, reducing the effort required to implement and integrate the systems.

GIS holds physical location and electrical connectivity of all our network assets overlaid with property boundaries, and the assets' physical and electrical attributes.

Information in GIS is derived from information originally held in NCS, CAD, and results of network surveys for pole locations.

7.7 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 and enables our field services to carry out worksite safety risk management 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 preparation of printed documentation for site visits, and
- Improved confidence in system data.

7.8 Network modelling software

We use Etap 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.

7.9 Supervisory control and data acquisition system

7.9.1 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 who operates the SCADA system on our behalf.

The SCADA system also manages the ripple injection plants at both Cambridge and Te Awamutu to control the load over peak times at GXP and/or feeder level.

Our SCADA system comprises a master station and a "hot standby" backup station located in our control room, and two remote operating terminals located in WEL Networks Control Centre.

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 programmes, network development planning, and to measure network performance.

7.9.2 Condition, performance, and risks

The condition and performance of the SCADA system depends on the overall configuration of the constituent elements:

- **Communication:** media (fibre, radio) and RTUs: Current system is now at its limits and does not have adequate capacity for additional bandwidth requirements, see section 8.14. Our standard communications protocol for RTUs is DNP3.0, however, DNP is not fully utilised directly due to bandwidth limitations, and this is currently managed by converting DNP points to another proprietary protocol before sending to the SCADA hub.
- **Hardware:** SCADA front end and central server/ master station
- **Software:** SCADA operating system, applications, and operator interface: Life of the system depends on availability of support, and we have an on-going support arrangement for existing system. However, the system does not have capacity to support development of advanced functionality that may be required in the future.

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.

7.9.3 Operate and maintain

The SCADA system is continuously monitored through self-checking systems and a third-party monitoring system. The communications network is part of this monitoring system and alerts operators to communication failures or overloaded communications network. Our preventive maintenance schedule is outlined in Table 21.

Asset type	Maintenance description	Frequency
SCADA master station	Software upgrades, database checks	3 monthly
SCADA master station	Hardware upgrades follows IT server replacements	5 Yearly

Table 21: Maintenance schedule for SCADA equipment

7.9.4 SCADA contingency management

WEL Networks runs 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 the full control services. WEL Control also 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.

7.10 Asset management information

7.10.1 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 in developing asset condition data, asset health indicators and forecasts of network equipment renewal expenditure.

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, and this will be stored and accessible 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 need work to improve its accuracy and completeness. 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 defects information (that has health and safety implications) is captured via Assura. The data is used to drive corrective work and track 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.

7.10.2 Asset data and data quality

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

7.10.2.1 Asset data

We hold records for electrical assets and non-electrical equipment such as plant, 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 their condition is imperative in facilitating the safe operation of the network.
- **Reliability:** knowing the types of assets, their location, condition, their relationship (including connectivity) allows the assets to be managed effectively to assist in minimising failures and network outages.
- **Regulatory:** We are required to 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 better planning of maintenance and renewal activities.

Asset information is managed by our Engineering, Network information and administrative staff. Changes to assets (and some asset components in the field) are recorded by field crews and then passed back to our network information team to update the asset management system(s) as appropriate.

We review and update the information held by adding attributes for various assets when and where it becomes apparent that there would be benefit in holding that information. We manage relatively high volumes of low value assets which are geographically dispersed making invasive inspection techniques uneconomic. This means the scope for data collection is targeted to be mostly visual inspection records and high-volume aerial survey techniques.

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 generally must be extensive for the pole strength to be affected, but even a small exposure of steel within a pre-stressed concrete pole is considered cause for repair or replacement. Our inspection criteria reflect these different asset-specific risk assessments.

We also utilise information disseminated from organisations such as Electricity Engineers Association (EEA) and 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, there are limitations that include general limitations and known data limitations described below.

7.10.2.2 Data limitations

General data limitations include:

- 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 the restoration of supply from outages).
- 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 been lost at times, or during the transfer from one asset system to another, data may have been compromised or lost, meaning that asset records today are not always entirely complete and accurate. Whilst the existence of visible assets is known, for a proportion of assets, the installation date (for example) may be unknown. We have a good understanding of the asset information that is not complete or accurate. We do not currently have a programme of re-establishing this data as, in most cases, there is no viable way to determine it.
- Timeliness of inspections. Due to the rapid expansion of our network, inspection delays can occur if not prioritised. 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.

7.10.2.3 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 condition other than by 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, and 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 records, although this is a common issue across the whole sector for this particular asset class.
- **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 for the purposes of assessing condition alone, cable testing of distribution cables is generally not undertaken by us. As such, cable renewal is largely based on age, failure consequence and operating history of the cable sections.
- **Underground cable location:** Historically there are cables whose plotted location is less accurate than the current requirements under the Utilities Code.
- **Pole and cross-arm condition:** The condition of cross-arms in rural area condition 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 2023 by drone. Timber poles only account for a small proportion of the pole fleet, and an inspection program is planned for 2024. 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 prioritise safety.
- **We monitor industry practice and testing innovations and will review our approach should the situation change.**

7.10.3 Network surveys

Network surveys provide us with 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 completed the second asset condition survey on all feeders, and in 2021 completed the third asset condition survey of overhead and ground-mounted network assets. The 2021 overhead survey included 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.

In 2023 we will focus on surveying urban poles, our network surveys to find more effective ways of collating and using network condition data, and the survey schedules to ensure coordination with equipment inspection programmes for the different asset classes.

7.11 Documentation and control

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; and
- **Network instructions:** provide further instructions on constructing, maintaining, and operating network assets and processes.

All 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. We make the documents available to both internal users and external contractors and consultants. Generally, documents are intended to be reviewed every three years. However, due to their nature or criticality to business function, some documents are subject to more frequent reviews.

7.12 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 management of the business and the assets. We have developed an Information Systems Strategic Plan (ISSP) that includes a roadmap for improving and updating systems to provide new integrated features and capabilities. This work commenced in FY2021.

7.12.1 Information systems strategic plan (ISSP)

We completed a review of our asset management process and systems to determine gaps in functionality and identified a need to improve integration in asset management systems and reduce the need for staff intervention to integrate between data sources. We are improving our asset management systems by replacing legacy systems such as NCS with a new set of systems that can deliver capabilities, as identified in our information system strategic plan (ISSP). NCS sub-databases are being replaced with independent database systems with new features that enhance our asset management capabilities and structures that enable integration with other systems. The main systems to be upgraded/replaced are:

- NCS, and
- MagiQ Integrated Data Warehouse, and
- Abbey SCADA system

The Information Systems Strategic Plan (ISSP) has workstreams to identify and prioritise the required enhancement of asset management systems and includes a corresponding roadmap. Figure 49 shows the components of the ISSP.

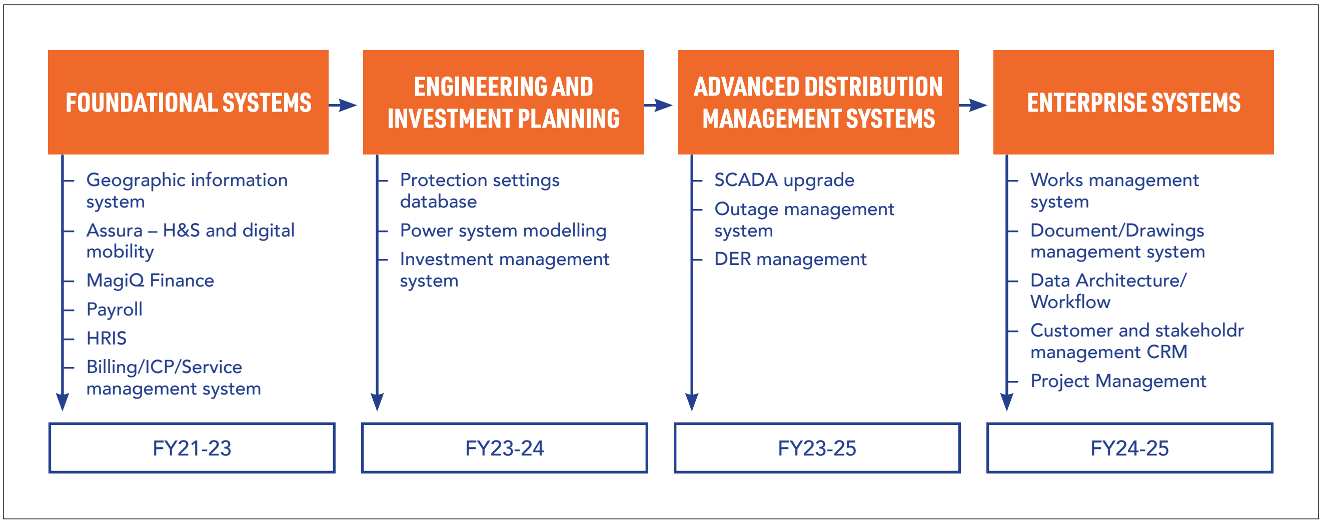


Figure 49: Information systems strategic plan overview

7.12.2 Foundational systems

We have identified information management systems we consider foundational in delivering our information systems strategic plan. We have completed implementing:

- **Assura:** health and safety, and digital mobility platform. Assura equips our people with access to information and process documentation in the field, and facilitates improved safety management and reporting.

  We plan to extend access to network asset information, geographic information systems, and to a work management system through Assura to enable field staff access to richer contextual information. We are also evaluating whether Assura may be utilised elsewhere across field work, e.g., capturing of as-built data in the field.
- **Geographical Information System (GIS)** that replaced AutoCAD drawings for network assets allowing better asset data management and access by users.

We have scheduled:

- **Implementation of ARC** - Billing, ICP Management SaaS Solution, to provide single platform view and automation of Billing processes, and increased security and management of ICP data.
- **Implementation of ARC (stage 2)** - Service Management (Faults) to improve fault management by ICP, improved job allocation, reporting and communication with customers. The Service Management system will replace the existing legacy Faults Dispatch system and provide significant improvements in functionality and efficient faults management particularly during major events such as storms.
- **Cloud based MagiQ enterprise database** due to go live in July this year.

7.12.3 Engineering and investment planning

The following are scheduled for implementation in the 2023-24 horizon:

- DigSILENT Powerfactory for network modelling and analysis with a link to GIS to sync asset data for updating the network model. In 2023 implement Powerfactory as a replacement for Etap. Powerfactory is widely used in New Zealand and enables more efficient, accurate and sophisticated power system analysis.
- Powerfactory will enable a more efficient, accurate and sophisticated approach to assess network impacts from the revised demand forecasts, outage requests, new loads, and distributed generation applications.
- Protection relay configuration management system – A centralised protection setting database and device management tool.
- Investigation of options for a system to manage investment projects from inception to delivery. This will assist in forecasting renewal expenditure for all asset classes, and support investment workflow (identification, evaluation, approval, and handover for delivery).

7.12.4 Advanced distribution management system (ADMS)

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 FY24 we will investigate:

- Requirements for the SCADA system from infrastructure to applications and future functionality
- Replacement for the SCADA system and operational arrangement to consider:
  - Future integration with GIS via a common information model
  - Incorporating the LV network into SCADA
  - Waipā owned and operated SCADA and OMS
  - Shared SCADA and OMS operations

  Enhanced field communication to support the SCADA system is discussed in Section 8.14.
- An advanced distribution management system (ADMS) that will integrate the core SCADA with other functions, including the outage management system (OMS) and the potential to 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.

7.12.5 Enterprise support systems roadmap

We are investigating requirements for business support systems and development options. The systems include functions for:

- Works management
- Data architecture and workflow
- Project management
- A drawing management system to manage standard design drawings, asset and site drawings, and project design drawings.

7.12.6 Asset information systems forecast expenditure

Modernising our information system is a significant undertaking. Actual capex amounted to \$1.8m across FY2021 and FY2022 and is forecast to be \$6.2m across FY2023 to FY2028. Our forecast IT related capex amounts to 8% of total capex over the next 10 years, reflecting the significance of the work.

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

8. NETWORK DEVELOPMENT

This section describes our approach and plans for network development to meet expected growth, reliability, security, and resilience.

8.1 Introduction

The historical setup of our 11kV distribution network presents challenges in planning and supplying power to connected customers. The 11kV network has been developed to a point where capacity in both current and voltage is reaching its design limitations in several parts of our network. We acknowledge this is a factor for a change in approach, and this AMP submission focuses on the projects we have programmed to mitigate the risks in terms of capacity, security, reliability and quality of supply.

The growth in demand is driving an increase in the requirement to augment network capacity, enhance network security, and mitigate future voltage constraints. In this AMP, we have defined the full suite of development planning criteria covering security, capacity, voltage, and reliability across all levels of our network. Our adopted criteria are consistent with industry standards for the size of demand served.

While larger projects such as the GXP and zone substation builds will assist with the quality of supply, in the interim, we are implementing short-medium term solutions to ensure we continue to serve our customers. This means continuing with installations of equipment such as voltage regulators and capacitor banks and preparing ourselves for the changes that larger projects will have on us as a network, i.e., staffing, training, equipment familiarisations, etc.

This section covers the following:

- The methodology we use to identify the need for network upgrades and the key considerations which form part of this process.
- The demand forecasts and the forecasting methodologies we use.
- A description of our network constraints and issues on our network.
- Network projects to address the growing demand, reliability, and security issues we are facing, as well as projects to ensure our systems and processes are streamlined.
- A summary of expenditure forecasts.

8.2 Network development strategy

8.2.1 Planning requirements and inputs

We have adopted planning processes and technical and engineering standards to ensure our network meets the following requirements:

- Capacity to convey electricity.
- Security of supply (probabilistic, n-1 or n), including providing the required operational flexibility and efficiency of operations
- Quality of supply limits (voltage and harmonic distortions within regulatory limits).
- Reliability: minimise interruption duration and frequency (SAIDI, SAIFI).
- Safety of the public, customers, and staff.
- Prevent unnecessary investment and minimise the risk of long-term asset stranding.
- Maximise fit with organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with regulatory requirements.
- Comply with environmental requirements.

Other inputs to our network development plans come from District Councils, Waikato Regional Council, property developers and major industrial customers. We use these sources in the following ways:

- The District Councils in Waipā's reticulation area have adopted a 30-year planning horizon for local development. We regularly assess the impact of these developments on our network and make submissions on these plans as appropriate.
- In response to the growth in the Cambridge area and interest from industrial customers, we have developed a comprehensive grid exit point capacity and sub-transmission network development plan to address the long-term capacity needs of our area.
- A similar grid exit point and sub-transmission plan are under development for the Te Awamutu network area.
- The impact of developers subdividing existing properties is assessed yearly.
- The two Fonterra dairy factories, our largest customers, inform us annually of their maximum demand (MD) requirements. Any significant increase in the long-term capacity requirements is discussed as they arise, and a solution is agreed upon between the parties.
- Major developments are monitored as they arise, with network development plans being developed to determine efficient supply methods. Examples are the Waikeria Prison upgrade, APL aluminium and glass joinery factory development, and industrial park development.

8.2.2 Materials

As our network comprises only 11kV and 400V reticulation assets, we need only buy equipment to cover these assets. Our equipment is chosen to comply with our network's load requirements and fault duty.

As we have several long radial rural feeders, we need to provide conductors of adequate cross-sectional area to maintain satisfactory voltage levels along and at the extremities of these feeders. Typically, for feeder sections out of Cambridge and Te Awamutu GXPs, we apply 300mm^2 Al cables and/or equivalent for overhead sections to achieve adequate fault rating, back feed capacity and voltage support.

Our main assets comprise cables, lines, reclosers, voltage regulators, ring main units, enclosed switches/ABS, and dropout fuses. Due to the simplicity of our network, it's cost-effective to limit the number of models for the equipment installed on our network.

When procuring materials, we will:

- Only use or allow onto our network, materials and equipment which meet recognised industry standards approved by our internal standards and policies.
- Endeavour to procure materials locally, where and when appropriate.
- Relative to the cost and other considerations, consider the total lifecycle costs of network components when assessing offers.
- Recycle materials where practical, considering the total lifecycle costs and risk.
- Purchase timber products such as poles from sustainable and renewable resources.
- Consider environmental impacts in purchasing and utilising items in our operations.

8.2.3 Asset configuration

To ensure assets meet short and long term needs, we:

- Work with Transpower to minimise our fixed asset requirements commensurate with providing customers with a reliable and secure supply.
- Where it is both feasible and economical:
  - Configure our network with flexibility for long-term asset requirements.
  - Seek opportunities to improve our network interconnection for security and reliability.
- Consider non-network solutions, including demand-side management and distributed generation.

8.2.4 Standardising assets and designs

Our network standards document the design and construction of network assets. Our network standards are used for assets where ownership and/or maintenance responsibility ultimately rests with us.

Our standards contain information and drawings for designing and constructing network assets. These standards are based on safety by design principles, i.e., consideration of safety at all stages of the equipment lifecycle at the design stage. This assists us in meeting our obligations under the Electricity (Safety) Regulations 2010.

Standardising assets helps us achieve the following:

- Safety from the use of proven construction and maintenance techniques,
- Improved reliability of supply targets through equipment with verified performance, and consistent operational approaches
- Cost efficiencies from reduced equipment inventories and having staff familiar with fewer asset manufacturers.

Our business, along with other New Zealand EDBs, has access to and the use of the PowerCo Contract Works and Network Operations standards library. PowerCo's documents are used to develop and update our standards where appropriate. This also increases the standardisation of practices across the industry for greater efficiency.

Table 22 summarises some of the key strategies for standardising our assets and designs.

Asset category	Standardised features	Standardising methods
Distribution,and LV lines	Standard suite of conductors/cables to selected from – generally available conductor/cables.	Our Design Manual. Other types not included in the standard need specific network review and management approval.
Distribution substations/ transformers	Size of transformers (pole-mounted) generally, dictate requirements for the supporting pole. Off-the-shelf models for network consistency.	Our Construction Manual.
Distribution switchgear	Selection generally from preferred suppliers of off-the-shelf goods – bespoke options avoided unless exceptional circumstances warrant.	Our preferred suppliers list.
Poles	New concrete poles are pre-stressed type. Load changes to existing wood poles or condition result in a replacement of the pole. Select from approved manufacturers and use limited pole types only.	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 22: Summary of standard strategies for assets/design

8.2.5 Strategies for asset efficiency

We monitor and consider losses in our system configuration and network development. In practice, the physical considerations (e.g., conductor size and pole spacing) and the requirement to deliver regulatory voltage take priority at the asset design and construction phases of the lifecycle, which determines the losses.

Demand management also plays a part in energy efficiency. Future increase in demand is factored into the capacity selection of new or replacement transformers.

We specify the power factor level that network users must meet to maximise utilisation efficiency. Similarly, maximum harmonic levels are specified for customer installations and to comply with statutory limits at the point of common connection.

We consider energy efficiency when purchasing and replacing future substation power transformers and the cost of the fixed and variable losses over the transformer's life.

Lines pricing incentivises customers to install transformers of an appropriate rating. However, in many cases, customers and their consultants prefer to over-specify transformer capacity in anticipation of future requirements (thus increasing standing losses).

Energy efficiency initiatives also pertain to electricity users. We don't have direct contact with most customers, limiting our ability to influence customer behaviour. However, we have Use of System Agreements (UoSA) with electricity retailers. As the local EDB, we advise customers through publications like newsletters.

8.2.6 Setting asset capacity

In determining capacity requirements, we monitor and review loading data across our network, assess trends in the loading data, and liaise with relevant stakeholders in the district (for example, the Waipā District Council around its development plans). The expected load is reviewed against the existing infrastructure to determine capacity constraints.

The theoretical starting point for providing new capacity is to build "just enough, just in time" and then add incrementally over time. However, as network assets typically have long lifespans, far more than the 10-year horizon of this Plan, we take these practical considerations:

- The standard size of many components.
- The ability of our business to obtain a commercial return on investment.
- The one-off costs of construction, consenting, traffic management, access to land and reinstatement of sealed surfaces make installing additional capacity preferable to returning in short to medium term.
- The addition of extra capacity can, in some cases, require complete reconstruction, for example, where a larger conductor requires stronger poles or closer pole spacings, leading to considerable increases in the total cost of ownership if an incremental approach is used at the outset.
- The need to avoid overload risk. Overload can lead to asset failure, service capability reduction and reduction in asset lives.
- In terms of some items, e.g., power transformers and underground cables, the marginal cost of providing additional capacity for the future is typically small relative to overall project costs.

Our guiding principle is to balance minimum investment ahead of demand by minimising our asset's costs over its lifetime. In many cases, the investment cost before requirements is preferable to investment after asset failure or customer supply is lost.

More detailed criteria are considered at the asset level in determining asset capacity. Some of these are summarised in Table 23.

Asset category	Criteria to assess capacity
Distribution and LV lines	Existing loading, growth forecasting, health and safety considerations. Surrounding land use (man-made or natural environment), climatic conditions, topography.
Distribution and LV cables	
Distribution substations and transformers	
Distribution switchgear	
Transformers/ switchgear/ buildings	Expected future fault and load levels – generally only available in step sizes.
Conductor	Conductor mechanical loading (i.e., size of conductor and span lengths drive pole size), environment, loading from other sources (i.e., steady-state and/or dynamic loads).
Cables	Current loading, expected future growth and demand forecasting.

Table 23: Example of criteria used to determine the capacity of network assets.

8.2.7 Network resilience

Building network resilience[30] is an important asset management strategy (#3). As the reliance on electricity increases, the resilience of our electricity network needs to improve to meet future customer needs (with a particular focus on reducing the effect of high-impact and low-probability events that can have a large economic impact).

The resilience work and the regional security strategy (#1) overlap, as network security improvements generally make our network more resilient. Our resilience strategy also encompasses work on climate change adaptation. Our work on adaptation is in its early stages and will include network design standards reviews and environmental hazard assessments. The use of automation to deliver fast restoration of our network after a severe weather event is also part of our resilience initiatives.

Improving resilience is a wide-ranging programme that will be fully scoped, during CY2023 and implemented over the next decade. Some specific work concerning network criticality, network adaptation, segregation and automation, control system disaster recovery and analysis of third-party damage is underway. The 2024 AMP will provide visibility on our resilience maturity and set out the results of our assessments completed and the potential implication of our resilience improvement programme on network expenditure.

8.3 Investment selection and approval process

Potential projects come from various drivers, including customer requests, load growth, examination of existing constraints or limitations within our network, and asset condition.

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 50 shows the stages of our investment approval process.

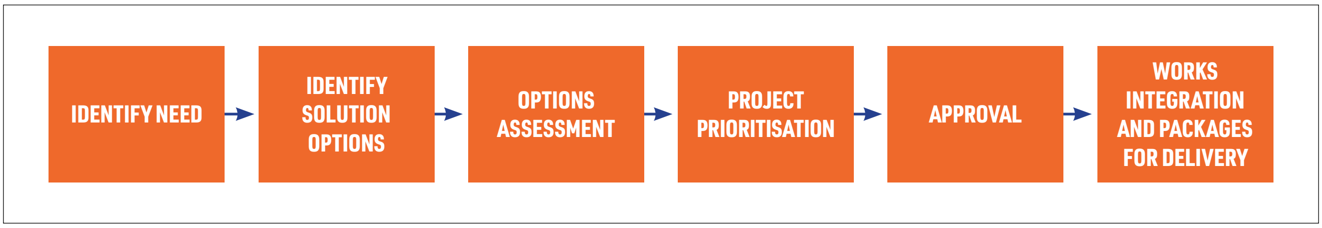


Figure 50: Investment selection and approval process

8.3.1 Need identification

Customer engagement gathers information about future demand, distributed generation, and opportunities for load management. This is compared against existing network capacity and asset condition to set the context for identifying investment needs.

Transpower's GXP capacity and our network development capacity are assessed with load flow analysis to determine when an asset will become constrained.

- Capacity Constrained Feeders

  We deem that a feeder has reached its capacity constraint when its 10th MD is forecast to exceed the maximum thermal rating of its switchgear, cable, or overhead line.

- Voltage Constrained Feeders

  We deem a feeder reaches its voltage constraint when the delivered voltage levels anywhere along the length of the feeder fall below the minimum limit of ±5% and prescribed regulatory voltage of ± 6% for LV networks at peak demand.

- Security of Supply Constrained Feeders
  - Our security of supply objective for 11kV urban and suburban areas and other 11kV lines where interconnection can be provided economically is switched n1. This provides security of supply in the event of a fault close to the GXP or the feeder circuit breaker being removed from service for maintenance.
  - The practice of limiting 11kV feeders to be loaded up to 66% of their rating so that there is the ability to switch the load to two (or more) adjacent feeders accounts only for thermal capacity, therefore, is not used as the only criteria for capacity, but voltage performance is also considered. Load flow analysis of back-feeding Cambridge feeders showed that voltage is often a key limiting factor for back-feeding.

[30] Resilience is defined as "the ability of assets, networks, systems, organisations, and people to anticipate, prepare, absorb, adapt to and / or rapidly recover from a disruptive extreme event."

8.3.2 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. Possible options categories are:

- Non-network solutions, e.g., demand management, embedded generation, etc.
- Upgrade to existing assets
- New assets, and
- Decommissioning assets.

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.

Investment in voltage regulators and capacitors to achieve security of supply through back feeding is a relatively much lower cost than providing feeder interconnections or constructing new feeders. However, some longer rural feeders are encountering voltage limits, and it is imperative to investigate alternative solutions for the long-term ability of our network to continue to meet forecasted demand. Solutions to security issues will be economically tested where the cost is high or the security benefit provided is modest.

8.3.3 Options assessment and project prioritisation

8.3.3.1 Conflicting interests

Most activities result in a need to balance several different factors, e.g., quality, cost, and time. Finding a balance acceptable to all stakeholders requires that various solutions are carefully considered, and priorities evaluated according to specific circumstances and environments.

We select the preferred option using a cost/benefit assessment which provides a framework for managing conflicting stakeholder expectations and interests. The assessment focuses on the whole-of-life cost of each investment option to identify the one which maximises net benefit. The level of analysis depends on the size and risk of the projects.

The drivers of the work are considered, along with the benefits to stakeholders. Table 24 summarises the priority that the Waipā places on these drivers.

Description	Comments	Rating (10 = highest)
Safety	We will not compromise the safety of staff, contractors and the public. Safety is fundamental to how we undertake our activities and has the highest priority.	10
Supply quality	Customers require stable voltage levels free of harmonic interference for their electrical plant and equipment to work.	9
Capacity	Overloading can lead to overheating, reduced asset life, fire, explosion, or loss of supply.	8
Reliability	Customers want a reliable supply.	8
Security	Customers want a reliable supply.	7
Environmental	Managing the impact on the environment is a key part of our values, especially in highly sensitive areas and seeks to eliminate or mitigate the impact of our operations on the environment.	6
Energy Efficiency	Medium customer-density EDBs like us have relatively high numbers of transformers, all of which incur losses regardless of consumption. Energy efficiency is considered during the design and purchase of network assets. We also seek to maximise the efficiency of our network through operations, notwithstanding the limitations of our network's physical constraints.	5
Renewal/ end of life	Lower priority if it is safe, has adequate capacity and voltage, and has low costs.	4

Table 24: Considerations in prioritising projects

We recognise the need to operate as a successful business and earn a realistic commercial rate of return. This ensures that funding will be available for future activities and that ongoing supply continues to be available to consumers.

In assessing the potential benefits of the work, consideration is also given to the number of affected customers, the total kW/kWh, and the impact (if any) on revenue/costs, e.g., reductions in maintenance or increased line charges.

The assessment typically covers a 20-year timeframe, but as this is less than the expected life of most of our asset classes (e.g., concrete poles have an expected life of 80+ years), we also consider a view of the potential needs of our network in the longer term.

8.3.3.2 Transmission

We prioritise Transpower's new investments for transmission assets that supply our network, and our network development projects by combining the number of customers affected and when Transpower's transmission, GXP assets and our feeder assets become constrained.

These predictions are made by analysing the following:

- Transpower's transmission line security level.
- Transpower's GXP maximum demand growth.
- Our feeder load trends.
- Customer-driven work.
- Our feeder reliability (SAIDI, SAIFI) performance.
- Our feeder security level.

We then prioritise and schedule projects so that our assets are not constrained, and solutions are implemented promptly.

8.3.4 Approval

Our engineering staff identify and develop the projects, and complete budget pricing annually. The benefits are assessed using the criteria above, and projects are ranked accordingly. From this information, a draft plan and budgets are developed. Our CEO reviews this before being submitted to our Board for approval. Once a project is approved, it's included in our annual business plan.

8.3.5 Delivery

8.3.5.1 Delivery resource

Our delivery strategy includes utilising our internal contracting group, which understands our local community and network geography to deliver value to our customers and stakeholders. Where we lack expertise, we use reputable third parties who understand our needs and value health, safety, and service similarly.

We periodically review how we manage work activities for maximum efficiency and what spare inventories we need. Progress on the works programme is tracked on an ongoing basis (both in the active implementation phase and planned projects) to ensure that expenditure is within budget limits and planned projects are still relevant.

Monthly reviews are undertaken by engineering and finance staff to manage the status of Capital projects and capitalise or expense costs when and where appropriate.

8.3.5.2 Stakeholder engagement

All engagement is planned for and coordinated following our stakeholder engagement strategy. Following identification of options, plans for stakeholder engagement can be enacted, i.e., engagement with customers, landowners, councils, iwi, and broader project communications.

When the preferred option is chosen, further engagement may be undertaken with landowners and the community on the proposed works.

8.4 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 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 any voltages or harmonics outside regulatory limits, interfere with network protection systems or inject fault currents above network capabilities.
- Generator owners must provide protection against over and under frequency, overcurrent, phase-to-phase faults 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, while 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 emergency situations 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. This type of distributed generation has had little effect on our network, given the low levels of penetration to date. Still, high voltage issues on LV feeders have been observed and this remains a potential issue with increasing penetration.

8.5 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. The use of non-network solutions, where appropriate and economic, 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 network demand and energy consumption by customers within their installations. We use our load control system to reduce maximum demand on our network effectively moving load to low load periods. This has the effect of deferring need for demand-driven network investments.

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, to address network constraints. The approach of tendering for market provided non-network solutions will be considered when opportunities are identified.

8.5.1 Operation

We recognise that the scale of individual installations for non-network solutions may not be able to deliver effective network support, therefore will consider a portfolio approach to utilising the available non-network solutions.

8.5.2 Line pricing incentives

We offer incentives for non-network solutions through pricing tariff, 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 was 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.

8.5.3 Customer advice

Our website (Info for Customers/Energy Efficiency) contains suggestions for customers to save power without adversely impacting on their lifestyle.

8.5.4 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 economic to do so.

8.5.5 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 utilises 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 driving a case for short term renewal.

We don't currently have plans for any significant investment in RAPS within the next five years.

8.5.6 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 the services we provide.

8.5.7 Uptake of new technologies

The factors driving the uptake of new technologies are likely to result in a need for evolving asset management practices within the period of this AMP. However, plans can be adapted as the technology becomes established and its effects more certain. We will continue to monitor these technologies and consider how our network can best be managed to give maximum benefit to all stakeholders. We anticipate that a degree of investment will be required to accommodate EVs when their additional demand increases.

The main issue from a strategy perspective is that the future take-up rates for these technologies is uncertain with no trends yet to build on. We are mindful of this and will continue to monitor developments closely.

In addition, the cost of the acquiring/implementing non-network solutions needs to be balanced with the need for cost reflective network prices as signalled by the Electricity Authority.

8.5.8 Learning from others

We follow the work of a national industry group considering the potential impact of new disruptive technologies and the way network assets will be operated and managed in the future. Technologies which are becoming increasingly available and affordable are expected to impact our network. These include distributed generation (photo-voltaic, in particular), wind generation and electric vehicles, and storage batteries.

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 networks 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.

8.6 Network planning process and criteria

Our planning process forecasts expected demand, and identifies changes needed to accommodate growth on our network and serves as the first step of the full investment approval process (IAP) as discussed in section 8.3. Figure 51 shows a high-level overview of our network planning process steps.

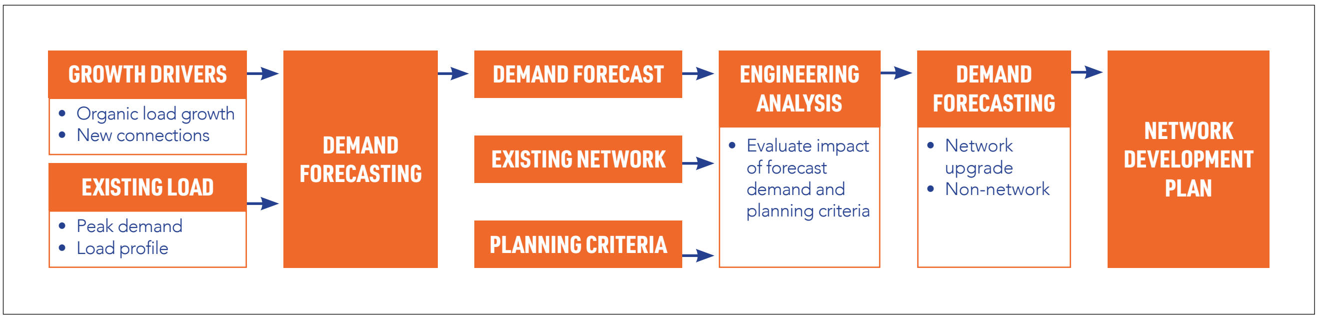


Figure 51: network development planning process

8.6.1 Demand forecasting

Demand forecasting provides a target for network development plans. Section 8.7 provides details of our approach to demand forecasting.

8.6.2 Planning criteria and standards

While Transpower owns the Grid Exit Points (GXP's) that supply Waipā,[31] we must operate our network within the capacity and security limitations within these GXP's. Therefore, our planning criteria needs to consider Transpower 110 kV assets and are based at the current levels of supply – 110kV,11kV and 400V.

The planning criteria seeks to provide network capacity, maintain supply quality, increase asset utilisation, reduce system losses, balance between capital and operational expenditure, and match the security of supply with customer requirements. Table 25 summarises the elements of the planning criteria in terms of the triggers where investment is required.

[31] Transpower/Waipā asset demarcation is at the 11kV cable termination at the GXP.

Network Element	Capacity	Security	Reliability	Voltage	Location
Sub-transmission and transmission[32]	Load exceeds 100% of normal rating.	N-1 Use short-term rating	Fault rate above industry standards.	Voltage drop that cannot be compensated for at substations	Load cannot be reasonably supplied by distribution configuration therefore requires new sub-transmission lines or cables and substation.
Distribution Feeders	Load exceeds 66% of thermal rating more than 3000 half-hours per year. Load exceeds 100% of thermal rating more than 10 consecutive half-hours per year.	TBA	Fault rate above industry standards and/or identified as a worst performing feeder.	Voltage at HV terminals of transformer consistently drops below 10.5kV and cannot be compensated by local tap setting.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables.
Distribution substations	MDI or data logger readings exceed 100% of nameplate rating	N/A	Fault rate above industry standards	Voltage at LV terminals consistently below 1.0pu.	Substation is not efficiently located in relation to load
Low voltage system	Load exceeds 100% of thermal rating.	N/A	Fault rate above industry standards	Voltage at point of supply consistently drops below 0.94pu. Voltage is normally the constraint on LV feeders.	Existing LV circuits do not reach new customer.

Table 25: Planning criteria

8.6.3 Engineering analysis

This step assesses the impact of the forecast demand on our network through power flow simulations and performance evaluation against planning criteria.

