

Northpower

# 2026 – 2036 Asset Management Plan





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**Head Office:**

28 Mt Pleasant Road,  
Raumanga, Whangārei, 0110,  
New Zealand

**Postal Address:**

Private Bag 9018,  
Whangārei Mail Centre 0148,  
New Zealand

**Phone:** 09 430 1803

**Fax:** 09 430 1804

**Email:** [info@northpower.com](mailto:info@northpower.com)

**Web:** [www.northpower.nz](http://www.northpower.nz)

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2026 - 2036

# Asset Management Plan



DO NOT STAND ON SEATS

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# Introduction from our chief operating officer

## Tēnā koutou katoa

As we look ahead to the next decade, Northpower's role as an enabler of the energy transition has never been more important. The way our communities use and generate electricity is changing rapidly, and our network must evolve to meet these expectations while remaining safe, efficient, and resilient. This Asset Management Plan reflects our commitment to supporting the transformation in a way that benefits our consumer-owners and the wider region.

Delivering this future starts with safety. No matter how much technology changes or how fast our network transforms, the wellbeing of the public, our contractors, and our people is paramount. As our network becomes more complex, we continue to lift our capability to ensure that everyone working on or living near our assets can do so with confidence. This means continuing to invest in training, systems, and processes that manage risk and embedding safety into every decision we make. Safety is not negotiable — it is the foundation on which everything else rests.

As electrification accelerates, keeping electricity affordable for our region is critical, we must optimise the network to maintain cost-effectiveness and reliability. We are strengthening our asset management capability and using advanced tools and analytics to make smarter investment decisions. By embracing innovation and improving how we operate, we can balance reliability, affordability, and sustainability for the communities we serve. This includes deploying technologies that give us better visibility and control, enabling faster responses and proactive planning for future needs.

Alongside these priorities, we cannot lose sight of the fact that much of our network is ageing. Many assets have served our communities well for decades, but they are now approaching the end of their useful life. Continued strong investment in renewal and modernisation is essential to maintain reliability and resilience. This Asset Management Plan continues the strong investment levels needed to replace and reinforce critical infrastructure, ensuring that our network remains a robust platform for the future. Without this investment, the benefits of electrification and decarbonisation cannot be fully realised.

The shift toward low-carbon technologies — distributed generation, distributed energy resources and electrified industrial processes - presents both opportunity and responsibility. We know that decarbonisation and electrification are central to New Zealand's future, and Northpower is determined to play a leading role in enabling this change. Our focus is on ensuring that we have the capability, technology, and processes to connect these new loads and generation sources efficiently. This means investing in systems that streamline customer connections and working closely with stakeholders to ensure that the transition is smooth and equitable. We see this as a critical part of our purpose — helping our communities embrace cleaner energy without complexity or delay.

Northpower's purpose is clear, to enable a cleaner, smarter, and safer energy future for Northland. This Asset Management Plan sets out how we will achieve that — through disciplined investment, innovation, and a relentless focus on safety and efficiency. Together, we are building a network that supports our region's aspirations and delivers enduring value for our consumer-owners. The journey ahead is exciting, and we are committed to leading it with integrity, foresight, and care for the communities we serve.

Ngā mihi nui



**Michael Gibbs**

Chief Operating Officer

# Executive summary

## Introducing our 2026 asset management plan

This is Northpower's 2026 asset management plan (AMP). It sets out our approach to managing our electricity network assets and related expenditure over the next 10 years, from 1 April 2026 to 31 March 2036.

The AMP summarises and explains our asset management approach for our customer owners and other stakeholders. It complies with the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination.

Our AMP is informed by our Statement of Corporate Intent (SCI), our group strategy, and our electricity business plan. It explains how we will deliver on our commitments to provide a safe, secure, and reliable electricity distribution service.

Our AMP outlines how we will invest to maintain our assets, cater for growth, and transform our network over the next 10 years to meet the evolving needs of our consumer owners.

Reflecting improvements to our asset management approaches, this 2026 AMP has been revised and expanded from previous versions to reflect our continuous improvement of our asset management maturity journey. This includes refining and restructuring content, simplifying asset related discussions, and making the content more accessible for stakeholders. We hope the changes to our AMP will make it easier for customers and stakeholders to connect with us.

## Background

New Zealand is now well into the transition towards a decarbonised, increasingly electrified economy. The uptake of technologies such as wind, solar and battery storage, are accelerating, supported by continued cost reductions. It's an exciting time and distribution networks are at the forefront as key enablers of the transition.

As part of this transition, we expect our customers to take up opportunities to generate a portion of their own energy and adopt new energy technologies, particularly electric vehicles. Our vision for the future is one where our electricity network not only provides a safe and reliable link to existing energy sources, but also helps our customers to unlock more flexibility, innovative solutions, and cost-effective services.

To support this, we are committed to managing our assets in a prudent way over the long term. This means developing the network to serve new customers and supporting the evolving demand of existing customers.

New Zealand is in a critical period as we look to decarbonise and electrify our economy.

It's a transition we anticipated and are well prepared for. Since AMP23 we have continued to deliver our increased investment levels, strengthened the network backbone, and invested in modern operational systems and customer capability. Our advanced distribution management system (ADMS) is fully operational and we are focussing on the renewal of our asset information management systems.

Alongside the opportunities we see over the coming years, we know we will face some challenges. Our asset management activities take place in a wider environment with multiple drivers and influencing factors. How we manage these external factors is key to our asset management approach. These factors consider the increasing impacts of climate change, the need for increasing network resilience, and increasing renewal needs. A key part of our response to address these factors is to continually improve our underlying capabilities.

This AMP sets out some of the main challenges and opportunities we face and the initiatives we are undertaking to address them.

## Supporting our communities

Northpower's electricity network spans the Whangārei and Kaipara districts, and connects the national electricity grid to our customers' homes and workplaces. We provide residential and business customers a safe, secure, and reliable electricity distribution service. These customers are also our owners—every customer connected to our network is an owner through the Northpower Electric Power Trust.

Our overarching purpose is to generate value for the regions of Kaipara and Whangārei from infrastructure ownership. We pass on the benefits of ownership to our customers through discounts on distribution charges (passed on through their power bills) and dividends through the trust.

Enabling our communities to thrive by powering a more sustainable future.

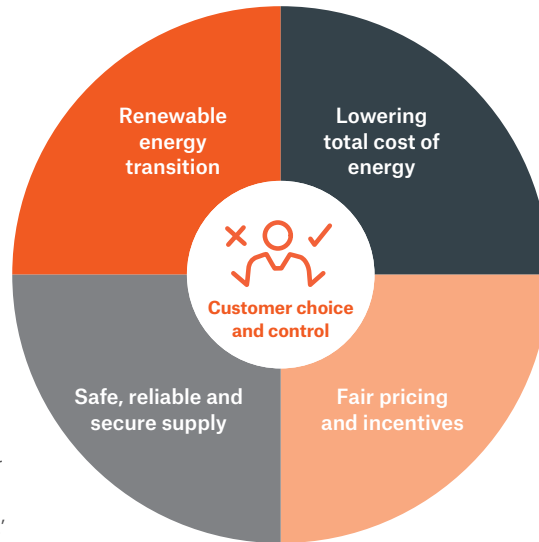
Customer views and feedback are incorporated into our decision making through regular surveys, market research, engagement with iwi and community groups, and ongoing customer feedback. This allows us to improve customer experience and gain a deeper understanding of our customers' needs, now and in the future.

We engage with our communities through a range of channels and actively consult with them on what matters most to them and their experience of dealing with us. Our dedicated Customer Experience team puts customers at the heart of all we do.

Consistent themes from our engagement include:

- customer choice and control
- renewable energy transition
- safe, reliable, and secure supply
- lowering total cost of energy
- fair pricing and appropriate incentives.

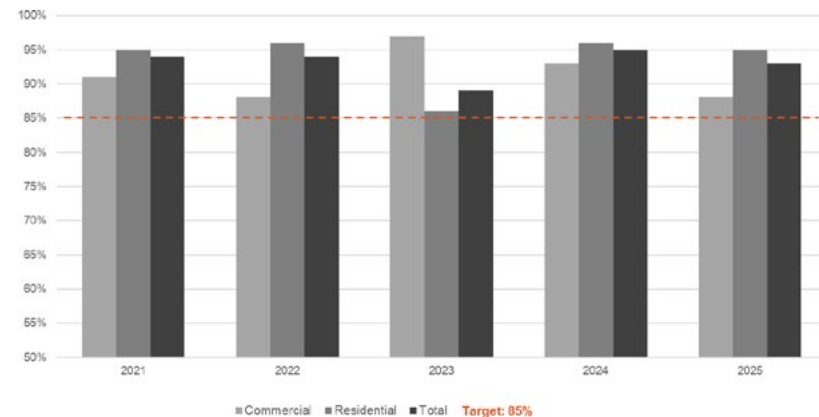
As part of our 'Your Energy Future' initiative, we continue to actively engage with customers and stakeholders. We use insights from our latest customer survey to develop a better understanding of our customers' needs and concerns. Customers tell us that ensuring the network is able to manage their future energy needs and choices is important. We recognise that energy choices can be complex, and our aim is to make it easier for our customers to make informed energy choices.



### Delivering for customers

A key focus is ensuring we meet our customers' expectations. We have a long-standing performance target for customer satisfaction of at least 85%. We consistently achieve this target. In our last annual survey, 93% of customers were satisfied or highly satisfied. This was made up of 88% satisfaction amongst commercial customers and 95% satisfaction amongst residential customers.

#### Customer satisfaction results



### Delivering a cost-effective service

We recognise that energy hardship is a growing issue in our communities, so one of our key goals is to help customers reduce their total energy costs. Our objective is to support healthy homes in our communities with access to safe, reliable, and affordable energy. We are committed to helping our customers better manage their energy use and improve efficiency.

Our consumer outreach programme helps Northlanders by providing practical energy saving advice and assistance to reduce total electricity costs. Working with community partners to reach households in need, we have delivered personalised electricity and support to over 4,000 households over the last three years. This practical help includes home energy assessments, advising customers on finding the best retail plans, and providing free LED lightbulbs.

We need to continually improve the way we do things, making sure that our investment decisions are prudent and efficient. This includes adopting a whole-of-life approach to make trade-offs between opex and capex over the full lives of our assets. This supports more cost-effective asset management, lowering costs over time.

We are refining how we charge our customers to ensure our charges are equitable, reflect actual cost, and fair as new energy solutions emerge. We have a strong focus on managing our wider business operations in a way that will enable us to lift the level of contribution we provide our customers over time. This includes an ongoing focus on costs through continuous improvement and efficiency initiatives.

### Partnering with stakeholders

Delivering for our communities is underpinned by meaningful and effective engagement with our customer owners. We engage through a range of channels, actively consulting with them on what matters most to them and their experience in dealing with us. This engagement informs our planning, investment and operational decisions, helping us to ensure we deliver outcomes that are valued by our communities.

We continue to strengthen our relationships and work collaboratively with stakeholders, mana whenua, community leaders, social and health organisations, industry participants and government agencies.

Ongoing engagement with stakeholders helps us understand what is important to them and how we can improve our service. We are improving the way we work with customers by streamlining and modernising the ways they can engage with us. We engage with our community to understand their needs and actively partner with iwi and mana whenua to make informed decisions. We invest in and operate our assets in a way that respects cultural considerations and supports responsible stewardship of the environment and communities in which we operate.

## Your energy future

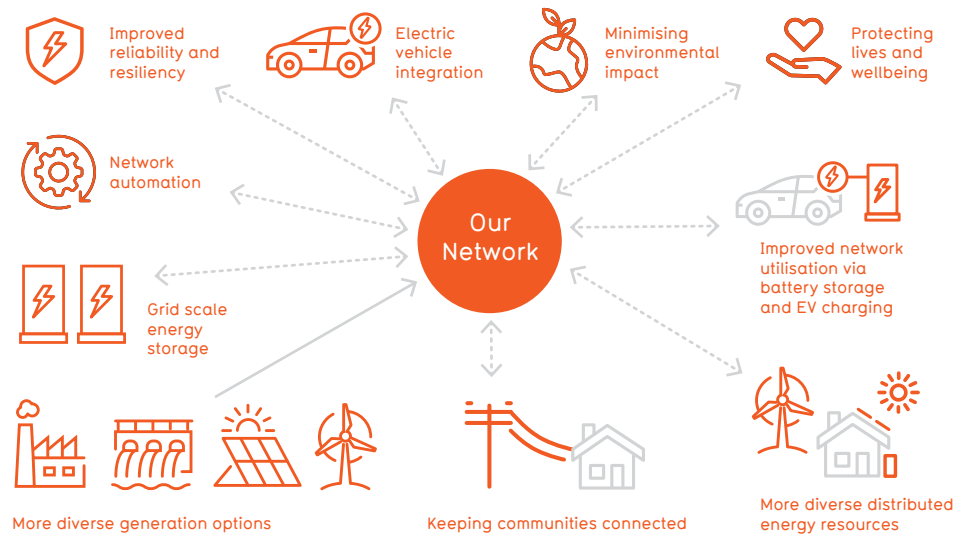
The ongoing energy transition is the beginning of a new phase in electricity supply, with options for customers to take an increased role in generating, balancing, and tailoring their electricity use. This transition reflects a shift towards a more decentralised and dynamic electricity system. We support this transition and the increased uptake of new renewable energy supply options and technologies, such as rooftop solar and electric vehicles (EV). We see these as complementary to our current energy supply arrangements, and we are actively developing our capabilities to enable customers to connect these technologies simply and efficiently, while maintaining network performance and safety.

We are committed to supporting this integration of new energy solutions, and our network is a key platform to support their implementation. They have the potential to unlock more cost-effective energy solutions and help customers reduce overall energy costs while supporting energy decarbonisation.

Supporting our communities in accessing new energy solutions, while retaining our focus on a safe, reliable, and cost-effective service.

As shown in Figure A, alongside continued growth in the number of EVs, we envisage connecting small and large DER<sup>1</sup> to our distribution network. These include wind farms, solar farms, batteries. In preparation, we are making targeted, least-regret investments to ensure our network can support these technologies, while remaining prudent about uptake scenarios.

Figure A: Supporting our customers' energy future



## Supporting new generation

We are investing in monitoring and control systems to facilitate expected increases in distribution generation. These changes will ensure our network can accommodate increasing numbers and sizes of DER installations. We take a balanced approach to these installations as we need to manage a range of customer outcomes, including safety, reliability and affordability.

We engage with customers seeking to connect and discuss their proposed solutions. Our aim is to make it easy for customers to understand their connection options and associated costs. We believe it is important to support connecting parties so they can make informed choices.

We continue to see significant large-scale distributed generation connection requests on our network. The majority of these are located in rural areas where network demand is relatively low. We expect that these connections will require some significant upgrades. We continue to work with our generation customers to enable them to connect to our network as economically as possible.

Additionally, we are partnering with solution providers, other distribution businesses, and industry parties to share learnings, support industry collaboration, develop future-proofed standards, and ensure our approach is consistent with good practice.

<sup>1</sup> Distributed energy resources are located within the distribution network and include small and large scale generation (such as solar photo-voltaic systems and wind power), batteries, electric vehicles connected to smart two-way chargers, and other new smart technologies that will see our homes and business play an active role in the operation of future power systems.

## Innovation and new technologies

As the energy market evolves and technologies develop, our network will need to adapt. We expect this to include changes to our control systems, the introduction of distributor system operator (DSO)-type capabilities or enablement, greater use of flexibility services, new pricing models to optimise network utilisation, and robust technical standards. We actively look to adopt innovations and new technologies where they will improve the services we deliver. This will need to be underpinned by solid underlying asset management practices to incorporate these new power flows and commercial relationships. With the uptake of DER and new technology, more opportunities exist to deploy non-network solutions and leverage them to cost-effectively address network constraints.

Northpower is actively participating in several technical advisory groups that are examining and developing new standards and guides for photovoltaic (PV) installations, EV charging, and flexibility management.

Our aim is to make it easier for our customers to make informed choices. Technology will enable us to enhance the level of advice and information our customers can access about their service. For example, improving visibility of network capacity, constraints on real-time network status.

The emerging energy future is front of mind for us. We see it as a chance to support our communities so they can access new energy solutions. While doing so, we will retain our traditional focus on safe, reliable, and resilient network operation. As we prepare for the future, energy affordability and equity of pricing will remain at the forefront of our strategy.

## Managing our electricity assets

The role of our electricity network assets is to deliver a safe, secure, and reliable electricity service to the communities of Whangārei and Kaipara, today and in the future. We need to be a responsible steward of the electricity assets for the benefit of our consumer owners.

### Keeping our network safe

Safety is our foremost organisational value. We continually challenge ourselves to maintain a safe and healthy environment, and we place safety and wellbeing at the heart of everything we do. We take an uncompromising approach to safety and act decisively when we identify risks that could affect the public, our staff, or our service providers.

As an electricity network owner, we know our assets and some asset management activities may pose hazards to our staff and the general public. We need to proactively safeguard those working on our network, as well as the wider public. Furthermore, as an employer, we aim to ensure an injury-free workplace, and we actively promote the wellbeing of our people.

As a lifeline utility, it is critical that we invest prudently to ensure our assets are safe, secure, and resilient in the longer term. We need to manage our asset fleets to maintain their condition and performance to prevent increases in safety risk. Our renewal investments, operations and maintenance activities help ensure our network and our activities do not cause harm to the public, our staff, and service providers.

Our investment plans focus on ensuring our network continues to safely serve communities in Whangārei and Kaipara. While delivering our investment programmes, we will not compromise our efforts to ensure the safety of our staff and the general public. This will always be our foremost priority and it informs everything we do.

### A secure network to support growing communities

Over the past five years, Northpower has seen a decline in peak demand, on average 2% per year over the last five years. Annual energy consumption has also seen a decline. This is largely driven by the closure of the Marsden Point refinery in April 2022 and the impacts of the Covid 19 pandemic on industrial and commercial activity. Since 2023, these trends have continued, with increasing rooftop solar PV also contributing to reduced energy delivered.

Lower peak demand reflects a mix of more diverse domestic load profiles, warmer winters, improved appliance efficiency, and off-peak pricing incentives. Looking ahead, growth in domestic connections and industrial decarbonisation are expected to increase demand and consumption. We are closely monitoring these trends to ensure timely and prudent network investment.

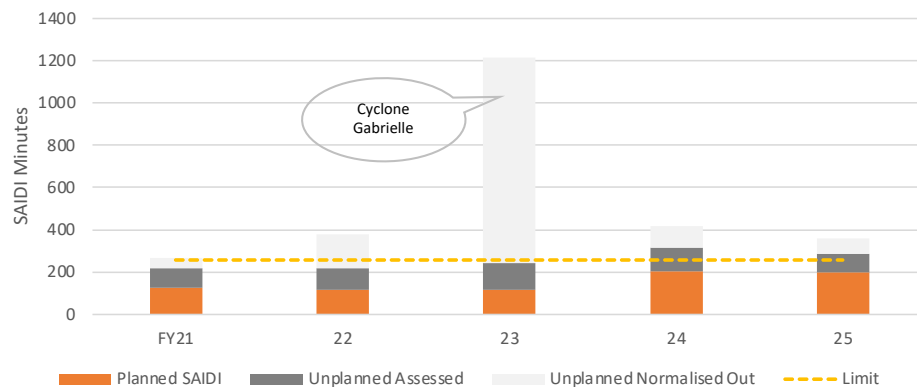
To meet this ongoing growth, we will invest \$55.3 million over the 10-year AMP period. Key investments include the upgrade of our Maungatapere regional substation, upgrades to our subtransmission network around Whangārei, a second 33kV supply to Mangawhai, future supply options to support growth in Waipū, and an upgrade of Bream Bay zone substation.

## Delivering a reliable service

Service reliability is a priority for our customers. The service they receive is influenced by a range of factors, including asset condition, weather, third-party activities, our capacity to respond to incidents, and network security in terms of backup or alternative supply. The levels of reliability we can deliver also reflect historical trade-offs between cost and service. Improving service performance is often a long-term undertaking and has cost implications. Future trade-offs should be based on changing customer preferences and the need to also deliver a safe and resilient service.

Consistent with the wider industry, we measure reliability in terms of duration (SAIDI) and frequency (SAIFI) of interruptions for an average customer.<sup>2</sup> Reflecting their importance, we have set out related reliability targets in our SCI.

### Historical reliability performance (SAIDI)



Our network reliability compares well against peer utilities in New Zealand, and we generally meet our reliability targets. However, we are increasingly seeing extreme events skew performance results. In the last three years, we exceeded our targets due to a number of factors, including extreme weather, defective equipment and an ongoing rise in outages caused by third-party events. Planned outages to safely undertake maintenance and other works have been increasing over the past two years due to an increase in activity within our work programmes.

<sup>2</sup> System average interruption duration index (SAIDI) measures average length (duration) of outages per customer per year. System average interruption frequency index (SAIFI) reflects number of outages per year for an average customer.

When surveyed, the vast majority of customers want existing service levels to be maintained, and their preferences have been reasonably consistent over the last five years.

Some level of outages will always occur.

When they occur, our customers value good communications and timely information on service restoration. They also have increasing expectations of real-time information about network outages and planned works. We aim to advise customers of planned outages well ahead of time and publish information on both planned works and unplanned outages on our website.

Accurately forecasting reliability performance is challenging, as it is affected by multiple factors such as asset condition, prevailing climate, new network configurations and technologies, and our capability to deliver planned interventions. While Northpower is exempt from price-quality regulation, we updated our network performance measures in FY22 to align with regulated targets applied to other distribution businesses in New Zealand. These performance metrics will allow better comparisons with other distributors and provide a clearer view of underlying reliability.

Our reliability performance and future targets are discussed further in Chapter 5.

## Renewing our assets

To be a good steward of long-life assets on behalf of our customer owners, we need a thorough understanding of their performance and condition and how these factors contribute to risk on the network. To manage network risk, we need to monitor our assets' condition and performance. Based on this, we maintain and renew assets at the appropriate time. It also requires us to be a prudent network operator, ensuring assets are not used in ways that are unsafe or could lead to service interruptions.

Our asset inspection process and defect classification methods have improved, allowing us to model an asset's remaining life more accurately. Using this improved asset information, we are modelling the future health of our assets to understand renewal needs and the appropriate level of residual risk. To maintain appropriate asset health, we prioritise investment in our most critical assets. We are also finalising new asset fleet strategy documents, outlining the performance criteria for managing our asset fleets. This ensures we get the most value from our assets, minimise risk, and continue to make prudent investments.

Customers are happy with current reliability, but we are increasingly seeing extreme events leading to longer outages.

### Asset health modelling

In combination, asset health and criticality can be used to estimate the overall risk to our assets. This enables us to prioritise and optimise the timing of asset renewal.

- **Asset health:** is an indicator that represents an asset's proximity to the end of its useful life. This can be used as an indicator of failure likelihood.
- **Criticality:** reflects the impact that an asset failure would have on reliability, safety, and other outcomes. This can be used as an indicator of failure consequence.

Asset health, criticality, and risk modelling provide opportunities to better understand and quantify asset risks and enable defensible fact-based (and prioritised) infrastructure investment decisions.

Effectively managing network risk is a core focus. To ensure we effectively manage the health of our assets and their performance, we will continue our current level of investment in asset renewal and further optimise our maintenance programmes. The ongoing improvements to our asset management systems and processes are helping to ensure we optimise the timing of these investments.

Our overhead line assets have large impacts on service reliability and security of supply. They can also pose risks to public safety if a pole fails, or a conductor drops. We plan to increase investment in our crossarm and conductor replacement programmes. Over the next 10 years, we expect to spend \$215 million on renewing end-of-life overhead assets.

We have renewed a number of our critical assets that entered service in the 1950s and 1960s, such as zone substation power transformers and 33kV and 11kV switchboards. We are continuing with this programme and our forecast renewals for these asset categories are \$42 million. This will provide important investment in Northland's energy infrastructure future.

Our improved asset management modelling and forecasting has helped us quantify the scale of asset ageing. This enables us to better sequence investments to maximise risk reduction while minimising long-term cost.

The level of investment we expect to make over the next decade aligns with previously established benchmarks. This ensures we manage our ageing asset base to provide a safe, secure, and reliable service to the communities we serve.

## A resilient network

Network resilience, the ability to adapt and respond quickly to external impacts, is becoming an urgent priority. A changing climate brings with it more frequent and powerful storms and floods. In addition, the increasing complexity of our systems, use of automation, and sophistication of cyberattacks highlight the importance of an electricity supply that is resilient to external threats.

The term 'climate change' refers to the change of weather patterns over an extended period of time. Climate modelling and our own recent experiences suggest that extreme weather events will continue to increase in both frequency and intensity over the coming decades, despite global efforts to reduce carbon emissions. The impact of climate change has the potential to adversely affect the performance and safety of electrical assets. As a result, climate change poses material risk to our network and its performance.

Our assets and operational systems will need to offer increased resilience to extreme or unforeseen events, including those from climate change and cyberattacks. We need to anticipate and adapt to these emerging threats, withstand and absorb their impacts, and recover quickly.

### Climate change adaptation

Climate change is a global issue that requires significant and immediate action. The global climate is changing at an accelerated rate and the main driver for it is an increase in greenhouse gas emissions from human activities. With a measure of climatic change already locked in, adaptation to mitigate its impact becomes increasingly important.

The impacts of a changing climate will bring significant direct and indirect changes and challenges. These include a growing frequency of extreme weather events, more prolonged dry periods, ground movement due to higher levels of rain, rising sea levels, and increased coastal flooding and erosion. The severity and frequency of these events will increase over time as climate change continues to accelerate. These events damage, destroy, and compromise the performance of infrastructure, and increase risk to the reliable supply of electricity.

These resilience risks need to be systematically assessed to ensure associated risk and mitigation costs are understood. Without doing so, there is danger these evolving risks will not be recognised and there will be missed opportunities to address them while it is still relatively feasible.

There is uncertainty in the development of climate change adaptation strategies. We are progressively strengthening our journey of climate understanding, response, mitigation, and adaptation. Our aim is to operate a low-carbon organisation that is resilient to climate impacts. This means engaging our people on the issues and assessing the vulnerabilities of our assets and services in a changing climate.

Our planned investment aims to strengthen network security and resilience to better withstand high impact, low probability (HILP) events, including the increase in extreme weather events due to climate change. We need to develop planning and modelling capabilities that can effectively manage the risk posed by climate change through prudent and efficient investment.

This is not a challenge we can face on our own. We have joined with Electricity Networks Aotearoa (ENA), Electricity Engineers' Association (EEA), and Northland Lifelines Group to work collaboratively on these issues. We discuss our response to climate change in more detail in Chapter 2.

## Cybersecurity

The introduction of digital technologies and enhanced data capabilities create significant operational efficiencies, while transforming the roles and required skills of our future workforce. This increased complexity and disaggregated workforce potentially increases the risk of cyberattacks.

Northpower, as a lifeline utility, needs to address these risks, particularly as cyberattacks become more frequent and sophisticated. We need to maintain effective cyber resiliency that can both combat the rise in cyberattacks and protect internal systems to maintain capability and services.

We plan to assess our cybersecurity preparedness, including implementing an improvement plan and stabilising and securing our network architecture. Implementing stronger and more sophisticated cybersecurity protections will maintain the resilience and security of our operations and mitigate these threats.

## A sustainable future

Our purpose includes Kaitiakitanga, the importance of guardianship of the environment for current and future generations. Northland's spectacular natural landscapes, extensive coastlines, and indigenous flora and fauna need to be preserved and protected.

We take a long-term view of our operations to ensure a sustainable future for Northland. Improved sustainability outcomes can be achieved by facilitating and supporting the development of renewable generation and increased electrification.

Kaitiakitanga expresses the importance of guardianship of the environment for current and future generations.

We strive to exceed regulatory requirements across our operations and projects. We aim to limit the impacts our assets and activities have on our communities and the environment, as far as practicable. This includes the appropriate disposal of redundant assets, equipment, and hazardous substances. We ensure that materials such as oil, lead, SF<sub>6</sub>, and asbestos which may cause harm to the environment or people's health, are disposed of appropriately. We recycle materials where practical.



We are committed to being environmentally responsible and ensuring we do not cause harm to the environment. We will identify and manage works in cultural sites such as urupā and pā through a collaborative and consultative approach with stakeholders. We strive to protect archaeological sites so we can identify, preserve, and protect heritage structures.

## Emissions reduction

Northpower recognises that our network will play a foundational role in the achievement of emission reduction targets in Northland. We recognise the part we should play to support New Zealand's transition to a low-carbon energy future. This is increasingly the case in the context of climate change.

Limiting our carbon footprint is a key focus for us and is reflected in our environment and sustainability strategies. We are proactively managing the emissions produced by our operations.

The pursuit of a net zero economy will transform the way we generate and consume energy.

More generally, Northpower is committed to making a positive contribution to decarbonisation by investing in more distribution and transmission assets and systems to support Northland's longer-term adaptation needs and electrification plans. Where necessary, we will work with the sector to develop additional capacity to enable the decarbonisation of industry, including increased renewable generation.

## Our planned expenditure

We are committed to making the investment necessary to ensure we continue to meet the needs of Whangārei and Kaipara communities. Our planned capex expenditure during the AMP period is \$415 million. This level of investment is necessary to continue to manage safety risk, maintain network performance, and prepare our network and operation for the future.

We are strengthening and deepening our commitment to make sure our networks continue to meet the needs of our customer owners. Since AMP 2023, we have refined our forecasts, both in terms of what is most important and when action is needed, drawing on enhanced asset data, improved risk modelling, and updated information about asset condition. We are also placing ongoing focus on lifting the maturity of our asset management practices to further improve these key areas.

We've lifted investment in network renewals, growth-related upgrades, and customer capability.

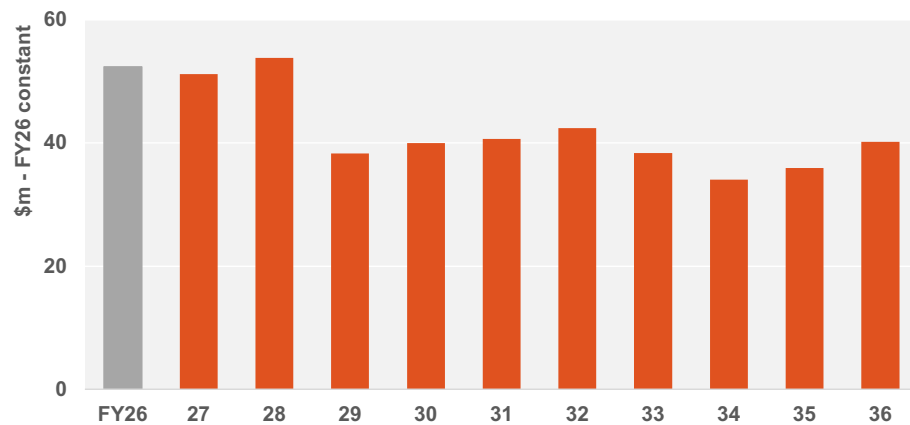
The following profiles our expected total capital and operating expenditure over the AMP period. These forecasts represent our best estimate of network need based on currently available information and reflect our current levels of delivery capability.

## Capital expenditure

Our planned capital expenditure (capex) during the AMP period is set out below. Our capex forecast of \$415 million has increased since our AMP 2023 for the reasons set out in Chapters 8 and 9. It reflects a need to proactively manage our ageing assets and ensure we are ready to meet the evolving needs of customers.

In general, the initial years (FY27 to FY29) are more certain and are supported by more detailed plans. For those investments later in the period, we may refine our plans as we obtain updated asset information or refine our risk analysis.

### Forecast capital expenditure FY26-FY36



Our capex profile varies due to the impact of individual, large investments towards the beginning of the period. The timing of these growth-driven projects reflects the latest prudent timing for addressing the related constraints. Our underlying renewal programmes have a steady ramp-up throughout the period.

See the following examples of our planned capex investments.

- Based on improved modelling and better asset data, we plan to increase levels of renewal in our overhead fleets, particularly overhead conductors, crossarms and poles.
- Large substation renewal projects, including an upgrade (ODID) at Maungatapere substation, Maungaturoto substation and Breambay 33kV switchboard replacement.
- Replacement of some of our 33kV oil filled cables improving network resiliency and future capacity. We will cater for future growth in several areas.
- The Kensington substation upgrade is scheduled for completion in early 2027, with upgrades to the Maungatapere 110kV transformers commencing at that time.

- Construction of the new 33kV line between Maungaturoto and Mangawhai, along with the Bream Bay transformer installation, is also underway. We will increase network resilience in the Whangārei area and make opportunistic improvements during renewal works, for example, raising assets at flood-prone sites.
- Non-network investments to support future applications include upgrading our management systems.

Further detail on these investments is set out in Chapters 8 and 9.

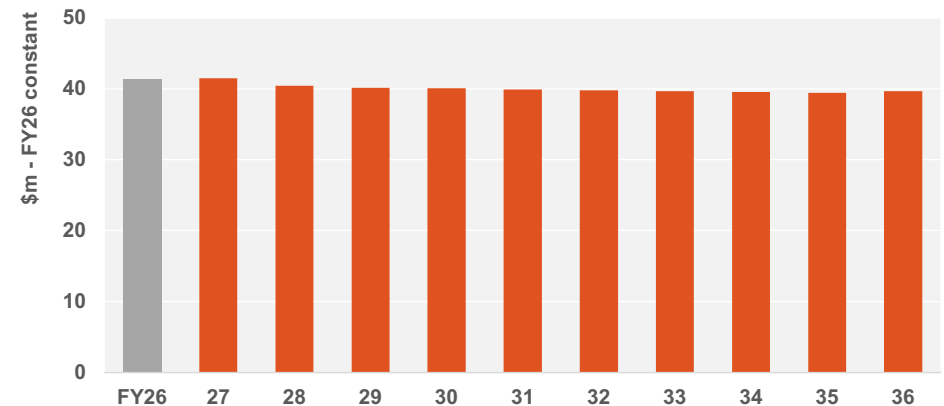
Through improvements in planning, work practices, and the increased bundling of works, we expect to reduce our overall cost of delivery.

This is a significant and necessary level of investment, so we can replace assets which are reaching the end of their service life, connect new customers, and ensure that current levels of reliability and security can at least be maintained. It will also allow us to enhance our networks with the necessary supporting infrastructure and operational controls to support the future use of our network.

## Operating expenditure

See the following for our planned operating expenditure (opex) during the AMP period. Our opex forecast of \$400 million has increased since our AMP 2023.

### Forecast operating expenditure FY26-FY36



Our planned opex is forecast to be relatively stable over the AMP planning period. It reflects the underlying levels of operations and maintenance we need to undertake, support costs, and people costs in the coming years. Capex expenditure associated with digital platforms and data services (including AMIS, GIS and analytics) will increase, however, this will be offset by reductions to IT related capex. Consistent with good practice, we plan to optimise our maintenance programmes and rely on more proactive work. We expect reactive work such as repairs will then reduce.

In the early years of the AMP26 period, we will increase expenditure on several transformation and capability uplift initiatives. These include:

- digital initiatives to improve asset management capability, data quality, and analytics, including implementation of a new Asset Management Information System (AMIS) and GIS upgrade
- additional resources to uplift asset management, data and analytical capability
- expanded inspection, testing, and assessment programmes to improve asset condition information and risk modelling.

Our opex forecast is discussed further in Chapters 9 and 11.

## Refinements to our planned expenditure

Our expenditure forecasts have been developed with a focus on ensuring we have a network that is positioned to meet the needs of Whangārei and Kaipara communities, now and in the future.

This increase in investment will initially put some upward pressure on prices. However, in the longer term, price pressure will reduce as we implement new solutions to help us manage the network at a lower cost. Ultimately, the costs of reactive maintenance, repairs, and unplanned renewals would result in less optimal expenditure and larger future price increases than if we smooth the investment requirements over time, as planned.

Our 10-year expenditure forecast is based on current information and analysis of asset health, demand growth, and estimates of the rate of uptake of new technologies. We will continue to update our thinking on assumptions and our planning more generally over time. We consider this to be consistent with good asset management planning practice as well as in the long-term interest of our consumer owners.

## Improving our capability

Our people play a critical role in managing our electricity network and are essential to everything we do. Managing long-life electricity assets safely and effectively requires a range of specialised and evolving capabilities. This means we need to have the right capabilities (including in emerging areas such as asset analytics), and we need to help our staff learn and adapt as the electricity sector evolves.

To lay the foundations for our future network and to meet the challenges we face, we need to further improve our asset management capability. We believe strong asset management drives efficient delivery, and we're continuing to make that shift. Underpinning all of this has been an active continuous improvement approach. Capability development, such as embedding appropriate processes, systems, and techniques in our business, is essential, and our focus on this continues.

Our asset management capability comes from our people, the tools we use, and the processes we follow. Having enough people with the right skills is essential if we want to be effective stewards of our distribution network.

In the coming years, effective workforce planning and competency training will become more critical, as older and experienced staff retire and are no longer available for on-the-job training. For this reason, we are placing an increasing focus on formal competency planning.

We believe strong asset management drives efficient delivery, and we're continuing to make that shift.

## AMMAT assessment

Our latest asset management maturity assessment tool (AMMAT), see Chapter 6, has resulted in a higher score than in 2023. This assessment reflects improvements made in various areas since our last evaluation. This forward-looking review assessed our current capability against best practice asset management and the capabilities required to support:

- our future readiness strategy, including leveraging new technology and innovation
- increased network resilience to meet the challenges of climate change
- improved analytics to support increasing renewal needs.

Gaps identified during this review have been included in improvement initiatives planned or already underway.

## Continuous improvement programme

As we deploy new technologies and increase our asset management capability, we need to make sure we foster an appropriate learning environment. We need to identify and embed the right capabilities so we can deliver innovative solutions. This will be especially important as we ramp up expenditure to ensure the ongoing safe and reliable operation of the network and make our network future-ready so we can efficiently support our customers' energy choices.

Recognising opportunities for improvement in our approach and the challenges we, and the wider electricity distribution face, we have developed a continuous improvement programme aligned with our asset management maturity objectives and future readiness strategy. Our planned improvements will support increased efficiency and are directed towards aspects of our systems and processes that can deliver the most benefits.

The increasing use of DER, new energy technologies, and the importance of digital platforms, asset data and advanced analytics will have far-reaching implications for how we operate. The mix of required capabilities will change, and it is important that we identify and embed these through targeted capability uplift, system improvements, and new ways of working so we can continue to deliver an efficient service to our customer owners.

Our continuous improvement programme will support the delivery of our commitments to our customer owners.

The link between improvement initiatives and better performance or efficiency gains are complex and often lagged. As a result, we expect that the impact of these initiatives will be gradual, noting that many of them will take several years to fully implement. Ultimately, the aim of our continuous improvement programme is to support the delivery of our commitments to our customer owners.



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## Chapter 1

# Introduction

# 1 Introduction

This chapter introduces Northpower's 2026 Asset Management Plan (AMP). It explains its purpose and how it addresses the Commerce Commission's information disclosure requirements. Lastly, it explains the structure of the AMP so that readers can quickly find the information they are interested in.

## 1.1 Purpose of the AMP

This AMP sets out our overarching strategy for managing our electricity network and delivering electricity distribution services to customers. It explains the asset management approaches we use, including asset management principles, forecasting techniques, and the day-to-day practices we use to ensure our assets continue to provide a safe and reliable service to customers. We hope that it will help stakeholders to better understand our approach to managing our electricity network assets.

### 1.1.1 Period covered by the 2026 AMP

The AMP looks ahead to the next 10 years, from 1 April 2026 to 31 March 2036.

The earlier years of the AMP are based on more detailed analysis of demand forecasts and asset information, resulting in greater levels of certainty. The greatest certainty of projects will be determined over the next financial year. Beyond five years, while our forecasts and project schedules provide a firm indication of our plans, a degree of change and refinement is anticipated as we respond to the changing needs of our customers and the performance of our assets.

### 1.1.2 Objectives of the AMP

Our AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. A reference of how it meets the detailed regulatory information disclosure requirements is included in Appendix E. In addition to these requirements, we have developed our AMP to explain to stakeholders our approach to managing our electricity distribution network.

The AMP was approved by our Board on 25 March 2026.

Our AMP seeks to provide our stakeholders with a view of how we develop and operate our network for the good of our community. It sets out our commitment to responsible stewardship of intergenerational assets and how we will prepare our network for the future energy needs of our customer.

To achieve these aims, we have developed a set of objectives to guide the development of our AMP. These objectives include the following:

- setting out our commitment to minimising safety risks on our network
- explaining how we reflect stakeholder needs in our corporate objectives and how these inform our asset management approach
- explaining our risk management approach and the systematic processes in place to mitigate risks inherent in electricity networks
- providing visibility of our investment plans to stakeholders
- setting out our performance targets and explaining how we plan to meet them
- highlighting our approach to managing our assets by providing accessible descriptions and detailed explanations
- summarising our asset management document suite, showing how these are aligned with corporate goals and setting out our work plans for the planning period
- demonstrating the 'line of sight' between the objectives of the AMP, our corporate goals, business planning processes, and investment plans
- updating stakeholders on improvements to our asset management practices.

Over time we strive to improve our AMP by reflecting on customer insights, considering shifts in external factors, and incorporating advances in new technology and practices to enhance outcomes for our customers.

## 1.2 Structure of the AMP

The remainder of this document is structured as follows.

**Table 1.1:** Document structure

Chapter	Description
<b>Executive summary</b>	Summarises the key points of the AMP
<b>1 Introduction</b>	This chapter
<b>2 Background</b>	Sets out relevant context for our 2026 AMP
<b>3 Network overview</b>	Describes our network across Northland and sets out key statistics
<b>4 Strategic context</b>	Explains how we ensure our investments support the needs of stakeholders
<b>5 Our performance</b>	Outlines how our network is performing and initiatives we have in place to improve performance
<b>6 Approach to asset management</b>	Explains our overall approach to asset management, including assessments of our capability
<b>7 Risk management</b>	Explains our risk management approach, outlines our key risks and how we manage them
<b>8 Network development</b>	How we address demand growth, security of supply, and connect new customers
<b>9 Asset lifecycle management</b>	How we manage our existing asset fleet, key issues, and current network condition
<b>10 Supporting activities</b>	Overview of the activities that support our asset management
<b>11 Summary of Expenditure Forecasts</b>	Sets out our planned investments over the AMP planning period

Appendices	Description
<b>A Glossary</b>	Sets out the meaning of acronyms and technical terms
<b>B Disclosure schedules</b>	AMP disclosure schedules required by Commerce Commission
<b>C Further network details</b>	Detail of our network feeders and substations. This includes details on our larger network investments over the AMP period
<b>D Further risk information</b>	Provides further detail on the network risks, and how we manage them
<b>E Disclosure requirements</b>	Sets out how the AMP addresses Information Disclosure requirements
<b>F Director's Certificate</b>	A copy of the AMP's director certification



## Chapter 2

# Background



## 2.1 Introduction

Northpower provides residential and business customers with a safe and reliable electricity distribution service. Our network spans the Whangārei and Kaipara districts and provide the physical link between the national grid<sup>1</sup> and our customers' homes and premises.

Our customers are also our owners — every customer connected to our network is an owner, represented by the Northpower Electric Power Trust. Trustees are elected by the community and represent the customers by defining the desired outcomes to be achieved by Northpower on behalf of our consumers. The trust engages with the Board of Directors on long-term matters affecting Northpower's business strategy.

In this chapter, we discuss the overarching context for our 2026 AMP and how this has impacted our approach to asset management. The wider environment we operate in is an important factor in how we deliver our services. Factors such as the evolving energy market and the increasing impacts of climate change mean we need to continually improve our underlying capabilities.

Reflecting our efforts to improve our asset management approaches, the 2026 AMP has been revised and expanded from previous versions. In particular, we include expanded discussion and supporting information on our future investment plans.

Getting closer to our customers is still an underpinning theme of this AMP. Our aim is to better understand the views of our customers and stakeholders so we can evolve our services to best meet their changing needs while delivering the best possible value for money. In this chapter we outline how we engage with our customers and incorporate their views in our decision making.

We also provide an overview of our strategy to continue to evolve our electricity network so it will meet the future needs of our customers and facilitate their energy choices.

## 2.2 Overview of Northpower

As an electricity distribution business (EDB), Northpower provides residential and business customers a safe and reliable electricity distribution service. The key activities we undertake to deliver this important service include:

- maintaining assets to ensure they are safe, secure, and provide reliable service
- building new assets and upgrading existing capacity as our region grows
- replacing assets as they reach the end of their service life
- managing our network in real time, to ensure its effective operation and the safety of those interacting with our network
- connecting new customers to the network
- enabling renewables generation and new technology to be connected to our network.

### 2.2.1 Proudly trust owned

Our customers are also our owners — every customer connected to our network is an owner, represented by the Northpower Electric Power Trust.

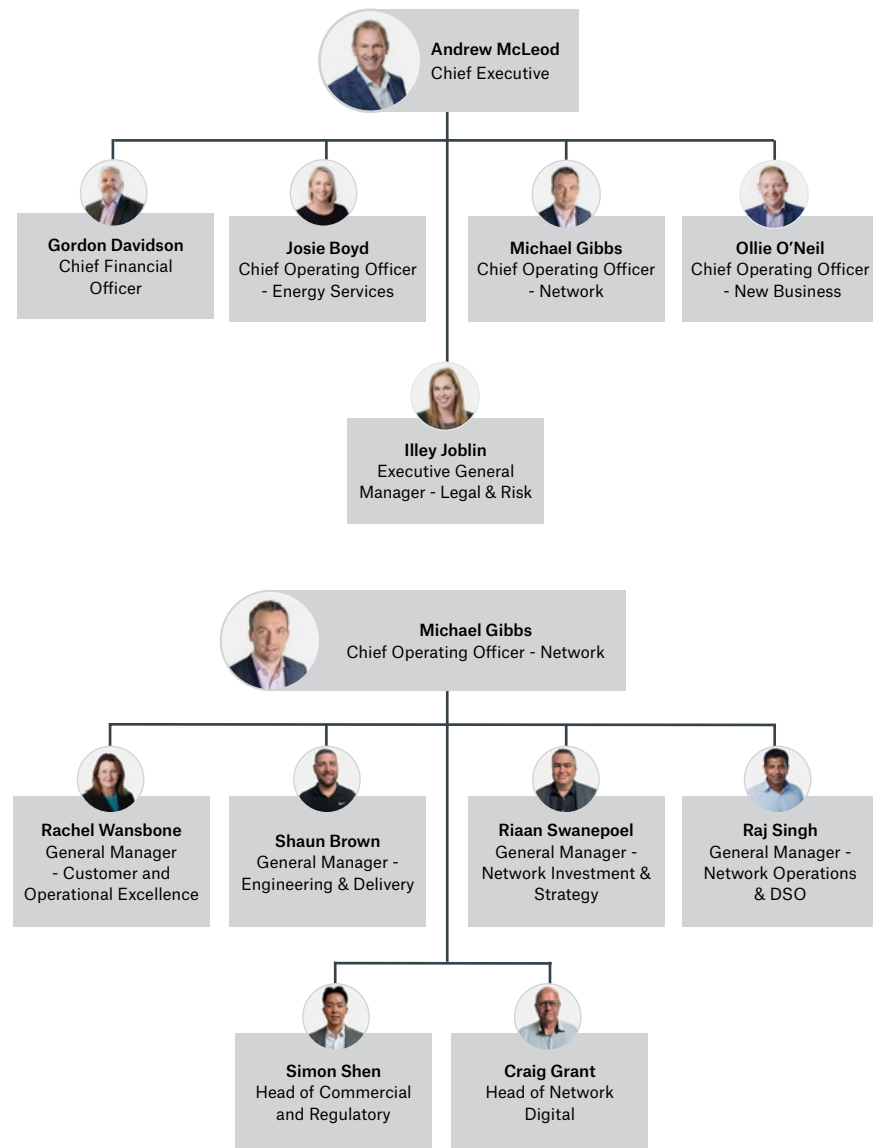
Trustees are elected by the community and represent the customers by defining the desired outcomes to be achieved by Northpower on behalf of our consumers. It appoints Northpower's directors and sets the expectations for the performance of the organisation. The trust engages with the Board on long-term matters affecting Northpower's business strategy.

### 2.2.2 Our structure

Within Northpower, the network division is responsible for the electricity-related asset management functions. As depicted in Figure 2.1, the Chief Operating Officer (COO) - Network leads a set of functional teams to perform this role.

1 Owned and operated by Transpower

**Figure 2.1:** Electricity network division within our organisation structure (as of March 2026)



The COO – Network is accountable to the Chief Executive for meeting the network operational and financial targets as set out in our Statement of Corporate Intent (SCI). The COO – Network oversees six teams that manage the following areas and responsibilities.

- **Network Investment and Strategy:** this team is responsible for developing the asset and network strategy, asset replacement planning, asset information management, and network development. It also leads the development and maintenance of our asset management plans, systems, and frameworks. Key responsibilities include aligning asset management strategies with customer and stakeholder needs, enhancing understanding of network growth and asset risk, and improving decision-making processes to effectively manage risk and deliver long-term value.
- **Engineering and Delivery:** this team is responsible for engineering design, maintenance and project execution across both our Capital (Capex) and Operational (Opex) budgets. Key areas of management include driving operational excellence, reviewing and refining maintenance strategies, enhancing procurement practices, and improving project management capability and execution. These responsibilities ensure efficient delivery of network investments and support long-term asset performance.
- **Operations and Distributed System Operator (DSO):** this team is responsible for network operations, including control room functions, control systems, and the delivery of reactive services. Key areas of management include the development of our DSO strategy, strengthening our ability to learn from operational events, and enhancing existing operational practices with a focus on operational excellence, particularly in real-time low voltage (LV) network management.
- **Commercial and Regulatory:** this team is responsible for managing our relationships with regulators and retailers, setting our pricing and commercial oversight.
- **Network Platforms:** this team is responsible for managing and developing the digital platforms that support the electricity network. Key areas of responsibility include continuing the development of our digital roadmap to support business needs, improving planning processes and portfolio delivery, and lifecycle management of our digital systems.
- **Customer and Operational Excellence:** this team is responsible for core customer services, including helping customers get connected to the network, enabling distributed generation, and all consumer engagement, including ensuring we understand consumers' needs and deliver to meet those needs as well as managing our relationships with our approved network contractors and other external parties that provide services to support the network. The Operational Excellence team is responsible for documentation management and change management, ensuring improved efficiency across the network.

Shared services functions, which sit across the other divisions, support our electricity business by providing specialised capabilities, management and assurance functions, processes, and systems. These functions include:

- **Legal and Risk:** provides legal support and sets the enterprise risk management approach. Provides second line of assurance oversight and manages third line of assurance activities.
- **Finance and digital:** responsible for corporate financial functions and oversight. Provides enterprise digital support through provision of underlying digital infrastructure, security services, and enterprise digital and data systems.
- **People, Safety and Training:** provides people and capability support including managing recruitment, onboarding, remuneration, learning and development, staff wellbeing. Provides health and safety specialist support.

### 2.2.3 The communities we serve

Northpower provides a safe and reliable electricity distribution service to residential and business customers across the Whangārei and Kaipara districts, comprising:

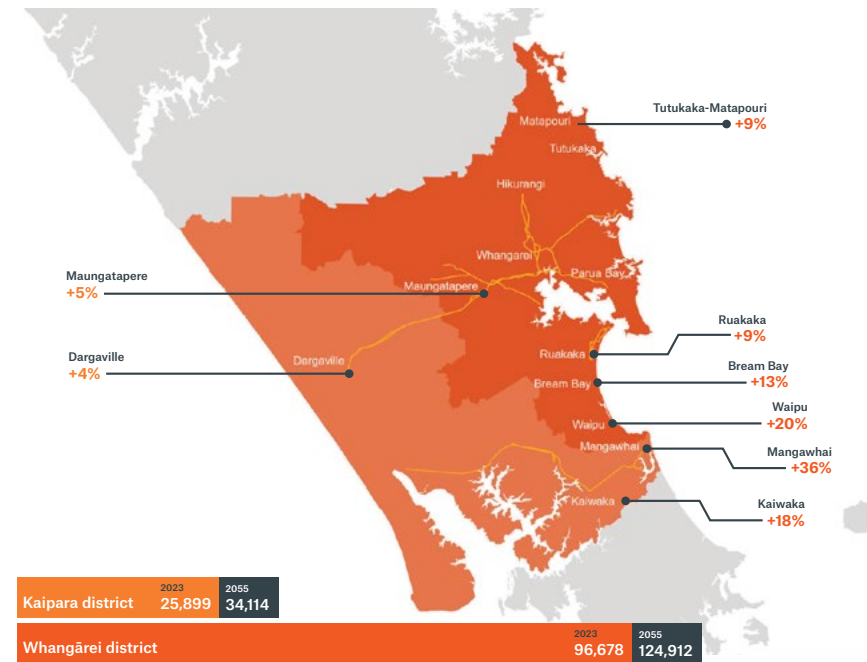
- 102,000 people in the Whangārei district
- 27,300 people in the Kaipara district.

Based on the 2023 Census data, the population rate growth in Whangārei slightly exceeded the national average, reflecting continued momentum likely driven by regional development and migration.

New connections are slightly lower than the preceding period. In the past three years, we have added 2,089 new customer connections to our network. Development along the coastal regions, in particular Tutukaka and Matapouri, Marsden Cove, Waipū, and Mangawhai, as well as the rural hub of Dargaville, continue to attract new subdivisions and businesses requiring additional supporting infrastructure.

Whangārei is Northland’s only city and its major service centre. Primary industry is the largest employer across the rural sector in Northland (particularly in agriculture, fishing, and forestry). We recognise the importance of gaining a deeper understanding of the customers and communities we serve, especially as our region changes and evolves. This is a core part of our strategy. We carefully plan investment in our network to ensure we continue to provide resilient and reliable infrastructure that supports our communities and the future growth of Northland.

Figure 2.2: Population growth projections for Kaipara and Whangārei districts<sup>2</sup>



Against this backdrop of growth and migration, our inland communities continue to fuel our local economy through horticulture and agriculture, with the Whangārei district adding marine services, manufacturing, and processing industries. We are also seeing more applications for large-scale generation connecting to our network across the region. As the mix of industries continue to develop, longer term prospects for the region remain positive.

### 2.2.4 Managing stakeholder interests

We have a wide range of stakeholders and understand the importance of appropriate stakeholder management, see Section 2.4.7. Our stakeholder engagement framework outlines how we liaise with stakeholders to understand their priorities and work alongside them to ensure stakeholders are informed, consulted or collaborated with as appropriate. Figure 2.3 shows how we manage stakeholder interests, including where there are conflicting objectives.

<sup>2</sup> Growth figures from 2023 Census and Infometrics growth projections.

**Figure 2.3:** Understanding and managing stakeholder interests



### Identify interests through engagement and research

- Customer surveys, focus groups, major customer engagement, data analysis and market research
- Employee feedback and engagement surveys
- Supplier technical assessment meetings
- Service provider engagement and performance meetings



### Reflect good asset management practices

- Health and safety planning, auditing and compliance
- Customer growth and demand forecast
- Coherent network planning to ensure we maintain security of supply standards
- Risk management
- Network standards and operational procedures



### Manage conflicting interests

- Consider stakeholders' interests and needs as part of the development process of our AMP
- Balance cost of non-supply and investment to provide security of supply
- Reflecting our commitments and objectives to our shareholder as set out in the SCI
- Consider the cost and benefit of alternative options

## 2.2.5 Staff engagement

Effective staff communication involves clear, timely, and relevant messaging between senior management, team leaders, and our field staff. It helps us embed effective asset management across our business.

Clear communication helps avoid misunderstanding and error, which is essential when worker and public safety might be compromised. Staff are more productive, with better job satisfaction, when they have access to the information they need to do their jobs well.

Examples of our asset management communications include:

- engagement and feedback while developing our AMP
- publishing asset management material and information on our intranet
- internal presentations and updates on our works plan for network and contracting teams
- leadership communications and presentations
- internal monthly updates on asset management issues
- formal and informal learning sessions.

If our people are well informed, they can make better decisions, and this is important as we continue to increase our asset management capability. Ultimately, effective communication provides the information needed to make informed decisions, leading to better outcomes for all our stakeholders.

## 2.2.6 Field services

Northpower's Energy Services division is the primary field service provider operating on the Northpower network. The Network Delivery Manager administers the interface with the Electrical Services division under a defined governance structure, underpinned by a service level agreement (SLA). The schedules to the SLA have defined task-based activities determining scope, resources, and time required to complete the activities. This provides the ability to benchmark performance and improve efficiency.

Northpower's Energy Services is one of the largest electricity distribution contractors in the North Island, giving our electricity business access to a wide breadth of capability, a large and mobile workforce should additional resources be required, and extensive purchasing power for subcontractors and materials. One advantage of this arrangement is better alignment between our planning and delivery functions, ensuring consistent approaches, standards, and operating practices.

To ensure sufficient delivery capability, large value capital works may be subject to competitive tender. This also facilitates benchmarking of our delivery function against the wider market. External contractors and the internal contracting division are subject to the same health, safety, quality, and environmental management policies and standards as the wider company and must be authorised to work on the Northpower network. Internal and external work at Northpower sites are subject to field audits to ensure the work has been completed to required standards.

## 2.3 Context for our 2026 asset management plan

In this section, we discuss the context informing our 2026 AMP and how this has influenced our planned investments over the 10-year AMP planning period.

### 2.3.1 Addressing our ageing network

As we improve our condition monitoring, asset information, and analytical capability, we recognise a growing need to increase the rate of asset renewal on our network. As our assets continue to age, their condition continues to deteriorate, increasing the risk of asset failure. The detailed planning and analysis we have undertaken to support our AMP investment plans shows a need to continue with our renewal expenditure in some of our asset portfolios. This is necessary due to the large portion of assets that continue to degrade. If this is not addressed, they will begin to pose unacceptable levels of risk and could adversely impact supply.

### Managing network and safety risks

Elevated safety risk is one potential consequence of poor asset health and is often accompanied by other risks, such as reliability issues, environmental damage, and non-compliance. Public safety risk is greatest for asset classes in close proximity to people, particularly overhead line assets. Safety risk to workers extends to assets in our substations and increases with the deterioration of asset health. These issues are discussed further in Chapter 7.

As a lifeline utility, it is critical that we invest prudently to ensure our assets are safe, reliable, and resilient in the longer term. This involves carefully managing our asset portfolios to ensure stable condition and performance to effectively manage network and safety risk.

### Improvements to our renewals planning

To effectively manage risk on our network, we need to ensure our work programmes prioritise assets that pose the greatest risk. This needs to be driven by accurate needs identification, underpinned by good practice analysis that utilises comprehensive, robust asset information.

We continue to invest in the following to improve our renewals forecasting approach:

- developing asset lifecycle strategies
- refining our inspection techniques to support a quantitative asset condition analysis approach
- developing asset risk models to drive decision making
- investing in an Asset Management Information System to support workflows and asset management.

Over time we will augment our analytical capability with improved and expanded inspections and testing to better understand asset condition and related risk.

### Implications of our planned investments

We continue to observe an increasing risk of asset failure across our overhead line fleets, excluding the poles fleet, which benefits from historical investment in concrete poles. With improved insights into overhead asset condition, we have maintained and expanded our conductor and crossarm replacement programmes. These portfolios contain a significant volume of assets with modelled deterioration, indicating a growing number of end-of-life components. Addressing these risks requires sustained, targeted investment to reduce the likelihood of in-service failures and ensure network reliability. Key benefits of our proposed renewal investments include:

- **Keeping our networks safe:** modelling suggests that increasing asset-failure risk requires increased investment levels in several portfolios to reduce the safety risk posed by failure of these assets.
- **Manage asset health:** ensure asset health is stable through proactive renewal, focusing on assets in poor condition and using criticality for prioritisation. This approach will help prevent asset failure and reduce the need for less cost-effective reactive repairs and replacement.
- **Prudent defect management:** ensure we do not accumulate replacement 'backlogs' by addressing the increasing number of ageing assets. It is important that we maintain sustainable (steady state) volumes of work and address risk through a proactive programme.
- **Deliver a reliable service:** as the AMP period progresses, we expect to increase our focus on ensuring that customers receive their preferred levels of service. An important aspect of this will be successfully meeting our reliability targets, which we have aligned with the DPP regime. Investments we make to address the risk of asset failure will, over the medium term, lead to improvement in our reliability performance.

Delivering a safe, secure, and reliable service into the future requires that we invest more in the network. We have committed \$415 million over the next 10 years to this purpose. The cost of building and maintaining electricity distribution supply infrastructure is recovered through the line charge component of consumers' electricity bills. Ultimately those costs are passed on to customers through increased line charges on their power bills.

All things being equal, increased investment places upward pressure on prices, and we are working hard to minimise this cost impact on customers. Given concerns around affordability for our consumer owners, we have sought to minimise, our 10-year expenditure through rigorous review and challenge. This ensures our planned projects and programmes are appropriate and that we have deferred expenditure where possible.

### 2.3.2 Evolving energy market

The New Zealand energy market, like many overseas, is seeing the emergence of new renewable energy supply options (such as rooftop solar), new applications for electricity (such as electric cars), and new methods of storing electricity (such as in-home battery systems). These developments are complementary to current energy market arrangements. Such developments herald a new phase in electricity supply, with options for customers to take an increased role in generating, balancing, and tailoring their electricity use.

To act as a foundation for future energy markets, our network should not limit customers' options to adopt technologies such as rooftop solar generation and electric vehicles.

We are committed to facilitating the integration of new energy solutions. We firmly believe that our network is a key community platform to support them. We are preparing for this future in a number of ways, including:

- lifting investment in our electricity network to ensure it continues to provide secure and reliable service while accommodating growth in our region and supporting integration of new energy solutions
- refining the way we charge our customers to ensure the charges we impose are reflective of actual cost, and ensuring equitable and fair charges as new energy solutions emerge
- improving how we work with customers by streamlining and modernising our communication tools and taking an active stake in understanding, enabling, and providing advice on new energy options
- making targeted, least regret investments in enabling technology
- improving our ability to manage the LV network through investment in smart meter data and analytics and, mapping and labelling LV equipment.
- developing a DSO strategy that positions Northpower to actively participate in future market developments shaped by evolving regulatory frameworks and market dynamics.

The objectives and investment plans within this AMP reflect this balanced focus on network safety, reliability, enabling future energy choices, and maintaining high levels of customer satisfaction.