Engineering analysis identifies potential constraints – the need for network upgrades, and solutions that relieve the forecast constraints. Non-network solutions are also considered, and potential benefits tested through engineering analysis.

8.6.4 Project considerations

Once a need is confirmed and solution options identified, the options are compared based on the following criteria to determine the priority of the solution and the development path that we will take.

- **Network strategic goals:** Consider whether the project outputs contribute towards addressing our strategic goals i.e., alignment with asset management strategy, business plan and targets etc.
- **Capacity:**
  - enhance supply capacity within our region.
  - reduce congestion on existing infrastructure.
  - address local supply i.e., LV network.
- **Security/resilience /Reliability:** Predominantly this is considerations into:
  - ability to maintain supply to customers.
  - effects on SAIDI and SAIFI
  - our networks' ability to withstand extreme weather.
- **Capital cost:** consideration into the best financial cost to ensure we are providing value for money for our customers.
- **Risk:** in terms of safety, reputation, compliance, and operations.
- **Visual impact / consents/ land acquisition / public opposition:**
  - Ultimately, we are a consumer-owned entity and consideration on the communities' thoughts and the effect projects will have on our community image must be considered.
  - Projects which fall under the local consenting process must first be approved by the local council. This process is relatively early within the project viability phase.
- **Project timeline:** Considering equipment supply lead time, urgency on the factors above, and the actual delivery time.

8.6.5 Prioritisation criteria

Following the project consideration phase, projects are then programmed within (or sometimes outside) the planning period. The prioritisation of the projects is based on several factors, including:

- Elimination of risk (where priority is given to projects that eliminate or minimise critical risks, including health and safety risks).
- Connection of customers (typically a customer contributes which ensures the connection is economic for us and existing customers). For projects which require network upgrades, we will consider our existing assets condition and age and may contribute as described in our connection policy.
- Business benefits (where priority is given to improving reliability and security).
- Deliverability.

[32] *The GXP assets are Transpower-owned, and Waipā must consider these triggers to plan for alternate supply scenarios.*

8.7 Demand forecasts

8.7.1 Introduction

Network development comprises projects to support customer connections that heavily influence maximum demand growth, and the projects required to ensure that our network meets regulatory requirements and equipment continues to operate within its design specifications. Over the last 10 years we have connected on average 520 customers per annum onto our network, which is a significant number compared to the overall ICP count within the region. Through this growth, maximum demand within our Waipā region has been growing at a rate where the existing infrastructure (in some areas) is now reaching its limits.

System demand is forecast to increase from 90MW in FY2022 to 148 MW in FY2033, which equates to a compounding annual growth rate (CAGR) of 4.6%. This growth is below that included in the FY2022 AMP but remains high. The forecast demand is driven by a continuation of the strong historical growth in connections (as there are presently no indicators of a decline.

Growth is driven by a mixture of residential developments, industrial growth (APL, Fonterra) and urban densification (infill builds). Our forecast is aligned with the local council's strategic growth plan and new industrial demand associated with new development in Hautapu, expansion of existing industrial customers, and the likely decommissioning of a co-generation plant at Fonterra's Te Awamutu site in 5-10 years.

The new industrial demand amounts to 26.5 MW, 18% of the demand in FY2033. There is some uncertainty around the industrial demand forecasts, as whilst the growth was identified in consultation with customers, it is still subject to various consents and approvals.

Our demand forecasts still need to specifically identify the electrification of process heat, residential and commercial gas, or the impact of changes in hot water demand response and controllable distributed energy resources (DERs). Some considerations for EV charging have been included. For the FY24 submission we will include forecasts which incorporate distributed generation, electric vehicles, and provide an initial view into process heat conversion estimates.

While visualisation of the exact energy requirements for these elements is uncertain, incorporating these factors into the forecasts will provide a better understanding of infrastructure requirements.

In this AMP we discuss forecast maximum demand at a GXP and feeder level and provide any assumptions we have made, as well as the likely impacts this will have on our existing infrastructure and expenditure.

8.7.2 Factors influencing network demand

8.7.2.1 Distributed generation

Distributed generation connections have been increasing at an exponential rate in terms of capacity connected in the last three to four years, see Figure 52. Based on this trend we have forecast additional small-scale connections of 1-2MW per annum for the next five years. In addition, the existing 11kV based network architecture limits the integration of larger applicants (>1MW). This is likely to change with the installation of new zone substations and sub-transmission line on our network.

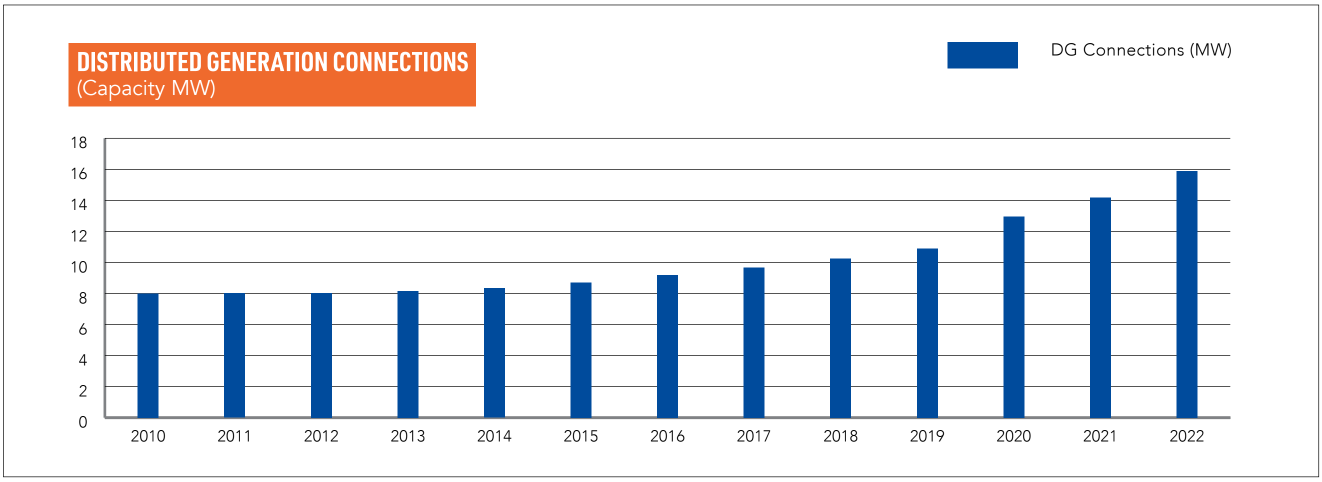


Figure 52: DG Connection Capacity (MW)

As of 1 January 2023, there is roughly 7-8MW of predominately small photovoltaic distributed generation connected to our network.

Additional larger connections on our network include:

- A 7.5MVA[33] co-generator at Fonterra Te Awamutu dairy factory is directly connected to the Te Awamutu GXP via two 11kV dedicated feeder cables. This generator has no effect on our other network assets, but it has an impact on the demand at Te Awamutu GXP.
- Standby diesel generation of 3 MVA has been connected on the Hautapu Fonterra feeders to assist the Cambridge GXP during peak periods. Note: This has also been excluded from the above graph due to its operating period and function.

Historically the capacity of distributed generation (Specifically solar) on our network wasn't sufficient to warrant inclusion into forecasts. But (as above), with the current and forecast capacity being a material figure we will be looking at this piece of work in the following year(s).

8.7.2.2 Electric vehicles

The transportation sector utilises a significant amount of energy, and electrification of transport to achieve decarbonisation targets is expected to introduce significant load growth on our network.

The impact of EVs on our network remains to be determined and depends heavily on the level of EV adoption in our network area and the time of charging. Without effective demand control and incentives for off-peak use, peak demand could increase significantly. Increased electrification also alters the load diversity that is assumed in sizing our network.

The Cambridge area is a relatively affluent area and considering the distance to commute to larger areas (Hamilton/Tauranga/Auckland) is within an EV's range. EV uptake is likely to accelerate in the future. Visibility of low voltage networks will be critical as EV penetration increases to ensure that loading on LV circuits and distribution transformer capacity can be managed.

8.7.2.3 Demand side management

The growth within the regions and capacity issues within our supply network means that ripple control is still a requirement (and sometimes a necessity) for our network. We own two 11kV ripple control plants, which control approximately 5MW of connected load in Cambridge and 6MW in Te Awamutu.

For the purposes of forecasting maximum demand, we have assumed that ripple control is fully functional and is being exercised over peak load periods. We have seen some decline in the uptake of ripple control relays for new connections and we assume that's partly due to alternative water heating options such as instant hot water gas heaters.

Modelling of our low voltage network (Medium to long term view) will provide us with usage patterns for the various consumer types during peak loads. Pricing signals or additional demand management can be used to reduce load during these peaks.

8.7.2.4 Energy efficiency

Due to the network supply configuration, our network's efficiency is relatively high with our loss ratio being approximately 5.5%. It's expected that this value will slightly increase with the introduction of the sub-transmission network but should be offset through the efficiencies gained in decreasing the 11kV network feeder lengths and customer connectivity numbers.

We have recently installed 11kV line capacitors to reduce losses within the distribution network with several more programmed to be installed next year. The capacitors also improve power quality to customers.

[33] *Typically operates at 5MVA.*

8.7.3 Cambridge area load forecast

The historic demand growth, refer to Figure 53, shows that Cambridge demand is growing at a sustained rate that has led to capacity and security issues at the GXP. Several high-load customers have indicated significant load step changes, highlighting the need for a capacity increase at GXP level.

Over the past five years, the average growth in energy (kWh of electricity) imported through Cambridge was +1.67% per annum. The MD growth over the next ten years at Cambridge is forecast at between 2.5% and 4% and is higher than the growth experienced within the last couple of years. This increase reflects the strong economy and proposed developments within our region.

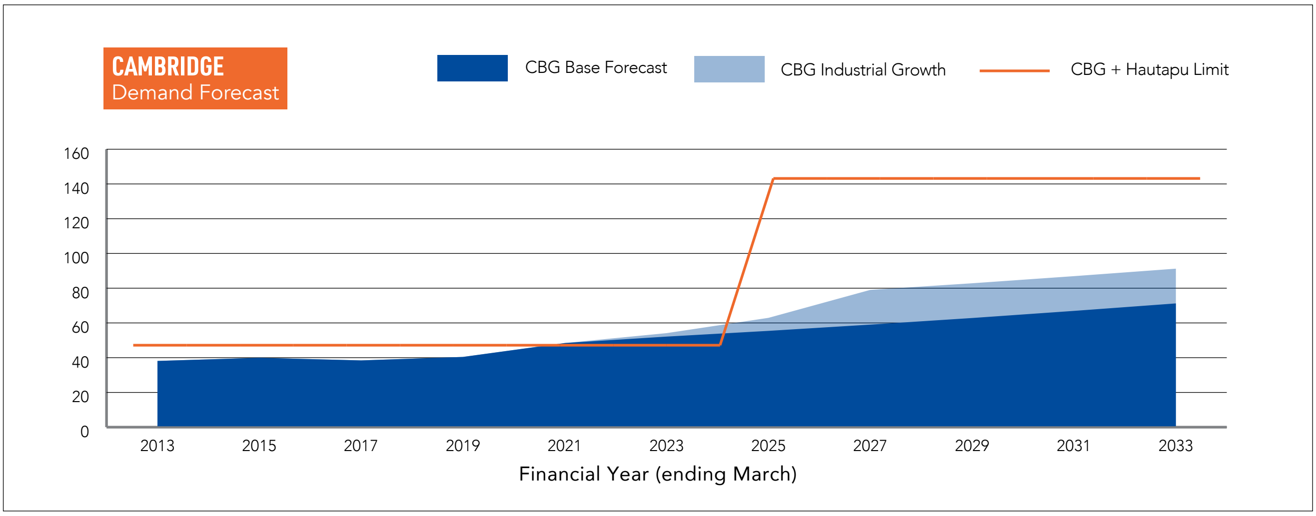


Figure 53: Cambridge Demand (MW)

Table 26 shows the major customers that are connected to the Cambridge GXP which have signalled load increases.

Major consumer/ developments	Proposal	Timing
APL	Proposed new industrial consumer which has indicated an additional peak load of roughly 7-9MW, with a future stage that will increase the electrical demand to 18MW within 5-10 years.	Already using 3MW Total 12.5MW in the 3-5Yr period
Fonterra	Currently have an existing load of 10MW with a proposed new waste-water treatment plant expected to increase load by 2MW. Fonterra has indicated that through process changes an additional 5MW is likely in the medium to long term forecasts.	New WWTP 2MW 1-3Yrs Process change 5MW 5-10Yrs

Table 26: Major customer developments – Cambridge

An additional input for the forecasts is sourced through collaboration with the local district council. This is to ensure that upgrades and network developments are designed and positioned in-line with the growth plans and figures for our community and area. While the growth within these plans typically aligns with the base growth forecasts, larger developments may need to be accounted for in both the overall GXP maximum demand and feeder development plans.

Figure 54 is the Waipā District Council's growth map for the Cambridge Area. The council updates the timing and size of each growth zone, and we regularly communicate to ensure that we are aware of upcoming developments.

Figure 54: Cambridge growth areas[34]

[34] *Waipā 2050 Growth Strategy - Final November 2017 (waipadc.govt.nz)*

8.7.4 Te Awamutu area load forecast

Te Awamutu has had steady but relatively low load growth which reflects the rate of change of economic activity in the areas for the period. Te Awamutu serves as a commuter town, supporting Hamilton and as a centre for the rural economy and is expected to support continued residential growth. Over the past five years the average growth in energy (kWh of electricity) imported through Te Awamutu GXP was +1.82% per year. Over the same period the 5-year average growth in maximum demand at Te Awamutu GXP (with full load control) was 2.14%.

Figure 55 shows the demand forecasts for the Te Awamutu GXP. Again, the forecasts have predominantly been based on continual base growth with incorporation of the known larger industrial step changes.

Given the forecast demand, we are already in the beginning phases of planning for solutions to the overall GXP maximum demand growth.

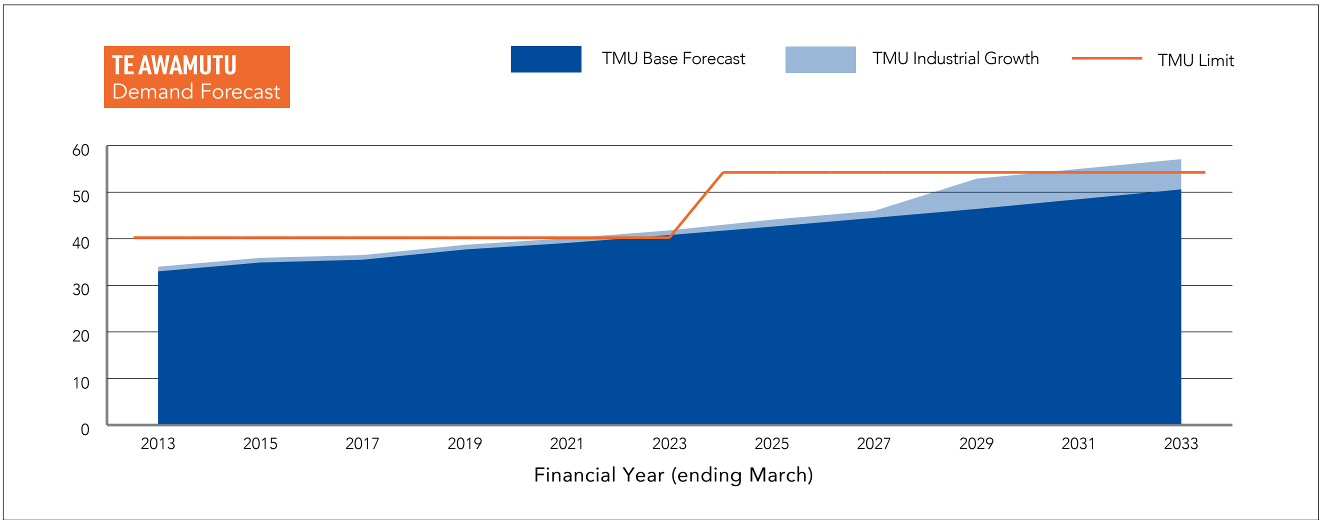


Figure 55: Te Awamutu Demand Forecast (MW)

Major customers on the Te Awamutu GXP that will introduce step changes in load are shown in Table 27. There's some uncertainty around timing for several projects as developments and lead times on construction and materials vary, however the certainty around whether the projects will proceed is relatively high.

Major customer/ development	Proposal	Timing
Waikeria Prison	The Waikeria prison is expanding to allow for additional space and beds within its facility. There is currently no urgency around this development and load increase is estimated at 1-2MVA. 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 10 years.	1-2MVA between 2-3 Years
Fonterra	Decommissioning 5MVA generator will increase maximum demand on the GXP accordingly.	5 MVA in 5-10Years
Bond Rd Development	PGG Wrightson have indicated a possible 3MVA load increase for their site on Bond Rd. Additional development in the area is also likely however sizing is yet to be determined.	Early enquiry
Frontier Estate development	This development is made up of three areas which includes the Frontier Estate, Kotare height and Te Awamutu Country Club.	Between 1-5 years.
Pirongia	Development is continuous within this region as residential development grows. Natural growth to roughly 2MVA is likely.	2MVA between 1 – 5 years.

Table 27: Major customer developments - Te Awamutu

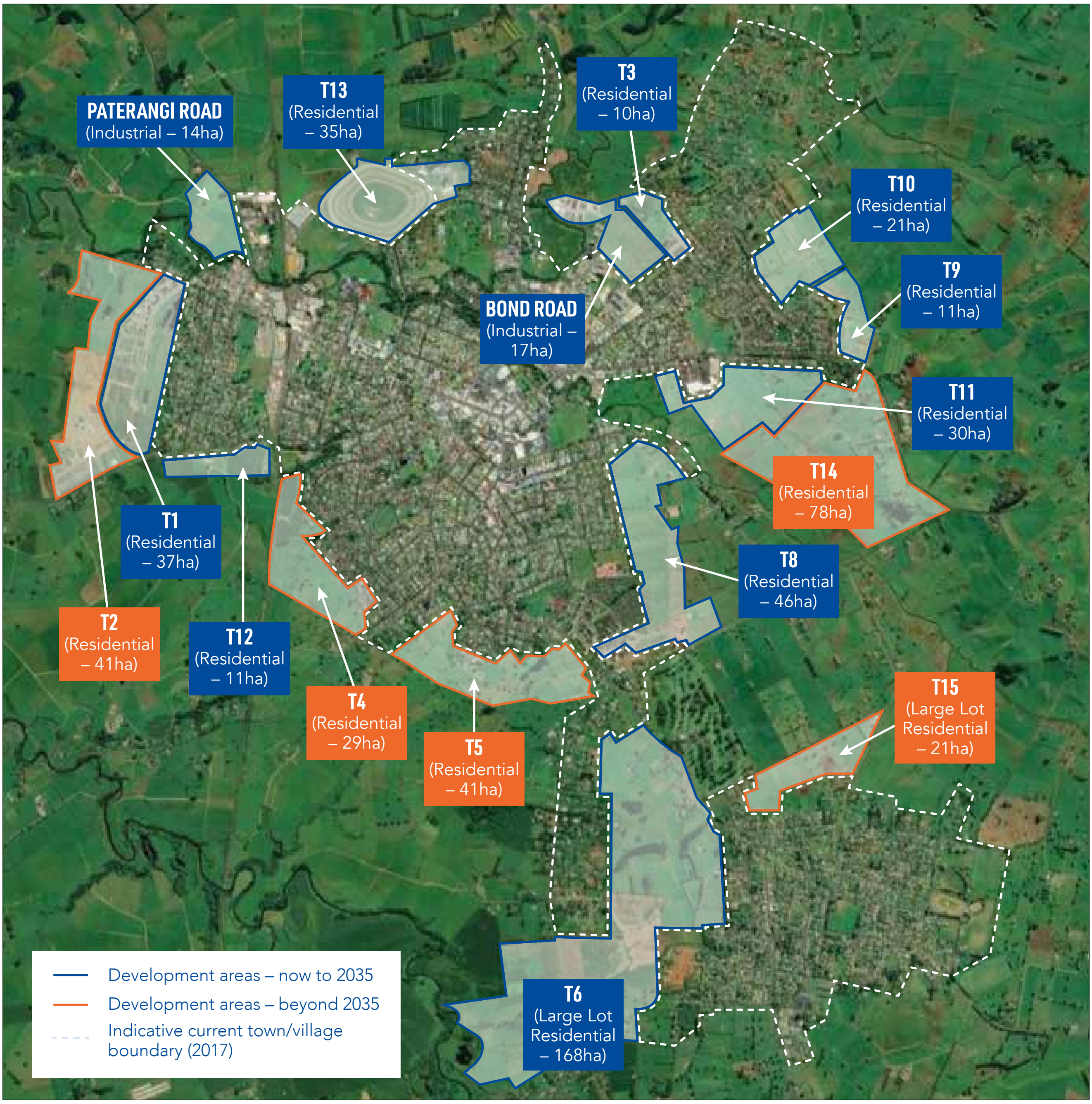


Figure 56: Te Awamutu growth areas[35]

Figure 56 shows an overview of the Waipā District Council's development areas for Te Awamutu. The timing and yield of each growth zone are yet to be confirmed therefore no specific forecast demand is included in our forecasts. However, the growth areas are considered when establishing network development path.

[35] *Waipā 2050 Growth Strategy - Final November 2017 (waipadc.govt.nz)*

8.8 Cambridge area development plan

8.8.1 Cambridge GXP and the new Hautapu GXP

Cambridge GXP had two transformers installed in July 2002 that provide a capacity of 40MVA continuous with a firm post contingency rating of 45MVA / 47MVA (summer/winter).

The 110kV circuits (Transpower owned) supplying Cambridge GXP will likely be constrained following an additional 5MVA load increase if Karapiro generation isn't running to its peak capacity. The Hamilton-Cambridge section of the 110kV circuits that supply Cambridge GXP is limited to 57MVA in summer and 72MVA in winter. Load increases at Cambridge will not have 110kV circuit firm capacity at peak times.

The transmission capacity and associated security of supply issues at Cambridge don't meet our security of supply criteria and isn't in line with good industry practice. Peak demand at Cambridge now exceeds the transformer n-1 post contingency firm capacity, requiring intervention from the recently commissioned 3MVA Swayne Road diesel generation facility and ripple control to manage GXP loads. This generation also minimises the risk of tripping feeders / shedding load through the Special Protection Scheme at the substation should a power transformer outage event occur at the same time.

While the frequency at which the load peaks above the GXP level is below 0.5% of the total annual half hour periods, the risk of breaching is increasing and has prompted investment into alternate supply options.

In 2019, the investigation into alternate supply options began, with the engineering process along with consultation with Transpower providing three solutions for the GXP. These options included:

1. Building and commissioning a new 220/33kV GXP,
2. Upgrade the existing Cambridge GXP, and
3. Building and commissioning a new 110/33kV GXP.

Following the project evaluation process, in FY21 we approved option one to build a new 220/33kV GXP to the west of Cambridge at an estimated cost of $36m (2022 figure). This option will provide additional capacity and resilience through the diversity of transmission connection into the Cambridge area. The project is now underway and is scheduled for commissioning in FY2025.

8.8.2 Sub-transmission network and zone substations

In conjunction with the GXP build, we have identified the need for up to four zone substations in the Cambridge area to alleviate our current network constraints and provide for the large developments in the area. Two zone substations establishment and one zone substation land purchase are committed in the AMP planning period. These projects are programmed within the forecast period.

Forrest zone substation

A new 33/11kV 26MVA zone substation will be established immediately adjacent to the new 220/33kV GXP. It will supply the existing and future load growth on the Tamahere, Pencarrow and Kaipaki feeders' areas and in-progress C2/3 growth cells in the west of Cambridge zoned for residential developments. This zone substation along with adjoining circuitry is scheduled to be completed and livened at the same time as the GXP build.

Victoria (or Bardowie) zone substation

A second 33/11kV 26MVA substation will be established either adjacent to Fonterra Hautapu dairy factory (Victoria Zone Substation) or in the Hautapu industrial zone on land in the Bardowie industrial park (Bardowie Zone Substation). This zone sub is approximately 3.4km east of the Forrest substation and will be supplied through two 33kV underground cables.

It will predominantly supply the Hautapu industrial load and other emerging industrial loads in the adjacent C8/C10 industrial growth cells. An area of at least 40m × 40m is required for the substation. This project timing will mainly be customer driven – and is tentatively planned for completion in mid FY26. We are actively engaging with local industrial customers in 2023 to confirm the technical, commercial arrangements.

Should the loads in our areas grow at a higher pace exceeding the Victoria (or Bardowie) Zone Substation capacity, then constructing another zone substation in the vicinity (<1km radius) has also been considered. It will be included in the future AMP upon further evaluation.

Leamington zone substation (land purchase only)

The Leamington zone substation will preferably be located on the northeast corner of the intersection of Matos Segedin Dr and Cambridge Rd. In future, this zone substation will shift load off the Cambridge substation and supply the southern 11kV feeders. An area of at least 40m × 40m is required for the substation. An allocation of expenditure for land purposes has been allowed for in FY24-25. We have yet to program/time the build for the zone substation.

8.8.3 New forrest zone substation 11kV feeder integration plan

Phasing of the new GXP build and subsequent zone substations will match the existing Cambridge GXP supply. Although infrequent, it will allow for interconnection between the two Cambridge GXP's and allow us to 'make before break' for the integration process. It will also provide a good source of interconnectivity to happen between the feeders, which will assist with reliability and quality of supply.

A result of the build is that several of the larger Cambridge feeders will be significantly altered in terms of both length, load, and customers as they will be split and tied into the new substations.

Exact details on the multiple feeder open points, load expectations and feeder arrangements are still under review. Several scenarios have been analysed and we have a good indication of the likely loads which will be transferred once the new GXP is operational. Below is a likely 'scenario' for the load transfer.

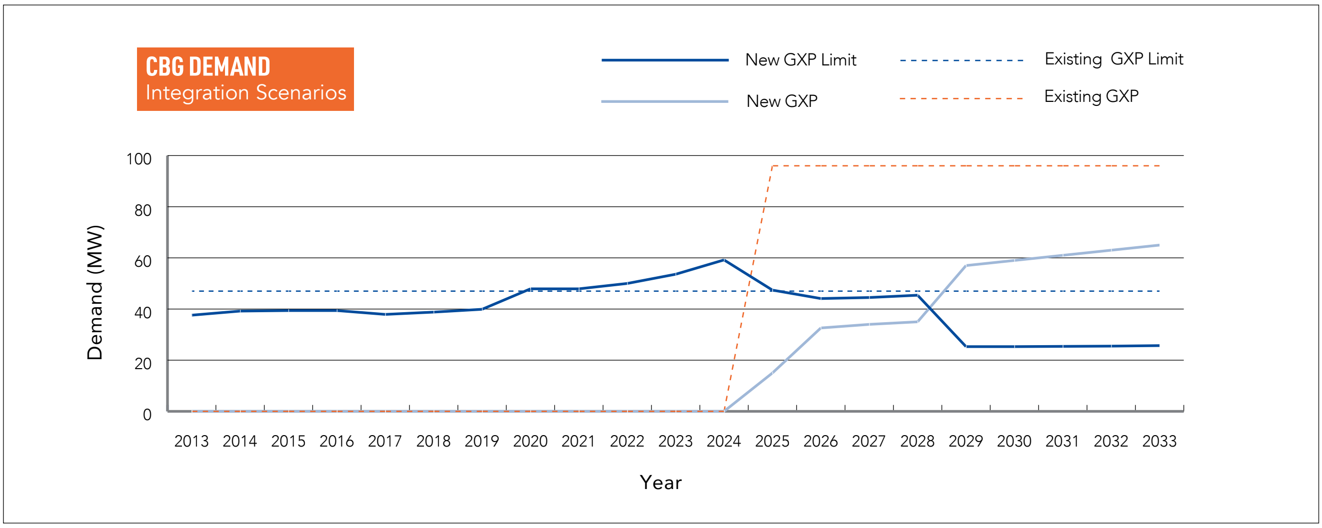


Figure 57: CBG GXP Load forecasts

8.8.4 Project timeline

Based on the forecast developments in our area and the level of security and capacity available, we have developed the following timeline for the projects.

Project development Timeline	Timeline
A feeder load shedding scheme and non-network capacity support is implemented at the Cambridge GXP to manage the post-contingency overloading of the transmission network (following tripping of HAM-KPO circuit or CBG transformer).	Current to 2025:
Transpower completes the commissioning of the new GXP	Dec 2024
The new Forrest Zone Substation and Bardowie Zone Substations are commissioned. This time frame accounts for the timeline to consent/plan/design/procure/construct the substations. The maximum forecast demand at Cambridge GXP in 2025 is projected to be 48.4 MVA which will be beyond the GXP supply transformer N-1 limit.	2025
During this period, we will undertake minor works to reconfigure/re-balance the 11kV feeder network so that the maximum demand at each of the substation loads are maintained within N1 limit. The N-1 constraint will be avoided for approximately 10 years based on the current growth predictions, but feeder constraints to the south of Cambridge will trigger the next step.	2025-2033
A new zone substation at Leamington will be commissioned to supply the southern feeders. It is assumed the Leamington substation will take an initial 17MVA of load from the Cambridge GXP, which is approximately 85% of the total load supplied by the southern feeders, including Leamington, Roto-o-rangi and Monavale, at that time.	2033 (TBC)
The demand is expected to continue to grow and possibly exceed the N-1 limits by ≈2050.	Beyond 2033

Table 28: Cambridge development timeline

8.8.5 Cambridge 11kV distribution

The 11kV network is made up of 14 feeders which supply the local town, the industrial loads and surrounding areas. While there are some network constraints on our distribution network the majority of these will be resolved by the proposed sub-transmission projects.

Our assessment is based on current demand forecasts, and this will be revised to reflect the energy transformation scenarios in the 2024 AMP. A number of feeders also have very high customer numbers, which will require re-balancing over time.

8.8.5.1 11kV network constraints

During peak loading periods, our rural pole line feeders require support to deliver a supply within regulatory limits. We have established a program for installing voltage regulators to address voltage issues and have also started installing 11kV capacitors to correct line power factor and reduce losses.

Based on both load-flow modelling and SCADA data the following feeders are currently constrained, and we have developed a programme to address these constraints as below, and Appendix E provides details of network loads, constraints and projects.

Feeder	Constraint Description	Project which addressed Constraint
CBG Town	66% capacity is expected to be exceeded in FY25	New GXP project will reduce load and consumers on this feeder
Pencarrow	66% capacity is expected to be exceeded in FY30, currently experiencing voltage issues	New GXP project will reduce load and consumers, and will also improve voltage profile on this feeder
CBG East	66% capacity is expected to be exceeded in FY32	To be defined
Tamahere	Additional approved load for FY24 has been modelled as requiring voltage support	Voltage regulator installation programmed for FY24
St Kilda's	Additional approved load for FY24 has been modelled as requiring voltage support	Voltage regulator installation programmed for FY24
Monavale	66% capacity is expected to be exceeded in FY32	To be defined

Table 29: Cambridge feeder constraints

Voltage regulators associated with improving Voltage Quality during normal configuration will be prioritised over supporting back feeding.

Expected constraints only emerge during contingency events (in the case of security) or at high load times (in the case of voltage). They can be managed through more aggressive hot water load control or temporary increases to the 11kV bus voltages. These operational controls are only temporary, and the extent of distribution constraints indicates that additional investment at the distribution feeder level is required in the near to medium-term.

8.8.5.2 11kV distribution substation enhancement

Distribution transformer loadings are monitored as part of our routine inspection (section 10.10) for ground mount units or through After Diversity Maximum Demand calculations for pole mount units. Waipā is a fast-growing region facing domestic load intensification and in-fill developments, and overloaded transformers are identified from time to time. Overloading may not result in immediate voltage issues. Still, sustained overloading will risk transformer overheating, reduced life and potentially premature failures, or ground mount transformer low voltage frame overheating and potential fire.

We have budgeted proactive transformer upgrades to mitigate transformer overloading risks at up to two or three sites per year. Note: transformer upgrade due to low voltage complaint (mainly in rural areas) will be addressed under Section 8.10.2.

8.9 Te Awamutu area development plan

8.9.1 Te Awamutu GXP

Te Awamutu GXP is supplied through a Transpower owned 110kV Karapiro-Te Awamutu line and our 110kV HangatikiTe Awamutu line. The GXP has two 40MVA transformers installed in 2004 providing a firm post contingency capacity of 40MVA limited by protection equipment.

In the short-term, a protection upgrade, scheduled for completion in FY24 (a Transpower project) will increase transformer firm post contingency capacity to 52MVA (summer) and 54MVA (winter), alleviating the current capacity constraints.

However, the load growth will exceed this capacity within the forecast period.

We are currently assessing long-term solutions for GXP capacity in Te Awamutu, considering the capacity, voltage, and security constraints of the 11kV southern feeders. A preliminary analysis considered the following options:

1. Status quo
    a. Continuing with incremental 11kV feeder development and accepting degraded security at the Te Awamutu GXP
2. New GXP substation
    a. Build an additional GXP at 110kV or 220kV which will have similar advantages to the Cambridge GXP option. An additional option being considered is to collaborate with neighbouring EDB's to share costs.
3. Upgrade the distribution network to 22kV.
    a. Option involves significant upgrades to our distribution network including the upgrade of insulators, switchgear and transformers.
4. Upgrade of Te Awamutu GXP
    a. Convert the existing the GXP transformers to 110/33/11kV and build a sub-transmission network and network of zone substations.
5. Non-Network development options
    a. Battery energy storage systems as a solution to manage peak demand on some of the fastest-growing feeders.
    b. Battery energy storage systems to alleviate GXP demand.

As part of the above GXP and sub-transmission option evaluation process, we have also started working with Transpower and our neighbouring EDB, to conduct a joint study for the regional 110kV subtransmission network. This is to ensure the future major investment for the Te Awamutu areas is optimised at transmission, GXP, sub-transmission and distribution levels.

Once a decision has been made on the preferred option, a more detailed plan along with forecast expenditure will be added to the AMP.

While new subtransmission solutions are being investigated and will eventually be needed in the longer term to resolve security and voltage constraints for the Te Awamutu area, distribution solutions such as voltage regulators and capacitor banks are being deployed to address our near-term needs.

8.9.2 Te Awamutu GXP 11kV feeder cable upgrade

Investigation into the capacity of cables exiting the Te Awamutu GXP has revealed that some installation details are unknown, and the paper insulated lead covered (PILC) copper cables installed circa 1966 could be underrated for the feeder loadings. Given the uncertainty around the actual cable ratings, there is risk that thermal stress may cause cable failure.

The PILC cables are 55 years old, compared to the PILC cable expected life of 70 years. A recent partial discharge test on our feeder cables indicated only one cable with elevated partial discharge activity.

To address our cable capacity issue, a full cable thermal design is being completed for our feeder cables exiting the GXP, using thermally stabilised backfill to achieve a reliable cable capacity.

We are currently in the final stages of the design phase, with the project due to be completed in FY24.

8.9.3 Pirongia 11kV feeder upgrade

We have completed the first stage of our development with the additional two stages expected within the next two years. The immediately adjacent Kotare Height and Tamahere Country club are also progressing. The supply to the developments will be from the Pirongia feeder which has a weak section of 70mm2 Cu on a multi-circuit pole (shared with the Kawhia feeder). A feeder upgrade project will:

- Underground the weak section of line as a way of upgrading the Pirongia feeder.
- Provide a strong link to the Kawhia feeder, and
- Improves the overall security on our line.

8.9.4 Te Awamutu 11kV distribution

The 11kV network is made up of 15 feeders which supply the local town, the industrial loads and surrounding areas. Our assessment is based on current demand forecasts, and this will be revised to reflect the energy transformation scenarios in the 2024 AMP. A number of feeders also have very high customer numbers, which will require re-balancing over time.

8.9.4.1 11kV Network Constraints

There are 16 feeders supplying the Te Awamutu area. The larger development options discussed in section 7.5.1 are still a few years away, so we are progressing with voltage regulator and 11kV capacitor installations to manage feeder voltages and improve usable feeder capacity. Table 30 shows the type and timing of constraints on Te Awamutu feeders, and Appendix E provides overall summary of constraints.

Feeder	Constraint Description	Project which addressed Constraint
TA West	66% capacity is expected to be exceeded in FY23	GXP feeder cable upgrade project
Pirongia	66% capacity is expected to be exceeded in FY29, currently experiencing voltage issues	GXP feeder cable upgrade project, Voltage regulator installation programmed for FY24
Hairini	66% capacity is expected to be exceeded in FY23	GXP feeder cable upgrade project
Paterangi	66% capacity is expected to be exceeded in FY25	GXP feeder cable upgrade project
Kihikihi	66% capacity is expected to be exceeded in FY28 and will likely start experiencing voltage problems in the next 3 years	GXP feeder cable upgrade project. Voltage regulator in FY25
Mystery Creek	Seasonal voltage issues due to large events	Offload load onto the Kaipaki feeder upon the commissioning of new GXP and Forrest Zone substation
TA East	66% capacity is expected to be exceeded in FY23	GXP feeder cable upgrade project
Pokuru	66% capacity is expected to be exceeded in FY23, voltage issues	Cap bank programmed for FY24

Table 30: Te Awamutu Feeder Constraints

During FY23 we installed an 11kV capacitor bank on the Pukeatua feeder to reduce losses and alleviate voltage issue at the end of the feeder.

VR associated with improving Voltage Quality during normal configuration will be prioritised over supporting back feeding.

8.9.4.2 11kV Distribution Substation Enhancement

Distribution transformer loadings are monitored as part of our routine inspection for ground mount units or through After Diversity Maximum Demand calculations for pole mount units. Waipā is a fast-growing region facing domestic load intensification and in-fill developments, and overloaded transformers are identified from time to time. Overloading may not result in immediate voltage issues. Still, sustained overloading will risk transformer overheating, reduced life and potentially premature failures, or ground mount transformer low voltage frame overheating and potential fire.

We have budgeted proactive transformer upgrades to mitigate transformer overloading risks at up two or three sites per year. Note: transformer upgrade due to low voltage complaint (mainly in rural areas) will be addressed under Section 8.10.2.

8.10 Projects which address quality of supply

8.10.1 Kihikihi Grey St and Oliver St 11kV network extension

There were several low voltage complaints from the customers along Grey Street, and analysis shows that the issue is caused by a very long and small LV run. The area is at the very edge of the urban network, and LV reconfiguration or upgrade was not a viable solution due to the lack of alternative transformers in the proximity.

The only solution to resolve this is to extend the 11kV network into Grey Street and install a new transformer and new LV cable to supply customers. This project will also enable future intensification in the neighbourhood.

8.10.2 Low voltage complaint (LVC)

In the 2023 AMP, we have introduced a dedicated budget provision to address LVC issues caused by overloaded transformers or long low-voltage lines requiring upgrades.

Voltage complaints are treated on a case-by-case basis, often being rectified through simply adjusting the voltage tap of the associated distribution transformer.

In cases where the 11kV feeder voltage variation is excessive then, other solutions are investigated, including feeder enhancement through the installation of voltage regulators, or switched distribution capacitors for voltage support.

8.11 Projects which address compliance

8.11.1 New automatic under frequency load shedding (AUFLS) scheme

Currently, the feeder AUFLS functions are being provided by Transpower-owned SEL-351 feeder protection relays. Transpower's new AUFLS requirements include moving from two to four load control blocks with enhanced data recording starting from 2025.

The new requirements will require either hardware upgrades to the GBG and TMU GXP 11kV feeder protection systems owned by Transpower, or we need to add a dedicated AUFLS relay per GXP. We will start working with Transpower in 2023 to confirm whether the work can be best completed under a Customer Investment Contract directly with Transpower, or solely by Waipa.

8.12 Projects which address reliability

We have a semi-rural network with relatively high consumer density on rural feeders. As a result, faults on rural feeders affect a larger number of customers than other, more typical rural and semi-rural networks. Travel times to these faults are likely to be longer than for urban networks.

Our objective is to continually improve the reliability performance of our network feeder assets in line with the growing expectations of customers. The reliability assessment has not indicated any systemic issues on any feeders. However, there are opportunities for continuous improvement by reducing the number of customers on feeders, between controllable switches and reclosers, and/or prioritising renewal or vegetation management on the worst-performing feeder.

We are implementing a programme to improve the reliability and resilience of distribution feeders. This work includes installing reclosers to segment feeders, automating open feeder points to reduce restoration times, installing dropout fuses on spur lines, and installing loop protection schemes. Loop protection schemes allow faults to be isolated to the smallest possible extent and restore healthy network sections quickly.

New sub-transmission and zone substations to serve growing loads also have a major additional benefit in the reduction of customer numbers per feeder and length of feeders, which reduces the impact of a single feeder outage.

8.12.1 Recloser installations

Our network has long 11kV feeders supplying very large numbers of customers (greater than 2,000 ICPs per feeder in some cases). The utilisation of 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 EDB's show that we have a high ratio of reclosers per line length compared to other EDBs as shown in Figure 58.

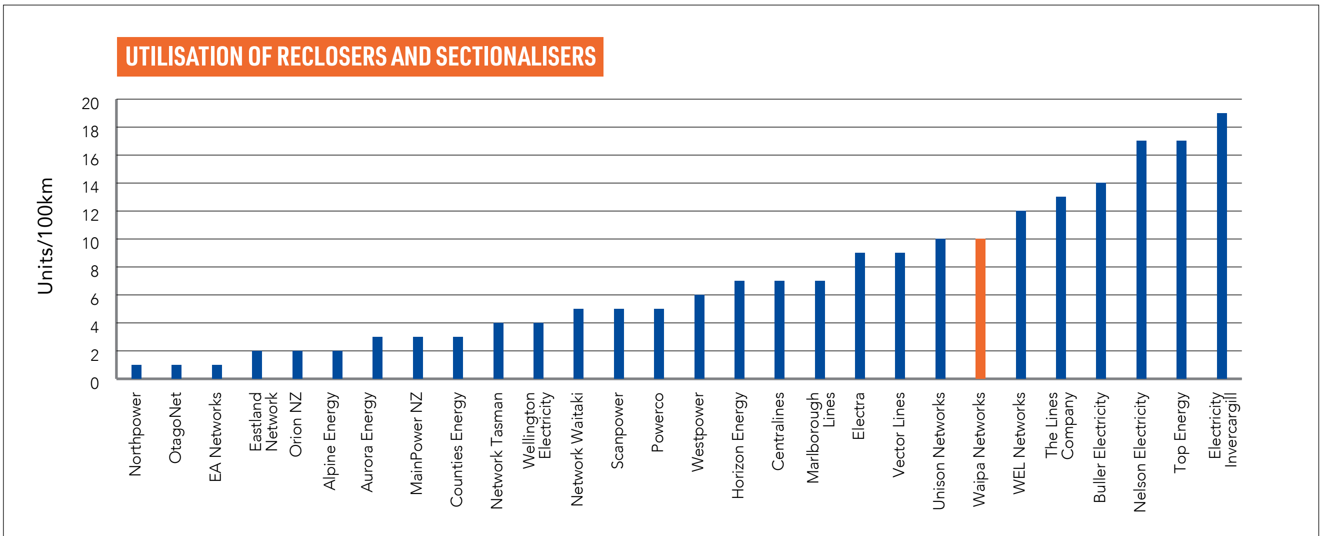


Figure 58: Industry recloser and sectionaliser density ranking

We have a target of no more than 200-300 customers or 15-20km of 11kV line between remote-controlled 11kV auto reclosers or switches. Our target is used to prioritise the installation of new reclosers, mainly for remote long spur lines. Our budget includes pole replacement, new recloser with isolating links, bypass switch, LV supply, recloser controllers and automation equipment.

The installation of remote-controlled 11kV auto reclosers increases feeder segmentation which reduces the number of customers impacted by faults and enables quicker supply restoration, thereby improving reliability. However, the impact of reclosers is limited by existing protection discrimination constraints and the constraints on our communications network.

Further work is planned to implement loop automation schemes using reclosers to provide a self-healing network that sectionalises faulted sections and automatically restores supply to healthy sections of feeders.

8.12.2 Drop-out fuses for spurs

Our Cambridge and Te Awamutu pole lines were historically constructed with a minimum of isolation points installed between the main 11kV distribution lines and the 11kV distribution network spur lines or the customers' 11kV service mains. Consequently, when a fault occurs on an 11kV spur line or consumer 11kV service main, all our distribution network up to the nearest protective isolation device is impacted.

Installation of 11kV dropout fuse isolation points on network spurs and customers' service mains will reduce the number of customers impacted by phase-to-phase faults on these spur lines and provide easier disconnect points enabling quicker supply restoration to other customers, thereby improving reliability.

Approximately 35 additional two or three-phase 11kV dropout isolation fuses will be installed on network feeder spurs, and 35 additional two or three-phase 11kV dropout isolation fuses will be installed on customers' service mains each year to minimise the number of customers affected by faults and improve fault isolation and restoration of supply times.

8.12.3 Automated open points

In conjunction with the Recloser Installation, the next step in improving reliability through automated network devices will be to increase the speed of sectionalising faults and restoring network sections through remote-controlled open point switches. This programme will install modern enclosed and motorised load break switches equipped for remote control at open feeder points and logical points for fault sectionalising. The programme is designed to target the worst-performing feeders, where the greatest benefit of remote restoration will be obtained and where fault response is delayed due to distance.

8.12.4 Te Awamutu ripple control alternate supply

To reduce the risk of a circuit breaker or switchboard failure causing the loss of load control and street light control in Te Awamutu, a duplicate supply was completed in late FY23. This duplicate supply also allows Transpower to proceed with Switchboard A arc flash protection installation that requires outages of the switchgear.

8.12.5 Multi-circuit poles

In several locations on our network, multiple feeder circuits have been erected on a single pole line. This is due to congested line routes in the vicinity of GXPs and the desire to reduce cost. However, in several cases the feeders on a single pole line serve adjoining areas, which restricts the ability to back feed significant network areas during planned maintenance or forced outages. There is risk of being unable to supply a significant number of customers following a single car versus pole accident that can takes out up to three feeders.

- The new supply to the Waikeria Prison upgrade project converted the first section of the new Kiokio feeder to cable along the route of the multi-circuit feeder, to improve voltage performance. This will reduce risk by removing one of the feeders from the multi-circuit line and providing a cable feeder to back up the overhead section of the other two feeders in the event of a fault.
- Review of the remaining multi-circuit poles will be conducted in conjunction with distribution network capacity and security risk review.

The risk of failure of the overhead multi-circuit feeders is currently managed by our maintenance regime, see section 10.6.

8.13 Projects which address safety and environmental concerns

This section describes the projects which we have programmed to address the reliability, safety, and environmental projects we have submitted within our ten-year forecasts.

8.13.1 Two-pole transformer upgrades

We have five two-pole substations remaining on our network. While the hardwood platforms of the transformer structures have been maintained as required over the years, these assets are approaching end of life. In addition, this type of structure poses a public safety risk and no longer conforms to modern industry standards. The last structure will be replaced in 2023.

8.13.2 Conductor low clearance road crossing

Low clearance conductor road crossings are identified and prioritised through the 2021 LiDAR survey and routine network inspection. This 2023 AMP has increased our original budget provision from a three-year to a ten-year program, prioritising low clearance conductors on our high-load routes.

8.13.3 Voltage regulator seismic strengthening

Most of our 11kV voltage regulators were constructed on two-pole structures, especially for the high current-rated 300A-rated sites. These structures are no longer deemed seismic compliant.

To coincide with the voltage regulator Can refurbishment and controller renewal program (section 10.11), we will upgrade the supporting structures to the new design standard at a rate of two sites per year.

8.13.4 Soundproofing Cambridge ripple plant building

We received a noise complaint from a neighbouring resident in the St Kilda subdivision (bordering the Cambridge Substation where our ripple plant building is sited). Noise monitoring confirmed that the ripple plant was not compliant with the Waipā District Plan noise consent levels. This project will install sound proofing material into the building and is due for completion in FY24.

8.13.5 Earthing practices

We have a process to install, test and maintain earthing of various equipment as per their respective design manual. Site safety with respect to touch and step voltages are assessed in accordance with the requirements of the EEA Guide to Power System Earthing Practice, which provides a means of compliance with Electricity (Safety) Regulations 2010.

The risk of hazards associated with non-standard earthing practices must be managed and we engaged Mitton ElectroNet to perform on site testing at twelve transformer and ring main unit distribution assets in the Te Awamutu and Cambridge areas. The assets tested were selected based on the risk they present to the public due to their location (i.e., proximity to residential property, public parks, or schools) and ease of testing i.e., proximity to large areas of soil to allow accurate voltage traverse investigation.

As part of this investigation, the following tests were performed:

1. Soil resistivity, to determine the respective topsoil resistivity.
2. Off-frequency earth grid current injection, to determine:
3. Asset earth system impedance.
4. Touch and step voltages around the asset.
5. Transferred hazards on to equipment in the area.

The investigation identified the need for further improvements of the design standards and drawing sets to clarify the earthing requirements at each site, i.e., provide clarity on earth testing, industry standard installation practices and earthing in special locations. Additional training and consultation will be carried out in FY24 to improve the overall approach, testing, measured results and installation standard.

8.14 Communication systems

Existing network

We have a legacy analogue communication system for its voice and data requirements. Data is used for SCADA system to monitor and control automated devices and voice channels to talk to our control room for the purpose of operating or switching network devices. Both these networks need to have good availability and reliability. However, with the additions of several automated devices, the bandwidth for both voice and data through the analogue channels is getting narrower and we are currently evaluating the option of migrating analogue communication to digital.

Some repeater channels have exceeded the maximum recommended RTUs per line, having an impact on overall SCADA system performance. The existing SCADA cannot be expanded significantly because it's constrained by the bandwidth between our Depot and the repeater sites and between repeater sites. Although in the interim, it may be possible to install additional SCADA repeaters to try and alleviate the overload by reducing the number of RTUs per line to enable more devices to be connected, overall SCADA system speed will not be improved by these measures.

The current analogue mobile voice network also has poor quality voice between field staff and the control room and between operators in the field. This has the potential of both operational security and safety consequences. A digital mobile voice network will provide better clarity in communication due to considerably less background noise.

Interim development

We recognise the need to deploy an interim solution to alleviate the current constraints in our SCADA communication network by:

- Digitising one of the existing analogue radio links to improve its bandwidth allowing more traffic volume.
- The freed-up analogue channel license will be reused. Many automation devices on an existing congested channel will be diverted to this free-up channel.

While the above solution does not eliminate the future development need, it will provide an acceptable level of performance until the major future development is completed.

Future development

While a new network could be designed for the minimum requirements to meet current needs, we recognise the advantage in futureproofing our new network. A ring topology is preferred as it allows for a diversity of access to each repeater to enhance availability. Such a topology provides more robust protection against a failure of a communications site or circuit. Installation of a microwave backbone between repeater sites offers the opportunity to upgrade the mobile voice network to digital.

We are investigating options to deliver the communications network upgrade. The solution can either be a Waipā-owned communications network or a third party-owned network using the high bandwidth microwave-link network. If the Waipā-owned communications network option is taken, it will be based on a microwave ring and include the following components:

- Microwave backbone network
- SCADA radio repeaters
- Mobile voice DMR repeaters
- Repeater site SCADA gateways
- Remote site radio equipment
- Setup up of an alternative disaster recovery facility

A cost estimate for the Waipā-owned option has been included in the expenditure forecast.

8.15 Low voltage network monitoring

In St Kilda, Cambridge we have a 100% solar PV residential subdivision, with all dwellings required by covenant to have at least 3kW of solar PV generation installed. An LV monitoring system allows visibility of the current and voltage at the distribution transformer and the power flows on individual LV feeders. As well as being useful for understanding the behaviour of the LV power flows associated with solar PV export, the system will also be a useful test bed if St Kilda residents adopt electric vehicles or batteries in large numbers.

This programme initially installed Gridkey LV monitoring on St Kilda transformers and is being rolled out on other representative transformers elsewhere in our network, to learn more about transformer utilisation and LV circuit loadings.

In conjunction with Grid-Sight, we are also looking to utilise this information along with revenue metering data from local energy retailers to provide a more informed view of the LV network. This is further detailed in the following section.

8.16 Development of an energy transformation roadmap supporting decarbonisation

Our demand forecasts, as shown in Figure 3 and Figure 5, still need to specifically identify the electrification of process heat, residential and commercial gas, or the impact of changes in hot water demand response and controllable distributed energy resources (DERs). Some considerations for EV charging have been included.

Developing and implementing an energy transformation roadmap supporting New Zealand's decarbonisation is a key strategy for us (asset management strategy #2) and is necessary to support New Zealand's decarbonisation through electrification.

We support distributed generation on our network and continue to have an increasing number of small-capacity distributed generation (mainly solar PV systems) connections each year. The penetration rate for distributed generation is 3.5% in our region, which is significantly higher than the national average of 2.2%.

Electric vehicle ownership in the Waikato region is currently around 0.8%, below the national average of 1.1%.

As detailed in Section 3.5, electricity demand growth is expected to accelerate towards the end of the decade because of electrification, and the industry is forming a view that flexibility service is part of the solution. Significantly higher demand growth from electrification may risk resulting in shortfalls of flexibility services to shift EV charging to low-demand periods and/or be unable to procure sufficient flexibility services from controllable DERs.

The impact of energy transformation drivers is not expected to be uniform across our network. That is, growth in EVs and general growth in new connections are likely to be significantly greater in Cambridge compared to other parts of our network.

Our development of the energy transformation roadmap is a key focus for our forthcoming year. The purpose of the roadmap is to develop a strategy that is the most cost-effective means of ensuring Waipā's network can meet the needs of customers in a net-zero world. Broadly, this will comprise the following:

- Assessing the potential impacts of our energy transformation (i.e., electrification and decarbonisation) specific to our region.
- Building a new demand forecast model, considering scenarios with/and without access to flexibility services.
- Reviewing the network development plans, information system plans, and opex and capex forecasts considering our new demand forecast scenarios. This will include considering whether there are future projects where alternative non-network options could be viable.
- Improving the visibility of our demand (including LV) to understand the real-time impacts of electrification on our network and enable flexibility to be dispatched to support capacity constraints and/or energy market needs.
- Assess the need for flexibility services and the size required, followed by forming a view on the industry market model for flexibility procurement, assessing the value of flexibility and the extent that flexibility could be a viable (and economical) alternative to network investment.

Inherent in developing the energy transformation roadmap is our strategy, in the immediate term, is to learn and respond to potentially disruptive technologies as a "fast follower". Key focuses will be:

- Monitoring the economics of non-network solutions (compared to the cost of network projects) and avoiding network projects where alternatives offer a lower-cost solution at the same or similar utility.
- Identification and execution of 'no-regret' enabling investments such as network capacity, network information/data and technology readiness, and people capacity/capability, putting ourselves in a position to act fast should we need to.

Work has already commenced in this space where we are:

- Building our new Hautapu GXP, 33kV sub-transmission network and zone substations injecting new capacity to the Cambridge area.
- Working with GridSight, an Australian-based company, to develop a solution to identify and detect solar PV, battery, and EV installations on our network. The GridSight tool will enable the visualisation of LV power quality issues, LV consumption data aggregation and (in the future) network congestions, providing information to understand distribution transformer and circuit loading better. This work is being supported by Ara Ake, New Zealand's future energy centre, as part of their work to develop solutions to help decarbonisation via electrification.
- Commissioning a Waipā region-specific study to assess regional drivers for growth (such as electrification of process heat, transport and gas).
- Further improving our customer engagement to be closer to our customers and community and to better understand their future energy needs and service level (e.g. reliability and resilience), so customers' voices can influence future asset management objectives.
- Upon the go-live of the new state-of-the-art ESRI GSI system, commit to a network data improvement plan, particularly the LV network.

8.17 Expenditure forecast

Our material network development projects are shown in Table 31 below. These projects amount to $37.9m over the next ten years and are mostly scheduled for the first five years, representing 37% of our network capex.

Project description	Driver	Timing	Forecast
Transmission/Subtransmission			
• Te Awamutu GXP capacity increase • Removal of GXP protection constraints • 11kV feeder cable upgrade	Security	GXP work is complete Cable upgrade occurring in FY2023-FY2024	$4.0m
Cambridge subtransmission development: • New Hautapu GXP west of Cambridge and a new zone sub at the GXP • A second new zone substations and associated subtransmission • Associated 11kV network integration will include eight new feeders	Security Capacity Voltage	New GXP and associated zone sub due to completion in FY2025 A second zone substation and subtransmission are due for completion in FY2026	$25.2m
Distribution Feeders			
Cambridge: New voltage regulators on five feeders	Voltage	FY2024-FY2029	$1.2m
Cambridge: Fusing, recloser and loop automation	Reliability	FY2024-FY2033	$2.9m
Te Awamutu: Capacity upgrade on Pirongia feeder	Capacity	FY2024	$0.5m
Te Awamutu: New voltage regulators on five feeders	Voltage	FY2025-FY2029	$1.2m
Te Awamutu: Fusing, recloser and loop automation	Reliability	FY2024-FY2033	$2.9m

Table 31: Summary of major network development projects

Figure 59 summarises our forecast system growth and reliability-related capex. It also indicates our possible direction of travel for capex in the 2024 AMP. In this regard, medium to long-term system growth capex will likely increase as feeder security and voltage solutions are required.

With our current profile, expenditure is higher in the first three years due to the following:

- Cambridge region zone substation and subtransmission network;
- Feeder augmentation in Te Awamutu.

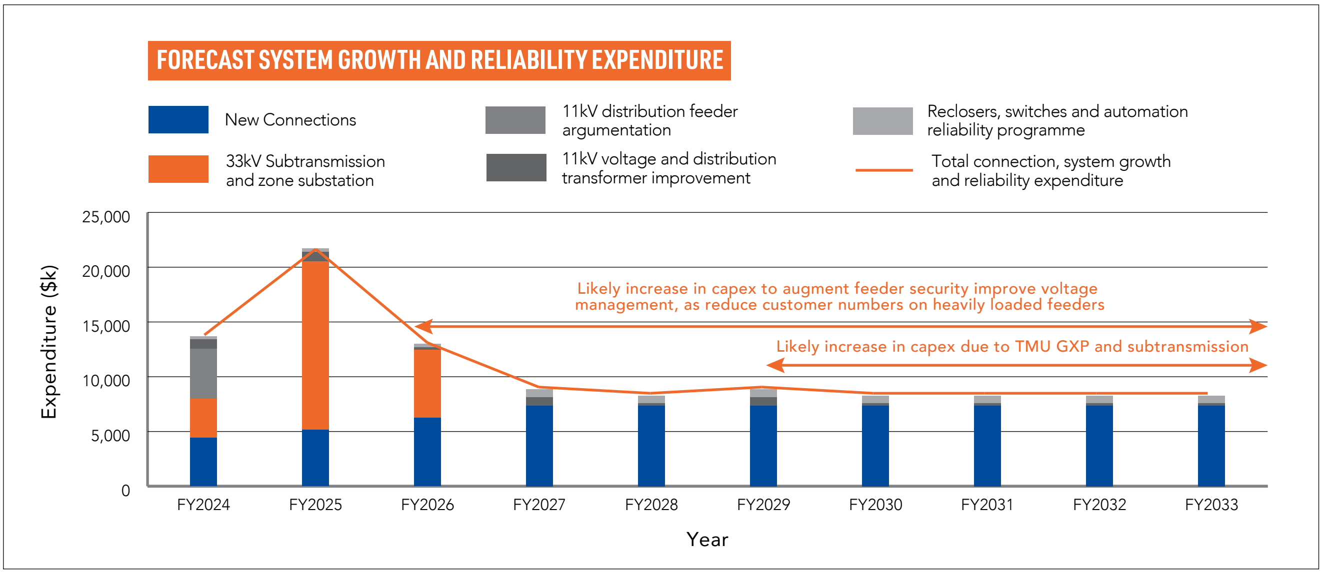


Figure 59: Forecast system growth and reliability expenditure

Following our preparation of new demand forecast scenarios, we will refresh the constraint analysis, that could reveal our need for additional network development work at the back end of our planning horizon. Any new projects will be identified in the 2024 AMP and incorporated into our wider optimisation review that will be necessary when expenditure forecasts change.

Table 32 shows the detailed network development forecast expenditure over the next ten-years.

Network Development and Growth	FY 23/24	FY 24/25	FY 25/2	FY 26/2	FY 27/2	FY 28/2	FY 29/3	FY 30/3	FY 31/3	FY 32/33
Forrest Zone Substation	2,853	8,191	-	-	-	-	-	-	-	-
Bardowie Zone Substation	635	3,807	4,479	-	-	-	-	-	-	-
Bardowie Zone Sub-transmission Circuits x 2	-	2,076	1,384	-	-	-	-	-	-	-
Leamington Zone Substation Land	100	900	-	-	-	-	-	-	-	-
Te Awamutu GXP Feeder Cable Upgrade	4,000	-	-	-	-	-	-	-	-	-
Forrest Zone Substation - 11kV Integration plan	-	750	-	-	-	-	-	-	-	-
Priongia Feeder weak sections bypassing	519	-	-	-	-	-	-	-	-	-
New Voltage Regulators & Capacitors	649	649	-	577	-	577	-	-	-	-
Transformer & Sub Enhancements	228	228	228	228	228	228	228	228	228	228
Future Digital Data Communications Network	195	1,299	325	130	130	104	104	104	104	104
SCADA Disaster Recovery Facility	-	-	130	-	-	-	-	-	-	-
Total	9,179	17,55	6,892	935	358	909	332	332	332	332

Table 32: CAPEX forecast – Network Development and Growth

Table 33 shows the forecast expenditure for Reliability, Safety and Environment related initiatives.

Total Reliability, Safety and Environment	FY 23/24	FY 24/25	FY 25/26	FY 26/27	FY 27/28	FY 28/29	FY 29/30	FY 30/31	FY 31/32	FY 32/33
Low Voltage Complaint	130	130	130	130	130	130	130	130	130	130
Kihikihi Grey St and Oliver St 11kV network extension	455	-	-	-	-	-	-	-	-	-
Install Remote Control Switches/ Loop Automation	171	171	171	570	570	570	570	570	570	570
Install 11kV Reclosurers / Sectionaliser, Dropout Fuses Spurs & Services	130	130	130	130	130	130	130	130	130	130
Replace Two Pole Transformers and Sub Structures	117	-	-	-	-	-	-	-	-	-
Seismic strengthening of Voltage Regulator structures	295	295	295	295	295	295	295	295	-	-
Soundproofing Cambridge Ripple Plant Building	130	-	-	-	-	-	-	-	-	-
Low line mitigation	97	97	97	97	97	97	97	97	97	97
High resolution photo pole-top condition Survey	500	300	-	-	-	-	-	-	-	-
Total	2,025	1,123	823	1,222	1,222	1,222	1,222	1,222	927	927

Table 33: CAPEX forecast – Total Reliability, Safety and Environment

9. CUSTOMER WORKS

This chapter outlines our approach to customer-initiated work and how related expenditure is forecast. Customer initiated work includes new connections, upgrade of existing connections and the relocation of distribution assets.

New connections or the changing of existing connections initiated by customers have an impact on 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 managing existing customer service levels and ensuring integration with network development and fleet management plans.

9.1 New connections

9.1.1 Overview of customer connections

Every year, we connect approximately 520 new residential, commercial, and industrial electricity customers to our distribution network, and this is expected to grow to 600 in FY2028. The strong connection growth sees the number of new connections increase 50% over the forecast period (compared to the 2022 AMP).

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.

On occasions, the new customer connection may require 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 which is reflected in the forecasts in this AMP.

9.1.2 Connection process

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 then be reviewed and approved, provided our distribution assets have sufficient capacity. Upon approval, the installation will be planned and performed by our contracting division.

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 level of contribution, if any, that we will provide. It is beneficial for us to work with developers during the connection process as it provides an opportunity to upgrade assets that may be approaching end of life or near to their capacity rating.

Our customer connection process and capital contributions policies are set out in further detail on our website.

9.1.3 Major customer projects

Kiokio / Waikeria

The 600 bed Waikeria Prison upgrade is under construction and expected to open in the first quarter of 2023. This has required significant network and Transpower reinforcement to create capacity for the additional 2 MVA load, with potential to expand to 4 MVA in future.

The network upgrade is now complete, with the Waikeria and Kiokio feeders split and additional capacity added.

In 2022 Transpower also upgraded Te Awamutu GXP 11kV Switchboard B with two new circuit breakers to connect the new Kiokio and Waikeria feeders to provide additional capacity.

Other

Other proposed major customer connection projects, where we have not yet received a specific connection application, are discussed in Section 8.8 Growth/demand projections.

9.2 Asset relocations

This section outlines our approach to the relocation of distribution assets when required by external stakeholders, such as landowners or 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.

9.2.1 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., the replacement of water pipes, telecommunications circuits, roading activities, or through the development of land for farming, commercial activities, or urban development.

Working with our stakeholders requiring asset relocations provides an opportunity to upgrade segments of our network, or replace aged assets, at an overall 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 the form of materials in accordance with required legislation. For other projects, we consider these on a "case by case" basis. Our capital contributions policy is set out on our website.

Expenditure is capitalised where replaced assets are approaching end of life and can be renewed or upgraded during the asset relocation process. Otherwise, relocation of the same individual asset is considered operational expenditure.

Where major works are required for asset relocation, such as major roading and other infrastructure projects, we will include the project into 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.

9.2.2 Asset relocation projects

Asset relocation projects proposed for the planning period are:

- The next phase of the Cambridge Rd undergrounding west of Kelly Rd for Waipā District Council. This will remove overhead lines associated with a roading development that will be completed during 2023-24.
- Hautapu Road industrial area undergrounding, Waipā District Council has requested pricing.
- Te Awamutu Mutu Street undergrounding, Waipā District Council has requested pricing.

9.3 Expenditure forecast

The ability to forecast precise works relating to customer-initiated works is relatively difficult as it relies on external factors. 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 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 to continue at or around current rates.
  - Asset relocations: We will assume a trend in line with historical expenditure.

The new connections expenditure forecast has been increased in AMP2023 based on regional future growth prospects.

Table 34 shows forecast expenditure for customer-initiated works over the next ten years.

Customer initiated works	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33
New connections	4,418	5,150	6,247	7,344	7,344	7,344	7,344	7,344	7,344	7,344
Asset relocations	189	189	189	189	189	189	189	189	189	189
Total	4,607	5,339	6,436	7,533	7,533	7,533	7,533	7,533	7,533	7,533

Table 34 – Customer initiated works forecast

10. ASSET LIFECYCLE MANAGEMENT

10.1 Introduction

Asset lifecycle management describes the different steps within an asset's lifespan and ensures that an asset (or asset fleet) is utilised to its maximum potential. Methods and approaches for each step within the lifecycle plans differ nationally and are based on how the asset management system within each company is organized.

Traditionally, we have used a mixture of asset age, observations from planned inspections, and defect-driven inspections to inform asset renewal plans and expenditure. The approach to asset renewal planning now requires a shift from conventional thinking to resolve some of the emerging issues (e.g., adverse weather, SAIDI performance, sustainable fleet plan expenditure, etc.) and to ensure closer alignment of the asset lifecycle management with our strategy and goals.

While we have yet to change our fleet plans to align with the shift, our intention in this AMP is to highlight the pathway we are on to developing key aspects within the fleet plans. This will provide confidence that our renewal programs will be based on informed decisions derived from a change in approach towards asset health, criticality, and risk.

Previous work completed on the network has resulted in a high percentage of concrete poles installed on the network (compared to wooden poles) which has shifted focus of the asset renewals from replacing pole structures to the replacement of crossarms. This reflects the difference between ageing rate and life expectancy of concrete poles and wooden crossarms. The age profile of the crossarm and our aerial inspection show a proportion of assets reaching the end of life. We have set the renewal expenditure in the short term to address this area.

Adverse weather (specifically in FY22) continues to be a significant driver for reliability issues; however, defective equipment outage counts overall remain stable, suggesting that network assets are performing within their required capacity, but external forces (Trees/weather etc) are affecting performance (see SAIDI/SAIFI trend in section 4.2). Given these two trends, our inspection programme will be focussed on crossarm conditions and vegetation management to resolve the issues on our network.

In this section, we cover:

- Lifecycle management
- Lifecycle management improvement plan
- Asset fleet planning
- Overview of our current fleet plans, and
- Renewal and replacement expenditure forecast.

10.2 Lifecycle management

We consider our network assets within a lifecycle framework that covers the assets from design and procurement through installation, commissioning, operation, maintenance, renewal and finally to disposal.

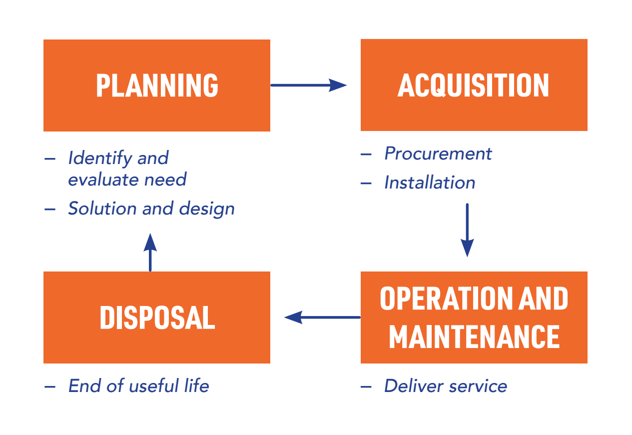


Figure 60: Asset lifecycle management

The goal of lifecycle management is to maximise the utility of the assets while minimising total cost over the life of the assets. It may be more cost effective over the life of the asset to pay more up front 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 top 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.

In addition to work undertaken on our network assets, it is also necessary to maintain access to assets and the environment around the assets, e.g., keeping trees clear of overhead lines and maintaining tracks to access assets such as switches. For us, a significant part of the maintenance budget is allocated to vegetation control.

Network assets are exposed to wind, corrosion, and other environmental effects and, therefore, deteriorate over time, albeit at different rates. Asset type and age can be a key predictor in assessing the general state of the network.

10.2.1 Lifecycle functions

Much of the existing network was developed in the 1970s and 1980s and accordingly would have, without ongoing prudent maintenance, reached the end of its useful life. Key lifecycle components are described below.

Condition-based maintenance

We undertake a condition-based maintenance programme centred on regular inspection and testing of network equipment. The programme includes the following aims:

- To manage the risk from hazards to staff, customers and the public.
- To achieve a reliable, secure system in accordance with service levels and customer expectations.
- To comply with our environmental policy.
- To identify required corrective maintenance before failure.
- To minimise the total cost of ownership and maximise the efficiency of our operations.
- To satisfy legislative requirements.