### Our focus on future technology will increase over the AMP period

Over the coming years, we plan to increase our focus on future technology to allow research and development, and testing of new and innovative network and non-network solutions. With increased efforts to promote decarbonisation, we expect to see more electric vehicles, photovoltaic installations, and battery storage systems installed on our network. We believe it is prudent to prepare for increased uptake of these resources now, rather than react at a later stage.

### 2.3.3 Responding to climate change

Climate change is a global issue that requires significant and immediate action. The global climate is changing at unprecedented levels and the main driver for this is an increase in greenhouse gas emissions contributed from human activities. The term 'climate change' refers to the change of weather patterns over an extended period of time.

#### Potential impacts

The impacts of this changing climate will bring significant direct and indirect challenges. These include a growing frequency of extreme weather events, increased prolonged dry periods, ground instability due to higher levels of rain, rising sea levels, and increased coastal flooding and erosion. The impact and frequency of these events will rise over time as climate change continues to accelerate.

In New Zealand, potential impacts of climate change are likely to include (but are not limited to):

- higher average temperatures,
- extreme rainfall events,
- more severe storms with higher wind speeds,
- droughts will become more common and more severe, leading to fire risk,
- communities and infrastructure assets near the coast will be increasingly vulnerable to sea level rise,
- more ground instability due to high rainfall events,
- storm events combined with sea level rise will increase the likelihood of river flooding and coastal inundation.

Over the 10-year AMP planning period, we expect to see further evidence of the above impacts and will need to respond accordingly.

#### How we are responding

We are beginning a journey of climate understanding, response, mitigation, and adaptation. Our aim is to operate a low-carbon organisation that is resilient to climate impacts. This means engaging our people on the issues and assessing the vulnerabilities of our assets and services in a changing climate.

There is a large amount of uncertainty in the development of climate change adaptation strategies. This includes incomplete data sets on which to base decisions and a significantly changing landscape. We will need an adaptive approach that specifies actions to be taken immediately, as well as those required to adapt in the future if needed in light of tipping points and triggers. To ensure our response to climate change is flexible and effective to the unpredictable environment, regular reviews will take place.

These reviews will consider:

- central government legislation
- views of the wider electricity industry, both in New Zealand and overseas
- local government's plans and strategies
- changing Northpower priorities and needs of our customers.

A periodic scan of these changing factors will be used to provide direction and insight over the AMP period.

We need to act now, even with uncertainty. This means acting now on 'no regret' measures that can be implemented without knowing the full impact of future climate change. We will identify areas within our control (such as substation locations) and external factors we can influence (such as choices by third-party developers) to find mechanisms for addressing them. We are beginning by:

- **decision making:** factoring climate change into decision-making and operationalise it to become business as usual. We will consider medium- and long-term climate change in relevant investment and planning decisions.
- **mitigation:** pursuing climate change mitigation strategies, including reducing our greenhouse gas emissions on an ongoing basis.
- **adaptation:** developing strategies and approaches to ensure our assets and operations are resilient to the impacts of climate change.
- **evolving strategy:** evolving our strategies as more certainty is gained on the impacts of climate change and the effectiveness of actions to adapt and mitigate.
- **agile work programmes:** adopting agile project management with flexibility and innovation — this will be most suitable when addressing climate change.
- **engagement:** seeking inputs from all parties impacted by climate change, including mana whenua and Northland communities.

This is not a challenge we can face on our own. We have joined with the Electricity Networks Aotearoa, Electricity Engineers' Association, and Northland Lifelines Group to work collaboratively on these issues. We also work with district and regional councils at planning and operational levels to ensure that we take into account the latest information when carrying out our activities.

Our response to climate change fits under our environment focus area, see Chapter 4. We discuss our broader approach to resilience and risk management in Chapter 7.

### 2.3.4 Improving our asset management capability

Recognising the challenges and opportunities presented by our ageing assets, climate change, population growth, and the evolving energy landscape, we are continuing to focus on improving our asset management maturity and approach. This work has already made good progress, and the analysis set out in this AMP illustrates some of the advances we have made.

As discussed in Chapter 6, we are committed to further developing our overall asset management capability to ensure we meet accepted best practice standards. This will require investments in our people's capability and our supporting systems.

To guide our progress, we have undertaken a detailed review of our asset management capability as part of our AMMAT review<sup>3</sup>. This review of our current capability considered inputs from core departments and their views. This assessment, discussed in Chapter 6, resulted in a score of 2.4 (out of 4). This is an increase compared with our 2023 score, which had an overall score of 2.0. Our latest score reflects our evolving view of good practice and the need for EDBs to continuously improve, given the challenges. Our aim is to be open and transparent about our capability. We will continue with a number of initiatives, which started after 2023, to lift our maturity over the coming years.

Over the planning period, we will focus on improving staff competency, rolling out a new Asset Management system along with a GIS upgrade, and adopting proven innovations. This includes further improvements to our risk management approach, largely based on refining our asset health modelling and embedding a network-wide criticality framework. These initiatives will enable targeted interventions and better inform our renewal forecasts over the planning period.

Our ultimate aim is to ensure our asset management is consistent with good practice within five years. We have adopted a target to achieve an AMMAT score of 3 or greater by 2029. This reflects a commitment to further improve our overall asset management capability to ensure we can cost effectively meet the needs of customers. We will invest in the capability of our people and ensure that our systems, supporting data, and processes effectively enable our wider work programmes.

## 2.4 Customer engagement

In addition to operating and maintaining our network, ensuring we deliver for our customers requires understanding their needs and aspirations so that we can ensure our service remains relevant to them.

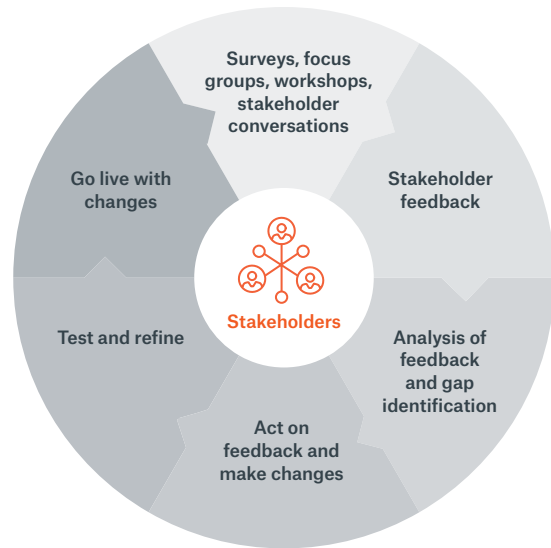
We are continuing our investment in our Customer Experience team to improve customer service. Our customer relationship management (CRM) system helps us to keep track of all interactions and requests, ensuring we meet our commitments to our customers.

### 2.4.1 What our customers have told us

We engage with customers through a range of channels and actively consult with them. We seek out customer views on future investment plans by asking what matters most to them and their experience in dealing with us. Our dedicated Customer Experience team focuses on putting customers at the heart of all we do. As depicted in Figure 2.4, customer views and feedback are incorporated into our decision making through regular surveys, market research, engagement with special interest and community groups, direct consultation, and ongoing customer feedback.

<sup>3</sup> AMMAT refers to the asset management maturity assessment tool which is an information disclosure requirement that needs to be prepared and included in our AMP.

**Figure 2.4:** Northpower’s customer engagement model



Ongoing surveys and focus groups are increasingly important given the significant changes taking place in the energy market, including the uptake of distributed generation (DG) and growing energy hardship in the region. The increasing adoption of electric technologies such as electric vehicles and solar power by consumers are changing the way our customers use energy. However, Northland’s overall low socioeconomic status means many of our customers live in deprived areas and are at risk of being left behind as others benefit from these new technologies. We see it as part of our role to understand our customers’ needs and support our community in ways that are meaningful to them, while at the same time ensuring it is fair and equitable for everyone.

These factors support a wider project to ensure we can adapt to meet the needs of customers in a rapidly evolving energy market. This has shaped our communication strategies and directed our focus on to our consumers’ main areas of concern, guiding our focus as we engage with customers on new energy technologies and energy efficiency education, and provide advice on reducing energy costs. We see a role for us in helping our customers get the most from their energy choices to help them drive down their total energy costs.

## 2.4.2 Customers’ top priorities

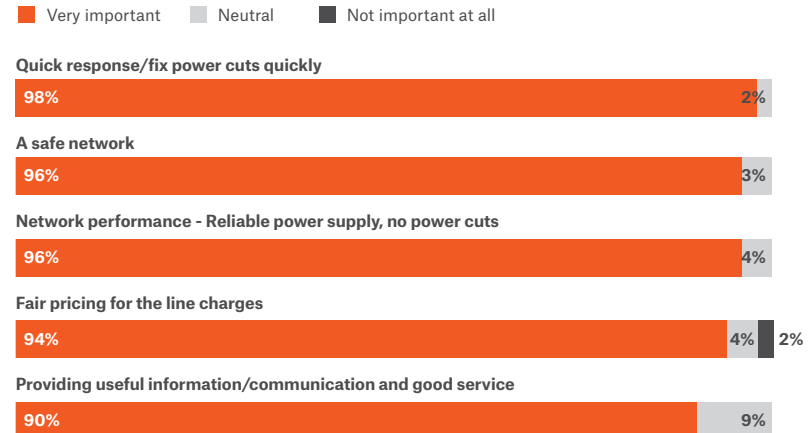
Our customers are consistent on what matters to them most. Our customers continue to rate a reliable and safe network as a high priority. Responsiveness, which is quick restoration of power, is also highly important to them. They recognise that an investment in maintaining the lines is important to achieve, but want to ensure we balance it with being cost-efficient so that pricing remains fair. They’ve told us their key priorities, see Figure 2.6.

**Figure 2.6:** Customers’ top priorities

These priorities are fundamental to how we manage and operate our network.



**Figure 2.7:** Top priorities as identified in annual customer survey, March 2025

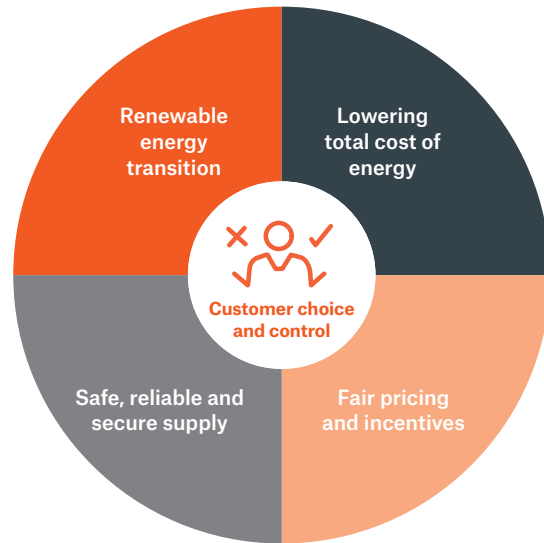


Ninety-eight percent of customers consider a **quick response** very important, followed closely by **a safe network and network performance**, both at 96%.

### 2.4.3 Supporting customer choice

Customers have told us that ensuring the network is able to manage their future energy needs and choices is important. We are investing and preparing to ensure our network is resilient and able to cope with these changes, while ensuring pricing remains fair.

**Figure 2.8:** Our approach to supporting our customers' energy choices



We take a balanced approach to supporting our customers' energy choices, acknowledging we need to balance the following outcomes:

- ensuring our electricity assets are safe and will not cause harm to the public, staff or service providers
- ensuring our electricity assets meet current and future customer demand and deliver a reliable and resilient power supply
- supporting our community through delivering value for money, enabling regional growth and meeting our customers' expectations
- supporting New Zealand to decarbonise through enabling renewable energy in our region and supporting our customers to decarbonise
- ensuring our network keeps up with changing customer choices and behaviour and integrates new technology as appropriate.

### 2.4.4 'Always on' customer contact centre

Our Customer Experience and Network Operations teams provide a 24/7 customer contact centre. We talk to around 2,600 customers per month over the phone and in person. We are also available through social media channels, where approximately 70,000 customers per month engage with us.

While responding to requests and helping customers get the information they require, we can keep track of key trends and concerns through our CRM system. Reviewing these trends helps us identify and improve our processes. Monthly surveys are completed, where customers who have interacted with us (during faults or customer-initiated projects) are called and asked for ratings and feedback. This feedback is considered to further enhance our service.

### 2.4.5 Customer engagement on major projects

Iwi and customers affected by major projects are consulted and their views are taken on board during the project planning phase. Changes to planning dates or other mitigations may be considered and provided where appropriate. Frameworks for Iwi and Stakeholder Engagement have been developed to guide all teams dealing with various stakeholders – from planning through to delivery. Over the last five years, we have worked on several substation upgrade projects. These projects have involved heavy machinery, earthworks, and the installation of new transformers. Neighbours living or working close to Kensington, Dargaville, Poroti, Mangawhai, Maungaturoto, Parua Bay, Kaiwaka, and Ruawai substations have been consulted and included in the planning phases of our projects. We worked with the stakeholders to ensure that they are aware of the work happening and that the disruption caused was as minimal as possible.

Local iwi were involved in planning the build of our newest substation on our network at Mangawhai Central. Local iwi and all neighbouring property owners were kept informed through information sharing events and a sod-turning ceremony to kick off the project. When the project was finished, stakeholders, neighbours, and the public were invited to tour the new substation. This was a valuable learning exercise for our team who were able to better understand customers' views and questions. We are currently engaged in detailed discussions and negotiations regarding the development of a new 33kV feeder between Maungaturoto and Mangawhai, which will include both overhead and underground circuits.

### 2.4.6 New connections

One of our customer centre's main goals is to make it easy for customers to connect to our network, upgrade their connection, and to change to solar energy at any time. Our main principle is to guide customers through what can seem like a daunting process, make it easy and straightforward, and to be fully transparent about any issues, helping customers and their electricians to work through them.

Our CRM system is used to record these interactions with customers, and customers can use our portal to request required services, see Box 2.1. This portal walks customers through the application process, guides them to find information, and submits the application to our Customer Experience team.

The application is reviewed by our dedicated customer Technical team. Once the connection is approved, the team coordinate with the retailer and living contractor to connect the customer.

### Connection time frames

Our target for service is five working days between submission and our approval. This is achieved for over 90% of applications. After our approval, the living process time frame is dependent on customer time frames, retailer approval, ordering of metering, and availability of the contractor to inspect and live. If power is already available at the boundary, the living contractor will usually have the connection live 10 working days from receiving our order and getting approval from the retailer.

For those that require additional work or where we identify complexities, our Technical team contacts the customer or electrician to advise what may be required and help them solve this. One commonly encountered issue is the need for power to the boundary to be made available. This can require engineering and design input as well as construction work. The required time frames will depend on the complexity of these works.

For those customers wanting to change their connection to import/export metering to enable the export of excess generation, it is usually straightforward, and approval is issued within five working days. Customers in rural areas or on long service lines may need to overcome voltage drop issues or reduce export to manage it.

Larger or new industrial connections can take some time to design and to reach agreement with the customer on commercial arrangements. The time frame for these is also dependent on other external factors, including procurement of required equipment and work scheduling. These applications go through the Network Business Development Manager, a team specifically set up under the Customer Excellence team umbrella dedicated to handling large load and large DG applications.

We have recently enabled a wider range of approved contractors to undertake customer connections to the network. This has resulted in positive change for our stakeholders and customers, providing customers with a choice and new opportunities for local businesses.

#### Box 2.1: Connections information

Information for customers wanting to connect to Northpower's network is [on our website](#).

Information for generation customers, both small and large scale is [on our website](#).

## 2.4.7 Stakeholder engagement

### Monthly customer surveys

We engage an independent customer research agency to carry out monthly surveys with customers who have had contact with us in the prior month — either a new connection, customer-initiated works, or a fault response. Customer satisfaction is measured across key touchpoints and verbatim comments are reported along with net promoter score and satisfaction results. Feedback is reviewed by customer and operations staff and performance scores are reported to the Board monthly. Changes are made, when required, to ensure continual improvement.

### Annual survey

An annual survey of 400 customers (both commercial and residential) across the region is undertaken by an independent research company. Customers are called and invited to give their views on a range of questions, around what is most important to them and how we are doing in those areas. The results of the survey are discussed in Section 5.3.1.

### Direct engagement

Ongoing meetings with key stakeholders in the new connections area, such as electricians, builders, developers, and community groups, help us understand what is important to them and how we can improve our service.

A technical advisory group has been formed from a representative group of community electricians, solar installers, and inspectors in the Northland region. This group meets as required to discuss any proposed changes and new energy developments. They also participate in focus groups to help form any improvements we make around our CRM, requirements and communications.

The input from this group has been instrumental in directing the changes to our processes and services, helping us respond to changing requirements with new technology entering our industry.

Our key stakeholder engagement also includes consultation and feedback from key community stakeholders such as councils, large industrial customers, tangata whenua, and landowners. Internally, Northpower consult with our electricity Network team, shared services teams, and our contracting partners. This feedback helps prioritise improvement initiatives.

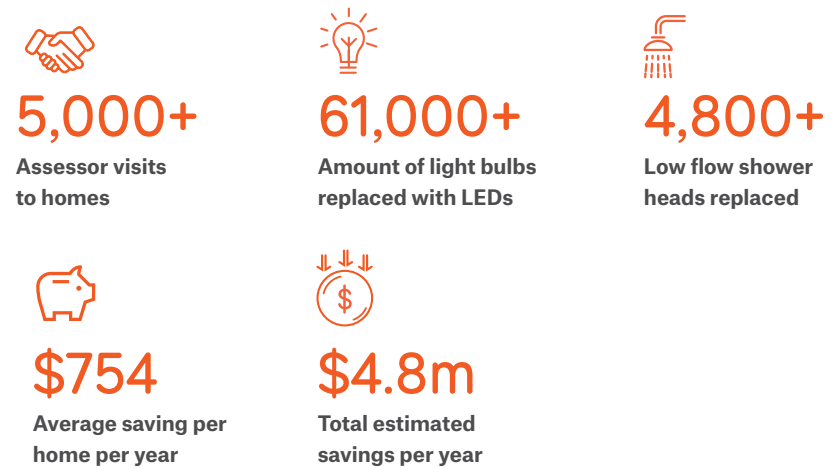
### Community outreach and education

With customer feedback and statistics from our region showing that many of our consumers are in energy hardship or have difficulty paying their power bills, Northpower put together a consumer outreach programme aimed at helping Northlanders with practical energy-saving advice and assistance to reduce total electricity costs.

Northpower has been working with community partners and the Ministry of Business, Innovation and Employment (MBIE) Support for Education in Communities (SEEC) since 2022 to deliver personalised electricity advice and support to over 5000 households across the Whangārei and Kaipara districts in the last three years. This includes practical help through home energy assessments, helping customers find the best retail plan for their needs, and providing free LED lightbulbs and low-flow shower heads to help lower energy use.

Over the past three years, we helped over 5,000 customers find the right retail plan, and installed over 61,000 light bulbs and 4,800 shower heads. Implementing the energy saving actions and changing retailers gave an average saving per home of \$754 per year, saving customers approximately \$4.8 million in total every year.

**Figure 2.9:** Serving our communities – Energy Education Programme



As well as these in-home assessments, we have been using online and print media platforms, as well as presentations to community groups to share energy saving tips and advice to educate our consumers on energy efficiency. This has included interactive power saving calculators and quizzes on our website to encourage engagement.

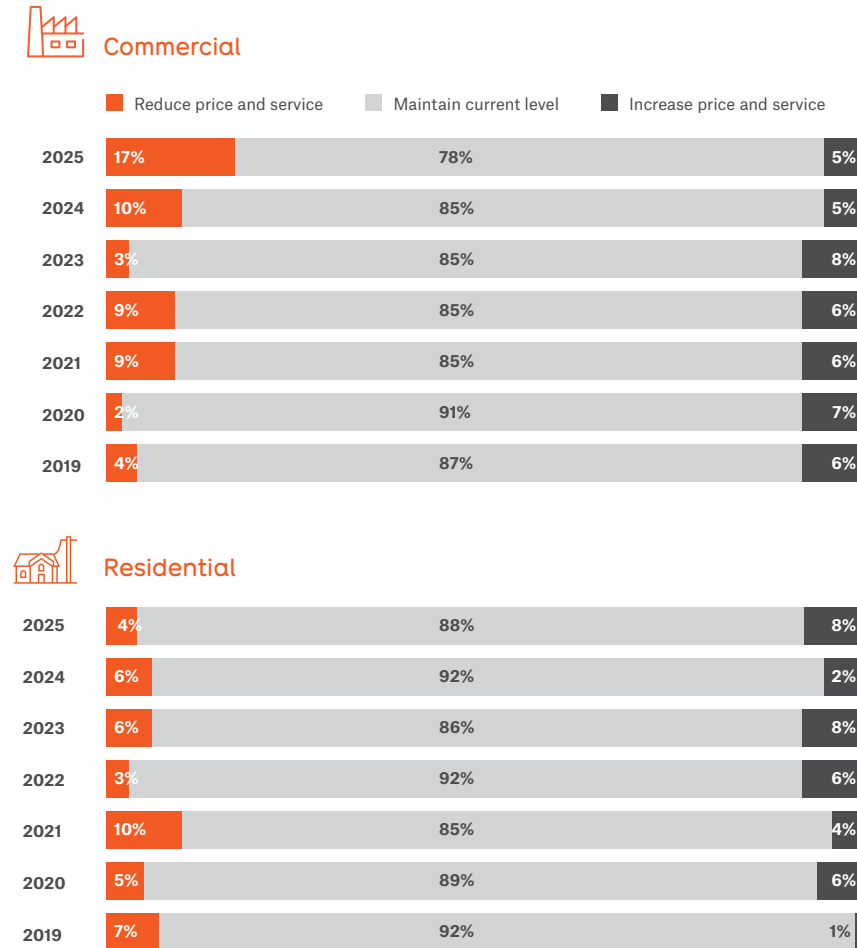
### Public safety campaigns

The safety of the public around our network assets is important, so we have introduced a Stay Safe Together campaign into our public communications plan. The monthly themes include messaging about how to keep safe around downed power lines, how to work safely around our assets, and tips to keep safe in the summer months. We use our website, social and print media to reach our consumers with these messages and are able to report on the levels of engagement we are getting.

## 2.4.8 Customers are happy with existing reliability levels

The majority of customers indicated in our surveys that they want existing service levels maintained, and these results have been reasonably consistent over the last five years. This is an important input when determining the level of network investment into reliability associated projects.

Figure 2.10: Preferred level of service, annual customer survey, March 2025



The customer responses were received when they were asked about their preference for Northpower's level of service<sup>4</sup>, noting that changes in service levels may require changes in price. Over the last three years, residential customers preferences to retain the current levels of service have been consistent — 86% in 2023 to 88% in 2025. The proportion of commercial customers who prefer to reduce price and service has increased from 3% in 2023 to 17% in 2025, however, the majority (78%) are happy to maintain the current levels of service.

## 2.4.9 The right communication is increasingly important

In the last annual customer survey, customers told us they wanted to be kept informed. A top priority when it came to communications for commercial customers was being informed about power supply matters, while residential customers wanted communication about the things we are doing.

The customer feedback we receive reinforces the increasing expectations of real-time information about network outages and planned works. As well as advising customers of planned outages well ahead of time, we publish both planned works and unplanned outages on our website. For large unplanned outages, or events such as storms, we also utilise social media channels such as Facebook.

This is becoming a preferred communication channel for many customers and is utilised for updates around network plans, investment news, and outage information sharing, as well as keeping customers engaged.

### 2.4.10 Outage communications

In the last three years, we have made significant improvements to our Outage Management System (OMS) and the way outage information is portrayed to customers for both planned and unplanned outages. Along with the investment in our CRM, we are now able to integrate these two systems, allowing them to be much more automated and streamlined. This enables an improved customer experience as we can provide up to the minute, detailed information to customers.

#### Planned outages

We directly inform customers of planned outages with at least 10 working days' notice. Retailers are advised at the same time, but we do not rely on retailers to advise our customers. All Installation Control Points (ICP) that may be impacted by the outage are automatically identified and grouped by network topology. Automated emails advising of the outage are sent at the time of processing, and then 10 days, five days, and the day before as a reminder. Around 85% of our customers have up-to-date email addresses. For those without an email address, a letter is printed at the time of sending and posted to customers.

<sup>4</sup> Level of service being based on reliability of supply, supply quality, and response times to faults.

If an outage is cancelled or changed, this is updated in the system and an automated email is sent to affected customers instantly.

When work is being planned, large industrial customers, sensitive customers, and essential services are taken into account and, as much as possible, plans are discussed and agreed upon (and often changed to suit) well in advance with these customers.

Details of planned outages and any cancellations are available [on our website](#).

## Unplanned outages

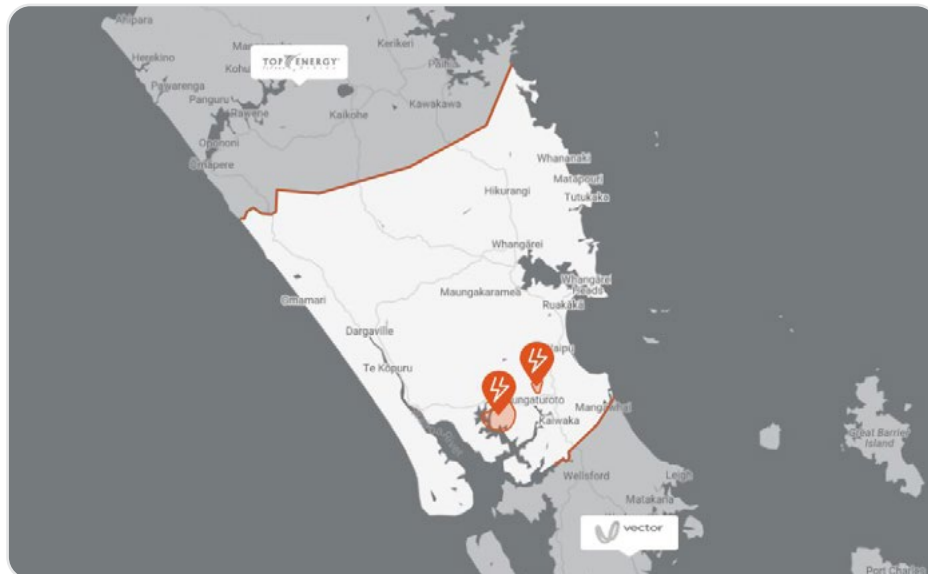
Our 0800 number for faults is the first port of call for most customers experiencing an unplanned outage. Our local team takes calls 24/7 and dispatches fault staff quickly.

The 0800 number has an automated answer message which has a recording of known faults. This can save customers time waiting for an operator if the call centre is busy during a large outage.

When there are outages affecting a large number of customers or clusters of outages in a storm event, we post updates on the Northpower Facebook page. We use this page to interact and answer questions from customers related to that outage.

Our [website](#) displays a map showing current unplanned outages and information, including cause and expected time of restoration, as this information becomes available.

**Figure 2.12:** Example from our outages webpage



## 2.4.11 Addressing customer complaints

If our customers have a complaint or problem, we want to fix it.

We want to help resolve issues our customers are experiencing. Often a discussion with one of our team is all that is required to resolve concerns. Our local call centre takes calls, emails, and Facebook messages, or feedback from staff, around customer complaints.

### Complaints resolution process

We are a member of the Utilities Disputes Scheme. Customers are advised on our phone messaging system, and on outgoing emails from the Customer Excellence team that we are a member of the Utilities Disputes scheme and that if any complaint they make is not resolved within 20 working days they can call Utilities Disputes. We provide contact information for this scheme on our website. Information about our complaints process is on [our website](#).

### Voltage quality

We take power quality complaints very seriously. We work closely with customers to identify the issue and find a solution. We continually assess how well our processes address these issues and refine them as opportunities to improve are identified.

Customers can find information about quality issues and report their quality issues by calling our 0800 number, or via a form on our website.

This is picked up by our Dispatch team who send a staff member out to check on the customer's connection or to identify if there is an issue upstream of their connection point. For example, power quality issues are usually due to the distribution transformer tap setting being incorrect, the customer's motor start-up not operating correctly, or voltage rise due to solar generation. The majority of these issues can be resolved quickly by adjusting the distribution transformer tap setting. Our staff member on site will advise the customer, or our Customer Excellence team will get in touch to let the customer know the source of the issue and the plan to resolve it.

We also take a proactive approach to voltage quality management, especially as distributed generation continues to increase across our network. We have completed the procurement of smart meter data, which, combined with advanced analytics, helps us identify and resolve power quality issues across the low voltage network more efficiently. Smart meter data lets us see how voltage levels respond to changes in demand and embedded generation, giving us insights into daily, weekly and seasonal voltage patterns for distribution transformers and feeders. With these insights we can resolve many power quality issues without the expensive and time-consuming task of installing on-site data logging equipment. The insights also support voltage management at distribution transformers and feeders, letting us view voltage patterns for all distribution transformers on a feeder and plan tap setting changes to bring them into alignment. We continue to work closely with our vendors to improve the availability of real-time data, develop new applications and improve our existing applications, that help us identify potential network risks early, supporting both safety and performance.



## Chapter 3

# Our Network

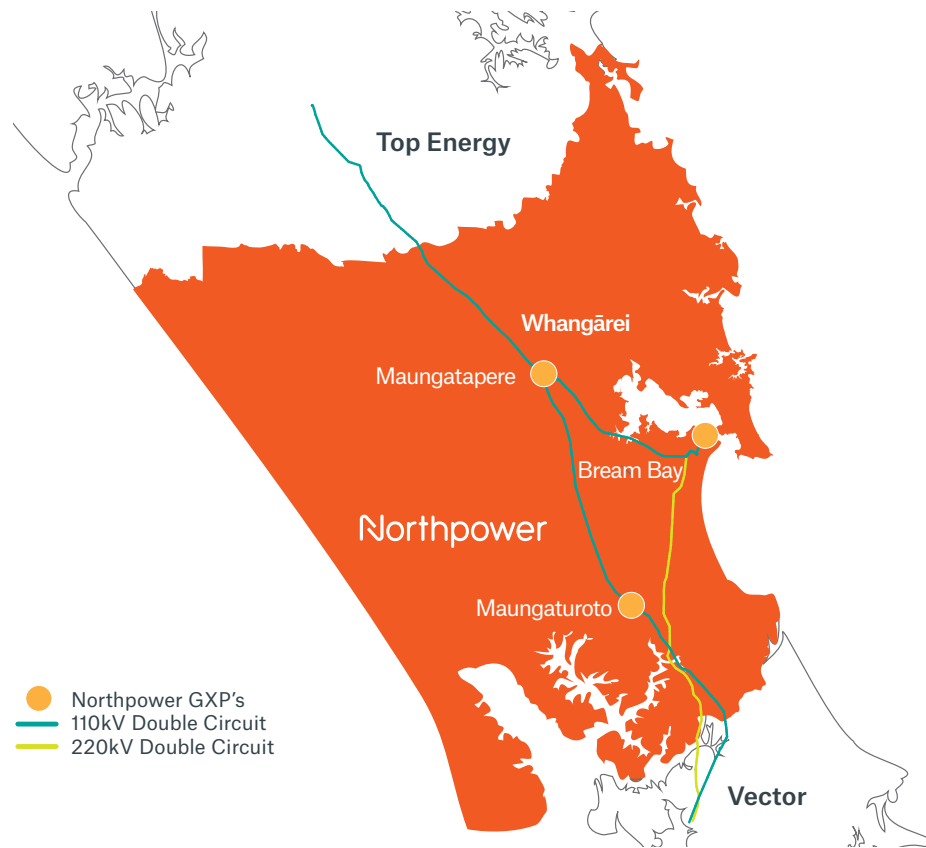
### 3.1 Introduction

Our network distributes electricity from the Transpower grid to our customers. The network is made up of a number of key subtransmission, distribution, low-voltage, and secondary system elements. This chapter summarises the network architecture and the key elements that make up our electrical network. Further details of the assets that make up these parts of the network can be found in Chapter 9.

### 3.2 Transpower grid exit points

Our electricity network is supplied from three Transpower grid exit points (GXP's) at both 110kV and 33kV. The following map shows the transmission network and location of the three grid exit points supplying our network.

**Figure 3.1:** Transmission network supplying the Northpower network



● Northpower GXP's  
— 110kV Double Circuit  
— 220kV Double Circuit

**Table 3.1:** Grid exit points – supply voltage and proportion of customers supplied

Grid exit point	Supply voltage	Customers supplied
Bream Bay	33kV	9%
Maungatapere	110kV	73%
Maungaturoto	33kV	18%

Northpower also owns assets located at the grid exit points, as set out in the following table.

**Table 3.2:** Grid exit points – Northpower owned assets

Grid exit point	Northpower assets
<b>Bream Bay</b>	33kV power cables and associated sheath voltage limiters (SVL) 33kV switchgear Buildings Protection and control equipment, including Supervisory Control and Data Acquisition (SCADA) control and communication and pilot cables
<b>Maungatapere<sup>1</sup></b>	110kV, 50kV and 33kV power cables 110kV, 50kV and 33kV line termination structures, conductor, and fittings 50kV and 33kV outdoor buses 50kV and 33kV switchgear (circuit breaker and isolators), HV voltage and current transformers 110/50kV and 110/33kV power transformers Local supply transformer Protection and control equipment, including SCADA control and communication cables
<b>Maungaturoto</b>	33kV line termination structures, conductor, and fittings Part of 33kV outdoor bus 33kV switchgear (circuit breaker and isolators) 33kV current transformers Protection and control equipment, including SCADA control and communication cables

<sup>1</sup> all 50kV network is being upgraded to 66kV in FY27

### 3.3. Network architecture

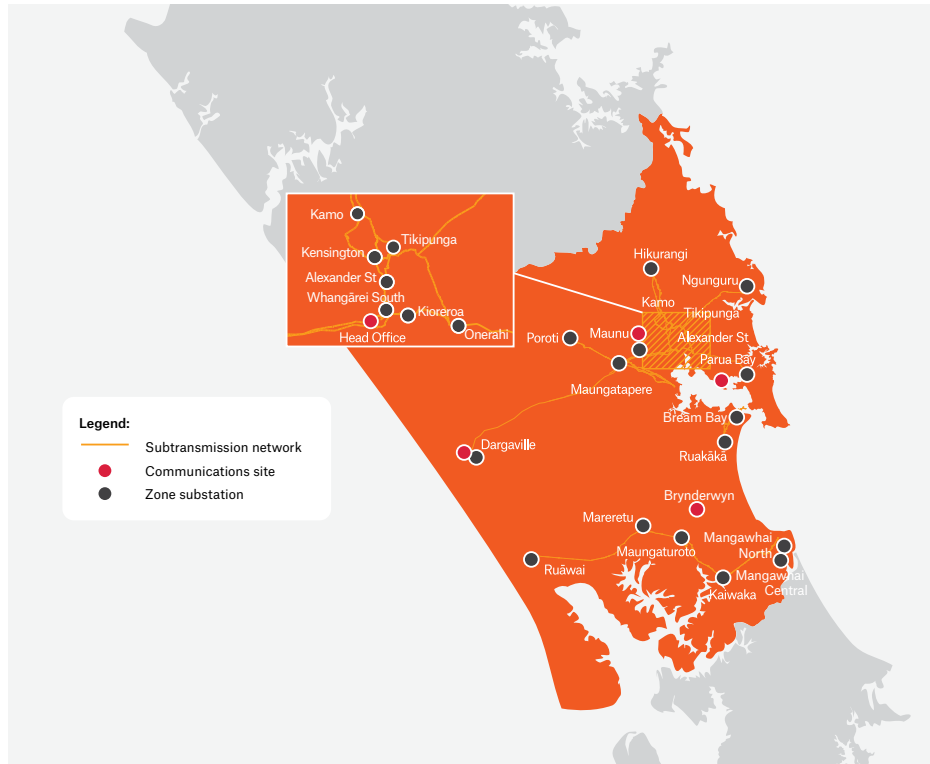
#### 3.3.1. Subtransmission network

The following map shows our distribution area and the location of zone substations and subtransmission circuits.

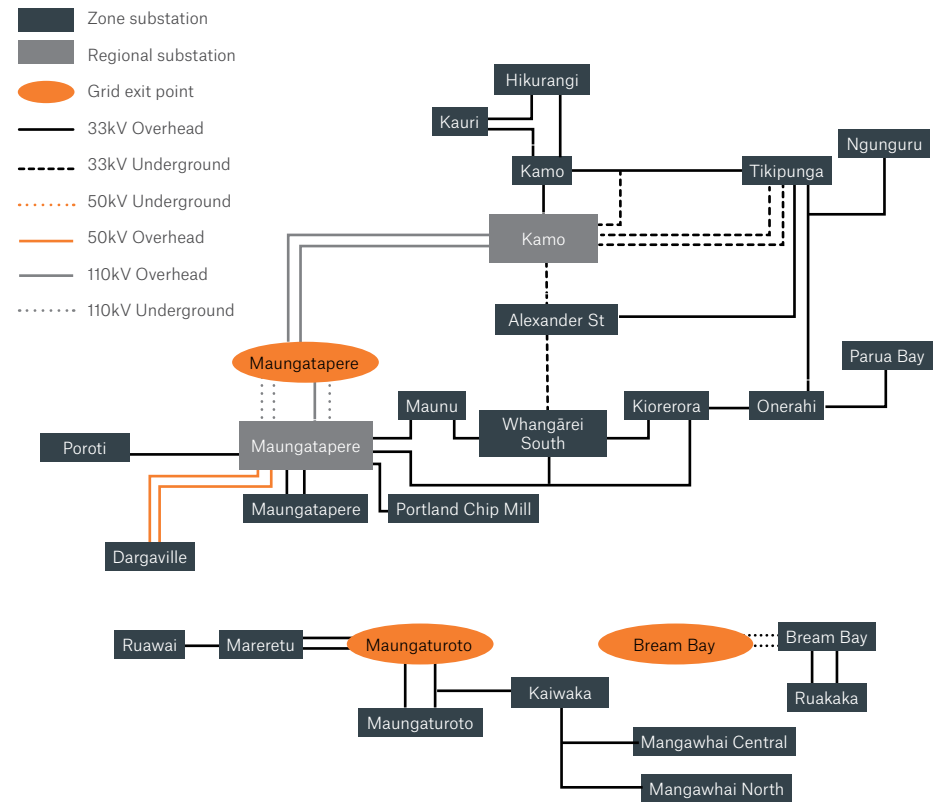
Most remote zone substations are supplied via a single 33kV line, with varying levels of back-feeding capability through the 11kV network. Mobile generation can be deployed for voltage and load support where back-feeding capacity is not adequate.

Detailed information on substation transformer capacity, loading, and security of supply is provided in Appendix C.

**Figure 3.2:** Northpower’s substations and interconnecting subtransmission circuits



**Figure 3.3:** Network schematic



#### 3.3.2. High-voltage distribution network

The high-voltage (HV) distribution network originates from the zone substations and includes:

- two 11kV express lines (we use this term for an 11kV feeder with no distributed load connected)
- ninety-eight 11kV distribution feeders and associated low-voltage reticulation.

Most customers are supplied from 11,000/415V distribution transformers. However, some are supplied directly at 11kV. There are also several large industrial customers supplied direct from the 33kV subtransmission network.

**Table 3.3:** High-voltage distribution network circuit length overhead and underground proportions

HV distribution	Underground (km)	Overhead (km)	Total (km)
Circuit length	326 (9%)	3,508 (91%)	3,834

### 3.3.3 Distribution substations

Distribution substations deployed on the network range in size from 0.5kVA to 1,500kVA and are either pole or ground mounted. They comprise an 11,000/415V transformer, high- and low-voltage fuses, and associated earth grids. Fuses on the high-voltage side of the transformer provide fault protection for the transformer. Fuses on the low-voltage side provide both transformer overload and downstream fault protection for cables or lines.

There are also a small number of 33,000/415V transformers supplying industrial customers. Transformers with a rating exceeding 150kVA are normally ground mounted due to their weight and size. Transformers with a rating of 50kVA and below can be either two phase or three phase, while those larger than 50kVA are all three phase.

A distribution substation typically supplies one to 100 customers. There are approximately 7,815 distribution substations installed on our network.

### 3.3.4 Low-voltage network

Northpower's low-voltage (LV) network is a mixture of overhead and underground circuits operating at 400/230V. The LV feeders distribute power from distribution transformers (connected to the 11kV network) to customers' service lines, generally from poles or pillars near property boundaries.

Each LV circuit is protected by fuses at the transformer and each customer point of connection. Electricity meters and ripple relays or pilot control contactors (for control of water-heating load) are generally located at the end of the service line or cable at the installation control point (ICP), or the meter station on the customer's premises.

Where increased security of supply is needed, the LV network is configured in a ring, to allow an alternative supply should it be required. This type of arrangement is common in the central business district and urban residential areas.

**Table 3.4:** Low-voltage distribution network circuit length overhead and underground proportions

LV reticulation	Underground (km)	Overhead (km)	Total (km)
Circuit length	885 (43%)	1,179 (57%)	2,064

The point of supply between our network and our customers is generally on the road reserve (at the fusing point). We have information on our website to help customers understand the demarcation point and their responsibilities for maintaining service lines.

### 3.3.5 Auxiliary and secondary systems

Our main network operations centre (NOC) is located at our headquarters in Raumanga and is attended 24 hours. There is a backup NOC located at one of our zone substations. The electricity network can be fully monitored, managed, and controlled from both the main and backup NOCs.

A SCADA system continuously monitors loads, alarms, and operation of equipment in all substations, including regulators and remote-controlled switches on the network.

Our telecommunication network is integral to the remote monitoring and control of network equipment and utilises radio and fibre optic systems. A separate land mobile radio network provides contact with operating staff and contractors in the field.

Ripple injection plants are installed on our network, providing ripple control signalling to activate load control. This is utilised for hot water load control, streetlights, tsunami warning activation, and other controlled loads.

Metering is installed at Transpower GXP supply points (Maungatapere, Maungaturoto, and Bream Bay) to record energy delivered to our network from the national grid.

Northpower leases a single large mobile generator. Further units are rented when required for managing planned outages<sup>1</sup>.

## 3.4 Major customers

We have five major industrial customers (VLLs) on our network who have loads over 3MW. With the closure of the Marsden Point oil refinery (re-purposed as an import terminal), the remaining customers are engaged in wood processing, cement manufacture, and milk processing. These customers collectively consumed approximately 24.1% of the electricity conveyed across the network.

- Fonterra operates milk processing plants at Kauri and Maungaturoto. The Kauri plant is supplied by two 33kV lines ring fed from the Kensington regional substation. The security of the entire ring is to be reinforced, and Kauri will maintain security with the upgrade of the existing circuits from Kensington to Kamo. The Maungaturoto plant, with a load of more than 4MW, is supplied by a single 11kV feeder. Backup is provided by the ability to switch to a secondary supply through another network feeder.
- The Golden Bay cement manufacturing plant is supplied directly from the Maungatapere regional substation through two dedicated 33kV feeders owned by Golden Bay.
- The Carter Holt Harvey wood processing plant at Marsden Point is supplied by two 33kV cables from the Bream Bay substation.
- Marasumi operates a wood processing plant at Portland, supplied by a single 33kV feeder from the Maungatapere regional substation.

<sup>1</sup> The Northpower group owns a hydroelectric generation installation (Wairua hydroelectric plant).

The decommissioned refinery site at Bream Bay is now owned by Channel Infrastructure and is currently supplied by four dedicated 33kV feeders, which have become significantly underutilised following the cessation of refining operations. We are actively assessing customer-driven load growth opportunities to support industrial development in the region. Further details are provided in Chapter 8.

Although not classed as a VLI customer, Northland Base Hospital is a critical site with a significant and growing load. The Northpower connection comprise of remote-controlled ring main units, enabling fast switching to a secondary supply in the event of a primary supply outage. If demand continues to increase, a transition to a dedicated 11kV or 33kV supply for this customer may be considered.

Our VLI customers receive a higher level of service, reflecting their reliance on electricity to operate significant sized and often critical industrial processes. In most cases these customers have dedicated 33kV feeders supplying their site from a Northpower substation, and often have dedicated backup feeders to provide N-1 security. We work with them to understand their security and reliability requirements and ensure our development plans are aligned with their own investment plans. Outages can have major financial impact on these customers, and we actively seek to coordinate our outages for planned maintenance to minimise the impact on their operations.

## 3.5 Supporting distributed generation

We are investing in our network to support expected increases in distribution generation. These changes will ensure our network can accommodate increasing numbers and size of Distributed Energy Resources (DER) installations.

We take a balanced approach to supporting these installations, acknowledging we need to consider a range of customer outcomes by adopting the following broad approach:

- engaging with customers seeking to connect to our network, discussing their proposed energy solutions
- making it easy for customers to access a range of new solutions
- supporting and educating consumers so they can make informed choices
- partnering with providers, other distribution businesses, and industry parties to learn from others and ensure our approaches are consistent with good practice.

### 3.5.1 Current levels of distribution generation

As at April 2025, there are approximately 3,000 distributed generation systems connected onto the network with a capacity of 67MW. Included in these systems are five large scale generators which equates to approximately 80% of the total capacity.

We expect ongoing growth in the number of customers using solar to meet their energy needs. As technology improves and storage options become more affordable, customers will have more flexibility to manage their energy use and participate in the energy market.

Ensuring our LV network has sufficient capacity to handle unpredictable customer load profiles has become a key focus of our future network strategy. The recent announcement to statutory voltage bands being extended will further improve the network's ability to host distributed generation and other forms of smart technology.

Adapting our network to accommodate changes in power flow and customer energy usage demand and patterns requires greater visibility and control of our network. Key initiatives in this area include integration of LV sensors, metering, and installation of devices to gain visibility of our LV network. In addition, we are focusing on the development of data, analytics, and modelling to better understand our capacity, constraints, and opportunities.

Over the past several years we have been committed to better understand our LV network and have made major improvements in LV visibility. In 2024, we entered a contract with a metering equipment provider (MEP) to supply us with network operational data (NOD) for approximately 63% of the network. We have also installed LV monitors on a selection of distribution transformers. We use this data in conjunction with analytical platforms to provide valuable LV insights which allows us to better understand the limitations of the LV network.

Over the next several years we are aiming to gain access to a wider set of network operational data with the goal of reaching at least 80% of ICPs. Additionally, we will continue to work with metering providers to increase the frequency at which we receive data to allow us to dynamically respond to network issues as they arise.

We will also continue to take an active education role in the community. Ongoing initiatives include participation in an advisory group with installers to ensure potential roadblocks are removed and constraints understood. We will continue to use periodic surveys to better understand the potential market for solar and the information our customers need.

These initiatives are covered in greater detail in Sections 2.3 and 8.7

In addition to the growth in small-scale distributed generation (DG) on our network, we have seen an increasing interest in connecting large-scale DG to our network. At present we have a mixture of solar, hydro and diesel connected onto the network including:

- Northpower Renewables - 5MW Hydro
- Contact Energy's - 10MW Diesel
- NewPower Energy - 4.2MW Solar
- Northpower Renewables - 16.8MW Solar
- Solar Bay - 17.6MW Solar

In addition to the above generators, Mercury Energy is currently in the process of constructing a large 77MW wind farm which will connect directly into our subtransmission network in the Dargaville region.

Large-scale DG applications require a significant amount of study and design to be able to connect. This has led us to build more capability in this area. We are also focusing on building capability, systems, and processes to manage large-scale DG once connected to our network.



## Chapter 4

# Strategic Context

## 4.1 Introduction

This chapter describes our strategic approach that informs and guides the management of our electricity distribution network.

When managing our electricity network assets, we consider how others may be impacted by our actions, activities, and performance. To ensure we identify and address the needs of our stakeholders, we use a strategic framework that provides a structured way of aligning our long-term plans and everyday priorities with stakeholder interests. A key focus is ensuring that we engage meaningfully with our community owners on how we manage our assets.

To support the delivery of our strategic priorities and the asset management principles set out in our Asset Management Policy, we have defined a set of asset management focus areas that guide our efforts to meet the needs of our customers. We need to continue to focus on core services and optimise the existing network, while adapting and upskilling to support our customers' future energy needs.

Our asset management documentation describes the approach taken across the lifecycle of our electricity assets, and the methodologies used in managing our asset portfolios and network development investments.

## 4.2 Strategic alignment

Leading asset management standards (including ISO 55000) emphasise the importance of aligning an organisation's strategic plan with asset management objectives, strategies and plans, right through to on-the-ground daily activities. In Figure 4.1, we explain how we translate our corporate purpose and the needs of stakeholders into our day-to-day investment and operational decisions.

The concept of having clear 'line of sight' between stakeholder needs and daily activities is considered a key feature of effective asset management. This line of sight is illustrated in the key elements of our asset management system. Figure 4.1 depicts this alignment through our strategic priorities and strategic asset management framework.

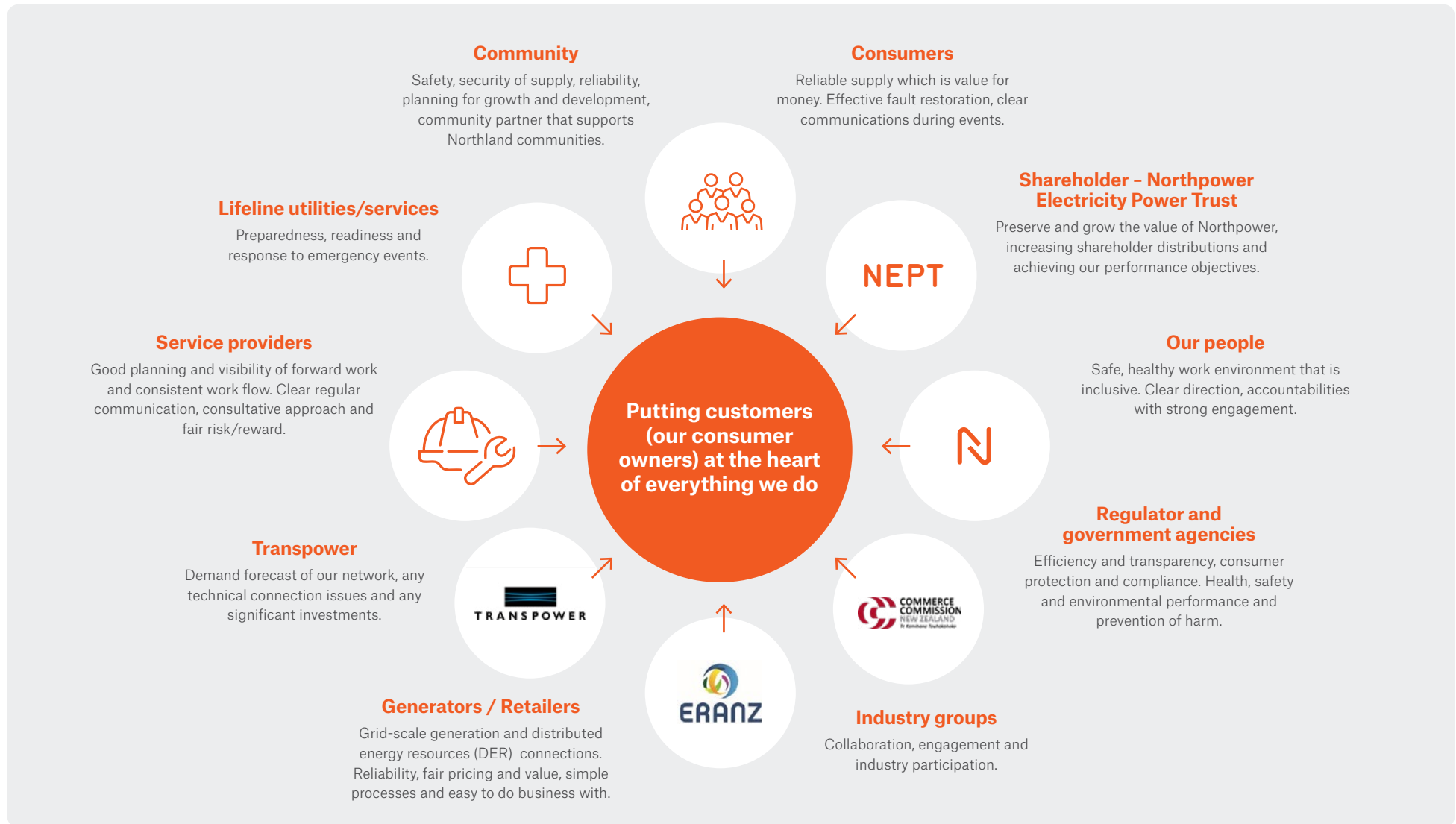
**Figure 4.1:** Line of sight between stakeholder needs and asset management objectives



### 4.2.1 Customer and stakeholder needs

To effectively manage complex, long-life assets for a range of stakeholders we need to balance a range of requirements. To do so, we exercise our best judgement and engage with our community owners to transparently explain our investment decisions, including through this AMP. A stakeholder engagement framework is being produced to further document the best practice for engagement. We use best practice stakeholder engagement methods, and follow processes outlined in our stakeholder engagement framework. Figure 4.2 summarises the interests of our consumer owners and other stakeholders.

**Figure 4.2:** Our key stakeholders and their main interests



When managing our electricity network assets, we consider how others may be impacted by our actions, activities, and our performance. Development of our AMP and investment plans considers the interests of our stakeholders and reflects these in our strategies and plans. We include further detail on our approach to customer engagement in Section 2.4.

## 4.2.2 Northpower strategic priorities

Northpower's overarching purpose is to generate value for the regions of Kaipara and Whangārei from infrastructure ownership. We provide consumers with the benefits of ownership through a combination of posted discounts on their distribution charges (passed on through their power bills) and dividends through the Northpower Electricity Power Trust (NEPT).

Northpower has a tight focus on returning value to the community, including reliable electricity network operations, strong commercial performance, and wider economic benefits for the North. As a key large organisation in Northland, we contribute to the local community via employment, training and skills development, local expenditure, sponsorship, and community collaboration with other organisations.

This overarching purpose is summarised in our group mission.

### Box 4.1: Group mission

Our group strategy is guided by an overarching mission:

***Connecting communities, building futures, for Northland***

We deliver on our mission by supporting positive economic outcomes through our infrastructure, social outcomes through skills and capability building, and having a direct, supportive financial impact through distributions. We generate value through the management of our networks, services, and investments, while enabling a low-carbon future. Together, these will benefit our consumer owners in Northland and the communities we serve.

The following expands on the mission.

### Connecting communities



Reflects Northpower's focus on deployment of enabling infrastructure supporting the Kaipara and Whangārei regions. This includes its core electricity network and its fibre communications network.

### Building futures



Reflects Northpower's focus on the development of skills, capabilities and careers for its staff. Northpower is an engineering and construction organisation of scale, and the organisation is committed to ensuring sustainable skills development for the regions and sectors in which it operates.

### For Northland



Reflects Northpower's focus on delivering economic value to the region beyond the value created through networks and through skills development. This includes delivering a strong financial return to consumer owners, supporting key local causes and advocating for the region on political and sector issues.

The targets within our Statement of Corporate Intent (SCI) underpin our focus on delivering positive outcomes to the communities we serve.

## 4.2.3 Our electricity business plan

Our electricity network plays an important role in delivering our strategic goals. Its core function is to deliver a safe, affordable, and reliable supply of electricity to our customers, now and into the future. Our role is broader than maintaining and operating today's network, it extends to meeting future needs and enabling a more sustainable energy future.

### Box 4.2: Electricity strategy

Our electricity strategy is guided by an overarching mission:

***Enabling our communities to thrive by powering a more sustainable future***

Our strategic pillars are applied to our electricity network through our electricity business plan. We need to continue to enhance our focus on core services, while optimising the existing network. We will adapt and upskill to support our customers' future energy needs.

We have expended our electricity strategy into three main themes.

## Enabling our communities to thrive by powering a more sustainable future



### Operational excellence

The core function of our electricity network business is to deliver a safe, efficient, and reliable supply of electricity to our communities. We continue to improve the way we do this through investment in our network management capability, systems and processes.

### Network transformation

As the use of our networks evolves with the uptake of DER, we need to ensure that the way we manage our network keeps up and is prepared for the future.

### Enabling renewables

To support New Zealand's decarbonisation goals and to electrify fossil fuels, we need to support developers to unlock the abundant renewable resource in Northland.

### Operational excellence

The principal objective of our network business is to provide a safe, efficient and reliable supply of electricity for the benefit of Kaipara and Whangārei consumers. To continue to improve how we deliver this, we continue to invest in our network management capability, systems and processes. To support this, we are:

- investing in a best-of-breed asset management information system
- optimising asset spend through improved condition assessment practices and enhanced analytics tools
- leveraging new technology and AI to deliver improved value in our asset management activities
- continuing to invest in our people's capability
- continually improving our asset management processes.

### Network transformation

With the evolving use of our network and the uptake of DER, we need to ensure that our network is prepared for the future. This means transforming how we operate our network to ensure our customers have the choice to connect new technology and use our network in the way that they want. To help achieve this we will:

- facilitate the connection of DER on our network, through improved connection processes and provision of information to our customers that supports decision making
- obtain greater visibility of our network, in particular LV, to ensure that we are able to proactively manage constraints
- invest in advanced operations platforms to enable integration and real time management of DER on our network
- contribute to standardisation of connection processes across the industry
- actively support customers to decarbonise.

### Enabling renewables

Northland has abundant renewable energy resource and significant transmission infrastructure in the region. To ensure that this resource is unlocked to contribute to New Zealand's electrification we will:

- support distributed generation developers to connect to our network
- develop our operations platforms to integrate large scale distributed generation on our network
- continue to advocate for Northland through initiatives such as the Energy Bridge.

## 4.3 Strategic asset management framework

Our strategic asset management framework sets out principles and objectives that help us ensure our investments deliver safe, cost-effective electricity services that meet the current and future needs of Kaipara and Whangārei communities.

### 4.3.1 Asset management principles

Our Asset Management Policy sets out a set of asset management principles that reflect the aims of our electricity business plan. It reflects our expectations for the way we will manage our assets. The policy has been developed to ensure a continuous focus on delivering the services our customers want in a sustainable manner that balances risk and long-term costs.

#### Asset management policy statement

Northpower is committed to managing its electricity distribution assets in a way that provides customers with safe, reliable, affordable, and sustainable services. We demonstrate this commitment by delivering on the following asset management principles:

- **a safe network:** our electricity assets and operations will not cause harm to members of the public, our staff, or service providers.
- **network performance:** our electricity assets and operations deliver reliable, resilient power supply, with the quality expected and meet current and future customer demand.
- **community support:** we continue to deliver value for money for our community, support regional growth and connect with our community in meaningful ways.
- **sustainability:** we ensure that our decision making is in the long-term interest of our consumers and builds sustainable capability within the organisation. We will also focus on reducing our carbon footprint and support New Zealand to decarbonise.
- **future readiness:** we ensure that DER and large-scale distributed generation are enabled on our network. We keep on top of changing consumer behaviour and ensure that our network is fit for purpose for future demands.

This policy guides the development of our asset management objectives, plans, and activities to ensure Northpower delivers outcomes valued by customers.

### 4.3.2 Asset management objectives

To ensure appropriate line of sight, our asset management framework translates our asset management principles into asset management objectives that guide our investment and operational decisions. To support consistent alignment, we have defined seven asset management focus areas, (see Section 4.4), that build on our group strategy, electricity business plan, and asset management principles.

We have defined performance indicators, (see Chapter 5), in each of the focus areas. These inform our asset management decision making and set the direction for managing our electricity distribution network. They have been developed to achieve the following aims:

- ensure that our organisational objectives are effectively delivered by our day-to-day asset management activities
- focus on outcomes that are meaningful to customers and other stakeholders
- monitor progress on how well our asset management activities deliver valued outcomes for our community owners
- guide our investment decision making so that we efficiently deliver our electricity business plan
- inform our continuous improvement programme.

We set ourselves targets in each of the focus areas and monitor our performance in meeting the targets. Chapter 5 sets out recent performance against our targets.

### 4.3.3 Asset portfolio objectives

Portfolio objectives guide our day-to-day asset management activities in each of our asset portfolios. These are organised based on our seven asset management focus areas. Our asset portfolio objectives are set out in Chapter 9.

### 4.3.4 Assurance Framework

Northpower applies a structured, multi-layered assurance approach to confirm that the Asset Management System (AMS) is effective, aligned with strategic objectives, and meets regulatory and statutory requirements. Our assurance framework integrates risk management processes, internal audit activities, external certification programmes, and governance oversight to drive continuous improvement.

#### Integration with risk management frameworks

We undertake a formal, network-specific risk review each year with the Network Leadership Team. This review re-examines risk registers, evaluates changes from the previous year, reassesses inherent risks, and validates the effectiveness of key controls. Residual risk ratings are agreed collaboratively, and issues requiring attention are assigned to dedicated action owners. This ensures that risk insights directly inform asset management planning and prioritisation.

#### External certification and independent reviews

Northpower maintains several externally certified management systems that require ongoing surveillance and three-yearly recertification audits. These assessments provide independent verification of the maturity and compliance of our AMS and related functions. Findings from these audits are incorporated into improvement programmes and reviewed in subsequent audit cycles.

Current certifications include:

- NZS 7901 – Safety Management Systems for Public Safety
- ISO 9001 – Quality Management
- ISO 14001 – Environmental Management
- ISO 45001 – Occupational Health and Safety

In addition to certification activities, we commission independent reviews of the AMP. The reviews alternate between evaluating the robustness of capital planning processes and assessing delivery performance for the prior financial year, providing transparency and alignment with strategic objectives. While Northpower is not currently pursuing full ISO 55000/1 certification, we continue to strengthen AMS alignment with the standard where practical.

### Internal audits and self assessments

Internal audits and self-assessments are conducted periodically to verify compliance with asset strategies, technical standards, operational practices, and safety requirements. These reviews provide assurance that processes are applied consistently and that critical controls are effective.

Key internal assurance activities include:

- safety in design reviews and technical peer reviews
- worksite audits validating critical risk control implementation
- end-to-end project reviews assessing quality, specification compliance, and safety outcomes.

### Oversight and Governance

Strong governance ensures that insights from reviews and audits, incident investigations, and performance metrics are incorporated into strategic decision-making. Senior leadership forums monitor trends, review corrective actions, and ensure that performance outcomes inform continuous improvement.

Key governance mechanisms include:

- oversight through the Health, Safety, Quality and Environmental (HSQE) Steering Committee
- integration of safety and asset performance metrics into business planning
- monitoring of incident trends, control effectiveness, and corrective action closure.