We seek to achieve these aims by undertaking maintenance efficiently and effectively. It is a process of continuous improvement and one that becomes more effective over time. We endeavour to purchase quality new equipment with minimal maintenance costs to assist with future reliability when this minimises the total cost of ownership.

Typical maintenance tasks on critical equipment include the following classes of activities:

- Identification of abnormalities.
- Maintenance in accordance with the manufacturer's requirements.
- Checking insulation components such as SF6, vacuum and/or replenishment of grease.
- Checking and minor repairs or replacement of semi-consumable components e.g., brushes, contacts, gaskets, and seals.
- Checking and minor repairs to breakable components e.g., sight glasses.
- Calibration of components such as thermocouples, protection relays, etc.

The key outcome of these tasks is to restore the asset to its original service capacity or utility. They do not increase that capacity or utility.

Asset replacement and renewal

Our strategy is to replace assets that deteriorate to health grade H1 and H2 if at critical locations. Except for certain asset classes, allowing assets to run to failure is generally not a viable strategy due to safety considerations. Where possible, our renewal work is prioritised based on asset criticality and risk. We plan to bring more formality to the criticality and risk assessment process, which will result in some assets being replaced when they reach H1 health and others being replaced when, or even before, they reach H2 health.

We will continually and systematically renew our assets. However, replacement of assets requires consultation with stakeholders, and this may represent the longest activity in the time scale of executing the works. It can take considerable time to reach agreements with stakeholders such as landowners over access and asset configuration.

Our guiding asset renewal principles are:

- Safety and reliability – Obtain maximum value from each asset without compromising safety and reliability. Network assets are renewed when condition assessment indicates that they no longer possess the ability to meet their design requirements.
- Levelling renewal expenditure to maximise efficiency and achieve consistency in operations. A regular renewal approach avoids large portions of the network falling into a deteriorated state at the same time, which may cause a sudden significant deterioration of reliability and issues with deliverability of necessary asset renewal.

- Economic efficiency – We may choose to replace assets ahead of "end of life" 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 condition. Such a strategy is economically efficient due to the one-off project and site set-up costs, especially in rural and remote locations, and in the avoided cost of multiple interruptions to customers.

Consideration is given to making assets "smarter" on renewal. Developments in smart grid technologies are making new assets easier to monitor and operate remotely, which is an advantage when assets are difficult to access in a timely way.

Routine maintenance

Most of the routine maintenance is planned. The maintenance plans are informed by output of the condition monitoring detailed in section 10.2.2 on asset surveillance. Where possible, we prescribe time-based condition monitoring over time-based servicing.

Corrective maintenance

The asset condition H0 is treated as a fault and some faults this may include an emergency shutdown. Asset conditions scored H1 and H2 (refer to Table 35 below for definitions) would typically trigger a defect to be logged with an appropriate urgency assigned for resolution.

10.2.2 Surveillance

Asset surveillance (inspections, monitoring, testing and condition assessments) is a major input to determining the health of the network assets and provides us with information that can be used to assess safety risks and reliability issues.

A balance must be struck between repeated surveillance and condition or time-based servicing or replacement.

The approach adopted will principally be governed by risk of failure, public safety and the criticality of the asset with respect to network reliability, cost of replacement and the cost of more frequent re- inspection.

Inspections

Our surveillance comes in the form of asset inspections performed by field crews or by aerial survey. Due to the spatial diversity of our network the cost of field inspections per asset is high. For this reason, to date field inspections focus on defect identification, with condition data being limited to a subset of assets (ground mounted transformers, ring main units, reclosers and voltage regulators). Aerial surveys provide condition data for the overhead assets, i.e., for poles, crossarms, and pole mounted transformers for rural feeders.

Our condition-based data currently shows a materially lower quantity of H1 and H2 assets. This work was recently reviewed, and the initial finding suggests there is a greater proportion of H2 health assets than originally surveyed. Following internal validation of the condition-based data, the crossarm fleet health will be updated in the 2024 AMP.

Condition assessment

During routine inspections, field crews undertake a condition assessment on each asset that leads to a condition score based off the definitions in Table 35. We have adopted and adapted the Asset Health Indicator (AHI) levels from the EEA Asset Health guide.[36]

Where asset health condition data is not available from the maintenance inspection programme then age is used as proxy for asset condition.

AHI category	Serviceability Criteria	Suggested rectification interval
H0	Unsafe Conditions or defects that are considered unsafe or could fail under normal loads and should therefore be addressed without delay.	As soon as practicable consistent with the hazard.
H1	Unserviceable Conditions or defects that are likely to fail in high load conditions and should not remain in service.	Rectify or mitigate within 6 Months
H2	Conditionally Serviceable Conditions or defects that are suspect and may be left in service on a risk assessed basis.	Rectify or mitigate within 12 months for high-criticality locations. Optional deferment for medium and low criticality locations.
H3	Serviceable Degraded Serviceable condition but showing deterioration. Not expected to fail in high load conditions.	No action required at this time, review at next inspection. Consider inclusion in work packs if economically viable.
H4	Fair Serviceable condition – no expected loss of strength	For info only
H5	Good Good serviceable condition near new condition.	For info only

Table 35: Waipā's AHI scores with definitions

[36] *Asset Health Indicators are measures of asset condition based on a set of criteria developed for network asset categories to represent an assets lifecycle stage and ongoing fitness for purpose.*

10.3 Lifecycle management improvements

This section highlights key areas within our existing operation and systems we are currently developing to enhance our asset fleet plans. The goal is to improve our internal operational workflow, and ultimately improve the lifecycle of our assets.

10.3.1 Developing a comprehensive fleet plan and renewal forecasts

Completing inspections at fleet level and the assessment of asset health will provide additional data for the overall health of the fleet and help us verify the accuracy of our existing data. This will give us the ability to create and/or adopt strategies to deal with any emerging issues. We will update the fleet plans in the next submission to present this approach better and provide additional information.

Given the progressive aging of the network, we are committed to developing comprehensive asset fleet plans for our material asset classes (asset management strategy #4). As mentioned in Section 1.6, we expect to observe more end-of-life drivers over the coming decade. Ensuring we have quality asset condition, asset health, and asset risk information will be important to enable the optimal renewal of our network.

Presently, an asset health assessment is a mix of age and condition-based, with our forecasting of health deterioration predominately based on asset age. As a first step in revising our fleet plans, we'll assess available asset health assessment and forecasting methodologies and review inspection standards to ensure we capture the correct data on end-of-life drivers. Assessing asset criticality and asset risks will also be a feature of the revised fleet plans in the 2024 AMP. Our renewal forecasts will evolve over the next 2-3 years as new condition information is captured and our forecasting approach evolves.

10.3.2 Evolution of asset health assessment

Figure 61 shows the evolution of our asset health for our material asset classes over the past three AMPs. H1 or H2 refer to assets with low health, meaning replacement is required or where end-of-life drivers are present, and there is a high risk of asset failure. The assessed asset health has been changing over the past three years, reflecting the renewal of assets, the use of the most recent asset condition information, and the evolution in the health assessment methodology applied.

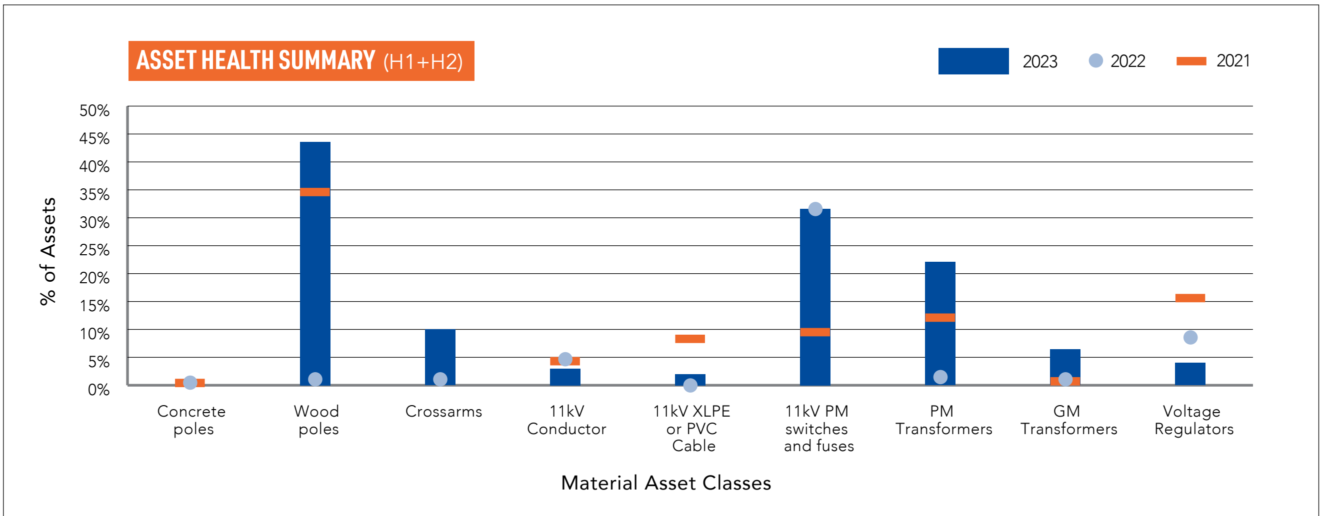


Figure 61: Asset health summary for material asset classes

The asset classes showing a high proportion of low health are wood poles, crossarms, 11kV pole-mounted switches and fuses, and pole-mounted transformers. For most asset classes, there is a view that the quantity of low health assets may have been overstated by either the EEA age-based health assessment, the quality of the age data, or conservativism in the observation-based condition assessment. As noted below, work is underway to improve the quality of the condition data and health assessment. Specific commentary on asset classes showing a high proportion of low health are:

- The wood pole fleet is relatively small (less than 1,600 poles), and the health assessment is age-based using the EEA guidelines[37]. The pole-top survey data has not been used for health forecasting this year as wood pole failures almost always occur at or below the groundline. Further work is planned in FY2025 to capture groundline/below ground condition drivers for the wood pole fleet.
- Waipā has both a condition-based data set (covering the majority of the fleet) and an aged-based data set for crossarms. Figure 10 currently shows our aged-based dataset. Our condition-based data currently shows a materially lower quantity of H1 and H2 assets. This work was recently reviewed, and the initial finding suggests there is a greater proportion of H2 health assets than originally surveyed as H4. Following internal validation of the condition-based data, the crossarm fleet health will be updated in the 2024 AMP.

[37] *The Electricity Engineers Association (EEA) have produced a guideline to determine asset health based on age data and also based on condition drivers. This is an industry standard guideline.*

- 11kV pole mount switches and fuses health is derived from age data using the EEA guidelines. Our age data is not completely reliable (as many of these types of assets, especially fuses, do not have an observable manufacture or installation date, so the installation date has been derived from other sources). We have some condition data from the recent pole-top survey (mostly in rural areas), however this does not cover our full fleet. We are validating the pole-top survey data, which may be utilised in future health assessments.
- Pole mount transformer health is derived from age data using the EEA guidelines. We have some condition data from the pole-top survey; however, this does not cover our full fleet. We are validating the pole-top survey data, which may be utilised in future health assessments.

10.3.3 Future approach to asset health assessments and risk based asset renewal modelling

Most of our overhead assets have traditionally been assigned a condition ranking based on age. While this is an acceptable method in determining asset health, our current view is that a future move to a condition/risk-based methodology is needed, given our operating context and the expectation on long-term performance and reliability.

This change will provide several benefits, which include:

- Accuracy of asset condition data
- Improve the accuracy of the required expenditure levels for each asset fleet to maintain or increase performance
- Validation of our asset database information
- Allow for better forecasting of future health conditions, and:
- Increase overall reliability by targeting renewals in areas where there are a larger number of H1 and H2 assets.

For FY24 and FY25 we have planned and budgeted additional drone-based inspections (mainly urban and the balance of rural areas) to provide further input data for our existing asset health model. Completing this program will provide the foundation and information required for our future change in assessment methodology.

The workstream for the implementation of these improvements is split up into two sections¬ –bottom up and top down. The bottom-up approach focuses on decisions for individual assets and the top-down approach considers questions related to the overall fleet population.

The bottom-up approach

The bottom-up approach will target improvements in the acquisition, grading, and use of asset condition information for short-planning horizon decision-making. The bottom-up stream acknowledges that the quality of data produced by asset inspections significantly influences safety and service level outcomes and drives a significant proportion of the organisation's OPEX and CAPEX expenditure. Some key tasks for the bottom-up stream are as follows:

- Ensure completeness and quality of asset data (section 7.10.2 covers data quality improvement initiative)
- Implement the EEA AHI methodology consistently for all asset fleets.
- Develop and implement criticality and risk indicators.
- Implement defect triage and short/medium work planning and prioritisation processes based on risk.

The top-down approach

The top-down approach will target improvements in modelling the relationship between asset renewal investments and the 10-year trajectory of asset condition related risk. The purpose of this modelling will be to quantify the benefits of various expenditure profiles so that we can optimise our asset health and risk profile to meet safety and service level targets with insight into renewal programme deliverability. The top-down stream leverages the work of the bottom-up stream by adding the following capabilities:

- Forecasting the asset health and risk profile for the overall fleet for future years (up to 10) without replacement.
- Forecasting the asset health and risk profile for future years with varying replacement volumes.

10.3.4 Asset criticality

We will start considering the criticality of an asset to set priority in our inspection, maintenance, and renewal programmes. We have yet to apply criticality on an individual asset level given the complexity in assessing each asset. Our approach is to assess fleets at a feeder section level to enable us to apply criticality over the entire range of assets. This will enable us to provide an initial view on asset risk for our asset fleets and inform our replacement programmes.

Asset criticality is determined by the impact of an asset on:

- **Risk to public safety:** ground mounted transformers and ring main units have a higher risk of public safety if they are insecure or faulty, so a specialised maintenance regime and three yearly inspection programme applies to these assets.
- **Vulnerability to third party damage:** assets vulnerable to third party damage are protected where possible. Defects from condition monitoring are prioritised to ensure that those that have a high probability of causing outages or that may pose a health and safety risk are attended to urgently.
- **Security of supply:** the load served by the assets (type and magnitude), availability of back-feed connections and risk of multiple feeder faults drives a higher criticality. As one example, sections of multi-circuit lines with more than one feeder on a pole are subject to additional condition monitoring to mitigate the risk of multiple feeder faults.
- **Reliability:** This includes assets supplying large numbers of customers, or that can help isolate fault sections of the network or can support in restoring supply.
  - Reclosers are critical to isolating transient faults to avoid sustained outages, and to isolate faulted areas so that a fault only affects the minimum number of consumers as possible.
  - First sections of feeders that have the highest reliability impact if faults occur have more regular vegetation patrols to identify and trim vegetation.
  - Several cables that exit the Te Awamutu GXPs have also been temporarily de-rated due to unknown soil conditions and hence temperature at high load; and are being replaced.

- **Power quality:** ability to maintain regulated voltage. Voltage regulators are critical to maintaining regulated voltage limits to consumers at peak load periods. A specialised maintenance regime is applied to voltage regulators.

Once an initial criticality assessment is completed, we will look to fine tune the assessment to include local parameters such as local schools, high population density areas etc.

10.4 Asset fleet class summary

A summary of the length and units of Waipā owned assets is highlighted below:

Asset class	Asset Class type	Unit	Quantity
Poles	Concrete and Steel	No	21,224
	Wood	No	1,357
Crossarms	Wood	No	29,369
	Steel	No	2,381
Overhead conductor	110 kV (HV)	Km	36
	11 kV (HV)	Km	1,232
	400 V (LV)	Km	432
Cables	11k V (HV)	Km	150
	400 V (LV) *	Km	340
LV pillars		No	8,167
Distribution transformers	Pole mounted	No	2,765
	Ground mounted	No	908
Distribution switchgear	Ring main units, RMU	No	181
	Reclosers	No	114
	Air-break switches & gas switches & fuse switches	No	5,396
Voltage management	Voltage regulator	Sites	21
	Capacitors	Sites	1
Communication systems repeaters		Sites	5
Relays	Protection relays	No	132
	Load control ripple relays	No	18,956
Generation	Diesel generators	No	5

** Excludes service cable and streetlight cable*

Table 36: Waipā asset classes

10.5 Asset fleet plans structure

Asset lifecycle planning seeks to balance the cost and risk of maintaining an asset in service with the cost of replacing it. Premature asset replacement is costly as the service potential of the replaced asset will not have been fully utilised. Equally, replacing assets too late can increase the risk of safety incidences and service interruptions. Therefore, asset replacement planning requires a balance between the costs of premature replacement against the risks of asset failure, public or contractor safety and the deterioration of supply reliability that will occur if assets are allowed to fail in service.

In this AMP, we have structured our fleet plans as follows:

- Fleet overview
- Asset fleet objectives
- Condition, performance, and risks
- Lifecycle activities
  - Design and construct
  - Operate and maintain
  - Renew and dispose

10.6 Overhead structures

10.6.1 Fleet overview

Our pole fleet is the backbone of the network as it physically supports the distribution of electricity throughout the Waipā region. These assets are spread over the three operating voltages (110kV,11kV and 400V), with the assets predominantly being used on the 11kV distribution network.

There was a large replacement drive in the 1970's and 1980's to convert the asset fleet to concrete poles, with the 22,581 overall pole count being made up of concrete (93%), wooden (6%), and steel poles (1%). This direction has put Waipā in a very good position in terms of asset fleet reliability and expenditure requirement for these assets.

To complement this approach and to continue on our network resilience path, Waipā networks has changed from traditional hardwood crossarms to steel cross arms. The existing hardwood crossarms are coming up for renewal and failures have increased in the last three years (compared to the previous 10). This analysis is also confirmed by the inspections completed in FY22, with a large number of crossarms in the H1 an H2 categories. In response to this, we have introduced a transitional budget for the next three years to increase the number of crossarms we are replacing and target the H1 and H2 category assets. Further inspections are programmed in FY24/25 for the more urban assets which will increase our insights into forecast renewals and budgeting requirements.

While we have a plan for this asset fleet in terms of replacements, our network development plans to build substations will build the additional resilience required to reduce the number of people affected for the minor incidences of failure we are currently seeing for this fleet.

In terms of the 110kV lines, construction of the Te-Awamutu – Hangitiki line was completed in FY17 to increase the security of supply for the Te Awamutu area. This line is owned and maintained by Waipā and is made up of both steel and concrete poles. The line is relatively young in terms of replacement and maintenance requirements, however there is still maintenance work with respect to vegetation clearances and fall risks which continue on an annual basis.

Pole fleet summary

Table 37 below provides a summary of the pole assets on our network.

Pole Types	Material	Number	% of fleet
Hardwood	Wood	301	1%
Softwood	Wood	935	4%
Larch	Wood	121	0.5%
110kV Line	Concrete and Steel	188	1%
Brown Bros Light	Concrete	10139	45%
Brown Bros Heavy	Concrete	317	1%
Stresscrete	Concrete	7394	33%
Bill Young	Concrete	510	2%
Window	Concrete	182	1%
Other	Other	4	0.0%
Busck	Concrete	2440	11%
Concrete	Concrete	63	0.3%
Total		**22,581**	**100%**

Table 37: Pole fleet Assets Summary

Poles and crossarm profiles

Figure 62 and Figure 63 show the age profile of the pole and crossarm assets. A significant proportion of the crossarm population are hardwood. Our current policy is to install galvanised steel crossarms for HV circuits to align with the concrete pole lifespan.

The nominal life of a hardwood cross arm is approximately 40 years, the age profile in Figure 63 shows that there is potential for a spike in the volume of crossarms that will need replacement in one period. Our upcoming risk-based renewal modelling initiatives (Section 10.3.3) will assist in determining a sustainable long-term renewal rate.

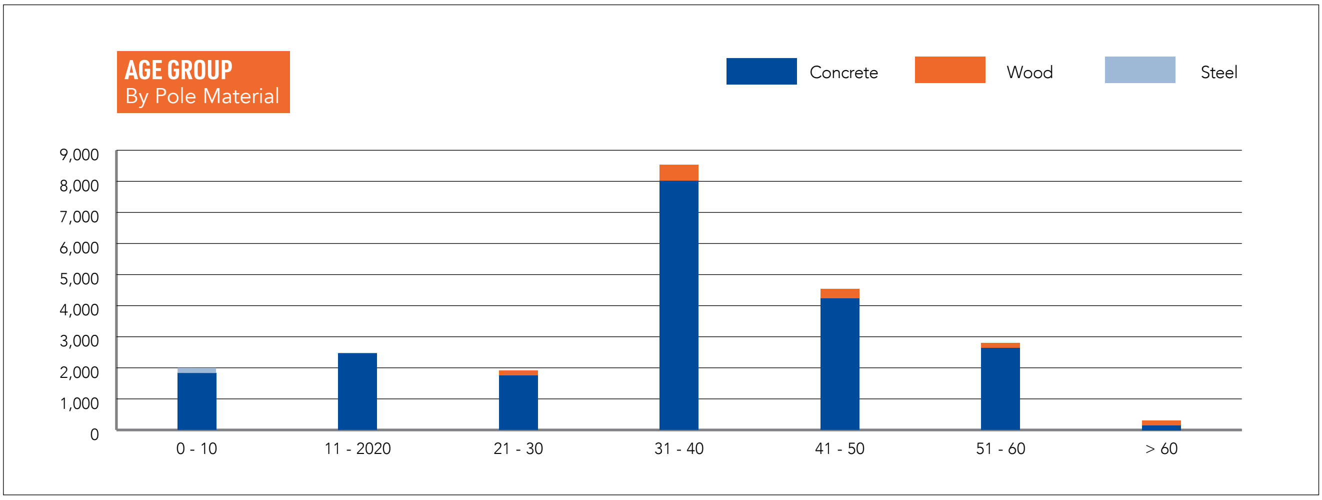


Figure 62: Pole Age Graph

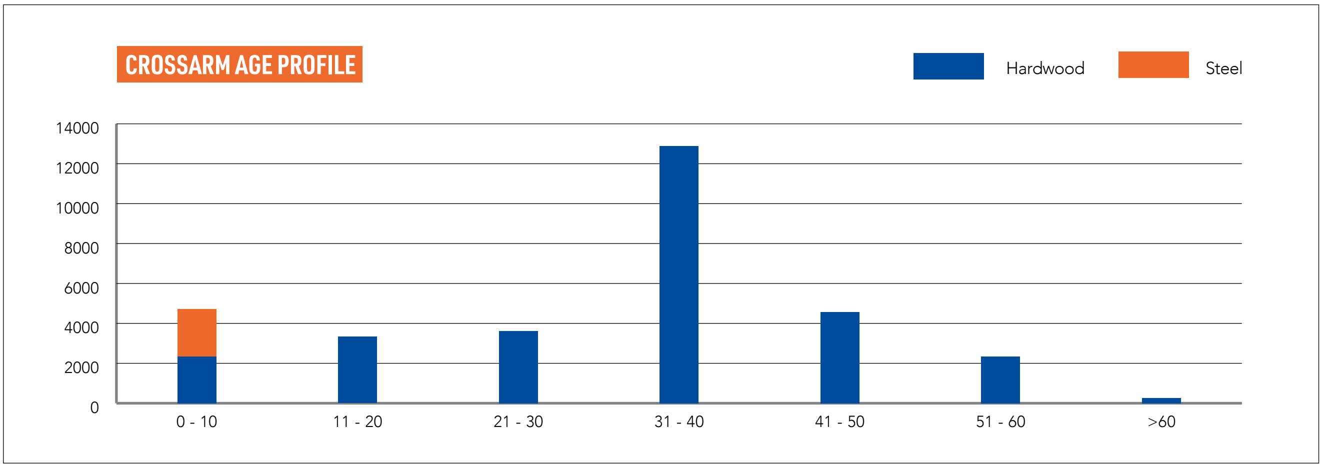


Figure 63: Crossarm Age Graph

10.6.2 Condition, performance, and risks

Figure 64 below shows the overall pole asset health indicator scores, derived from the age data. This profile shows that most of the pole population is in good condition and is supported by considering the high percentage of concrete poles on the network.

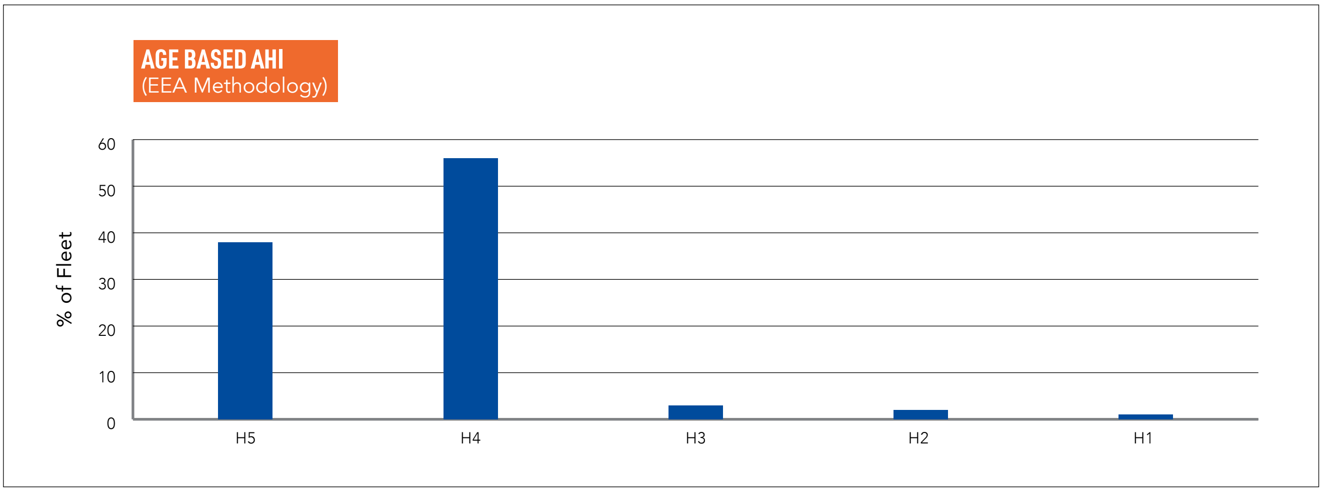


Figure 64: Overall Pole Health

10.6.2.1 Wood poles

Common condition issues with timber poles are deterioration of pole strength due to internal or external decay. Poles which are leaning, have head splits or incur third party damage, may necessitate pole remediation or replacement.

The hardwood pole asset health indicators show that most poles are in the H3 and H4 category. The management strategy of phasing them out of the network by condition is therefore appropriate to manage safety risk due to loss of strength in service.

The pole-top survey data has not been used for health forecasting this year as wood pole failures almost always occur at or below the groundline. Further work is planned in FY2025 to capture groundline/below ground condition drivers for the wood pole fleet.

10.6.2.2 Softwood poles

The softwood pole asset health indicators show that most poles are in the H4 category, reflecting the mid-life age of this pole population. These will also be phased out of the network based on condition.

10.6.2.3 Steel poles

Steel poles are mostly on the 110 kV line from Te Awamutu to Hangatiki that is Waipā owned but operated by the Transpower System Operator as part of the national grid. This line was constructed in 2016 with a 50-year design life and has robust steel pole and concrete pole construction. The steel pole asset health indicator H5 category reflects the near-new age of this pole population.

10.6.2.4 Concrete poles

The population of reinforced concrete poles within the network is in good condition with AHI of either H4 or H5. Common condition issues with concrete poles include cracks, spalling (loss of concrete mass due to corrosion of the reinforcing steel), leaning poles and third-party damage.

Crossarms

Condition assessments identify signs of deterioration for hardwood cross arms – primarily through splitting. Where possible, cross arms exhibiting these conditions are grouped for replacement, with the insulators renewed at the same time.

Figure 65 shows the age profile of the crossarm asset health indicator scores. This profile shows that most of the crossarm population is in good condition. A high proportion of the H5 scores are of the galvanised steel cross arms installed since 2012. The crossarms with H1 and H2 scores will be prioritised for replacement.

We currently have about 669 steel crossarms on LV circuits. Equipment risk review has identified a low probability risk of raising LV neutral voltages in the event of an earth fault occurring when there is a faulty LV neutral insulator. To mitigate this risk, we will gradually transition back to non-conductive crossarms for LV circuits.

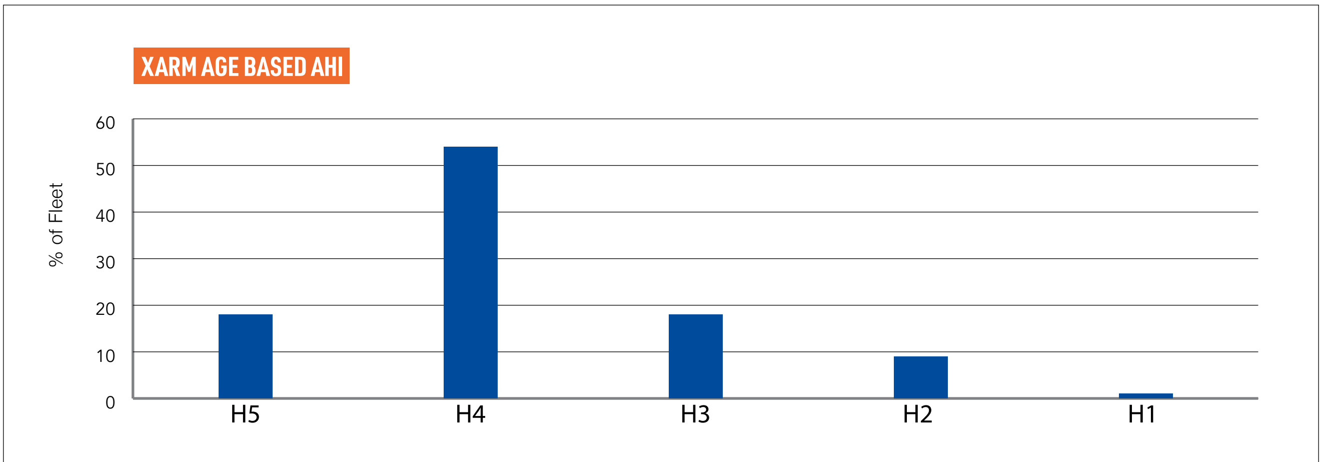


Figure 65: Crossarm asset health

Other overhead line hardware

- Pin type insulators develop reliability issues later in life such as split insulators due to pin corrosion or leaning on cross arms due to the bending moment on the pin causing the cross-arm hole to wear and enlarge, weakening the connection. These are identified through inspections and replaced as required.
- High wind loadings can sometimes result in fatigue failures with line hardware such as binders, compression sleeves, line guards and armour rods.

10.6.3 Lifecycle activities

10.6.3.1 Design and construct

New poles are required for the following reasons:

- New connections – growth
- Replacement of poles that are reaching end of life
- Conductor upgrade to increase capacity for growth and/or supply security
- Resolve hot spots to improve reliability and/or safety

Standard line hardware consists of prestressed concrete poles with galvanised steel cross arms and polymer insulators. Softwood treated poles are used in rare occasions where access prevents use of a concrete pole.

10.6.3.2 Operate and maintain

The risk of failure of the overhead multi-circuit feeders is managed by an intensive maintenance regime that involves acoustic and thermal surveying of the lines to detect any incipient faults before failures occur.

The maintenance schedule for overhead structures is based on a condition assessment, currently by high-resolution aerial photography of concrete poles and ground inspection of wood poles. The overhead inspections cover the pole, crossarm and line hardware. The period of inspection is 5 years.

We are updating our standard testing procedures for wooden poles based on the EEA timber pole condition assessment guide.

10.6.3.3 Renew or dispose

There are often economies of scale in replacing entire sections of the line at the same time, particularly in remote areas where crew transport and set-up costs are significant. We generally seek to resolve all defects in a switching module to reduce shutdown requirements to a minimum.

Crossarms are replaced at the same time as poles are replaced and when conditions require earlier replacement.

Planned actions include:

- Five yearly inspections of all poles. On-going review of the current approach to include consideration of asset criticality could result in a different inspection rate or customised on asset criticality.
- Prioritise poles in H1 condition.
- Replace poles in H2 condition based on criticality consideration. Modelled replacement volumes are currently informed by historical replacement levels and defect rate. Asset health and risk modelling will confirm the volume of replacements to achieve an acceptable risk profile and the desired performance level.
- Focus on HV larch wood poles replacement. There are 187 larch wood poles on the network, and they will be replaced at a rate of approximately 20 poles per year or faster if the type issue coincides with other drivers, and this will ensure all poles of this type are replaced within the planning period for this AMP.
- Over time, implement the strategy to replace all hardwood poles supporting HV lines.

Table 38 shows the forecast H1 and H2 poles and crossarms from age-based asset health modelling. The scheduled replacement quantities have been adjusted based on inspection observations for part of the network and will be revised on completion of the inspection exercise.

- Wood pole renewals are below the 5-year forecast for H1 and H2 assets as the renewals are currently scheduled over the next 10-years, rather than 5-years. The wood pole fault rate has been very low, indicating our current age-based forecasting is conservative. The forecast renewals will be refined when ground-line condition data is captured in FY25 and health forecasting transitions to condition-driven.
- Crossarm renewals are below the 5-year forecast for H1 and H2 assets. The forecast renewals are based on replacing all forecast H1 assets over the next 5-years. As mentioned above, the pole-top condition survey results have recently been reviewed and will result in changes to the current quantities of H1, H2 and H3 assets.

Upon completion of the internal validation, the development of a condition and risk modelling tool and inspection for timber pole, the 5-year forecast of renewals and budget will be revised and included in our 2024 AMP.

Asset Type	MPL	Overall Count	Forecast H1 & H2 (5yrs)	Forecast Replacements
Concrete Poles	100	21,049	0	0
Wooden poles	60	1,357	703	430
Steel Poles	100	175	0	0
Hardwood Crossarms	60	29,369	4457	1,450

Table 38: Pole and crossarm replacements

10.7 Overhead conductor

10.7.1 Fleet overview

Most conductor on the network is copper for both HV and LV circuits. Other conductor types are ACSR and AAAC. Some older spur lines where demand is relatively low and static still have galvanised steel conductor. Galvanised steel conductor is replaced based on condition determined by visual inspections.

Age of most overhead conductor is less than the expected useful life. Figure 66 shows the overhead conductor age profile.

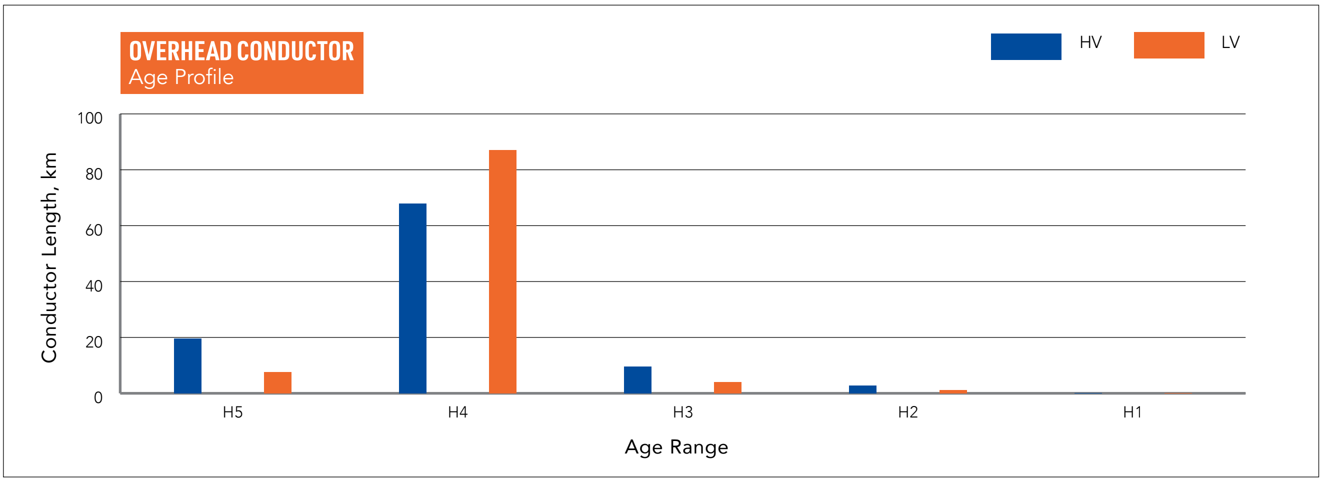


Figure 66: Overhead conductor age profile

Figure 67 shows the overhead conductor health grading. The AHI grading is based on asset age, given the difficulty in assessing the condition of conductor.

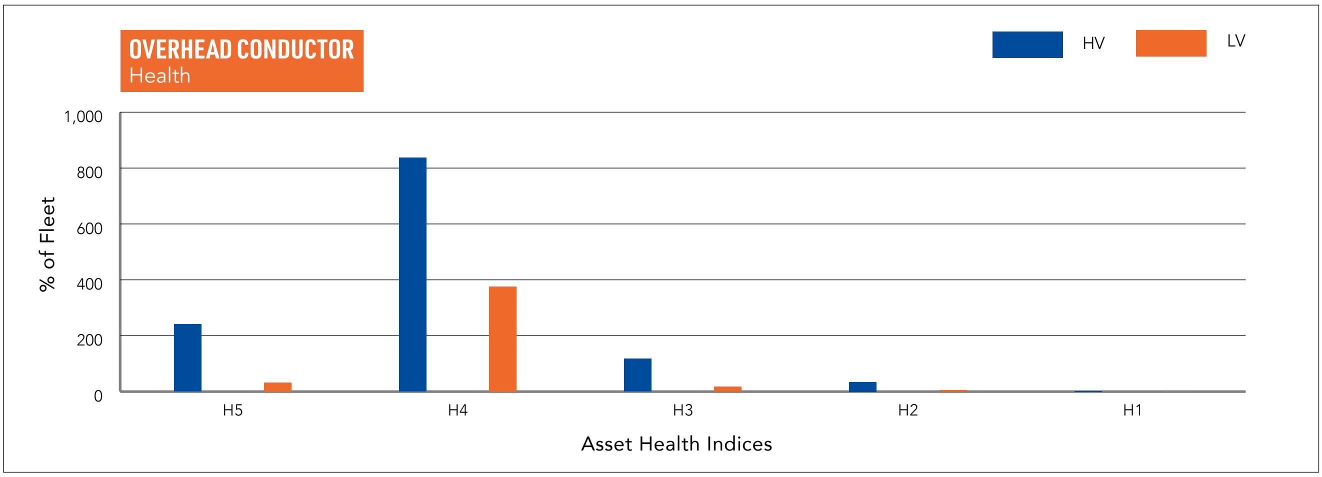


Figure 67: HV conductor health

10.7.2 Fleet management objectives

Conductor renewal is often undertaken with other works (such as pole replacements) where it is deemed economically beneficial to do so. Our specific objectives for the asset fleet are:

- Standardise the conductor types used on the network
- Increase the reliability of the overall asset fleet by targeting asset material type risk for replacement, e.g., galvanised steel.

10.7.3 Condition, performance, and risks

The condition of the network's copper, aluminium and ACSR conductor is mostly showing deterioration aligned with age but is in serviceable condition. The poorer condition distribution conductor is galvanised steel. Conductor failures are mostly caused by contact from foreign objects like trees or birds or from corrosion or fatigue. Conductor vibration and wind also contribute to metal fatigue.

Most of our network is away from the coast so steel corrosion generally progresses at a slower rate than where the conductor is exposed to coastal wind. The effects of corrosions and/or fatigue are cumulative over time.

10.7.4 Lifecycle activities

10.7.4.1 Design and construct

As a general guide, our standard line conductor specifications are:

- Primarily AAAC conductor – some AAC used on LV.
- ACSR where required (typically based on mechanical loading).
- Special consideration will be given to unique circumstances, for example, use of covered conductor in locations susceptible to windborne debris.

Periodic reviews identify those areas where changes in demand may require upgrades to the capacity of the network, generally by way of increases in the conductor size.

10.7.4.2 Operate and maintain

Conductors are generally long-life assets, with little maintenance required. Corrosion from sea spray or fatigue from wind driven vibration can age the conductor. The effects of corrosions and/or fatiguing can only be remedied by renewal.

The backbone of the distribution system is constructed at three phase 11kV. Most of the central area of the 11kV network is interconnected and configured to allow backfeed supply from at least one other feeder. This arrangement provides flexibility in the operation of the system and enables supply to be maintained to most consumers in urban areas during planned or unplanned outages. However, the edge portions of our network are supplied by radial spur lines which have no alternative supply options.

Determining conductor health is a complex process; sampling can provide meaningful insights but is not always practical or economic. Visual inspections are done on the conductor at the same time as pole inspections, and during LiDAR surveying. Following faults, field teams inspect the affected span to ensure any conductor defects are repaired at the time.

Where vegetation is a common failure mode on a line, the conductor configuration may be redesigned or modified to mitigate the consequence of further contacts. For example, use of delta configuration, and application of insulated conductor.

The maintenance regime for conductors is a five yearly visual inspection.

10.7.4.3 Renew or dispose

We apply a condition and risk-based strategy to determine the priority for conductor replacements. Galvanised steel conductor has higher risk of failure so is renewed when identified through the inspections.

Drivers for conductor renewal are analysed alongside pole and crossarm renewal as to coordinate replacement work. However, conductor renewal usually requires renewal of the supporting structures (poles) and their components, as:

- Older conductor is generally strung on older poles.
- The replacement conductor is commonly heavier necessitating a line redesign to current code requirements.
- Remnant pole strengths of older poles are often unknown (unless proven by testing) so cannot be reutilised under the new line construction codes regardless of their condition.

Table 39 shows the quantities of HV and LV overhead conductor and forecast conductor lengths with AHI of H1 and H2 informed by age based asset health. The replacement quantities are averaged over the period to provide a uniform work programme.

There has been a low volume of conductor renewal to date. In 2023, we will start investigating replacement of steel conductor, to better define our forecast replacement and renewal in the 2024 AMP.

Asset Type (Conductor)	MPL	Overall Length (km)	Forecast H1 & H2 (5yrs)	Forecast Replacements
Copper	70	883	31	-
Aluminium	60	340	34	-
Steel	50	8	3.3	3.3
Total	-	**1231**	**68.3**	-

Table 39: Conductor forecast replacements

10.8 Distribution (HV) cables

10.8.1 Fleet overview

Our fleet of distribution cables operates at 11kV and is 166 km in length. The distribution cable system is largely installed within the urban areas of Te Awamutu and Cambridge in the CBDs and in recent subdivisions, and to a lesser extent in Kihikihi. Longer lengths of cable are installed from the Cambridge and Te Awamutu GXPs as the first section of feeders and to increase the capacity to industrial customers like the APL glass factory.

There are two classes of cable, the Paper Insulated Lead Cover (PILC) cable with an expected service life of 70 years, and the Cross-Linked Polyethylene (XLPE) cable with an expected service life of 45 years. Figure 68 shows the cable distribution network is relatively young, with most of the cable installed within the last 20 years.

The key driver for installation of distribution cable in urban areas is to increase network reliability, deliver increased capacity and compliance with district planning regulation requirements for assets in built up areas.

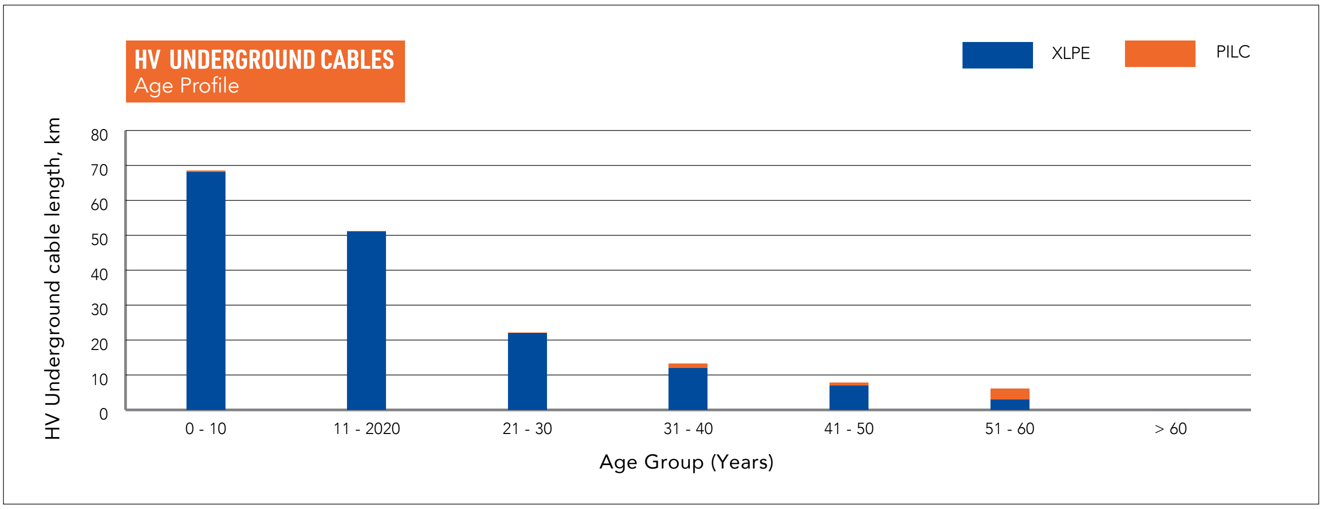


Figure 68: Distribution cable age profile

Replacement of older generation distribution cable is performed with other work on urban distribution network such as circuit capacity upgrades, or transformer or ring main unit replacements. This has gradually seen a decline in first generation XLPE cables (e.g., CANZAC type) and PILC cables. However, there are still sections of cable that are approaching end of life that will need replacement over the planning period.

10.8.2 Fleet management objectives

In addition to the networkwide objectives, we have the following fleet-specific objectives for cables (the fleet objectives are the same for both LV and HV cables):

- No injuries from working on and around 11 kV and LV cables
- Reduce overall cost by specifying cable systems appropriate for expected load and installation environment

10.8.3 Condition, performance, and risks

Cable degradation is driven by several factors including:

- Design and manufacture including insulation material type
- Installation type and environment, particularly thermal heating
- Electrical loading
- Cable age
- External factors (third party damage, ground movement, etc).

The distribution cable fleet is relatively new, and the majority uses modern XLPE plastic insulation technologies including water blocking and water-tree retardant properties. This newer cable imposes minimal risk to network reliability beyond the current planning period. The cables are typically buried, and where the cable transitions to overhead connections on a cable termination pole, the cable is surrounded by mechanical protection to minimise damage from third parties.

The distribution cable fleet asset health in Figure 69 shows the distribution cable fleet is in good condition. A small proportion of the XLPE cable with asset health indicators of H1 and H2 are pre-1980 cables that are prone to the water-treeing failure mode.

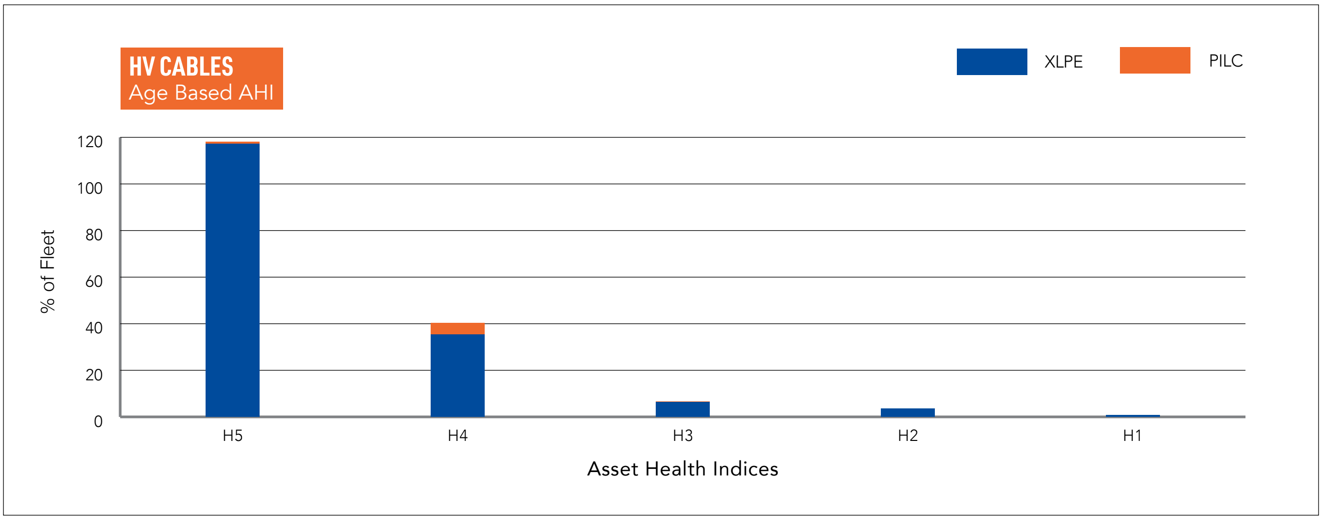


Figure 69: Distribution cable AHI summary

10.8.4 Lifecycle activities

10.8.4.1 Design and construct

When installing new sections of underground distribution network during new-builds or cable replacement, we use a standardised set of cable sizes. We install 35mm2, 95mm2, 185mm2 or 300mm2 multicore aluminium cables with XLPE insulation. Single core cables and other conductor sizes may be used for specific applications, such as when there is need for higher-than-normal current ratings or to suit the installation environment. Standardisation of cable size allows for the reduction in the requirements for critical spares, such as jointing kits, etc., as well as ensuring staff are competent in handling and working with regular sizes.

Cables connected to overhead lines are protected from lightning strikes with surge arrestors.

10.8.4.2 Operate and maintain

Cables are generally maintenance free as they are typically buried, with the only exposed sections being at the overhead to underground transitions, or at termination onto switchgear and other plant.

We regularly perform asset inspections, which include visual inspection of cable termination poles and ground-mounted switchgear for signs of wear or damage, including condition degradation due to exposure to UV.

Cable faults most commonly occur due to interference from third parties during activities such as excavation or underground thrusting. Where distribution cables have been damaged and there is an increased risk of failure, corrective action is immediately taken to avoid a fault developing through:

- Replacement of mechanical protection on cable termination pole
- Replacement of the cable termination due to degradation, and/or
- Removal of failed/damaged section.

10.8.4.3 Renew or dispose

Our renewal approach for distribution cables is to replace on condition (when and where known) and/or age. Assessing cables' condition through testing can be difficult, largely due to the time and cost involved, and the nature of the testing.

We use the EEA AHI guide to assess need for renewal of cables. The EEA AHI guide provides end of life drivers for cables based on known issues, loading history, partial discharge and failure history which can be used to deduce condition. Another key determinant of life of a cable is the installation method and the ground conditions within which it is installed.

Table 40 shows the statistics for the cable on our network split into the two different cable types (XLPE and PILC). We also have estimated the forecast replacement requirements to maintain asset health.

We will better define our forecast replacement scope and budget in the 2024 AMP.

Asset Type (Cable)	MPL (years)	Overall Length (km)	Forecast H1 & H2 (5yrs)	Forecast Replacements
XLPE	60	513	7.2	7.2
PILC	100	7	-	-
Total	-	**520**	**7.2**	**7.2**

Table 40: Cable replacement forecast

10.9 Low voltage cables and LV pillars

10.9.1 Fleet overview

Our LV cable fleet operates at 230V/400V. The main assets within this class are cables, link boxes, LV cabinets, service boxes and pillar boxes.

The LV distribution network provides the typical interface between the distribution system and customer installations. The typical customer installation is supplied from either an overhead service line or from a service cable connected to an LV underground distribution box.

Our LV underground cable network consists of 491 km of circuit length, including street light circuits. The bulk of the LV cable population was installed within the last 25 years, during new subdivision installations or overhead to underground conversions. Figure 70 provides the age profile of our LV cables.

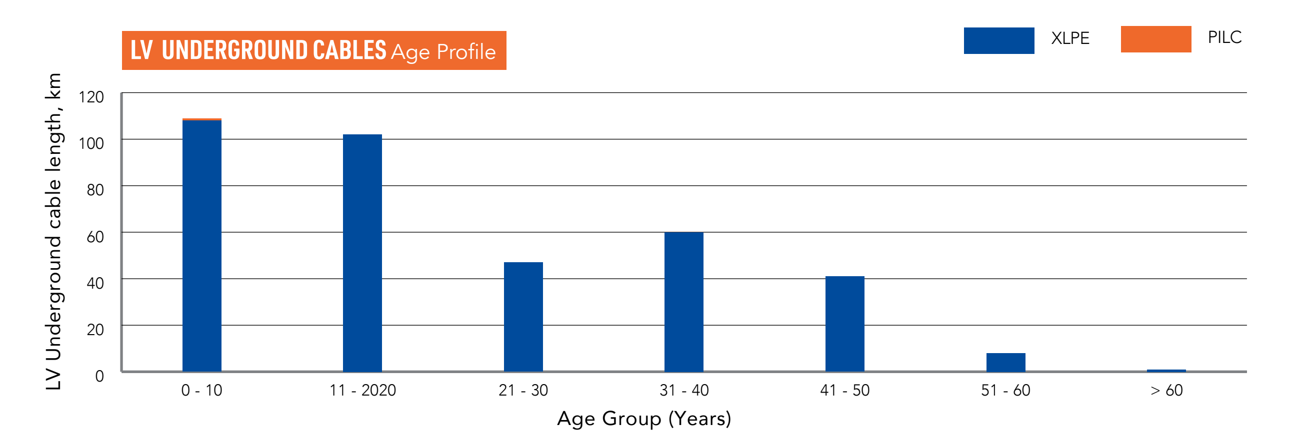


Figure 70: Low voltage cable age profile

10.9.2 Fleet management objectives

In addition to the networkwide objectives, we have the following fleet-specific objectives for cables (the fleet objectives are the same for both LV and HV cables):

- No injuries from working on and around 11 kV and LV cables
- Reduce overall cost by specifying cable systems appropriate for expected load and installation environment

10.9.3 Condition, performance, and risks

Customer service cable connect to the LV cable network at the LV service pillar box (usually located on the property boundary or on the street frontage near the property).

There are portions of the LV cable network that employ early types of XLPE or PILC insulated cables that are approaching end of life. When a portion of the LV network is approaching the end of its useful life and is supplying several customers, such as in the CBD area, we use condition assessment based on the AHI guide before renewing/replacing it. Repeated failures are a typical trigger for replacement.

LV cables are typically buried but where the cable transitions above ground to overhead connections on a cable termination pole, the cable is surrounded by mechanical protection to minimise damage from third parties.

Many LV outages are due to failure at the transformer LV box caused by external interference including vehicle impact, vandalism, vermin or failure of terminations and joints. To manage this risk, LV boxes are typically installed in protected areas, sheltered from external influences, and inspected regularly.

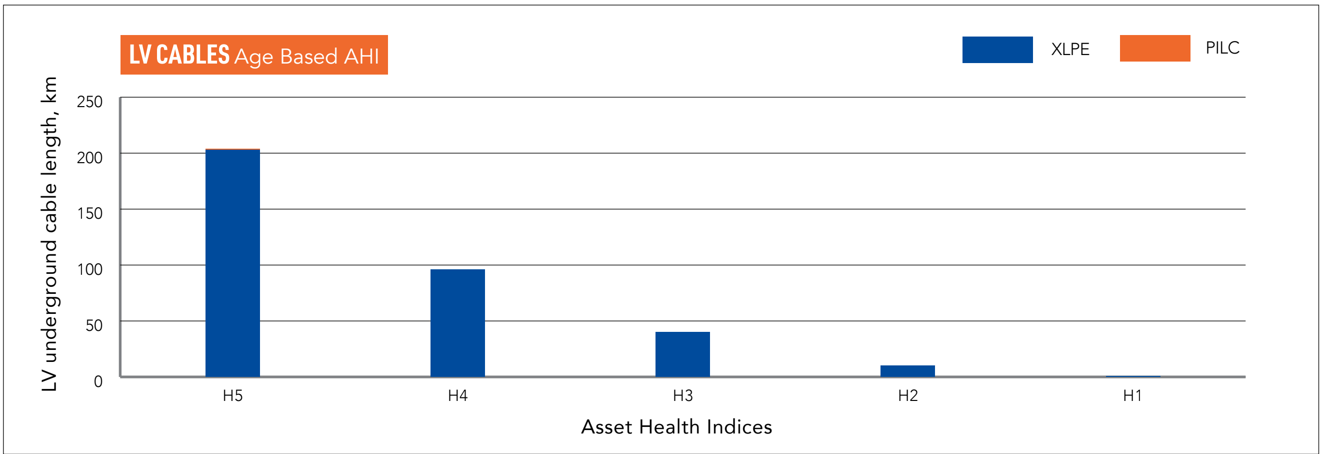


Figure 71 - LV cable age-based AHI

10.9.4 Lifecycle activities

10.9.4.1 Design and construct

We carry stock of numerous sizes of aluminium and copper cables for use on the LV cable network or to perform customer work. Due to the relative simplicity of LV cable terminations, there is reduced need to standardise on a reduced selection of cable sizes. However, it is necessary to pick the right size cable for the application, considering voltage drop, continuous loading, fault current capacity and mechanical performance.

LV box types are assessed and approved before use on our LV network. Considerations include the ability to cover metallic bus sections, compatibility with approved fuse carriers, mechanical performance, locking ability, ease of installation, connection, and fault repairs. We have adopted a large urban type fibreglass LV box, to replace metallic types used on the network to improve safety for field crews working on the LV box.

10.9.4.2 Operate and maintain

Our pillar inspection programme identifies poor condition low voltage pillars to address the safety risk to both the public and our field crews due to insecure pillars. The capital cost of replacing pillars has been estimated based on the cost of pillar replacements undertaken to date.

10.9.4.3 Renew or dispose

Renewal of LV cables is managed using a run to failure strategy unless the cable supplies critical customers where alternative supply options are limited or non-existent. Volume of LV cable renewal work is expected to remain relatively low given the age and size of the existing LV cable fleet.

10.10 Distribution transformers

Distribution transformers convert electrical energy from 11kV to low voltage 400V (or 230V single phase). They help deliver a safe and reliable network at an appropriate voltage. Our transformers are oil filled and therefore have inherent environmental and fire risks that must be managed.

Transformers come in a variety of sizes, can be single or three phase, and be ground- or pole-mounted. Larger ground mounted units are typically used for urban situations and for commercial customers requiring greater capacity.

Table 41 summarises the population of distribution transformers by kVA rating. Approximately 37% are 30kVA or smaller. A transformer of this size typically supplies one or two houses in a rural area.

Rating	Numbers of transformers	% of total	% of fleet
≤ 15kVA	474	13%	1%
> 15 and ≤ 30kVA	895	24%	4%
>30 and ≤ 100kVA	1,743	47%	0.5%
>100kVA	561	15%	1%
Total	**3,673**	**100%**	**45%**

Table 41: All distribution transformer population by kVA rating

Transformer replacement is triggered by failure in service or occurrence of defects such as oil leaks or excessive rust, and by third parties (e.g., vehicle accidents). The common causes of equipment degradation are:

- Deterioration of the insulation, windings and/or bushings.
- Moisture and contaminant concentrations in insulating oil.
- Thermal failure because of overloads.
- Mechanical loosening of internal components, including winding and core.
- Oil leaks through faulty seals or corrosion.
- External tank/enclosure damage and corrosion.
- Lightning strikes.

Distribution transformers have risks of oil fires and oil leakage, but proper installation reduces these events. We have oil spill kits and our field crews are trained to handle oil spills.

10.10.1 Fleet management objectives

Fleet specific objectives for managing the lifecycle and risks of distribution transformers assets in addition to fleetwide objectives, are to:

- Reduce risk to public safety from transformer located in road reserve,
- Minimise customer interruptions due to transformer faults, and
- Correctly disposing of these assets when they are retired.

10.10.2 Pole mount transformers

10.10.2.1 Fleet overview

Most of the transformer fleet is pole mounted with ratings up to 100kVA. Larger pole-mounted transformers, particularly those serving urban areas, were historically mounted in a 2-pole configuration. We are replacing the 2-pole mounted transformers due to the risk of structural or mechanical failure and last installations will be replaced in early FY24

We have 2,762 pole mounted transformer substations on the network. Figure 72 shows the age profile of the fleet as of March 2022. The expected life of pole mounted transformers ranges from 45 to 70 years. Approximately 15% of our fleet is within this age group.

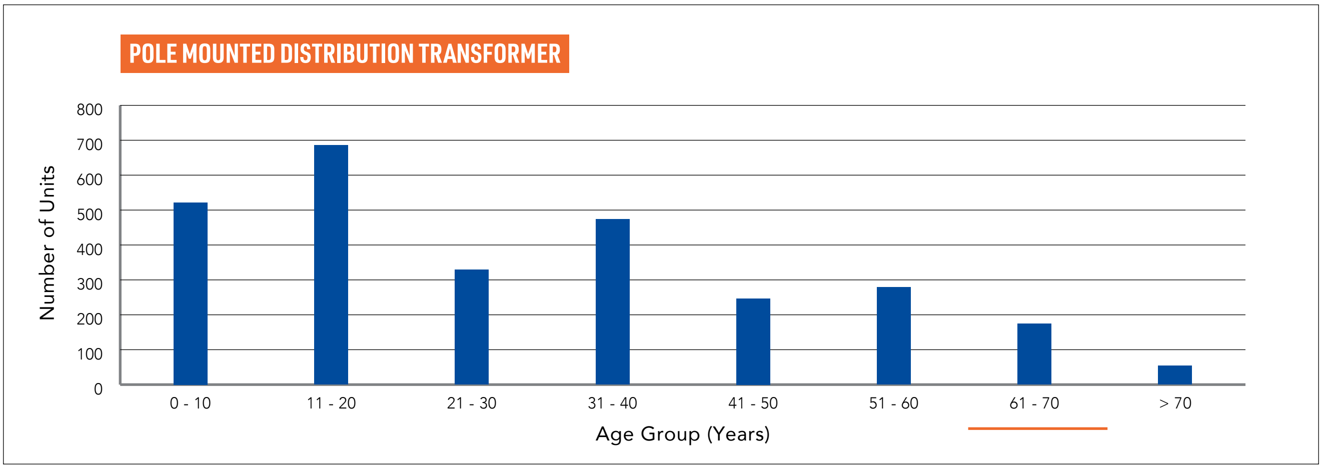


Figure 72: Pole mounted distribution transformers age profile

10.10.2.2 Condition, performance, and risks

Pole mount transformer health is derived from age data using the EEA guidelines. We have some condition data from the pole-top survey; however, this does not cover our full fleet. We are validating the pole-top survey data, which may be utilised in future health assessments.

Figure 73 shows the asset health profile of the pole mounted transformer assets derived from the aerial survey data. The pole mounted transformer population is generally in good serviceable condition, with only a small proportion of the assets in H2 needing closer monitoring and/or replacement based on risk of each unit in that category.

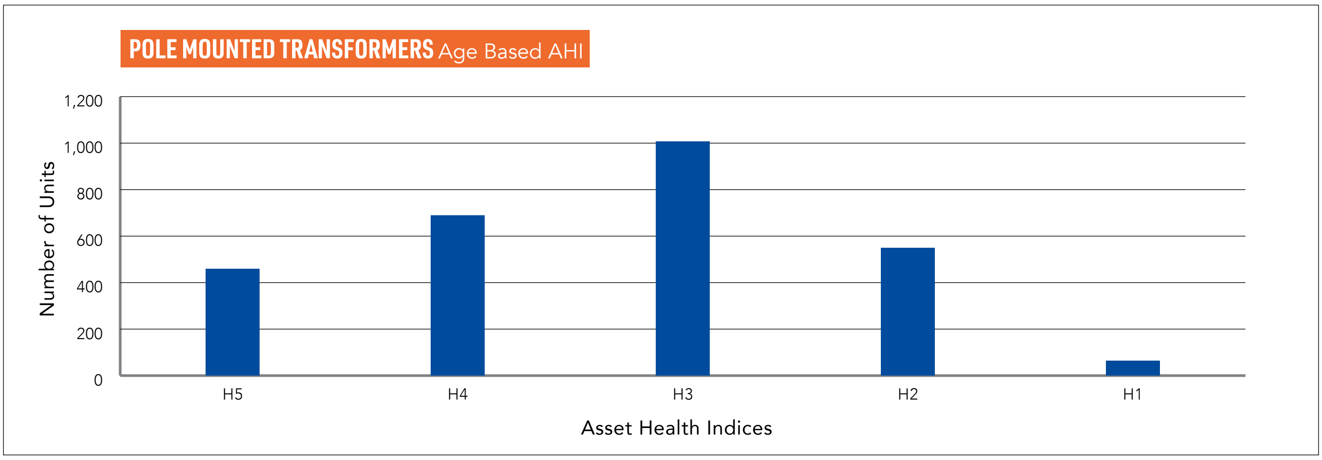


Figure 73: Asset Health Indicators for pole mounted rural distribution transformers

10.10.2.3 Design and construct

To improve resilience to major seismic events, new pole-mounted transformers are limited to 100kVA and below, with standard designs detailing pole and foundation requirements. When transformers are replaced, the pole may also be upgraded to comply with modern standards, and size selected to meet expected demand.

10.10.2.4 Operate and maintain

Reactive replacement of pole-mounted transformers can usually be done quickly, reducing the outage time for affected customers. Suitable spare transformers in stock at our depot ensures supply is restored quickly if a transformer fails.

Our preventive maintenance inspections for pole-mounted distribution transformers are visual inspections at five yearly intervals. There is need to balance customer impact due to in-service failure of transformers with the cost of obtaining better asset condition information. However, either online monitoring or offline inspections are generally not feasible or disproportionate for the failure modes of this asset class.

An extra issue with offline inspections is that supply may need to be temporarily disconnected. This asset is replaced either when visual condition indicates leaking, extensive corrosion or upon failure.

10.10.2.5 Renew or dispose

Pole mount transformer renewals are below the age-based 5-year forecast for H1 and H2. The forecast renewals are based on the replacement of all forecast H1 assets. H2 assets are not included in the forecast as, based on fault statistics and field observations, age-based forecasting is overestimating low health assets.

Notwithstanding the above, industry practice for small rural pole-mount transformers is run to failure (as the failure mode has low safety and environmental risk). Hence the above renewal forecast based on H1 is also considered conservative. Work is planned to capture condition data in urban areas and move to condition-based forecasting for the full network in our 2024 AMP.

Asset Type	MPL	Overall Count	Forecast H1 (5yrs)	Forecast Replacements
PM Transformer	70	2,765	612	125

Table 42: Forecast PM Transformer Replacements

10.10.3 Ground-mounted transformers

10.10.3.1 Fleet overview

We have 908 ground mounted transformer substations on our network. Ground-mounted transformers may be installed in a customer's building, housed in a concrete block town substation, or in the road reserve in a variety of enclosures. A ground-mounted-substation includes the transformer and LV distribution panel.

Transformer capacity depends on load density but is generally 50kVA or 100kVA in semi-rural lifestyle areas, 200kVA to 500kVA in newer suburban areas, and 500kVA to 1.5MVA in CBD and industrial areas.

Figure 74 shows Our ground-mounted distribution transformer age profile as of March 2022. The expected life of these units ranges from 45 to 60 years.

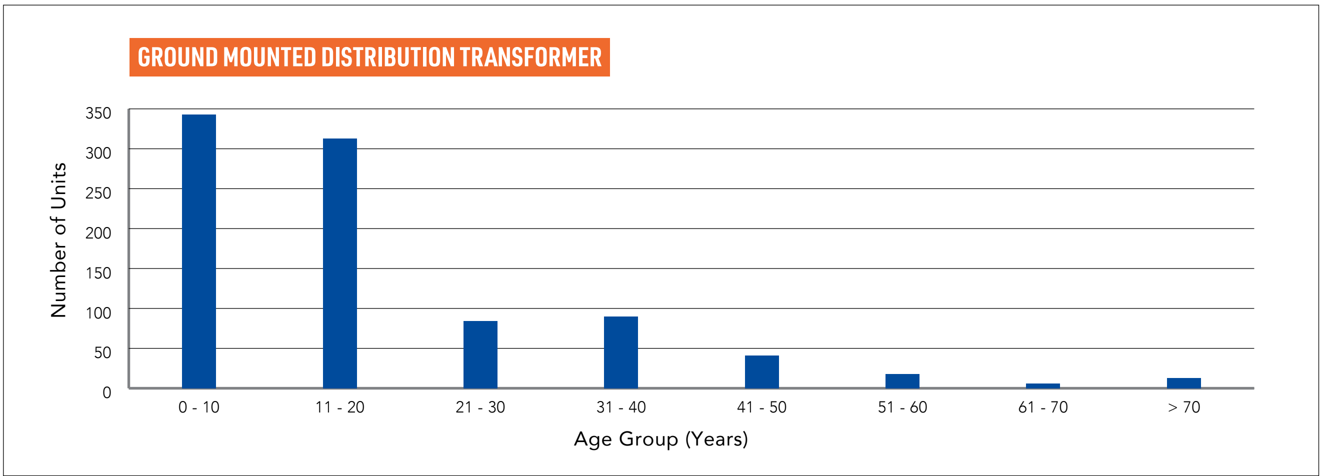


Figure 74: Ground mounted distribution transformers age profile

10.10.3.2 Condition, performance, and risks

Porcelain J type LV fuses are considered a safety defect that triggers replacement of ground mount transformers.

Figure 75 presents the ground mounted transformer fleet condition scores, based on inspected condition. The asset health of the population is good, with only 6% of the asset fleet in H1 or H2 condition.

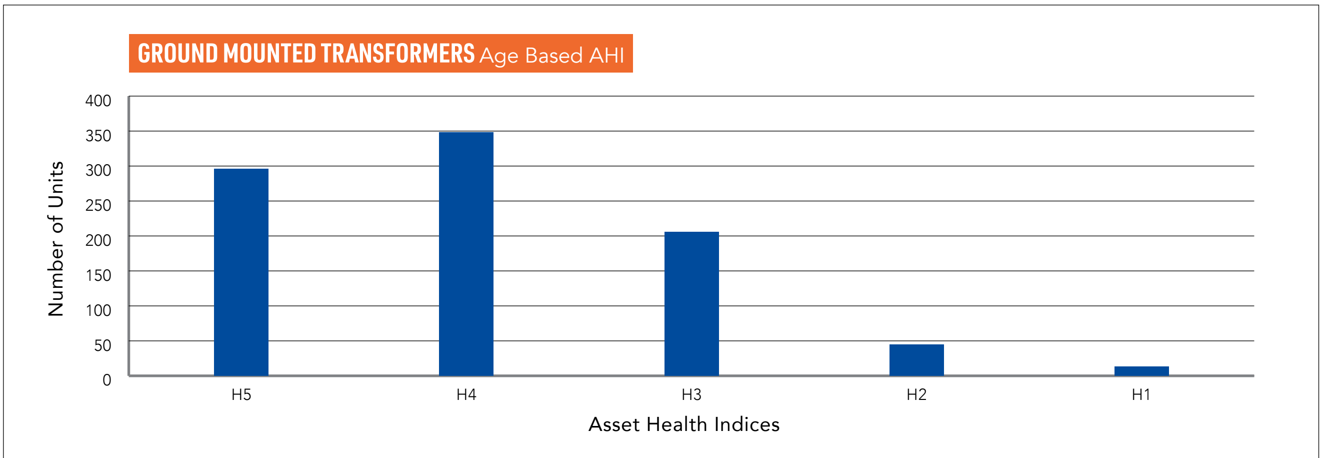


Figure 75: Ground mounted Transformer Asset Health Indicators

10.10.3.3 Design and construct

Ground-mounted transformers require seismically designed foundations (if not housed in a building), along with earthing and an LV panel.