## 4.4 Asset management focus areas

To support the delivery of our strategic priorities and principles set out in our policy, we have defined a set of asset management focus areas. The seven focus areas are:

- **safety:** the need to protect the public, our staff, and our service providers informs everything we do.
- **delivering for customers:** outcomes that reflect the levels of service provided to our customers.
- **network performance:** reflecting the performance of our network assets and the quality of service we deliver to customers.
- **environment:** protecting the environment from the risks posed by our assets and preparing our network for climate change.
- **supporting communities:** managing our assets prudently and efficiently to ensure we deliver cost-effective and valued services to the communities we serve.
- **capability:** developing our people and improving our asset management system.
- **future readiness:** our ability to deliver new solutions that can meet the changing needs of our customers and facilitate future energy markets.

These focus areas have been developed to enable and support the delivery of our corporate objectives and meet the needs of our customers.

In Chapter 5, we set out asset management objectives and initiatives under each of these focus areas.

### 4.4.1 A safe network

Safety is our foremost organisational value. We believe that all incidents are preventable, and that no other objective should override the safety of our employees, service providers, or the general public. Our network assets and some asset management activities pose potential hazards to our workers and to the general public.

We continually challenge ourselves to protect life and put people's safety and wellbeing at the heart of Northpower. As an electricity asset owner, we are responsible for safeguarding both those working on our network as well as the wider public. As an employer, we aim to ensure an injury-free workplace and promote the wellbeing of our people.

## Our electricity assets and operations will not cause harm to the public, our staff or service providers



### We will achieve this by:

- ensuring our network and our activities do not cause harm to the health and safety of the public, our staff and service providers
- adopting 'safety in design' principles for planning, building, and maintaining our network
- implementing a robust corrective maintenance programme to address defects that may lead to safety risks
- proactively identifying and investing in network improvements to enhance health and safety
- ensuring vegetation management targets areas of our network with potential safety risks
- inform our customers about the hazards of live electricity, the network in general and ensure they have simple, accessible ways to reach us
- continuously learning from incidents and near misses on our network and implementing corrective actions.

### 4.4.2 Delivering for customers

We recognise that our customers are best placed to define what 'value' means to them. This is a change in emphasis from using performance measures purely focused on asset performance to measures that reflect the service customers receive. Doing so will help better target our capital investments and operational activities to deliver performance that our customers value. This includes increased proactive engagement with Māori around natural resources and cultural values.

## Deliver services customers want and value, maintain trust to retain our licence to operate



### We will achieve this by:

- actively seeking to understand and meet our community owners' needs, now and in the future
- continually improving our customer engagement and our customer service
- being socially responsible in our actions
- implementing our sustainability strategy to promote positive community outcomes
- undertaking analysis to gain deeper insight into metrics that reflect customer outcomes
- increasing our engagement with customers, communities, and mana whenua to better understand how our assets and activities impact them and to make informed decisions.

### 4.4.3 Network performance

The service that our customers receive reflects the performance of our network and its constituent assets. Network performance depends on how well we manage and maintain asset condition and how well we deal with interruptions when they occur.

The capability and performance of the network today reflect historical trade-offs between cost and service. Future trade-offs should be based on changing customer preferences and the need to deliver a safe, reliable, affordable, and resilient service.

To deliver appropriate levels of network performance we plan to increase our focus on customer outcomes. This will establish the aspects of our performance that should guide our measures and targets. Achieving appropriate levels of network performance is a key driver for our capital investment and maintenance levels. This will also support the ongoing integration of new energy solutions.

## Manage risk, asset lifecycles, and network operation to deliver a safe, reliable, and resilient system



### We will achieve this by:

- reaching our performance targets as set out in our SCI
- planning and investing to replace end-of-life assets and cater for growth
- considering asset condition, criticality, risk and whole-of-life costs in making asset management decisions
- investing to enhance resilience and prevent extended outages
- proactively managing quality of supply, network capacity, and constraints
- facilitating and supporting the integration of renewable and battery storage solutions to strengthen the resilience of our network.

#### 4.4.4 Environment

Our behaviours and values recognise the role of kaitiakitanga (guardianship) that expresses the importance of environmental stewardship. We are committed to being environmentally responsible and ensuring we do not cause harm to the environment. We will identify and manage works in cultural sites such as urupā and pā, through a collaborative and consultative approach with stakeholders. We strive to safeguard archaeological sites so we can identify, preserve, and protect heritage structures.

We take a long-term view of our operations to ensure a sustainable future for Northland. We strive to exceed regulatory requirements across all our operations and projects, focusing on environmental enhancement. We aim to limit and manage the negative impacts our assets and activities have on our communities and the environment as far as practicable. A key objective is to ensure our operations do not cause harm to the environment.

Increasingly, in the context of climate change, we recognise the role we play in supporting Northland's longer-term adaptation needs and decarbonisation aims. Environmental benefits can be achieved by facilitating and supporting the development of renewable generation and the decarbonisation of transport. We discuss this further in Chapter 4.4.7.

## Practice stewardship, ensuring our assets and activities do not adversely affect the natural environment



### We will achieve this by:

- ensuring our network and our activities do not cause harm or adversely impact the natural environment
- fulfilling our legal responsibilities
- minimising Northpower's sulphur hexafluoride (SF<sub>6</sub>) emissions
- operating oil containment facilities and adopting oil spill mitigation procedures
- using resources sustainably and ensuring responsible disposal of waste to minimise negative environmental outcomes
- reporting on our progress on climate change risk mitigation
- assessing our emissions baseline and developing plans to reduce it.

#### 4.4.5 Supporting communities

As a trust-owned business, Northpower has a strong focus on ensuring equitable and sustainable outcomes for our consumer owners. Our trust ownership ensures the profits we make are returned to the communities we serve. Since 1993, this arrangement has delivered more than \$278 million to our connected electricity consumers.

Delivering a valued service to our customers means that we provide positive outcomes to them at an efficient cost. To achieve this, we challenge ourselves to improve our cost performance through efficiency initiatives and innovation. This will enable us to deliver safe, reliable services for our customers at lower cost over the medium to long term. Effective asset management will help ensure this expenditure is prudent and efficient, delivering a cost-effective service to our customers.

**Support Northland's communities by enabling access to affordable energy solutions, lowering overall energy costs for consumers, delivering value for money, and ensuring our services align with customer expectations**



**We will achieve this by:**

- focusing on reducing whole-of-life costs across our network assets
- ensuring our pricing is fair, transparent, and equitable for all consumers
- helping customers navigate their energy choices and make informed decisions
- working closely with key stakeholders, community leaders, social organisations, and government agencies to support affordable outcomes
- running our ongoing Energy Education Programme, see Chapter 2
- running information programmes to help customers reduce their total energy costs.

We provide more detail on how we are supporting affordable outcomes in Section 5.6 where we set out our ongoing efficiency and pricing initiatives.

#### **4.4.6 Capability**

We are committed to continually improving our asset management capability. Effective capability development (for example, embedding appropriate processes, systems, and techniques) is a key enabling step, and we will continue to focus on this in the foreseeable future. We will continue to develop our asset management skills, processes, and systems to achieve our objectives and deliver on our purpose. These improvements will help us to better understand network performance and to further optimise our investments.

Our organisational asset management capability is the result of our people, the tools we use, and the processes we follow. Ensuring we have enough people with key competencies is essential if we are to achieve our asset management objectives.

**Promote robust asset management capability to deliver a safe, reliable, affordable, and resilient system**



**We will achieve this by:**

- addressing gaps in our capability
- lifting our digital and analytical capability
- developing and implementing an asset management competency framework
- aligning our asset management and risk management with the ISO 55000 and ISO 31000 frameworks
- ensuring we have the skills and capability to operate a future-ready network
- evolving our capability to ensure we focus on delivering valued outcomes.

The levels of network investment we are proposing are significant. This will also require investment in our people and decision-making tools. This is necessary if we are to maintain the capability necessary to be effective asset managers and increase efficiency. Our asset management planning is evolving and is shifting to a largely proactive approach.

In the coming years we anticipate that effective workforce competency planning and training will become increasingly critical, as older and experienced staff retire. For this reason, we are placing an increasing focus on formal competency planning.

#### **4.4.7 Future readiness**

Future readiness is a strategic focus for us as we evolve our electricity network to support decarbonisation and the uptake of distributed energy resources (DER) — including solar generation, battery storage, electric vehicles (EVs), and flexible loads. As these technologies become more widespread, our network must be agile, scalable, and digitally enabled to meet emerging customer and system needs.

The traditional one-way distribution model is being replaced by a dynamic, decentralised, and bi-directional system. In response, we are developing a Distribution System Operator (DSO) strategy that will enable our network to facilitate customer choice, unlock renewable energy potential, and support sustainable economic growth in Northland.

**Our network will enable sustainable outcomes for our community and support New Zealand’s decarbonisation**



**We will achieve this by:**

- helping customers understand new technologies and how to connect these to our network
- working with customers to integrate new energy resources on our network and find cost-effective ways to alleviate network constraints
- supporting our communities to transition to a low-carbon future, including the adoption of EVs
- implementing systems that provide increased visibility, active management and control of the network
- developing new standards to cater for integration of DER
- collaborating with the wider distribution industry, Electricity Networks Aotearoa (ENA), and other stakeholders to leverage their knowledge and experience
- developing a DSO strategy enabling us to support future energy trends and markets shifts.

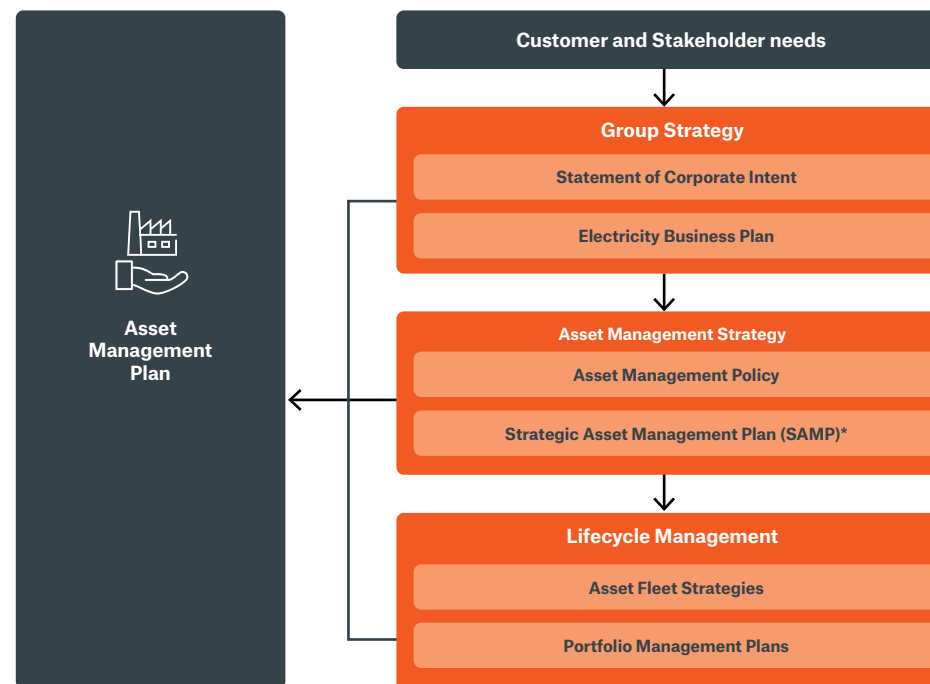
## 4.5 Asset management document suite

Our asset management system is supported by a hierarchy of asset management documentation. The documentation seeks to reflect good industry practice and explains our overall approach to asset management.

Figure 4.3 show we organise our core set of asset management documents into a hierarchy that begins with the views of stakeholders informing our group strategy and asset management strategy material, before being implemented through our day-to-day life cycle management activities.

Our asset management documentation operates under structured governance with defined ownership and approval, with periodic review schedules (see sections 4.5.2 to 4.5.9). We maintain clear approval pathways, see Figure 4.4. This includes assessing the effectiveness of the documents over time, including through external reviews based on stakeholder feedback.

**Figure 4.3:** Asset management document hierarchy



\* This document is in development

### 4.5.1 Stakeholder needs

Our asset management document hierarchy has been developed to reflect the needs of our customers and stakeholders. This includes ensuring that we consider how others may be impacted by our actions, activities, and performance. Development of our AMP and other asset management documentation considers the interests of our stakeholders and reflects them in our strategies and objectives.

#### 4.5.2 Statement of Corporate Intent

Our SCI is a governing document setting out Northpower's performance commitment to the NEPT and our consumer owners.

The operations of the Northpower group are overseen by a board of directors that uses the SCI to guide the group's direction and deliverables. Targets set out in the SCI include financial and non-financial measures such as network reliability and customer satisfaction. These KPIs reflect discussions between NEPT trustees and Northpower directors on our purpose, outcomes, and community role.

#### 4.5.3 Electricity business plan

Our electricity business plan sets out how the management of our electricity network supports our corporate objectives as set out in the SCI. As discussed in Section 4.2.2, it reflects the interests of internal and external stakeholders who have an active interest in how our electricity network is managed.

#### 4.5.4 Asset Management Policy

Our Asset Management Policy discussed in Section 4.3.1, aligns our asset management approach with our electricity business plan. It provides overall direction and guidance for our asset management approach.

The policy sets out high-level asset management principles that reflect our purpose as a consumer-owned electricity distributor. The policy has been developed to ensure we continually focus on delivering a valued service for our customers.

#### 4.5.5 Strategic asset management plan

We are developing a strategic asset management plan (SAMP) to act as an overarching document that sets out our asset management objectives. It will incorporate objectives and KPIs aligned with our group performance targets and will provide strategic direction for asset fleet strategies, see Section 4.5.7. The SAMP will distil our corporate objectives through our Asset Management Policy and set out asset management level objectives in the seven focus areas described in Section 4.4.

#### 4.5.6 Network Development Strategy

Our strategy outlines Northpower's development framework, including the processes, criteria, tools, and steps used to manage network security of supply, capacity planning, and performance standards.

#### 4.5.7 Asset fleet strategies

Our asset fleet strategy documents reflect our asset life cycle model and set out how these processes and activities are applied to individual asset fleets. We are currently developing this suite of important documents. These have been summarised in Chapter 9.

#### 4.5.8 Portfolio management plans

Reflecting our delivery approach, we aggregate planned asset fleet interventions into an overarching portfolio management plan. These set out a summary of activities and costs for the particular portfolio over a set period. These are used to manage the delivery of our capital investments and our proactive maintenance activities. These plans help ensure that project and maintenance work is scheduled and delivered efficiently.

#### 4.5.9 Asset management plan

Our electricity network AMP (this document) is a stakeholder-focused summary that reflects our overarching approach to managing our electricity distribution network. It sets out asset management objectives and investment plans over the AMP period, focusing on explaining these to stakeholders and complying with relevant disclosure requirements.

## Development of our AMP

The development of our AMP is a collaborative effort combining the skills, experience and knowledge of our staff with the need of stakeholders. Figure 4.4 shows our AMP development process, the role of our Board and management, and consultation with stakeholders.

**Figure 4.4:** AMP development process

	Board	Management	Stakeholders
<p><b>Strategy</b></p> <p>Align strategy, business plan and asset management policy with our SCI, and feedback from customers and stakeholders</p>	<ul style="list-style-type: none"> <li>- Strategy review session and review of asset management focus</li> <li>- Approve the SCI, business plan and expenditure budgets</li> </ul>	<ul style="list-style-type: none"> <li>- Consider shareholders' expectations in developing strategy</li> <li>- Stakeholder consultation</li> </ul>	<ul style="list-style-type: none"> <li>- Analyse external factors, performance, capability and risk</li> <li>- Test business strategy and asset management strategy</li> </ul>
<p><b>Performance review</b></p> <p>Monitor and analyse performance and service levels, report and adjust operations to improve outcomes</p>	<ul style="list-style-type: none"> <li>- Confirm service level assumptions</li> <li>- Review progress on AMP and expenditure plans</li> </ul>	<ul style="list-style-type: none"> <li>- Review/report progress on AMP and expenditure, and network performance</li> <li>- Review load growth, capacity constraints, security, asset risk</li> </ul>	<ul style="list-style-type: none"> <li>- Stakeholder consultation and consider shareholders' expectations</li> </ul>
<p><b>Project definition &amp; scoping</b></p> <p>Ensure prudent and efficient investment decisions based on data, evidence and sound engineering judgement</p>	<ul style="list-style-type: none"> <li>- Review overall Capex plan ensure strategic alignment</li> </ul>	<ul style="list-style-type: none"> <li>- Prepare scope, cost estimates for programme and project capex plan</li> <li>- Ensure resources and capability to deliver</li> </ul>	<ul style="list-style-type: none"> <li>- Stakeholder consultation and consider shareholders' expectations</li> </ul>
<p><b>Develop AMP</b></p> <p>Communicate our asset management policy, strategies and expenditure plans to ensure best practice stewardship of our electricity network</p>	<ul style="list-style-type: none"> <li>- AMP strategy, focus areas and expenditure principals</li> <li>- Approve AMP, expenditure budgets and Information Disclosures</li> </ul>	<ul style="list-style-type: none"> <li>- Prepare AMP, investment plans, and expenditure budgets</li> <li>- Manage reviews of AMP, compliance review of Information Disclosures</li> </ul>	<ul style="list-style-type: none"> <li>- Stakeholder consultation and consider shareholders' expectations</li> </ul>

The process involves gathering inputs from subject matter experts within the business, internal peer review by senior management, external review by asset management specialists, and testing against customer and stakeholder feedback. Our Board approves the AMP to ensure it meets our commitments and the expectations of the trust and our consumer owners. This approach helps to ensure our investment plans efficiently and effectively meet the future needs of the communities we serve.

Public comment and feedback is welcomed and carefully considered.



## Chapter 5

# Our Performance

## 5.1 Introduction

This chapter outlines how we monitor and manage our performance. It sets out how we measure performance and our plans to meet these targets over the planning period. We continually review our performance to ensure we continue to meet the needs of our community. Key performance indicators (KPIs) such as safety, reliability, and customer satisfaction are set out in our Statement of Corporate Intent (SCI).

Our performance monitoring is broadly classified to align with our asset management focus areas, discussed in Chapter 4. In some areas, such as emissions, we have begun to collect performance information but have not yet set related targets.

Northpower is committed to safeguarding the public and ensuring an injury-free workplace. Safety is about people, including our employees, subcontractors, and the general public. We want to ensure that everyone goes home to the people, places, and things that mean the most to them.

Our electricity network provides an essential service to the communities of Northland. Understanding what matters most to our customers and their satisfaction with our services helps to ensure our service remains relevant for customers. This is a key commitment in our SCI and a key focus area of our asset management strategy.

We have measures and targets to track our progress in reducing any negative impacts our assets and operations may have on the environment. This extends to ensuring our network and operations are ready for the growing challenges of climate change.

We engage with our customers to understand their needs and expectations in terms of network performance. Customers tell us that a reliable electricity supply remains a top priority. Delivering a reliable service is a key focus for us, and related targets are included in our SCI.

Reflecting our trust ownership model, we maintain a strong focus on delivering our service efficiently and using fair pricing to keep service costs low. We plan to explore potential performance indicators to help ensure we continue to deliver cost-effective services to our customers.

Additionally, we have measures and targets to track our progress in improving asset management capability and ensuring our network is ready for the evolving energy markets.

## 5.2 Safety

Our electricity network assets and related activities may pose hazards to the public and to our staff. We are committed to safeguarding the public and ensuring an injury-free workplace. When operating our network, we take all practical steps to minimise the risk of harm to the public, contractors, and our people.

Health and safety is about people. Our approach to health and safety encompasses the relationships between our people, the work they do, and the environment they do it in, held together with leadership. Our aim is to operate our network free from harm.

The Health and Safety at Work Act 2015 states the objective of “protecting workers and other persons against harm to their health, safety, and welfare by eliminating or minimising risks arising from work”. This goal is reflected in our approach to managing safety on our electricity network.

Effective management of health and safety risks associated with our assets and activities is fundamental to our business and to fulfilling our statutory obligations. To ensure our network does not present significant risk to public safety we ensure we comply with the Electricity Safety Regulations 2010. All potential public safety risks identified are managed to a level that is ‘as low as reasonably practical.’

We are responsible for ensuring the safety of all electricity reticulation and equipment from the Grid Exit Point (GXP) up to the customer’s point of supply. We ensure that network assets are appropriately secured, preventing unauthorised entry or access to exposed live equipment.

We certify our approach and process to managing public safety.<sup>1</sup> Compliance requires ongoing monitoring of our approach which is tested through an audit by an accredited third party at least once every three years. Surveillance audits are carried out annually between the accreditation audits. We passed our last accreditation audit in September 2024 and annual surveillance audit in December 2025.

### 5.2.1 Safety targets

The following KPIs are used to track our safety performance. We closely monitor our performance against the annual limits/maximums, and the measures are reviewed annually. The KPIs set out our anticipated performance and originate from group-wide SCI performance commitments to the Northpower Electric Power Trust (NEPT) and customer owners, which incorporates network’s public safety management system (PSMS).

#### The network focus on public and occupational safety

- Public safety events covers incidents caused by assets or equipment failure. It does not include incidents caused by the public, although data from these events is collected.
- Occupational safety events refer to events occurring from work conducted on our network.

Both event types are investigated so that we can make improvements to avoid further risk.

<sup>1</sup> NZS7901:2014 Electricity and Gas Industries - Safety Management Systems for Public Safety.

We use high potential events (HPE) incidents as a performance measure of our safety. HPE include events of either an actual or potential catastrophic consequence to measure our safety performance.

**Table 5.1: Northpower group and network safety targets**

Performance indicator <sup>2</sup>	FY26	FY27	FY28
Permanent disability and/or fatality - Staff permanently disabled or fatally injured at work (target = 0)	0	0	0
Permanent disability and/or fatality - People harmed due to asset failure (target = 0)	0	0	0
Public safety HPE caused by Northpower network asset/equipment failure (target < 4.5)	2	2	2
Number of occupational HPEs	4	4	4

### 5.2.2 Safety performance

In the following table, we summarise our recent performance against our key safety targets.

**Table 5.2: Northpower group and network safety performance**

Measure	FY21	FY22	FY23	FY24	FY25
Permanent disability and/or fatality - Staff permanently disabled or fatally injured at work	0	0	0	0	0
Permanent disability and/or fatality - People harmed due to asset failure	0	0	0	0	0
Public safety HPE caused by Northpower network asset/equipment failure	0	2	6	2	2
Number of occupational HPEs	0	3	2	1	0

We have consistently met these targets in previous years, except during Cyclone Gabrielle in 2023. A member of the public struck a downed line that had resulted from the flooding and high winds of the cyclone. The network has applied the lessons learned from this event to enhance its foundational design in at-risk areas.

Both public and occupational safety HPE have trended downward in the preceding three years. Greater visibility of public safety events and increased asset safety has also led to a reduction of Northpower public safety events.

<sup>2</sup> The long-term target is zero for all instances and near misses of public harm and property damage. The remaining targets are in place for the planning period, though they will be subject to periodic review.



### Supporting initiatives

The following key strategies and initiatives help drive a stronger safety culture.

- **Bow tie methodology:** Approach is applied to identify risks in our health and safety risk matrix. We utilise bow tie methodology to identify the causes and consequences of material events, which in turn create high and very high health and safety risks.
- **Incident management procedure:** We have an established incident management procedure that sets clear expectations for the reporting, investigation, and implementation of corrective actions following incidents. This approach ensures consequences are minimised and that appropriate measures are taken to reduce the likelihood of similar events occurring in the future.
- **Assurance framework:** We have an assurance framework with regular monthly auditing and management safety leadership site visits. Elements of the audits include assessing for hazard and risk awareness, what the controls are, and how well this is accomplished.

To manage the risk that our assets pose to the public we have lifted our asset investment programmes and continue to deliver at the elevated levels. We have a close focus on the timeframes for remediation of defects to ensure they do not fail in service and cause a public safety risk. We are also focussing on deepening our understanding of asset risk, enabling us to further enhance the effectiveness of our asset management programmes. This is further discussed in Chapter 9.

A key strategy in managing public safety risk is education. Raising awareness of electrical risks is essential for all audiences—from children and homeowners to farmers and contractors. Northpower’s approach ensures safety information is accessible, timely, and relevant, using a multi-channel communication strategy.

- Safety and general information, as well as contact details, are provided on our website, which serves as the central hub for safety resources and updates.
- Fault and emergency contact details are published in the phone book and displayed prominently on our assets and communications.
- Safety information is distributed to customers through published materials, local media, and social media campaigns.
- Public participation in community events extend our safety messaging and build trust within the community.
- Safety radio advertising is delivered in cooperation with our neighbouring network, Top Energy, to reach a wider audience.
- Targeted awareness campaigns leverage both digital and traditional media, including social media, email, radio, and local newspapers to deliver timely safety messages, especially during outages or urgent events.
- Print media remains important for reaching those not digitally engaged, ensuring inclusivity across our communities.

Specific warning notices are placed on certain network assets in public areas, such as ground-mounted distribution substations, pillars, zone substation security fences, to reinforce safety awareness.

A reliable 24/7 emergency contact line is maintained and clearly displayed, ensuring the public can report safety concerns or incidents at any time. Internally, public safety awareness is embedded into staff onboarding, training, and performance expectations. Learnings from incidents and corrective actions are shared across teams to drive improvement, and regular audits and engagement metrics are used to measure effectiveness and refine our approach.

Chapter 7 describes our broader approach to safety risk management.

### 5.3 Delivering for customers

Our electricity network provides an essential service to our communities. Understanding what matters most to our customers and their satisfaction with our services helps to ensure our service remains relevant for customers. This is a key commitment in our SCI and a key focus area of our asset management strategy.

We monitor customer satisfaction monthly and annually to gauge overall satisfaction for both residential and commercial customers.

#### 5.3.1 Customer satisfaction targets

Our performance target for customer satisfaction is >85%. Our customers’ views on our performance are collated through an annual survey of 400 customers across our network, conducted by an independent research company as described in Section 2.4.7.

**Table 5.3:** Customer satisfaction targets

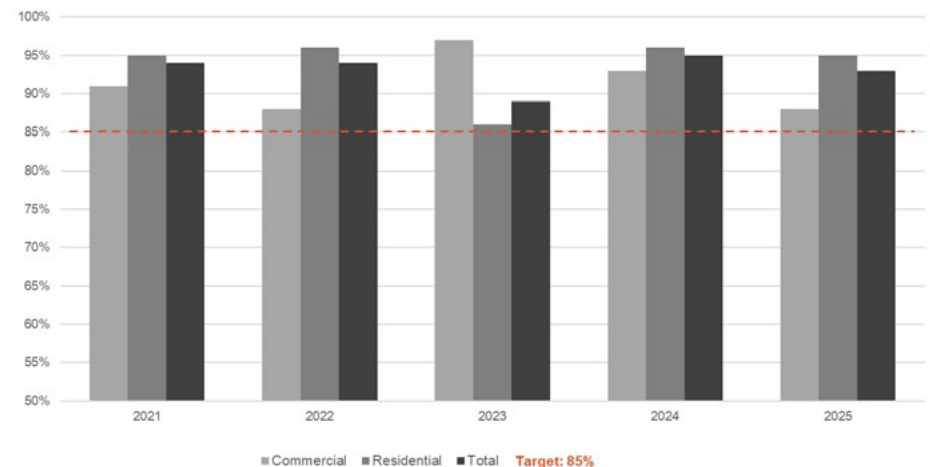
Measure	Targeted performance
Customer satisfaction	At least 85% of customers indicate they are satisfied or highly satisfied (by rating Northpower 7 to 10, out of 10)

#### 5.3.2 Customer satisfaction performance

As shown in Figure 5.1, we consistently meet our customer satisfaction target of > 85%. We expect the 85% target will remain in place for the Asset Management Plan (AMP) period, noting that as customer expectations change and the reliance on electricity increases further, this level of satisfaction will be increasingly difficult to achieve. We are confident in our ability to continuously adapt and improve to reach this target.

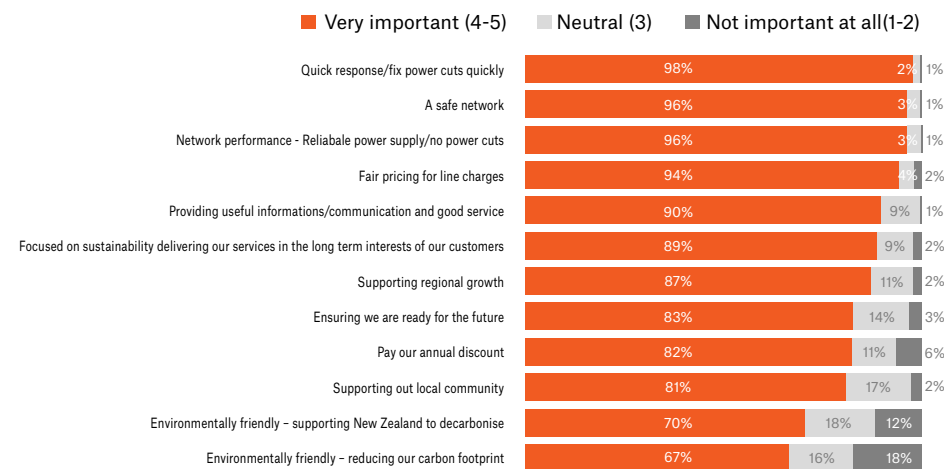
The most recent annual survey showed our overall customer satisfaction is high — overall 93% of customers are satisfied or highly satisfied. This was made up of 88% of commercial customers being satisfied or highly satisfied and 95% of residential customers being satisfied or highly satisfied.

**Figure 5.1:** Customer satisfaction results



**Figure 5.2: Customer priorities**

In FY24, the annual customer survey was expanded to contribute to our strategic direction. Customers told us that the following factors were most important to them:



This validates our strategic direction and shows we need to take a balanced approach to the following outcomes.

- Ensure our electricity assets are safe and will not cause harm to the public, staff, or service providers.
- Ensure our electricity assets meet current and future customer demand and deliver a reliable and resilient power supply.
- Supporting our community through delivering value for money, supporting regional growth, and meeting our customer’s expectations.
- Support NZ to decarbonise through enabling renewable energy in our region and supporting our customers to decarbonise where appropriate.
- Ensure our network keeps up with changing customer choices and behaviour and integrates new technology as appropriate.

## 5.4 Environment and sustainability

Northpower is committed to being environmentally responsible. We recognise our role as kaitiakitanga, including the importance of being good stewards of the environment. A key objective is to ensure our organisation’s operations do not cause harm to the environment.

Our business is committed to supporting our Northland community’s long-term adaptation needs and decarbonisation aspirations.

We are committed to being environmentally responsible. This is consistent with our purpose. Northpower’s Environmental Policy communicates our principal commitments to ensure we do not cause harm to the environment.

- Sulphur hexafluoride (SF<sub>6</sub>) is a potent greenhouse gas that is used as an interruption medium for switchgear. We are committed to minimising Northpower’s SF<sub>6</sub> emissions, and we carefully monitor and report losses.
- We operate oil containment facilities. We have oil spill mitigation procedures and staff are trained in mitigating this risk. We have a target of zero uncontained oil spills.
- Our work requires building, demolition and earthmoving activities. We have procedures in erosion and sediment control, water management and dust control. We actively train our staff with the best environmental practice.
- All staff are trained on archaeological and accidental discovery procedures in the event that archaeological evidence, or taonga is uncovered through our earthwork activities.

### 5.4.1 Environmental targets

Northpower has reported and monitored discrete and adverse environmental impacts for many years. Reflective of a maturing approach, in 2023 Northpower determined our baseline emissions inventory and commenced monitoring of a suite of other environmental indicators to provide a clear line of sight to environmental performance. In time, as baselines and trends are known, targets are set to drive improvements. Northpower Group has forecast a 42% reduction in Scope 1 and 2 emissions by FY31 from 2023 levels. Our recent performance is set out in Table 5.3.

### 5.4.2 Environmental performance

Improved environmental performance is underpinned by good information. We now track environmental indicators, as indicated in Table 5.3. Our key contributors to our emissions profile (excluding line losses) are transport and fuel consumption as well as waste to landfill. This data informs future initiatives to improve our existing resource recovery programmes that divert waste from landfill.

**Table 5.3: Environmental performance**

Measure	2023	2024	2025
Waste to landfill (tonnes)	34	38	44
Waste diverted (tonnes, % of total)	10.0 (23%)	12.0 (24%)	15.0 (25%)
SF <sub>6</sub> losses % of holding (Target < 2% of holdings)	1.27%	0.91%	0.37%
Breaches/legislative non-compliance	-	-	-

Scope	Emissions (tCO <sub>2</sub> e)	2023	2024	2025
1	Fuel	90	111	114
1	Refrigerant use - SF <sub>6</sub>	354	296	118
1	Travel - Car hire	0	0	0
2	Electricity	33	30	25
<b>Scope 1 &amp; 2</b>		<b>477</b>	<b>437</b>	<b>258</b>
3	Transmission and distribution losses	3	3	2
3	Travel	25	37	37
3	Waste	22	27	32
3	Wastewater treatment	4	4	4
3	Water supply	0	0	0
<b>Scope 3</b>		<b>54</b>	<b>73</b>	<b>75</b>
<b>Total</b>		<b>531</b>	<b>510</b>	<b>333</b>

## Supporting initiatives

Some of our recent initiatives to improve our environmental performance include:

- development of further performance targets to monitor and reduce our emissions across the business
- a commitment to a sustainable transition of our vehicle fleet that includes exploring alternative vehicle types. As of 2025, all of Northpower's pool vehicles are either hybrid or electric, with field-based vehicles transitioning as viable, cost-effective alternatives become available
- improving our waste sorting and management of recyclable and non-recyclable materials through environmental education and awareness campaigns
- phasing out of SF<sub>6</sub> insulated equipment (where practicable)
- embedding environmental stewardship in our field staff through environmental awareness trainings that focus on erosion and sediment control, accidental discovery, and biodiversity
- partnership with Digital Wings, a not-for-profit organisation that repurposes end-of-life electronics, redistributing them to deserving community groups. A large volume of our end-of-life electronics are now refurbished and redeployed.

## 5.5. Network performance

Northpower recognises that network performance is a priority for our customers. Ensuring a safe, reliable, and resilient network is a key focus area of our asset management strategy and electricity business plan.

In terms of network performance, our overarching aim is to achieve an appropriate balance between cost, risk, and the performance delivery to customers. We consider two main aspects of network performance: service reliability and power quality.

### Service reliability

Reliability of supply is measured in terms of duration and frequency of interruptions per customer. The service our customers receive from the network is largely determined by the assets we use to deliver their electricity. We track network reliability using measures consistent with regulatory regimes in New Zealand and overseas (SAIDI and SAIFI, discussed further in Section 5.5.1). We have also historically used 'faults per 100km' as an indicator of underlying network performance.

## Power quality

Power quality relates to the voltage delivered to a customer's point of supply. Performance requirements are specified in the Electricity (Safety) Regulations 2010 and in industry standards.<sup>3</sup> Consistent with these, we target the following levels of power quality:

- 230V: within  $\pm 10\%$  at point of supply (except for momentary fluctuations)
- High voltage: within  $\pm 6\%$  of the agreed supply voltage unless otherwise agreed (except for momentary fluctuations)
- frequency: is maintained within 1.5% of 50 Hz except for momentary fluctuations.

We manage the power quality received by customers through good network design, responsiveness to voltage complaints, and active monitoring of load throughout the network. We aim to provide quality supply to all customers within regulatory standards.

In addition to existing performance measures, planned improvements to outage management and asset management systems will provide an opportunity to extend the reporting of performance-related metrics.

### 5.5.1 Network reliability targets

Accurately forecasting future reliability performance is challenging as it is impacted by multiple factors such as asset condition, prevailing climate, new network configurations and technologies, and our capability to deliver our proposed interventions, including reactive maintenance. A number of these factors are beyond our direct control.

A number of measures are used to report our network reliability performance to stakeholders, including the Commerce Commission. The main measures are:

- SAIDI (System average interruption duration index)
- SAIFI (System average interruption frequency index).

SAIDI and SAIFI measure average length (duration) and average number (frequency) of outages, respectively, per customer per year.

Our reliability targets reflect the measures that would apply if we were subject to price-quality regulation (DPP) and are based on historic performance for both planned (7 year period) and unplanned (10 year period) interruptions. For unplanned interruptions this removes the volatility caused by major weather events.<sup>4</sup> The methodology for planned SAIDI is designed to incentivise an electricity network to provide impacted customers with a high-quality experience. For the five-year regulatory period from 2026, these targets have been reset in accordance with DPP4 methodology. As metrics used in the wider sector, we consider these targets to be appropriate for informing our asset management and investment decisions.

<sup>3</sup> Traditionally ECP36 has been used for standard harmonic level, however, AS/NZS 6100.3.6 is a more recent standard and is regarded as a better and more appropriate standard/code for the distribution industry.

<sup>4</sup> Recent regulatory changes have extended the allowable LV limits to  $\pm 10\%$ . We are currently reassessing our LV voltage regulation strategy to align with these updated requirements

In addition to SAIDI and SAIFI, we have a target for average fault rate performance. Fault rates are based on the number of faults per 100km of network length for both the overhead and underground networks.

Our forward performance metrics and targets are shown in the table below.

**Table 5.4: Northpower electricity network reliability forecasts<sup>5</sup>**

Measure	Type	FY26EST	FY27	FY28	FY29	FY30	FY31
Network interruptions SAIDI minutes	planned	105	178	178	178	178	178
	unplanned	115	98	98	98	98	98
Network interruptions SAIFI	planned	0.60	0.80	0.80	0.80	0.80	0.80
	unplanned	2.90	2.40	2.40	2.40	2.40	2.40
Average faults per 100km		11	10	10	10	10	10

Network Planned SAIDI is estimated to be below target primarily due to Northpower implementing the de-weighting of planned SAIDI in line with DPP rules. Network unplanned performance is adverse to target largely due to increasing frequency and scale of adverse weather events, which account for 77% (275.94 SAIDI) of year-to-date raw SAIDI.

<sup>5</sup> These targets remain in place for the planning period and have been reset to reflect the transition to DPP4 from 2026.

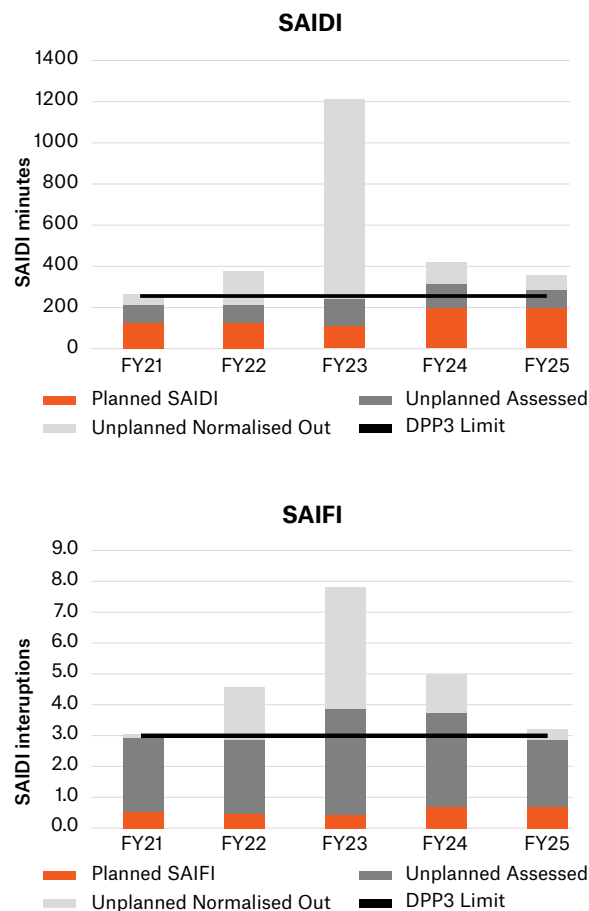
## 5.5.2 SAIDI/SAIFI performance

### Total SAIDI/SAIFI

Prior to the adoption of a DPP4-based normalised approach, performance targets were reviewed annually and raw values established for both planned and unplanned SAIDI/SAIFI. The following charts compare the total raw (non-normalised) performance with these targets.

In most years, a reasonably strong correlation exists between SAIDI and SAIFI for both planned and unplanned outages.

**Figure 5.3: Total raw SAIDI and SAIFI**



Historically, network reliability has generally been achieved against targets. In FY23 and FY24, DPP3 SAIFI limits have been exceeded, even after normalising out the extreme weather events. We are working on a better understanding of how extreme weather events create latent defects on the network (impending failure due to damage) that create additional outages in the months following the extreme event. We have also seen an ongoing rise in the number of outages caused by third-party events. Actions intended to mitigate the impact of unplanned outages are outlined in the following section.

Planned SAIDI and SAIFI have risen in recent years in line with an increase in work volumes undertaken and a positive reflection of capital works programmes being rolled out. There have been some 33kV subtransmission line outages for security of supply remedial works, mitigating customer interruption would have imposed huge generation cost. However, works have been carried out in the night which had minimal impact on customer experience.

After reaching a peak in FY25, planned SAIDI is expected to decline, largely as a result of efforts to increase the amount of planned work performed under live line conditions, and the introduction of a formal SAIDI mitigation plan and options analysis to manage outages above certain thresholds. Planned outages are now being normalised under DPP4 regulations which further de-weights SAIDI when the outages occur as scheduled.

### Unplanned outages

The number and frequency of adverse weather events continue to have a significant impact on the raw values. The impact of adverse weather (unplanned normalised out) is illustrated in Figure 5.3.

Following a substation bus fault in FY22, which contributed 53 SAIDI minutes, the subtransmission network has generally been reliable and attributed only 26 SAIDI minutes from defective equipment for the three years during FY23-FY25.

While the number of unplanned outages on the network are expected to fall as a result of initiatives designed to improve reliability, we do not expect these benefits to be fully reflected in unplanned SAIDI and SAIFI. Factors that are likely to offset benefits arising from reliability improvement programmes include the following:

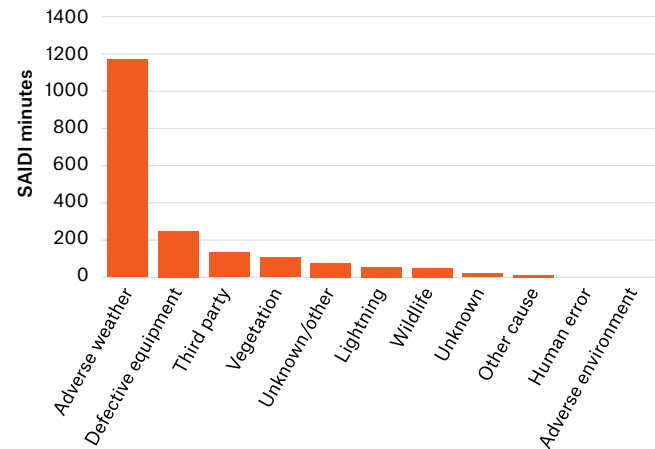
- an ongoing rise in the number of third-party interference incidents in line with the rate of population growth and traffic density
- an expected increase in the number and intensity of major weather events associated with climate change
- new rules introduced by the Commerce Commission for counting successive interruptions have increased unplanned SAIFI (by 3% across FY24 and 25) compared to the previous methodology.

## Major causes of unplanned outages

Expressed as an average over the last five years, 89% of all unplanned SAIDI can be attributed to one of four high-level causes: adverse weather, defective equipment, third-party interference, and vegetation.

The following charts illustrate the relative impact of the major causes of unplanned outages on the distribution network and the trend over time.

**Figure 5.4: Unplanned SAIDI by major cause FY21-FY25**



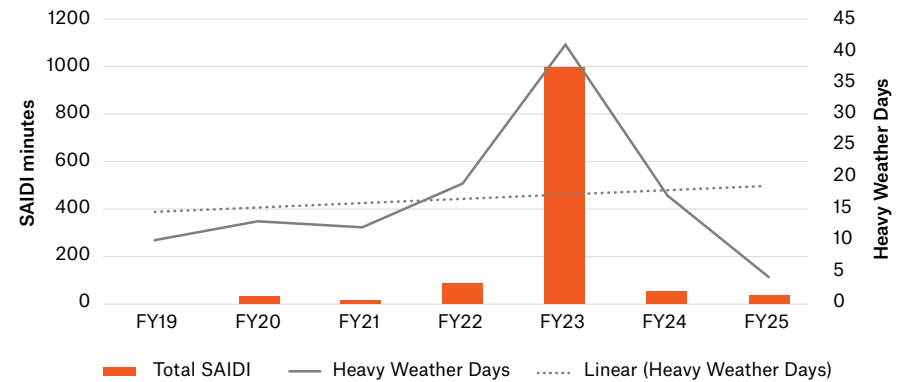
## Adverse weather

While major weather events are infrequent, they produce major fluctuations in SAIDI and can have a significant impact on the frequency and duration of unplanned outages.

Cyclone Gabrielle was a major factor in our five-year unplanned SAIDI due to adverse weather. This single event, the costliest tropical cyclone on record in the Southern Hemisphere, contributed nearly 1000 SAIDI minutes to FY23.

The following chart illustrates the number of heavy weather days that have caused outages. These are overlaid on the trend in SAIDI caused by adverse weather.

**Figure 5.5: Adverse weather**



The chart highlights high variability in the number and intensity of unplanned SAIDI events attributable to adverse weather.

We expect this variability and impact to continue due to the impacts of climate change. These events will continue to challenge the resilience of the network in the medium to long term.

We have introduced a number of strategies designed to mitigate storm impacts and increase the resilience of the network to adverse weather. These include:

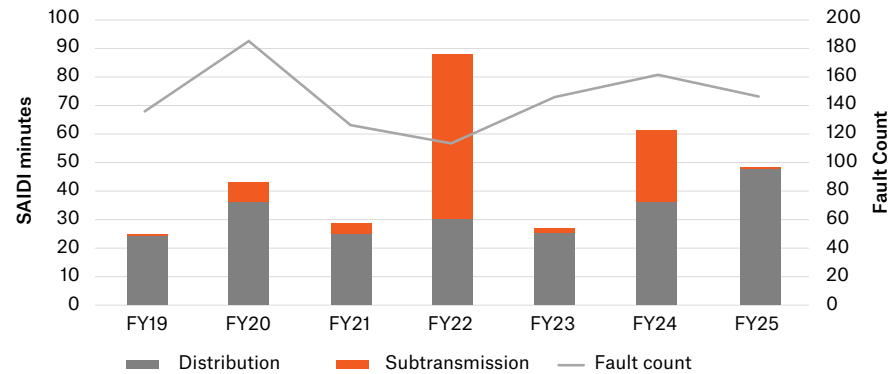
- accelerated deployment of automation and intelligent devices across the 11kV network. This includes the installation of smart automated overhead switchgear at feeder mid-points and tie points, enabling faster fault restoration and reducing the area that requires patrolling
- better identification and management of high-consequence fall-zone trees and targeted reduction of wind-blown vegetation debris
- using vegetation growth modelling to drive inspection and cutting programmes
- increased engagement with tree owners where hazards are identified that aren't covered by the Electricity (Hazards from Trees) Regulations 2003
- continued focus on the subtransmission network to ensure the backbone of our network is increasingly resilient to weather-related events.

Ongoing enhancements to design standards and processes are focused on strengthening the resilience of the network.

## Defective equipment

The following chart illustrates the trend in unplanned SAIDI caused by defective equipment.

**Figure 5.6: Defective equipment SAIDI**



Defective equipment SAIDI on the subtransmission network is characterised by numerically few outages, with high SAIDI impact and a large number of customers affected. The criticality of this network has been recognised by a significant uplift in investment in replacement programmes for end-of-life subtransmission assets.

We have applied more scrutiny to events during adverse weather and are attributing events to defective equipment where there is supporting evidence. Previously all events during adverse weather were attributed to adverse weather. This refined approach provides better insight to equipment reliability and goes some way to explain the increase in SAIDI attributable to defective equipment.

Several initiatives have been put in place to address reliability of the distribution network. These initiatives include:

- enhanced monitoring to ensure priority work is delivered within specified timeframes
- adequate corrective maintenance budgets committed to defect remediation
- full structure maintenance and acoustic testing of substation assets.

Increased resourcing has enabled a renewed focus on data analysis and modelling, designed to identify high-risk areas of the network and optimise asset replacement at these locations.

Data-driven models have also been introduced to drive asset renewal forecasts. To realise the full benefit of these models, we continue to improve the quality, accuracy and timeliness of data capture feeding into these models. This is driving improvements in data capture requirements from overhead inspections.

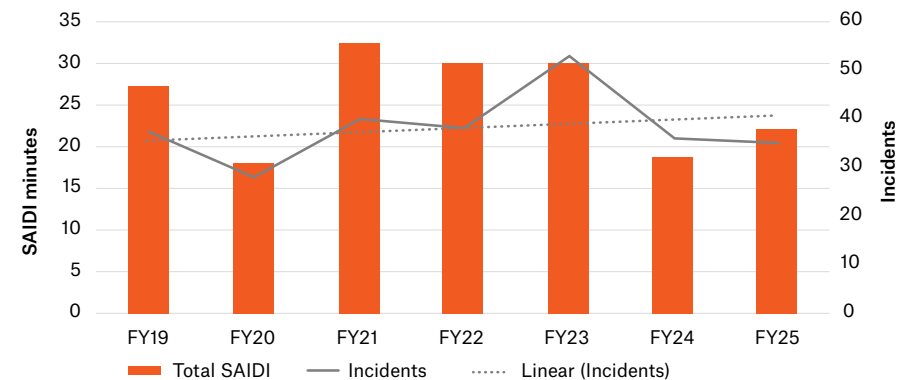
Improvements to the asset-failure investigation and root-cause analysis support the data-driven models and investment by enabling more effective targeting of investment to reduce failure rates.

As a result of current and new initiatives, we expect unplanned SAIDI caused by defective equipment to stabilise and begin to trend downwards over the planning period.

## Third-party interference

The number of outages caused by third-party interference feature significantly in unplanned SAIDI statistics. This appears to be an industry-wide trend. Dominant scenarios are vehicles hitting poles in road accidents and construction vehicles hitting lines.

**Figure 5.7: Third party interference SAIDI**



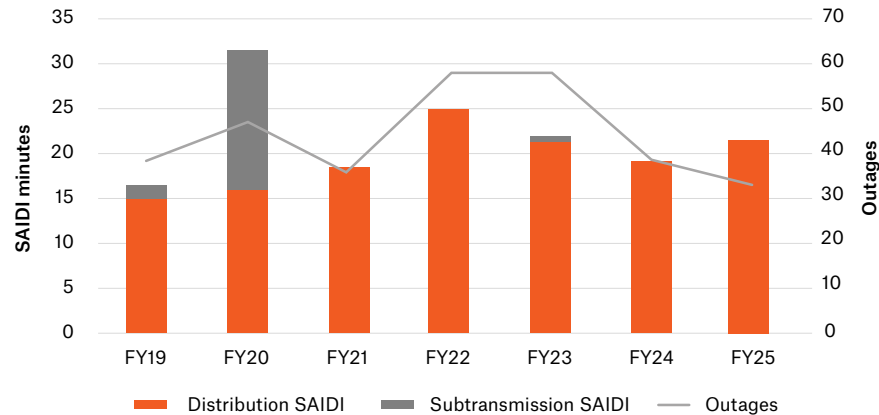
We routinely review locations when a vehicle collides with our assets to identify how we can reduce the location's vulnerability to a vehicle-related event. Options include relocation of the network or undergrounding the relevant network where this can be justified.

However, an underlying driver for this type of outage is the population growth, particularly in urban areas where there has been a major increase in traffic density and construction in recent years. This trend shows no sign of slowing and we expect growth in vehicle movements to be reflected in the number of third-party incidents.

## Vegetation

The following chart illustrates the number of outages over time caused by vegetation overlaid on SAIDI, split by subtransmission and distribution.

**Figure 5.8: Vegetation SAIDI**



Helicopter surveys and line patrols of subtransmission networks focus on identifying risks from fall-zone trees and wind-blown vegetation debris. We use a risk-based approach to reduce the impact of vegetation on our network and actively engage with landowners to get their agreement to remove vegetation that provides an elevated risk of interference with the network.

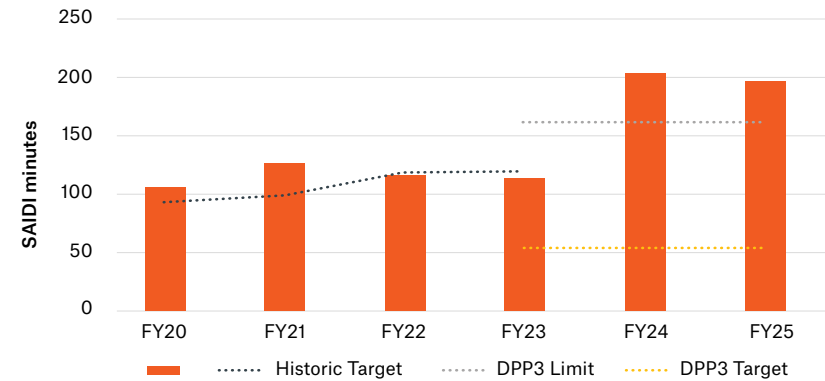
Vegetation efforts have been focused on high-criticality lines, which is reflected in the low fault rate for subtransmission. We expect that the number of vegetation-related faults will not decrease, however, the impact on SAIDI will reduce as a result of this effort. The absence of vegetation-related SAIDI on the sub-transmission assets in FY24 and 25 provides confidence that this approach is working.

We have applied more scrutiny to events during adverse weather and are attributing events to vegetation where there is supporting evidence. Previously all events during adverse weather were attributed to adverse weather. This refined approach provides better insight to the vegetation programme. We expected a small uplift in the number of minor vegetation-related events because of this more accurate approach, however, this is not evident in the data. The number of outages related to vegetation has fallen.

## Planned outages

The following chart shows planned SAIDI performance for the period FY20-25.

**Figure 5.9: Planned SAIDI versus historical limit**



In AMP 2023 we forecast increased investment in asset renewal and this is reflected in planned outage impact (planned SAIDI) for FY24 and 25.

In FY23, we changed from our historic targets to the DPP3 targets and limits.

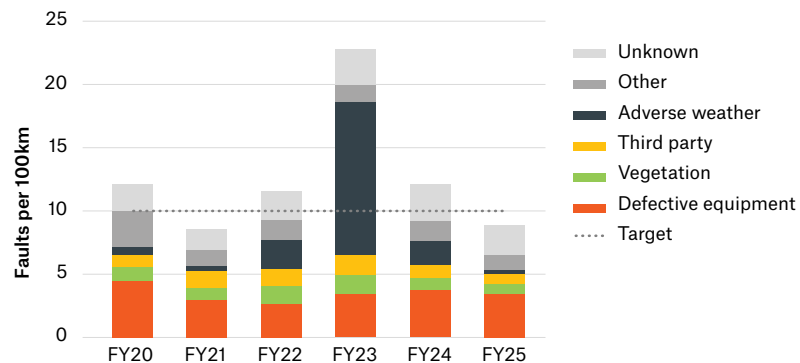
From FY26, we introduced DPP4 methodology for planned SAIDI which allows a discount of 50% on planned SAIDI events if schedule compliance is met, whereas penalties apply if schedule compliance is not met. An uplift in recent years in planned SAIFI reflects the same drivers as those for planned SAIDI — an increase in our planned work programme, an ongoing focus on defect remediation, and targeted end-of-life asset replacement.

We have other strategies in place that minimise customer impact (for example, planning work for night-time to minimise impact on residential customers) but do not reduce SAIDI metrics.

### 5.5.3 Fault rate

The following chart illustrates the six-year trend against a target of fewer than 10 faults per 100km of network. The four major contributing causes (defective equipment, adverse weather, third party, and vegetation) are shown separately, while the balance (wildlife, lightning, adverse environment, and human error) have been combined in order to present a clearer picture. Note: Fault counts may not reflect the relative contribution of each cause to SAIDI.

**Figure 5.10:** Faults per 100km due to main causes



Historically the major contributor to the fault rate has been equipment failure. This has stabilised as maintenance budgets and resourcing have increased. These efforts have been directed at improved identification and prioritisation of defects enhanced by active monitoring of resolution timeframes.

FY23 is an outlier due to the impact of Cyclone Gabrielle, the costliest tropical cyclone in the Southern Hemisphere.

Faults from other sources have remained fairly consistent in recent years.

Targeted investment programmes for reliability improvements covered in Chapters 8 and 9 include:

- a programme to improve feeder performance and visibility of the network by installing remote controlled switches with fault passage indication throughout the network
- replacement of existing manual switches with remote controlled switches
- addition of N-1 security on critical subtransmission circuits
- investment in asset renewal driven by data analysis and modelling
- sustained use of destructive sampling of end and near end-of-life assets to better understand the condition of the network
- embedded vegetation management risk-based strategy supported by rapid inspections.

## 5.6 Supporting communities

As a trust-owned business, we have a strong focus on ensuring equitable and sustainable outcomes for the communities we serve. As discussed in Chapter 2, our customers have told us in our annual survey that fair pricing and cost efficiency are among their top priorities. We are committed to keeping our service costs low and actively look for efficiencies in the way we invest in and operate our network.

Recognising this, we are developing a set of performance indicators to help ensure we continue to deliver cost-effective services to our customers.

### 5.6.1 Delivering cost-effective services

Service affordability is impacted by the level of asset investment and the operational costs required to provide our network services to customers.

Although we have not set specific targets around affordability, we ensure that our operational expenditure and network investments are cost-effective through strict investment planning processes, internal challenge, and governance oversight. We are committed to continually improving our asset management capability to further understand our network assets, our investment decision making and our ability to deliver our services more affordably.

### Consumer distributions

We have a strong focus on ensuring equitable and sustainable outcomes for our consumer owners. Our trust ownership ensures the profits we make are returned to the communities we serve. Since 1993, this arrangement has delivered more than \$278 million to our connected electricity consumers.

## Fair pricing

We are increasing our focus on ensuring our pricing is fair, transparent, and equitable for all consumers. We seek to implement fair pricing for all users of our network and make sure our pricing is well understood by customers.

To maintain equitable pricing, our policies focus on those customers that drive network costs paying their fair share of those costs. Two key elements include:

- **capital contributions:** our policy means fairer allocation of costs to those requesting investments (developers). On balance, those driving growth on the network will largely fund the required investments, meaning that total costs for consumers will be lower over the long run.
- **pricing reform:** moving towards more cost reflective pricing will ensure customers pay a fairer proportion of the cost of the service they receive. For some low-income, high-use households, this will reduce their line charges. By adopting time-of-use charging, we aim to signal times of peak usage, to encourage consumption outside the peak. Over time this reduces the need to invest in more capacity.

## Energy education

Our ongoing Energy Education Programme, see Chapter 2, helps our customers get the most from their energy choices. We have also put together a consumer outreach programme to help communities by providing practical energy-saving advice and assistance to reduce total electricity costs.

We are working with community partners to reach households in need, delivering personalised advice and support to households across the Whangārei and Kaipara districts. This includes practical help through home energy assessments, helping customers find the most suitable retail plan, and providing free LED lightbulbs and low-flow showerheads.

## Efficient works delivery

Efficient network expenditure does not mean simply minimising short-term expenditure as we need to consider whole-of-life costs, including the financial impacts of poor performance.

To maintain safe and reliable services for customers we must continue to invest in network assets at appropriate levels and to make sure that we maintain these in a fully functional state. This includes testing our investments to ensure major new capacity upgrades provide the lowest cost/best outcome for consumers. The focus is on ensuring we achieve maximum long-term benefit from our investments and reduce whole-of-life costs across our network.

## Network utilisation<sup>6</sup>

An important indicator of the efficiency of our investments and network operations is the level of utilisation of our assets. Our strategy aims to ensure maximum value from our investments by ensuring good design and lifecycle management practices. We are developing a set of KPIs that will help to target ongoing, efficient levels of utilisation.

We have calculated 25% utilisation of our distribution transformers. We have installed some low voltage (LV) monitoring devices on selected distribution transformers which are used to record actual utilisation. We have since transitioned to the use of LV meter data (NOD), to support our understanding of individual transformer utilisation.

We believe a low utilisation factor can be accounted for due to historical assumptions relating to customer loads and behaviours. Before acquiring LV data, calculations were very conservative ensuring the network was not under designed. This has led to distribution transformers becoming underutilised. Many of our rural distribution transformers only supply a few properties which is a large contribution towards a low utilisation factor.

Our aim is for distribution transformers to have an 80% utilisation factor. With the addition of LV data, we can now measure transformer loadings which allow us to better size transformers and avoid unnecessary upgrades. We are expecting transformer utilisation will improve significantly over the next five to ten years.

### 5.6.2 Capability performance

Having appropriate levels of capability is critical for effective asset management. Our people need to have the right capabilities to manage long-life electricity assets safely and effectively. This is particularly important as the electricity sector evolves.

Asset management capability includes processes, systems, tools, and knowledge that we employ to deliver our asset management activities. Our AMMAT<sup>7</sup> assessment discussed in Section 6.5 sets out our self-assessment of our asset management maturity. Our assessment has an overall score of 2.4, which is higher than our assessment of 2.0 in our 2023 AMP. This scoring reflects improvements into our asset management practices, reviewed through a robust, systematic assessment of our full asset management system.

This forward-looking review assessed current capability against best practice asset management and the ongoing need for continuous improvement to address the challenges and opportunities the business faces.

We have been forthright in our AMMAT assessment of our capabilities and strengths as well as shortcomings, and we recognise that the discipline of asset management continues to evolve and improve over time.

<sup>6</sup> We calculate network utilisation as the maximum demand across all distribution feeders on the network, divided by the distribution transformer capacity on the network.

<sup>7</sup> Asset management maturity assessment tool (AMMAT). See Chapter 6.

We continue to reposition and enhance our asset management approach. We have recognised that this is a critical enabling step, given the increasing levels of expenditure required on our networks, and the need to manage this investment prudently. We have invested heavily in capability and support to enable us to deliver what has been a material shift in approach. However, there is considerably more to do.

Good practice asset management helps us deliver a cost-effective, safe, reliable service to our customers. For this we need to continuously improve and develop our people, our systems, and our processes.

Since publishing our AMP in 2023, we have increased our efforts to refine and update our approach to asset management. It has become apparent that our asset management practices, while fundamentally sound, need to evolve, given increasing investment needs and increasing uncertainty about future energy markets.

We have begun to develop a set of targets to measure our progress in this area, see Table 5.5.