Transformers units are picked form a limited standardised range to manage spares inventory.

10.10.3.4 Operate and maintain

Maximum Demand Indicator (MDI) readings are performed on all large distribution transformers to assess capacity usage. The frequency of the readings is every three years unless triggered by a customer complaint. In these cases, we also use electronic loggers for spot monitoring to provide load profile data. A limited number of transformers have time of use data logging for monitoring purposes.

Transformers used for large industrial loads can be exposed to more onerous load conditions than residential transformers, making it critical that they are regularly visited and tested.

Our routine inspections for:

- All ground mounted substations on a three-year inspection rotation, and
- Fonterra Hautapu transformer fleet requires visual checks and dissolved gas analysis (DGA) and breakdown oil testing annually. This information assists in assessing internal health of these transformers for remedial action.

10.10.3.5 Renew or dispose

While minor remedial work is carried out when a defect is detected, the asset is only replaced when it fails in service, significant tank defects are found, or load growth requires larger capacity to be installed.

Table 43 shows the ground mounted transformers due for replacement with aged-based AHI score of H1. H2 assets are not included in the forecast as, based on fault statistics and field observations, age-based forecasting is overestimating low health assets. Ground mount transformer renewals are below the age-based 5-year forecast for H1. We currently replace GM transformers based on routine inspection results; hence the forecast amount (based on age data) is conservative.

Asset Type	MPL	Overall Count	Forecast H1 (5yrs)	Forecast Replacements
GM Transformer	70	908	58	13

Table 43: Forecast GM Transformer Replacements

10.11 Voltage regulators

10.11.1 Fleet overview

To maintain regulatory 11kV voltage on our feeders we have a significant number of voltage regulator units in service on the distribution network.

Voltage Regulators are typically rated at 100, 200 or 300 amps at 11kV and are installed in an open delta (2 tank) or closed delta (3 tank) configuration. For new sites closed delta configuration is the preferred connection configuration as it is relatively less prone to voltage fluctuations with unbalanced loads and has better efficiency compared to the open delta configuration.

About 40% of our 11kV voltage regulators were constructed on two-pole structures. The structure is not compliant with current seismic standards.

There are a total of 21 Voltage Regulator sites in operation with 15 on the Te Awamutu network and 6 on the Cambridge network with 42 and 16 Voltage Regulator Cans respectively.

	Te Awamutu		Cambridge	
Size (amps)	Sites	Cans	Sites	Cans
100	2	5	2	4
200	8	23	3	9
300	5	14	1	3

Table 44: Voltage Regulator quantity

Figure 76 shows the age profile for the Voltage Regulator fleet. The expected life is 55 years assuming good maintenance and servicing programmes and the replacement decisions is condition based. Control systems for voltage regulators have a shorter life requiring mid-life controller replacements.

There are only two Voltage Regulator Cans in service (at one site) that is older than 40 years with the rest 23 years or newer.

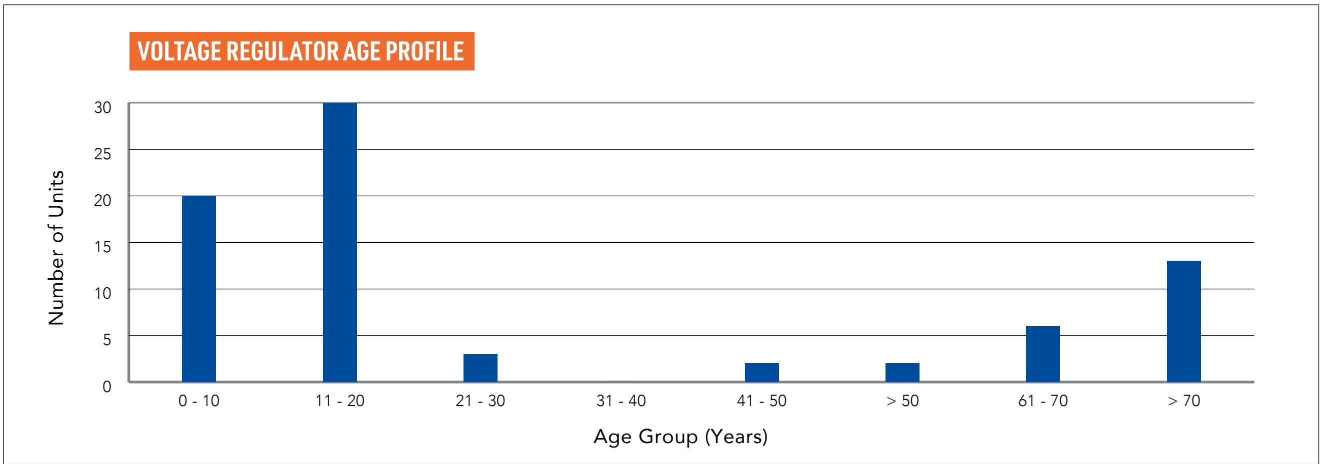


Figure 76: Voltage regulator age profile

10.11.2 Asset management objectives

In addition to the fleet-wide asset management objectives, voltage regulator application objectives include:

- Compliance with regulatory power quality limits,
- Improve distribution feeder utilisation and minimise costs of feeder upgrades,
- Improve supply security by supporting backfeed supply from alternative feeders.

10.11.3 Condition, performance, and risks

The main failure modes for Voltage Regulators are equipment degradation such as:

- Deterioration of the insulation, windings and/or bushings.
- Moisture and contaminant concentrations in insulating oil.
- Thermal failure because of overloads.
- Mechanical loosening of internal components, including winding and core.
- Oil leaks through faulty seals
- External tank/enclosure damage and corrosion.
- Control system failure through ingress of moisture or vermin.
- External factors that can result in failures include lightning strikes and third parties (e.g., vehicle accidents) causing major damage to the structure.

Figure 77 gives the asset health profile for the voltage regulators. Age is used as proxy for condition to complement the inspection data. Voltage regulators are inspected every four years for external corrosion and damage, and SCADA and communications availability.

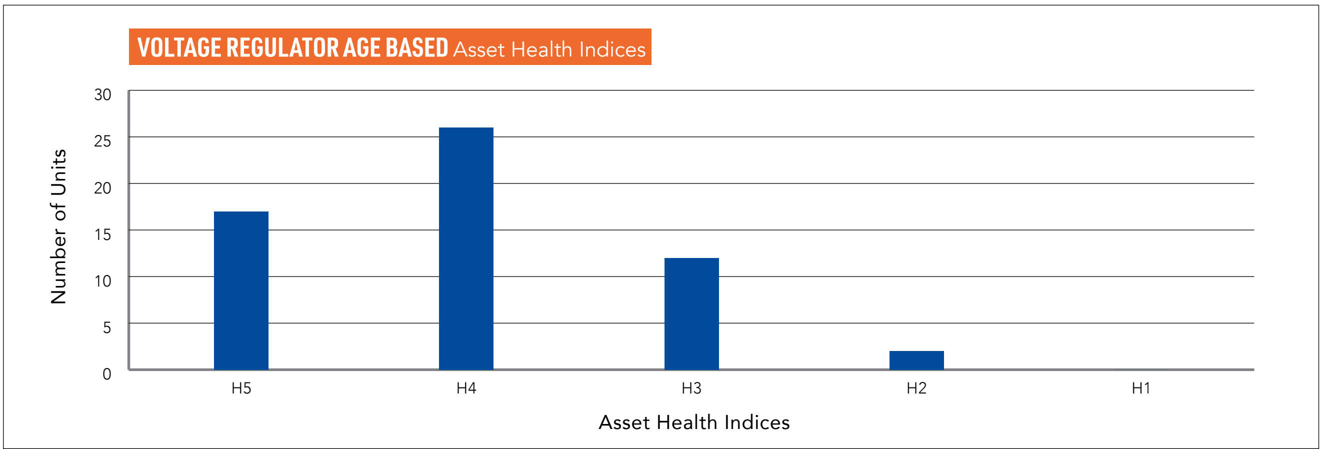


Figure 77 voltage regulator fleet asset health profile

The biggest risk to site security are car vs pole incidents. The impact is minimised by having spares that can be quickly installed to restore service. Vandalism can also be a problem which is managed by routine inspections and ensuring the integrity of cabinet locks.

Voltage Regulators are generally reliable, but there are risks of oil fires or oil leakage. We have oil spillage mitigation and our field crews are trained in their use.

10.11.4 Lifecycle activities

10.11.4.1 Design and construct

A voltage regulator site comprises of:

- Voltage regulator unit,
- Control systems. Single phase controllers are being replaced with three phase units that provide a single control and monitoring point for each site, and
- Structures which are poles with standard platforms to support the voltage regulators.

We use a limited standard range of voltage regulator equipment for efficient management of spares and familiarity for field staff.

10.11.4.2 Operate and maintain

The Voltage Regulators are located at key points in the network to maintain voltage under normal operating conditions and support the voltage under back-feed situations as necessary.

Some sites that have 3 voltage regulator units, can be reconfigured to operate as an open delta to cover the contingency of one unit failing when no operational spares are readily available.

Routine maintenance is conducted in accordance with the manufacturer's recommendations and operations counter. The inspection programme for the voltage regulator fleet ensures that actual asset condition is used to inform the asset maintenance and replacement programme.

10.11.4.3 Renew or dispose

We have implemented a fleet asset management plan for voltage regulators that includes a programme of renewal and to prioritise structure rebuilds to make the voltage regulator structures seismically compliant. Therefore, the replacement of voltage regulators exceeds the condition based 5-year forecast for H1 and H2 assets. The high level of renewal results from replacing the pole structures due to the low seismic ratings and the renewal of voltage regulator controllers.

Table 45 shows the voltage regulators forecast for replacement in the next 5 years.

Asset Type	MPL	Overall Count	Forecast H1 & H2 (5yrs)	Forecast Replacements
Voltage Regulators	70	58	4	24

Table 45: Voltage Regulator Forecast Replacements

10.12 Distribution switchgear

10.12.1 Asset management objectives

In addition to the broader asset management objectives for the entire network, the following are fleet-specific objectives for distribution switchgear:

- Safety from working on and around distribution switchgear, and
- Minimise customer impact from switching operations.

10.12.2 Ground-mounted switchgear

10.12.2.1 Fleet overview

Our fleet of ring main unit (RMU) switches provides switching points for parts of the network with distribution underground cables. Almost all the RMUs are in the urban, newer residential and the industrial areas and installed mostly in the road reserve with significant public exposure.

We currently have 119 Ring Main Units (RMU) in service. The fleet is relatively young due to a safety initiative where older oil filled ring main units were replaced to reduce fire risk.

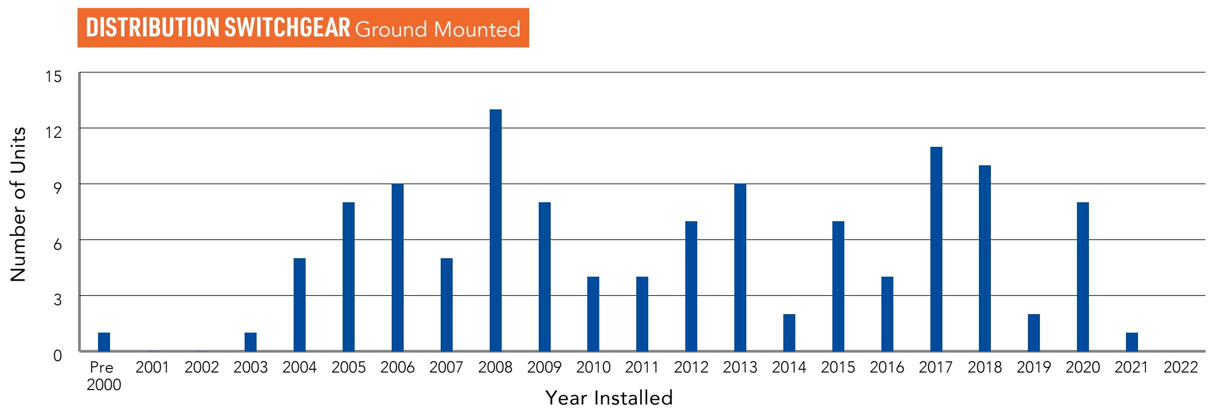


Figure 78: RMU age profile

10.12.2.2 Condition, performance, and risk

The fleet is in good condition due to its age. A small number of installations are affected by the ABB Safelink type issue where the switch moving contacts overshoot the OFF position. The affected units have been tagged and field crews trained in the use of the correct way to operate these units safely.

10.12.2.3 Design and construct

Our standard specification for ring main units requires a BLFR internal arc classification for both operator and public safety. This adequately contains internal arc energy, so the equipment is safe for installation in public places.

We install only SF6 switchgear currently and expect that these RMUs will not require major maintenance over their useful lives. We will install vacuum RMUs or solid dielectric RMUs if cost effective in the future.

10.12.2.4 Operate and maintain

Visual inspections of RMUs are undertaken on a three-yearly basis. For efficiency, these inspections are combined with the inspection of any associated transformer.

10.12.2.5 Renew or dispose

The current fleet is near new, and no replacements are planned.

10.12.3 Pole mounted load break switches (ABS)

10.12.3.1 Fleet overview

We currently have 669 load break switches in service on the distribution network. These are either open air-break switches or the modern equivalent enclosed load break switch type used to segment and isolate lines and provide inter-ties between feeders.

Figure 79 illustrates our pole-mount switch age profile. The assumed age for switches of unknown age produces the significant single age range between 41 to 50 years. 1976 has been assumed as the installation year where the actual age is not known.

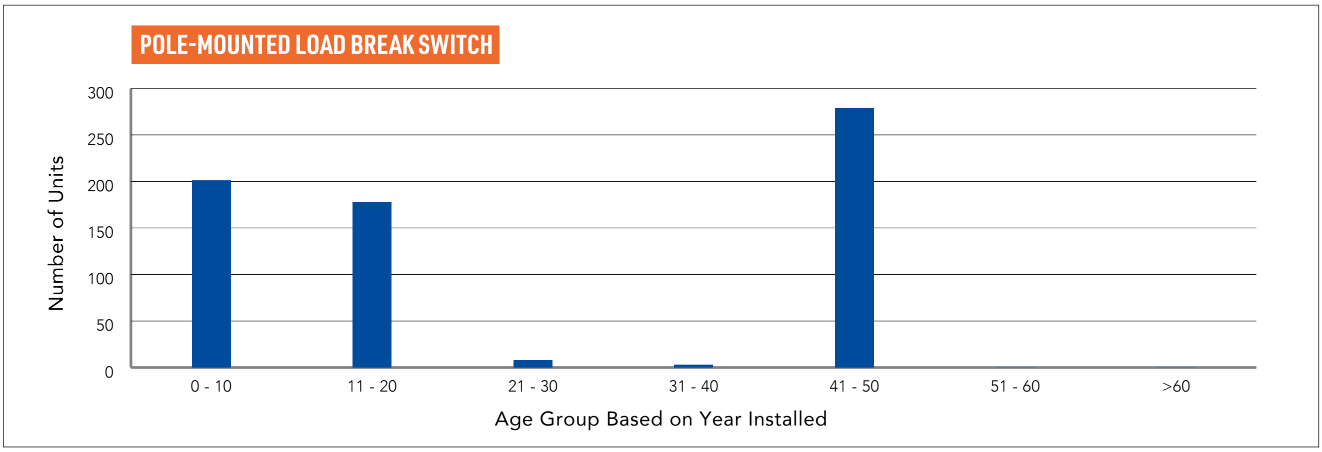


Figure 79: Pole mount switch age profile

10.12.3.2 Condition, performance, and risks

11kV pole mount switches and fuses health is derived from age data using the EEA guidelines. Our age data is not completely reliable (as many of these types of assets, especially fuses, do not have an observable manufacture or installation date, so the installation date has been derived from other sources). We have some condition data from the recent pole-top survey (mostly in rural areas), however this does not cover our full fleet. We are validating the pole-top survey data, which may be utilised in future health assessments.

The most common ABS failure modes are to "freeze up" through infrequent use, for the switch contacts to weld together when they pass fault current or due to insulator failures.

Figure 80 shows the asset health for ABS load break switches compared with other pole mounted switches. The age-based asset health indicators show that about 40% of the ABS are unserviceable. ABS units with H1 rating are not necessarily unsafe, but inoperable. The affected units will not be used for switching until replaced.

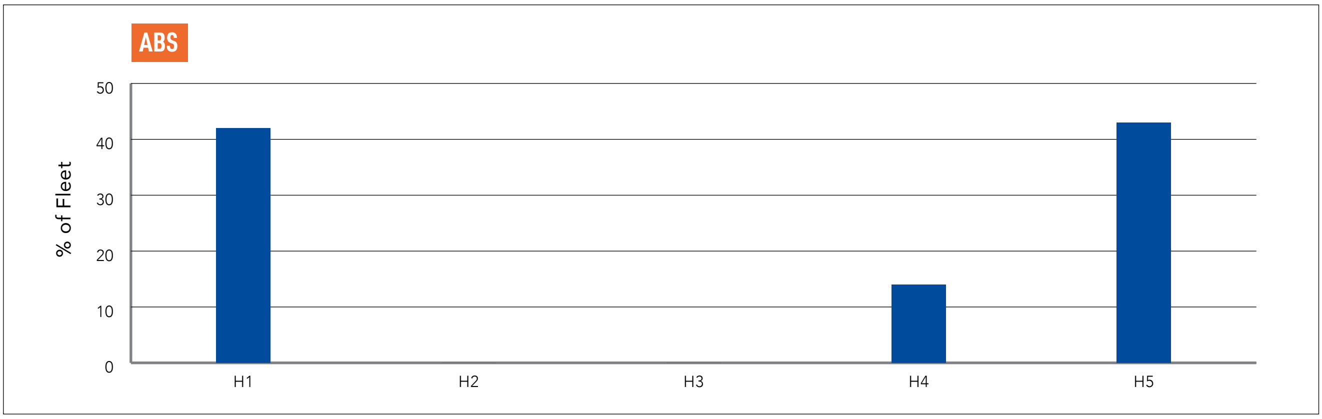


Figure 80: Pole mounted load break switch (ABS) asset health indicators

10.12.3.3 Design and construct

We use load break switches on distribution lines for:

- Sectionalising feeders to reduce outage impacts for construction, maintenance, and fault work.
- Providing tie points within or between feeders.
- Bypass connections to facilitate maintenance of reclosers.

In the future we will install enclosed load-break switches in place of air break switches as:

- The contacts are not exposed, the load break switches are more reliable and have longer life with less maintenance costs, and
- The ability to automate these switches to act as auto-sectionalisers or remote-controlled open points provide a reliability improvement to the network.

10.12.3.4 Operate and maintain

We do not undertake regular maintenance on the ABS units, but the associated earthing systems are tested on a periodic basis.

Our preventive maintenance inspections for ABS are visual inspections at five yearly intervals.

Defective air-break switches are replaced when they fail in service or at the time the pole line is reconstructed with Entec Ecoswitch vacuum interrupting load break switches.

10.12.3.5 Renew or dispose

ABSs are generally disposed of during the process of a line rebuild, or in the case of bypass ABS, when the primary equipment (recloser or voltage regulator) is being renewed. The new line will generally be specified with new switches located in positions appropriate to the new route configuration.

When a defective disconnector is identified, a review process is used to determine if the ABS disconnector is still required for network operations.

11kV pole-mounted switch and fuse renewals have not been adjusted from the 2022 AMP. A 5-year forecast for H1 and H2 has not yet been prepared for this fleet as further work is required to validate the current quantity of H1 and H2 assets, especially for pole-mounted switches. Validating the current condition and developing a more accurate forecast for renewals is a key focus for the current year and will be included in our 2024 AMP;

Asset Type	MPL	Overall Count	Forecast H1 & H2 (5yrs)	Forecast Replacements
PM ABS	40	669	280	24

Table 46: Pole mounted ABS replacement forecasts

10.12.4 Fuse switch (drop out fuse, DDO)

10.12.4.1 Fleet overview

Drop out fuses are used to clear faults from spur lines, protecting the main feeder, and to provide 11kV side protection for line connected distribution transformers. We currently have 4,388 sets of 11kV pole fuses in service. Figure 81 illustrates Our drop out fuse age profile. Where actual age is not known 1976 has been assumed as the installation year.

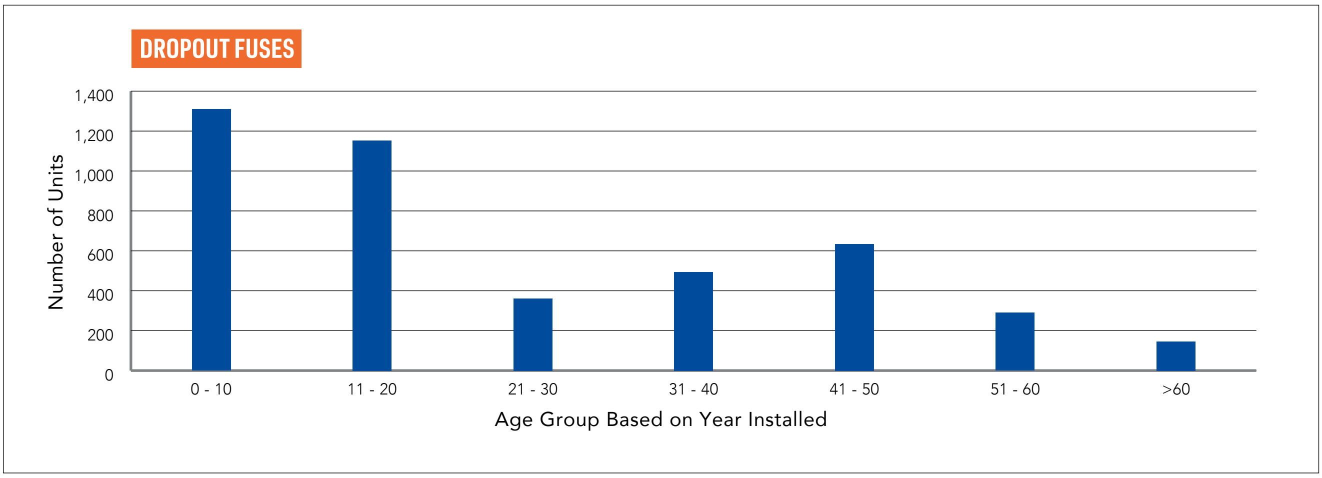


Figure 81: Drop out fuses age profile

10.12.4.2 Condition, performance, and risks

Figure 82 shows the asset health profile for the DDO units and other pole mounted switches. The older "Vulcan" drop out fuse sets comprise varnished paper insulating tubes and powder fuses which deteriorate over time.

Some newer sets were constructed using stainless steel brackets but with galvanised nuts and bolts which have corroded and need replacing. We will continue to replace these defective fuses with stainless steel assemblies when they fail in service and when they are identified as a defect during the programmed visual inspections.

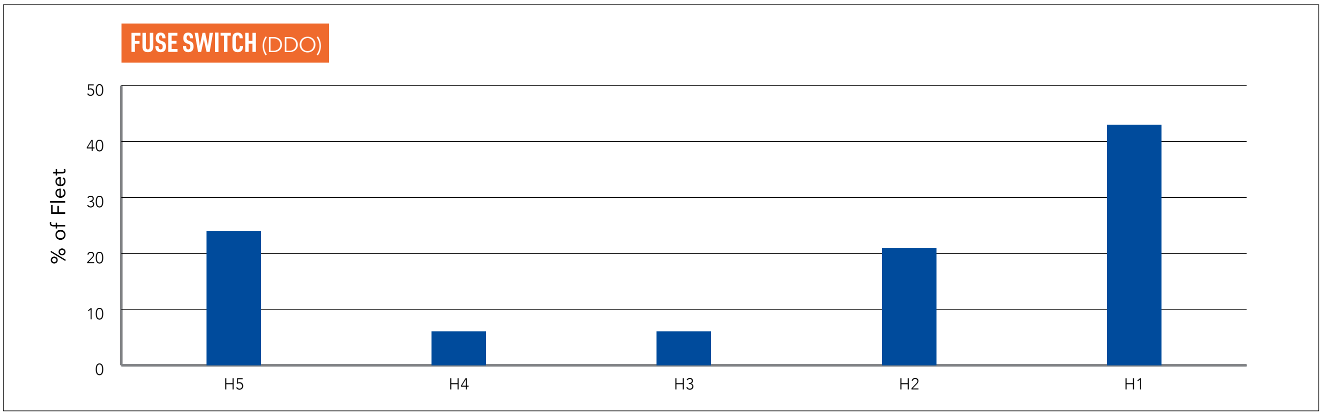


Figure 82: Pole mounted fuse switches asset health

10.12.4.3 Design and construct

DDO units provide a point of switching and protection for spur lines and distribution transformers. For greater efficiency the DDO fuse choice is coordinated with protection on the main line.

10.12.4.4 Operate and maintain

We do not undertake regular maintenance on DDO fuses, but the fuse element is replaced when the DDO operates to clear a fault.

10.12.4.5 Renew or dispose

In line with the industry practice, the need for DDOs is reviewed when primary equipment is being changed, and DDOs are replaced or disposed of when crossarm, transformer or pole are replaced or as identified for replacement as part of our defect reporting / inspection process. Units associated with a transformer are reviewed when the transformer is renewed.

Asset Type	MPL	Overall Count	Forecast H1 & H2 (5yrs)	Forecast Replacements
PM Fuse Switch, DDO	40	4,388	1,317	158

Table 47: PM HV fuse switch replacement forecasts

10.12.5 Reclosers and sectionalisers

10.12.5.1 Fleet overview

We have 120 reclosers and sectionalisers in service to sectionalise the network when faults occur and limit the number of customers affected by faults.

Figure 83 summarises our reclosers and sectionalisers age profiles. The profile reflects the large reliability improvement initiative that focussed on increasing controllable switches on the network over the last twenty years. The fleet is relatively young with a small number of older devices on the network.

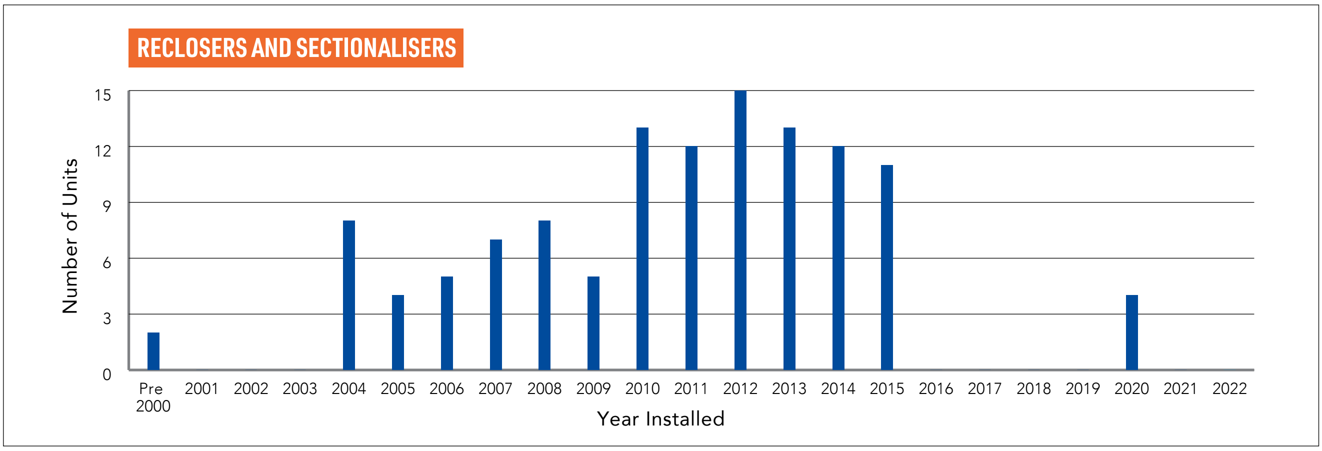


Figure 83: Reclosers and sectionalisers age profile

10.12.5.2 Condition, performance, and risks

A summary of the age-based asset health profile for reclosers is summarised in Figure 84.

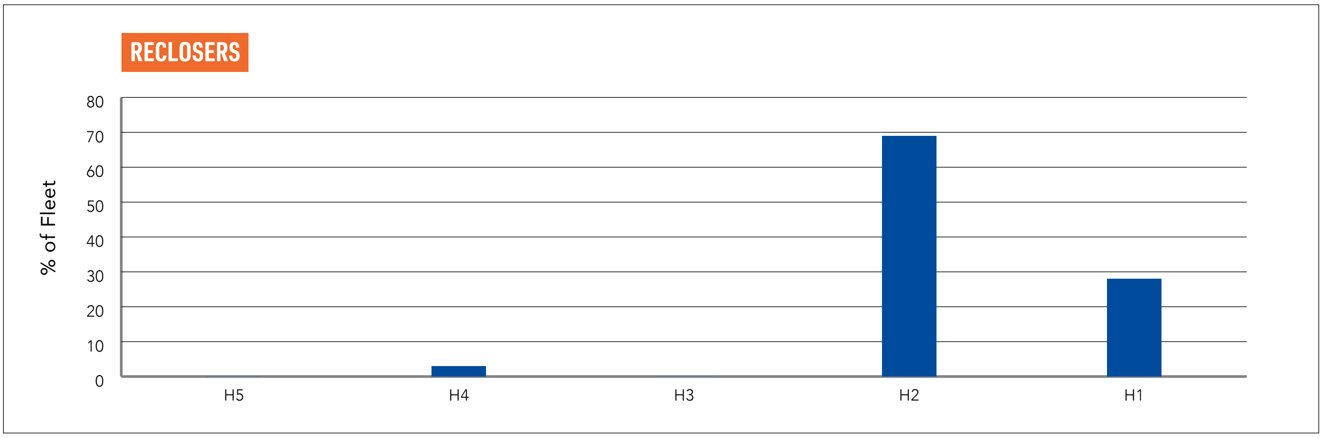


Figure 84: Pole mounted reclosers asset health

Reclosers are inspected for control operation, external corrosion and damage every year. Repairs on existing installations are done after indicators for deterioration are detected. Routine maintenance is conducted in accordance with the manufacturer's recommendations.

The fleet consists of vacuum reclosers, but older units are prone to corrosion. Control lead plugs are also prone to corrosion and deterioration due to environmental factors.

Control unit failures and the unavailability of replacement parts is driving renewal of the control units.

10.12.5.3 Design and construct

Reclosers are located according to network reliability criteria, to protect network sections containing 200 ICPs or 20km of distribution line. Positioning of reclosers considers operability and maintainability, to ensure ease of access to the site for field staff.

Communications connectivity is a critical feature for new recloser sites to enable remote monitoring and control. Reclosers are also fitted with a backup battery system designed to provide eight hours of operability after loss of mains supply, and isolating links and bypass switches to facilitate maintenance.

10.12.5.4 Operate and maintain

Modern reclosers have online monitoring systems which reduces the requirement for site visits. We are progressively rolling out remote engineering access for desktop maintenance and oversight of the control settings via the communications network.

Visual inspections and battery checks are done annually, which is coordinated with testing programme of the associated earth.

A programme of replacing the aged RC01 control boxes with new RC15 control boxes will assist in maintaining the operation of the recloser fleet until the recloser circuit breaker units require replacement.

10.12.5.5 Renew or dispose

Reclosers have a mid-life controller replacement. This enables integration of new protection functionality, monitoring and remote controllability as well as extending the life of the circuit breaker unit. The ability to change between group settings of protection relays on reclosers is of particular benefit at times of high fire risk.

Replacement of a complete recloser unit is made on condition, with consideration given to reliability of the unit and the criticality of its location.

Table 48 shows the switchgear units due for replacement. 11kV pole-mounted switch and fuse renewals have not been adjusted from the 2022 AMP. A 5-year forecast for H1 and H2 has not yet been prepared for this fleet as further work is required to validate the current quantity of H1 and H2 assets, especially for pole-mounted switches. Validating the current condition and developing a more accurate forecast for renewals is a key focus for the current year and will be included in our 2024 AMP. Industry practice for 11kV fuse is to replace at the same time when crossarm, transformer or pole are replaced, while pole-mounted switch should be subjected to a more proactive approach.

Asset Type	MPL	Overall Count	Forecast H1 & H2 (5yrs)	Forecast Replacements
PM Reclosers and Sectionalisers	40	114	5	5

Table 48: Reclosers and sectionalisers replacement forecasts

10.13 Earthing Systems

Earthing systems provide three main functions:

- A voltage reference to earth for the power system.
- An effective fault return path, enabling protection to trip quickly, isolating faulty equipment.
- Reduce earth potential rise (EPR) in case of an earth fault on conventional circuits.

10.13.1 Fleet overview

Every metal clad piece of network equipment that is installed at ground level or designed to be operated from the ground using uninsulated tools is bonded to earth to protect both the public and our field crews from the risk of EPR.

As earthing systems may be shared between different assets at the same site and assets like transformers and switches may be replaced without affecting the earthing system, we treat earthing systems as a separate asset class, with an associated programme of testing earthing effectiveness and carrying out repairs where required.

The age and population of earthing systems has historically not been recorded separately, so the age of the installation is assumed to be that of the original installed equipment. Earthing systems are upgraded if testing reveals non-compliancy with earthing standard, or when the primary equipment is replaced.

10.13.2 Asset management objectives

We will ensure that our staff, contractors, and the public are safe around the network by ensuring that our system earthing, and bonding complies with AS/NZS 3000:2007 earthing standards and NZECP 35 New Zealand Electrical Code of Practice for Power System Earthing.

10.13.3 Condition, performance, and risks

Historically, we have taken a conservative approach to the electrical requirements of earth grids ensuring minimum regulatory requirements are met. Our earthing systems are in a good condition, however there are locations where dry or sandy ground conditions limit the performance of the earthing system requiring additional mitigations beyond standard design.

Where the soil resistivity is not ideal for the construction of earthing systems, we drive additional earth rods deeper than normal, extends the earth grid, and uses conductivity enhancers around the earthing conductors.

The most common causes of earthing system defects are civil or horticultural conversion works on the land causing damage where the earthing system is located. To assist in preventing this, we show earthing zones around assets when underground service drawings are requested.

We have also experienced a growing number of copper earth thefts consistent with recent industry trends. In response we:

- Replace stolen copper earths immediately once discovered,
- Continue to investigate alternative materials for earthing that have lower scrap value, and
- Install copper clad steel conductor on new sites in vulnerable areas and replaces stolen copper earths with copper clad steel conductor.

The cost of installing copper clad steel conductor earths is comparable with pure copper earths, but has significantly lower scrap value, which is expected to act as a deterrent to thieves.

10.13.4 Design and construct

The earth testing and repair programme is based on an even spread of earth banks requiring testing each year. The programme results in each system earth being checked every eight years.

We have standard earthing designs for various asset classes and refers to industry guides for industry best practice, especially where deterministic performance values are not easily achievable. The EEA's Guide to Power System Earthing assesses the risk associated with an earthing system's EPR with a probabilistic methodology that considers:

- The probability of human exposure to an EPR hazard at the site.
- The probability of an EPR event occurring.

10.13.5 Operate and maintain

The resistance of earthing systems is periodically tested at eight yearly intervals. Earth test results drive the corrective maintenance.

Soils around our supply area is generally not corrosive, however, corrosion of earth grids, particularly older connection types have been observed. These are repaired as part of the earth testing programme.

Emergency repairs are also made after damage by external parties.

10.13.6 Renew or dispose

Condition based renewal is generally not applied to earthing systems but are improved or extended if testing identifies deterioration in performance of the earthing. In some cases, there may be a safety reason to rebuild the earthing system to improve the EPR exposure at the site.

Disposal of an earthing system may occur when an entire site is decommissioned which is generally due to asset relocation.

10.14 Secondary systems and assets

Secondary systems include communication, protection, and control systems and are a critical part of operating a safe and reliable electricity network. 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 changes in technology and a commitment to continually improve the performance of the network to meet reliability requirements also drive need to renew the fleet at shorter intervals than primary equipment

10.14.1 Asset management objectives

In addition to the objectives for the whole network the following objectives are also applied to the secondary system assets.

- Fail safe configuration that ensures correct operations including during faults
- Reduce network costs by minimising equipment damage and increasing remote operation and control.

10.14.2 Protection

10.14.2.1 Fleet overview

Protection assets 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 to network assets. This fleet includes fuses and relay protection systems.

Relay protection systems comprise of the sensing devices (CTs and VTs), and a protection relay with signal processing and control logic. Protection relays are configured to operate switchgear with fault current breaking capacity. On our network, protection assets are installed on reclosers and sectionalisers, and on some RMUs.

Automatic Under Frequency Load Shedding (AUFLS) relays are installed at the two GXPs. These are programmed to trip feeders in the event of the system frequency dropping below certain set points, as required by the Electricity Industry Participation Code.

10.14.2.2 Condition, performance, and risks

Protection systems once properly configured perform reliably. Long feeders on our network have very low fault levels at remote ends, which can limit how much a feeder can be extended to provide alternative back-feed while retaining protection sensitivity.

10.14.2.3 Design and construct

The latest protection relays that are being installed provide remote engineering access. This allows technicians and engineers to access information remotely removing the need to download the data at the site. This reduces the time required to understand and react to a fault.

10.14.2.4 Operate and maintain

When a protection device has been identified as defective, it is replaced immediately using a critical spare. If the performance is adequate but showing signs of deterioration, the device is included into the replacement programme.

10.14.2.5 Renew or dispose

The protection replacement programmes consider continued availability of vendor support, and condition (condition is not biggest driver as the systems are generally installed in a controlled environment), functionality, and the risk to the network. Replacement is coordinated with other projects, especially for assets such as switchgear and transformers.

10.14.3 Communication systems

10.14.3.1 Fleet overview

The communications network carries our SCADA system traffic and voice systems. Data is used for SCADA system to monitor and control automated devices whereas voice is used for voice communication between the field staff and the control room for the purpose of operating or switching network devices.

Our communications network consists of different data systems and physical infrastructure including fibre optic circuits, UHF point-to-point digital radios, microwave point-to-point digital radios, point-to-multipoint UHF repeaters and cellular/ADSL circuits.

There is an increasing number of automated devices on the network and the available bandwidth for both voice and data through the older analogue channels is getting narrower.

10.14.3.2 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. Although 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), overall SCADA system speed will not be improved by these measures.

10.14.3.3 Design and construct

Limitations with existing analogues systems highlight the need to go to a digital solution. Key design considerations for communications system renewal/replacement are:

- **Capacity:** new higher capacity equipment that can handle more channels and connect more devices/ increase number of repeater sites
- **Functionality and obsolescence:** This supports a digital solution to increase flexibility
- **Reliability:** ring topology to provide multiple paths for redundancy
- **Quality/grade of service:** This also supports a digital solution to minimise loss of signal strength.

10.14.3.4 Operate and maintain

Yearly visual inspection is completed for radios, switches, and antennas at automated devices and radio sites.

10.14.3.5 Renew or dispose

We are currently evaluating the option of migrating analogue communication to digital platform. This initiative will develop capacity and is covered in section 7.9.

10.14.4 Load control relays and system

10.14.4.1 Fleet overview

We operate a ripple control system for managing peak demand and has a 283Hz ripple injection plant at each GXP. We also own all the ripple relays installed at ICPs on the network.

The ripple plant at Cambridge GXP has two supply connections, one off each 11kV bus section so can that it can still be operated in the event of a half switchboard outage. The Te Awamutu ripple plant has a single supply connection, and a project scheduled for completion in 2023 will provide a second connection.

10.14.4.2 Condition, performance, and risks

The unavailability for service of the ripple plants will put us at risk of exceeding the load control targets and risking load shedding if the ripple plant outage coincides with a Transpower outage that requires us to reduce load.

10.14.4.3 Design and construct

We intend to continue with the existing frequencies.

10.14.4.4 Operate and maintain

We have a service agreement with Landis and Gyr providing annual condition monitoring and access to a contingency spare replacement converter panel and other strategic spares. This enables major faults to be rectified within 48 hours provided the failure is not catastrophic or involving the primary reactor or capacitor plant.

Regular inspection and testing of the ripple injection system assets ensures continued and reliable operation. The preventive maintenance schedule includes yearly onsite testing and physical inspection of ripple plant. To comply with the Electricity Industry Participation Code 2010, we have a 10-year inspection and recertification of ripple relays.

10.14.4.5 Renew or dispose

There are no plans to renew or change the ripple control within the period of this plan. In the absence of other technology developments, the ripple control system will be renewed to maintain this load management capability.

10.15 Generation

10.15.1 Fleet overview

We maintain a small fleet of generator sets for network reliability – support critical parts of the network during outages and provide supply security ahead of delivery of permanent network solutions. The existing generator sets are:

- Swayne Road: 3x 1.5MVA (fixed)
- Te Awamutu depot: 1x 275kVA (portable), 1x 200kVA (fixed)

10.15.2 Asset management objectives

The generator fleet is deployed as a short-term solution to a network problem used on demand, therefore the generator sets need to be serviceable when required to run.

10.15.3 Operate and maintain

The three generator units at Swayne Road are operated to maintain supply security to large industrial customer and reduce peak load at Cambridge GXP. The generator capacity can be used to participate in the reserve market when not needed for their primary function.

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.

The maintenance routine includes inspection and service according to manufacturer specification, and routine operational tests to ensure the generators will run when need to. These assets are not part of the standard network assets, so their maintenance is outsourced, commonly as part of the supply contract.

10.15.4 Renew and dispose

The need for generator sets is reviewed when the asset is nearing end of life 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 is preferred to renewal.

10.16 Systems operation and network support

System operations and network support comprises our functions that directly support electricity network operations. This covers a range of activities on the network to support the **operate and maintain** part of the asset lifecycle management. These include:

- Network operations
- Fault response, maintenance and inspection
- Vegetation management

10.16.1 Network operations

Our network uses its SCADA system to carry out centralised network operations through outsourced control room services. The control room services cover network monitoring, switching, permitting and access control.

Outage management – Planned outages require balancing customer requirements with the need to safely undertake the maintenance and renewal of the network.

10.16.2 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 the number of weather-related outages and the increasing fault restoration times, we have increased the system interruption and emergency budget by 35% increase over the next 10-years (compared to the 2022 AMP). The new forecasts reflect the level of expenditure being incurred in recent years.

10.16.2.1 Maintenance

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 is a more efficient approach and may avoid the disruption of a shutdown to customers.

Safety is a key consideration in choosing whether to use live-live techniques or not. 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 guideline and industry best practice.

Deenergised work

The current approach to deenergised 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.

10.16.2.2 Inspection

Field inspections carry out defect identification on ground mounted equipment that includes transformers, ring main units, reclosers and voltage regulators, using inspection guides and inspection record forms.

10.16.3 Vegetation management

Overview

Vegetation management is necessary to ensure reliability of supply by preventing interference to lines and provides access to network assets, and public safety by reducing the risk or 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.

Our network extends through heavily vegetated areas. Vegetation growth rates are typically high, which increases fire risk in dry summers. Inspections includes frequent assessment of the network to establish where vegetation is encroaching (or approaching encroachment of) overhead lines. It also includes liaising with landowners with subsequent first-cut costs associated with physical trimming or felling of vegetation borne by us.

10.16.3.1 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 as well as contacting those owners whose vegetation is approaching at or exceeding the specified minimum distances.

Vegetation owners have the option of taking ongoing responsibility for maintaining vegetation outside the minimum distance(s) or granting the network owner approval to maintain the vegetation outside the minimum distance by appropriate trimming or removal. The process of cut and trim notices must be repeated for every individual tree on a property. A network owner has no mandate to remove a small tree from under a line but must wait until it encroaches within the growth limit zone before any action can be taken.

The tree legislation requires EDBs to offer tree owners a first free cut. The landowner must then meet the cost of resulting cuts, but this 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 with vegetation management

Trees are one of the significant causes of long duration outages on the network. The current tree legislation only permits minimal clearances and removal of vegetation within the prescribed growth limit zone. However, in areas of high growth, the limits are quickly exceeded after trimming, thereby requiring frequent return visits.

Another concern is that 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 risk of a fire being initiated.

Vegetation management strategy

- 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 are a combination of a rotational survey and reactive trimming of vegetation hot spots. The inspections are undertaken by vehicle, foot, and LiDAR survey.
- Records: Records of vegetation that present a risk to our network are established and managed similarly to an asset, i.e., a record is created with attribute data and specific location details assigned to it. Liaison with the vegetation owners then occurs as appropriate. Where applicable, work packs are designed and compiled to allow either our team or external contractors to undertake the corresponding vegetation control work.
- Stakeholder engagement: We have directed our efforts to manage the risk of vegetation interference by, where possible, obtaining greater clearances 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 inspection required (and subsequent re-trimming of vegetation) and enhances the safety of landowners.

Improvement initiatives

To improve vegetation management practice to reduce the outage impacts, we have identified these initiatives:

- Developing a tree inspection and tree-cut programme based on criticality, and reliability, targeting high-risk in-zone and fall-zone trees
- Develop a program that improves private tree owner approval rate for full cuts
- Develop inspection tool to better visualise/capture network vegetation issues; and
- Increase vegetation management resources in the region.

The implementation plan is being developed over the coming months and more details and improvement targets will be provided in the 2024 AMP.

Risk-based vegetation management

Comprehensive data on vegetation encroachment from the LiDAR aerial survey allows a risk-based approach to vegetation management to be applied. The survey data is used to select the vegetation encroachments to trim based on criticality of the affected assets, as well as operating experience. It is expected that this new approach will maximise the effectiveness of the vegetation expenditure by reducing vegetation faults and the consequential reliability impact.

The approach to vegetation surveying will be evaluated over each planning period to consider effectiveness in reducing vegetation related faults and expenditure on vegetation management. To support the strategy, vegetation management expenditure has been increased by 40% over the next 10-years (compared to the 2022 AMP).

10.17 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.

10.18 Business support (non-network)

This covers corporate activities including:

- CEO and director costs, legal services, non-engineering/technical consulting services.
- Commercial activities including 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.

10.19 Vehicle fleet

10.19.1 Description

We own and manage a vehicle fleet to support the business. Vehicles are an essential asset that enables our activities and to meet our asset management objectives. Our vehicle fleet as at March 2023 includes:

- 28 utility vehicles (utes).
- 13 trucks (including crane, bucket and tipper trucks).
- 10 light vehicles (cars and SUV).
- 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 considers electric or electric/hybrid motors if appropriate), and operational requirements (i.e., suitability for intended use).

10.19.2 Management

Records of our vehicles are maintained in the financial management system, the Smartrak fleet management system, 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 fault utes) travel the greatest distances. These vehicles are typically replaced between three to six years depending on the make and models, 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.

10.20 Buildings and land

10.20.1 Overview

We own and maintain non-network property and buildings, including the main office building and depot in Te Awamutu. This houses engineering, network, financial, commercial, and corporate services staff, and Contracting business staff, including management, supervisors, engineering, design estimators, fault crew and administrative support.

The depot includes an electrical workshop, stores warehouse, plant and vehicle sheds, hazardous goods store and the yard housing materials and equipment.

10.20.2 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 storage of transformers. An off-site storage area is being developed at 220 Racecourse Road, on land purchased next to the Te Awamutu GXP site.

10.21 Capital expenditure forecast

The current replacement volumes and associated forecast expenditure are mainly driven by routine inspection and defect survey outcomes. It is expected that the planned asset health and risk modelling will determine the replacement volumes and their effect on the asset age/health profile that can achieve the desired level of performance or risk.

We consider the differences between the 5-year forecast of H1 and H2, and the 5-year forecast of renewals does not currently increase safety or reliability risk. Whilst our level of renewal may increase in the 2024 AMP from around FY2027 (or earlier based on our modelling work in 2023 to provide a levelled and sustainable long-term renewal programme), we are confident all actual poor-condition assets are being maintained or replaced promptly over the next three years. Our current level of asset failures, our programme to remediate defects found during our recent pole-top survey, and our current inspection programme results support this conclusion.

The forecast expenditure will be reviewed in FY24 to reflect the outcome of asset health and risk modelling. Table 49 shows asset fleet forecast expenditure over the next ten years for replacement and renewal for each asset class.

Asset Replacement & Renewal CAPEX ($000)	FY 23/24	FY 24/25	FY 25/26	FY 26/27	FY 27/28	FY 28/29	FY 29/30	FY 30/31	FY 31/32	FY 32/33
Replace Transformer and Sub Structures - Ground Mounted	483	483	483	483	483	483	483	483	483	483
Replace Transformer and Sub Structures - Pole Mounted	304	304	304	304	304	304	304	304	304	304
Switchgear Replacement Disconnectors	403	403	403	403	403	403	403	403	403	403
Replace Pillar Boxes	255	255	255	255	255	255	255	255	255	255
Replace Pole, Crossarms and insulators	737	737	737	737	737	737	737	737	737	737
Replace Pole, Crossarms and insulators - a 3-year transitional budget addressing prioritised sites from Fugro's pole top inspection	857	857	857	-	-	-	-	-	-	-
Switchgear Replacement Noja Control Boxes & Reclosers	546	546	546	130	130	130	130	130	78	78
Voltage Regulator can replacement and controls renewal	156	156	156	156	78	78	78	-	-	-
SCADA system replacement	50	100	1850	-	-	-	-	-	-	-
Total	**3,791**	**3,841**	**5,591**	**2,468**	**2,390**	**2,390**	**2,390**	**2,312**	**2,260**	**2,260**

Table 49: Capital expenditure forecast - Asset Replacement & Renewal

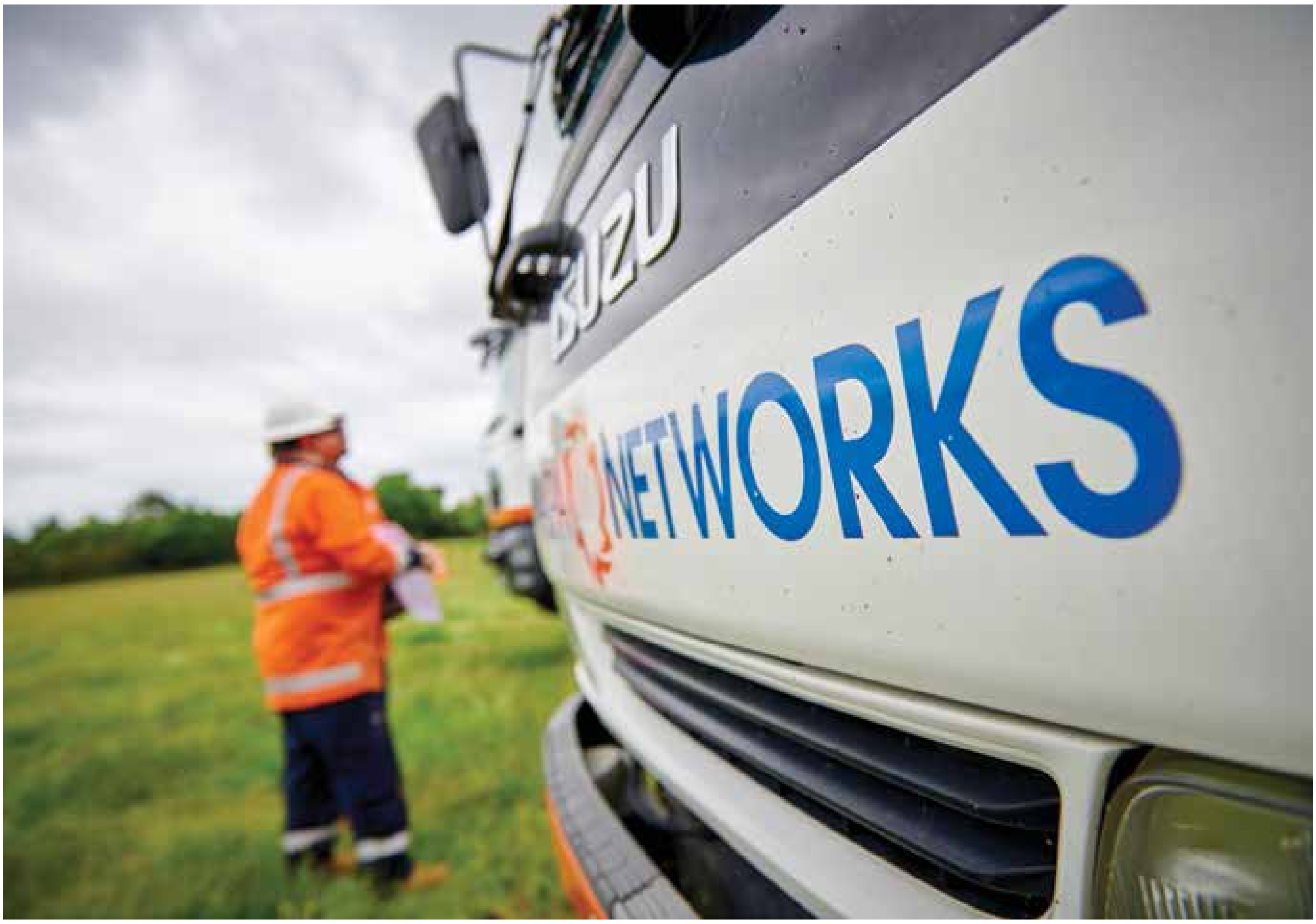
10.22 Operational expenditure forecast

Table 50 shows operational forecast expenditure over the next ten years for managing the asset fleet. Service interruptions and emergency maintenance can only be forecast and reported at a system level.

No material changes have been made in relation to correct and preventative maintenance, and inspection and testing programmes. However, given the increase in the number of assets and the progressive aging of the network, work volumes are expected to increase. As a result, forecast expenditure on routine and corrective maintenance and inspection has increased 4% (compared to the 2022 AMP). Asset replacement and renewal (opex) has increased 14% (compared to the 2022 AMP) due to a forecast increase in work on transformers, switchgear and voltage regulators.

Operational expenditure forecast ($000)	FY 23/24	FY 24/25	FY 25/26	FY 26/27	FY 27/28	FY 28/29	FY 29/30	FY 30/31	FY 31/32	FY 32/33
Service interruption and emergencies	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
Vegetation management	1,532	1,532	1,532	1,532	1,535	1,532	1,532	1,532	1,532	1,532
Routine and corrective maintenance and inspection	788	767	788	767	788	767	788	767	788	767
Asset replacement and renewal	961	659	755	659	755	652	748	652	748	652
Network OPEX	4,707	4,384	4,501	4,384	4,504	4,377	4,494	4,377	4,494	4,377
System operations and network support	3,682	3,780	3,526	3,539	3,552	3,565	3,579	3,593	3,593	3,607
Business Support	8,557	8,557	8,557	8,557	8,557	8,557	8,557	8,557	8,557	8,557
None-Network OPEX	12,239	12,337	12,083	12,096	12,109	12,122	12,136	12,150	12,150	12,164
Total OPEX	**16,946**	**16,721**	**16,584**	**16,480**	**16,613**	**16,499**	**16,630**	**16,527**	**16,644**	**16,541**

Table 50: Operational expenditure forecast



11. EXPENDITURE FORECAST AND CAPACITY TO DELIVER

11.1 Assumptions on cost inflators

We face cost pressures from several sources, including labour, fuel, construction costs, and international commodities such as copper and aluminium. Exchange rates will also impact on the final prices we pay for many inputs that are utilised into our business.

Escalation in these cost drivers has not been explicitly included in our estimation of the nominal values of its cost forecasts over the planning period but could be material in future years.

- For key or new project, such as the 33kV subtransmission and zone substation projects, we review the costs on a one-by-one basis.
- For standard or volumetric works, rather than taking a complex approach to escalating expenditure forecasts given there are large inherent uncertainties, we applied a CPI 6.23% adjustment to 2022 AMP's figure to obtain the 2023 AMP figures.
- For comparing the 10 years expenditure between the 2022 and 2023 AMP, a CPI of 6.23% has been applied to the 2022 AMP figures as the 'indexed' 2022 AMP costs in 2023 terms. This is demonstrated in the graphs in the following sections.
- For disclosure purpose (Normal Values in Schedule 11b), a long run CPI of 2% has been applied for expenditure forecasts for future years.

All % inflation figure used are consistent with the Reserve Bank of New Zealand's mid-point CPI inflation figures.

All other dollar figures disclosed in this AMP are in constant dollar unless specified.

11.2 Capex

Figure 85 shows the forecast capex for the period FY2023/24 to FY2032/33. Values are expressed in constant prices dollars. The ten-year forecast table is provided in Appendix F.

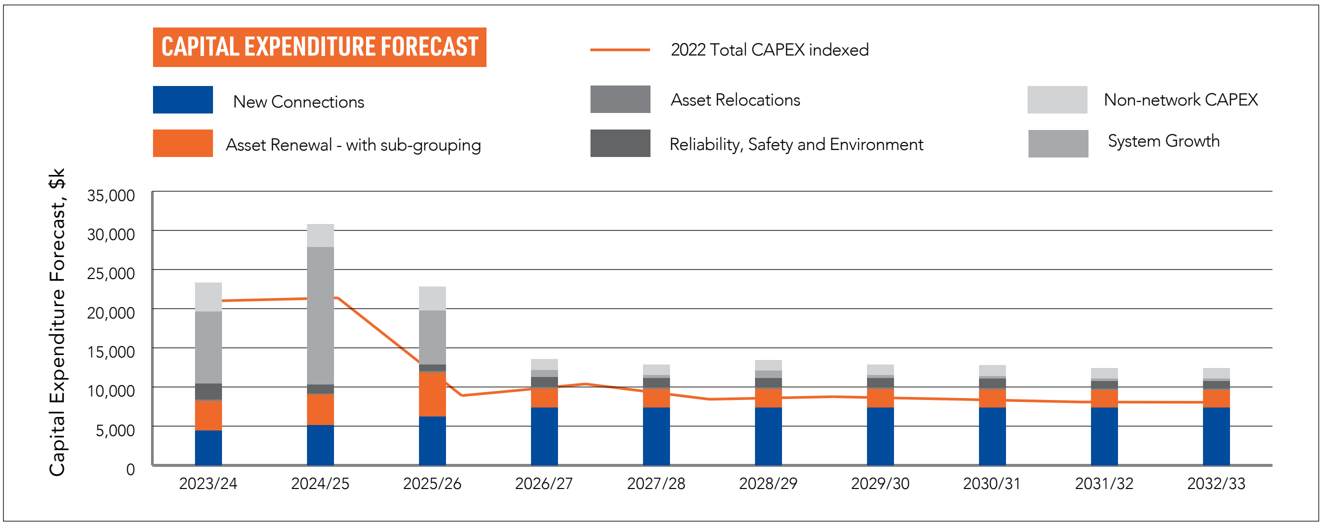


Figure 85: Summary of forecast capex ($k) by expenditure category

This shows the network capex forecast increasing significantly in the first three years of the period due to expenditure on:

- Sub-transmission and zone substation investment in Cambridge to meet load growth and overcome network constraints. Any expenditure to meet load growth in Te Awamutu has been removed until the area development plan has been confirmed.
- Significant updates to information systems in the first three years of the period (categorised as non-network assets) to replace out of date legacy systems and assist in efficient operation and asset management to meet modern regulatory and business requirements.
- Communication systems upgrade subject to a review of the development options.

The 10-year network capex sees a $30m increase (comparing to 2022 indexed numbers). Some of the projects have been reclassified under different drivers. The material changes were discussed in the prior sections, and:

- An increase in forecast customer connection to support the continued high regional connection growth.
- An increase in zone substation and subtransmission project costs.
- An increase in 11kV feeder augmentation work in Te Awamutu.
- Additional prioritised asset renewal following the FY2022 pole-top inspection.
- The inclusion of the SCADA replacement project.
- The removal of the project to monitor distribution transformers via SCADA, as this will be achieved through LV meter data aggregation.
- The reduction in certain categories as projects (e.g., voltage regulator project installation program) processed through the year, or re-scheduled (deferred) based on phasing between different programs.

Table 51 provides comparison between this year's ten-year capital forecast and the 2022 AMP and 2023 AMP capital forecast, with the AMP2022 figures indexed by the CPI value of 6.23%. This shows the differences in the capital forecast, related to the factors listed above.

CAPEX category	AMP2022 indexed to 2023$ ($k)	AMP2023 ($k)	Change ($k)	Change (%)
New Connections	44,808	67,223	22,415	50%
System Growth	31,543	37,155	5,612	18%
Asset Renewal	26,027	29,693	3,666	14%
Asset Relocations	1,891	1,890	-1	0%
Reliability, Safety and Environment	13,284	11,935	-1,349	-10%
Quality of Supply	320	1,755	1,435	449%
Legislative and Regulatory	-	-	-	-
Other Reliability, Safety & Environment	12,961	10,180	-2,781	-21%
Network CAPEX	117,553	147,896	30,343	26%
Non-network CAPEX	9,474	19,403	9,929	105%
Total CAPEX	**127,027**	**167,299**	**40,272**	**32%**

Table 51: Comparison between AMP2022 and AMP2023 10-year total capex forecasts

Contribution to drivers

For accounting and regulatory disclosure, system capex projects and programmes are allocated over the eight regulatory categories.

Accounting allocation is against the category most applicable to the works expenditure. However, in most cases any project will impact across multiple objective drivers. For example, a line renewal may be driven by the age and condition of the line and therefore be allocated to replacement and renewal, but renewal will also impact the line reliability and safety implications from avoided faults. Generally, capital is allocated to the largest driver.

Line breakdowns of the capital expenditure are provided in Appendix F and the regulatory schedules included in Appendix I.

11.3 Opex

Figure 86 shows our opex forecast for the period FY2023/24 to FY2032/33. A tabular presentation of the ten-year forecast is provided in Appendix F.

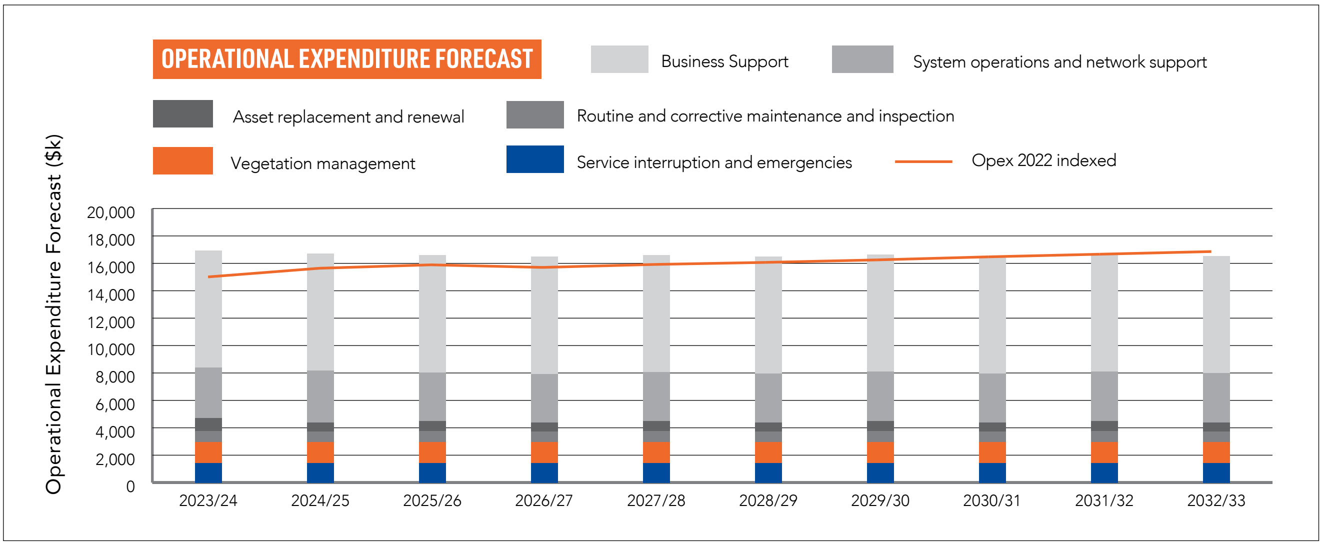


Figure 86: Summary of forecast capex ($k) by expenditure category

Network expenditure has been adjusted in recent years to match expected levels of activity in faults, corrective maintenance and asset replacement and renewal etc. This expenditure is expected to be relatively constant over the period in real terms. There is potential for more planned maintenance routines for zone sub-stations to increase costs in the second half of the period, this will be confirmed with the revised approach to replacement forecasting.

We are seeking to hold non-network expenditure increases to a minimum where possible. Additional staff to assist in operational delivery, increased resources in health and safety management and engineering for technical and asset management improvements also add to operational costs compared to levels seen in 2020/22. We will seek to advance asset management capability to make the best use of systems and processes and optimise future expenditure and network performance.

Movements in operational expenditure between AMP2022 and AMP2023 by category are shown in Table 52, with the AMP2022 figures indexed by the CPI value of 6.23%. This shows reductions in routine and corrective maintenance via transferring replacement of defected individual poles and pole top hardware to asset renewal capex and reducing the budget for inspections of ground mounted transformers and ring main units. Asset replacement and renewal opex is increased cater for increased inspection and maintenance of pillars.

The following summarises the key difference in opex compared to 2022 AMP:

- Faults and vegetation individually increase from ~$0.9m to ~$1.2m annually to reflect our current performance.
- Increased Asset Replacement and Renewal to start with the proactive voltage regulator and recloser maintenance program and RMU partial discharge tactical inspection.
- The non-network opex has reduced spending in System Operation and Network Support due to a correction to the historical figures.

Operational Expenditure Forecast	AMP2022 indexed to 2023$ ($k)	AMP2023 ($k)	Change ($k)	Change (%)
Network Opex	35,274	44,599	9,325	26%
Service interruption and emergencies	10,559	14,260	3,701	35%
Vegetation management	10,959	15,323	4,364	40%
Routine and corrective maintenance and inspection	7,500	7,775	275	4%
Asset replacement and renewal	6,256	7,241	985	16%
Non-network Opex	129,102	121,586	-7,516	-6%
System operations and network support	42,588	36,016	-6,572	-15%
Business Support	86,514	85,570	-944	-1%
Total Operational Expenditure	**164,375**	**166,185**	**1,810**	**1%**

Table 52: Comparison between FY2021/22 and FY2022/23 10-year total opex forecasts

11.4 Capex/opex trade-off

Some works, such as remote-controlled network switches, will reduce the need for manual switching and hence may reduce operational costs marginally. However, the capital programme set out in this plan does not encompass productivity improvement projects of any significance that would see an offset in opex costs. We will always seek opportunities for productivity improvement but in this current round it has not identified projects that net benefits above costs in this area.

11.5 Capacity to deliver

11.5.1 Existing

As part of our Asset Management Strategy, we are committed to retaining our current field services staff for fault restoration, inspections, maintenance, and capital work. This means that our in-house delivery resource will be our preferred option to delivering the standard volumetric works in our AMP. We will 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 in-house resource consists of 40 staff; includes a vegetation management team, field services and faults team, two live line crews, three-line crews and cable jointers and electrical fitter resource. The delivery of work in the field is supported by our Works Planning and Delivery Team. Ten staff provides dedicated and integrated resource and leadership to scope, design, estimate, plan, and project manage our work delivery.

We also use contractors/consultants where our staff do not have the required skill sets, where resources are inadequate for our works programme or where it is more cost-effective to do so, e.g., specialist work such as civil engineering design and radio equipment installation and maintenance. Examples where we use external capacity to deliver include:

- The Cambridge GXP reinforcement via new 220/33kV GXP and our sub-transmission investment. We have engaged AECOM to design the solution, Edison Consulting to provide project management services, and a third-party service provider to undertake the build will be procured through a competitive RFP process.
- Our Network inspection programme being supplemented by LiDAR and a high-resolution photo arial survey undertaken by Fugro and PLP.

We also manage in-house procurement, inventory management, stores, and dispatch services. We currently procure approximately $10 million each year of inventory using five main suppliers.

11.5.2 Future

To ensure that we have the required capacity and capability to deliver in the timeframe equal to this AMP, we have initiated two improvement initiatives; improve our works planning and delivery capability, and a review our inventory management and procurement processes. Both these initiatives commenced January 2023.

Due to Covid we have experienced, along with the rest of our industry, considerable disruption to our supply lead times for some materials (for example, the lead time for voltage regulators has been up to 72 weeks). As a result of this disruption, we have undertaken a review of our current inventory management and procurement processes to ensure that they are resilient and fit for purpose. Several actions have been identified. These include:

- Review current supply agreements and vendors to ensure supplier lead time risk is reduced.
- Leverage access to The Northern Network Group supply agreements for purchasing large equipment items (e.g., transformers, switchers, and voltage regulators)

- Review internal end-to-end processes for large equipment items to ensure clear communication occurs to relevant business process owners for supply lead times.

We have also recently reviewed the way we annually plan our work for delivery and ensure that the way we scope, design estimate, plan and project manage work is integrated and fit for purpose. This has resulted in the establishment of the Works Planning and Delivery Team in February 2023. This team will embed an annual planning and forecasting process to ensure that we have the required capacity and capability to deliver in the timeframe equal to this AMP.

The annual planning process will commence at the start of each year and use the Annual Works Plan (AWP) to determine the resource capacity required, specific competencies and craft types expected to deliver the required work program throughout the financial year. Progress against the AWP will be reviewed on a quarterly basis, which will allow us to adjust its resource planning requirements for both internal and third-party resources.

We have also introduced a Fortnightly Forward Work Planning Meeting. The purpose of this meeting is to:

- Ensure that the work specified in the AWP is delivered on an annual basis and under budget.
- That work requested from customers (both Private and Capital Contributions) is delivered on a timely basis and meets customer expectations.
- That the trade off and timing between the delivery of Defects, Assert Renewals, Network Projects, and Customer Initiated Work is proactively managed.
- That plant and equipment, material and resourcing requirements are proactively managed and planned.
- That schedule utilisation achieves the annual KPI targets for delivery set by the Head of Operations.