**Table 5.5: Our capability targets**

Performance indicator	TIMING
AMMAT score of 3	2029
ISO gap analysis to inform next full AMP	2027
Develop an asset management competency framework	2027

## Supporting initiatives

Over the next five years we will move to fully embed and leverage changes in our asset management approach to ensure ongoing prudence of investment and efficiency of spend. This will include fully documenting our approach through a formal shift to the ISO 55000 framework and developing the level of advanced asset management capability necessary to be able to deploy and leverage more advanced techniques.

Recognising the need for improvement in our asset management capability and the challenges that we and the wider electricity distribution sector face, we have developed a continuous improvement programme, see Section 6.5.2.

## 5.7 Future readiness

As discussed in earlier sections, we are taking action to ensure we are ready for the evolving energy market and the increasing use of technologies that will have material impacts on energy use and flows on our network. By doing so we will continue to provide services that will meet our customers' energy needs reliably and efficiently, now and in the future.

As more electric vehicles, solar panels, and batteries are deployed, our network will need to handle two-way power flows and increasing voltage fluctuations. Developing good technical standards and ongoing network monitoring is critical to keeping our costs down and ensuring continued reliability of our supply to customers.

We are continuing to develop network standards for service connections and customer agreements, as well as our operations manuals, capital contributions, and asset management-related standards to adapt to the changing electricity network. This means striving to keep connection standards simple and future-proofed, ensuring pricing is fair and equitable across all customer groups, and working with local partners to enable new solutions that benefit our customers.

### 5.7.1 Future readiness targets

These targets provide our teams with clear guidance on the asset management aspects we must focus on to ensure we are ready to enable our customers' future energy choices.

We are developing a set of targets to measure our progress in this area, see Table 5.6. We will continue to develop these targets as we progress this work further.

**Table 5.6: Our future readiness targets**

Performance indicator	TIMING
Build greater visibility and modelling of our LV network to enable proactive management of LV constraints	FY27
Deploy new Asset Management Information System (AMIS) to enable better data capture and analytics	FY27
Gain insight to customer usage and impacts of electric vehicle (EV) charging through half hour data from retailers	FY26
Continue to work closely with photo-voltaic installers and solar wind farm operators to enable distributed energy resources (DER) on the network, adapting as increasing large generators connect	Ongoing
Deploy advanced distribution management system (ADMS) module to automatically manages congestion on the high-voltage network by dynamically controlling distributed generators through SCADA, ensuring network security while maximising renewable generation capacity.	FY26

These performance indicators have been developed recently and we are yet to begin formally tracking our performance against them. We expect to report on our progress in this area in our next AMP.

### Supporting initiatives

As society changes and technologies develop, standards need to evolve. We are actively participating in a number of technical advisory groups, examining, and developing new standards and guides for EV charging, earthing, integration of inverters, and voltage regulation.

To advance our performance in this area, we are undertaking a range of initiatives and are continually enhancing our capabilities.

- Increasing digital and analytical capability.
- LV and HV visibility (short term) and LV control (medium term) of our network.
- Monitoring and publishing hosting capacity for distributed generation (DG).
- Enabling the connection of large-scale DG on our network.
- Monitoring evolving energy market developments and opportunities for improving value for our consumer owners.
- Developing and implementing a remote area power supply (RAPS) alternative for remote areas of our network where this is the most cost-effective option.
- Making timely, prudent investment decisions that meet the demand for growth and build the enabling foundations for an active modern network.
- Adopting new technology and methods where proven to add value.
- Developing and implementing supply options for remote areas of our network.
- Evaluating non-network alternatives to address constrained areas of our network.
- Providing pricing signals to enable customers to make informed decisions about their energy use.
- Developing flexibility services and pricing options for customers.
- Providing our customers with easy-to-understand information on making wise energy choices to save money on their total energy, as well as educating customers on future energy choices with non-biased information around PV and EV.



RATED LOAD 250kg

## Chapter 6

# Approach to Asset Management

## 6.1 Introduction

This chapter explains our overarching approach to managing the assets on our electricity network.

Effective asset management needs to consider the full asset lifecycle. This includes initial development investments, maintaining performance and safety during an asset's life, managing cost of ownership, and efficiently renewing and disposing end-of-life assets.

Asset management at Northpower uses a holistic approach that considers the full lifecycle of an asset. This includes the creation of the asset, operation and maintenance over its lifetime, and decommissioning and disposal at end-of-life stage. We have adopted a typical staged approach that governs the activities we adopt to manage assets over each stage of their lifetime. When managing our assets, we use a hierarchy of asset portfolios and asset fleets to help ensure consistency in our approach.

Delivering for our customer owners requires effective investment decision making. Our decision-making approach takes a long-term view, accounting for customer needs, whole-of-life costs, asset performance and long-term sustainability. We continue to consider the evolving nature of the electricity industry, including what future networks may look like, and the associated network services and asset solutions.

Finally, this chapter discusses our asset management capability, including our plans to improve our approach and competency in support of our future work plans.

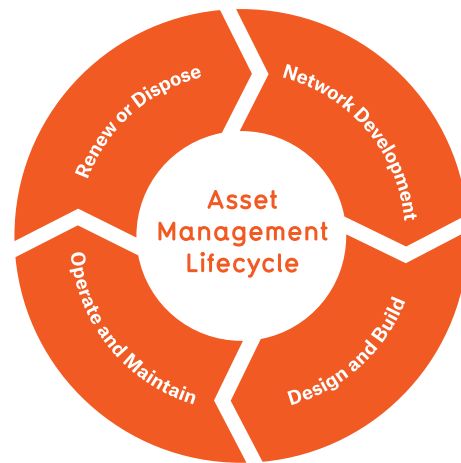
## 6.2 Lifecycle approach to asset management

Our lifecycle-based asset management approach supports our strategy to provide a safe, affordable, and reliable electricity supply to our customer owners.

Each asset fleet is guided by an individualised asset strategy that aligns our strategic objectives with the unique requirements of the fleet. This approach ensures a consistent direction and method in managing the lifecycle of assets, fostering uniformity and clarity across all stages of asset management.

Our asset management practices aim to prudently manage the performance of our assets between the time of commissioning and eventual renewal.

The four stages are described as follows, with further detail provided in the referenced chapters.



- **Network Development:** encompasses the development of new or upgraded assets, beginning with the identification of future demand and network constraints. This stage includes recognising the initial need, evaluating possible solutions, and developing conceptual designs to address needs. This stage is described in more detail in Chapter 8.
- **Design and Build:** this stage includes detailed design, tendering, construction, project management, commissioning, and handover of new assets to our operational teams. This stage is discussed later in this chapter.
- **Operate and Maintain:** covers the operation and maintenance of our network assets. These activities aim to ensure safe and reliable performance over the expected lives of the assets. This is described in more detail in in Section 6.2.2.
- **Renew or Dispose:** covers how we decide to renew and/or dispose of assets. Generally, a decision to renew or dispose of an asset is needed when it becomes unsafe, obsolete, or costs more to maintain than to replace. This stage is discussed in Chapter 9.

### 6.2.1 Network development

We use the term network development to describe capital investments that increase the capacity and improve the security and reliability of the network to acceptable levels.

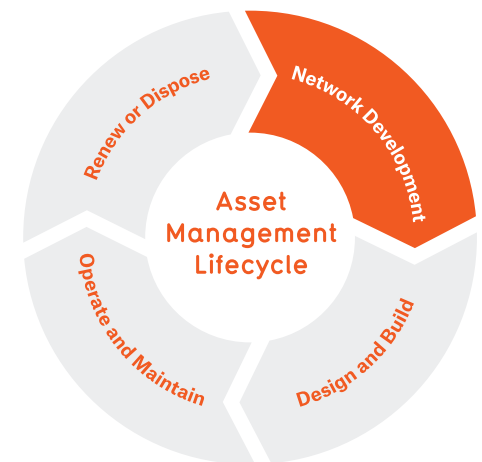
These investments help ensure our assets continue to operate within performance limits and provide an appropriate level of service to customers.

We need to maintain appropriate levels of security and performance to meet growing demand and to provide flexibility to customers wishing to connect.

Network development typically responds to four key investment drivers:

- **growth and security:** network investment to ensure demand on the network is met, while maintaining our levels of security of supply.
- **reliability and quality of supply:** targeted network investment to improve reliability and quality of supply. This includes investments to improve feeder performance by installing remote-controlled devices and increasing back-feed capacity.
- **consumer connections:** network investment to enable new customers to connect to our network.
- **network transformation:** network investment to meet the evolving needs of our customers and manage constraints arising from changing network behaviour.

Chapter 8 sets out how we will invest to meet these drivers over the AMP planning period.



## 6.2.2 Design and build

Delivering for customers will require a significant level of network investment over the AMP planning period. To support this increased level of investment, we need to maintain effective design and build capability. This includes the capacity and capability of both our field delivery teams and our internal planning capability. We also need to ensure that sufficient plant and materials are available. To support this, we have a range of applicable network standards and specifications, see the following.

### Safety in design

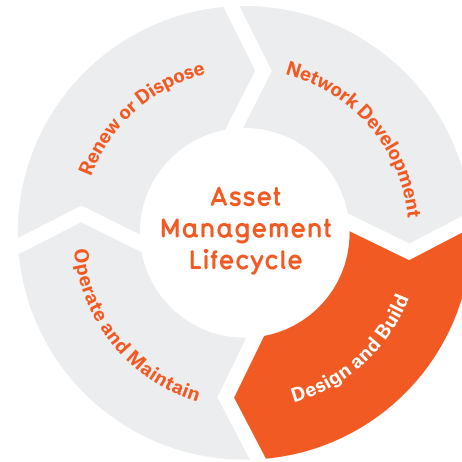
We apply safety in design principles to ensure our network is designed so it is safe to build, operate, maintain, and decommission. Our safety in design framework is adapted from the Electricity Engineers' Association (EEA) guide for safety in design. The main objective of the framework is to ensure that our design process does not introduce new hazards, as well as minimising current hazards during the construction, operation, and maintenance phases of an asset's lifecycle.

### Design and technical standards

To manage the safety, cost, efficiency, and quality aspects of our network, we standardise network design and work practices where practicable. The use of standardised designs can lower costs by reducing spares holdings and simplifying maintenance procedures.

Our technical standards apply to Northpower staff and authorised service providers working on our network. They reference the relevant codes of practice and industry standards as appropriate. We engage external consultants to provide designs for our critical assets, including zone substation, transmission line design and complex cable designs.

To effectively manage network risk, we conduct a comprehensive review of all scheduled outages for complex projects during the construction phase. This approach enables us to minimise network risk and ensure that appropriate contingency measures are in place whenever the network is required to operate at a security level below normal.



## Equipment specifications

We aim to adopt standardised equipment for construction on the network. We have developed specifications detailing accepted performance criteria for significant equipment on our network (such as power transformer and switchgear). New equipment must conform to these specifications. We maintain a list of approved equipment for use on the network, which meet our quality requirements. New equipment types are assessed and often tested before being approved on the network.

## Documentation control

Northpower's controlled documents are maintained with a high degree of accuracy, with all updates managed through a structured change control process within our Quality Management System (QMS). The Network Management team oversees the maintenance and implementation of these updates in accordance with the established document control standards.

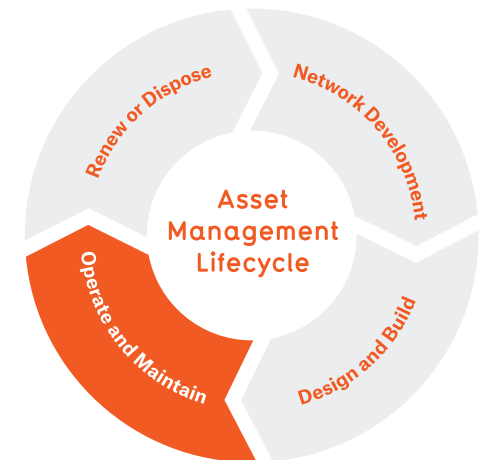
In FY24, we implemented Autodesk Vault as a dedicated system for managing engineering drawings, with a focus on centralising and streamlining the management of substation drawings. As part of this initiative, we conducted a detailed review and systematic upload of both legacy and current substation drawings, including their associated metadata, into the Vault platform. The adoption of this system has enhanced change and version control processes and established more structured workflows. The transition to full business-as-usual (BAU) integration and operation is planned for completion during FY26.

## 6.2.3 Operate and maintain

Effective asset management uses appropriate operations and maintenance over an asset's lifecycle.

Following commissioning, assets are put into service and maintenance and operation of the asset begins and continues until renewal or disposal. These activities often vary over the lifecycle of an asset, for example, increasing repairs as an asset ages.

The operate and maintain stage includes network operations, maintenance, vegetation management, and spares management.



## Overview of operations

Network operations refers to the range of activities necessary to ensure the day-to-day safe and reliable control and management of our distribution network. The primary role of network operations is to provide a reliable supply of electricity to our customers by operating the network in a way that ensures we meet network, operational, safety, and asset performance objectives on a 24/7 basis. This is achieved through system monitoring, switching and load control, fault response coordination, and providing contractors access to the network for works required to develop and maintain the assets. It includes the use of:

- **equipment operating instructions:** to ensure safe operation of our network we have operational instructions covering the different types of equipment on our network. We create instructions for new equipment introduced onto the network
- **operating standards:** to ensure our network is operated safely we use standards related to the release of network equipment, commissioning procedures, system restoration, and access permit control.

## Overview of maintenance

Maintenance is the care of assets to ensure they provide the required capability in a safe and reliable manner throughout their lifetime. It involves monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring the condition of the asset, if renewal is not the optimum intervention. Feedback from maintenance activities is used to improve our asset standards and planning processes, as well as to inform our Capex renewals programme.

We manage and organise our maintenance work into three network opex portfolios:

- **preventive maintenance:** routine maintenance activities including testing, inspections, condition assessments, and servicing
- **corrective maintenance:** primarily involves remediating defects, by replacing components or minor assets, or undertaking repairs
- **reactive maintenance:** responding to faults and other network incidents. This may involve making a situation safe until a full repair is scheduled or the repair work is complete.

Chapter 9 provides more detail on our approach to maintenance and sets out our planned expenditure for the 10-year AMP period.

## Vegetation management

Vegetation management is used to keep trees clear of overhead lines. This is necessary to minimise vegetation-related outages and meet our safety and statutory obligations. Left unchecked, vegetation can have a significant impact on network reliability and public safety. The main vegetation management activities are inspections to determine the amount of work required, liaison with landowners when work is required, and subsequent follow-up to undertake tree trimming and removal.

Chapter 9 provides more detail on our approach to vegetation management and sets out planned expenditure for the 10-year AMP period.

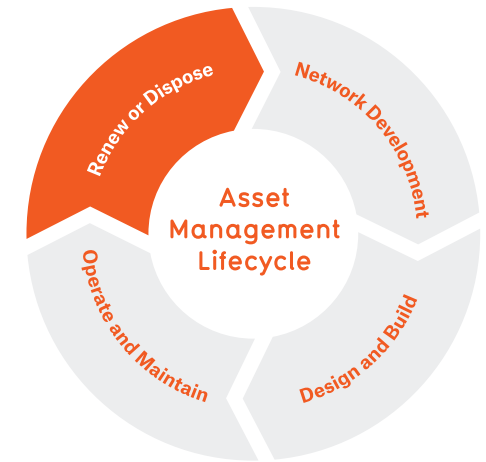
### 6.2.4 Renew or dispose

As assets deteriorate, they eventually reach a state where ongoing maintenance to keep them safe and serviceable becomes ineffective or uneconomic.

Asset renewal is the replacement of ageing, damaged, or underperforming assets, or the refurbishment of existing assets to extend their useful life or increase their service potential.

Asset disposal follows the decision to remove an asset from our network, either because it is being replaced or has become redundant.

Refurbishment and replacement of assets are used to manage asset condition, safety risk and network performance, resilience, obsolescence, and to meet regulatory and legislative requirements. Our approach to renewal varies by asset fleet and, in some cases, there will be a range of risk reduction options to consider.



### Renewal forecasting

Our asset replacement decisions are based on balancing several considerations, including the need to provide a safe, resilient, and affordable electricity supply. We take a balanced approach and consider whether continued maintenance is economic, asset criticality, and the potential asset health, safety, and environmental risk, along with the impact on reliability.

Our renewal expenditure is forecast in two ways:

- **volumetric forecasting:** for large volume fleets we use a replacement expenditure (Repex) technique to forecast replacement volumes over time. These are combined with P50<sup>1</sup> unit rates to forecast expenditure. The individual assets are then identified for replacement through our inspections and defect management approach.
- **identified projects:** for lower volume fleets (typically with higher value assets) we plan on the basis of individual projects using asset condition (visual inspection and test data) and criticality, as well as consideration of other factors such as obsolescence, type issues, and environmental considerations. These projects are scoped and costed using a customised estimate. Our more complex and high-value assets have clearly defined scopes and scheduled replacement timelines within the 10-year Capex programme.

<sup>1</sup> A P50 cost is an estimate of a cost based on a 50% probability that the cost will not be exceeded.

These projects are subject to annual reviews to identify any significant changes that may impact their prioritisation or delivery schedules. For example, power transformers and zone substation switchgear are managed using asset health models that incorporate consequence factors to guide decision making.

## Replacement delivery approaches

Our asset management approach differs depending on the asset class and what asset condition information we currently hold. Our current approach is as follows.

- High-value, critical substation assets that have a high consequence of failure are replaced based on condition assessments and prioritised based on criticality. Robust, regular inspections feed into frequently updated condition assessments.
- Distribution overhead assets (such as poles, crossarms, and insulators) are inspected regularly and replaced once they pose a risk to reliability, public safety, or the environment.
- Distribution underground assets, such as transformers, ring main units, and low voltage (LV) pillars, are subject to regular inspection and are replaced when they are identified as presenting risks to public safety, network reliability, or the environment. We implement a targeted replacement programme for our four oil-filled cable 33kV circuits, while distribution and LV cables are typically maintained or replaced on a reactive basis in response to identified issues.
- Our buildings are inspected regularly, maintained, and repaired when required.

We plan asset replacements when asset health falls below acceptable thresholds, guided by our structured, age, type, visual inspection, and testing regimes. These practices enable us to proactively monitor asset condition and undertake maintenance or replacement prior to failure, supporting reliability and safety across the network. Replacement strategies are tailored by asset class, but generally, our renewal programme for volumetric fleets is delivered through two distinct streams: corrective replacements, which respond to urgent short-term needs identified through defect management, and targeted replacements, which focus on longer-term, strategically planned replacements that consolidate asset works for greater efficiency and alignment with overarching network objectives:

- **corrective replacement:** high-volume asset replacements are planned using our defect management approach. When an asset inspection identifies that an asset meets criteria for replacement, as set out in our defect management standard, a defect is raised and replacement planned before asset failure.

A significant portion of our renewal activities, particularly within the corrective capex programmes, is directed at addressing identified defects with high priority. This typically applies to large, volumetric asset fleets within the overhead network, such as poles, crossarms, and conductors. Smaller components detected through our preventative maintenance inspections, including insulators, connectors, and fuses, are replaced via our opex corrective programme.

- **targeted replacements:** our Asset Lifecycle team review our visual inspection and test data as well as other inputs, such as obsolescence and industry experience, to identify and plan replacements to manage asset failures. Unlike corrective replacements, which generally involve like-for-like asset replacement, targeted works are undertaken with a more strategic focus to support our overarching objectives. These works typically concentrate on higher-value assets or sectionalised areas, where multiple asset fleets are addressed within a consolidated replacement programme. For volumetric replacement activities, our designers also assess opportunities to upgrade installations to the latest design standards, particularly when dealing with older assets that were constructed under previous standards, where it is practical to do so.

All targeted replacements are supported by a business case proposal that considers alignment with our strategic objectives as applicable. For more complex projects, additional options analysis is undertaken as appropriate. This ensures that replacements align with network development requirements, supporting future network growth and enabling opportunities for new customer connections. The approach also seeks cost efficiency by considering the inclusion of adjacent assets not yet at end-of-life where it is economically prudent to do so, thereby achieving the lowest overall lifecycle cost and minimising customer disruption by avoiding multiple return visits for asset replacement. Furthermore, we assess the potential for non-network solutions as alternatives in instances where capital investment is substantial, and deferral of Capex may be beneficial.

## Prioritisation across fleets

Asset criticality is considered generally in both our defect management and targeted replacement approaches. Assets with a higher consequence of failure whether due to potential network disruption, environmental impact, safety concerns, or reputational risk, are prioritised for replacement ahead of those with a lower consequence. Currently, our approach to risk definition is primarily qualitative and relative in nature, as we do not yet have a fully quantified risk framework that applies consistently across all asset fleets. This limits our ability to compare and prioritise all asset fleets on an equal risk basis. Our asset data relies on age, which is a mixture of known data and derived ages, and our field inspection data is currently structured to trigger work replacements rather than provide detailed, qualitative asset condition assessments.

To improve our data quality and gain a more comprehensive understanding of individual and comparative asset risks, we have initiated an asset management transformation programme. This programme is running alongside our traditional practices and will be phased in over time. The key initiatives include:

- **field inspection techniques and technologies:** we are moving from ground-based, corrective replacement triggered by identified defects to a more data-rich, observation and severity-based inspection framework. This enables our analytical tools to support quantitative condition analysis and failure mode assessment. The adoption of advanced tools is improving the clarity, accuracy, and comprehensiveness of our asset data.

- **network consequence models:** we are developing transparent, spatially aware models to quantify the impact of asset failures across network performance, public safety, and environmental risk. This modelling approach allows for consistent risk scoring across asset classes, which is critical for prioritising capital investment and ensuring intervention strategies are aligned with actual risk exposure. Initial focus is on our overhead portfolio, with underground portfolios to follow
- **analytical tools:** our aim is to enable a data-driven, risk-informed asset management strategy that moves beyond age-based replacement and towards risk-based decisions. Developed for asset fleets such as poles, conductors, crossarms, and pole top assets, these tools codify asset data and failure modes, providing a deeper understanding of performance and consequences of failure than traditional age-based models
- **Asset Management Information System (AMIS):** AMIS is being implemented to support a data-driven, asset-centric approach, enhancing our asset management maturity across the organisation. This system consolidates legacy platforms, improves asset lifecycle visibility, and streamlines both capital and maintenance planning through standardised workflows, ultimately increasing operational efficiency. For comprehensive risk understanding, AMIS will integrate with GIS, field, and analytical data, as well as operational systems such as OMS
- **GIS upgrade:** closely integrated with AMIS implementation, the GIS upgrade is essential for achieving a unified, real-time view of data across the asset lifecycle. Bi-directional data flow between GIS and AMIS maintains the integrity and accuracy of both linear and fixed asset locations.

Chapter 9 discusses our asset management approach for each asset class in more detail.

### Asset disposal

We are committed to disposing of our assets safely, in a way that minimises environmental impact and complies with all legislative and local authority requirements. This includes the disposal of redundant assets, equipment, and hazardous substances, while ensuring that materials such as oil, lead, PCBs, and asbestos, which may cause harm, are disposed of appropriately. We seek to recycle materials where practical.

## 6.3 Asset portfolios and fleets

When managing our network assets, we use a hierarchy of portfolios and fleets. The asset fleets form the basis of our asset intervention strategies, which are then organised into a set of portfolios.<sup>2</sup> The hierarchy reflects the way we manage our network assets and how we plan our investments. Our portfolios and the fleets within them are set out in Table 6.1.

<sup>2</sup> The portfolios differ slightly from the asset categories specified in information disclosure.

**Table 6.1: Mapping between our asset portfolio, fleets and main forecasting approach**

Portfolio	Asset fleet	Forecasting approach
<b>Overhead lines</b>	Conductors*	Volumetric / Repex
	Poles*	Volumetric / Repex
	Crossarms*	Volumetric / Repex
<b>Substation equipment</b>	Indoor switchgear	Scheduled / Risk-based
	Outdoor switchgear	Scheduled / Risk-based
	Substation power transformers	Scheduled / Risk-based
	Infrastructure and facilities	Historical
<b>Underground cables</b>	Subtransmission cables	Scheduled
	Distribution cables*	Volumetric / Repex
	LV cables*	Volumetric / Repex
<b>Distribution equipment</b>	Distribution transformers*	Volumetric / Repex
	Ground-mounted switchgear	Volumetric / Repex
	LV distribution units*	Volumetric / Repex
	Pole-mounted switchgear*	Volumetric / Repex
<b>Secondary systems and other assets</b>	Protection systems	Scheduled
	AVRs (tap changer controls)	Historical
	Auxiliary power supply systems	Scheduled
	Capacitor banks	Scheduled
	Load control	Scheduled
	SCADA system	Historical
	Automation and control systems	Scheduled
	Communications	Scheduled / Risk

\* Note: Developed a probabilistic model, to determine Probability of Failure. Not currently used in AMP 26 to determine replacement and capex forecast approach.

Chapter 9 explains our day-to-day approach to managing the above portfolios and fleets.

## 6.4 Asset management decision making

Asset management decision making refers to the system of roles, responsibilities, authorities, and controls that support our asset investment decisions. This section explains our approach to these decisions and the governance processes used. This builds on our descriptions of organisational structure and main governance levels in Chapter 2.

Asset management decision making occurs at various levels in our organisation – from our Board through to our planning and delivery teams. The Northpower Electric Power Trust maintains a strong, structured engagement with Northpower’s Board, which is responsible for ensuring investment focus and business performance are delivered in line with the trust’s expectations. Investment decisions take place within a system of responsibilities and controls that reflect the cost, risk, and complexity of the decision being considered.

Our asset management governance framework is designed to ensure clarity, accountability, and robust oversight for all key investment decisions. The Network Investment Governance Framework outlines delegated financial authority levels and specifies the circumstances under which proposals must be escalated for Board consideration. Significant capital investments, business cases exceeding management’s approved thresholds, and capex variations outside the Chief Executive’s delegation are all subject to formal Board review and approval.

Regular and structured reporting ensures the Board maintains visibility over asset management outcomes. Directors receive comprehensive updates through established governance forums, covering asset performance, risk management, network investment plans, progress on capital delivery, and compliance status. The Board also undertakes an annual review and approval of the Asset Management Plan, confirming that it is consistent with strategic priorities, stakeholder interests, and regulatory obligations.

### 6.4.1 Investment decision making

Effectively managing assets over their full lifecycle requires effective investment decision-making. This includes decisions about the services and service levels we wish to provide, how we will manage our assets, network architecture, and performance goals.

#### Investment drivers

The evolving nature of the electricity industry and associated network services and asset solutions is increasingly important.

Our investment process is driven by our asset management focus areas, including:

- **a safe network:** our electricity assets and operations will not cause harm to members of the public, our staff, or service providers
- **community support:** we deliver affordable power prices for our community, support regional growth and connect with our community in meaningful ways

- **sustainability:** we ensure that our decision making is in the long-term interest of our consumers and build sustainable capability within the organisation. We will also focus on reducing our carbon footprint and support New Zealand to decarbonise
- **network performance:** our electricity assets and operations deliver reliable, resilient power supply, with the quality expected and meet current and future customer demand.
- **future readiness:** we ensure that Distributed Energy Resources (DER) and large-scale distributed generation are enabled on our network. We keep on top of changing consumer behaviour and ensure that our network is fit for purpose for future demands

Later chapters set out how the above areas influence our investment plans during the AMP period.

In summary, we use the following priorities to guide our investment decision making:

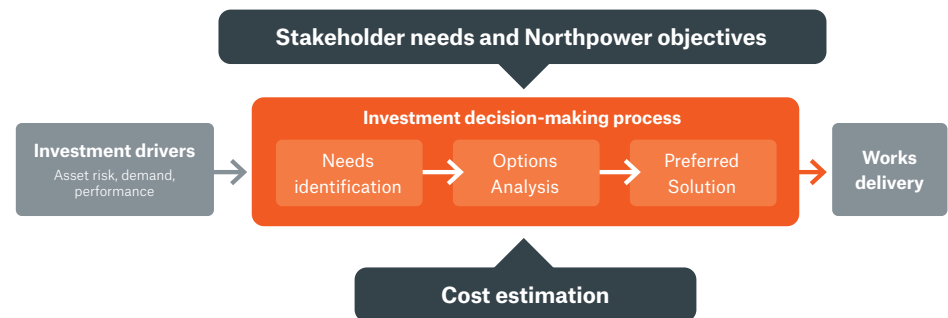
- our primary focus is on investing to reduce the level of risk on the network
- ensure we do not accumulate replacement backlogs, leading to poor performance as a result of underinvestment
- ensure that our network is prepared for growth and the changing needs of our customers
- support our investment planning through targeted improvements to our asset management capability.

To support this, we will pursue improvements in our delivery capability and supporting processes to drive further efficiencies.

### Investment decision making

We have developed a structured decision-making approach for network investments, as illustrated in Figure 6.1. Chapters 8 and 9 provide more detail on how this generalised process is applied to our network development and lifecycle investments, respectively.

Figure 6.1: Asset investment decision-making framework



The main steps in the investment decision-making process are:

- **needs identification:** this involves assessing safety risks, capacity constraints, security, reliability, asset condition, type issues, spares availability, and a range of network and site-specific feedback. Identified needs are further assessed based on a range of inputs, including fleet strategies, risk assessments (including criticality attributes), and subject matter expert judgement.
- **options analysis:** in this step, potential options are developed for each identified need. These options are defined and costed to varying degrees based on the complexity, scale of the identified need, and the costs of feasible solutions. The potential solution is evaluated against approval criteria and reviewed.
- **preferred solution:** in this step, solutions that have been developed in previous stages or planning rounds are prioritised based on the risks associated with the identified need, deliverability, and trade-offs with other investment needs. A preferred solution is identified that may include bundling of multiple needs into one packaged solution.
- **works delivery:** the chosen solutions will be entered into a draft work programme, which sets out planned works. The deliverability of the overall set of solutions is then evaluated in more detail. Projects in the early years of the plan will be subject to review for full investment approval in accordance with our Delegated Authority Policy.

## Investment governance

We developed a Network Investment Governance Framework to ensure that investments go through a rigorous challenge and approval process corresponding to the size and complexity of the investment. We have four work types which are summarised as follows:

- **complex work:** following needs identification and a high-level options analysis, these projects require a conceptual investigation before proceeding towards delivery. These projects are typically high value and have three approval stages: investigation project, project design and procurement, and project delivery approval.
- **non-complex work:** these projects can typically be scoped at a reasonable level of detail following needs identification and options analysis, without an investigation, and then moved towards delivery. These projects have one stage of approval for delivery of the entire project.
- **volumetric work:** are defined as large volumes of equivalent works to be delivered. Volumetric programmes are approved during budget approval for the year and as the replacements are identified, individual replacement work orders are approved by the appropriate delegated financial authority's holder, including the Board.
- **reactive capex:** these are projects that arise due to equipment failure during the year. They are typically approved by the delivery governance group, making wider budget adjustments, as necessary.

We develop business cases for projects to ensure that the need for investment is well understood, credible options are considered, and investments are appropriately challenged. Business cases are reviewed and approved in accordance with our delegated financial authorities, with our large investments being considered and approved by our Board.

We have formed two governance groups that oversee network investment:

- **investment governance group:** made up of the Chief Executive, Chief Financial Officer, Chief Operating Officer – Network, and senior leaders of the Network team, the investment governance group is responsible for overseeing all network investment. Where issues are required to be escalated to the investment governance group, they are either resolved at this level or escalated to the Board as appropriate.
- **delivery governance group:** made up of the Chief Operating Officer – network and senior leaders in the Network team, the delivery governance group is responsible for overseeing the delivery of all network investment and ensuring that investment processes are followed, risks are managed, and changes are appropriately controlled. The delivery governance group escalates as appropriate to the investment governance group.

Our governance processes need to manage the degree of uncertainty inherent in the development of large work programmes. These uncertainties are exacerbated when the scoping and pricing of the project involves long lead times, as is generally the case in the electricity industry. Our development plans are also influenced by third-party requests and timelines for new connections. Over a 10-year AMP period there needs to be flexibility; for example, using scenarios to support planning decisions. In future AMPs we will provide further detail on these scenarios.

### 6.4.2. Cost estimation

Good practice cost estimation utilises a range of qualitative and quantitative methods to establish the most likely expenditure at project or programme level depending on the nature of the work. The development of estimates can be complex, leading to a degree of uncertainty and estimation risk, in particular for longer-term forecasts.

Investments are estimated using our cost estimation process which differs depending on the type of project.

- **Volumetric projects:** for large volume, low-cost replacement programmes, a volumetric unit rate is used to estimate the programme costs. The unit rate is derived using historical out-turn costs.
- **Customised estimates:** for low volume and one-off projects, an estimate is derived using a desktop study of the project to determine a breakdown of the scope, to which unit rates are applied based on historical out-turn costs. As the project moves into delivery, the scope and cost estimate become more accurate through further engineering investigation and detailed design.

## 6.5 Asset management capability

Our people play a central role in our asset management approach, and they need to have appropriate capabilities to manage long-life electricity assets, safely and effectively.

This means our people need to have the right capabilities (including in emerging areas such as asset analytics), and our organisation needs to help them to learn and adapt as the electricity sector evolves.

The increasing use of small-scale distributed generation, the uptake of new energy technologies, and the increasing importance of analytics will have far-reaching implications for the way we operate. The mix of required capabilities will change in the future, and it is important that we identify and implement these so we can continue to deliver an efficient service to our customer owners.

Asset management capability includes processes, systems, tools, and knowledge that we employ to deliver our asset management activities. Some examples of relevant asset management capabilities include:

- development of appropriate objectives and performance monitoring
- data analytics and network modelling, including asset health and criticality analysis
- innovation and prudent adoption of new solutions
- developing planning guidelines and technical standards
- setting out effective maintenance and renewal strategies and plans
- retaining and developing specialist knowledge (for example, for SCADA and protection).

Effective capability needs to be supported by staff engagement, leadership, and collaboration between different teams and functions. To support these aspects, we are increasing our focus on developing a formal asset management competency to develop shared understandings around required capability.

### 6.5.1 Assessing our asset management maturity

This section covers the outcome of our 2026 asset management maturity assessment and how it compares with the assessment we undertook in 2023.

#### AMMAT

We have used the asset management maturity assessment tool (AMMAT)<sup>3</sup> to undertake a self-assessment of our asset management maturity. As part of the Commerce Commission's information disclosure requirements, we need to include this assessment as part of our AMP.

AMMAT includes 31 questions in six subject areas. It provides a clear and consistent approach to assessing the maturity of an electricity distribution business's (EDB) asset management, including an overview of documentation, controls, and review processes. Each of the 31 topics is allocated a maturity score based on those in Table 6.2.

<sup>3</sup> Our assessment was completed using the Commerce Commission's AMMAT, which is a subset of PAS 55, the precursor of ISO 55001.



**Table 6.2** Description of AMMAT maturity score

Maturity score	Description
<b>0</b> Innocence	The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function.
<b>1</b> Aware	The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them.
<b>2</b> Developing	The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation.
<b>3</b> Competent	All elements of the function are in place and are being applied and integrated. Only minor inconsistencies may exist.
<b>4</b> Excellent	All processes and approaches go beyond the requirements of PAS55. The boundaries of asset management development are pushing to develop new concepts and ideas.

### 2026 AMMAT assessment

For our 2026 assessment, our Asset Management team undertook a comprehensive review of current capability to reassess our asset management maturity. This included use of the EEA guide, while leveraging experience and insights from new staff. Based on this review, we updated and revised our AMMAT score.

#### Box 6.1: 2026 AMMAT score

Our 2026 AMMAT assessment has an overall score of 2.4, which is higher than our assessment of 2.0 in our 2023 AMP.

This scoring reflects a more robust, systematic assessment of our full asset management system. This forward-looking review assessed current capability against best practice asset management and the capabilities required to support:

- our future readiness strategy, see Section 4.4.7
- our ability to leverage new technology and solutions
- increased network resilience to meet the challenges of climate change
- improved analytics to support increasing renewal needs.

The review shows meaningful improvement from our previous assessment, however, we recognise that there is still room for improvement, and we remain committed to our ongoing improvement programme.

Our assessment also indicates that we still have progress to make before reaching our target AMMAT score of 3.

### Comparison with our 2023 assessment

We have been forthright in our 2026 AMMAT assessment, recognising our strengths as well as the opportunities for improvement. Recognising that the asset management discipline continues to evolve, we have fully updated our assessment from the 2023 version to reflect capability levels needed to manage our network effectively, now and in the future.

Figure 6.2 provides a comparison between our 2026 and 2023 assessments. It is set out in terms of the six subject areas covered by the AMMAT.

**Figure 6.2:** Asset management self-assessment results



The following list describes the key changes in scoring since AMP 2023.

- **Asset strategy and delivery:** we continue to refine our asset management approaches and embed these into our business. Since our previous AMP, we have identified a number of areas that can be improved and have made substantial gains in the development of our asset fleet strategies and project management framework and the uplift of our annual Capex delivered matching our increased Capex allocation.
- **Documentation, controls, and review:** we have asset management documentation and performance measures to ensure that our processes are being delivered consistently and our network continues to perform. We will continue to integrate improvement and audit processes into our business to ensure our asset management system is working as intended. Since the AMP 2023, we have strengthened our Procurement team, increased the capacity of our Delivery team, and clarified objectives and roles across planning, design, and project management. We have also updated our inspection methodologies, developed a suite of models to more accurately assess asset condition, and introduced the first iteration of consequence models for overhead networks.
- **Systems, integration, and information management:** as our asset management has matured, we have recognised the need to improve our data capture, quality, and relevance. We have also recognised that our current AMIS will not meet our future requirements. We've revised our Asset Information Strategy and formed a data governance group to ensure improvements in processes, systems, and data integrity. The functional design for the new AMIS is complete and we're starting the initial design phase to replace the GIS.
- **Communication and participation:** while we have some channels in place to communicate our asset management information, we recognise the need to have a systematic and formal communications plan to ensure our stakeholders receive the most relevant information in a timely manner. Our Asset Management Strategy aligns with our electricity strategy and is shared through challenge sessions, company updates and project delivery.
- **Structure, capability, and authority:** as our Network team has grown, we have recognised the need to have roles and responsibilities defined with more clarity and progression pathways. To support our future readiness strategy, we need to embed innovation and technology trials into our business processes. Position descriptions and team roles are now well aligned with our strategy as well as our Investment and Project Governance frameworks. Our event management process for investigating asset failures has also improved and better fits daily operations.

- **Competency and training:** a more formal asset management competency framework should be developed with more structured asset management training, to ensure staff have appropriate capabilities. We are currently drafting our Work Type Competency Standard and are aligning our standard with the EEA Common Competency Framework. With the recent uplift in forecast renewal requirements, we have identified the need to have more robust resource planning in place to ensure that our plans are deliverable.

The revised scoring highlights the areas where improvement in our asset management system has been made and future improvements are required. We have used this review of our asset management maturity as an important input to the development of our continuous improvement plan, see Section 6.5.2.

### 6.5.2 Continuous improvement

We take pride in delivering a safe, reliable, and cost-effective electricity service to our customer owners. To maintain this, given the opportunities and challenges we face in the coming years, we need to continually improve our capabilities. This will be especially important as we ramp up expenditure to ensure the ongoing reliable and safe operation of the electricity network and ensure our network is future-ready to support our customers' energy choices.

- While our current approach represents typical, and in some areas, leading practice among New Zealand EDBs, we recognise that the very best operators in other jurisdictions (such as Australia, the UK, and elsewhere) are moving to deploy more advanced asset management techniques.
- We face challenges in relation to stabilising asset health, ensuring future resilience, and continuing to maintain a safe and reliable service for customers. We need to ensure our investments that address these issues are efficient and prudent. This requires effective analysis and modelling, underpinned by sound engineering.
- Energy markets are changing and evolving. We are seeing total energy use per household change, and increasing use of new technologies, which may have material impacts on total energy volumes. This situation requires a more refined approach to load forecasting and network planning.
- Both operational and information technology continue to evolve quickly, and we now have access to data and systems which offer the potential to support more granular and incisive asset management decision making.

Recognising the need for improvement in our asset management approach and the challenges we and the wider electricity distribution industry face, we have developed a continuous improvement programme.

### Continuous improvement initiatives

Building on our assessment, we have begun a process to improve our asset management processes and capabilities. The following table summarises the main initiatives that we have begun or plan to start in FY26/27.

**Table 6.3:** Asset management improvement initiatives

Function/area	Initiative
<b>Asset management framework and strategies</b>	We have set up a document hierarchy to support our asset management framework and strategies. We will continue to build out this important material to ensure our asset management approach is applied consistently across the business.
<b>Communications plan</b>	We have aligned our electric strategy with our Asset Management Strategy. They also reflect in individual asset strategies as well as business cases which forms a key component of our asset management delivery plan. Our steering committee is represented well through various business divisions ensuring awareness and participation throughout affected departments. There is scope to develop a formal communication and engagement plan to inform our stakeholders of appropriate asset management information and to promote increased awareness within the wider organisation of the asset management system as a whole, and how it informs asset management decisions.
<b>Competency framework</b>	We are developing a competency framework that outlines the competencies required for asset management related roles. The framework will ensure we have training in place for competency levels to be reached. We have initiated the development of a competency framework for certified workers to access or undertake work on or in close proximity to our network.
<b>Asset information</b>	Building on our new asset information strategy, we will review our asset information standards to ensure that we are capturing the data we require to effectively implement our asset management strategies.
<b>Asset management information system</b>	Our current AMIS has limitations and will not fully support our future requirements. We have completed the functional design for our new system and a programme is underway to implement a new system.

Function/area	Initiative
<b>Asset risk modelling</b>	<p>We have developed a suite of asset health and forecasting models for a large number of our fleets, including trialling new asset modelling software. Based on the outcomes of the trial, we will roll this out across more fleets.</p> <p>We have developed our asset criticality framework for 11kV overhead circuits and have built our first iteration to determine the consequences of failure of our assets. We will continue to expand the modelling to our LV overhead networks and subtransmission networks while continuously improving existing models.</p> <p>We are also planning to improve and verify our probability of failure (POF) models to understand asset health.</p> <p>Effective POF and criticality modelling will improve our understanding of asset risk and support more risk-driven investment decisions.</p>
<b>Event management process</b>	<p>Improvements have been made to our event management process to ensure all events are appropriately escalated and resolved and, where required, are investigated. We have updated our incident procedure process and both investigations and corrective actions are tracked regularly to ensure learnings are embedded back into the business.</p>
<b>Further assessments</b>	<p>We are working to embed continuous improvement further to ensure learnings and improvements are becoming part of day-to-day operations. We plan to carry out a more complete review of our asset management system and this will help to inform our asset management maturity initiatives.</p>
<b>GIS upgrade</b>	<p>We are replacing the legacy GIS platform with a modern GIS platform. This will address data quality, integration and support risks, delivering a future-ready spatial system that underpins safe network operations and enables improved asset management, system integration and data-driven investment decisions.</p>
<b>Maintenance optimisation</b>	<p>Conduct a thorough review of our preventative maintenance plan to manage risk efficiently and ensure cost-effective, targeted maintenance.</p>
<b>Procurement capability</b>	<p>Develop, document and implement robust spend analysis, procurement pipeline and category management processes to strengthen procurement maturity.</p> <p>Establish a collaborative partnership with Energy Services' Procurement, including agreed performance and reporting metrics, and undertake a comprehensive Procurement Strategy review to ensure alignment with organisational objectives.</p>

The aim of these improvement initiatives is to ensure we continue to provide customers with a safe and reliable electricity service that meets their needs and expectations, while maintaining affordability. These initiatives support improved efficiency and are directed towards aspects of our business where improvement will bring the most benefit. The initiatives are aligned with and support our asset management objectives.

The links between these types of initiatives and improvements to service quality or efficiency gains is complex and often lagged. As a result, we expect that the impact of these initiatives on our performance will be gradual, noting that many of them will take a number of years to fully implement.





## Chapter 7

# Risk Management

## 7.1 Introduction

Risk management is a critical component of good asset management<sup>1</sup>. The consideration of risk plays a key role in Northpower's asset management decisions — from network planning and renewal decisions, through to operational decisions. The assessment of risk and the effectiveness of options to minimise it is one of the key factors in our investment choices.

Risk management at Northpower is fundamentally about delivering on our commitments (to our customers, communities, and people) and meeting stakeholders' expectations.

We are committed to managing risk proactively and consistently to:

- ensure a safe and secure environment for our people, partners, and consumers
- support our purpose, ambition, objectives, and commitments as expressed in our Statement of Corporate Intent (SCI)
- pursue opportunities in an informed way, aligned with our risk appetite.

Our approach to risk management is grounded in our belief that:

- every person at Northpower has a responsibility to identify and manage risks
- a healthy and collaborative culture is a vital part of our risk management
- effective risk management relies on sound judgement, supported by clear evidence
- we can always improve.

In this chapter, we explain how diligent risk management strengthens our ability to deliver a service that is safe, secure, and reliable.

## 7.2 Our risk management context

Our customers and communities depend on our service, so it is essential we identify and manage risks related to the delivery of a reliable, resilient, and safe electricity service. We recognise we need to be able to continue to supply electricity to our community following adverse events, including natural disasters such as major storms. For further context, our region is subject to the risk of tsunami and extreme weather events, including tropical cyclones.

Our lifelines duties are set out in Section 60 of the Civil Defence Emergency Management (CDEM) Act. As a lifeline utility, we must be able to fully function, even though this may be at a reduced level during and after an emergency.

It is critical that we assess potential risks to our business and develop and implement robust strategies to mitigate these risks. Our Board and Executive Leadership Team (ELT) are committed to ensuring that our exposure to risk is at an acceptable level and that we comply with all applicable laws and regulations.

Our risk appetite statement articulates the amount and type of risk that we are willing to take in pursuit of our ambition and strategic objectives, see Section 7.3.4.

<sup>1</sup> Note: We have formal corporate risk management strategies and procedures in place as well. In this AMP the focus is on asset risk management.



## 7.3 Risk management framework

Our Risk Management and Legal Compliance Policy and Framework is aligned to ISO 31000:2018. The policy sets out high-level principles, and the framework outlines our approach to managing risk and achieving compliance. A key objective of the framework is ensuring we operate robust, consistent, and coherent risk management and compliance processes.

Consistent with our risk management and legal compliance policy and framework, our approach to risk management is carried out in accordance with, or informed by, relevant standards and legislation. These include the following:

- ISO 31000:2018 Risk Management – Guidelines.
- AS/NZS 7901:2014 Electricity and Gas Industries – Safety Management Systems for Public Safety
- Electricity Engineers' Association (EEA) Resilience Guide (2022)
- EEA Asset Criticality Guide (2019)
- Health and Safety at Work Act 2015
- Electricity Act 1992 and Regulations
- Resource Management Act 1991
- ISO 45001:2018 Occupational Health and Safety Management Systems
- ISO 14001:2015 Environmental Management Systems

Our Risk Management and Legal Compliance Framework is reviewed by the Northpower audit and risk committee and approved by the Board at least every two years.

### 7.3.1 Principles and objectives

The objectives of our Risk Management and Legal Compliance Framework are to ensure that Northpower operates a robust, consistent, and coherent risk management and compliance process. This ensures an appropriate level of risk is maintained.

The framework recognises that the purpose of risk management is the creation and protection of value and ensures that the approach is:

- customised to Northpower's business activities
- integrated into Northpower's activities
- structured and comprehensive
- inclusive, ensuring that there is appropriate and timely involvement of stakeholders
- dynamic, by anticipating, detecting, acknowledging, and responding to change
- utilising the best available information
- taking human and cultural factors into account
- continually improved through learning and experience.

### 7.3.2 Risk management methodology

Our risk management methodology combines a top-down strategic assessment of risk against our risk appetite. This takes account of the external business environment. The top-down approach is complemented by the bottom-up operational identification and reporting processes. This includes the review and assessment of business unit risk registers.

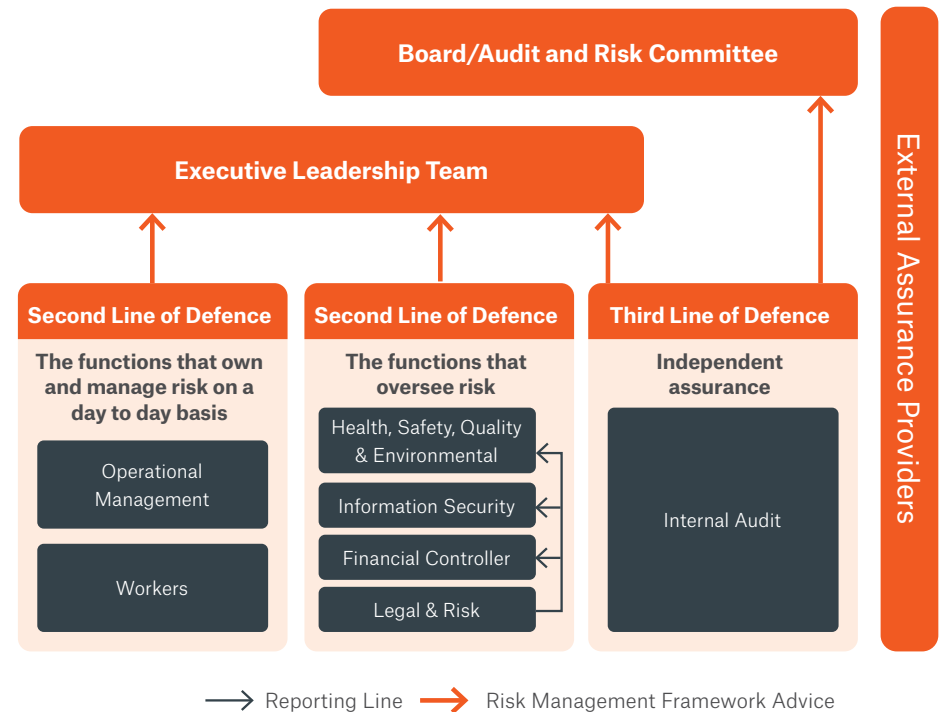
Figure 7.1: Risk management approach



### 7.3.3 Three lines of defence

We adopt a 'three lines of defence' approach to risk management. This approach provides an effective way to enhance communications around risk management and control by clarifying essential roles and duties.

Figure 7.2: Three lines of defence



The first line of defence is the operational management and workers that own and manage risk on a day to day basis. Management has ownership of the internal control measures and is responsible for ensuring they are operating at a level that mitigates risk to an acceptable level, in line with the risk appetite set by our Board. The responsibilities of the first line of defence includes reporting, escalating, and managing incidents, hazards, and safety concerns.

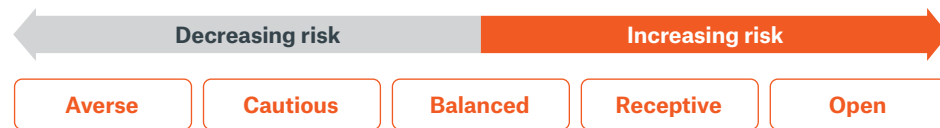
The second line of defence is the functions that oversee risk, including the Financial Controller, Health, Safety and Environment, quality, legal and risk. The responsibilities of the second line of defence include providing frameworks and assisting operational management to develop processes and controls to manage risk.

Internal audit sits as the third line of defence. It is the function that provides independent assurance on the effectiveness of risk management in the first two lines of defence. The first two lines report directly to senior management, while internal audit reports to both senior management and the Board of Directors.

### 7.3.4 Risk appetite

Our risk appetite statement (RAS) sets out the amount and type of risk that we are willing to take in pursuit of our ambition and strategic objectives. To aid this process we use the following risk appetite scale.

Figure 7.3: Risk appetite scale



We have a balanced appetite relating to network performance risk and an averse/cautious appetite relating to safety risk.

Our risk appetite approach has four key stages:

- 1. Agree:** our risk appetite is reviewed and confirmed on at least an annual basis. This normally happens in parallel with the strategy review process. Board workshops discuss and agree on risk appetite for each of our principal risks.
- 2. Articulate:** following Board agreement, statements on risk appetites are developed for each principal risk. Appropriate metrics with defined limits are then agreed upon to measure whether we are operating within risk appetite. Targeted management action is required if Northpower is operating outside of the defined limits.
- 3. Cascade:** following approval by the Board, a RAS is made available to staff. Our staff must ensure that consideration of risk appetite is embedded in day-to-day decision making (for example, business cases)
- 4. Monitor, report, and correct:** the approved metrics and any associated action plans are reported to the Board.

We aim to manage our electricity network in a way that ensures it achieves stable performance at a reasonable cost. We have a very limited appetite for assets failing in a way that results in prolonged outages to a significant proportion of our electricity network customers; or an inability to remain operational as a business. We accept that outages will occur from time to time, provided we can remobilise quickly. We accept that prolonged outages will occur in exceptional circumstances (such as extreme weather events) and we have plans in place to recover network function within a reasonable period.

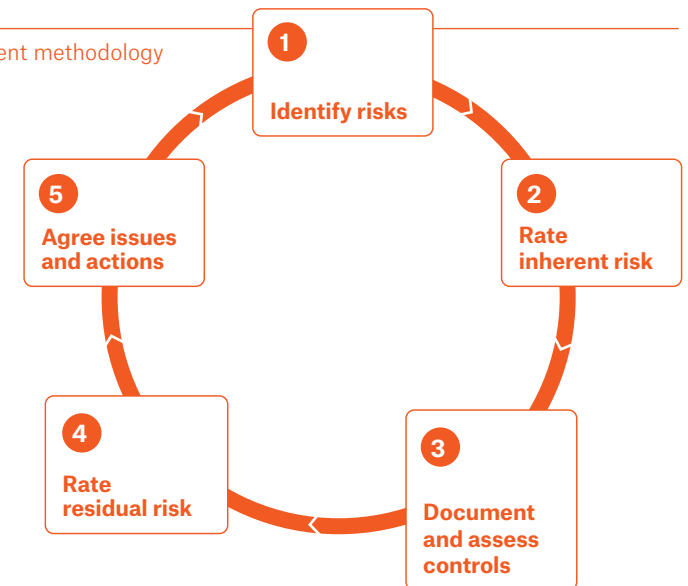
The safety of our staff and the public is of paramount importance. Health and safety risks are to be eliminated where possible or mitigated to the lowest reasonably practicable level when elimination is not possible. Where we cannot eliminate critical health and safety risks, we require critical risk controls in place and monitored.

### 7.3.5 Risk assessment

Our risk assessment methodology adopts the following approach:

- 1. Identify risks:** processes and stakeholders identify new, emerging, and changing risks. Specific details relating to how the risk materialises are captured, along with causes and consequences.
- 2. Rate inherent risk:** the consequence and likelihood of each risk is assessed on an inherent basis (for example, before consideration of the current control environment) using predefined parameters, and the rating is determined using our risk matrix.
- 3. Document and assess controls:** key controls in place to mitigate the risks are identified, documented, and assessed to determine an overall control effectiveness rating.
- 4. Rate residual risk:** the consequence and likelihood of each risk is then assessed on a residual basis (such as after consideration of controls) using predefined parameters, and the rating is determined using our risk matrix, see Figure 7.4.
- 5. Agree issues and actions:** based on the residual risk assessment, we form a view on the response required. The escalation and treatment protocol for each risk is determined based on the residual risk assessment.

Figure 7.4: Risk assessment methodology



### 7.3.6 Risk matrix

Network risk assessment and reduction, where economically feasible, forms an important part of overall asset management for electricity distribution networks. A wide range of events with differing probabilities and consequences are usually evaluated, with the results tabulated in a risk matrix format so the risk profile of a particular network can be evaluated.

Northpower’s Risk Management and Legal Compliance Framework sets out the approach we adopt to manage risk and achieve compliance. This framework includes a requirement to, on at least an annual basis, conduct a risk workshop to assess key network risks, determine any action that is required, and capture these in our risk register.

Figure 7.5: Risk matrix

Likelihood					
<b>Almost certain</b> (multiple times a year)	Low	Medium	High	Very High	Very High
<b>Likely</b> (once a year)	Low	Low	Medium	High	Very High
<b>Possible</b> (at least once every 1 to 3 years)	Very Low	Low	Medium	High	Very High
<b>Unlikely</b> (at least once every 3 to 10 years)	Very Low	Low	Low	Medium	High
<b>Rare</b> (less than once every 10 years)	Very Low	Very Low	Low	Medium	Medium
	Insignificant	Minor	Moderate	Major	Critical
	Consequence				

Table 7.1: Risk escalation and treatments

Risk rating	Risk escalation and treatment
<b>Very High</b>	<ul style="list-style-type: none"> <li>- Immediate escalation for Board attention.</li> <li>- Detailed plans to mitigate the risk required.</li> </ul>
<b>High</b>	<ul style="list-style-type: none"> <li>- Escalation for Chief Executive and ELT attention.</li> <li>- Board advised through normal reporting process.</li> <li>- Detailed plans to mitigate the risk required.</li> </ul>
<b>Medium</b>	<ul style="list-style-type: none"> <li>- Escalation to management required.</li> <li>- Plans to mitigate or senior management approval to maintain the risk required.</li> </ul>
<b>Low</b>	<ul style="list-style-type: none"> <li>- No further escalation required.</li> <li>- Consideration to be given to the implementation of appropriate cost-effective measures to further mitigate the risk.</li> </ul>
<b>Very Low</b>	<ul style="list-style-type: none"> <li>- No further escalation or treatment required.</li> </ul>

### 7.3.7 Risk records

A risk record is maintained for each risk that is applicable to our electricity network business. This includes:

- risk description
- causes and consequences of the risk
- description and assessment of the external environment relating to the risk
- inherent risk rating
- key controls in place to mitigate the risk and an assessment of control effectiveness
- residual risk rating
- key issues that need to be addressed.

### 7.3.8 Risk review

Risk workshops are held at least annually with senior management in our network business to assess the key risks, using the approach outlined above, to support achievement of our strategy and business objectives. Priority is given to progressing action plans that will mitigate the highest residual risks. Risks are reviewed at least quarterly to track progress of agreed management action plans. We then re-rate risks where appropriate to reflect control improvements or the identification of any new issues.

The results of the annual risk workshop and quarterly risk reviews are reported to our Board.

## 7.4 Managing our key risks

Our risk management activities include controlling safety risks, avoiding capacity constraints, managing failure likelihood through maintenance and renewals, and ensuring resilience to help mitigate the consequences of major events.

Consideration of risk plays a key role in our asset management decisions, from network planning and asset replacement decisions, through to operational decisions. Our asset management systems and our core planning processes are designed to manage existing risks, and to ensure that emerging risks are identified, evaluated, and managed appropriately.

There are many types of risk associated with electricity networks, some of which include:

- **safety risk:** electricity network assets and some asset management activities may pose hazards to our staff and the general public.
- **asset risk:** the possibility of damage to equipment, structures, and assets from third parties, bad weather, and natural events such as earthquakes and floods.
- **operational risk:** risk of equipment failure or human error that can result in outages.
- **cybersecurity risk:** as more systems in the electricity network become connected and automated, the risk of cyberattacks increases. This could lead to the disruption of supply and damage to equipment.

It is important for us to manage these risks effectively in order to ensure the reliable and secure operation of our electricity network.

The following sections set out the main types of risk that will be most relevant to the electricity business over the AMP planning period and discusses how we aim to manage them.

### 7.4.1 Safety

Safety is our foremost organisational value. We take an uncompromising approach to safety and will act when we believe there are safety risks for the public, our staff, and service providers. We need to proactively safeguard those working on our network as well as the wider public. Furthermore, as an employer, we aim for an injury-free workplace and actively promote the wellbeing of our people.

Our Health and Safety Management Framework enables the consistent and consolidated management of all our risk management obligations.

#### Source of risk

Our electricity network assets and some asset management activities may pose hazards to our staff and the general public. Some examples include power lines down, low-lying conductors, and pillar fires.

We have identified 10 critical risks associated with the management and operations of our electricity network. These are considered to be risks with the potential for catastrophic consequences.

Figure 7.6: Northpower's critical risks



Activities by the general public can lead to a range of safety risks, including:

- **general public:** contact with our assets (for example, car versus pole, vandalism or theft, unauthorised access to our assets or sites)
- **landowners:** vegetation care or management around our assets (for example, pruning)
- **trades and hauliers:** excavations striking cables, working in close proximity to live assets, oversize loads contacting overhead assets
- **developers and civil contractors:** excavations striking cables, oversize equipment coming into contact with overhead assets.

## Approach to safety risk management

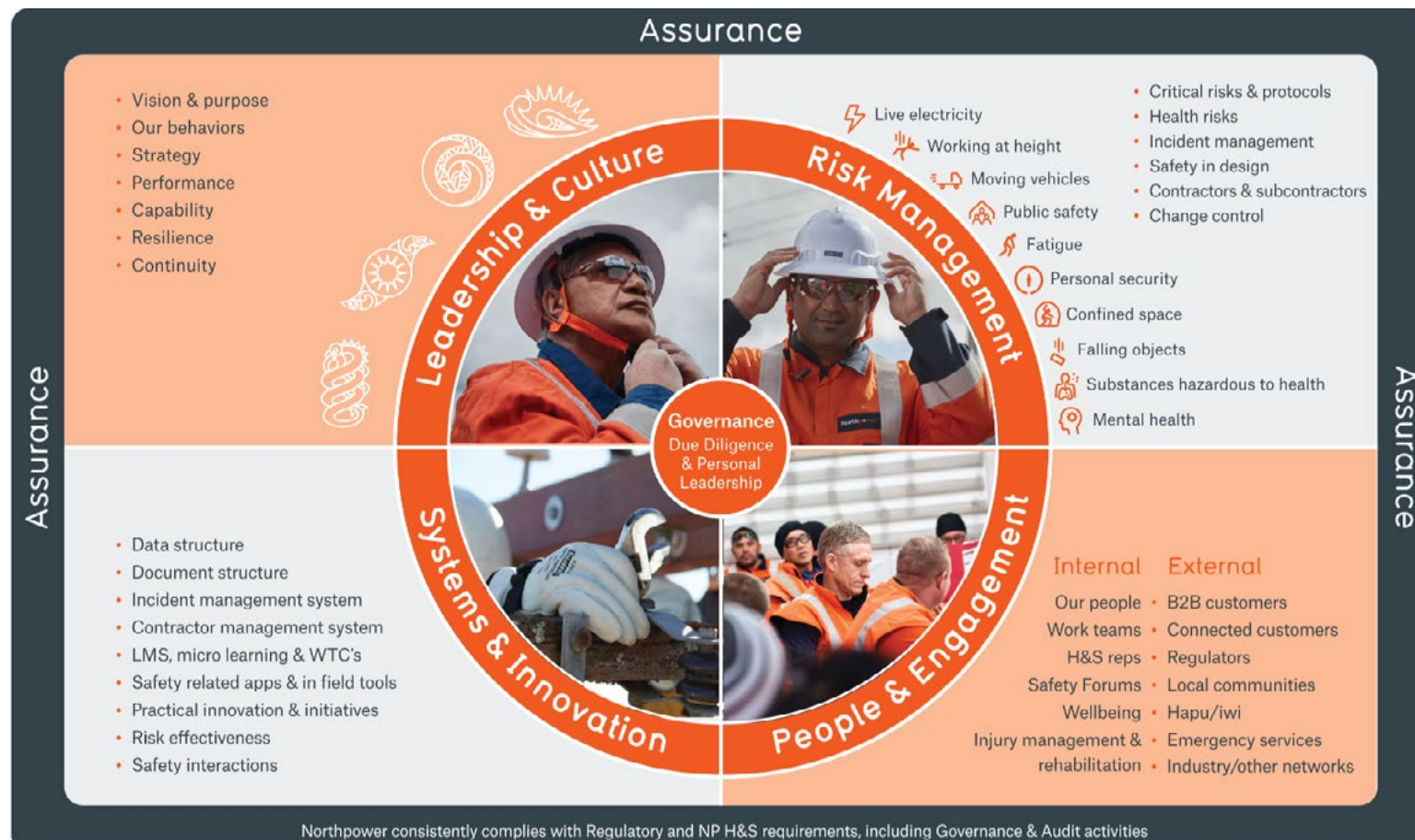
We continue to improve existing controls and adopt more effective ones for each of these critical risks. Our network has a focus on the controls relating to the critical risk of live electricity under direct network operational control.