The forecast network capex for the next five years (excluding the Cambridge GXP reinforcement via new 220/33kV GXP and our sub-transmission investment) is consistent with capex for the previous five years. With the implementation of our improvement initiatives, under normal conditions, we expect to be able to deliver our AMP over the coming period.

APPENDICES

APPENDIX A – ASSUMPTIONS

Area	Assumption	Sources of uncertainty	The possible impact of uncertainty
Resilience	That no major disasters or widespread systemic problems will occur.	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	That there are no significant changes to a local authority (i.e., Waipa'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 detail is presented in the expenditure forecasts section.
Regulatory environment	No significant changes to the regulatory regime and requirements.	Change in Government, changes to 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 customer market in residential sector is steady though building consents do show an increase. 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 connections from customers.
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 is fairly known, steady and no step change in expenditure is expected, except the transitional expenditure included in the plan to cater for deferred maintenance.	Investment levels may increase or decrease in response to changes in known asset condition 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. Routine of inspection and servicing programmes are not likely to change significantly.	Any material change to the annual maintenance programme or associated costs may lead to an increase or decrease in the Opex costs associated with inspection and maintenance.

Area	Assumption	Sources of uncertainty	The possible impact of uncertainty
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 the rate of failure of network equipment could lead to an increase in reactive maintenance requirements and costs.
Technology development	The rate of uptake 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 manged 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. Significantly reduction in the cost of battery storage could increase the benefit of PV installations. However, introduction of 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 upon the existing network assets located in the public domain.	Implementation of a safety management system, Assura, and promoting of 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 largely unchanged, and the transmission pass-through pricing will remain in place.	Transmission pricing is regulated as a pass-through cost and our expectation that this will remain as a pass-through cost with the net effect to 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 apart from agreed projects.	Our network developments drive changes to grid exit points and planned major transmission developments will be signalled well in advance of actual delivery.	A change to the configuration or capability of the transmission system could lead to a requirement for increased levels of investment on the network to provide alternative capacity or security.

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 in an unsafe condition).
- 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 1 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 Profiles Limited (APL) Department of Corrections Aotearoa Developments 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

Stakeholders	Relationship / Interface	Nature of Interest
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
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 1: Our key internal and external stakeholders

Managing stakeholder interest

Stakeholder	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, website, advertising, media stories and direct communication. Community engagement projects such as energy assessments and community sponsorships Public disclosure documents
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 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, website, 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.

Stakeholder	How we engage
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 Electricity Authority's website.
Utilities Disputes	Reviewing their decisions regarding other EDBs. Assistance with any complaint investigations.

Table 2: key stakeholder groups

APPENDIX C – RISK MANAGEMENT MATRIX

This risk management matrix is further described in our Risk Management Manual.

Risk assessment matrix

Consequence					
Severity	**Low – 1**	**Minor – 2**	**Moderate – 3**	**Major – 4**	**Critical – 5**
People	First aid	Medical treatment	Serious harm	Permanent disability	Fatality
Environment	No effect	Minor effect	Moderate effect	Major effect	Massive effect
Property	Insignificant damage	Minimal damage	Moderate damage	Significant damage	Extensive damage
Reputation	Minimally affected	Adversely affected	External reputation damaged	Severe damage	Irrevocable damage
Financial	Loss less than $5,000	Loss less than $60,000	Loss less than $250,000	Loss less than $1,000,000	Loss greater than $1,000,000

Likelihood								
Almost Certain	100%	5	Expected to occur regularly under normal circumstances	5	10	15	20	25
Likely	20%	4	Expected to occur at some time	4	8	12	16	20
Possible	10%	3	Distinct possibility of it happening	3	6	9	12	15
Unlikely	4%	2	Not likely to occur in normal circumstances	2	4	6	8	10
Rare	2%	1	Could happen, but probably never will	1	2	3	4	5

>=15	**High**	Work is unable to proceed without management approval
10-14	**Serious**	Review and introduce additional controls
5-9	**Moderate**	Monitor/maintain control measures – follow procedures
<=4	**Insignificant**	Manage with routine procedures

APPENDIX D – NETWORK HIGH-FOCUS RISKS

The following table summarises our network risk following the 2022AMP assessment. This will be revised in FY2023/24 to reflect the impact of risk treatments we've implemented and the updated residual risks.

Risk	Inherent Risk Rank	Residual Risk Rank	Level of Control	Current Actions
Overloaded Customer LV fuse bases cause pillar fire and public safety hazards.	High	Serious	Improving	Budgeted pillar inspection and fuse base replacements into AMP.
Overhead line Vegetation Faults cause loss of reliability.	High	Serious	Improving	Reactive trim of hot-spot feeders and continue cutting to the allocated budget. Develop a risk-based vegetation management approach and assess budget adequacy.
Inspections running behind the programme cause reliability risk and Health and Safety risks.	High	Serious	Improving	Defects Analysis and Options Plan to prioritise and present methodology for addressing defects, including resources required and budget. Commissioning a drone-based urban network pole top condition Determine the approach to private/network asset boundary. Set up wood pole inspection programme and methodology.
Cable capacity out of Te Awamutu GXP.	High	Serious	Improving	AMP project for FY2021/22 – FY2022/23 to replace TMU cables. A construction project to be mobilised.
Cambridge GXP Firm capacity is exceeded, and loss of supply occurs (Transpower tripping at peak load).	High	Serious	Improving	Swayne Rd peak-lopping diesel generation project completed. GXP design and designation are underway. Sub-transmission project planning & concept design are underway.
Te Awamutu GXP Firm capacity exceeded, reducing security (Transpower tripping at peak load).	High	Serious	Improving	Implement Transpower protection upgrade 2023. Development planning to determine the most economical solution and timing, engagement with Transpower (transmission options & GXP), non-network solutions, and subtransmission costs.
Major regional storm (tropical cyclone) causes widespread network damage; external contractor assistance is limited.	Serious	Serious	Improving	Review major storm contingency planning. Establish relationships with further afield EDBs, network contractors and equipment providers—and provide network inductions beforehand.
Operating 11 kV oil ring main units owned by others (Fonterra, St Peters School) - risk if operated live.	High	Serious	Improving	We currently don't switch third-party oil RMU live. Ensure the switching manual is available to all team members with switching competency. Review the switching manual for complete coverage of network switchgear.
Lack of 11kV network back feed capacity for planned or unplanned outages causing customer damage (low voltages) or extended outages.	Serious	Serious	Further Controls Needed	Network development planning to identify solutions to network constraints. Complete currently identified voltage reinforcement projects.
Public access inside Pillar boxes in areas where power is underground.	Serious	Serious	Further Controls Needed	The pillar inspection programme commenced informing the estimation of the defect rate. Budget pillar replacements.
Overhead asset inspection programme being behind plan resulting in unidentified defects that fail, causing loss of supply.	Serious	Serious	Improving	Implement drone-based overhead inspection for areas not covered by the earlier helicopter-based survey.

APPENDIX E – FEEDER CAPACITY, SECURITY, AND VOLTAGE CONSTRAINT ANALYSIS

GXP	Feeder Name	ID	Feeder Type	Capacity	Capacity (Based on cable rating)	66% Capacity	Feeder MD FY23
Cambridge Grid Exit Point							
CBG	Roto-o-Rangi	2702	Predominantly Residential	400	300mm Ali	264	307
CBG	Cambridge North	2712	Predominantly Residential	400	300mm Ali	264	137
CBG	Cambridge Town	2722	Predominantly Residential, some commercial	400	300mm Ali	264	302
CBG	Kaipaki	2732	Predominantly Residential, some agricultural	400	300mm Ali	264	184
CBG	Pencarrow	2742	Predominantly Residential	400	300mm Ali	264	259
CBG	Hautapu A	2762	Industrial	632	2 x 300mm Ali	417	370
CBG	French Pass	2772	Predominantly Residential, some agricultural	400	300mm Ali	264	221
CBG	Leamington	2802	Predominantly Residential	400	300mm Ali	264	227
CBG	Hautapu B	2812	Industrial	632	2 x 300mm Ali	417	259
CBG	Cambridge East	2832	Predominantly Residential	400	300mm Ali	264	241
CBG	Tamahere	2842	Predominantly Residential	400	300mm Ali	264	193
CBG	St Kilda	2852	Predominantly Residential	400	300mm Ali	264	164
CBG	Monavale	2862	Predominantly Residential	400	300mm Ali	264	281
CBG	APL	2872	Industrial	400	300mm Ali	264	182

99th Percentile	% of Overall Capacity	% Of 66% Capacity	FY expected to exceed 66% Capacity	FY expected to exceed 100% Capacity	Existing Voltage Problems	Constraint addressed through:
187	77%	116%	Beyond planning period	Beyond planning period	N	
121	34%	52%	Beyond planning period	Beyond planning period	N	
251	76%	114%	**FY25**	Beyond planning period	N	New GXP FY25/26
149	46%	70%	Beyond planning period	Beyond planning period	N	
217	65%	98%	**FY30**	Beyond planning period	**Y**	New GXP FY25/26
339	59%	89%	Growth by step change	Beyond planning period	N	
185	55%	84%	Beyond planning period	Beyond planning period	N	
162	57%	86%	Beyond planning period	Beyond planning period	N	
242	41%	62%	Growth by step change	Beyond planning period	N	
203	60%	91%	**FY32**	Beyond planning period	N	
122	48%	73%	Beyond planning period	Beyond planning period	Y	VREG FY24
142	41%	62%	Beyond planning period	Beyond planning period	Y	VREG FY24
201	70%	106%	**FY32**	Beyond planning period	N	
141	46%	69%	Beyond planning period	Beyond planning period	N	

GXP	Feeder Name	ID	Feeder Type	Capacity	Capacity (Based on cable rating)	66% Capacity	Feeder MD FY23
Te Awamutu Grid Exit Point							
TMU	Kawhia	22	Predominantly rural residential	295	160mm PILC	195	200
TMU	TA West	24	Predominantly Residential	295	160mm PILC	195	299
TMU	Pirongia	25	Predominantly Residential	295	160mm PILC	195	197
TMU	Hairini	26	Predominantly Residential	295	160mm PILC	195	307
TMU	Paterangi	27	Predominantly Residential	295	160mm PILC	195	216
TMU	TA Load Cell	28	-	402	300mm Ali	265	0
TMU	Kiokio	2732	Predominantly Residential	402	300mm Ali	265	241
TMU	Kihikihi	2742	Predominantly Residential	295	160mm PILC	195	209
TMU	Mystery Creek	2752	Predominantly Residential	295	160mm PILC	195	103
TMU	Pukeatua	2762	Predominantly Residential	402	300mm Ali	265	238
TMU	TA Fonterra A	2782	Industrial	800	2 x 300mm Ali	528	305
TMU	TA Fonterra B	2802	Industrial	800	2 x 300mm Ali	528	273
TMU	Ohaupo	2822	Predominantly Residential	402	300mm Ali	265	238
TMU	TA East	2832	Predominantly Residential	295	160mm PILC	195	301
TMU	Pokuru	2842	Predominantly Residential	295	160mm PILC	195	242
TMU	Waikeria	2852	Mixture of commercial and residential	402	300mm Ali	265	187

99th Percentile	% of Overall Capacity	% Of 66% Capacity	FY expected to exceed 66% Capacity	FY expected to exceed 100% Capacity	Existing Voltage Problems	Constraint addressed through:
145	68%	103%	Beyond planning period	Beyond planning period	N	
219	101%	154%	**FY23**	Beyond planning period	N	Feeder Cable Upgrade FY24
175	67%	101%	**FY29**	Beyond planning period	**Y**	Feeder Cable Upgrade FY24 & Vreg install Fy24
191	104%	158%	**FY23**	Beyond planning period	N	Feeder Cable Upgrade FY24
188	73%	111%	**FY25**	Beyond planning period	**Y**	Feeder Cable Upgrade FY24
0	0%	0%	Beyond planning period	Beyond planning period	N	
199	60%	91%	Beyond planning period	Beyond planning period	N	
178	71%	107%	**FY28**	Beyond planning period	**Y**	Feeder Cable Upgrade FY24
88	35%	53%	Beyond planning period	Beyond planning period	**Y**	Offload onto CBG feeder
205	59%	90%	Beyond planning period	Beyond planning period	N	
262	38%	58%	Growth by step change	Beyond planning period	N	
182	34%	52%	Growth by step change	Beyond planning period	N	
160	59%	90%	Beyond planning period	Beyond planning period	N	
237	102%	155%	**FY23**	Beyond planning period	N	Feeder Cable Upgrade FY24
201	82%	124%	**FY23**	Beyond planning period	**Y**	Feeder Cable Upgrade FY24 and (Vreg and Cap bank FY25)
158	47%	70%	Beyond planning period	Beyond planning period	N	

APPENDIX F – EXPENDITURE FORECASTS

Capital expenditure

Capital Expenditure Forecast	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
New Connections	**4,418**	**5,150**	**6,247**	**7,344**	**7,344**	**7,344**
System Growth	**9,179**	**17,554**	**6,892**	**935**	**358**	**909**
33kV Sub-transmission and Zone Substation	3,588	15,378	6,209	0	0	0
11kV Distribution Argumentation	4,519	0	0	0	0	0
11kV Voltage and Distribution TX Improvement	877	877	228	805	228	805
New Communications Infrastructure and DR site	195	1,299	455	130	130	104
Asset Renewal	**3,791**	**3,841**	**5,591**	**2,468**	**2,390**	**2,390**
General Distribution - Poles/Xarm, Dist Tx, ABS, Pillars	2,182	2,182	2,182	2,182	2,182	2,182
Transitional budget (3 years) – resolve existing defects	857	857	857	0	0	0
Reclosers and Voltage Regulator (including structures)	702	702	702	286	208	208
SCADA System Replacement	50	100	1,850	0	0	0
Asset Relocations	**189**	**189**	**189**	**189**	**189**	**189**
Reliability, Safety and Environment	2,025	1,123	823	1,222	1,222	1,222
Quality of Supply	585	130	130	130	130	130
Legislative and Regulatory	0	0	0	0	0	0
Other Reliability, Safety & Environment	1,440	993	693	1,092	1,092	1,092
Network CAPEX	**19,602**	**27,857**	**19,742**	**12,158**	**11,503**	**12,054**
Non-network CAPEX	**3,756**	**2,939**	**3,069**	**1,377**	**1,377**	**1,377**
Total CAPEX	**23,358**	**30,796**	**22,811**	**13,535**	**12,880**	**13,431**

Operational expenditure

Operational Expenditure Forecast ($k)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Service interruption and emergencies	1,426	1,426	1,426	1,426	1,426	1,426
Vegetation management	1,532	1,532	1,532	1,532	1,535	1,532
Routine and corrective maintenance and inspection	788	767	788	767	788	767
Asset replacement and renewal	961	659	755	659	755	652
Network Opex	**4,707**	**4,384**	**4,501**	**4,384**	**4,504**	**4,377**
System operations and network support	3,682	3,780	3,526	3,539	3,552	3,565
Business Support	8,557	8,557	8,557	8,557	8,557	8,557
Non-network Opex	**12,239**	**12,337**	**12,083**	**12,096**	**12,109**	**12,122**
Total OPEX	**16,946**	**16,721**	**16,584**	**16,480**	**16,613**	**16,499**

2029/30	2030/31	2031/32	2032/33	Ten-year total
7,344	**7,344**	**7,344**	**7,344**	**67,223**
332	**332**	**332**	**332**	**37,155**
0	0	0	0	25,175
0	0	0	0	4,519
228	228	228	228	4,732
104	104	104	104	2,729
2,390	**2,312**	**2,260**	**2,260**	**29,693**
2,182	2,182	2,182	2,182	21,820
0	0	0	0	2,571
208	130	78	78	3,302
0	0	0	0	2,000
189	**189**	**189**	**189**	**1,890**
1,222	1,222	927	927	11,935
130	130	130	130	1,755
0	0	0	0	
1,092	1,092	797	797	10,180
11,477	**11,399**	**11,052**	**11,052**	**147,896**
1,377	**1,377**	**1,377**	**1,377**	**19,403**
12,854	**12,776**	**12,429**	**12,429**	**167,299**

2029/30	2030/31	2031/32	2032/33	Ten-year total
1,426	1,426	1,426	1,426	14,260
1,532	1,532	1,532	1,532	15,323
788	767	788	767	7,775
748	652	748	652	7,241
4,494	**4,377**	**4,494**	**4,377**	**44,599**
3,579	3,593	3,593	3,607	36,016
8,557	8,557	8,557	8,557	85,570
12,136	**12,150**	**12,150**	**12,164**	**121,586**
16,630	**16,527**	**16,644**	**16,541**	**166,185**

APPENDIX G – 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 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
					1.022	1.044	1.065	1.086	1.108	1.130	1.152	1.175	1.198
7			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	4,218	4,418	5,265	6,522	7,820	7,976	8,135	8,296	8,462	8,630	8,802
11		System growth	3,322	9,179	17,947	7,196	996	389	1,007	375	383	390	398
12		Asset replacement and renewal	3,021	3,791	3,927	5,837	2,628	2,596	2,647	2,700	2,664	2,656	2,709
13		Asset relocations	178	189	193	197	201	205	209	214	218	222	227
14		Reliability, safety and environment:											
15		Quality of supply	1,065	585	133	136	138	141	144	147	150	153	156
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	460	1,440	1,015	724	1,163	1,186	1,210	1,234	1,258	937	955
18		**Total reliability, safety and environment**	1,525	2,025	1,148	859	1,301	1,327	1,354	1,380	1,408	1,089	1,111
19		**Expenditure on network assets**	12,264	19,602	28,481	20,612	12,946	12,493	13,352	12,966	13,134	12,987	13,246
20		Expenditure on non-network assets	4,103	3,756	3,005	3,204	1,466	1,495	1,525	1,556	1,587	1,618	1,650
21		**Expenditure on assets**	16,367	23,358	31,486	23,816	14,413	13,988	14,877	14,521	14,720	14,605	14,896
22			1										
23	*plus*	Cost of financing											
24	*less*	Value of capital contributions	3,286	3,530	4,195	5,180	6,195	6,319	6,444	6,573	6,703	6,837	6,973
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	13,081	19,828	27,291	18,637	8,217	7,670	8,433	7,949	8,017	7,769	7,923
28													
29		Assets commissioned	13,081	16,340	24,607	24,809	8,217	7,670	8,433	7,949	8,017	7,769	7,923
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
32			**$000 (in constant prices)**										
33		Consumer connection	4,218	4,418	5,150	6,247	7,344	7,344	7,344	7,344	7,344	7,344	7,344
34		System growth	3,322	9,179	17,554	6,892	935	358	909	332	332	332	332
35		Asset replacement and renewal	3,021	3,791	3,841	5,591	2,468	2,390	2,390	2,390	2,312	2,260	2,260
36		Asset relocations	178	189	189	189	189	189	189	189	189	189	189
37		Reliability, safety and environment:											
38		Quality of supply	1,065	585	130	130	130	130	130	130	130	130	130
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	460	1,440	993	693	1,092	1,092	1,092	1,092	1,092	797	797
41		**Total reliability, safety and environment**	1,525	2,025	1,123	823	1,222	1,222	1,222	1,222	1,222	927	927
42		**Expenditure on network assets**	12,264	19,602	27,857	19,742	12,158	11,503	12,054	11,477	11,399	11,052	11,052
43		Expenditure on non-network assets	4,103	3,756	2,939	3,069	1,377	1,377	1,377	1,377	1,377	1,377	1,377
44		**Expenditure on assets**	16,367	23,358	30,796	22,811	13,535	12,880	13,431	12,854	12,776	12,429	12,429
45													
46		**Subcomponents of expenditure on assets (where known)**											
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													

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref					1.022	1.044	1.065	1.086	1.108	1.130	1.152	1.175	1.198
51			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
52		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
53	**Difference between nominal and constant price forecasts**		**$000**										
54	Consumer connection		-	-	115	275	476	632	791	952	1,118	1,286	1,458
55	System growth		-	-	393	304	61	31	98	43	51	58	66
56	Asset replacement and renewal		-	-	86	246	160	206	257	310	352	396	449
57	Asset relocations		-	-	4	8	12	16	20	25	29	33	38
58	Reliability, safety and environment:												
59	Quality of supply		-	-	3	6	8	11	14	17	20	23	26
60	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment		-	-	22	31	71	94	118	142	166	140	158
62	**Total reliability, safety and environment**		-	-	25	36	79	105	132	158	186	162	184
63	**Expenditure on network assets**		-	-	624	870	788	990	1,298	1,489	1,735	1,935	2,194
64	Expenditure on non-network assets		-	-	66	135	89	118	148	179	210	241	273
65	**Expenditure on assets**		-	-	690	1,005	878	1,108	1,446	1,667	1,944	2,176	2,467
66													
67			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*					
		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**					
68	**11a(ii): Consumer Connection**												
69	*Consumer types defined by EDB**		**$000 (in constant prices)**										
70	Customer Connections		4,218	4,418	5,150	6,247	7,344	7,344					
71													
72													
73													
74													
75	**include additional rows if needed*												
76	**Consumer connection expenditure**		4,218	4,418	5,150	6,247	7,344	7,344					
77	*less* Capital contributions funding consumer connection		3,197	3,435	4,008	4,866	5,723	5,723					
78	**Consumer connection less capital contributions**		1,021	983	1,142	1,381	1,621	1,621					
79	**11a(iii): System Growth**												
80	Subtransmission		-	-	1,730	1,730	-	-					
81	Zone substations		455	3,588	12,898	4,479	-	-					
82	Distribution and LV lines		-	-	-	-	-	-					
83	Distribution and LV cables		1,755	4,519	750	-	-	-					
84	Distribution substations and transformers		214	228	228	228	228	228					
85	Distribution switchgear			649	649	-	577	-					
86	Other network assets		898	195	1,299	455	130	130					
87	**System growth expenditure**		3,322	9,179	17,554	6,892	935	358					
88	*less* Capital contributions funding system growth		-	-	-	-	-	-					
89	**System growth less capital contributions**		3,322	9,179	17,554	6,892	935	358					
90													

Company Name: **Waipa Networks Limited**
AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

sch ref 1.022 1.044 1.065 1.086 1.108 1.130 1.152 1.175 1.198

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
92	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission						
95	Zone substations						
96	Distribution and LV lines						
97	Distribution and LV cables						
98	Distribution substations and transformers	741	787	787	787	787	787
99	Distribution switchgear	894	1,105	1,105	1,105	689	611
100	Other network assets	1,386	1,899	1,949	3,699	992	992
101	**Asset replacement and renewal expenditure**	3,021	3,791	3,841	5,591	2,468	2,390
102	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**	3,021	3,791	3,841	5,591	2,468	2,390
104							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
106	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
107	**11a(v): Asset Relocations**						
108	*Project or programme**	**$000 (in constant prices)**					
109	NZTA and District Council Relocations	178	189	189	189	189	189
110							
111							
112							
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations						
116	**Asset relocations expenditure**	178	189	189	189	189	189
117	*less* Capital contributions funding asset relocations	89	95	95	95	95	95
118	**Asset relocations less capital contributions**	89	94	94	94	94	94
119							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
121	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
122	**11a(vi): Quality of Supply**						
123	*Project or programme**	**$000 (in constant prices)**					
125	Install 11kV Dropout Fuses Spurs & Services	195					
124	Install Remote Control Switches	570					
128	Te Awamutu Ripple Plant RMU alternate supply	300					
126	Low Voltage Complaint		130	130	130	130	130
127	Kihikihi Grey St and Oliver St 11kV network extension		455	-	-	-	-
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply	-	-	-	-	-	-
131	**Quality of supply expenditure**	1,065	585	130	130	130	130
132	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
133	**Quality of supply less capital contributions**	1,065	585	130	130	130	130
134							

								Company Name	Waipa Networks Limited
								AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref				1.022	1.044	1.065	1.086	1.108	1.130	1.152	1.175	1.198

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135							
136	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	$000 (in constant prices)					
139	Nil						
140							
141							
142							
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	$000 (in constant prices)					
156	Install Remote Control Switches/Loop Automation		171	171	171	570	570
156	Install 11kV Reclosurers / Sectionaliser, Dropout Fuses Spurs & Services		130	130	130	130	130
153	Replace Two Pole Transformers and Sub Structures	117	117	-	-	-	-
154	Seismic strengthening of Voltage Regulator structures	278	295	295	295	295	295
156	Soundproofing Cambridge Ripple Plant Building		130	-	-	-	-
156	Low line mitigation (aka High Load Crossings - underground	65	97	97	97	97	97
157	High Resolution Photo Survey		500	300	-	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment		-	-	-	-	-
160	**Other reliability, safety and environment expenditure**	460	1,440	993	693	1,092	1,092
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	460	1,440	993	693	1,092	1,092
163							
164		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	$000 (in constant prices)					
169	Motor vehicles, fleet and plant	958	1,395	928	1,058	1,058	1,058
170	Office furniture and plant	1,160	58	58	58	58	58
171	Computer equipment	1,925	1,892	1,892	1,892	200	200
172	Land and buildings	30	411	61	61	61	61
173		-	-	-	-	-	-
174	**include additional rows if needed*	-	-	-	-	-	-
175	All other projects or programmes - routine expenditure	30		-	-	-	-
176	**Routine expenditure**	4,103	3,756	2,939	3,069	1,377	1,377
177	**Atypical expenditure**						
178	*Project or programme**						
180			-	-	-	-	-
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	4,103	3,756	2,939	3,069	1,377	1,377

Company Name: **Waipa Networks Limited**

AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	994	1,426	1,455	1,484	1,513	1,544	1,574	1,606	1,638	1,671	1,704
11	Vegetation management	1,034	1,532	1,563	1,594	1,626	1,662	1,691	1,725	1,760	1,795	1,831
12	Routine and corrective maintenance and inspection	689	788	782	820	814	853	847	887	881	923	917
13	Asset replacement and renewal	591	961	672	786	699	817	720	842	749	876	779
14	**Network Opex**	3,308	4,707	4,472	4,683	4,652	4,875	4,833	5,061	5,028	5,265	5,231
15	System operations and network support	3,648	3,682	3,856	3,668	3,756	3,845	3,936	4,031	4,127	4,210	4,311
16	Business support	7,520	8,557	8,728	8,903	9,081	9,262	9,448	9,637	9,829	10,026	10,226
17	**Non-network opex**	11,168	12,239	12,584	12,571	12,836	13,107	13,384	13,667	13,957	14,236	14,537
18	**Operational expenditure**	14,476	16,946	17,055	17,254	17,489	17,982	18,216	18,728	18,984	19,501	19,768

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	994	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
23	Vegetation management	1,034	1,532	1,532	1,532	1,532	1,535	1,532	1,532	1,532	1,532	1,532
24	Routine and corrective maintenance and inspection	689	788	767	788	767	788	767	788	767	788	767
25	Asset replacement and renewal	591	961	659	755	659	755	652	748	652	748	652
26	**Network Opex**	3,308	4,707	4,384	4,501	4,384	4,504	4,377	4,494	4,377	4,494	4,377
27	System operations and network support	3,648	3,682	3,780	3,526	3,539	3,552	3,565	3,579	3,593	3,593	3,607
28	Business support	7,520	8,557	8,557	8,557	8,557	8,557	8,557	8,557	8,557	8,557	8,557
29	**Non-network opex**	11,168	12,239	12,337	12,083	12,096	12,109	12,122	12,136	12,150	12,150	12,164
30	**Operational expenditure**	14,476	16,946	16,721	16,584	16,480	16,613	16,499	16,630	16,527	16,644	16,541

sch ref												
31	**Subcomponents of operational expenditure (where knc**											
32	Energy efficiency and demand side management,											
33	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
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	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
36	Insurance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	29	58	87	118	148	180	212	245	278
43	Vegetation management	-	-	31	62	94	127	159	193	228	263	299
44	Routine and corrective maintenance and inspection	-	-	15	32	47	65	80	99	114	135	150
45	Asset replacement and renewal	-	-	13	31	40	62	68	94	97	128	127
46	**Network Opex**	-	-	88	182	268	371	456	567	651	771	854
47	System operations and network support	-	-	76	142	217	293	371	452	534	617	704
48	Business support	-	-	171	346	524	705	891	1,080	1,272	1,469	1,669
49	**Non-network opex**	-	-	247	488	740	998	1,262	1,531	1,807	2,086	2,373
50	**Operational expenditure**	-	-	334	670	1,009	1,369	1,717	2,098	2,457	2,857	3,227

Company Name: **Waipa Networks Limited**
AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the 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.	-	-	-	59.67%	40.33%	-	3	-
11	All	Overhead Line	Wood poles	No.	11.42%	32.20%	54.02%	2.06%	0.30%	-	3	31.50%
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				2.35%	97.65%	-	3	-
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 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the 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	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.							N/A	
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.16%	2.80%	9.53%	67.94%	19.57%	-	2	4.00%
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	-	2.00%	4.00%	22.00%	72.00%	-	1	4.00%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	4.00%	83.00%	13.00%	-	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.	-	-	0.88%	46.49%	52.63%	-	3	2.70%
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.	26.70%	4.90%	4.90%	20.50%	43.00%	-	1	3.60%
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.	-	-	-	-	100.00%	-	3	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.31%	19.82%	36.38%	24.88%	16.60%	-	3	4.48%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.43%	4.96%	22.69%	38.33%	32.60%	-	3	1.43%
53	HV	Distribution Transformer	Voltage regulators	No.	-	4.00%	21.00%	46.00%	30.00%	-	3	41.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	0.10%	1.19%	4.09%	87.06%	7.56%	-	2	2.00%
56	LV	LV Cable	LV UG Cable	km	0.19%	2.93%	11.39%	27.37%	58.13%		1	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.40%	8.70%	46.10%	16.10%	28.70%	-	1	-
58	LV	Connections	OH/UG consumer service connections	No.	19.00%	18.60%	18.90%	17.20%	26.30%	-	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	-	72.00%	28.00%	-	1	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	-	-	100.00%	-	-	-	1	2.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.00%		4	-
62	All	Load Control	Centralised plant	Lot	-	-	100.00%	-	-	-	4	-
63	All	Load Control	Relays	No.	0.30%	1.60%	46.80%	39.60%	11.70%	-	1	2.00%
64	All	Civils	Cable Tunnels	km							N/A	

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this 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	50	47	N-1	-	106%	143	54%	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 was installed in May 2020 to avoid 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
10	Transpower GXP Te Awamutu	41	41	N-1	-	101%	54	85%	No constraint within +5 years	Firm capacity is currently being exceeded, however the period is minimal <1%. Transpower's transformers will be uprated in FY24 by new protection to 52/54 MVA capacity. This will ensure capacity is adequate for at least the next five years. Currently on our planning
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 2023 – 31 March 2033**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in 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

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

sch ref		Number of connections					
		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11	*Consumer types defined by EDB**						
12	Residential	539	555	570	586	601	616
13	General	80	80	80	80	80	79
14	Unmetered	-	-	-	-	-	-
15	11kV	-	-	-	-	-	-
16							
17	**Connections total**	619	635	650	666	681	695
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

12c(ii) System Demand

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
25		GXP demand	94	101	106	122	124	132
26	*plus*	Distributed generation output at HV and above	-	-	-	-	-	-
27		**Maximum coincident system demand**	94	101	106	122	124	132
28	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**	94	101	106	122	124	132
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	436	486	521	568	665	704
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**	436	486	521	568	665	703
36	*less*	Total energy delivered to ICPs	412	459	492	537	629	665
37		**Losses**	24	27	29	31	37	39
38								
39		**Load factor**	53%	55%	56%	53%	61%	61%
40		**Loss ratio**	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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*
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	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 2023 – 31 March 2033
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 policy is reviewed every two years with oversight from Risk and Asset Management sub-committee of the Board.	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 obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2.5	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 the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	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?	2	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 2023 – 31 March 2033
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.

Company Name	Waipa Networks Limited
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	Based on PAS 55

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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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
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name: Waipa Networks Limited
AMP Planning Period: 1 April 2023 – 31 March 2033
Asset Management Standard Applied: Based on PAS 55

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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**Based on PAS 55**

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 appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	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?	2.5	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 Manual for construction and Commissioning policies and procedures ensures that new assets are sized appropriately for their intended use and service life.		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	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 reported to the Board and Network Management.		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?	2.5	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 models to determine risk associated with each asset and further inform the replacement and renewal priorities.		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 nonconformitie s	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. Recommendations related to network equipment and asset management are communicated to the Network Asset Manager. Any equipment or design hazards identified are replaced in a planned controlled manner through the asset management plan process.		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?	3	The organisation participates in industry fora (that include ENA, EEA) to share and, or identify 'new' to sector asset management practices and seeks to evaluate them. 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.

Company Name	**Waipa Networks Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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
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 H – 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		1.6, 3.5, 5.5 Appendix A
3.10	An overview of asset management strategy and delivery		1.7, 5.1
3.11	An overview of systems and information management data		7.3

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;	Chapter 10, 7.3, 7.10
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.	10.2, 8.6, 5.4
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;	11.1
3.17	The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.2 of the determination.	1.2
Assets covered		
4.	The **AMP** must provide details of the assets covered, including:	3.1, 3.2, 3.3
4.1	a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including: 4.1.1 The region(s) covered 4.1.2 Identification of large consumers that have a significant impact on network operations or asset management priorities 4.1.3 Description of the load characteristics for different parts of the network 4.1.4 Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	
4.2	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, 10.4, 10.6 - 10.14
4.3	If **sub-networks** 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		
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.	10.6 - 10.14

Information disclosure requirements 2012 clause	AMP section
4.5 The asset categories discussed in subclause 4.4 above should include at least the following:	
4.5.1 Sub transmission	10.6 - 10.15
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**.	
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**.	5.5.1
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.	5.5.1
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.	4.1, 5.3, 5.4
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	8
11. AMPs must provide a detailed description of **network** development plans, including: 11.1 A description of the planning criteria and assumptions for **network** development;	8.6 - 8.15
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;	8.6
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;	8.3
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.	8.2.4
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	8.2.5
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**.	8.2.6
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.	8.3

Information disclosure requirements 2012 clause	AMP section
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.	8.7, 8.8, 8.9
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.	8.8 - 8.15
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**.	8.8 - 8.15
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.	8.4
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.	8.5
Lifecycle asset management planning (maintenance and renewal)	10
12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including: **12.1** The key drivers for maintenance planning and assumptions;	10
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**.	10.2 - 10.15, 10.6 - 10.15, 10.21, 10.22
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**.	10.6 - 10.15
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.	

Information disclosure requirements 2012 clause	AMP section
Non-network development, maintenance and renewal	7
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;	7.12.7
13.4 A description of material maintenance and renewal projects (where known) planned for the next five years.	10.19, 10.20
Risk management	6
14. AMPs must provide details of risk policies, assessment, and mitigation, including: 14.1 Methods, details and conclusions of risk analysis;	6.1
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
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 14.2;	6.1, 6.2
14.4 Details of emergency response and contingency plans.	6.4
Evaluation of performance	4
15. AMPs must provide details of performance measurement, evaluation, and improvement, including: 15.1 A review of progress against plan, both physical and financial;	4
15.2 An evaluation and comparison of actual service level performance against targeted performance;	4
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the **EDB**'s asset management and planning processes.	1.11, 3.8
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.	1.11, 5.2.3, 7.12
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;	1.15, 2.3.2, 11.5
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the **AMP** plans.	2.3.1

APPENDIX I

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

18 April 2023

THANK YOU!

WAIPĀ NETWORKS