We manage our assets to maintain their condition and performance to mitigate safety risk. We achieved this with our renewal investments, operations, and maintenance activities.

We use procurement as a strategic objective to embed safe equipment throughout our construction programmes and alignment with our design standards.

We regularly engage with and educate our community regarding public safety and our communication is aligned to raise awareness, promote safe behaviours and ensure the public has access to timely and accurate information.

Figure 7.7: Northpower's Health and Safety Management Framework



Effective health and safety performance revolves around people. As shown in Figure 7.7, our approach to health and safety encompasses the relationships between our people, the work they do, and the environment they do it in, held together with leadership and assurance practices.

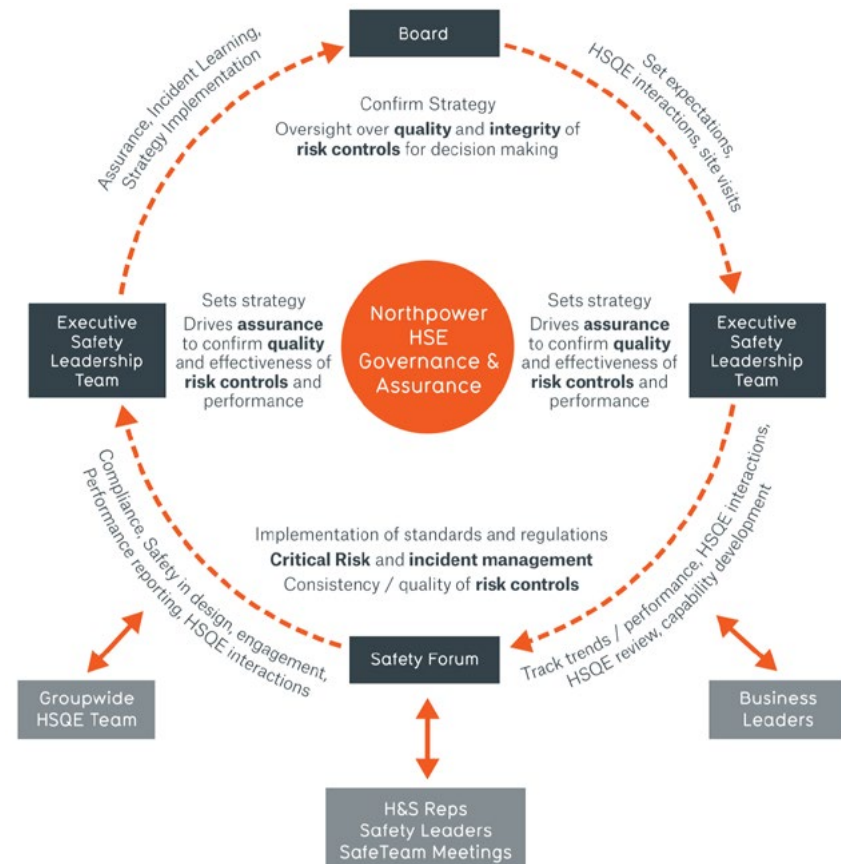
Northpower operates a public safety management system in four domains:

- asset description (including assets, service area, and demarcation)
- risk identification, risk assessment, and treatment of significant risks (including documentation, reviews, and information)
- safety and operating processes (including documentation, responsibilities, legislation, emergency, competencies, change, and incidents)
- performance monitoring (including audits and key performance indicators).

We have adopted the International Council on Mining and Metals' Health and Safety Critical Control Management: Good Practice Guide and Implementation Guidance to support our approach to managing our critical risks. We use bow tie methodology to identify the causes and consequences of material unwanted events, which have a critical people safety consequence.

Figure 7.8 outlines governance and assurance accountabilities, consultation, communication flows across Northpower, and two-way engagement with our safety forums.

Figure 7.8: Northpower's Health and Safety Governance and Assurance



We use a plan-do-check-act cycle, forming a continuous improvement approach that encourages iterative improvement. This is consistent with the hazard management methodology prescribed in the legislative framework for health and safety.

**Table 7.2:** Plan-do-check-act cycle

<p><b>PLAN</b> Identify and assess hazards and safety risks</p> <ul style="list-style-type: none"> <li>✓ <b>hazard reporting:</b> through our health and safety reporting system. It is the mechanism to report suggestions for improvement, hazardous conditions or behaviours, and incidents.</li> <li>✓ <b>safe work method statements:</b> conducting job/tasks analysis, emphasising the work health and safety requirements.</li> <li>✓ <b>experience:</b> workers learn on the job and gain experiences with the hazards and risks they have encountered while working.</li> <li>✓ <b>hazard profile:</b> using risk registers to identify and assess health and safety risks.</li> <li>✓ <b>industry experience (EEA, Electricity Networks Aotearoa, peer utilities):</b> our relationships with local industry in the Northland region, with other electricity distributors nationally, and with industry groups.</li> </ul>	<p><b>CHECK</b> Monitor the effectiveness of control measures</p> <ul style="list-style-type: none"> <li>✓ <b>asset inspections:</b> inspection programmes to identify assets that may pose safety risks, for example, due to increased likelihood of failure.</li> <li>✓ <b>event reviews:</b> relevant managers meet fortnightly to review high potential events and events of significance. Investigations of these events are reviewed and actions are taken as required to share learnings or improve processes.</li> <li>✓ <b>worksite auditing:</b> monthly worksite audits to assess hazard and risk awareness and verify that controls are being applied and are effective.</li> <li>✓ <b>safety leadership:</b> senior leaders conduct visits and discuss with the worksite team members the hazards and risks, and the controls they are using to manage these.</li> <li>✓ <b>safe teams:</b> monthly team meetings to disseminate health and safety information, and an opportunity for all staff to highlight health and safety issues in their areas.</li> <li>✓ <b>industry learnings:</b> circulating lessons learned from EEA and other groups on incidents or events that have occurred in their business.</li> <li>✓ <b>external audit:</b> periodic external auditing of health and safety systems, such as hazard and risk management, including against the requirements of ISO 4801:2001.</li> </ul>
<p><b>DO</b> Eliminate and minimise hazards and risks</p> <ul style="list-style-type: none"> <li>✓ <b>emergency management:</b> responding to incidents, making sites safe, and recovery.</li> <li>✓ <b>incident management:</b> responding to incidents, investigating them, and drawing learnings from these to share with individuals and teams.</li> <li>✓ <b>network operations centre (NOC):</b> coordinate workers in the field, providing access permits that isolate workers from electrical hazards and risks.</li> <li>✓ <b>security:</b> electrical assets, such as zone substations and transformers, are locked and secured against unauthorised access.</li> <li>✓ <b>work instructions:</b> detail the methodology required for the task being undertaken to control hazards and risks.</li> <li>✓ <b>work type competency:</b> prescribing competency requirements for workers who access or undertake work on or near the network. This ensures they are competent for the tasks.</li> <li>✓ <b>training:</b> assigning competency requirements to tasks and recording completed training.</li> <li>✓ <b>personal protective equipment (PPE):</b> is provided to our workers.</li> </ul>	<p><b>ACT</b> Review and improve control measures</p> <ul style="list-style-type: none"> <li>✓ <b>board review:</b> the board reviews the operation and management of the network. This includes its health and safety performance, and review of hazards and risks.</li> <li>✓ <b>safety governance steering committee:</b> responsible for overall management of health and safety, providing oversight and guidance on needed improvements.</li> <li>✓ <b>document reviews:</b> network standards, work instructions, safe work method statements, and other controlled documents undergo periodic review. Updated documents and communications are circulated to stakeholders.</li> <li>✓ <b>management review:</b> executive management team review effectiveness of controls in light of risk appetite statement.</li> </ul>

## 7.4.2 Network asset performance

We aim to manage our network in a way that delivers stable performance at a reasonable cost. We have a very limited appetite for asset failures that result in prolonged outages to a significant proportion of our electricity network customers. Outages will occur from time to time, and it is important that we can remobilise quickly and ensure that outages do not overly impact our performance.

### Source of risk

Managing asset performance is a key part of effective risk management. Addressing asset risk is a focus of our asset management decision making, from network planning and asset renewal decisions, through to operations and maintenance. The assessment of risk and the effectiveness of options to minimise risk are key drivers of our investment choices.

Electricity networks have several potential risk sources. These are inherent in the assets used and the functions they perform. The key sources of risk on our network are:

- **asset failure:** equipment can fail due to a variety of reasons, including poor condition, lack of maintenance, and manufacturing defects
- **ageing assets:** over time, our network assets deteriorate and become more prone to failure, requiring repair or renewal
- **obsolescence:** assets can become obsolete or inoperable, leading to reduced performance or increased risk of failure
- **third-party interference:** accidental or deliberate damage to assets by third parties, such as contractors or the public
- **increasing demand:** as our communities grow and customers use more electricity (for example, for EVs), demand will increase. Network upgrades help ensure we can meet increased demand and continue to provide reliable service to customers
- **legacy equipment:** these are items of equipment that may be at higher risk of failure due to type issues
- **environment:** exposure to environmental factors such as heat, moisture, and UV radiation can increase the risk of asset failure
- **human error:** during installation, maintenance, or operation of equipment can increase the risk of asset failure or damage.

We use records of historical incidents and asset failures, inspection data, staff experience, and modelling to identify asset risk on our network. By identifying and mitigating these sources of asset risk, we reduce the likelihood of asset failure, helping to maintain reliability and safety of the network.

## Approach to risk management

Our asset management systems and planning processes are designed to manage existing risk and to ensure emerging risks are identified, evaluated, and managed appropriately.

Managing asset risk involves implementing strategies to identify, assess, and mitigate the risks associated with the assets used in the network. We achieve this through a few steps including the following:

- **risk identification:** involves monitoring and inspecting assets including their performance, condition, and criticality
- **risk assessment:** involves assessing the risk associated with each asset, taking into account factors such as age, condition (health), performance, and potential consequences (criticality)
- **risk mitigation:** measures to mitigate the risks associated with each asset, such as maintenance, upgrades, and renewal of ageing assets
- **monitoring and review:** monitoring the condition and performance of assets through inspections, and refining our planned interventions to ensure they remain effective over the planning period
- **operational readiness:** developing and testing response plans for severe weather, equipment failures, and other incidents to ensure a rapid and effective response in the event of an outage.

We identify practical interventions that can be applied to mitigate the risks, according to their likelihood and consequence, to ensure the residual risk is at an acceptable level. These mitigation measures are a key input into developing our intervention strategies for network upgrades, maintenance, and renewals.

- **network upgrades:** includes increasing capacity of our assets and network to ensure that they can meet this increased demand and provide reliable service to customers. Our approach is set out in Chapter 8.
- **asset maintenance:** includes inspections and repairs designed to identify and manage existing or potential risks associated with our assets. The goal of our asset condition monitoring approach is to ensure that assets are replaced before their condition and probability of failure starts to deteriorate to an unacceptable level. Our approach is set out in Chapter 9.
- **asset renewal:** assets are generally planned for replacement when the asset's health deteriorates beyond acceptable limits. Our visual inspection and test regimes ensure that the condition of our assets is monitored and that they are maintained or replaced prior to failure. We are also continuously advancing our methodologies for individual asset classes to place greater emphasis on risk-based assessments, rather than relying primarily on asset condition as the main driver. Our approach is set out in Chapter 9.

### Box 7.1: Asset risk modelling

We identify the need for asset renewal using a combination of asset health and asset criticality. Initial identification of assets is based on asset health modelling, while our criticality framework will be used to prioritise renewals during the planning period.

We are continually developing our health modelling and probability of failure modelling to gain a better understanding of our assets and to support better investment decision making. We are currently developing a consistent approach to asset criticality modelling to enable better risk-based prioritisation, and to ensure we keep the overall fleet risk at a manageable level as our asset fleets age.

These interventions result in a range of investments and activities which make up our AMP capex and opex forecasts.

### 7.4.3 Digital asset performance

Information technology is key in ensuring our network operates safely and reliably. Our digital asset performance risk relates to poor reliability or performance of critical information technology systems and processes. This includes protection of our systems against cybersecurity threats. Digital asset performance risk management provides confidence that our systems are secure, with the right level of controls. Overall, we need to ensure the availability and resilience of system capabilities that enable our electricity operations.

#### Source of risk

Potential consequences of this risk include network disruption, reputational damage, regulatory scrutiny, litigation, and financial loss. We have identified the following as the key potential sources of this risk:

- under-investment in lifecycle renewals
- poor system configuration and change management practices
- insufficient maintenance of information technology
- environmental factors (such as heat and dust) that impact the performance of equipment
- insufficient capacity planning
- inadequate redundancy
- cybersecurity attacks.

Of the above digital asset risks, cybersecurity is becoming increasingly important. We need to maintain leading edge cyber resiliency that can both combat the rise in cyberattacks and protect internal systems to maintain capability and services.

### Approach to risk management

We manage risk to our digital asset performance by maintaining a risk register which is continuously assessed, categorised, grouped, and prioritised.

In our risk register we have collated risks from across the business and extracted from our externally assessed Security Maturity Assessment and our top risks are:

- supplier/third-party cyber risk management
- operational technology (OT) cybersecurity uplift
- Cyber Risk Management Strategy
- security awareness and training
- end of life (EOL) operating systems and applications
- vulnerability management

### 7.4.4 Environmental

Managing environmental risk is a crucial aspect of ensuring the safe and sustainable operation of our electricity network. To manage these risks, we use a proactive and systematic approach to risk assessment and management.

#### Source of risk

Long-term sustainability and environmental performance of our business will depend on our ability to understand and mitigate, as far as practicable, the risks our assets and activities pose to the wider environment. These risks include:

- **sulphur hexafluoride leaks:** SF<sub>6</sub> is widely used as an insulating gas in electrical equipment but is also a potent greenhouse gas that has a high climate change potential. Accidental releases of SF<sub>6</sub> can occur during maintenance, servicing, and other activities, and can contribute to the overall levels of this gas in the atmosphere
- **oil leaks:** from transformers can have significant environmental impacts. Transformers contain large amounts of oil. Leaks can potentially contaminate soil and groundwater. Leaking oil can also pose a fire risk
- **recycling:** we recycle equipment and other materials, where practical, to minimise the environmental impact of waste disposal and to conserve resources
- **waste disposal:** if not managed correctly, waste disposal can pose environmental risks. Redundant assets can contain waste such as metals, printed circuit boards, insulating liquids, and other materials with hazardous substances that may harm the environment if not disposed of properly.

Given the increasing impact of climate change, we cover this separately in Section 7.4.5.

## Approach to risk management

Our environmental management system supports increased environmental capability and management of risk, ensuring regulatory compliance. We are certified to the international standard ISO 14001:2015 Environmental Management Systems (EMS). This certification is evidence that we operate to a compliant environmental management plan with clearly articulated processes.

Environmental risk management is undertaken through application of a plan, do, check, act process, with an emphasis on continuous improvement.

**Figure 7.9:** Electricity network Environmental Management Framework



Improvements to our environmental management processes include monitoring and reporting of a suite of environmental metrics, see Chapter 4. Robust assurance processes provide evidence of our environmental performance and support policies and initiatives including:

- **sulphur hexafluoride leaks:** minimise future use of SF<sub>6</sub> and implement measures to reduce the risk of accidental releases by ensuring equipment is properly maintained and disposed of
- **oil leaks:** regularly inspect and maintain oil-filled transformers in tandem with effective spill response and clean-up plans to minimise the impacts of oil leaks if they occur
- **waste management:** properly identify, label, and dispose of hazardous waste in accordance with relevant regulations
- **other initiatives:** include waste reduction programmes and recycling.

By effectively managing environmental risks, we ensure the continued safe and sustainable operation of our network and minimise the impacts on customers and the environment.

### 7.4.5 Climate change

Climate change has the potential to affect the way customers use electricity and to adversely impact the performance of electrical networks. As a result, climate change poses a number of material risks to our network and its performance.

With a measure of climatic change already locked in, adaptation becomes as important as mitigation. We recognise we have a critical role to play in both for Northland. This is reflected in the evolution of our asset management approach to develop a more resilient network.

### Sources of risk

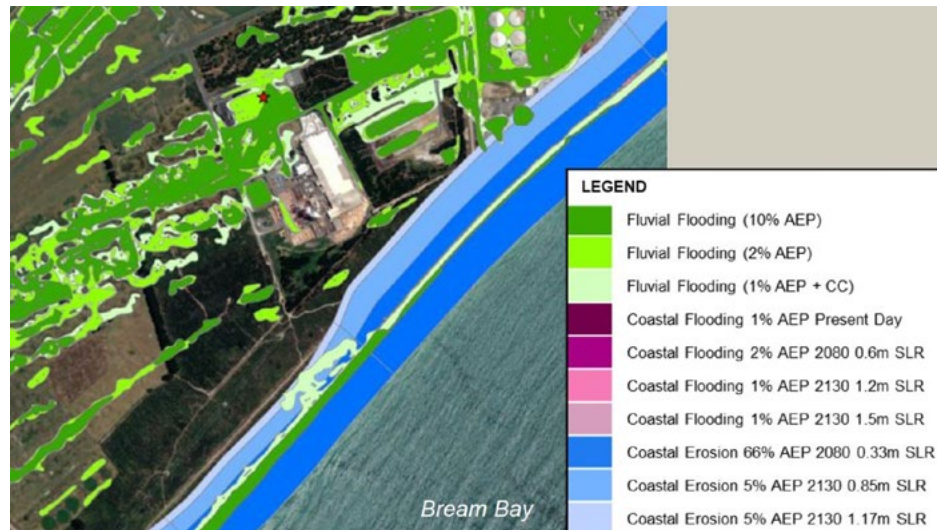
We recognise that to ensure a reliable network we need to be ready to adapt and respond to climate change impacts, particularly where there is proven risk of the potential for more extreme events. We are aware of the potential impacts that climate change may have on our electricity network.

- **Severe weather:** more frequent/severe windstorms with increased likelihood of lightning. Longer outages and more damage to exposed infrastructure from more extreme events (such as floods, droughts, and high wind).
- **Increasing temperatures:** leading to reduced current-carrying capacity of lines and transformers, and increased losses in lines due to operating at elevated temperature. Likely to increase network demand due to increased use of cooling.
- **Sea level rise:** leading to increased flooding risk and storm surges, particularly during high tides. Increased likelihood of flooding/damage to coastal/low-lying infrastructure.
- **Bushfire risk:** potential for more fire starts with more fuel (due to drier vegetation).

- **Increasing rainfall and ground instability:** increasing likelihood of flooding impacting infrastructure at ground level or in low-lying areas. Damage to facilities and infrastructure related to soil erosion and slips.
- **Environmental changes:** higher and more prolonged levels of humidity reducing equipment performance and the need to control faster growing vegetation.

Through our involvement in the Northland Lifelines Group (NLG), we have a broader insight into the impact our service has on other utilities and how climate change driven service interruptions could impact other utilities. The group maintains a map of the interdependencies across each sector and has documented infrastructure risk profiles for a wide range of hazards. Work undertaken by the NLG considers infrastructure climate change risk across the energy, water, transport, and telecommunications sectors.

**Figure 7.10:** Example hazards map



We will evaluate potential impacts of credible scenarios, based on what we are seeing regionally and nationally, and formulate actions to address any probable shifts. We will also review our planning approach considering potential credible impacts of climate change in the project development phase, as well as our operations and emergency response.

### Climate change related initiatives

We have undertaken a high-level review of these risks and continue to review and reset our response plans. In time, more detailed modelling of climate change induced impacts through scenario analysis will be used.

The following table lists strategies and actions to better understand and address the potential impacts of possible climate scenarios on our electricity assets.

**Table 7.3:** Potential climate change mitigations

Risk	Potential Mitigations
<b>Severe weather</b>	<ul style="list-style-type: none"> <li>Implement more rigorous structural standards.</li> <li>Review our current risk-based approach to vegetation management.</li> <li>Investigate options to reduce impact of airborne debris on critical assets (lines and outdoor switchyards).</li> <li>Review suitability of design standard for assets.</li> <li>Consider greater diversity of supply routes to improve resilience.</li> </ul>
<b>Increased air temperatures</b>	<ul style="list-style-type: none"> <li>Increase thermal rating and capacity of assets.</li> <li>Use of more heat-resistant materials.</li> <li>Implementation of more effective cooling for transformers.</li> <li>Peak load shedding.</li> <li>Research availability of more appropriate equipment.</li> <li>Consider options to improve future load forecasting.</li> </ul>
<b>Sea level rise</b>	<ul style="list-style-type: none"> <li>Build in and/or relocate to less exposed locations.</li> <li>Raise structure levels.</li> <li>Improve drainage systems.</li> <li>Engage with local district and regional councils to understand their forecasted changes to sea levels, likely areas impacted, timeframes and plans for managed retreat.</li> </ul>
<b>Bushfire</b>	<ul style="list-style-type: none"> <li>Revise and improve bushfire mitigation options.</li> <li>Consider the option to underground of equipment.</li> <li>Examine other bushfire mitigation strategies (operations and equipment selection).</li> </ul>
<b>Increasing rainfall and ground instability</b>	<ul style="list-style-type: none"> <li>Improve flood protection for equipment at vulnerable locations (such as flood plains, overland flow paths, erosion prone land).</li> <li>Position new equipment in flood-free areas.</li> <li>Transition to more indoor equipment with humidity control.</li> <li>Scan network for assets in low-lying areas and rank according to criticality of asset.</li> <li>Consider outdoor to indoor options for key outdoor infrastructure.</li> <li>Conduct geotechnical assessments of critical assets and carry out mitigations to improve ground stability.</li> </ul>
<b>Environmental changes</b>	<ul style="list-style-type: none"> <li>Adjust equipment specifications to improve humidity performance.</li> <li>Review vegetation management strategy.</li> </ul>

The New Zealand Government has published the second Emissions Reduction Plan (implemented in 2024 to address 2026–2030) which sets targets to achieve net zero by 2050 in order for New Zealand to contribute towards the global efforts to limit temperature rise to 1.5 C above pre-industrial levels. Major actions include electrification of transport systems and industrial processes, and improved management of waste and potent greenhouse gases like SF<sub>6</sub>.

When planning for new substations and lines, we use district and regional council information to identify risks from climate change, as well as tsunami inundation zones and other protected sites. Climate change risks are balanced with the obligation to maintain supply to connected customers. Therefore, maintaining and renewing assets in these at-risk zones will continue unless there is a decision made collectively to retreat.

Wind events and increased fire risks can impact the entire network and require a managed approach. From experience, most wind damage comes from vegetation impacting overhead lines. Our approach is to be more proactive and work with landowners to remove fall-zone trees as these do significantly more damage than wind-blown debris. Extreme fire risk is currently managed to some degree by turning off auto reclosers under advice from Fire and Emergency New Zealand.

More generally, Northpower is committed to making a positive contribution to decarbonisation. We are investing in more distribution and transmission assets and systems to support New Zealand's transition to a low-carbon energy future.

## 7.5 Emergency response and High Impact Low Probability Risk (HILP)

Emergency response refers to the actions we take in response to an imminent or ongoing crisis or emergency. The goal of emergency response is to prevent harm, restore services, and ensure we can continue to operate effectively. The specific nature of our response will depend on the type and scale of the incident.

### 7.5.1 Risk management approach

We have four plans in place for emergency response and ensuring operational continuity.

#### Coordinated incident management plan (CIMP)

This sets out actions in response to incidents that have (or may have) an impact on supply or the normal operation of the electricity network, and which cannot be managed within normal business-as-usual operations. It outlines details about:

- incident response strategy and procedures
- escalation points for the initiation of the incident management team (IMT)
- roles, responsibilities, and competencies of IMT members
- reporting to manage and advise stakeholders on recovery plans and progress.

#### Network contingency plans

These detail specific actions to be taken when responding to the loss of certain strategic network assets. This includes the switching plans that should be followed, the critical spares that should be deployed, and the key specialist support to be engaged.

As we develop a greater understanding of credible HILP events, we are developing plans to document operational response, assess the feasibility of possible infrastructure resilience, and establish greater access to other strategic spares and specialist resources.

#### Crisis management plan (CMP)

This documents our response to a major disruptive incident. The CMP details:

- how incidents with potential to become a crisis should be assessed and escalated
- when our crisis management team should be activated
- how a crisis should be managed
- how a crisis should be closed, and the effectiveness of the response evaluated.

## Business continuity plan (BCP)

Our BCP documents the key resources, infrastructure, tasks, and responsibilities required to support critical business functions in the event of disruption. The BCP highlights the critical processes within each business unit and the strategies to be adopted if the facilities, people, applications, suppliers, and equipment we depend on are unavailable.

We test aspects of the CMP and BCP annually, ensuring they can be successfully applied to respond to a crisis and recover critical business functions. This includes hard testing of physically relocating critical staff and the recovery of core systems.

### 7.5.2 HILP

HILP events are a particular class of event that typically have return periods of 100 to more than 1,000 years. They can occur at any time. While HILP or extreme events occur very infrequently, their consequences can be significant in terms of damage to an electricity distribution or transmission network, so consideration in terms of overall risk analysis and network vulnerability is warranted.

#### Source of risk

Some typical examples of HILP or extreme events which can adversely impact a network are:

- a major asset failure or multiple asset failures leading to power system stability problems or long-duration loss of supply, and possible widespread blackouts
- a major earthquake event causing asset damage, resulting in extended-duration power supply interruptions, and prolonged repair timeframes
- tsunamis
- a major extreme weather event such as a cyclone with very high wind speeds
- a volcanic eruption in the North Island, with major ashfall.

To carry out a complete risk reduction assessment for emergency preparedness planning, it is vital that we identify any vulnerability to plausible HILP events, the likely consequences, and potential mitigation options. Economic analysis enables risk reduction options to be compared.

HILP analysis helps organisations increase their understanding of their relative risk exposure to major events and supports good engineering judgement when making decisions about network resiliency improvements.

## Approach to risk management

It is not feasible to protect a network from all HILP events. However, there can be cost-effective ways to reduce exposure and enable faster power supply restoration following a major event, allowing us to meet recovery time objectives. The issue is how much investment should be made to achieve a certain level of risk reduction and where to target expenditure to achieve the greatest benefits. We have carried out a high-level assessment of major and catastrophic HILP events, identifying possible mitigation strategies. These strategies include operational actions, improved recovery strategies and resources, and infrastructure investment options.

These events are listed in Appendix D with possible mitigation options and proposed actions to improve our electricity network resilience.

Some of the investments required to implement these options have been included in this AMP, such as the Kensington upgrade which will be completed by 2028, and upgrades to the 33kV subtransmission network between Kensington and Maungatapere. The Maungatapere power transformer project is also underway, and orders have been placed for the transformers which has a substantial lead time. Over the next few years, we expect to review the remaining HILP risks identified, consult with our stakeholders, and assess whether to make further investments to increase our resilience to such HILP events.



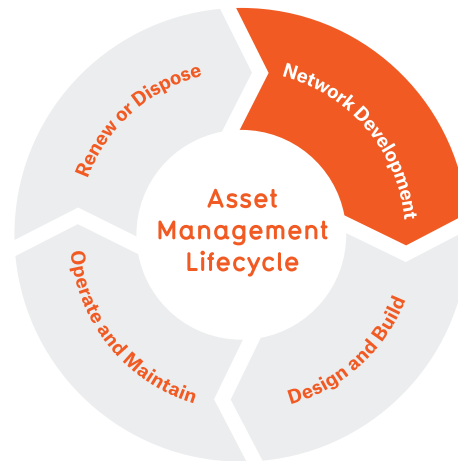
## Chapter 8

# Network Development

## 8.1 Introduction

This chapter sets out our approach to developing our network to meet customer demand and connection requirements. It includes our approach for identifying and forecasting constraints, carrying out options analysis, and developing solutions to meet these constraints.

This chapter also includes how we invest to improve our reliability, how we consider non-network solutions, and how we are managing the uptake of distributed generation and other new technology on our network. A more detailed overview of our planned network development investments is included in Appendix C.



## 8.2 Network development overview

As our network grows, we need to ensure that our assets continue to operate within their designed operating limits. We need to continue providing appropriate power quality and levels of security to manage risk and maintain network performance. Network development is the term we use to describe these types of investment. It is typically broken into four key investment drivers:

- **growth and security:** investments to ensure the demand on the network is met while maintaining security of supply
- **reliability and quality of supply:** targeted network investment with the purpose of improving the reliability and quality of supply
- **consumer connections:** expenditure to support new connections or increase the capacity of existing connections
- **network transformation:** network investment to enable the evolving needs of our customers and manage constraints arising from this changing network behaviour.

The following sections discuss how we plan to meet these investment drivers.

## 8.3 Network planning process

We follow a defined process to systematically identify and address current and future needs on the network. Figure 8.1 shows a simplified view of our network planning process.

Figure 8.1: Network planning process



The following sections describe each of these steps in more detail.

### 8.3.1 Forecast network demand

Our network development plans are driven by growth in peak demand, not energy consumption. For this reason, we concentrate on forecasting peak demand across all levels of our network. We forecast growth at distribution feeder, zone substation, and subtransmission level. We then aggregate these at grid exit point (GXP) level, and finally a total network demand forecast.

Our load forecasting is updated annually and combines a range of data inputs including:

- historical load data
- Whangārei and Kaipara district councils' spatial and growth plans
- Statistics New Zealand's dwelling projections
- known step load changes
- Distributed Energy Resources (DER) contribution estimates
- consideration of the reserve capacities allocated for large commercial and industrial customers.

We produce high, medium and low forecasts which are then used to identify network constraints. Investment is planned based on the medium forecast. The high and low scenarios are considered during the options analysis of investment planning which is discussed further in Section 8.3.3.

## Historical load data

Every year, forecasts are updated based on the latest network peak loads. This updated information establishes a baseline for constructing the 10-year demand forecast with the remaining inputs.

Historical load data is also used in the final stages of the forecast where we analyse it to identify trends which allows for fine tuning of each individual forecast. This reduces the extent of overestimating or underestimating demand.

## District plans and dwelling projections

Each council provides us with long-term dwelling forecasts by area. We then assign these areas with network architecture to accurately proportion forecasts to the correct assets. The councils provide low, medium, and high dwelling forecasts, which are applied to our low, medium, and high scenarios. The dwelling forecasts have a strong weighting to our network forecasts and heavily influence forecasted growth rates.

District spatial plans are considered, however, our medium or low forecast are not influenced by these plans due to the uncertainty surrounding them, in particular, the development types, potential load requirements and timing. We use these spatial plans for our high demand scenarios and they are considered during the options analysis of investment planning.

## Known step load changes

Upon approval of a new load or distributed generation (DG) application, step load changes are updated within the load forecast for the respective connection year. We monitor these applications and adjust the timing, if required.

For a step load to influence the master forecast, a strong level of confidence that the project will proceed is required. This ensures that speculative or low-commitment enquiries do not distort investment planning.

When planning network upgrades, all step loads are considered as part of the high demand forecast and appropriate capacity will be accounted for within the upgrade.

## DER contributions

Distributed generation can impact maximum demand. We include generation projects that will affect maximum demand as step loads. Most new DER connections are solar installations which do not affect maximum demand, this is due to network peak loads occurring outside of generation hours.

At present DER contribution has a small impact on the load forecasts. We are seeing an increased interest in battery storage systems. If this trend continues, we are expecting DER contributions to have a much larger influence in network demand forecasting.

We are currently in the process of creating minimum demand forecasts which will be useful to forecast for bi-directional power flows throughout the distribution network.

## Electric vehicle uptake

Using low voltage (LV) data, we have investigated the impact that electric vehicle charging is having on the network. These studies conclude that home chargers have minimal impact on the distribution network (11kV and above). For this reason, at present, we do not include electric vehicle forecasts into demand forecasts. We will continue to monitor the effects of home charging to better understand potential impacts.

We are seeing an increasing number of large-scale chargers being connected to the network. These are currently being captured within the load forecast as step load changes.

## Demand forecasting uncertainty

Due to the nature of demand forecasting, there will always be some level of uncertainty. The sources of uncertainty and impacts include:

- **rate of growth in the region:** residential and commercial growth is affected by many factors, including economic conditions and demand for housing in the area. We have made estimates based on historic growth as well as council and Statistics New Zealand forecasts, however, these forecasts still have some uncertainty. We have a higher level of confidence for the earlier years of the AMP period, but growth forecasts become more uncertain the further into the future we forecast. The uncertainty associated with demand forecasting may result in adjustments to the timing of growth projects, which could be deferred or expedited
- **step load changes:** the main uncertainties around customer driven load changes relate to the expected load increase. Frequently the actual electrical demand realised is less than initially indicated by customers and this results in a notable reduction in demand forecast once the load is connected. This risk is managed by monitoring the forecasts and ensuring that consideration to this uncertainty is taken during investment planning
- **DER uptake:** we have made assumptions around the rate of DER uptake and the impact that this will have on our network. We are still developing our approach to gaining visibility and managing constraints caused by this technology. Therefore, these estimates have some uncertainty. If the actual uptake differs significantly from our estimates, this may drive the need for new growth expenditure or a change to our existing growth plans
- **climate change:** climate change can have an impact on load forecasting and, the extent of this impact is unknown. We expect the risk to be low due to our forecasting methodology, by annually updating and adjusting load forecasts to match historical trends to account for long-term climate trends. We are expecting climate change to have a larger impact on network security and for this reason, we have several projects underway to improve network security.

To counteract these uncertainties, we produce high, medium, and low forecasts, but base our investment plans against the medium load forecast, while during the options analysis stage we consider both the high and low forecasts to ensure we have accounted for all possibilities.

We are continually looking to improve our load forecasting methodology to more accurately reflect emerging technology and potential changes in energy usage.

## 8.3.2 Identify network needs

Network constraints are identified through a systematic analysis of the network against our required levels of Security of Supply, Power Quality, Reliability, Resilience and addressing future needs of customers.

- **Security of supply:** security of supply criteria is set out to ensure Northpower can meet demand over time ensuring that single assets can accommodate the full load or when assets are required to be duplicated to reduce customer impact during outages.
- **Power Quality Standards:** Power Quality Standards are set to ensure that we comply with regulatory requirements and maintain the power quality in the network.
- **Reliability:** we aim to maintain network performance by setting SAIDI and SAIFI targets per year. Network reliability strategies are set out to address areas that fall outside of performance goals. These strategies are produced using engineering judgment and aim to manage the network SAIDI and SAIFI.
- **Resilience:** resilience supports issues arising from major emergency events, including natural disasters, large earthquakes, extreme weather events, and significant supply interruptions.
- **Consumer connections:** consumer connections are largely driven by population growth, from small residential to large subdivision developments as well as new commercial and industrial establishments being constructed.
- **Manage future needs of customers:** the decarbonisation of process heat and the rise of EVs are increasing electricity demand, while the growth of distributed generation causing bi-directional power flow. With proper forward planning, we aim to minimise the constraints resulting from the shifts in customer behaviour.

These criteria are outlined in more detail in the following sections.

## Security of supply

Security of supply is the ability of a network to meet the demand for electricity where equipment is out for planned or unplanned outages. The more secure an electricity network, the greater its ability to continue to supply electricity during outages.

Electricity supply interruption risks are managed by ensuring adequate capacity in our network to deliver peak power flows under normal and emergency conditions. This leads to redundancy/duplication of supply, depending on whether the additional costs of an outage to a large customer base outweigh the cost of investment. Security categories are:

- **N security:** a system that is unable to accommodate the full load following the loss of a single power system element
- **N-1 security:** a system that is still able to accommodate the full load following the loss of a single power system element
- **Switched N-1 security:** a system that will have a relatively short outage while alternate supplies are connected (such as switching to a back-up high voltage feeder) following the loss of a single power system element.

Our network only has full N-1 capacity in certain strategic areas such as, high-density urban areas, supplies to critical loads, or where a customer has requested and paid for it.

Our security of supply standard provides a benchmark to identify areas on our network that may not currently receive an appropriate level of security. Our security of supply criteria are outlined in Table 8.1.

**Table 8.1: Security of supply criteria**

Asset category	Capacity criteria	Reliability criteria (worst case)	Security of supply criteria
400V distribution network	Statutory voltage level	Supply restoration within repair time or within switching time where 400V link pillars present.	N security of supply for standard residential or commercial connection . N-1 where link pillars are present and backstop capacity available.
11kV/400V distribution substation	Transformer continuous rating	Supply restoration within fuse or transformer replacement time or within switching time where 400V link pillars present.	N security to most urban distribution networks. N-1 where link pillars are present and backstop capacity available.
11kV distribution network	Maximum operating load 80% of lowest segment rating	Supply restoration of 80% within switching time.	N-1 security except for spurs/radial feeds.
11kV distribution equipment	Lowest equipment rating	Supply restoration within switching time.	N-1 security except for spurs/radial feeds.
33/11kV zone substation	80% of firm maximum load relative to firm capacity	Load restored. 100% within 30 min for >5MVA. 80% within 1 hour for <5 MVA.	N-1 >5 MVA. N <5 MVA.
33kV subtransmission network	110% of overhead line rating for short periods of time. 80% of cable thermal rating	Load restored 100% within 30 min for >5MVA. 80% within 1 hour for <5 MVA.	N-1 for dual circuits. N for single circuits.
33kV assets within grid exit point (GXP)	Circuit breaker (CB) load	Supply restoration within switching time.	N-1 >5 MVA. N <5 MVA.

## Power quality

Northpower is committed to providing a safe and reliable electricity service and maintaining a high-quality power supply to customers. We rely on both load flow calculations and smart meter data (low voltage) to regularly monitor power quality in the network.

An electricity supply should be maintained at the stipulated voltage and frequency without distortion of the waveform or loss of symmetry, and with minimum instances or duration of variations beyond the specified limits, or unscheduled interruptions.

We regularly run load flow calculations and analyse smart meter data to ensure that quality of supply within the network is maintained. Using these methods, we can engineer solutions to constraints as they are identified. Typically, the issues that we identify can be solved by re-tapping the distribution transformer or installing a voltage regulator on the associated 11kV feeder.

The recent announcement to increase the voltage bands to  $\pm 10\%$  will provide positive benefits for the business by improving the network's ability to host distributed generation and other forms of smart technology. Smart meter data lets us see how voltage levels respond to changes in demand and embedded generation, giving us insights into daily, weekly and seasonal voltage patterns for distribution transformers and feeders. The insights support voltage management at distribution transformers and feeders, letting us view voltage patterns for all distribution transformers on a feeder and plan tap setting changes to bring them into alignment.

Our initial thoughts are that we will plan and design the high voltage network to ensure  $\pm 6\%$  is achieved at the LV side of the distribution transformer this allows the extra 4% voltage swing for abnormal configurations as well as the uptake in new technology. This approach will allow for more customers to be restored during network outages, increase distributed generation and electric vehicle penetration as well as minimise network risk due to the unpredictability of electricity landscape such as government incentives for new technology.

We will continue to monitor and evaluate the impact of these changes on our network, maintaining open lines of communication with other distribution companies and industry bodies to ensure our alignment with the industry in adopting and implementing these adjustments.

We take power quality complaints very seriously and will work closely with the customer to identify the issue and find a solution. Before dispatching a staff member to site our team will attempt to utilise smart meter data to diagnose the issue remotely. Where remote diagnosis is not feasible, and further on-site investigation is required, a staff member will be sent to inspect the customer's connection and determine whether the problem lies with their installation or is caused by an upstream network issue.

Quality complaints are usually due to distribution transformer tap setting being incorrect, customer's motor start-up not operating correctly, or voltage rise due to solar generation. Many of the power quality complaints can be resolved quickly by adjusting the distribution transformer tap setting. Our staff member on site will advise the customer, or our customer team will get in touch to discuss the source of the issue and the plan for rectification.

## Network reliability

Reliability of supply is defined by the Electricity Engineers' Association Security of Supply Guidelines as: "The actual performance of a network in terms of the amount of interruption actually experienced by the customer." We measure network reliability in terms of duration and frequency of interruptions per customer (SAIDI and SAIFI).

Planned outages generally occur so that maintenance or replacement can be undertaken. Unplanned outages occur when electricity is disconnected unexpectedly typically due to the equipment failure or external factors such as vegetation or adverse weather conditions. The reliability that customers experience is a combination of the service provided by substations, subtransmission networks, and distribution networks. However, most of the interruptions that affect SAIDI or SAIFI are caused by faults within the distribution network.

Network reliability constraints are primarily determined through the evaluation of the network against Network Reliability Strategies. The following describes key strategies that warrant investment.

- Limit customers on distribution feeders to 1,200 to reduce consequence of failure.
- Distribution feeders shall not exceed 80% of their line/cable thermal limit rating to allow supply to interconnected feeders under contingency.
- Spur lines with a total number of 300 customers or aggregated demand of 1MVA shall have feeder interconnection to reduce the consequence of failure.
- Distribution feeders must have at minimum two remote controlled smart switches, one at the midpoint of the feeder and one at the tie point to the adjacent feeder to reduce the duration of customer outages.

In cases where these strategies do not provide sufficient coverage, we examine historical fault data and feeder performance records to identify areas of potential concern. Additionally, Northpower conducts Reliability Risk Calculations by evaluating the Probability of Failure and the Value of Loss Load (VOLL). This enables us to conduct an economic analysis to determine whether investment in the network is economic.

## Network resilience

Network resilience is related to how the network performs during major events with potential to severely disrupt power supply to customers, which can have substantial economic impacts, as well as cause social disruption and raising public safety issues for whole communities. We refer to these events as high impact low probability events (HILP). Examples for HILP events are natural disasters such as cyclones, storms, and earthquakes, and large-scale technical failures (such as loss of one GXP and loss of a regional substation).

When designing and planning the network, we consider opportunities to improve network resilience and reduce the impact during HILP events. Some of the key considerations are as follows, when:

- planning work on sections of the network that supply critical customers, consider options available to improve resilience
- designing new sections of the network consider the use of diverse routes to improve resilience during a HILP event.

### Consumer connections

Consumer connections are largely driven by population growth, from small residential to large subdivision developments as well as new commercial and industrial establishments being constructed.

When there is new demand on our network, we determine the future impact will be. This can involve simple to complex analysis depending on the location, the timing, and the remaining capacity of the feeder and substations. We use SINCAL software to model constraints on our network to understand the impact on security of supply, power quality, reliability, and resilience.

When assessing complex load applications (Developer Driven Growth), an engineering assessment must be undertaken to review and identify probable network constraints that may occur over the next five year planning window.

Customers that are connecting large-scale distributed generation onto our network requires a separate process which involves further detailed analysis to understand the impact of the new distributed generation or battery storage on our network, as discussed in Section 8.7.

### Manage future needs of customers

Over the past 10 years we have seen a rapid increase in electric vehicle and distributed generation uptake on our network due to government programmes for decarbonisation. However, once these incentives were lifted the rate of EV adoption has significantly reduced whereas the distributed generation uptake continue to grow.

Adapting our network to accommodate the changes in customer energy usage requires greater visibility into our LV network. Over the past several years, we have invested in smart meter data, transformer monitoring and data analytics. Using these new insights, we believe we are well equipped to manage the uptake of these new technologies. More information on our LV visibility journey can be found in Section 8.8.

We keep open communication with our very large industrial customers around their decarbonisation plans and the possible impacts that may occur. However, there is still a varying degree of uncertainty around the timing of these plans. For this reason, when planning network upgrades, we consider possible decarbonisation scenarios and will allow extra capacity when economically feasible.

Electrical assets such as lines and substations have very long, useful lives, and often take many years to plan, consent, and construct. It can be more economic to build an asset with surplus capacity than to complete several small upgrades over its life. Taking this into consideration, when we replace existing electrical assets or responding to other drivers, we consider possible future demand growth and build in additional capacity where economic.

### 8.3.3 Options analysis

All new network investment needs are carefully examined, ensuring we adopt the most economical long-term solution that also delivers the identified need.

Several options are developed, and the most appropriate option is selected based on several criteria, including the output of an economic analysis. Non-network solutions are also considered where feasible and are employed where they are economic compared to traditional solutions.

We use a range of investment assessment techniques such as net-present value (NPV) analysis and risk assessment to determine which option will give the lowest lifecycle cost and deliver the desired outcome.

The degree to which decision tools are applied depends on the significance of the investment. For example, recurring decisions made at the operational level of our business typically use a predefined decision tool that considers several parameters and identifies one as being optimal. In contrast, non-recurring decisions made at the executive or governance level may consider wide-ranging and complex data and may use several decision tools to identify an optimal solution from many possible options.

Our guiding asset management principles ensure the proposed investment addresses the network constraint safely, economically, and in line with our long-term strategy. Accordingly, we evaluate the constraint with the following approach.

#### Initial long list of options

Following the identification of the network constraint or need, we consider both non-network and traditional network solutions to address the need, as well as the do-nothing option. Load forecasts are used when identifying viable options, if economically feasible, a solution that will account for our high demand forecast will be chosen. Each solution must account for the medium forecast.

Traditional solutions include investment in:

- installation of new equipment/assets
- upgrade of existing equipment/assets
- reconfiguration of the network architecture
- installation of remote-controlled equipment
- installation of reactive support
- other applicable solutions.

In addition, there are other solutions that could address constraints or defer investment. Some of these include:

- demand side management
- distributed generation or energy storage
- alternative supply options (off grid solutions)

These are discussed in the following sections.

### Demand side management and ripple control

Customer demand management can provide an alternative to distribution network development. Customer demand can be influenced to reduce peak demand where there is a benefit to the network, driving a more efficient outcome. The benefits of customer demand management include:

- deferral of capital investments
- increased utilisation of the network
- increased efficiency and improved capacity utilisation, lowering prices for customers.

We recognise that incentives are important for customers to shift their demand through such means as interruptible or off-peak tariffs. We currently use our ripple control system for customer demand management, this mainly controls hot water cylinders.

We have also utilised time-of-use pricing, which has a higher variable price for consumption in the peak period. We have set our off-peak pricing at zero where possible and set our peak pricing based on the long run marginal cost (LRMC) of the network, providing an incentive for customers to move consumption to times where there is greater capacity in the network.

### Distributed generation

There are some areas of the network, particularly during holiday times, where mobile standby generators could be considered to reinforce the supply. While this option has been evaluated as a potential solution for rapid load growth, it was determined that mobile standby generators do not provide a suitable long-term solution.

### Energy storage

In addition to batteries being used to buffer photovoltaics (PV) or for vehicles, batteries also have an application for grid or local electricity network support. Batteries are likely to be an option for grid support when the peak loads are infrequent and/or of short duration, due to the churn losses of the battery. The addition of more batteries with PV installations will help mitigate some of the potential problems that PV saturation could introduce.

The provision of batteries for support during peak load periods may in some cases be more economic than upgrading the network. This is likely to be an option when peak loads are infrequent and/or have a short duration due to battery losses, or if charging can be completed when electricity prices are low and injected when prices are high.

Use applications for grid-sized battery storage include:

- distribution network voltage support for locations with supply constraints
- remote area power supplies that involve PV and/or wind generation for storage of excess energy produced, and for stabilisation of the micro grid
- peak lopping for sites that have an established level of security and supply

We have no firm plans to adopt large-scale battery technology, but we will consider these as options to help manage infrequent and seasonal peak load spikes on our distribution network. In situations where large-scale batteries can support the network or help defer the need for investment, we are open to collaborating with developers who are also looking to install battery energy storage systems.

### Alternative supply options

We also consider alternative supply options for areas where it could be more economic to disconnect from the network, rather than upgrading the network. To date we have not yet identified any areas where this would be considered suitable. Most remote loads are farms and lodges and if these sites have unsustainable maintenance requirements, we will consider alternative supplies in collaboration with the customers. There are no current proposals to provide alternative supplies at this time.

### List of credible options

All options are narrowed down to a list of credible options that considers the following criteria.

- Ensure ongoing safety for the public and staff.
- Effectively meet the business needs and service requirements.
- Overall cost-effectiveness and maintainability.
- Meets future needs of our customers.
- Minimises environmental impact.
- Can integrate with other Northpower initiatives.
- In line with good industry practice.

To ensure that investment provides customers with the outcomes they value, all credible options are assessed against Northpower's strategic objectives and asset management principles. Once credible options are identified these are taken through to a more thorough analysis stage.

## Economic analysis

A comparison of shortlisted options is carried out by considering the whole-of-life costs for each option. A standard economic evaluation template has been developed to maintain a consistent approach to the analysis. It considers three main aspects for each option:

- the expected capital investment
- annual probabilistic reliability risk costs
- significant changes in ongoing operational expenditure.

The output of this template compares the whole-of-life costs of each option and helps to determine a preferred solution.

### 8.3.4 Project definition

Choosing a preferred option is based on balancing consideration of both the whole-of-life cost and intangible benefits of each option. The preferred option is selected based on the economic analysis output and how well it addresses the projects need.

Once the preferred option is defined, our projects go through a rigorous challenge and approval process as outlined in Chapter 6.

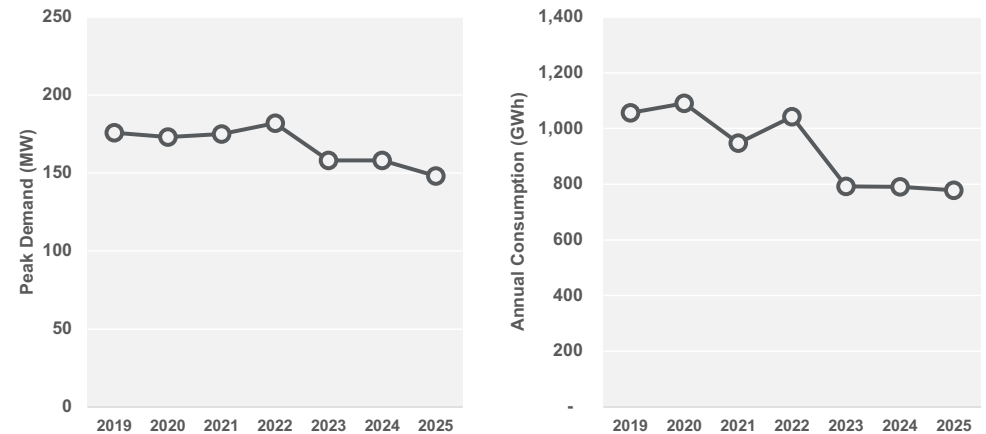
## 8.4 Network demand

This section gives an overview of historical and projected demand on our network over the next 10-year period.

### 8.4.1 Historical peak demand and energy consumption

Over the last five years, we have seen a decrease in peak demand as well as annual consumption, this is mainly due to the closure of the refinery during April 2022 that accounted for approximately 30MW. We also saw a sudden drop in consumption and demand due to the Covid-19 pandemic as this limited the operations of our large industrial customers as well as some commercial establishments.

Figure 8.2: Historical peak demand and energy consumption



In addition, both maximum demand and the energy delivered have shown slight decrease from 2023 onwards. We believe that the increase of roof-top solar PV could be reason for the decrease in energy delivered, however, it does not reflect the reduction in maximum demand as this generally occurs outside of generation hours.

Although, it is hard to pinpoint an exact reason for the reduction in maximum demand, the following are the reasons we believe account for the reduction of maximum demand.

- **Increased population working from home:** domestic loads are more diverse
- **Warmer winters<sup>1</sup>:** peak demand is normally caused by winter heating
- **More efficient appliances:** modern appliances require less power
- **Off-peak incentives:** retailers offering cheaper electricity outside of peak periods

With the steady growth in domestic connections and potential for decarbonisation of existing industrial facilities we expect an increase in both maximum demand and annual consumption. We are monitoring how each of the factors affect our network, so we can make necessary improvements in a timely manner.

### Historical peak demand per GXP

An overview of FY25 load and consumption on our three GXPs is shown in Table 8.2.

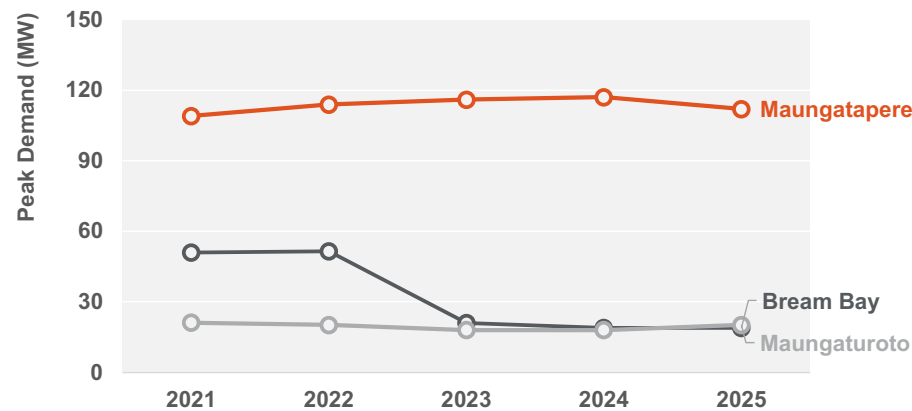
<sup>1</sup> According to Niwa the past several winters, have been relatively warmer in comparison to historical temperatures.

**Table 8.2:** Overview of the FY25 load and consumption on our three GXPs

Grid exit point	Supply KV	Peak demand MW	Annual consumption MWH	% of total
Bream Bay	33	18	99,344	12.75%
Maungatapere	110	109	577,927	74.19%
Maungaturoto	33	22	101,675	13.05%
<b>Total</b>	<b>148</b> <small>(see note 2)</small>	<b>778,946</b>	<b>778,946</b>	<b>100%</b>

Figure 8.3 shows each GXPs historical peak demand, the Bream Bay and Maungaturoto GXPs are relatively constant over the last three years whereas Maungatapere has had a slight dip in demand. However, we expect the load to increase across the network from new subdivisions and commercial establishments that are being developed in the Bream Bay, Mangawhai, and Kamo areas.

**Figure 8.3:** GXP historical peak demand



In April 2022, we had a decrease of around 30MW peak demand in the Bream Bay GXP due to the closure of the New Zealand Refinery which is the reason for the sudden decrease of Bream Bay's demand by around 30MW from FY22 to FY23.

<sup>2</sup> Total peak demand reflects the coincident peak between the three GXPs.



## Demand from industrial customers

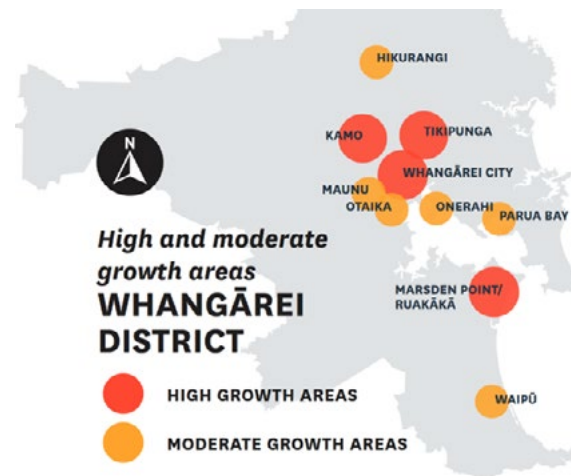
Customers with high demand or annual consumption are defined as very large industrial (VLI) loads. These customers generally have special requirements regarding the security of supply (typically duplicate transformers and lines or cables) as their loads are too large to supply with emergency standby or backup generation. These loads are normally supplied directly from the subtransmission system at 33kV, or by one or more dedicated 11kV distribution feeders from a nearby zone substation.

Our five VLI customers consumed around 24.1% of the electricity supplied by our network. However, this is expected to increase in years to come due to decarbonisation efforts.

### 8.4.2 Load growth considerations

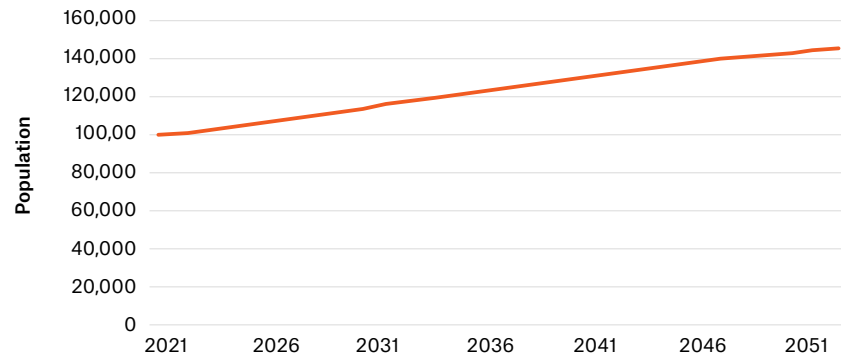
The Whangārei and Kaipara district councils have published their long-term plans and forecasted population increases over the next 30 years. The population increases are driving significant rezoning to support future large-scale residential and commercial growth, particularly in areas close to Auckland. There are also some forecasts that coastal beach towns may turn into 'zoom towns,' with people moving to more rural areas as remote working becomes more common.

**Figure 8.4:** Whangārei District Council growth strategy



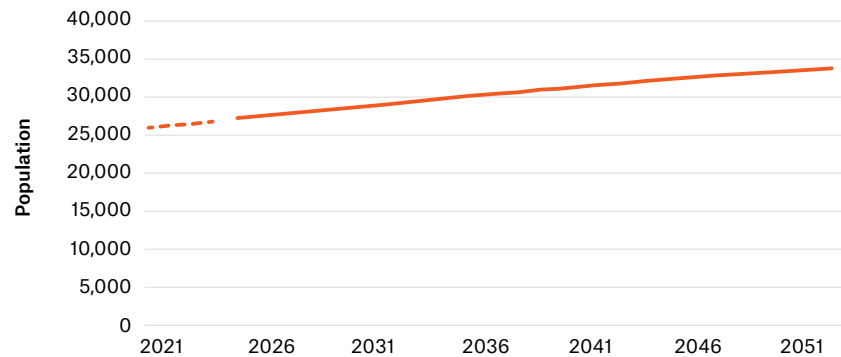
Population forecasts for the Whangārei district estimate a higher growth trend over the next 30 years compared to the previous census period (2018–2023), during which the district's population grew by 6.3%, in line with the national average. Whangārei District Council is forecasting the population to exceed 140,000 by 2051.

**Figure 8.5: Whangārei district population projections<sup>3</sup>**



The population for Kaipara is showing some softening compared to the 2018–2023 growth rate, which reached 13% over this period. Population predictions for Kaipara are forecast to exceed 34,000 residents by 2051.

**Figure 8.6: Kaipara district population projections<sup>4</sup>**



In the 30+ year population forecasts, Whangārei and Kaipara district councils are projecting significant residential growth in our region, in particular Kamo, Tikipunga, Whangārei, Ruakākā, Bream Bay, Waipu, and Mangawhai. Some coastal towns are also projected to see an increase in growth due to remote working.

<sup>3</sup> Source: Whangārei District growth strategy, Sustainable Futures, 23 September 2021.

<sup>4</sup> Source: Kaipara infrastructure strategy, Rev 6, February 2021.

**Table 8.3: Focused Growth Areas**

Area	Growth forecasts
<b>Bream Bay</b>	In recent years, we have seen multiple large subdivisions in this area as well as commercial and industrial developments. Whangārei District Council has also identified Bream Bay as a high growth area and are expecting this to continue into the foreseeable future. We are currently in the process of installing a second zone substation transformer to ensure significant capacity and security is available.
<b>Waipū</b>	Waipū is a fast-growing area, and we have noticed a sizeable increase in demand. With large areas being designated for development, we suspect the load to increase over the planning period. We have recently completed a capacity uplift to meet the existing demand; however, we are expecting further investment will be required to meet long term forecasts.
<b>Kamo</b>	High development of residential areas with lifestyle blocks is expected to continue for the next five to 10 years. This aligns with the Whangārei District Council development plans for this area. As the Kamo zone substation is approaching its capacity limit, we have initiated studies to explore avenues for meeting the expected increase in demand.
<b>Whangārei City</b>	The urban area is expected to grow out towards the west, meaning substantial residential load growth is expected on the Maunu zone substation which was recently commissioned to support development in this area.
<b>Mangawhai</b>	With its proximity to Auckland, the Mangawhai area has seen a significant increase in residential and commercial development as more permanent residents make this area their home and increased amenities and services are established. We have recently commissioned a new zone substation to support the rapid growth in this area. We are also installing a second 33kV subtransmission line to ensure that security of supply is maintained.

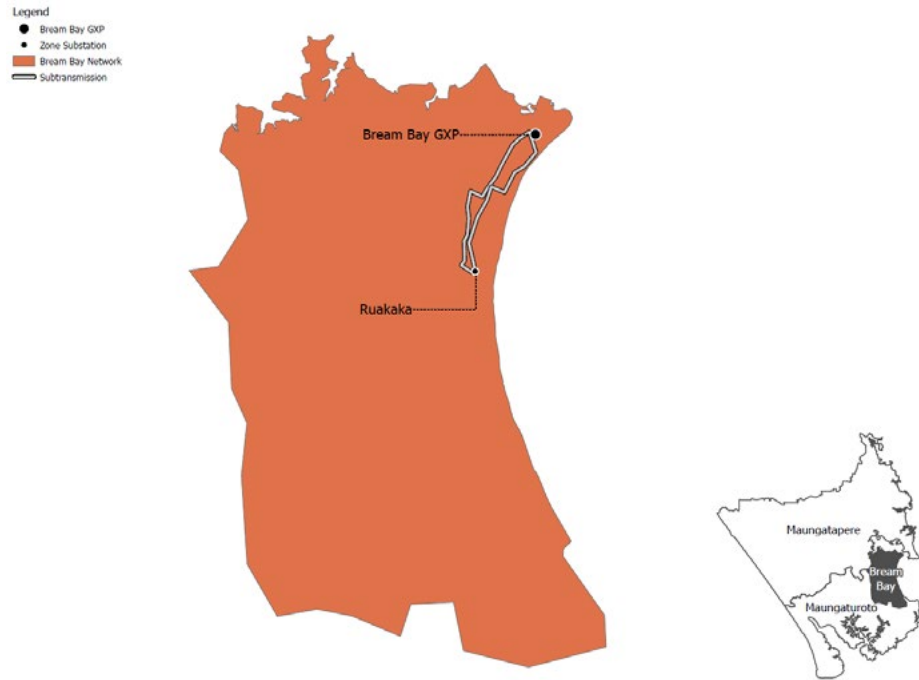
### 8.4.3 Forecast GXP load growth

This section sets out projected load growth for the three GXPs that supply our network.

#### Bream Bay GXP

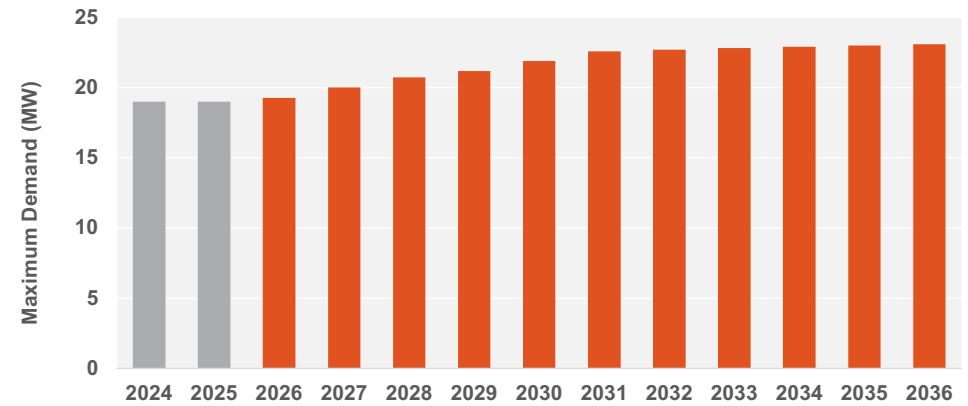
The Bream Bay GXP supplies Ruakākā, Marsden Point, and One Tree Point (adjacent to Bream Bay GXP). This includes large industrial customers such as Carter Holt Harvey wood processing plant.

**Figure 8.7:** Bream Bay GXP service area



Our demand forecast for Bream Bay GXP is shown in Figure 8.8. In recent years we have seen an increased interest in large subdivisions and other forms of commercial and industrial growth. Whangārei District Council has identified Marsden Point and Ruakākā as high-growth areas and are expecting this trend to continue.

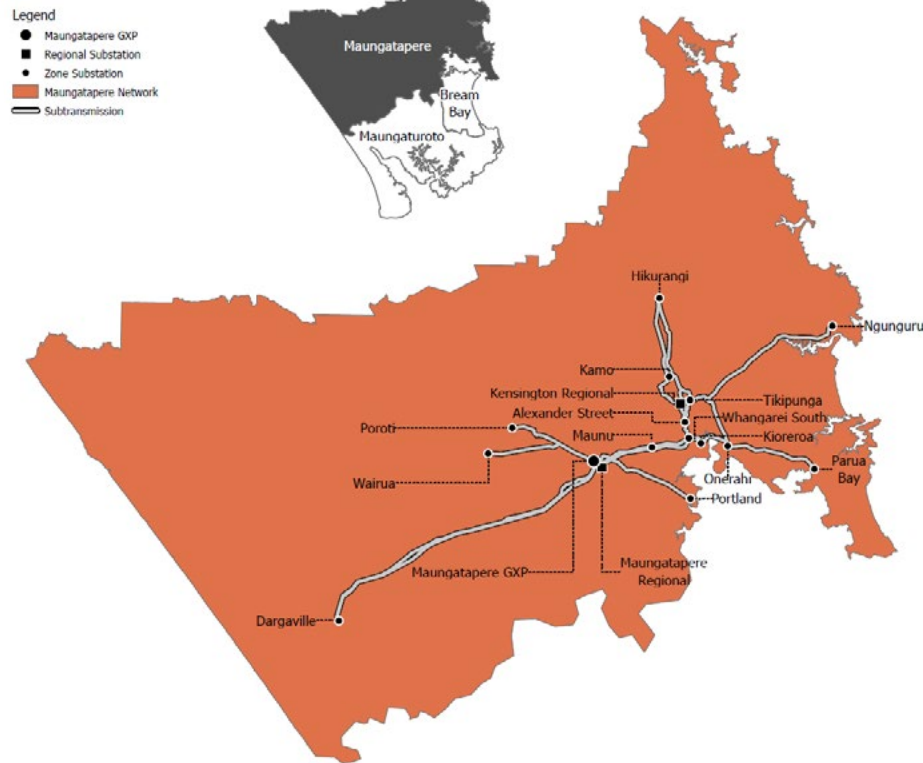
**Figure 8.8:** Bream Bay GXP forecast maximum demand



### Maungatapere GXP

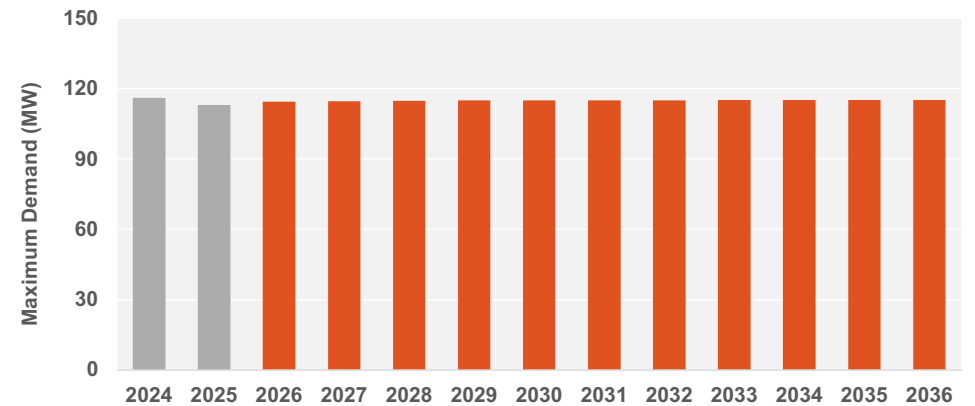
Maungatapere GXP supports the majority of our network, comprising of approximately 75% of peak demand. Maungatapere GXP supplies 15 zone substations spanning from the east to west coast including the Dargaville area as well as much of the Whangārei district.

**Figure 8.9:** Maungatapere GXP service area



Whangārei District Council’s growth strategy is anticipating significant development in and around the Kamo, and Tikipunga areas comprising of large subdivisions as well as an expansion to the Kamo commercial area.

**Figure 8.10:** Maungatapere GXP forecast maximum demand

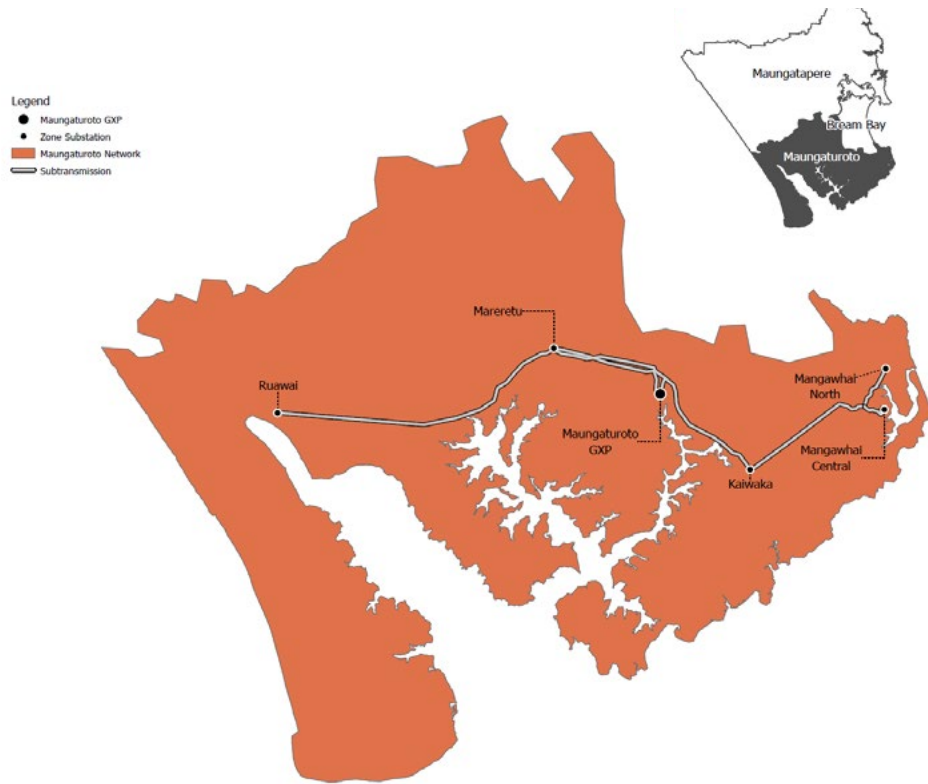


Our peak demand forecast for the Maungatapere area remains relatively flat showing little increase to maximum demand. The reason for this is due to a large windfarm being constructed in the Dargaville area as it is anticipated that a portion the generation will offset our peak demand for the GXP.

### Maungaturoto GXP

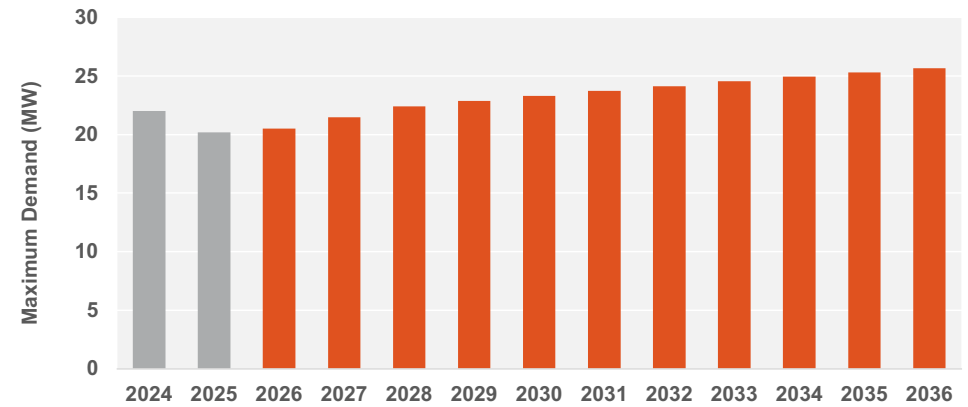
The Maungaturoto GXP supplies the Kaipara District Council region except for Dargaville (which is directly connected to the Maungatapere GXP), as shown in Figure 8.11.

**Figure 8.11:** Maungaturoto GXP service area



The growth on this GXP has primarily occurred along the east coast within the Mangawhai and surrounding areas. Historically, Mangawhai mainly consisted of holiday homes with a small commercial area. However in recent years this area has significantly grown with more people making Mangawhai their primary location of residence. We are expecting this trend to continue into the foreseeable future.

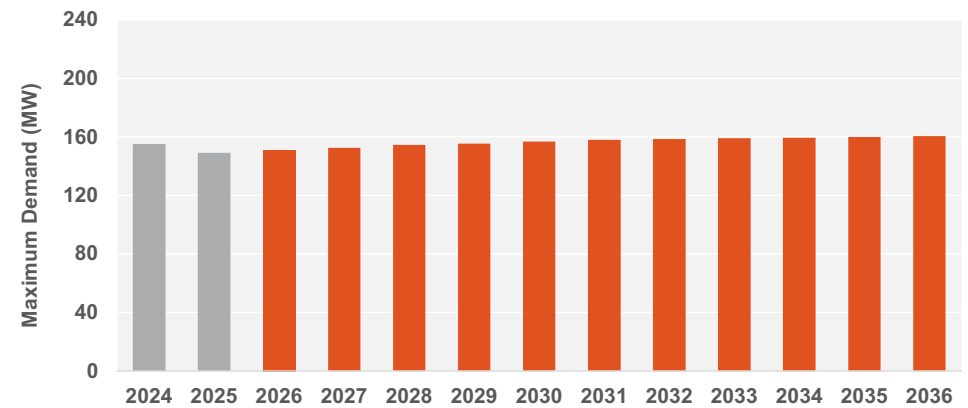
**Figure 8.12:** Maungaturoto GXP forecast maximum demand



### Total GXP load forecast

Our total GXP load forecast is based on coincident peak load and is shown in Figure 8.13. The demand growth averaged across the entire network is expected to be approximately 0.7% per annum for the 10-year forecast period. We are forecasting that the output from embedded generators will offset some of this growth, however, we do not include solar power into our load forecasts due to the network peak occurring outside of operational hours.

**Figure 8.13:** Total GXP forecast maximum demand



## 8.4.4 Substation and subtransmission load forecasts

The following table compares the firm capacity of our substations and subtransmission networks with the present and forecasted load. The uptake of solar PV connections is recorded but not incorporated into the forecast because the impact on peak demand (given our winter peak) is negligible. At this stage, we have not incorporated the impact of battery storage into our zone substation forecasts as we currently do not anticipate the impact of batteries to be significant. However, once more certainty is gained around residential batteries we will then incorporate into our after diversity maximum demand (ADMD) figures.

### Subtransmission load forecast

**Table 8.4:** Subtransmission load forecast

Subtransmission circuit	Security	Firm capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Kensington to Tikipunga A & B	N-1	<b>21.4</b> <small>(see note 5)</small>	20.7	20.9	21.2	21.4	21.7	21.9	22.1	22.4	22.6	22.8	23.0
Kensington to Kamo A & B	N-1	<b>25.7</b>	23.3	23.5	23.8	24.1	24.4	24.7	25.0	25.2	25.5	25.8	26.0
Kensington to Alexander to Tikipunga	N-1	<b>21.9</b>	8.1	8.1	8.2	8.3	8.3	8.4	8.5	8.5	8.6	8.7	8.7
Kamo to Hikurangi	N-1	<b>14.3</b>	6.4	6.5	6.5	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.9
Tikipunga to Onerahi	N	<b>22.9</b>	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2
Maungatapere Regional to Maungatapere	N-1	<b>13.7</b>	5.8	5.9	5.9	6.0	6.0	6.0	6.1	6.1	6.1	6.2	6.2
Maungatapere Regional to Poroti	N	<b>9.1</b>	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3
Maungatapere Regional to Dargaville	N -1	<b>19.2</b>	12.1	12.2	12.2	12.2	12.3	12.3	12.4	12.4	12.5	12.5	12.5
Maungatapere Regional to Whangārei A & B	N-1	<b>28.4</b>	22.9	23.2	23.3	23.4	23.5	23.6	23.7	23.8	23.9	24.0	24.1
Bream Bay to Ruakākā A & B	N-1	<b>13.7</b>	8.6	8.7	8.8	9.0	9.1	9.1	9.2	9.3	9.4	9.4	9.5
Maungaturoto to Kaiwaka	N <small>(see note 6)</small>	<b>13.7</b> <small>(see note 7)</small>	13.0	13.9	14.4	14.8	15.2	15.6	15.9	16.3	16.7	17.0	17.4
Kaiwaka to Mangawhai	N <small>(see note 8)</small>	<b>11.4</b>	9.2	9.9	10.1	10.3	10.4	10.6	10.8	10.9	11.1	11.2	11.4

**Legend**

- <= N-1 firm capacity rating
- > N-1 firm capacity rating

**Legend**

- <= N-1 firm capacity rating
- > N-1 firm capacity rating

- 5 Capacity upgrade FY32
- 6 N-1 Security in FY28, second 33kV line under construction
- 7 Capacity upgrade FY30
- 8 N-1 Security in FY28, second 33kV line under construction

## Substation load forecast

**Table 8.5:** Substation load forecast

Substation	Security	Firm capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
<b>Maungatapere GXP</b>													
Kensington Regional	N-1	<b>50</b> (see note 9)	64.6	65.3	66.0	66.8	67.6	68.4	69.1	69.9	70.6	71.2	72.6
Alexander Street	N-1	<b>15</b>	10.6	10.7	10.7	10.8	10.8	10.9	10.9	10.9	11.0	11.0	11.1
Hikurangi	N-1	<b>10</b>	7.4	7.5	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.3	8.5
Kamo	N-1	<b>15</b>	13.4	13.6	13.9	14.1	14.4	14.6	14.8	15.1	15.3	15.6	16.0
Ngunguru	N	<b>5</b>	3.0	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.4	3.4	3.5
Onerahi	N-1 switched	<b>15</b>	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.5	7.6	7.7	7.8
Parua Bay	N	<b>5</b>	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.3	4.3
Tikipunga	N-1	<b>20</b>	17.8	17.9	18.1	18.3	18.5	18.7	18.9	19.1	19.3	19.5	19.8
Maungatapere Regional	N-1	<b>30</b> (see note 10)	43.5	43.8	44.0	44.2	44.3	44.5	44.7	44.9	45.0	45.2	45.5
Maungatapere	N-1	<b>7.5</b>	5.8	5.9	5.9	6.0	6.0	6.0	6.1	6.1	6.1	6.2	6.2
Maunu	N	<b>10</b>	4.1	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.7
Kioreroa	N-1	<b>20</b>	9.4	9.4	9.5	9.5	9.5	9.6	9.6	9.7	9.7	9.7	9.8
Poroti	N	<b>5</b>	3.1	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.3
Whangārei South	N-1	<b>10</b> (see note 11)	10.7	10.8	10.8	10.8	10.9	10.9	11.0	11.0	11.0	11.0	11.1
Dargaville	N-1	<b>15</b>	12.1	12.2	12.2	12.2	12.3	12.3	12.4	12.4	12.5	12.5	12.6
<b>Bream Bay GXP</b>													
Bream Bay	N (see note 12)	<b>10</b>	6.4	7.0	7.3	7.9	8.5	8.6	8.6	8.6	8.6	8.6	8.7
Ruakākā	N-1	<b>10</b>	8.6	8.7	8.8	9.0	9.1	9.1	9.2	9.3	9.4	9.4	9.6
<b>Maungaturoto GXP</b>													
Maungaturoto	N-1	<b>7.5</b>	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.2	6.3	6.3
Ruawai	N	<b>5</b>	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Kaiwaka	N	<b>5</b> (see note 13)	3.0	3.2	3.4	3.6	3.8	4.0	4.2	4.4	4.6	4.8	5.1
Mangawhai	N	<b>10</b>	4.4	5.0	5.1	5.2	5.3	5.3	5.4	5.5	5.6	5.7	5.8
Mangawhai Central	N	<b>15</b>	4.9	5.0	5.1	5.2	5.3	5.4	5.4	5.5	5.6	5.7	5.8
Mareretu	N	<b>5</b>	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0

9 Capacity upgrade complete FY27 two 100MVA units.

10 Capacity upgrade complete FY29 two 100MVA units.

11 Capacity upgrade complete FY31 two 20MVA units.

12 N-1 Security in FY27 second transformer to be installed.

13 Capacity upgrade complete FY29 one 10MVA unit.

## 8.5 Network constraints

This section outlines the constraints identified on the network based on our load forecast, security of supply standards, power quality standards, and other planning criteria.

### 8.5.1 Growth and security of supply constraints

The following are key constraints relating to growth or security that have been identified across the network over the next 10 years. The full list of constraints can be found in Section 8.6

- The Kensington regional substation has already reached its N-1 firm capacity limit of 60MVA and is expected to reach 70MVA in the next 10 years. This is one of our critical substations, supplying seven zone substations with approximately 30,000 customers. The substation will be upgraded to two x 100MVA transformers which are underway and to be completed in FY27 as discussed in Section 8.6. during this time, we will also be replacing the 33kV switchboard, however the switchboard replacement is captured and recorded under asset replacement and renewal.
- The single subtransmission line supplying Kaiwaka and Mangawhai is causing reliability issues, and the demand forecast is expected to breach N security due to significant development in Mangawhai. A new subtransmission line from Maungaturoto to Mangawhai is underway and expected to be completed in FY28 as discussed in Section 8.6.
- The Maungatapere regional substation has reached its N-1 firm capacity limit of 30MVA and is forecast to increase to 45MVA over the next 10 years. To address this, the substation will be upgraded to two 100MVA transformers, with the project currently underway and scheduled for completion in FY29 as discussed in Section 8.6.

The following constraints relating to reliability and power quality have been identified.

- Kensington regional substation, supplying around 30,000 customers, does not have a 110kV bus, this is causing reliability and operational issues. A new 110kV bus arrangement is underway and expected to be completed in FY27 as discussed in Section 8.6.
- Parua Bay zone substation does not meet our security of supply criteria for N security sites. This project is aimed to address this issue by installing a switchable capacitor bank to improve reliability as discussed in Section 8.6.
- Recent efforts to gain better visibility into the LV network, allows us to better identify constraints relating to the LV network. This project aims to address these constraints as they arise. It is forecasted that majority of expenditure will be used to re-balance or replace LV assets. Further information is discussed in Section 8.6.
- Moureeses Bay overhead LV network is to be converted to underground due to safety issues. We will be undergrounding a section of the existing overhead network in Moureeses Bay as discussed in Section 8.6.

We are looking for opportunities to improve reliability across the network. For this reason we are installing more remote-controlled switches as well as fault location devices (FPIs). We expect these efforts will improve feeder performance by providing greater visibility of fault location and allow for faster restoration periods.

## 8.6 Network development projects

This section outlines significant network development, reliability, and power quality projects over the 10-year planning period.

### 8.6.1 Growth projects

Our planned growth projects ensure we maintain capacity and security of supply, and support forecast growth rates. We split the growth projects into two categories:

- **major projects:** typically involving substations and subtransmission circuit upgrades
- **non-complex projects:** typically involving upgrading of distribution feeders and LV networks.

These projects and forecast expenditures are presented in the following figures and tables.

#### Major projects

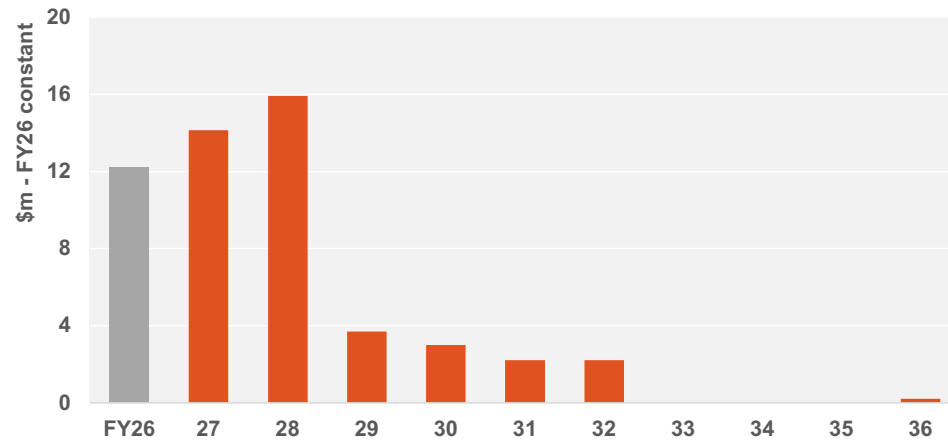
Over the AMP period, we plan to spend \$41.6M on major growth projects. The majority of the investment is in the early part of the period, with the Mangawhai and Kensington upgrades.

**Table 8.6: Forecasted major growth projects**

Growth – major growth projects	Year	Budget <sup>14</sup>
<p><b>Kensington 110/33kV transformer replacements</b></p> <p>The project will replace the existing two 50MVA power transformers with two 100MVA units. This will restore N-1 security, meet the forecasted demand at the substation, and provide switching capacity during a HILP event at the Maungatapere 110/33kV substation.</p>	FY26-27	\$2.7M
<p><b>Maungaturoto to Mangawhai 33kV line</b></p> <p>The project will install a new 28km subtransmission circuit from Maungaturoto substation to Mangawhai substation. It will improve the reliability and security of supply to Kaiwaka and Mangawhai zone substations. This will also support the growing demand in the Mangawhai area and provide contingency supply under planned outages to perform asset renewal and maintenance.</p>	FY26-28	\$16.5M
<p><b>Upgrade existing Kaiwaka to Mangawhai 33kV line</b></p> <p>This project proposes a conductor upgrade on the existing 33kV line supplying the Mangawhai area. To ensure N-1 security is maintained to meet the future demand growth, a capacity upgrade of the existing line is required.</p>	FY28-30	\$2.2M
<p><b>Maungatapere 110/33kV transformer replacements</b></p> <p>The project will replace the existing two 30MVA power transformers with two 100MVA units. We have decided to install similar units to match that of Kensington which will allow us to rotate these units, if required during major asset failures. This project will restore N-1 security, meet the forecasted demand at the substation, and provide switching capacity during a HILP event for the Kensington 110/33kV substation.</p>	FY26-28	\$10.1M
<p><b>Replacement of Kensington to Tikipunga 33kV subtransmission cables</b></p> <p>The project upgrades the existing subtransmission circuits that supply Tikipunga, Ngunguru, Onerahi, and Parua Bay substations. This will maintain N-1 security and meet growth forecasts for the area.</p>	FY28-32	\$9.6M
<p><b>Install additional 15MVA 33/11kV power transformer and 11kV switchboard upgrade at Bream Bay</b></p> <p>The project will install an additional 15MVA transformer to address security constraints and meet growth forecasts. In conjunction, a new 11kV switchboard will be installed to replace the existing 11kV switchboard, providing spare 11kV breakers for new connections.</p>	FY26-27	\$5.7M
<p><b>Upgrade existing subtransmission feeders to Kamo</b></p> <p>We are expected to reach the N-1 security of the existing lines supplying, Kamo, Hikurangi, and Kauri substations. We have also identified a future constraint relating to the capacity of the Kamo zone substation. We are currently exploring alternative options to address these constraints. Alternative options being considered consist of a new zone substation to offload the existing assets or a non-network alternative to reduce network peaks and maintain N-1 security.</p>	FY26-28	\$3.9M
<p><b>Ruakākā to Waipū 33kV line</b></p> <p>Waipū is undergoing a significant transformation driven by a surge in residential and commercial development. We are expecting a future zone substation will be required to support future development. This project aim is to produce a concept design for a 33kV supply to the future zone substation.</p>	FY36	\$0.2M

<sup>14</sup> If project is ongoing, the forecasted remaining budget is listed.

**Figure 8.15:** Forecasted major growth project expenditure



### Non-complex growth projects

Over the AMP period, we plan to spend \$14M on noncomplex growth projects. The majority of this expenditure is allocated towards programmes of work to meet the growing demand of the network.

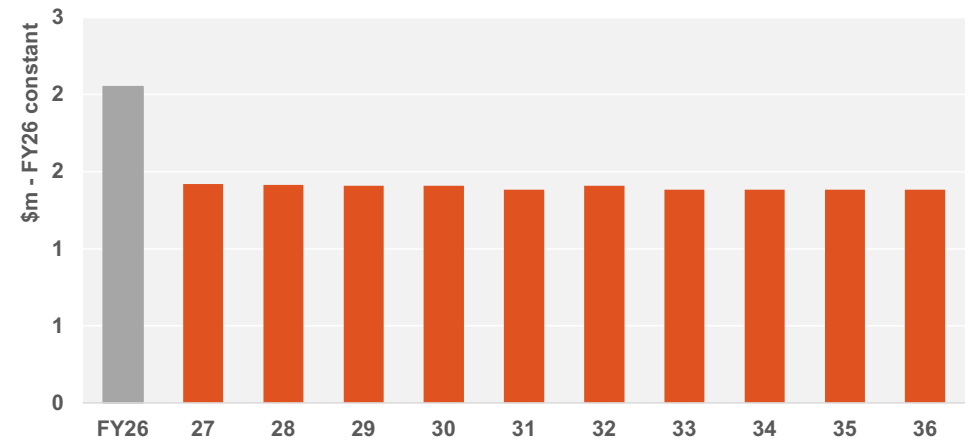
**Table 8.7:** Forecasted non-complex growth projects

Growth – Non-Complex growth projects	Year	Budget <sup>15</sup>
<b>Communication system upgrades</b>	FY26-32	\$0.2M

As more assets connect to the network, upgrading our communications infrastructure is essential to maintain security and reliability. This project will involve installing multiple Cisco switches across the network, enabling seamless and effective communication between new devices.

<sup>15</sup> If project is ongoing, the forecasted remaining budget is listed.

**Figure 8.16:** Non-complex growth Capex



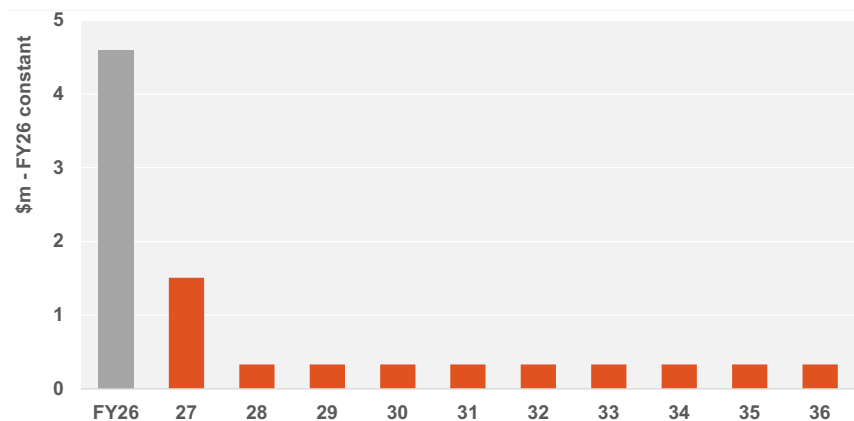
### 8.6.2 Reliability and quality of supply projects

Reliability and quality of supply projects help to enhance the performance of our network by improving outage restoration time and the impact of outages. Over the AMP period, we are forecasting to spend \$4.5M on reliability and quality of supply projects.

**Table 8.8:** Forecast reliability and quality of supply projects

Reliability and quality of supply projects	Year	Budget
<b>Kensington 110kV bus reconfiguration and transformer circuit breakers</b>	FY27	\$0.8M
The project creates a 110kV bus at the Kensington substation including a bus section circuit breaker, enabling both power transformers to be returned to service during a single 110kV line outage.		
<b>Parua Bay back-feed constraint mitigation</b>	FY27	\$0.25M
The project proposes an installation of a switchable capacitor bank at the zone substation which will allow for additional back-feed capacity to the Parua Bay substation. This project will ensure all N security substations meet our security of supply criteria.		
<b>LV constraint mitigation</b>	FY27-36	\$2M
Our LV visibility has improved significantly over the past several years, this project is designed to address quality of supply constraints that are identified by replacing distribution transformers or LV conductor.		
<b>Moureeses Bay overhead to underground conversion</b>	FY27	\$0.15M
The project will convert existing LV overhead lines to underground cables to address public safety issues.		

**Figure 8.17:** Forecast reliability and quality of supply expenditure



### 8.6.3 Consumer connection

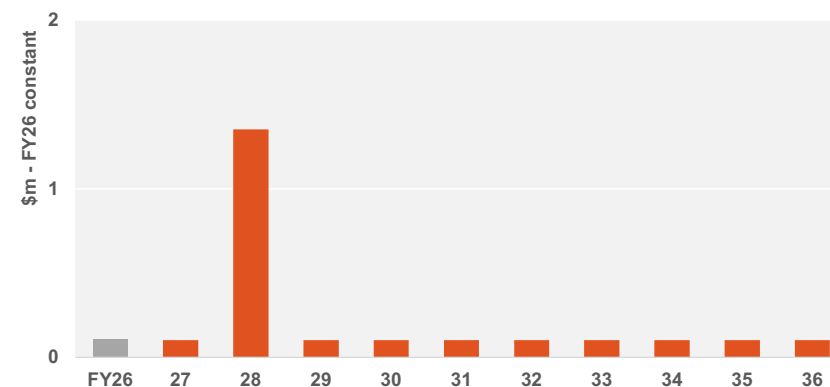
Consumer connection investment is expenditure to support the connection of new customers to the network. Connection volumes are largely driven by population growth, from small residential connections to large subdivision developments as well as new commercial and industrial establishments being constructed. In the last four years, we connected an average of around 800 new customers to our network per year.

To connect new customers, we use a process that ensures it is fair, cost-effective, and efficient. The goal of our capital contributions policy is to ensure that our existing customers do not cross-subsidise development costs. Therefore, developers pay for the network extension back to the nearest point of supply (that has sufficient capacity). The costs to the network for new development are kept at a minimal level, as reflected in Figure 8.18

Currently, we offer pre-application engagement meetings and transparent information for potential new customers who have projects requiring information around capacity on the network. We work directly with renewable energy developers and charge point operators as they look for best locations in the area. Capacity maps showing capacity available at both HV and LV assets on the network will be published by the first quarter of 2027.

Over the AMP period, we are forecasting to spend \$2.3M on consumer connection.

**Figure 8.18:** Forecast consumer connection expenditure (net)



### Capacity costing

Following the connection pricing reform from the Electricity Authority, we are now required to calculate posted capacity rates (previously called 'capacity charge') at each of the five network tiers. They will reflect the average costs of adding capacity at each tier. Once in place, we expect it will further enhance the efficiency to process new connection applications. Similar to previous approach, this allows us to invest in bulk capacity upgrades to make the cost of new capacity as low as possible for all customers connecting.

## 8.7 Distributed generation

### 8.7.1 Distribution generation policy

Where customers want to connect distributed generation, they are required to pay costs associated with upgrading the network to accommodate the connection and to deliver the required export capacity. We do not anticipate that distributed generation will materially impact development plans by requiring network expenditure to be brought forward.

Our connection of distributed generation policy follows the requirements set out in Part 6 of the Electricity Industry Participation Code 2010. Our website includes guidelines on connection requirements, consultation, and approval.

#### We recognise that distributed generation can provide a range of benefits:

- reduction of peak demand
- helping to manage existing network constraints
- deferring or even avoiding investment in additional network capacity
- contributing to supply security
- making better use of local primary energy resources

#### Distributed generation can, however, have undesirable impacts that need management:

- increased fault levels, requiring protection and switchgear upgrades
- more complex network management, resulting from multiple points of supply
- uncontrolled voltage rise beyond statutory ceiling limits
- potential to impact power factor at GXPs
- the introduction of harmonic currents
- potential for back feeding into the network with inherent safety implications
- imbalances on the low-voltage network
- increase line losses.

We work with those wanting to connect distributed generation to our network to deliver the benefits, while also ensuring that all parties manage and mitigate any adverse impacts.

The key requirements for those wishing to connect distributed generation to the network are covered in the following sections.

#### Connecting distributed generation

A party connecting distributed generation must comply with our safety requirements, as well as all electrical industry codes and regulations. Our requirements for small-scale generation are based on AS/NZS 4777 Grid Connection of Energy Systems via Inverters. To protect the network and other energy consumers, we may physically disconnect distributed generation that does not comply with these requirements.

Connection terms and conditions are set out in accordance with the Electricity Industry Act 2010. Information on the application procedure for potential connection of distributed generation (including relevant forms and required standards) is available on our website.

#### Distributed generation and development planning

As of April 2026, there are approximately 3,000 distributed generation systems with a total capacity of 67MW connected to our network.

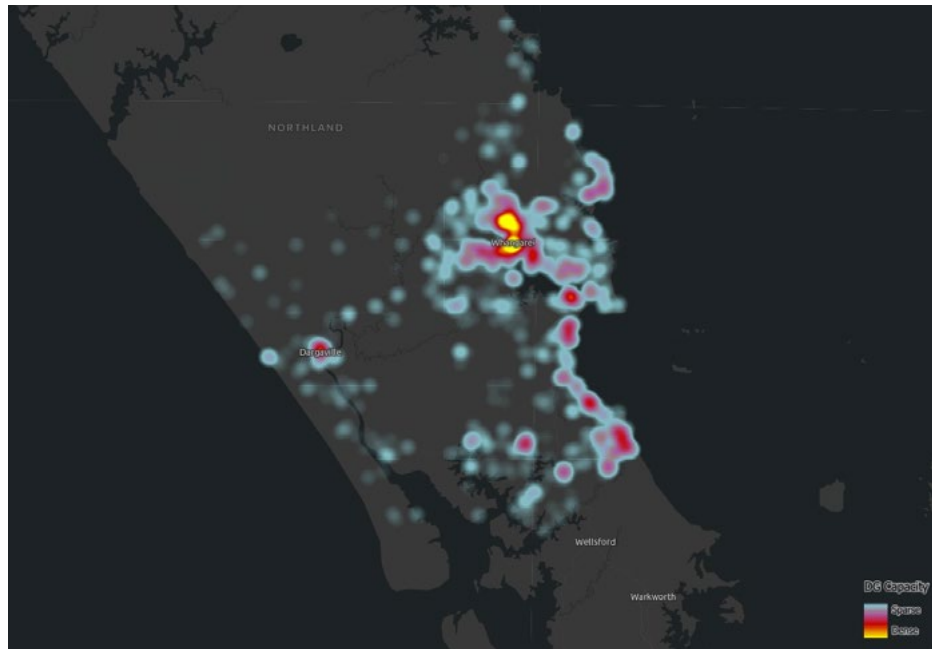
**Table 8.9:** Summary of distribution generation (data from September 2025)

Owner	Generation type	Number	Capacity MW
Contact Energy	Diesel	1	10
Northpower Renewables	Hydro	1	5
Northpower Renewables	Solar	1	16.8
Solar Bay	Solar	1	17.6
NewPower Energy	Solar	1	4.2
Private	Solar	3,000	13.4
<b>Total</b>		<b>3,005</b>	<b>67</b>

Solar PV generation has the potential to increase voltage levels above acceptable limits on 400/230V networks (LV), as maximum output occurs during sunlight hours when loading on these networks is generally low. High levels of residential PV will significantly increase voltage on the LV network. However, the recent announcement to statutory voltage bands being extended will significantly reduce the risk of voltage constraints arising. At present, we are not expecting any major constraints to occur with the forecasted adoption rate of residential distributed generation.

In addition to the growth in small-scale distributed generation on our network, we have seen an increasing interest in connecting large-scale distributed generation to our network. This growth remains consistent across each GXP. We are forecasting within the next several years that generation connected onto the network will exceed that of our total peak demand.

**Figure 8.19:** Heat map of residential solar penetration on our network



Although we are not expected to have wide scale issues, we are expecting some instances where the LV network will require some upgrades to match the rate of PV uptake, these upgrades may include:

- reducing the voltage of the LV network, typically adjusting the tap setting of the distribution transformer
- increasing conductor size or reducing conductor lengths, this will reduce voltage drop and rise
- installation of a new transformer, this will split the number of connections and increase capacity
- implementing line drop compensation at the zone substation level, this will dynamically reduce or increase the voltage across the feeder.

Battery storage is now becoming more common with solar PV installations allowing off-peak generation to be used during peak periods, reducing adverse effects on the network.

Distributed generation is considered in our long-term planning process, and operating connections are monitored. As trends develop, data will be used to understand the impact on changing network demand, and we will continue to monitor and model the potential impact of increased PV uptake.

## 8.8 Preparing for the future

As our customers' needs evolve and they adopt new technology such as electric vehicles and distributed solar, we also need to develop our approach to managing our LV network.

### 8.8.1 Case for change

In response to New Zealand's commitments to be carbon neutral by 2050, we are preparing for disruption to the electricity sector. With the decarbonisation of process heat and electric vehicles causing an uplift to electricity demand, along with the increase of distributed generation causing bi-directional power flow, our job as a distributor is to enable customers to adopt new solutions. Over the next 10 years we expect increasing:

- **distributed generation:** customers self-generating and storing their own electricity from sources such as wind and solar, leading to electricity being fed back into the grid.
- **advances in digital technology:** enabling increased control and information flow for customers to manage their energy use, and for new markets to emerge.
- **new consumption:** adoption of EVs and other technologies will create new demand for electricity. As batteries become more affordable, this will create greater flexibility to manage energy use, and more options to improve resiliency.

As these technologies become more accessible, our customers may wish to expand their energy choices, including:

- selling surplus energy into the market
- storing energy to either use when they want or to sell back into the market at a higher price
- developing neighbourhood storage networks
- charging their electric vehicles or devices at times when the cost of energy is cheaper
- lowering their energy consumption at peak times to reduce energy costs.

In recent years, we have observed a steady growth in electric vehicle adoption, alongside a more pronounced increase in the uptake of residential solar installations across our network driving the need to better understand our network's capabilities.

However, there is still a degree of uncertainty around the likely timing and level at which our large industrial customers will electrify. Most of these loads will come with the conversion of process heat, however, there are alternatives to electricity such as biomass.

With the level of uncertainty, it is currently not practical to heavily invest into accommodating these potential changes. Therefore, our plan is to improve our readiness to respond to these changes as they arise. We are working closely with our large industrial customers to understand their preferences.

We are also working towards a better understanding of our network's capabilities, particularly our LV networks. This will allow for a more dynamic approach with long-term planning.

### 8.8.2 Our journey

Adapting our network to accommodate changes in power flow and customer energy usage requires greater visibility and control of our network. Historically, our networks were planned with relatively predictable demand. Household consumption profiles and anticipated growth allowed for long-term investment planning with a fairly high degree of certainty.

We expect our LV network will see much of the change, due to the uptake of new energy technologies. Residential customers are fed off our LV network, and these new technologies give customers greater choice of when and how much electricity they want from the grid. With customer load profiles becoming more unpredictable, we can no longer rely on past assumptions. Making sure our LV network has sufficient capacity to enable customers the flexibility of service is central to our future network strategy.

At an aggregate level, large volumes of distributed generation and DER will impact our HV network. Our investment in our Advanced Distribution Management System is a key step towards moving to a more active distribution management system. In FY25, we completed the rollout of advanced applications, including Distribution Power Flow (DPF), implemented an Inter-Control Centre Communications Protocol (ICCP) interface with Transpower which facilitates real-time data exchange between the control centres. We are currently investigating use of an Adaptive Network Management module (ANM) to optimise use of high voltage capacity. These more advanced systems give us full visibility across our core network, enabling us to better manage capacity constraints.

In recent years, we have made significant strides in enhancing our understanding of the LV network. These efforts have included a range of targeted initiatives aimed at improving visibility and operational capability. This includes:

- purchasing network operational data (NOD) for approximately 63% of the network
- installing transformer monitors on a section of high interest LV networks
- implementing an advanced LV data analytical platform (analyses LV data to produce valuable LV insights)

These are discussed in more detail in the following sections.

### 8.8.3 LV network visibility and modelling

To build greater visibility and modelling of our LV network, we have improved the data we hold related our LV networks and are using this to more accurately model the networks.

#### LV Network Operational Data (NOD)

In 2024, we entered a five year contract with a metering equipment provider (MEP) to supply us with NOD for approximately 40,000 Installation Control Points (ICP) on our LV network, which accounts to roughly 63% of the network. These devices record power and voltage every five minutes. This data is then stored and made available every 24 hours.

Over the next several years, we are aiming to gain access to a wider set of network operational data with the goal of reaching all ICPs. Additionally, we will continue to work with metering providers to increase the frequency at which we receive data to allow us to dynamically respond to network issues as they arise. Access to near real-time data will enable more dynamic network management, faster fault detection, and enhance safety measures.

#### Transformer monitors

We have installed LV monitors on a selection of distribution substations. These monitors communicate through cellular connections to a cloud-based analytics package. The initial roll-out targeted specific distribution substations which provide the most benefit. These are in areas where we are seeing increased PV and EV activity in sites that will allow us to gain a better understanding of customer load behaviours, and in areas that are most likely to have existing constraints.

With the recent purchase of NOD, we have now shifted our strategy from transformer monitors. Due to the increased benefits and lower cost, we have decided to significantly reduce the number of new transformer monitors being installed and have switch our focus on locations where metering data cannot provide sufficient coverage.

## Data analytics

The large volume of LV data being received requires advanced data analytical algorithms to ensure the most value can be extracted. We are currently receiving over 30 million records per day across the LV network and have integrated a data analytics platform into our business operations.

These analytics have improved efficiencies in multiple business areas allowing us to be more effective with operational and planning functions across the network. These efficiencies include:

- new LV connections, load or distributed generation can be efficiently modelled using real data to understand potential impact on the network
- power quality investigations can be done at the desktop reducing the need for site visits and installation of data loggers
- constraints can be readily identified and categorised, enabling more efficient planning and execution of work
- proactive fault finding can be done by analysing NOD data to identify degrading assets which improves network safety and reduces unplanned outages.

These insights will allow us to gain a better understanding of our LV network and will give the required tools to ensure our network can accommodate the changes in power flow and customer energy usage.

## 8.8.4 Non-network solutions

As discussed in our options analysis section, where increases in demand impact performance metrics (such as capacity, reliability, and security of supply), we consider both non-network and traditional network methods to address these issues, and build the capability to deploy more advanced non-network alternatives.

At the time of writing this AMP, we have no non-network solutions (NNS) deployed as regular operational tools. We currently do not operate formal demand response, market-based flexibility, or contracted non-network services. While some non-network solution mechanisms are used, such as distributed generation run-back schemes, these are connection-specific rather than part of a structured programme. We evaluate options for non-network alternatives to meet investment needs as part of our options analysis process while building the capability to deploy more advanced non-network alternatives.

Northpower is actively developing its data capabilities and analysis capability to introduce future non-network solutions. A new role has been created specifically to lead the transition to active DER management. We participate with industry partners and other electricity distribution businesses (EDB) in forums such as the Flexibility Networks Forum to identify future opportunities.

We are developing a distribution system operator (DSO) roadmap that includes flexibility enablement, operational readiness and data governance. We are rolling out Active Network Management systems to enable us to manage DER exports and congestion. LV network visibility is being expanded through enhanced smart meter data access and modelling to identify and manage constraints. Operational tools, including advanced distribution Management System (ADMS), are being enhanced, including Advanced Distribution management system modelling, forecasting, telemetry, and switching support to enable real-time assessment of NNS feasibility.

We are establishing the data and communication infrastructure required to support real-time data exchange with Transpower. By the first quarter of FY27, we expect to publish high voltage and LV capacity maps, providing third parties with easy access to identify where non-network solutions could defer or avoid reinforcement.

### 8.8.5 Optimising operations

The ADMS outage prediction engine (integrated with our Salesforce CRM) speeds up identification and location of faults on the network, enabling faster fault finding. An ICCP interface to Transpower has been commissioned, and our NOC is now actively managing generation attached to our distribution network. Smart meter data has been used to create load profiles in our ADMS, supporting forecasting of behaviour of the network at different times of day. Operators can now model power flows around non-telemetered parts of the network on demand, supporting activities like real-time back-feed calculations when performing switching, helping minimise impacts on customers. We anticipate operators will soon be able to interrogate near real-time information from distribution transformers and smart meters on our network. This improved information is a key enabler for DSO functions.

### 8.8.6 Innovation

We actively try to improve management and work practices across the business, adopting innovations where value can be added. We attend conferences and engage with other EDBs, either formally through groups such as the EEA and Electricity Networks Aotearoa (ENA) or informally on particular problems.

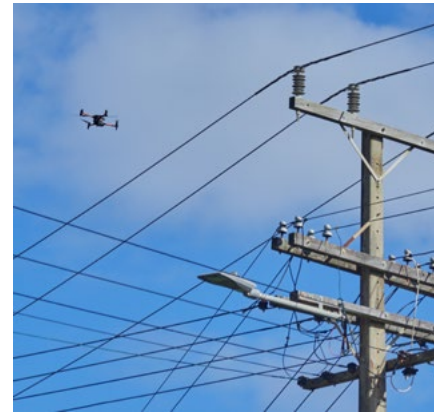
Northpower evaluates potential innovations based on practical outcomes such as improved safety, reduced costs, and better network performance. We monitor developments across the industry, learning from other EDBs and technology providers to understand what works for other EDBs and overseas utilities. We assess vendor demonstrations, pilot results, peer network experiences, and staff feedback before committing to wider deployment. We seek to ensure that innovations deliver genuine value before they become standard practice.

Recently Northpower has undertaken two innovation trials.

#### Field data capture technologies

Northpower has recently trialled the use of pole top imagery as part of its inspection technology and techniques programme. This innovation marks a significant shift from traditional ground-based inspections, offering enhanced image clarity, superior asset defect capture, and improved viewing angles. The trial demonstrated valuable insights and advantageous over stand-alone ground-based inspections, particularly in capturing detailed observations of critical components such as insulators, conductors, and binders. The inspection techniques provide richer data to support observation and severity-based inspection frameworks, enabling more accurate asset condition modelling and proactive maintenance planning.

LiDAR remains a valuable tool for targeted engineering and vegetation management applications. When integrated with platforms like Neara and GIS systems, LiDAR enables advanced analysis of conductor clearances, vegetation encroachments, and structural profiles. Although not required for routine inspections, LiDAR is proposed for strategic deployment in FY29 to align with GIS upgrades and support reconductoring and vegetation programmes.



We are also participating in a trial, with a number of other EDB's, to better understand the use of AI in identifying our electrical assets and defects detected. This AI-powered platform ingests imagery from drones, helicopters, ground inspections, and Google Street View to automatically detect and classify asset defects. It enables geospatial visualisation of assets and supports the creation of digital twins for simulation and planning. The collaboration aims to upskill internal teams, foster industry-wide innovation, and enhance asset management through machine learning and data integration.

#### Reverse power flow - current-dependent setpoint for voltage control

At times, some sections of our network experience high levels of reverse power flow due to large distributed generation systems. This can present operational challenges in traditional distribution networks, most notably voltage regulation during reverse power flow.

To manage the resulting bi-directional power flows and mitigate overvoltage conditions, a voltage regulation scheme was employed to control a zone substation on-load tap changer (OLTC), this was done based on measured active current. When local solar generation exceeds the 11kV load consumption, reverse power flows toward the 33kV network occurs and causes the voltage rise. By dynamically adjusting the voltage setpoint in response to real-time distributed generation export ensures that voltage stability maintains while minimising unnecessary transformer tap operations.

Simulation and operational data confirm that this current-dependent setpoint strategy significantly improves voltage control during periods of high PV output. This approach offers a scalable, cost-efficient solution for distribution networks facing growing renewable penetration and leverages existing infrastructure to support grid reliability and decarbonisation objectives.



## Chapter 9

# Lifecycle Management

## 9.1. Introduction

In this chapter, we outline our approach to maintaining and renewing electricity network assets. It includes sections explaining how we manage each asset portfolio throughout its lifecycle stages.

Asset renewal programmes represent a large portion of our 10-year capex programme. Preventative maintenance inspections identify areas requiring asset renewal, complemented by network consequence evaluations that inform risk models. Our renewal programme for volumetric asset fleets is divided into corrective and targeted workstreams. Corrective renewals address urgent, short-term replacements, while targeted renewals focus on longer-term efficiency by combining larger sections of asset replacements. Historical information also guides expenditure where inspections do not reveal systemic issues.

A significant portion of our renewal activities, particularly within the corrective capex programmes, focuses on addressing high priority defects. This mainly applies to large, volumetric asset fleets in the overhead network, such as poles, crossarms, and conductors. Smaller components identified through preventative maintenance inspections, including insulators, connectors, and fuses, are replaced through our opex corrective programme.

Our targeted renewal programme uses a range of models to inform planning for individual asset fleets and the overall portfolio. Only a few low impact asset classes rely on historical expenditure for future replacements. For most fleets, strategies and replacement models are already in place. Volumetric fleet renewal requirements are primarily determined using industry standard replacement expenditure (REPEX) models, adapted to asset data quality and availability, considering attributes such as age, type, and location. Identified defects are incorporated, and age-based assessments are benchmarked against accepted industry asset lives.

Additional fleet models support renewal forecasting by using asset condition and defect observations to estimate probability of failure. These models are implemented within the planning environment and continue to be refined to improve accuracy and validate the methodology.

Since FY24, Northpower has applied a risk-based approach to vegetation management within the framework of the Electricity (Hazards from Trees) Regulations 2003. During this period, we have inspected more than two-thirds of our overhead network and cleared approximately 60,000 at-risk trees. The programme has effectively reduced vegetation-related outages across the network. It is currently under review to further enhance performance, incorporating lessons from significant weather events, insights from inspection data analysis, and responding to recent changes to the Electricity (Hazards from Trees) Regulations 2003.

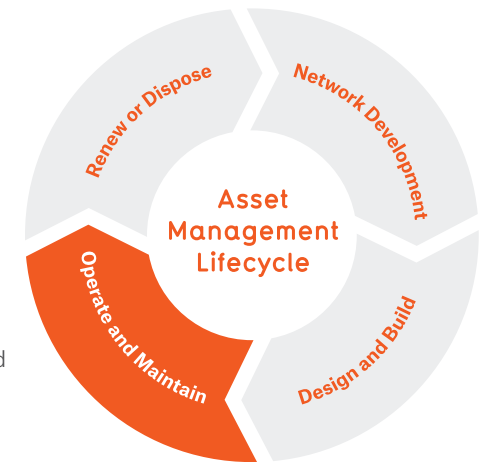
## 9.2 Operate and maintain

As discussed in Chapter 6, we manage our network fleets using a lifecycle approach. 'Operate and maintain' is a key stage in this cycle. The figure to the right shows operate and maintain in the four lifecycle stages within our asset management system.

Operate and maintain lasts for an asset's life and impacts the timing and scope of other stages (for example, the need for renewal). Our activities during the operate and maintain lifecycle stage ensure the asset's safe and reliable performance over its expected life. These include network operations (such as switching), maintenance, vegetation management, and spares management.

Effective asset management relies on appropriate integration between operations and maintenance and the other lifecycle activities, including network development, design, procurement, construction, and renewals. Once commissioned, assets are put into service and the operate and maintain stage begins. Many assets have a useful life exceeding 40 years, and the operate and maintain stage becomes an important and extensive phase of the asset's lifecycle.

Table 9.1 outlines how effective operations and maintenance practices play a critical role in achieving our asset management objectives.



**Table 9.1:** How operations and maintenance supports our asset management objectives

Objectives	
<b>A safe network</b>	The risk of our workforce and the public being exposed to injury, and of damage to the environment, are reduced by following our safety, maintenance, and operational standards while carrying out operations and maintenance work.
<b>Network performance</b>	Reducing unplanned outages will improve reliability for customers. Increased preventive work will help reduce unplanned outages in the longer term by informing our renewal work. Reducing the duration of unplanned outages through improved reactive maintenance will enhance the service our customers experience.
<b>Community support</b>	Planned servicing is generally more cost-effective than unplanned repair work. Lifecycle costs can be reduced by carrying out an optimal volume of preventive work. By gathering better asset information, well-informed asset management decisions will help reduce whole-of-life costs and the long-term cost of service to our communities.

### 9.2.1 Network operations

The primary role of network operations is to ensure a reliable supply of electricity to our customers. We do this by managing the network in a way that ensures we consistently meet network, operational, safety, and asset performance objectives. Key activities include:

- real-time network control and switching
- network monitoring and event response
- planning for equipment outages to enable safe access to network assets.

Control rooms in our head office and in a separate substation are configured to allow the network to be controlled from either location, improving our network resilience.

Our operations team must consider factors such as how asset loading and distributed generation imports affects asset life and performance, and how to safely remove assets from service for maintenance while minimising service impacts. Operations activities provide feedback on network and asset performance and risk to the lifecycle planning process.

### Spares management

Spare parts for our assets, stored in appropriate locations, help maintain reliable supply. We hold strategic, critical and rotatable spares across subtransmission, distribution and zone substation fleets, with holdings tailored to asset criticality, age and standardisation. Following development of our Spares Management Strategy, our approach is now formalised through a risk-informed framework that defines spare types, sets expectations for stock levels in critical and strategic spares, storage and inspection, and supports consistent decision making.

Stock levels are informed by subject matter expertise, ensuring minimum holdings. Storage and condition monitoring requirements ensure spares parts remain service ready, and standardising type and rating allows to reduce holdings while maintaining availability and minimising costs.

A Critical Spares Management plan is underway to establish the processes and systems needed to manage critical spares end-to-end, from identification to replenishment and lifecycle review.

### 9.2.2 Network maintenance

We undertake a range of maintenance activities to ensure our network assets operate in a safe and reliable manner throughout their lifetime. These activities include monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring service. Information gathered during maintenance activities is used to improve our asset standards and planning processes, and to inform our renewals programme.

Our maintenance activity is split into three types:

- **preventive maintenance:** includes asset inspections, condition assessments, and servicing. These are typically carried out on a regular basis (for example, every three months, annually, or every six years) in accordance with our maintenance standards. Recorded condition assessment data is used for analysis, forecasting, and renewal planning. Defects and repair work (corrective maintenance) also arise from preventive maintenance.
- **corrective maintenance:** this is planned work arising from preventive maintenance work, ad hoc identification of a defect, or as a follow-up to a fault (for example, following service restoration). It includes defect rectification, repairs and replacement of minor components to restore the condition of an asset. Failure to undertake this work can reduce reliability and increase safety risks.
- **reactive maintenance:** is work carried out in response to an unplanned event or incident that impairs normal network operation. Failure to undertake this work in a timely manner will adversely affect the service provided to our customers and may increase public safety risk.

## Approach to maintenance

Our maintenance standards define preventive maintenance activities and the frequency at which these are to be carried out. Some inspections are non-periodic and are based on the number of operations or faults, a requirement to gather data for decision-making purposes, or on the criticality of the asset. We use this information to plan our corrective maintenance programme and inform renewal decisions. Key drivers of our approach include:

- **maintenance standards:** that specify recommended inspection tasks, servicing intervals, and reporting requirements
- **decision making:** information on assets to make cost-effective, prudent decisions
- **legislative or regulatory requirements:** including frequency for inspecting overhead line assets, or safety requirements
- **manufacturer's recommendations:** around inspection tasks and servicing intervals
- **asset condition:** as identified by preventive maintenance activities
- **incident numbers:** leading to reactive maintenance or corrective maintenance.

Our lifecycle approach requires us to make trade-offs between maintaining our assets in service (opex) and replacing or refurbishing them (capex). For example, we may increase the frequency of maintenance for a particular asset type to increase asset life or defer renewal.

Details on specific maintenance activities are discussed in the following fleet sections.

## Planning and prioritisation of maintenance

Our maintenance standards define preventive maintenance activities and generally the frequency at which these are to be carried out. Asset condition is generally assessed on a scheduled time interval basis. Some inspection timings are based on number of operations or faults, or on the need to gather data for decision making.

We use information obtained from preventive maintenance activities, and occasionally reactive maintenance activities, to plan our corrective maintenance programme and inform renewal decisions. For defects, we consider several factors to prioritise assets for rectification under the corrective maintenance programme. This allows us to allocate our corrective maintenance funds and resources to more efficiently reduce risk and address performance issues.

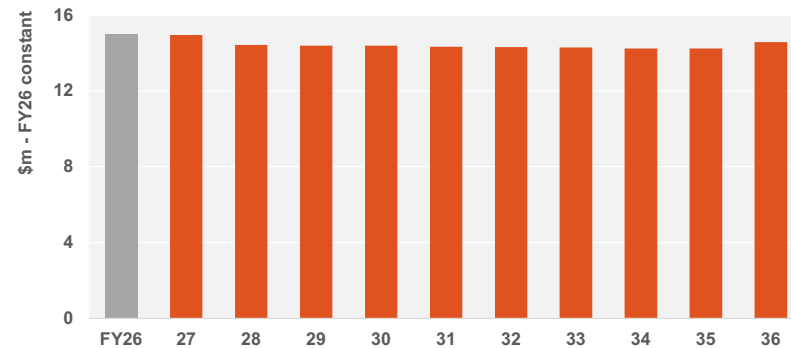
## Maintenance forecasting

Northpower's maintenance forecast is developed based on the main activity types. Preventive maintenance activity reflects specified frequencies, historical completion rates, and with adjustments for some fleets based on risk. Preventive maintenance forecasts incorporate these aspects and planned changes to maintenance strategies, as relevant. Corrective maintenance is informed by inspection records, outstanding defects, SME knowledge, site visits, risk reviews, and follow up to reactive maintenance and safety incidents. For reactive maintenance, forecasts are based on trends of historical work volumes. The forecasts also account for known emerging issues with asset fleets and top down step changes like anticipating fewer faults as network condition improves.

## Maintenance expenditure

The following chart shows our forecast maintenance opex. Our expenditure requirement over the planning period is approximately \$14.4 million per year.

Figure 9.1: Network opex budget



Our maintenance forecasts consider historical costs, and we update these base amounts to reflect changes in strategy, known emerging issues with our asset fleets, and expected trends (for example, anticipating fewer faults as the condition of the network improves). We then review preventive and corrective maintenance plans using a bottom-up approach, identifying work completed.

## Benefits

The main expected benefits of maintenance over the planning period include the following.

- **Management of safety risk:** the risk of our workforce and the public being exposed to injury, and of damage to the environment, is reduced by following our safety and operational procedures while carrying out the work as scheduled.
- **Improved customer experience:** effective maintenance will help reduce unplanned outages in the longer term by informing our renewal work. Scheduled work is generally less inconvenient to customers and landowners than unplanned outages.
- **Reduced cost of works:** planned servicing is generally more cost-effective than unplanned remediation work. Lifecycle costs can be reduced by undertaking an optimal mix of proactive and reactive work.
- **Asset and condition information:** inspections provide us with condition information that allow us to make better informed asset management decisions. Some asset attribute information is missing, and preventive maintenance can confirm this data or gather it as required.
- **Improved decision making:** by gathering better asset information, we can make well-informed asset management decisions to reduce whole-of-life costs.



### 9.2.3 Vegetation management

Left unchecked, vegetation growing close to our assets can have a significant impact on network reliability and public safety. Trees close to live conductors pose a risk of electrocution and fire to our communities. These events can also result in considerable damage to network equipment, causing network outages. Vegetation is one of the main contributors to unplanned SAIDI and SAIFI performance. Vegetation management is a key activity that enables our assets to perform to expected service levels.

We undertake vegetation management to keep trees clear of overhead lines. This is necessary to minimise vegetation-related outages and meet our safety and statutory obligations. The main activities are inspections to determine the amount of work required, liaison with landowners when work is required, and follow-up tree trimming and removal.

Effective vegetation management ensures we adhere to relevant regulations, including the Electricity (Hazards from Trees) Regulations 2003. These establish the rights and responsibilities for network owners regarding vegetation that encroaches overhead lines. The following table outlines how our vegetation programme supports our asset management objectives.

Vegetation-related faults are a significant contributor to unplanned SAIDI and SAIFI performance. Adverse weather events such as major storm events are a large contributing factor to vegetation-related faults.

**Table 9.2:** How vegetation management supports our asset management objectives

Objectives	
<b>A Safe Network</b>	Minimise vegetation-related safety and environmental risks (for example, fires).
	Improve education around risks associated with vegetation near conductors.
<b>Network Performance</b>	Lower the risk of vegetation-related events damaging network equipment to reduce customer interruptions.
	Reduce planned outages by targeting vegetation trimming, and ensuring this work is aligned with other activities.
<b>Community Support</b>	Improve vegetation management efficiency and programme effectiveness to reduce vegetation-related faults and the cost of service to our communities.

## Approach to vegetation management

Since FY24, Northpower has implemented a risk-based approach to vegetation management across the distribution network. This approach enables the prioritisation of vegetation work based on the likelihood and consequence of failure, with a focus on safety and network reliability. The programme has been supported by a rapid visual inspection process, allowing for efficient identification of high-risk vegetation.

A full inspection of the distribution network is scheduled for completion during FY27. To date, approximately two-thirds of the overhead network has been inspected, and around 60,000 at-risk trees have been cleared.

Where vegetation is identified as a risk, Northpower actively engages with landowners to obtain consent for removal or trimming. In addition, a new programme has been introduced to support private tree owners in managing vegetation near power lines, using qualified arborist contractors to carry out work safely and in accordance with industry standards.

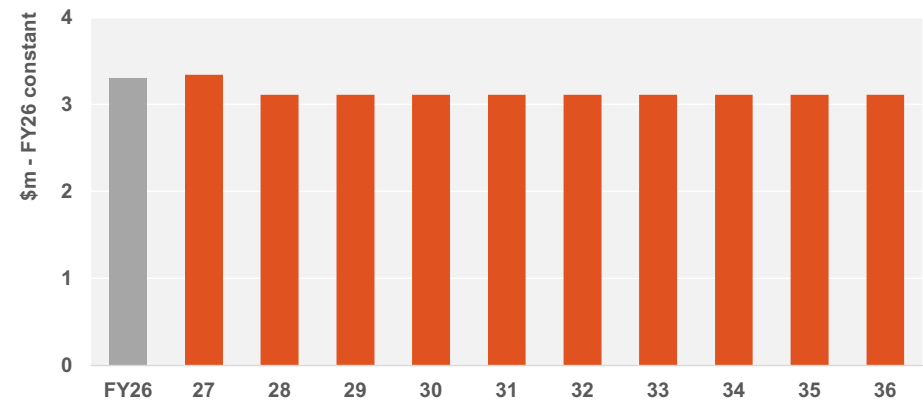
On the subtransmission network, we continue to apply a risk-based methodology through biennial ground inspections, complemented by annual aerial inspections using helicopters. This targeted approach has been effective in preventing vegetation-related faults on subtransmission assets and supports long-term network resilience.

Upon completion of the rapid inspection programme in FY27, we will maintain a three-year cycle of inspection and clearance. This will support a more comprehensive and sustainable approach focused on achieving long-term vegetation clearances. Our methodology will continue to evolve in response to changes to the Electricity (Hazards from Trees) Regulations 2003.

## Vegetation management expenditure

The following chart shows our forecast vegetation management opex. The expenditure requirement over the planning period is approximately \$3.1 million per year. This forecast is current and does not include estimated allocation derived from anticipated changes to the Electricity (Hazards from Trees) Regulations 2003.

Figure 9.2: Vegetation expenditure forecast



The key expenditure drivers for the portfolio are to:

- provide a safe network for the public, our staff, and contractors
- comply with tree regulations
- reduce the risk of vegetation-related events damaging network equipment
- provide a reliable network for our customers.

## Benefits

The main expected benefits of vegetation management work over the AMP period are:

- **management of safety risk:** reduced risks of our workforce and the public being exposed to injury
- **improved customer experience:** fewer unplanned outages, improving network reliability
- **compliance:** ensures that the network is in full compliance with the requirements set out in the tree regulations
- **engagement:** increased stakeholder awareness around risks associated with vegetation near conductors.

## 9.3 Overhead lines

This section describes our overhead lines portfolio and our fleet management plan. The portfolio includes three fleets:

- conductors
- poles
- crossarms.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational, and maintenance approaches and provides expenditure forecasts for the planning period.

### Box 9.1: Portfolio summary

We plan to invest in overhead lines to an average \$21.5 million per year over the period

This investment is needed to address our ageing fleet of conductors and crossarms, supporting our safety and reliability objectives. Failure of these assets can significantly impact public safety risk and network performance.

This renewals capex is driven by the need to:

- keep up with renewal requirements for our ageing crossarm and conductor fleets
- address type issues, particularly with small diameter copper conductors
- continue to replace poor condition concrete poles and phase out wooden poles.

Overhead lines are a core component of our network. Adequate performance of these assets is essential to maintaining a safe and reliable network. Most of our overhead lines are in public areas, therefore, managing our conductors and support structures is critical to minimise public safety risk, particularly in urban areas.

### 9.3.1 Overhead lines portfolio objectives

Our objectives for the overhead lines portfolio<sup>1</sup> are listed in Table 9.3.

**Table 9.3:** Overhead lines portfolio objectives

Objective area	Portfolio objectives
<b>A Safe Network</b>	No fatalities and injuries from unassisted overhead lines failures. Downward trend in unassisted overhead line failures.
<b>Network Performance</b>	Downward trend in unassisted overhead line failures. Minimise unplanned outages and supply interruption to customers. Minimise planned interruptions by coordinating with other works. Update design standards to support overhead lines resilience to weather extremes where practicable.
<b>Community Support</b>	Explore alternative technologies and materials to reduce lifecycle cost. Enhance condition data to improve renewal forecasting and optimise lifecycle cost.
<b>Sustainability</b>	Ensure all materials are sourced sustainably. Decommissioned assets disposed of responsibly.

### 9.3.2 Conductors

Conductors are a core component of our network. We use a variety of conductor types across a range of voltages. Our conductor fleet also includes conductor joints, hardware, and fittings.

We have defined our conductor fleet according to their operating voltage:

- subtransmission conductors (33 to 110kV)
- distribution conductors (11kV)
- low voltage (LV) conductors (400V and below).

This approach reflects the risks faced, the criticality of the asset, and the levels of service expected, all of which vary with voltage. This means these factors may require different lifecycle strategies.

Conductors are typically located in public areas, and asset failures could result in conductor drops, posing a risk of injury to the public. It is critical that we minimise this public safety risk by maintaining the fleet in good condition.

<sup>1</sup> All overhead lines capex is covered under asset replacement and renewal information disclosure category, line items 'subtransmission' and 'distribution and LV lines', included in Schedule 11a in Appendix B.

## Conductor fleet overview

### Subtransmission conductors

Subtransmission conductors connect our zone substations to a grid exit point (GXP) and generators operating at voltages ranging from 33kV to 110kV. We have a total of 324km of subtransmission conductors, of which the majority is aluminium clad steel reinforced (ACSR) type, followed by aluminium (Al) and a small amount of copper (Cu) type conductor, mostly on the Maungatapere lines.

Subtransmission lines often cross private land on direct routes rather than following roadside corridors commonly used for distribution and LV lines. This can mean that reconductoring involves extensive landowner consultation and consenting. Distribution and LV lines can also be installed underneath subtransmission lines on the same poles.

Subtransmission lines are critical assets as they generally transfer more power compared to distribution and LV lines. We typically design the subtransmission line network to have redundant (or N-1) supplies to our zone substations. This reduces the impact of the loss of any one circuit (in accordance with our security of supply guidelines outlined in Chapter 8).

Subtransmission conductors tend to be larger in size and require greater clearances compared to distribution and LV lines. Our 110kV subtransmission conductors are supported by towers, which are typically 15–25m above ground. These influences renewal costs when comparing subtransmission lines to distribution or LV lines. The maintenance regime differs from other conductors.

### Distribution conductors

Our distribution conductor fleet operates at 11kV, delivering electricity from zone substations to distribution substations, where it is converted to 400V for customer supply. Some customers connect directly to our network at 11kV.

We own approximately 3,500 circuit kilometres of overhead distribution conductor, comprising ACSR, copper, and aluminium types. Distribution conductors account for around 70% of our total overhead circuit length.

Distribution conductors are supported by overhead structures such as poles and crossarms, which may also carry a mix of LV conductors and service lines. A common configuration is distribution conductors positioned above LV conductors, with the lower conductors referred to as 'under-build'. In some cases, multiple distribution voltage circuits are installed on the same poles, either side by side or stacked vertically.

### LV conductors

LV conductors operate at voltages of 230V (line to ground), delivering electricity from our distribution substations to customers and supplying power to streetlights. We own approximately 1,200 circuit kilometres of overhead LV conductor, including streetlighting circuits. These are primarily composed of aluminium and copper, with a small volume of ACSR.<sup>2</sup>

LV conductors are supported by our overhead structures (poles and crossarms). Compared to distribution conductors, LV sections tend to be shorter in length, due to voltage drop limitations. Many LV lines serve only a small number of customers.

Historically, we have had limited visibility of our LV network, particularly in terms of asset data and utilisation, compared to our subtransmission and HV networks. However, with the recent integration of smart meter data, we now have partial visibility of LV utilisation. This enhanced data insight is helping us better understand network performance and customer demand at the LV level, enabling informed decision making and targeted operational improvements.

Due to these data limitations and the distinct physical characteristics of LV networks, such as shorter conductor spans and lower customer density, LV conductor are managed separately from other conductor fleets.

Like all overhead conductor types, LV conductors present inherent public safety risks, especially where live wires may become exposed in public areas due to conductor failure or damage. Although LV conductors operate at lower voltage than other fleets, they require specific safety management practices to address their unique risk profile.

### Population and age

The following table summarises our conductor population by type. ACSR conductors currently comprise 52% of circuit kilometres.

**Table 9.4:** Conductor circuit length (km) by type and voltage

Conductor type	Subtransmission	Distribution	Low voltage
ACSR	294	2,253	74
Aluminium	9	729	679
Copper	20	513	423
<b>Total</b>	<b>323</b>	<b>3,494</b>	<b>1,174</b>

The average age of our conductor fleet is 39 years. Breaking this down further, subtransmission conductors have an average age of 54 years, distribution conductors 38 years, and LV conductors 40 years. ACSR and all aluminium alloy conductors (AAAC) are the main conductor types used in our overhead lines. Over the past 20 years, new lines have been constructed, mainly to keep up with system growth, with only minor replacement activities undertaken. Up to about 15 to 20 years ago, ACSR and copper conductor were mainly used in the construction of HV and LV lines. Since then, aluminium type conductors have become the preferred choice. The following chart illustrates the significant network expansion that occurred 40 to 60 years ago. Most of these conductor fleets are now approaching, or have reached end of life.



<sup>2</sup> Consumer lines that serve a single customer are not owned and operated by Northpower, so are not explicitly covered explicitly in any statistics throughout this document.

**Figure 9.3: Conductor age profile**

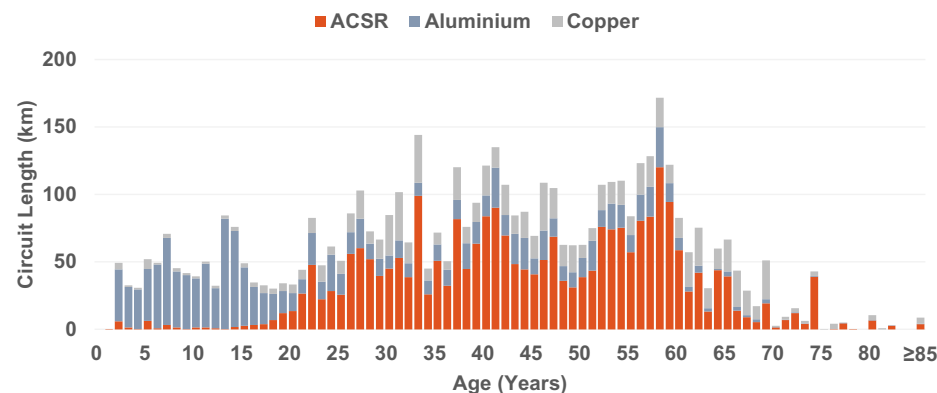


Table 9.5 sets out our conductors’ expected lives. This table applies across all voltages. Conductors of smaller diameter or located close to the coast have a shorter expected life. ACSR generally has a shorter expected life than other conductor types. Some ACSR conductors purchased before the mid-2000s had poor grease application quality control, many have patches with little or no grease. We refer to these as ‘grease issues’.

**Table 9.5: Overhead conductor expected lives**

Conductor type	Size (mm)	Within 500m of coast	500m – 5km to coast	>5km to coast
Aluminium	<100	77	93	110
Aluminium	≥100	87	103	120
ACSR – grease issues	<100	25	44	63
ACSR	<100	48	63	84
ACSR	≥100	58	73	94
Copper	<100	55	67	80
Copper	≥100	65	77	90

## Condition, performance, and risks

Managing the condition of our overhead conductor assets is critical to meeting our safety objectives. Asset failure can result in live conductors on the ground. Where the ground has high resistance, earth fault protection can have difficulty detecting faults, particularly if the conductor has landed on something other than the ground, such as a fence. Manual intervention by a circuit breaker operation following notification that a conductor is on the ground may be needed to de-energise the conductor.

Conductor failure can lead to loss of supply where there is N security. At subtransmission level, this is often not the case as the circuit will often comprise more than one line (such as N-1 security). However, at HV and LV levels, the circuit is commonly made up of a single line (such as N security) and loss of supply is the result. In most cases a back feed exists on the HV, but this usually requires a manual switching operation to restore supply.

To minimise public safety and network performance risk, we aim to proactively inspect and replace overhead conductor prior to failure.

### Condition

Overhead conductor condition assessment remains a challenge for the industry. A lack of visual defects does not necessarily mean the conductor is in good condition. Although our subtransmission conductor fleet is ageing, line failures are relatively rare due to its heavier, more robust construction.

#### Box 9.2: Meeting our portfolio objectives – network performance

Condition assessments on our subtransmission lines help to manage our failure risk on these assets. Early detection of issues allows us to address them before they fail and negatively impact network performance.

We have carried out a limited number of conductor break tests, and the results from the sample tests were compared against our expected life assumptions. These results are currently within anticipated statistical bounds.

We are expanding our conductor break testing programme to further verify our expected life assumptions, with a primary focus on small diameter conductors, as this is where we experience the most failures.

We will also begin undertaking detailed conductor assessment using images collected by drones, referencing the Electricity Engineers’ Association (EEA) Conductor Condition Guide published in August 2024.

**Box 9.3: Improvement initiative – expanding our conductor break testing regime**

To better understand the strength and expected lives of our conductors, we have been performing targeted destructive break testing, comparing test results against nominal rated tensile strength.

This testing programme is ongoing and sample selection will progressively be guided by drone-based detailed conductor assessment, helping identify assets nearing end of life. By evaluating actual strength and condition, we aim to improve our understanding of degradation, refine life expectancy estimates, and enhance asset health and forecasting models.

A network-wide sampling test undertaken in 2010 identified the presence of ACSR conductors suffering from grease issues. ACSR conductors have grease applied uniformly during manufacturing to provide a barrier to corrosion. However, if it is applied poorly, it is of little or even negative benefit. Grease application was poorly managed for conductors before to the mid-2000s and many conductors were ungreased before the 1970s.

Figure 9.4 shows the internal aluminium corrosion when grease has not been applied. In this case, the white aluminium corrosion product will gradually build up internally until the void space is filled, at which point bulging will occur. This reduces the strength of the conductor and may lead to conductor breakage.

**Figure 9.4:** Gopher ACSR conductor with broken strands and covered in aluminium oxide



We are unable to identify grease issues from historic records, and it would be difficult to identify these from visual inspections. However, as defects are uncovered through our inspections, we expect a higher proportion of these to be related to grease issues. We will replace these spans, rather than repair, when the defects are linked to greasing issues. We have estimated approximately 30% of our ACSR conductors suffer from greasing issues.

As part of the same initiative, we undertook destructive testing on select samples of copper conductors. The samples consisted of conductors that were installed near coastal regions, high wind areas, and in urban areas. The samples were hard-drawn bare copper conductors, which were between 20 and 50 years of age at the time of testing.

The results revealed that the copper conductors installed near coastal areas showed significant corrosion, with flaking<sup>3</sup> present and more than 10% reduction in tensile strength.

**Figure 9.5:** Copper conductor sample from a coastal area, showing corrosion



Figure 9.5 shows copper conductor sample that was installed in a coastal area. Approximately 50% of the cross-sectional area has been oxidised and easily flakes off.

The tests also revealed significant reduction in the cross-sectional area of conductors installed in both coastal and high wind areas. This area loss means that the power and fault capacity of the conductors has been reduced and could easily be overloaded, resulting in the conductor breaking.

This test has highlighted an elevated failure risk for our copper conductor fleet, particularly if they are installed near the coast or high wind areas. This fleet is the focus of our renewal programme in the short to medium term.

**Box 9.4: Meeting our portfolio objectives – network performance**

By identifying high-risk conductor fleet materials, we can update our network design standards to construct robust overhead lines to withstand harsh environmental conditions and minimise unassisted overhead line failures and unplanned outages.

3 Flaking is a result of green oxides building up on the conductor. They can be easily flaked off when handled.

## Performance

Our overhead network is designed to cope with certain environmental conditions such as defined wind loadings.<sup>4</sup> However, failures leading to conductor drops do occur, caused by the failure modes outlined in Table 9.6. This results in safety risk to the public and staff. We record outage cause data, and are working to further improve the accuracy of this data. We undertake follow-up investigations on all conductor incidents where we identify unassisted<sup>5</sup> failures. Knowing the root cause of a 'conductor down' event allows us to reduce the risk of recurrence.

**Table 9.6:** Conductor failure modes

Failure mode	Description
<b>Corrosion</b>	Corrosion occurs due to a chemical or electrochemical reaction between the conductor material and its environment. The conductor deteriorates and loses strength. A higher rate of corrosion can occur if the conductor is close to the coast where water containing sea salt will likely penetrate the conductor. The sea salt gradually builds up inside the conductor and promotes corrosion when dissimilar metals are present such as ACSR, or causes severe pitting in aluminium conductors.
<b>Oxidation</b>	When exposed to oxygen, a hard and resistant oxide coating forms on aluminium conductors, which reduces conductivity and makes working on it difficult. Some AAAC develop severe pitting and white corrosion, leading to a reduction in strength, when they are located close to the coast or near industrial plants. Some AAAC types are more brittle than others, leading to working difficulties and a higher chance of early failure from aeolian vibration.
<b>'Grease issues' / Galvanic corrosion</b>	This is applicable to ACSR conductors that have grease inconsistently applied during manufacture. This is prevalent in certain batches, manufactured during a particular period. Ungreased or 'grease holiday' conductors cause accelerated corrosion through galvanic cells forming due to dissimilar metals (such as aluminium, steel, and zinc), particularly if the conductor is located in salt-laden environments (such as coastal areas).
<b>Bulging</b>	Bulging is evidence of corrosion greater than 8% of cross-sectional area. Bulging is observable through both an increase in measurable conductor diameter, and discoloration of the line (white aluminium hydroxide).
<b>Fretting</b>	Fretting causes accelerated rates of degradation. Fretting is caused by rubbing between conductor strands and is associated with high conductor movement and lack of grease.
<b>Fatigue</b>	Fatigue occurs at locations of high conductor stress and cyclic load. Fatigue develops progressively and is not generally detectable with in situ visual inspection.
<b>Annealing</b>	Annealing occurs due to high temperatures (>100 degrees C) over an extended time period. Annealing reduces the yield strength of the conductor, and can be seen as changes in colour and sagging due to creep. Annealing reduces the ability of the line to withstand design loads and extreme events such as storms.
<b>Vegetation, wildlife or lightning</b>	Clashing of adjacent conductors or foreign object strikes (such as vegetation or birds) or lightning strikes can cause mechanical damage leading to loss of tensile strength.
<b>Small diameter copper</b>	Small diameter copper conductor is less durable than other types when it ages, simply based on its size. The loss of strength in even a small number of strands has a large impact on the strength of the overall conductor.

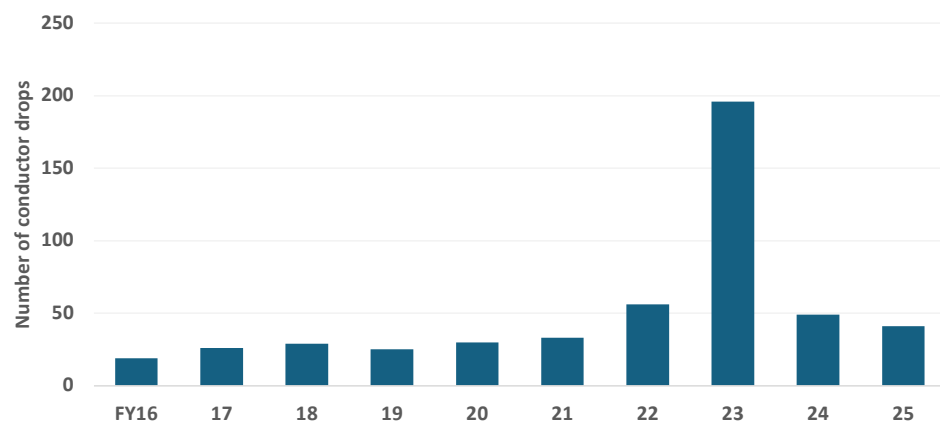
Over the past decade, the number of conductor drops per year has remained relatively stable. However, Cyclone Gabrielle caused a significant spike in incidents during 2023. Figure 9.6 indicates that the network is still in the process of recovering from some of the cyclone's impacts.

Vegetation has been a major contributing factor, either through direct contact with conductor or by being blown into lines during severe weather events. Additionally, some incidents have been linked to metal fatigue and poor connections.

<sup>4</sup> The design standards many of these assets were based on have evolved over time.

<sup>5</sup> An unassisted failure occurs when the asset fails, even though the mechanical loading forces being applied on the asset were within the original design strength capacity.

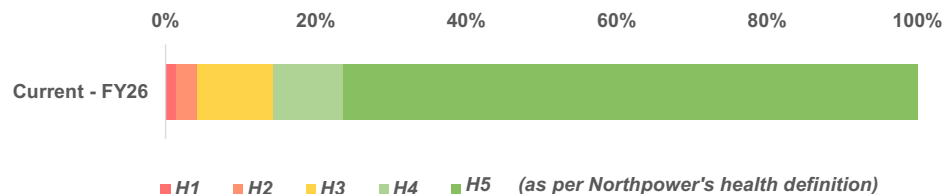
**Figure 9.6: Overhead conductor drops**



### Asset health

Conductor asset health is based on expected remaining life and considers the conductor's type, size, and location. Life expectancy is represented by a normal distribution for each expected life grouping. This approach is considered more robust than simply assuming equipment fails at a particular age.

**Figure 9.7: Conductor current asset health**



We expect to replace 15% of conductor lines over the next 10 years. The expected replacements mainly comprise copper and ACSR type conductors that have reached their expected end of life.

### Risks

Table 9.7 sets out a high-level summary of the key risks and mitigations we have identified in relation to our conductor fleets. They apply to varying degrees across all voltage levels. We are managing and mitigating these risks to the extent possible, including improving our understanding of condition through sampling and destructive testing, and managing condition through our renewal programme.

**Table 9.7: Conductor failure risks**

Description	Risk mitigation	Risk type
Conductor failure resulting in lines down or conductor drop to ground	Inspection regime and conductor break testing. Proactive replacement of conductor sections. Proactive replacement of joints and fittings. Standardisation of equipment. Training and educating lines workers on usage and installation of joints and fittings.	Safety, network performance
Conductor floating, due to failure of fittings and joints	Inspection regime including poles, crossarms, fittings, and joints. Proactive replacement of conductor sections.	Safety, network performance
Conductor overload, causing sag and potential for electrocution and fire.	Operating procedures, maximum demand indicator (MDI) readings, network planning, and subsequent work. Replace small conductor at risk of insufficient fault-handling capability.	Safety, network performance
'Low' conductor spans / non-compliant conductor clearances, elevating risk of contact with people, property, or livestock	Pole and conductor inspections or 'ring-ins' identifying low spans. Future: discussions with road owners about road level increases.	Safety
Conductor flashover due to tree contact	Vegetation management programme.	Network performance
Third party and wildlife causing conductor damage	Permit processes, public safety programmes, and inspection regime.	Safety, network performance
Accidental breach of safety clearances to live conductor, causing flashover	Safety programmes, first vegetation cuts, inspection regime.	Safety

## Design and build

All our overhead lines are designed using AS/NZS 7000 and related national standards such as NZECP34. The standards detail the design principles for overhead reticulation before and beyond the zone substation and up to the customer's point of connection. The design aims to minimise the amount of impact on landowners and the public. Conductor renewal is dependent on pole design, so we consider these together (as line design). Many poles usually require replacement on reconductoring projects.

We consider electrical, mechanical, environmental, economic, and standardisation factors across the network when determining the size and type of conductor. In most cases, we tend to choose AAAC conductor due to its high conductivity and low tendency to corrode. ACSR is our preferred option when we have long spans or high loading scenarios. We limit ACSR installations near the coast because corrosion can significantly reduce its lifetime. We also allow for 11kV lines to be run underneath subtransmission lines.

Climate change could influence overhead line design and construction standards. Higher ambient temperature could cause conductor sag, while more frequent and intense storms could lead to increased failures. As these events become more common, design standards and principles may be adapted to accommodate the changing environment.

Council requirements impose height restrictions for conductors in certain areas. When subtransmission conductors are due for replacement, we take these height restrictions into account. If we are unable to meet these height restrictions while maintaining safe clearances, we will assess the feasibility of rerouting or undergrounding the line.

Subtransmission conductor design is typically outsourced as they are more complex compared to distribution or LV lines. We have an in-house design team who fulfil a range of roles, from scoping, project engineering, and contractor design support through to standards development. Overhead conductor work is carried out by our contracting division. We have in-house quality assurance staff who carry out an audit of contractors' completed works.

## Operate and maintain

### Preventive maintenance

Overhead conductor maintenance and inspection regimes typically include visual inspections. Preventive maintenance and inspection tasks are summarised in Table 9.8. Conductors do not typically require routine maintenance. Due to wind-induced vibration and movement, as well as thermal cycling, they corrode and work-harden, becoming brittle. Inspections are typically done on a five-yearly basis to assess condition and support renewal decisions.

**Table 9.8: Conductor preventive maintenance tasks**

Maintenance and inspection task	Frequency
Helicopter inspection of subtransmission conductors. This is a visual inspection which picks up defects such as broken strands and signs of clashing. We also use infrared cameras to pick up overheating issues with loose terminations/joints.	Yearly
Aerial-based visual inspection (by drone) of a percentage of conductors as part of overhead network inspections which include conductor clearance checks and basic condition observations.	Five yearly
Break testing conductors to the manufactured standard. We test multiple samples, which then gives us a better picture of the line's strength and its future performance under loads.	Ad hoc

### Corrective maintenance

Corrective maintenance includes replacing damaged sections with new ones.

### Reactive maintenance

We undertake reactive maintenance on conductors when responding to faults which may be caused by conductor or fittings failures, adverse weather, or vegetation contact. To ensure we respond to faults in a timely manner, we maintain sufficient spares at strategic locations.

### Spares

We store spares for most conductor types in our warehouses/depots. As many of them are very old and we have a wide variety installed across the network, to ensure a reliable service, we often choose conductors of similar size if the required type or size is not readily available. Along with the conductor spares, we also maintain stocks such as fittings, joints, and other standard components.

#### **Box 9.5: Meeting portfolio objectives – network performance**

Having stock on hand allows us to act quickly to remediate unplanned outages and minimise disruption to our customers.

We are standardising our distribution conductors to AAAC. This will help reduce the range of conductors on the network, which in turn will mean less hardware is required in stock for spares.

## Renew or dispose

We trigger a review for conductor replacement based on age (versus expected life), as a proxy for condition. The review involves conductor sample testing to determine remaining strength and a follow-up with replacement where necessary. For known conductor-type issues, sample testing is usually not necessary (such as small diameter conductor). Our conductor forecasts include all replacement poles and pole-mounted equipment that are undertaken on the reconductoring project.

**Table 9.9:** Summary of conductor renewal approach

Aspect	Approach used
Renewal trigger	Age (versus expected life) and follow up condition assessment.
Forecasting approach	Repex modelling.
Cost estimation	Volumetric.

## Renewals forecasting

We use a repex<sup>6</sup> approach to do the forecasting for the conductor fleet. The repex methodology applies a normal distribution in expected life across the fleet. The use of a distribution reflects that statistically not all assets will require replacement at their stated end of expected life.

Our conductor life expectancies are based on trends observed in the industry. We will carry out more conductor sampling to verify these expected lives as discussed in earlier sections.

Our unit rates reflect the expected average cost to replace 1km of conductor and include an allowance for partial replacement of poles, crossarms, and pole-mounted equipment. The pole-mounted equipment is replaced where their condition is poor or they lack the strength or capacity to support the new conductor. The unit rates vary by voltage, as higher voltages generally require more expensive equipment and work.

## Options analysis

We typically replace conductor spans or line sections rather than the entire line. However, if most of the line is in poor condition, particularly if they were all built in the same era and use the same conductor type, then it is likely we will consider rebuilding the entire line. As such, we will consider options analysis, considering the following, but not limited to:

1. The condition of the support structures, such as poles and crossarms, and whether they will need replacing or if they can be reused. If the majority of the support structures require replacement, it may be cheaper to reroute the line. Rerouting the lines also reduces the impact of a prolonged outage compared to replacing in situ.
2. If the renewal need is combined with forecast growth, we often replace with a larger size conductor. This tends to require new poles to support the increased weight.
3. Undergrounding the existing line, particularly if we know a new development is proposed, or if it currently routes through heavily populated areas, or it is in a fault-prone area where trees cannot be cleared effectively.

Options analysis considers a wide variety of factors like whole lifecycle costs, growth options around the region, and network security risk.

Underbuilt conductors are considered for renewal with the distribution/subtransmission conductors, subject to their age versus expected life and economic efficiency of consolidating works.

Easement considerations are important when analysing options, as this can significantly affect project timing and budget. Where possible, we aim to use existing use rights. However, this is not always possible.

## Use of criticality in works planning and delivery

Large conductor projects are typically prioritised through detailed, site-specific quantitative studies (cost, constraints, and load/customer impact). For distribution and LV conductors, decisions are often made at section level, so a criticality rating is used to consistently prioritise works and schedule delivery.

## Disposal

When conductors are removed, they are typically in such a degraded condition that reuse is not an option. Removed conductors are scrapped.

<sup>6</sup> Repex refers to replacement expenditure and is based on a modelling technique typically used by Australian utilities and endorsed by the Australian Energy Regulator (AER).

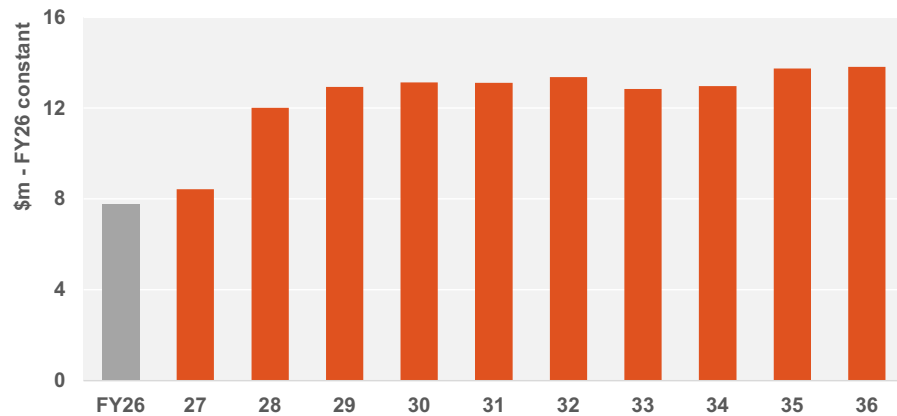
## Coordination with other works

Conductor replacement drivers may be combined with load growth. If a conductor requires replacement in the medium term, forecast load growth<sup>7</sup> will be considered. The preferred solution may be to replace with a larger size conductor. In the case of a like-for-like ampacity conductor, it may also increase the loading on support structures (for example, copper is smaller per ampacity than aluminium, so aluminium is lighter but has higher wind loading due to increased surface area). When we plan to replace conductors, we make sure that the support structures have sufficient mechanical load carrying capacity as per the latest standards.

## Conductor expenditure forecast

We have forecast conductor renewal capex of approximately \$126.3 million during the planning period.

**Figure 9.8:** Forecast conductor capex



<sup>7</sup> Analysis of future load growth in the area(s) supplied by subtransmission circuits, security of supply requirements, and network contingency scenarios are further discussed in Chapter 8.

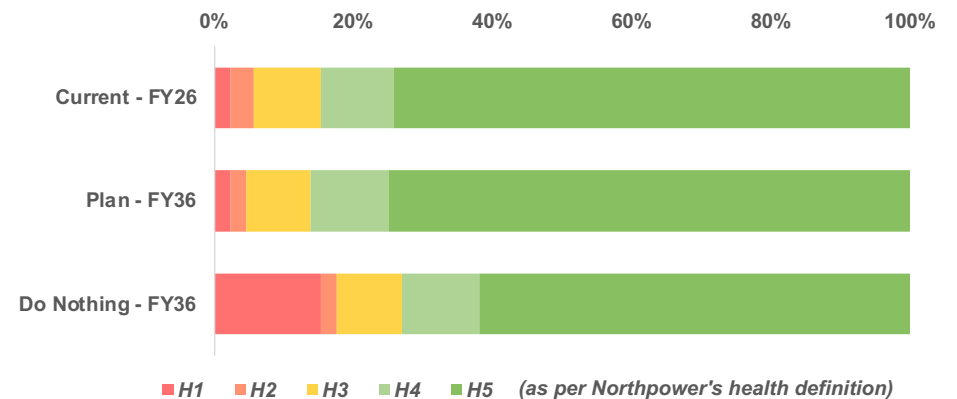
Historically, we have replaced conductors reactively, driven by conductor failure or damage, and at a relatively low rate. We are transitioning to a proactive replacement approach and expect this gradual increase to better manage the health of the conductor fleet.

## Benefits

The key benefits of our planned conductor renewal programme are improved overall asset fleet health, a reduced public safety risk, and maintained network performance. This is key to meeting our safety and network performance asset management objectives.

Figure 9.9 compares our projected asset health in FY26, following our planned programme of renewals, with a counterfactual do nothing scenario. This comparison indicates the benefits provided by our proposed investment programme.

**Figure 9.9:** Projected conductor asset health



Our proposed level of investment will improve overall fleet health, helping manage the risks associated with conductor failure. In the hypothetical do nothing scenario, 15% of our fleet, as depicted by the H1s, will be at risk of failure by FY36, leading to heightened public safety and network performance risk.

### 9.3.3 Poles

#### Pole fleet overview

Poles are key components of our network. Combined with overhead conductors and crossarms, they make up our overhead network that connects customers to the transmission system and enables electrical flow at various voltages. Poles also support distribution transformers, air break switches, and third-party assets such as streetlights, communication assets, and road signs. Figure 9.10 shows typical examples of our pole fleet.

**Figure 9.10:** Concrete poles - single pole (left) vs double pole (right) structure



Our poles fleet mainly consists of concrete poles and a relatively small number of wooden and steel poles. We have approximately 55,000 poles on our network. We also include our 48 transmission towers in this fleet.

#### Concrete poles

We have two types of concrete poles on our networks – pre-stressed and mass reinforced. Pre-stressed poles are manufactured with tensioned steel tendons (such as cables or rods). They are a mature technology and generally perform reliably over a long period. Most of the new poles we install are pre-stressed concrete. They are designed and manufactured to meet stringent structural standards. Pre-stressed poles are relatively robust against common concrete pole failure modes, such as cracking and spalling.

Mass reinforced concrete poles contain reinforcing steel bars covered by concrete. They were regularly used from the 1960s to 1980s, but only infrequently since then. We now prefer to install pre-stressed poles as mass reinforced tends to crack easily, which allows water ingress and eventual corrosion of the steel bars.

#### Wood poles

The wooden poles in use on the network are largely hardwood and have served reliably over time. However, they are no longer used for new lines or as replacements, as their strength and service life are generally lower than concrete poles. To support long-term resilience and performance, we now prefer concrete poles for new and replacement installations.

#### Steel poles

We have a small handful of steel poles in our fleet. These are mainly tubular-type steel poles, which are commonly used for supporting streetlights. In the past, we have installed these poles in very difficult terrain. They are manufactured in tubular sections, which makes them easy to transport and install.

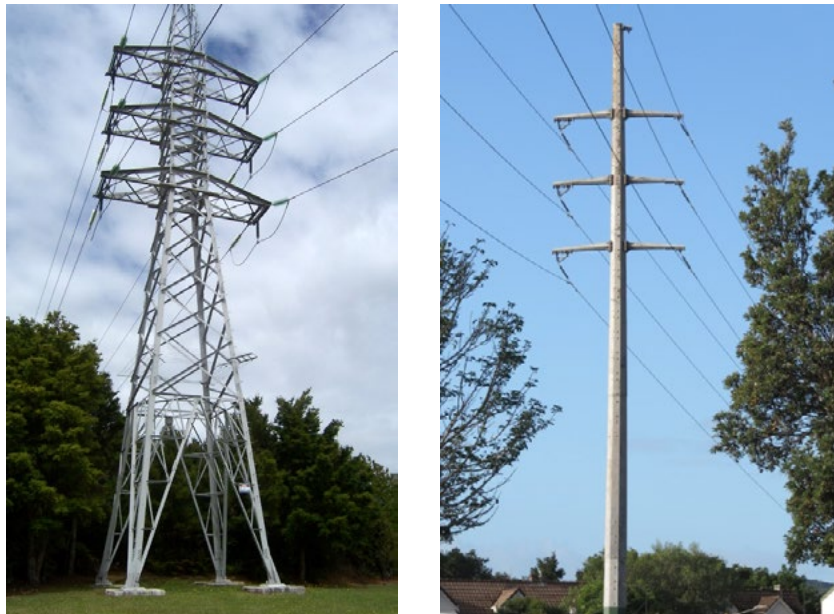
Most of these poles were installed without a concrete foundation directly embedded into the ground. We suspect this has caused significant corrosion to the steel below ground due to moisture ingress. Some of these are located close to the coast, exposing the steel to accelerated salt and moisture corrosion. We have abandoned the use of steel poles in favour of installing concrete poles, as they are expected to last longer.

#### Towers

We have one 110kV circuit which runs from Kensington to Maungatapere and one 66kV circuit from Dargaville to Maungatapere, which are both supported by towers. These towers are galvanised steel lattice structures, mounted on concrete footings. These towers are generally more complex than poles, comprising numerous components, such as steel members, bracers, attachment points, anti-climb hardware, lattice crossarms, signage, earth wire hardware, and insulator strings. Towers are connected to their concrete footings with baseplates. The concrete footings contain reinforcing which provides the structural strength to withstand the compression and lifting forces from the tower. The concrete footings also have an engineered earth grid surrounding the footings. This minimises hazardous step and touch potential, and voltage rises when a fault occurs on the tower. We maintain specific access tracks to these towers, which are used for maintenance and other planned work.

We also have two relatively large steel monopoles that support subtransmission lines. These are installed with engineered concrete foundations. Figure 9.11 shows the tower types.

**Figure 9.11:** Transmission lattice tower (left) and steel monopole structure (right)



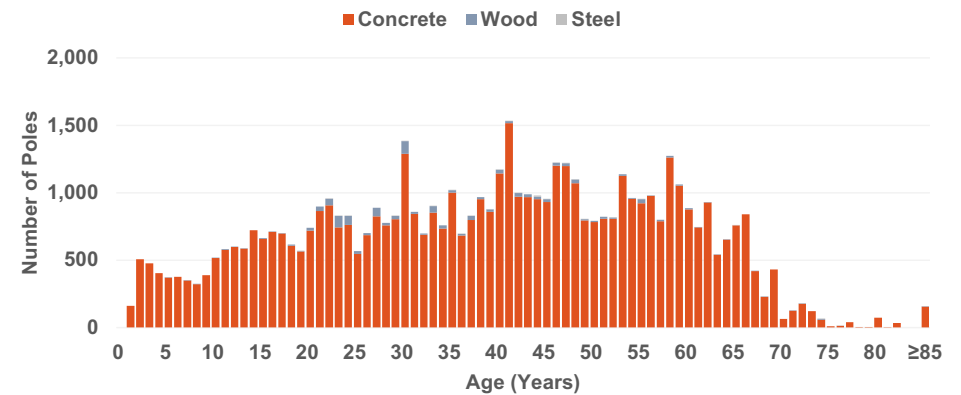
### Population and age

Table 9.10 summarises our population of poles by type. Concrete poles currently make up most of our poles (98%). In addition to our poles, we have 48 lattice towers.

**Table 9.10:** Pole population by type

Pole type	No of poles	Percentage
Concrete/ Steel Structure	53,924	98.0%
Wood	1,107	2.0%
Total	55,031	100%

**Figure 9.12:** Poles age profile



Our concrete pole fleet is relatively young, with an average age of 38 years old. Their expected life is 80 years. In contrast, the average age of our steel poles is 45 years old, and a large number of these have now exceeded their 30-year expected life. Our wooden pole fleet is approaching their 50-year expected life.

The subtransmission towers for the KEN-MPE line were first commissioned in 1975 and the DAR-MPE lines were constructed in 1993.

### Condition, performance, and risks

As with the conductor fleet, managing the condition of our poles is critical in meeting our safety and network performance objectives. When a pole fails in service, this presents a significant safety issue. It potentially exposes the public or our workers to hazards associated with falling equipment and live conductors on the ground or at unsafe heights. Typically, a pole failure will also result in loss of supply.

To minimise public safety and network performance risk, we aim to proactively inspect and replace poles prior to failure.

### Condition

Our poles are in relatively good condition overall. Historically the level of identified red-tagged poles<sup>8</sup> has remained relatively low, especially concrete poles. The majority of identified red-tagged poles are wood poles. We replace these poles within the legislated timeframe of three months.

<sup>8</sup> A red tagged pole means the pole is in poor condition and is identified as high priority for replacement. It is required to be replaced within three months of identification.

Our condition-driven concrete pole replacements are relatively few and mainly relate to spalling and cracking. Concrete poles tend to spall as they reach the end of their life. Spalling is where the internal reinforcing steel begins to corrode and swell, which causes the concrete to crack and break off in chunks, allowing more corrosion. Minor spalling does not reduce the strength of the pole significantly, but we want to prevent concrete from failing as that creates a safety hazard.

A larger proportion of our wood pole fleet, relative to concrete poles, is deemed to be in poor condition, based on our visual inspections. We verify the structural integrity of these poles undertaking ultrasonic measurements of the extent of decay to determine if these need to be replaced.

We suspect a portion of steel poles installed in ways that would not meet our current design standards, particularly those close to the coast, are in poor condition. We expect some significant corrosion in steel poles that have been directly embedded into the ground. It is difficult to assess the corrosion of the steel below ground or on the inside, but we are currently exploring options to do this work.

Condition assessment of our towers was undertaken in 2021. The towers were assessed to be in reasonable condition, with most components rated between 40–50 condition<sup>9</sup>. Key issues identified included rusting foundation bolts, insulator attachments, insulator pins, earth wire attachments, and cold/hot end suspension hardware. These issues have since been rectified through corrective maintenance and component replacement.

As part of the assessment, varying levels of corrosion have also been identified on steel surfaces, which led to the decision to recoat the towers in the Kensington-Maungatapere line. This work has helped extend the service life of the towers and improve their overall condition.

## Performance

Poles are generally located in public areas, so failures are a risk to public and worker safety. We specify poles, and use them in designs, so they can withstand the mechanical forces applied to them both by the equipment we have mounted on them and by expected external forces such as wind.

We have improved our outage data and are building more accurate records of pole failures/defects. Historically, pole failures have been low and have not led to any major public safety incidents. As part of our data improvement efforts, we are enhancing how outage data is captured and categorised, including details on fault types, causes, and remedies, to support better failure analysis and targeted corrective actions.

<sup>9</sup> The condition rating ranges from 0 to 100 where a condition rating of 20 or lower will require intervention.

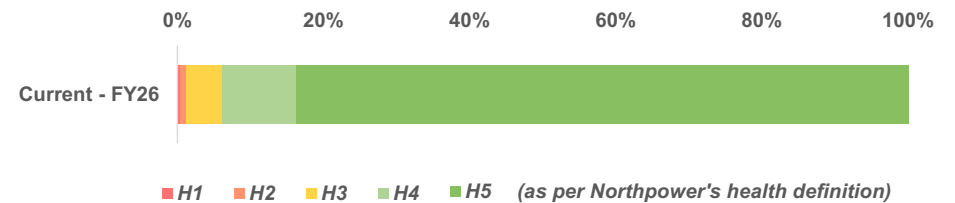
### Box 9.6: Meeting our portfolio objectives – a safe network and network performance

Identifying the cause of unassisted failures allows us to carry out corrective actions to our overhead network to lower public safety and network performance risk.

## Asset health

We have estimated our pole fleet’s asset health based on expected remaining life, for example, 80 years for concrete poles. Life expectancy is represented by a normal distribution, which is considered as a more robust approach compared to simply assuming the pole failing at a particular set age.

Figure 9.13: Poles current asset health



Current asset health shows that we expect to replace 6% of poles over the next 10 years. This is because the fleet is in relatively good condition.

## Risks

Table 9.11 summarises the key risks we have identified for poles.

**Table 9.11: Pole risks**

Risk/issue	Type	Risk mitigation	Main risk
Pole failure due to poor condition or slip failure	All	Visual inspection and/or proactive replacement.	Safety, network performance
Concrete spalling and falling	Concrete poles	Visual inspection and/or proactive replacement.	Safety, network performance
Assisted pole failure due to conditions that exceed design limits, such as extreme weather events, or vegetation onto line causing pole failure	All	Network planning/design, contingency planning, vegetation management and first response approach.	Safety, network performance
Outages or failures caused by a third party	All	Increase public awareness on safety risks, relocating poles.	Safety
Vermin-caused outages	All	Install possum guards / vermin deterrents on poles.	Network performance
Tower footings compromised due to slips	Towers	Routine visual inspection and engineering assessment of transmission lines after major storm events.	Network performance
Tower failure due to poor condition	Towers	Condition assessments and proactive replacement of components and corrective maintenance.	Network performance

We are managing and mitigating these risks where practical, including ensuring all poles are inspected within the legislated timeframes and proactively replacing poles in poor condition.

## Design and build

We specify our poles to mechanical loadings and clearances in accordance with NZECP34 and AS/NZS 7000. Newly installed poles typically have more mechanical loading capacity or better capability than the poles they replaced. Our current preferred pole type is pre-stressed concrete, which has the lowest overall lifecycle management costs compared to other types.

The physical placement of poles is important when considering historical frequency of car accidents on poles. If possible, we will locate them further away from roads and highways that are prone to accidents. We have in-house resource that provides design services while our contracting team carries out the replacements. There may be select cases where external resources are used for more complex designs and builds.

Our transmission towers and monopoles are engineered to specific site requirements, considering soil conditions, height restrictions, and landowner requirements. Typically, external resources will be used for engineering review and design services. Our contracting division is well equipped to install/repair/refurbish towers as required.

## Operate and maintain

Our maintenance activities for overhead support structures are listed in Table 9.12.

## Preventive maintenance

We inspect and test poles and undertake condition assessments for towers on a periodic basis. It is critical to regularly inspect all poles and towers because they may be damaged or compromised by an external party, land movement, deteriorating condition, or extreme weather events. Our preventive maintenance tasks are set out as follows.

**Table 9.12: Pole and towers preventive maintenance tasks**

Maintenance and inspection task	Type	Frequency
Transmission towers and monopole inspections	Towers	Two yearly
Transmission towers and monopole full condition assessment	Towers	Six yearly
Visual inspection, including other pole-mounted equipment such as distribution transformers and switches	Poles	Five yearly
Ultrasonic scan of wood poles to determine extent of decay	Wood poles	Five yearly or when identified by visual inspections

The pole visual inspection frequency is based on the legislative timeframe set out in NZECP34:2001. Where issues are identified, we may undertake further investigation before we decide to take further corrective action or replace the asset.

## Corrective maintenance

We undertake corrective maintenance on poles to repair or replace components of poles such as guy wires, bolts, and installing possum/cable guards. For the foreseeable future, we do not anticipate any uplift in corrective maintenance activities.

### Box 9.7: Improvement initiative – consumer poles

Electricity regulations require that consumer poles and conductors installed before 1984 are in a “reasonable standard of maintenance or repair” before ownership is transferred back to customers.

We are currently in the process of reviewing consumer poles to better understand the extent of inspection coverage and the level of compliance with regulatory requirements. Progress to date has been limited, and developing a comprehensive strategy remains a work in progress. As we further develop our position on managing risks associated with consumer poles, we will consider the potential implications for future expenditure.

## Reactive maintenance

Reactive maintenance on poles is the response to faults and failures. These may have been caused by extreme weather events or by an external party, such as car accidents. If reactive maintenance involves replacing the entire pole, the cost of the pole replacement itself, excluding first response cost is capitalised.

## Spares

Poles are standardised equipment and stock is held in our warehouses. These are located strategically around our network, allowing timely fault response. Our supplier also keeps a range of concrete poles in stock.

We have recently approved the acquisition of an emergency response tower to support rapid restoration in critical fault scenarios, as part of our new spares strategy.

## Renew or dispose

We replace poles when they are in poor condition or if they are below the strength requirements of a new conductor being installed. The latter will trigger an engineering review to ensure design standards are met.

Our preventive maintenance inspections identify poles for replacement. We have a targeted programme to replace wood poles with concrete poles as they reach the end of their serviceable lives. We also focus on identifying and replacing spalling concrete poles.

Table 9.13: Summary of poles renewal approach

Aspect	Approach used
Renewal trigger	Proactive condition-based. Reconductoring projects (forecast under conductors’ fleet or growth portfolio).
Forecasting approach	Repex modelling. Average poles replaced from planned reconductoring projects (forecast under conductors’ fleet or growth portfolio).
Cost estimation	Volumetric

## Renewals forecasting

We use a repex approach to forecast pole replacements. The repex methodology applies a normal distribution of the expected life across the pole fleet. The typical service lives for our poles are 80 years for concrete, 30 years for steel, and 50 years for wood. In the longer term, we intend to improve our forecasting methodology, so it becomes risk-based once we have improved our asset data collection process and inspections are strengthened.

Our unit rates are based on the expected average cost to replace a pole together with the crossarm assembly and the occasional pole-mount equipment.

## Options analysis

We consider the following options, which include both capex and opex trade-offs, to determine the lowest overall cost approach when managing pole risks.

- **Replace:** poles that are in poor condition or do not have the strength requirements to support existing or new conductors are replaced.
- **Repair:** we repair or replace pole components, such as guy wires, bolts, signs and guards if they are in poor condition.
- **Relocate:** if a pole location has a history of vehicle versus pole accidents we may consider relocating the pole to a safer location. Note: customer driven/funded relocation is covered under asset relocation capex.
- **Undergrounding:** we may consider undergrounding lines associated with poles in poor condition where modern clearance requirements cannot be feasibly met, or where district or council regulations restrict overhead installations. Note: customer driven/funded undergrounding is covered under asset relocation capex.
- **Remote area power system:** where there are very few customers, typically at the end of a rural line, it may be more cost-effective to install a remote area power system to supply these customers, compared to replacing the line.

For our transmission towers, we would undertake economic and optioneering analysis, to determine best way to manage their associated risks. Depending on the specific drivers and risks for each line or tower, this may include, but not be limited to, painting versus replacing the tower, componentry replacement, reinforcing ground condition such as installing retaining structures around tower footings, and replacement of the footings. The forecast presented in this section assumes periodic componentry replacement or repair. Other options may be undertaken in the future on an ad hoc basis, however, we believe this is immaterial with respect to the overall forecast as we expect very few to occur.

### Use of criticality in works planning and delivery

We prioritise pole replacements or defect repairs that could have a significant impact on public and worker safety and network performance. For concrete poles, this is done during an inspection or when the fault is found.

We have also actively developed a risk-based approach to pole replacement. The first version of this framework has delivered promising results and we will continue to improve and build upon it.

#### Box 9.8: Improvement initiative – criticality framework

We have developed a criticality framework to assess the consequence of asset failure. This framework is currently being improved to support works planning and delivery. It evaluates public safety risk by considering the proximity of poles to schools, hospitals, and other high foot-traffic areas and Network Performance set using Voll. Additional dimensions, including reputational, environmental, and legal or regulatory impacts are also being considered to provide a more comprehensive assessment.

### Disposal

We dispose of poles when they are replaced. Softwood poles treated with chromated copper arsenate (CCA) need to be disposed of at an appropriate facility. We currently do not repurpose poles for any reason.

#### Box 9.9: Meeting our portfolio objectives – sustainability

Wooden poles and crossarms are disposed of in an environmentally responsible manner.

### Coordination with other works

We replace pole-mounted equipment, such as distribution transformers and pole-mounted switchgear together with poles when they are in poor condition. During conductor replacements, we may also replace poles that are either in poor condition or under the strength required to support the new conductors. This enables efficient delivery and minimises customer disruption. All poles replaced on conductor projects are covered under the overhead conductor portfolio forecasts.

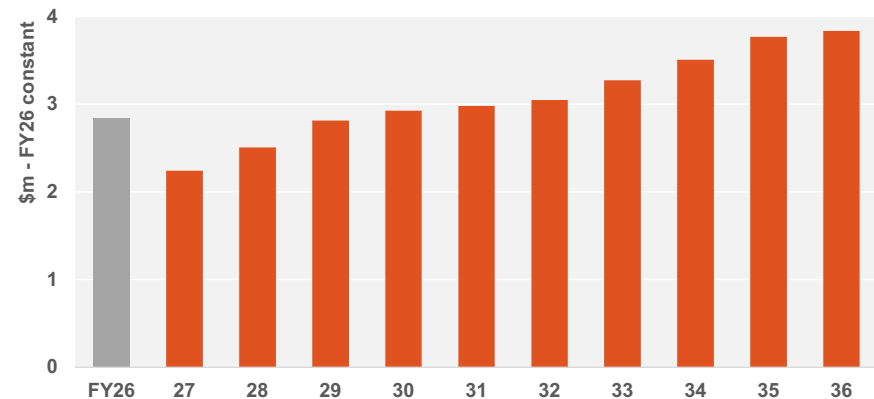
#### Box 9.10: Meeting our portfolio objectives – network performance

All surrounding and pole-mounted assets are assessed prior to planned pole replacements. Coordinating work helps minimise planned service interruptions for customers.

### Poles fleet expenditure forecast

We forecast renewal capex for poles and towers of approximately \$30.9 million in the planning period. This forecast excludes poles replaced with overhead conductors because of either condition or strength requirements. It covers the expected average cost of replacing pole-mounted equipment with the pole.

Figure 9.14: Forecast poles and towers capex

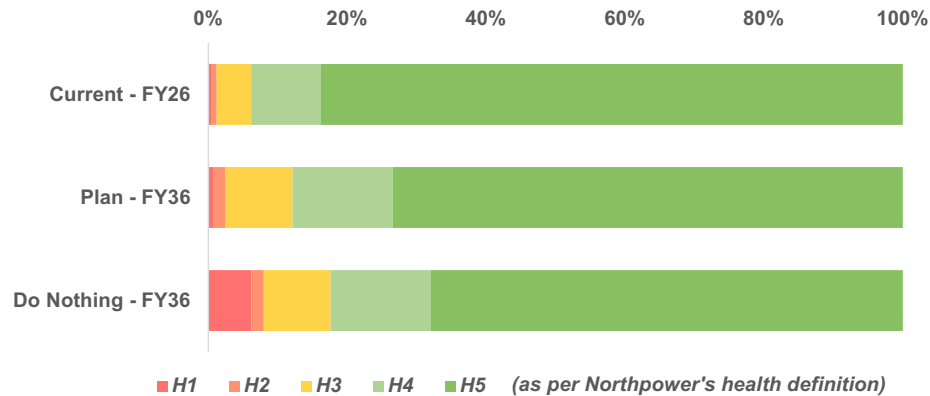


Our forecast aims to continue maintaining pole fleet health by replacing poles when they are in poor condition. This expenditure also includes an estimate of expected tower remediation. We expect this expenditure to gradually increase over time as the fleet population ages.

## Benefits

Figure 9.15 compares our projected asset health in FY36 following our planned programme of renewals, with a counterfactual do-nothing scenario. This comparison illustrates the benefits of our proposed programme.

**Figure 9.15:** Projected poles asset health



This proposed work programme will prevent approximately 6% of the fleet from becoming H1s over the period, relative to a do-nothing approach.

### 9.3.4 Crossarms

#### Crossarm fleet overview

Crossarms are used in conjunction with insulators to support overhead conductors. A typical crossarm assembly (commonly referred to as 'crossarm') consists of the crossarm itself, insulators, binders, jumpers, steel braces, and bolts. Other equipment can be mounted on crossarms, such as fuses, polemount switch, reclosers, and distribution transformers.

**Figure 9.16:** Crossarm assembly with drop-down fuses (left) and double crossarm arrangement (right)



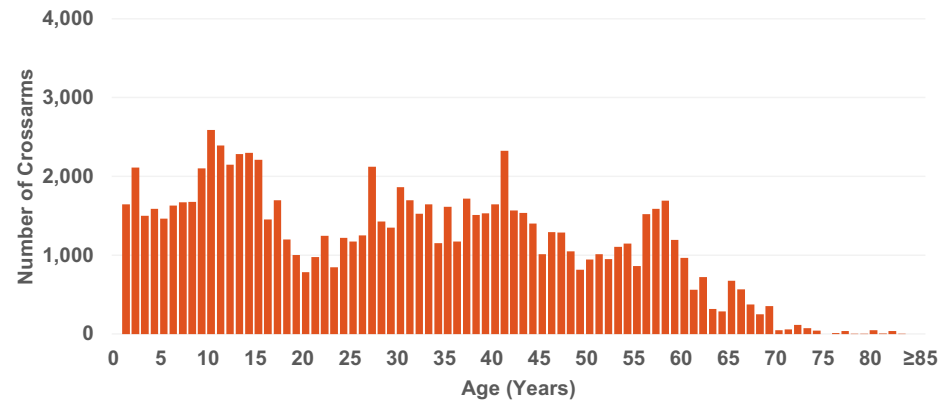
There are significant safety and performance risks associated with crossarm failure. Crossarms are always replaced when a pole is replaced. They are also replaced separately on an existing pole based on identified defects, even when the pole itself still has significant remaining life. We expect standalone replacement of crossarm assemblies to be a relatively large programme of work over the planning period.

#### Population and age

We have approximately 92,000 crossarms. Our crossarms are predominantly made from hardwood, with steel crossarms being used more recently on 11kV circuits. Wood crossarms have insulating characteristics that limit fault currents and can be easily drilled, allowing for simple installation of ancillary components. Steel crossarms are an alternative for high-strength requirements.

We are working on improving our data capture for crossarms to identify these separately as assets. Not all crossarm ages are recorded reliably, particularly older crossarms. Where this information is not known, we have assumed the crossarm is the same age as its pole. We believe this is a sound assumption as it is common to replace a crossarm at the same time as the pole. We are now capturing crossarm age information more consistently to improve asset data quality.

**Figure 9.17:** Crossarms age profile



We do not always record the type of crossarm we install. However, we know the majority of our crossarms are wooden as we have only recently installed steel crossarms on a limited basis. Wooden crossarms have an estimated useful life of 45 years, while steel crossarms are expected to last around 55 years.

**Box 9.11:** Meeting our portfolio objectives – a safe network and network performance

Our new asset management system and the input of accurate crossarm data will help improve our approach to crossarm renewal forecasting reducing the likelihood of failures.

### Condition, performance, and risks

In-service failure of a crossarm can lead to dropped conductors or spans lowered to unsafe clearances, presenting a significant safety risk to the public and usually leading to outages. Wooden crossarms typically fail from age-related deterioration, causing loss of strength, or from fungal decay, usually starting on the upper side because of exposure to moisture. Wooden crossarms also fail because of burning caused by electrical tracking from insulation degradation. Failure modes and rates of decay are strongly influenced by environmental conditions. Crossarm components also fail, for example when binders wear out over time and can loosen or break, allowing the conductor to swing free from the crossarm, usually resulting in an outage.

### Condition

Due to limitations in our data, we are unable to accurately confirm the condition of our crossarm fleet. Based on our assumptions, we suspect that many crossarms may be beyond their expected useful life. However, this may also reflect gaps in data quality rather than actual asset condition.

We are actively working to improve crossarm data to gain greater certainty around asset condition. This includes better recording of crossarms physical condition, type and age.

Currently, we conduct ground-based inspections as part of our overhead line inspection programme to identify defective crossarms. However, these inspections may not reliably detect issues such as decay, splitting, or weathering, especially on the top surfaces of wooden crossarms.

To address this gap, we have introduced a new inspection technique that include drone-based image capture, which will provide improved visibility of pole-top components. We are also introducing thermal imaging, acoustics testing, and pole-top photography to supplement ground-based inspections and improve condition assessment accuracy.



**Box 9.12: Innovation initiative – drone-based inspections for overhead line**

We are implementing drone-based image capture for overhead line inspections following a successful trial. This technique provides clearer, closer perspectives not achievable from the ground, enabling improved condition assessment and asset management.

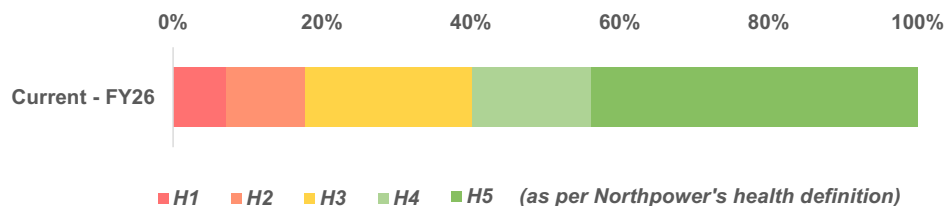
**Performance**

As discussed previously, we are working on improving our performance data to capture problem, cause, and remedy information at a more granular level. To date we have not had many crossarm failures, but this information will become more critical as the fleet ages.

**Asset health**

Our asset health index (AHI) for crossarms is based on expected remaining life where life expectancy is represented by a normal distribution with a mean of 45 years. Current asset health of our crossarm fleet is shown in Figure 9.18. It indicates approximately 6% of our crossarms are at end of life (H1), with a further 34% due for replacement over the next 10 years (H2 and H3). This is primarily due to many crossarms exceeding their expected life.

**Figure 9.18: Crossarms current asset health**



We are improving our crossarm inspections and asset data to have more certainty around the fleet health and investment requirements.

**Risks**

Crossarms by their nature may pose safety risks. For example, a crossarm failure can result in a conductor falling which, in turn, could result in an electrocution or fire. This will usually cause a loss of supply (except for instances where we have N-1 security).

**Table 9.14: Crossarm risks**

Risk/issue	Risk mitigation	Main risk
Insulator leakage leading to wood crossarm or pole fire.	Inspection programmes, leading to replacement of visually defective crossarms.	Safety
Leakage current on (generally pin type) insulators tracking along the wooden crossarm or tracking down the interface to a wooden pole, starting a fire. This often leads to the conductors floating above ground (potentially live) or falling to ground.	Ground-based inspection assisted by acoustics.	Network performance
Intermittent fault caused by leaking pin insulators. Often this is difficult to identify visually, particularly from the ground.	Inspection programmes, leading to replacement of visually defective crossarms.	Safety and network performance
Leaning insulator causing the conductor to detach, float, or fall to the ground.	Inspection programmes, leading to replacement of visually defective crossarms.	Safety and network performance
Wooden crossarm breakage due to wood ageing/degradation, causing conductor down or conductor floating event.	Inspection programmes, leading to replacement of visually defective crossarms.	Safety
Binder failure causing conductor down or to float.	Inspection programmes, leading to replacement of visually defective crossarms.	Safety

**Design and build**

Our current fleet mainly comprises hardwood crossarms, however, we are exploring the use of steel crossarms and have installed a small number. We may consider the use of fibreglass crossarms in the future. We are monitoring developments in polymer insulators and considering their wider usage. Wood crossarms are still preferred due to their non-conductive properties, lower upfront cost, and ease of customisation.

We specify post type insulators rather than pin type to avoid hole elongation failure due to conductor vibration and potential failure of the cement pin interface. Considerations around contracting options and design arrangements are the same for crossarms as for poles, however, crossarm replacement tends to require significantly less, if any, design work.

## Operate and maintain

### Preventive maintenance

Crossarm and insulator replacements generally result from preventive maintenance inspections and are often replaced in conjunction with pole replacements for efficiency. Renewals are done in conjunction with other maintenance tasks on poles or conductors.

**Table 9.15:** Crossarms preventive maintenance tasks

Maintenance and inspection task	Frequency
Helicopter inspection of crossarms on subtransmission circuits. This is a visual inspection which picks up defects such as cracks and decay.	Yearly
Ground-based visual inspection of crossarms as part of overhead network inspections, which includes basic condition observations.	Five yearly

Our inspections in the past have traditionally been ground based. However, wooden crossarms typically decay, split or weather from the top.

Starting next year, we will introduce a new inspection technique that includes drone-based image capture, which will provide improved visibility of pole-top components. We are also introducing thermal imaging, acoustics testing, and pole-top photography to supplement ground-based inspections and improve condition assessment accuracy.

This will help identify and diagnose defects faster and more accurately compared to traditional ground-based inspections.

### Corrective maintenance

Crossarm fault and defect repairs, identified by inspections or second fault responses, involve replacement of individual components. This typically includes:

- replacing broken or damaged arm braces and bolts
- replacing individual cracked or failed insulators
- repairing minor workmanship issues and defects, such as retightening on bolts, rust control on steel braces.

Any proactive work on crossarms that replaces the entire crossarm assembly, regardless of the defect, is considered capex.

### Reactive maintenance

Crossarm faults arising from first fault response involve similar activities as corrective maintenance, but they are unplanned. Occasionally, complete crossarm assembly replacement is needed to restore service.

## Renew or dispose

Historically, we have taken a reactive approach to crossarm renewal. This was mainly driven by defects identified. We have also replaced crossarms with poor condition poles. Our concrete poles typically last longer than crossarms, meaning this approach does not address the long-term failure risks associated with crossarms. We proactively replace crossarms as a standalone programme of works.

**Table 9.16:** Summary of crossarms renewals approach

Aspect	Approach used
Renewal trigger	Condition
Forecasting approach	Repex modelling
Cost estimation	Volumetric

We renew crossarms primarily based on condition, and we replace crossarms together with poor condition poles. We are working to transition into a more thorough condition-based renewal approach.

### Renewals forecasting

We use a repex approach to forecast crossarm renewals. The repex methodology applies a normal distribution in expected life across the fleet. Our crossarm expected life is 45 years, generally in alignment with others in the industry. In the longer term, we intend to improve our forecasting methodology, to be either condition or survivor curve based once we have improved our asset data collection process and inspections.

Our unit rates are based on the expected average cost to replace a standalone crossarm assembly. Conductors, poles, and pole-mounted equipment replacements are excluded as they are covered under their respective forecasts.

### Options analysis

Options analysis for crossarm replacements is generally limited to consider the most economical way to replace the crossarms, as opposed to ways to mitigate the crossarm failure risk. Generally, we replace the crossarm on the existing pole, if the existing pole has no issues or defects, or we replace the entire pole and crossarm assembly where both are in poor condition.

## Use of criticality in works planning and delivery

Crossarm replacements and defects that could have a significant impact on safety and network reliability are our priority. This includes prioritising poor condition or failed crossarms that pose a significant public safety risk (such as conductors have dropped due to a broken crossarm), potential to damage properties (such as crossarm fire), and/or significant loss of supply to customers. This prioritisation is currently done during the inspection or when the fault is found and can be subjective.

We have also actively developed a risk-based approach to pole replacement. The first version of this framework has delivered promising results, and we will continue to improve and build upon it.

## Disposal

Crossarm assemblies have no specific disposal requirements unless CCA treated, therefore, the same requirements as poles apply.

## Coordination with other works

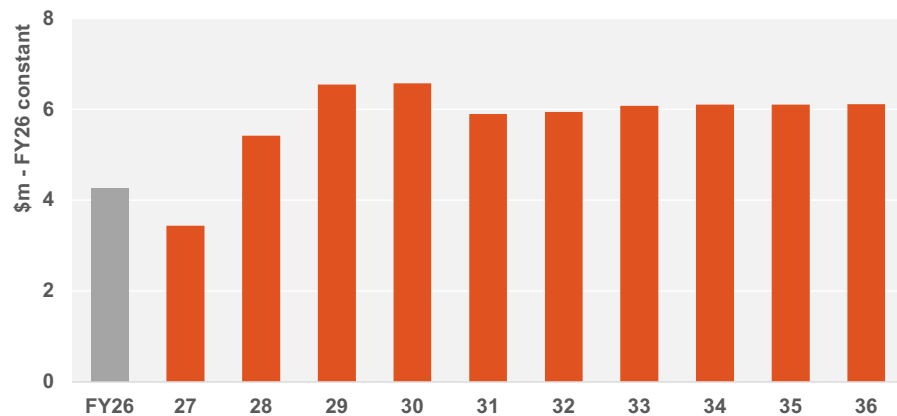
Like poles, crossarms are often replaced during overhead line reconstruction projects, such as conductor upgrades or network development works, or when replaced together with poles.

Because crossarms have a shorter expected lifespan than poles or conductor, their end-of-life replacement can often be efficiently coordinated with these planned works.

## Crossarm fleet expenditure forecast

We forecast renewal capex of approximately \$58 million for standalone crossarm replacements during the next 10 years. This excludes crossarms replaced with poles or conductors, other pole-mounted assets, distribution transformers, and reclosers.

Figure 9.19: Forecast crossarms capex



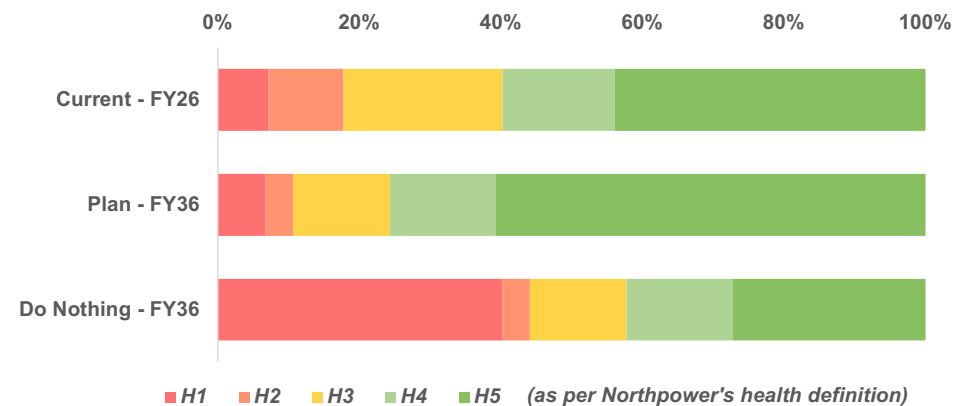
Our historical standalone crossarm replacement levels were low, as most replacements were bundled together with poles and conductors. We have increased our expenditure gradually and will continue this trend over the planning period while slowly ramping up to a steady state. This allows us to gradually lift the amount of work we can deliver in line with our long-term requirements.

The forecast assumes the standalone replacement of crossarms. Crossarms replaced with poor condition poles are included in the poles forecast.

## Benefits

Figure 9.20 shows our project asset health in FY36 following our planned programme of crossarm renewals and compares it with the current state, and a hypothetical do nothing scenario. This indicates the benefits provided by our proposed investment programme.

Figure 9.20: Projected crossarms asset health



Currently approximately 7% of our crossarm fleet have exceeded their expected life. Our planned renewals programme is expected to maintain the level at 7% by FY36. In the hypothetical do nothing scenario, 40% of our fleet will be H1 and at risk of failure by FY36. This would create significant risk on our network.

## 9.4 Substation equipment

This section describes our substation equipment portfolio<sup>10</sup> which includes four asset fleets:

- indoor switchgear
- outdoor switchgear
- substation power transformers
- infrastructure and facilities.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational, and maintenance approaches, and provides expenditure forecasts for the planning period.

### Box 9.13: Portfolio summary

During the planning period, we expect to increase our investment in substation equipment to an average of \$4.1 million per year. However, expenditure varies from year to year, due to the timing and size of each substation project.

In recent years, we have replaced equipment at our Poroti and Kaiwaka zone substations. We plan to continue with this programme of works, driven by a need to:

- replace poor condition assets, mainly replacing indoor switchgear, power transformers, and outdoor switchgear that have exceeded their expected life.
- manage safety risks, particularly for our workers. This is associated with some of our indoor switchgear which have higher than acceptable arc flash risks. As such, we have prioritised replacement of oil-filled, non-arc, fault-contained switchgear.
- manage reliability risks, particularly where equipment failure can disrupt supply to many customers. We have many areas supplied by buses that are not fully sectionalised or require manual switching to restore supply. This prolongs outages more than necessary. As such, we are prioritising substation equipment replacements that have high reliability impacts.

Our substation equipment portfolio includes equipment located in our regional and zone substations. We have two regional substations at Kensington and Maungatapere which take supply from GXPs at 110kV and stepping this down to subtransmission voltages at 66kV/33kV. These two regional substations then supply zone substations throughout central Northland. Other zone substations take supply directly from GXPs at 33V, such as Bream Bay and Maungaturoto.

Our zone substations provide connection points between subtransmission circuits and stepping down voltages (through power transformers) to supply the distribution network at 11kV. Within our zone substations, we use indoor and outdoor switchgear to control, switch, and isolate the network as part of day-to-day operations. Our regional and zone substations are high-value critical assets, as they supply many thousands of customers. Asset failures usually require a prolonged outage to replace.

Figure 9.21: Tikipunga zone substation outdoor switchyard



Some equipment is located within buildings, such as protection, SCADA, communication, and indoor switchgear. Most of our substation buildings have air conditioning units, ventilation, and other facilities to support the equipment housed there.

Power transformers, bus work, and outdoor switchgear are located in switchyards which typically contains engineered aggregate to minimise step and touch voltage hazards.

<sup>10</sup> All substation equipment capex is covered under asset replacement and renewal information disclosure category, line items zone substations, are included in Schedule 11a in Appendix B.

### 9.4.1 Substation equipment portfolio objectives

Our substation equipment portfolio objectives are listed in the Table 9.17.

**Table 9.17:** Substation equipment portfolio objectives

Objective area	Portfolio objectives
A Safe Network	No fatalities and injuries associated with our zone substation equipment, including from arc flash hazards. No fatalities or injuries to our workers or the public from step and touch potential hazards.
Network Performance	Manage failure risks through renewal and growth planning. Comply with our latest security of supply standard when renewing zone substation assets.
Community Support	Continue to develop and improve our asset health and risk modelling to support cost-effective decision making.
Sustainability	No uncontained oil spills or significant SF <sub>6</sub> leaks. Integrate the design of new zone substation assets with the neighbouring community to maintain or improve aesthetics.
Resolve any non-compliant noise pollution issues	Resolve any non-compliant noise pollution issues.

### 9.4.2 Indoor switchgear



#### Indoor switchgear fleet overview

Indoor switchgear consists of switchgear panels that contain internal circuit breakers and instrumentation. They also include protection, control, and automation devices. Indoor switchgear can be employed in 11kV and 33kV applications. Indoor switchgear is compact and is typically housed in rooms/buildings.

Due to its location and being less susceptible to harsh environmental conditions, indoor switchgear often exceeds life expectancy. Circuit breakers form an integral part of the switchgear and are used to interrupt both normal and fault current protecting primary plant. Due to the close and confined space, the failure of indoor switchgear poses a high safety risk. All modern switchgear is suitably specified to withstand arc flash incidents, resulting in a significant lower safety risk. Older switchgear is oil filled and does not include arc fault protection. Our approach to indoor switchgear renewal takes this risk into account and includes an oil-filled switchgear replacement schedule.

#### Population and age

Our zone substation portfolio includes a total of 197 indoor circuit breakers (making up 31 switchboards). Table 9.18 summarises the population by type and rated voltage.

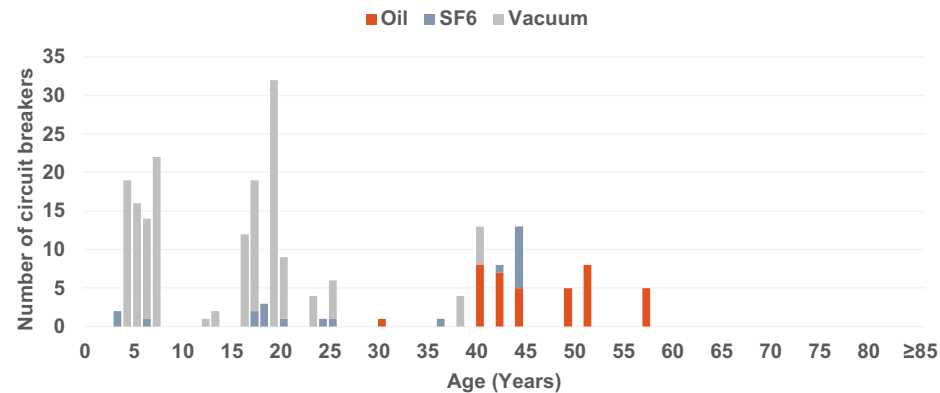
**Table 9.18:** Indoor switchgear circuit breaker population by rated voltage

Interrupting medium	11kV	33kV	Total
Vacuum	142	19	161
Oil	26		26
SF <sub>6</sub>		10	10
<b>Total</b>	<b>168</b>	<b>29</b>	<b>197</b>

Indoor switchgear technology has changed over time. Before the 1990s, most switchgear used oil as the insulation and arc quenching medium. Our older indoor switchgear population is mostly oil-filled. Over the last 20 years, all indoor switchgear installed was vacuum or SF<sub>6</sub> based. They have a lower maintenance cost over their lifetime, as well as better switching characteristics.

The average age of our indoor switchgear is 21 years. Life expectancy for vacuum and SF<sub>6</sub> circuit breakers is 45 years, with our current fleet at 14 years and 29 years respectively. Our oil circuit breakers have an average age of 46 years, with the oldest being 48 years. These circuit breakers have a life expectancy of 50 years based on standard industry practice.

**Figure 9.22:** Indoor switchgear age profile



## Condition, performance, and risks

### Condition

We carry out routine preventive maintenance which includes gathering information on the condition of the switchgear. Insulation resistance tests provide a good indication of potential insulation breakdown. We analyse test results and trends of the same make across zone substations. This gives us a good indication of any potential issues.

Overall, circuit breakers appear to be in good condition considering their age profile.

### Performance

In general, our indoor switchgear has proven to be reliable. Following a significant event in 2021, where a resin cast current transformer in a 33kV indoor switchboard failed during transformer re-livening, causing an explosion and tripping both 110kV circuits, we initiated a focused response to improve safety and resilience. Since then, we have been developing arc flash standards for both zone substation and distribution assets. These standards aim to quantify potential arc flash hazards across our existing infrastructure and establish clear guidelines and operational requirements to mitigate such risks moving forward.

#### Box 9.14: Meeting our portfolio objectives – a safe network

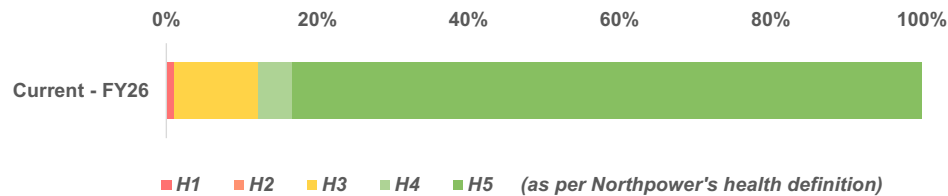
Ensuring operational procedures mitigate the risk of injury from arc flash hazard is prudent until the equipment is replaced or modified to meet modern Electrotechnical Commission (IEC) standards.

During scheduled preventive maintenance of indoor switchgear, circuit breakers are evaluated for operational integrity. Key indicators, such as breaker timing, interrupter oil condition and insulation resistance, are assessed in the context of equipment age and comparable models. The evaluation has confirmed that circuit breakers remain within acceptable operational parameters.

### Asset health

We consider the age of indoor switchgear to be a good proxy for asset health. We assign the AHI based on the remaining life of the asset when compared against the switchgear life expectancy. Life expectancy of the assets are varied in accordance with their field operating conditions. It is impacted by interrupter medium and the operating voltage ratio.

**Figure 9.23: Indoor switchgear current asset health**



We expect to replace 24% of indoor switchgear over the next 10 years. Around 5% of the assets are H1 and will need replacement in the short term. Most of these replacements will be driven by our ageing oil circuit breakers.

### Criticality

The key criticality dimensions are load serviced by the switchgear and operator safety. To prioritise the replacement of indoor switchgear, we have established a criticality index using a weighted average of the following factors:

- magnitude of the load supplied
- security levels of the operating zone substation
- fault rating capacity
- availability of spare parts
- arc flash criticality.

Replacement triggers have been identified by comparing the AHI values against the criticality index of the assets.

### Risks

The potential of arc flash is a significant safety concern. Arc flash can cause property damage, significant injury, or even death. Furthermore, if such a malfunction occurs, it would have a major impact on network performance because the switchboard will most likely be inoperable and will require full replacement.

Our new switchgear is oil free and equipped to detect and contain or disperse an arc flash event. As a result, arc flash dangers are reduced in new switchgear. Arc flash analysis has been completed on our 11kV switchboards to establish their risk levels. We have defined a prudent level of arc flash energy to be no more than 8cal/cm<sup>2</sup>. We use this, along with switchgear-specific factors, to categorise the risks of arc flash.

We use the following approaches to mitigate the risk of arc flash:

- personal protective equipment (PPE) used by the working personnel near the switchboards should have appropriate arc flash rating
- arc flash ratings can be reduced by reconfiguration of the upstream network
- carrying out switching operations through remote SCADA with workers outside.

Other types of circuit breakers, such as oil circuit breakers, can increase the risk of fire, while SF<sub>6</sub> circuit breakers can leak. Substation buildings also need to be vermin-proof to prevent rodents damaging the power and communication cables. We have rodent traps installed at all our substations to mitigate this risk.

### Design and build

Indoor switchgear is critical for the operation of our network. Our procurement, design, and installation process is rigorous enough to ensure the switchgear is fit for purpose. Vacuum and SF<sub>6</sub> circuit breakers no longer require frequent maintenance. The reliability of these units has significantly improved, which has considerably improved their whole-of-life cost.

We purchase indoor switchgear that has been arc flash tested in compliance with IEC 62271-200. In addition, when applicable, we are fitting our power transformers with neutral earthing resistors to lower phase-to-earth fault levels and the energy discharged during arc flash events to ground.

### Operate and maintain

#### Preventive maintenance

Indoor switchgear undergoes routine inspections and maintenance to ensure its continued safe and reliable operation. Partial discharge detection is a dependable maintenance technique for detecting a range of insulation-related faults that might cause failures. Also, condition monitoring of SF<sub>6</sub>, vacuum, and oil CBs are done on an as-needed basis.

**Table 9.19: Indoor switchgear preventive maintenance tasks**

Maintenance and inspection task	Frequency
Visual inspection of switchgear, circuit breakers, voltage transformers, and associated control panels as part of zone substation equipment inspection.	Two monthly
Acoustic emission and thermal imaging survey.	Yearly
Partial discharge survey.	Two yearly
Visual inspection of oil-filled 11kV switchgear condition, close/trip speed test, breaker service oil change, inspect and clean contact, electrical testing, and alarm check.	Four yearly
Visual inspection of vacuum and SF6 (11/33kV) switchgear condition, close/trip speed test, electrical testing, alarm check, check SF6 pressure, measure wear gap.	Four yearly
SF <sub>6</sub> moisture analysis.	Eight yearly

### Corrective maintenance

Indoor switchgear defects that were identified during inspections and maintenance are normally rectified under corrective maintenance. Normally SF<sub>6</sub> and vacuum circuit breakers are sealed for life and they seldom require any maintenance. In the event of a drop in pressure or leakage, maintenance is done by trained workers. Oil-filled circuit breakers can leak oil; this is addressed through corrective maintenance.

### Reactive maintenance

Reactive maintenance of indoor switchgear is response to maloperation alerts or alarms received in the control centre. In all cases, an on-site assessment is required, with potential follow-up action based on the results.

### Spares

Although switchboards are engineered to be highly reliable, they contain components that are crucial to their long-term operation. We have very limited spares available for older indoor switchgear. For the mid-life and new indoor switchgear, we carry spares so we can improve their repair times. When switchgear is retired, certain spare components may be held if they can be used for other assets still in service.

### Renew or dispose

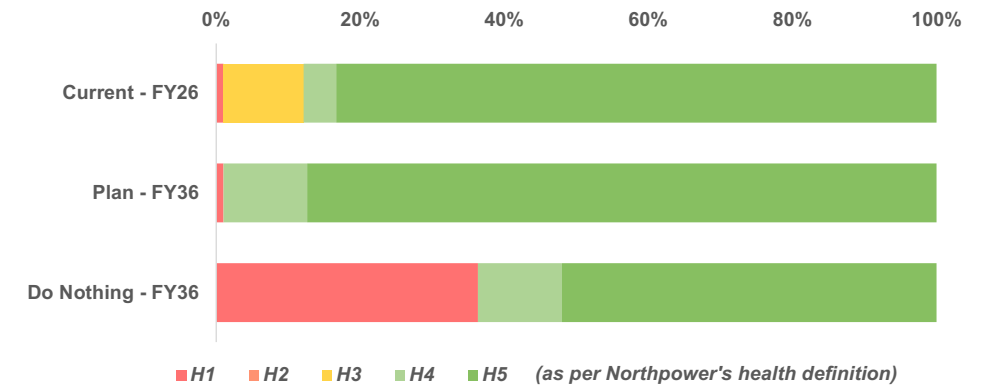
We plan our indoor switchgear renewal decisions based on the following factors: condition of the switchgear, known type and reliability issues, arc flash risks, fault levels, and spares availability. We examine all these aspects, as well as the criticality of the zone substation, to decide the best time for replacement.

We have a programme to replace old indoor switchboards equipped with oil-insulated 11kV circuit breakers with modern vacuum circuit breakers. Three 11kV switchboards are scheduled to be replaced over the next 10 years. In addition, there are two 33kV indoor switchboards which are planned for replacement during the same period.

### Renewals forecasting

We have created an asset health versus criticality risk matrix approach to forecast indoor switchgear renewals. The model allows us to forecast changes in asset health and asset risk over time. Figure 9.24 summarises AHI for our indoor switchboard fleet.

**Figure 9.24: Projected indoor switchgear asset health**



Our indoor switchgear fleet is getting older, and the chance of failure is growing. Asset health reflects this, with around 25% of our fleet requiring replacement during the period. Our planned fleet renewals programme will improve overall fleet health, decreasing H1s to around 2%. However, in the absence of any indoor switchgear renewals, asset health would deteriorate, creating a substantially greater level of H1s by the end of FY36.

**Table 9.20: Summary of indoor switchgear renewals approach**

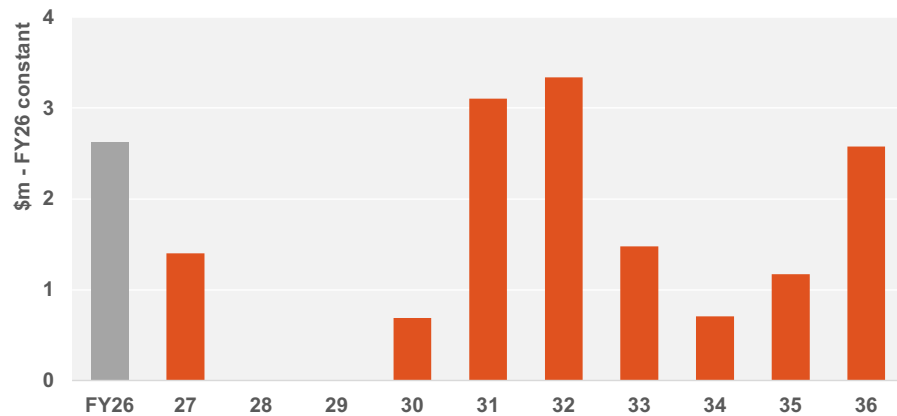
Aspect	Approach used
Renewal trigger	Ongoing programme replacing aged oil-filled circuit breakers with modern vacuum breakers over the next 10 years.

## Disposal

We dispose of any indoor switchgear that have reached end of life, as it is removed from service. As we face difficulty in sourcing spares for older makes of indoor switchgear, we assess if the same make/model switchboard is still in service at another location and consider retaining removed components as spares. We take great care while disposing of environmentally sensitive SF<sub>6</sub> circuit breakers, this work is handled by specialist contractors who appropriately dispose of them. Other parts of the indoor switchgear like oil, copper, aluminium, and steel are recycled.

## Indoor switchgear expenditure forecast

**Figure 9.25:** Forecast indoor switchgear capex



## Benefits

There are many benefits of our planned indoor switchgear renewal programme including:

- less safety risk, due to aged, oil-filled, or non-arc fault contained switchgear
- improved safety and network performance from reliable operation during faults
- enhanced safety in design with modern indoor switchgear
- enhanced network resilience through reduced downtime and fast arc flash protection clearance, preventing major equipment damage.

## 9.4.3 Outdoor switchgear



### Outdoor switchgear fleet overview

Outdoor circuit breakers, air-break switches, load break switches, and fuses are the asset categories connected with HV outdoor switchyards in the outdoor switchgear fleet. Outdoor switchgear, like indoor switchgear, is primarily used to regulate, protect, and isolate electrical circuits. It de-energises equipment and offers isolation points to allow access to equipment for maintenance or repairs.

Outdoor switchgear provides considerable flexibility for equipment replacement, however, it requires significantly more space than indoor. Where there are space constraints, we consider conversion of outdoor switchgear into indoor switchgear.

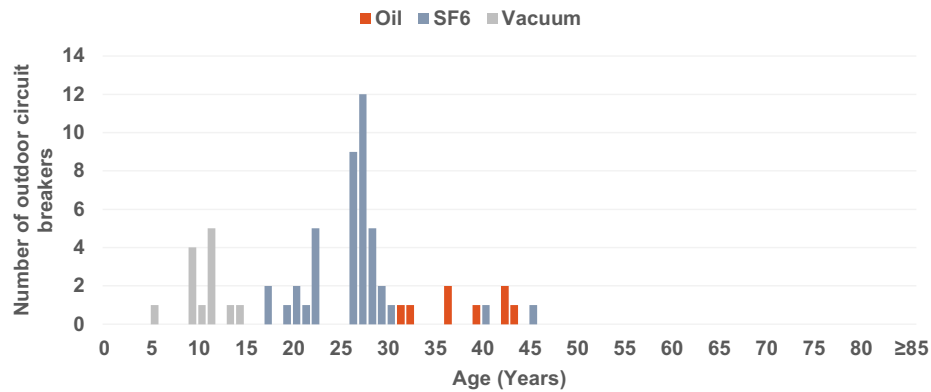
### Population and age

Table 9.21 summarises our population of outdoor switchgear by type.

**Table 9.21:** Outdoor switchgear population by rated voltage

Asset	Interrupting medium	33kV	50kV	Total
Outdoor circuit breakers	Vacuum	13		13
	Oil	8	8	
	SF <sub>6</sub>	36	6	42
Outdoor disconnectors & isolators		206	13	219
<b>Total</b>		<b>263</b>	<b>19</b>	<b>282</b>

**Figure 9.26:** Outdoor circuit breakers age profile<sup>11</sup>



The average age of our outdoor circuit breakers is 24 years, with vacuum and SF6 at 10 years and 26 years respectively. Our oil circuit breakers have an average age of 38 years and are in the process of being phased out.

### Condition, performance, and risks

#### Condition

Our oil circuit breaker fleet is obsolete as, in comparison to other types, oil-filled circuit breakers require more intensive maintenance and present a greater risk when switched, particularly when clearing faults. Spare parts are also difficult to obtain. We have developed a system for maintaining critical spares from retired circuit breakers and are in the process of retiring the remainder of the oil circuit breakers from our network.

Our SF<sub>6</sub> circuit breaker fleet is in generally good condition. We have had a small number of leaking SF<sub>6</sub> circuit breakers, and we are addressing these defects. The condition of the other outdoor switchgear assets on our network is generally satisfactory.

#### Performance

The outdoor switchgear fleet continues to perform reliably, with no recent in-service failures. However, we have identified recurring issues with gas leakage in a specific legacy model of SF<sub>6</sub> circuit breakers. These issues, while actively managed by targeted maintenance, highlight inherent design and ageing related vulnerabilities. As such, this has become a significant factor informing our current replacement strategy, ensuring long-term reliability and compliance with environmental and operational standards.

<sup>11</sup> This age profile excludes outdoor disconnectors and isolators.

### Criticality

In general, our outdoor switchgear has a high criticality because it is the main supply switchgear in our regional and zone substations. Outdoor switchgear replacements are mainly prioritised based on condition. The criticality framework under development will allow us to incorporate more criticality analysis into our outdoor switchgear replacement planning.

### Risks

Table 9.22 summarises the major risks identified with our outdoor switchgear fleet.

**Table 9.22:** Outdoor switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
SF <sub>6</sub> gas leaks	Regular check of pressure gauge. Fix leaks wherever possible.	Environmental
Lightning strike	Regular inspection of surge arrestor. Overhead earth wires.	Reliability Safety
Seismic event	Structural modifications.	Reliability
Failure to trip in fault conditions	Coordination of protection systems.	Reliability
Pests inside substation	Proper fencing. Pest detection sensors.	Reliability
Arcing fault – leading to explosion	Regular maintenance.	Safety

### Design and build

Our outdoor switchgear fleet has not yet been standardised with a particular type or make. To reduce emissions, we aim to use equipment that does not contain SF<sub>6</sub>, where economic. New outdoor switchyards are designed in accordance with best industry standard safety and access clearances. Wherever practical, to minimise downtime, replacements are planned to align with other replacements in the substation (such as power transformers).

#### Box 9.15: Meeting our portfolio objectives – sustainability

By reducing the SF<sub>6</sub> in our fleet, we lower the probability of leaking this greenhouse gas to the atmosphere. These alternative options are employed wherever they are economic.

## Operate and maintain

### Preventive maintenance

Preventive maintenance inspections on substation bus systems and structures highlight deterioration and issues requiring remedial action. Visual examination, thermal imaging, acoustic inspection, and partial discharge testing are used to identify components that need to be maintained and/or replaced. Our preventive maintenance routine is outlined in Table 9.23.

**Table 9.23:** Outdoor switchgear preventive maintenance tasks

Maintenance and inspection task	Frequency
Visual inspection of switchgear, circuit breakers, voltage transformers and associated control panels as part of zone substation equipment inspection.	Two monthly
Acoustic emission and thermal imaging survey.	Yearly
Partial discharge survey.	Two yearly
Visual inspection of Oil-filled 33kV switchgear condition, Kelman test, breaker service oil change, inspect and clean contact, electrical testing, and alarm check.	Four yearly
Visual inspection of vacuum and SF <sub>6</sub> 33kV switchgear condition, electrical testing, alarm check, SF <sub>6</sub> pressure, measure wear gap.	Four yearly
SF <sub>6</sub> moisture analysis.	Eight yearly

### Corrective maintenance

Defects observed during preventive maintenance or visual inspections are addressed through corrective maintenance. Common defects are corrosion, gas or oil leaks, and loose bolts. Outdoor switchgear is exposed to weather conditions, so it generally requires more preventative and corrective maintenance than indoor switchgear.

### Reactive maintenance

When there is an alarm from SCADA or a maloperation or failure, we send technicians on-site for inspections and corrective actions. One of the major hurdles faced in reactive maintenance of older outdoor switchgear is the lack of spare parts and technical expertise.

### Spares

We keep strategic spares to maintain our outdoor switchgear fleet. We also hold some older stock where spares are difficult to source. When switchgear is decommissioned, we determine if the unit is required as a whole or whether components can be re-used.

## Renew or dispose

Our strategy is to replace circuit breakers and other outdoor switchgear equipment based on condition. We strive to avoid equipment failure as network performance and safety consequences can be severe.

**Table 9.24:** Summary of outdoor switchgear renewals approach

Aspect	Approach used
Outdoor switchgear	Proactive condition-based replacement.

### Renewals forecasting

We individually plan (and forecast) outdoor switchgear replacements based on age and condition (visual and measured), while taking into account factors such as obsolescence and type issues.

Projects are individually costed based on desktop analysis of the scope required to replace the switchgear.

### Options analysis

Options analysis is carried out for each outdoor switchgear replacement. We generally consider two options for outdoor switchgear replacements where there:

- is sufficient room and clearances, we usually adopt a like-for-like replacement
- are clearance issues and space constraints (including consideration of future expansion requirements), we consider outdoor to indoor conversions.

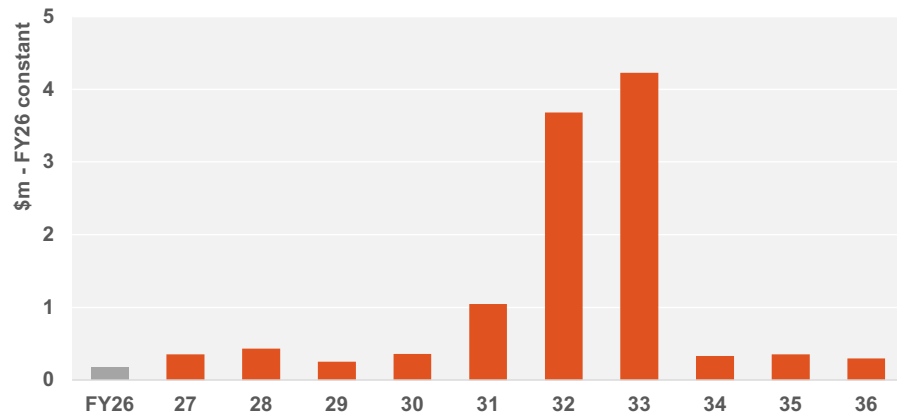
Both options are analysed and the option with the lowest whole-of-life cost that meets the required need is generally chosen.

### Disposal

When outdoor switchgear reaches the end of its service life and is removed from service, we dispose of it. We review the retention of spare parts for any switchgear that is currently operating at another location. Oil and SF<sub>6</sub> are carefully disposed without causing significant environmental impacts, while other switchgear components like copper, aluminium, and steel, are recycled.

## Outdoor switchgear expenditure forecast

Figure 9.27: Forecast outdoor switchgear capex



### Benefits

There are numerous benefits of our planned outdoor switchgear renewal programme:

- less safety risk as we will have less aged, oil-filled switchgear in the fleet
- improved safety and network performance from reliable operation during faults
- improved maintainability and worker safety due to better clearances around equipment.

## 9.4.4 Substation power transformers



### Substation power transformers fleet overview

Power transformers installed at the zone substations are used to transform power from one voltage level to another. Most of our power transformers operate at 33/11kV but there are some operating at 50/11kV and 110kV. Capacities range from 3.75 to 100MVA. The power transformers are equipped with on load tap changers which are designed to maintain the distribution supply voltage, irrespective of the load changes on the grid. To mitigate risks from oil leaks and fire in case of faults, modern power transformers incorporate fire walls and oil bunds.

The main components of a power transformer are the core and windings, housing (or tank), bushings, cable boxes, insulating oil conservation and management systems, breather, cooling systems, and tap-changing mechanisms. They are typically reliable. Condition assessment is determined by regular routine testing and inspections. Transformers are typically expensive and have long lead times; therefore, robust planning processes to avoid failure are required, especially for cases where there is only N security.

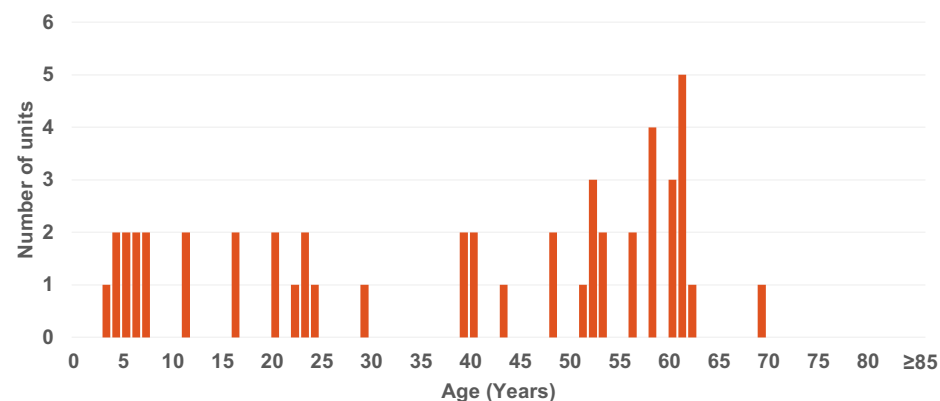
### Population and age

Table 9.25 summarises the power transformer population by its operating voltage and size. We buy standard sizes and vector configuration across the network to increase operational flexibility. Our substation power transformers are on average 38 years old, which is lower than the industry expected life standard of 60 years. We have four power transformers that are more than 60 years old, and 10 more are scheduled to reach that age in the next five years.

**Table 9.25:** Substation power transformers population by size

Highest operating voltage	Size (mVA)	Population
11kV	<10	2
33kV	<10	13
	10-20	19
50kV	10-20	2
110kV	10-30	12
	>30	2
<b>Total</b>		<b>50</b>

**Figure 9.28:** Substation power transformers age profile



Our network has 50 operational power transformers across 23 regional and zone substations. All except the 110kV transformers at Maungatapere substation have on load tap changers.

### Condition, performance, and risks

#### Condition

Our power transformer fleet is in generally good condition and displays no evidence of substantial internal deterioration, overheating, or arcing. They are regularly tested and inspected. This helps us understand their ageing and to identify defects.

### Performance

Power transformer failures are uncommon, but they can have serious consequences. A failure may lead to a long downtime, depending on its severity. Power transformer failures can result in loss of supply or reduced security of supply, depending on the security level of the zone substation. On load tap changer failures are often caused by wear and tear of the moving contacts, while large failures are mostly caused by manufacturing flaws in the core and windings.

Over the past 15 years, three significant power transformer failures occurred in our substations, each requiring complete replacement of the transformer.

- **Mareretu** (failed in 2017, age 52 at time of failure): A winding fault developed inside the transformer. It was uneconomic to repair since there were no winding facilities in the country for that size of transformer.
- **Kensington** (failed in 2015, age 57 at time of failure): A winding fault occurred within the transformer due to water drizzling from the conservator. It was uneconomic to repair considering its age and the fact there were no suitable winding facilities in the country.
- **Kaiwaka** (failed in 2015, age 55 at time of failure): There was a problem with the on load tap changer that led to the box deforming. This needed a full restoration. However, given the remaining life of the transformer and the necessity for parts to be fabricated abroad, it was decided that repair was not cost effective.

The age of the power transformers that failed prematurely supports the base life expectancy of 60 years. During analysis of the common faults occurring in transformers, it has been observed that a frequent contributor to the faults is on load tap changers, and in most of the cases this occurs due to defective contacts. When such problems arise, they are typically addressed through corrective maintenance.

### Asset health

Our routine testing and inspection of power transformers helps us understand the extent of degradation and allows for the early detection of any possible internal faults. The fleet's exterior condition, particularly the degree of corrosion and oil leaks, is in accordance with expectations based on age and location. We have used the EEA's AHI guide (2019) to assess power transformer health by determining scores for end-of-life drivers such as paper degree of polymerisation, bushing condition, tank external condition, and insulation system condition. We apply weightings to establish an overall health assessment.

Based on the AHI scores of our 50 transformers, two of them are programmed for replacement over the next 10 years.

## Criticality

Power transformers generally have a high criticality and are a priority for replacement based on condition. The criticality framework we are developing will enable us to incorporate more criticality analysis into our power transformer replacement planning.

## Risks

The major risks found in our power transformer fleet are summarised in Table 9.26.

**Table 9.26: Power transformer risks**

Risk/issue	Risk mitigation	Main risk
Oil spill	Bunding and oil containment are features of new transformers to contain oil spills.  Routine inspections to look for low oil levels, oil leaks, and corrosion that can lead to leaks.  Corrective maintenance remediation.	Environment and sustainability.
Fire caused by a faulty transformer	Replacements and new transformer installations are carried out to meet clearance standards, or firewalls are installed.	Safety
Seismic event	New transformers are designed to be seismically compliant.	Network performance Safety
Transformer noise	Remedial measures are undertaken in case of excessive noise.	Environment and sustainability
Failures in on load tap changer and transformer internals	Oil testing of on load tap changer.  Preventive maintenance of on load tap changers.  Strategic spares.  Maintaining N-1 security levels for larger loads.	Network performance
Lightning strike or switching surge	Surge arrestors on both LV and HV side of the transformer.	Network performance

## Design and build

We have procurement controls in place to ensure we install high-quality and reliable power transformers. By working with a limited number of manufacturers and using uniform standards and design, our procurement processes have become more effective. Quality control measures are employed throughout procurement, installation, and commissioning.

New power transformer installations are equipped with suitable oil containment facilities and, where required, suitably designed firewalls. These are constructed to meet local seismic requirements. Before the installation of any power transformer, where there may be potential noise implications, we conduct acoustic studies and install appropriate controls to ensure we comply with council noise rules.

### Box 9.16: Meeting our portfolio objectives – sustainability

We ensure non-compliant noise pollution issues are quickly resolved. We consult with local councils and communities on aesthetic requirements for new asset installations.

## Operate and maintain

### Preventive maintenance

Power transformers and their components, such as tap changers, undergo preventive maintenance to ensure their continued safe and reliable operation. Preventive maintenance activities for our power transformer fleet are summarised in Table 9.27.

**Table 9.27: Substation power transformers preventive maintenance tasks**

Maintenance and inspection task	Frequency
Visual inspection of transformers as part of zone substation equipment inspection: including inspecting oil levels/leaks, breather fault, Buchholz, winding/oil temperature, fans, tap changer, silica gel.	Two monthly
Acoustic emission and thermal imaging survey.	Yearly
Dissolved gas analysis to identify the presence of internal faults.	Yearly
Partial discharge survey.	Yearly
Polarisation depolarisation current testing.	Two yearly
Tap changer service as part of transformer service and structure inspection.	Four yearly
Visual inspection, insulation resistance, oil temperature gauge checks, Buchholz and pressure relief operational test, neutral earth resistor test.	Four yearly

## Corrective maintenance

Corrective maintenance activities on power transformers include corrosion treatment, silica gel replacements, and repair of faulty components. Where oil is found to be out of specification it is filtered or replaced. For transformers that are near to the coast, we usually paint and repair rust as part of their mid-life refurbishment.

Minor defects discovered during visual inspections, such as corrosion, oil leaks, loose connections, faulty earthing, are repaired on site. Major defects identified during inspections, such as internal flaws in the core, winding, and tap changers, may require specialist resources and take longer to resolve.

## Reactive maintenance

We carry out reactive maintenance on power transformers in response to minor and major faults. Alarms from sensors contribute to minor faults and may require an outage to repair. Major faults may be caused by issues in windings or the tap changer, which have caused the transformer mechanical protection to trip. These faults usually lead to prolonged outage and repair times.

## Spares

We maintain a 33/11kV 5MVA transformer and a 110/19.1kV 16MVA single phase transformer as strategic spares, ready to be deployed in the event of a major fault to support operational continuity under contingency scenarios. The 5MVA unit is scheduled for retirement due to its age and limited capacity, which no longer aligns with the load in most of our substations. A new spare will be procured to ensure adequate coverage and maintain network resilience.

In addition to transformer spares, we hold essential sensors and other major components in stock to enable timely fault response. When transformers are retired, reusable parts are assessed for compatibility with other units in the network and retained where practical. This practice supports asset lifecycle optimisation and strengthens overall system reliability.

## Renew or dispose

We plan for the renewal of our power transformers based on condition. This is assessed using a combination of age, measured and observed condition, type issues, and maintenance costs. Power transformer replacements are grouped with other renewal needs at the zone substation and are delivered as single projects.

## Renewals forecasting

Power transformers are individually scheduled for renewal based on condition. We carry out a desktop assessment to determine the approximate scope and cost of the replacement project for forecasting purposes.

We are developing a transformer risk model to forecast power transformer replacements based on risk. We are improving and refining our asset health and criticality models to enable improved risk-based decisions.

## Options analysis

When a transformer is identified to be in a poor condition, options for replacement, refurbishment, component replacement, or decommissioning/network reconfiguration are typically considered. The preferred option is selected based on the lowest whole-of-life cost.

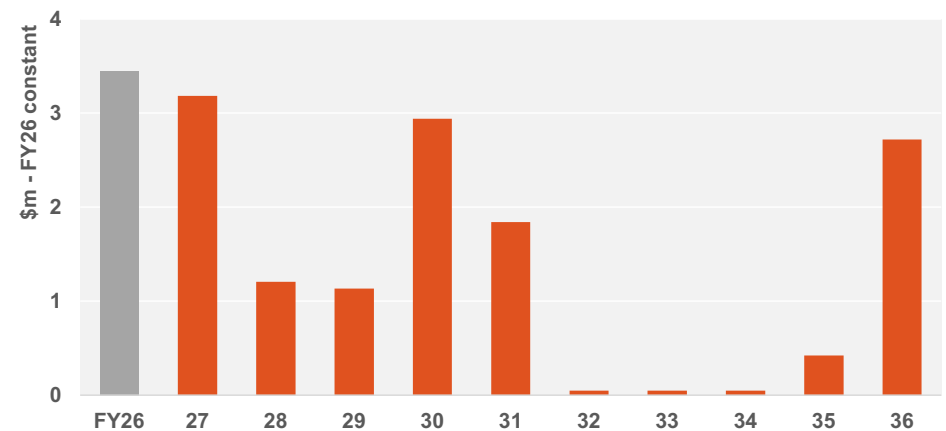
As part of our power transformer renewal programme, we will upgrade oil containment and separation systems, install transformer firewalls, and review and upgrade transformer foundations to ensure appropriate seismic standards are met.

## Disposal

When power transformers cannot be redeployed and can no longer be used as a spare, we dispose of them. Oil is disposed of through an approved handler and the transformer's copper and steel are recycled.

## Power transformer expenditure forecast

Figure 9.29: Forecast substation power transformers capex



## Benefits

The benefits of our power transformer renewal programme are:

- decreased disruption risk by removing higher failure-risk transformers
- mitigation of environmental risk by installing modern oil containment.

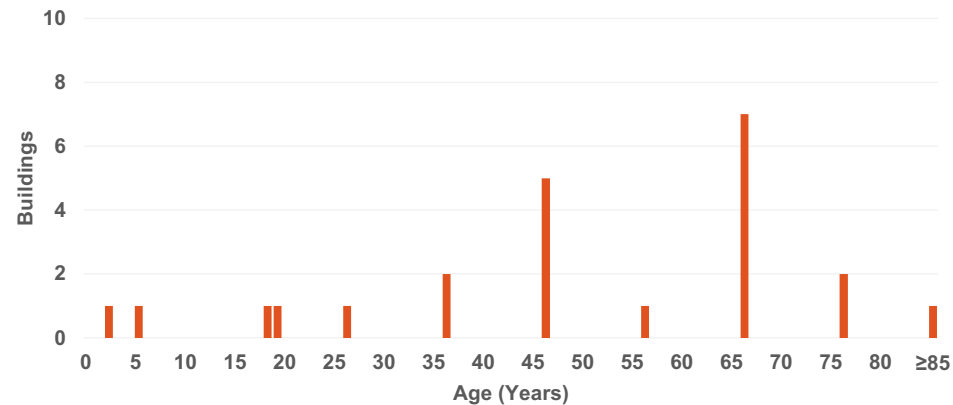
## 9.4.5 Infrastructure and facilities

### Infrastructure and facilities overview

We have 22 regional and zone substation sites, with 23 buildings housing equipment. Preventive maintenance inspections on substation buildings and grounds highlight potential deterioration issues requiring remedial action. The main driver for inspections is safety, and specific attention is given to site security and safety signage. Security and access control has been implemented at the main office and at several substations. We plan to roll out this system across all zone substations over the next few years.

### Population and age profile

**Figure 9.30:** Building age profile



### Condition

Our buildings are in satisfactory, functional, and safe condition. Buildings are either retained indefinitely or until no longer required. Our oldest building is 86-years old.

### Operate and maintain

Buildings play a vital role in the overall protection of indoor equipment from environmental elements, third-party access, and being structurally sound. To ensure overall integrity, defects are identified through routine inspection.

## Preventive maintenance

**Table 9.28:** Buildings and grounds preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Check operation, clean filters, and service air-conditioning as part of zone substation equipment inspection	Two monthly
Zone substation grounds maintenance including lawn mowing, garden and weed management	Monthly
Building, fittings, and fencing inspection for damage, weather-tightness, and security	Two monthly
Zone substation smoke detector testing	Six monthly
Visual inspection of oil bunding as part of zone substation equipment inspection	Two monthly
Test substation security alarms as part of zone substation equipment inspection	Two monthly

### Corrective maintenance

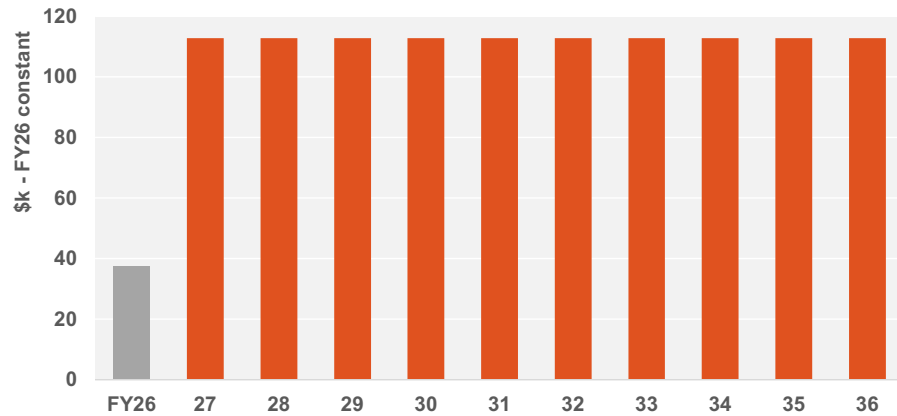
Water ingress into substation buildings can damage indoor equipment. Wooden doors and frames could be a source of water ingress. Where detected they are replaced with aluminium doors and/or frames. Much of our substation facilities are constructed from metal, including fences and gates, and these deteriorate over time. When rust is detected, it is treated at an early stage to prevent long-term damage and expedited replacement.

### Reactive maintenance

Reactive maintenance on buildings and facilities is typically performed to repair issues including vandalism and graffiti, especially where security of our facilities is compromised.

## Infrastructure and facilities expenditure forecast

**Figure 9.31:** Forecast infrastructure and facilities capex



### Benefits

The benefits of our infrastructure and facilities renewal programme are:

- maintaining our buildings and grounds fleet in good condition
- providing safe and secure housing for secondary systems and auxiliary systems.

## 9.5 Underground cables

This section outlines our underground cable portfolio and the corresponding fleet management strategy. The portfolio includes:

- subtransmission cables
- distribution and LV cables

It provides a summary of assets demographics, including total population, age, and current condition. The section also details our renewals strategy and presents a 10-year forecast to guide investment planning, asset replacement and lifecycle management.

### Box 9.17: Portfolio summary

We proactively replace subtransmission cable sections based on age and condition, while renewals of distribution and LV cables are primarily reactive, triggered by poor condition or failure. Subtransmission cable forecasts are developed on an asset-specific basis to align with network growth and upgrade needs, whereas distribution and LV cable forecast are generated using the Repex methodology.

We plan to spend an average of \$1.2 million per year on cable renewals.

Our cable renewal programme is designed to maintain network reliability and mitigate environmental risks. Faults in subtransmission cables can have a greater impact than those in overhead conductors due to longer fault detection and repair times. These repairs often require specialist resources, making timely restoration more challenging.

### 9.5.1 Underground cables portfolio objectives

Our portfolio objectives for the underground cables portfolio are listed in Table 9.29.

**Table 9.29:** Underground cables portfolio objectives

Objective area	Portfolio objectives
A Safe Network	No fatalities and injuries from cable and termination failures. Reduce third-party caused failures by increasing public awareness of safety risks associated with cable strikes.
Network Performance	Maintain underground cable failures at current levels. Review meshed subtransmission network for opportunities to simplify and strengthen network resilience around the Whangārei area.
Community Support	Consider options for improving network resilience, taking into account the whole-of-life costs for each option.
Sustainability	Minimise oil leakage from our oil-filled subtransmission cables. Manage obsolescence risk with our oil-filled subtransmission cables.

## 9.5.2 Subtransmission cables

### Subtransmission cables fleet overview

Our subtransmission cables form a critical part of the network, connecting GXP to zone substations and linking substations for load transfer and security. Unlike distribution cables which typically have multiple tee-off points, subtransmission cables are point-to-point and managed as a distinct asset fleet due to their importance and capacity.

The fleet comprises approximately 25km of cable, along with ancillary equipment such as surge arrestors, joints, and oil pressurisation equipment.

Aluminium cross-linked polyethylene (XLPE) is the standard cable type used on our underground subtransmission network. Older oil-filled and paper insulated lead covered (PILC) cables, installed between the 1960s and 1980s, remain in service but are now considered obsolete due to the unavailability of spare parts.

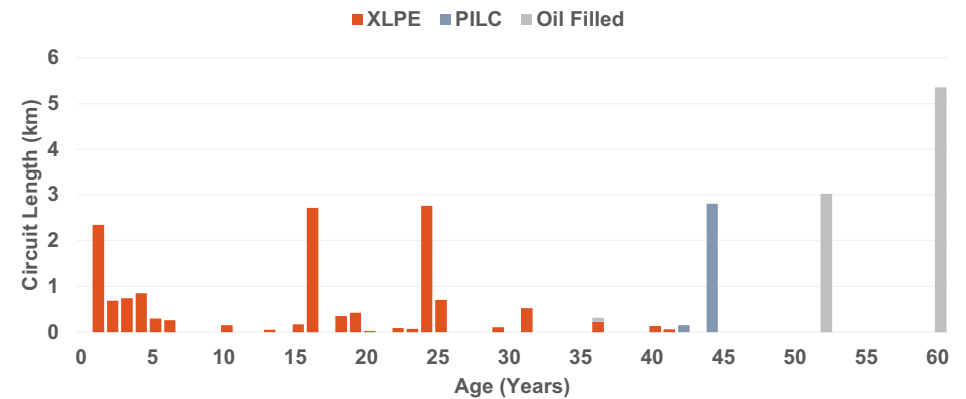
### Population and age

Our subtransmission cable network consists of XLPE, PILC and Oil-filled cables. Table 9.30 summarises their population by type. XLPE cables account for over 55% of total cable circuit length.

**Table 9.30:** Subtransmission cable population by type

Cable type	Circuit length (km)	Percentage
XLPE	13.7	54%
PILC	3.0	12%
Oil-filled	8.5	34%
<b>Total</b>	<b>25.2</b>	<b>100%</b>

**Figure 9.32:** Subtransmission cable age profile



PILC cables are manufactured using layers of paper impregnated with mineral oil for insulation, encased in an extruded lead sheath and wrapped in an outer sheath of tar impregnated fibre, PVC, or polyethylene. Widely used internationally for over a century and manufactured in New Zealand since the 1950s, PILC cables have a strong performance record. However, maintenance is increasingly difficult due to a shortage of skilled staff who have experience with them.

The oldest XLPE cable on the network was installed in 1984. No defects from water treeing have been observed. With a life expectancy of 60 years, this fleet is relatively young. XLPE cables are built with copper or aluminium conductors, with aluminium preferred for its cost-effective.

Oil-filled cable is designed to enhance the voltage withstand capability of paper insulation. Using oil as an insulation medium reduces the amount of paper required, resulting in a smaller and more cost effective cable. These cables depend on ancillary systems to monitor and maintain oil pressure. Most were installed in the 1960s. Given their typical service life of just over 70 years, these assets will be nearing end of life toward the end of the current 10-year plan.

We currently operate four oil-filled subtransmission cable circuits in the Whangārei area at a voltage level of 33kV. They help form a meshed network, providing redundancy for the connected zone substations as shown in Table 9.30. Three of these cables are scheduled for replacement within the current 10-year plan.

**Figure 9.33:** Overview of oil subtransmission cable network in Whangārei

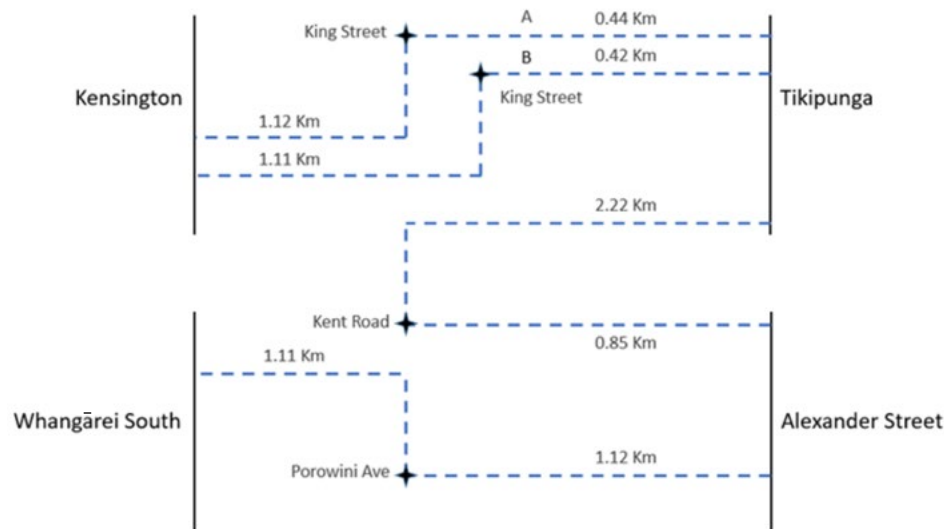


Table 9.31 indicates cable names, age, and length of each section.

**Table 9.31:** Subtransmission oil-filled cable asset age and length

Cable designation	Age	Length (km)
Whangārei South to Alexander Street	56	2.2
Alexander Street to Tikipunga	56	3.1
Kensington to Tikipunga A	48	1.6
Kensington to Tikipunga B	48	1.5

The cables between Tikipunga to Kensington operate at N-1 security level. The other two cables operate at N security which means there is no backup in case of an outage.

## Condition, performance, and risks

### Condition

XLPE cables account for more than 50% of the subtransmission cable population. The fleet is relatively young, with a weighted average age of 16 years. The cables are in good overall condition with no known issues. Due to the importance of the subtransmission cables we intend to monitor their performance closely and plan for their renewal when required.

The oil-filled and PILC cable are the main focus of our renewal programme as they have become an obsolete technology. We have limited spares in stock, and it is getting more challenging to source joints and termination for these types of cables. We also face a shortage of skilled cable technicians to maintain these assets.

As most of our oil-filled and PILC cables have surpassed their mid-life age, accurate condition assessment is vital to determine the health of these cables. Sheath integrity tests performed on these cables indicate that the cables' sheaths are generally in acceptable condition. However, there is some oil leakage. This raises some concerns, and we continue to monitor it.

On the four oil-filled subtransmission cables, we have carried out a comprehensive qualitative assessment considering age (against expected life), known condition, obsolescence issues, the extent of oil leakage, total maintenance cost, and the number and duration of faults. This assessment shows that the condition of one of the oil cables is becoming poor and requires replacement.

### Performance

Overall, our subtransmission cable fleet is performing well, with no major events occurring in recent years.

By comparing the maintenance frequencies in each cable section, we can see an increasing trend in the frequency of maintenance of the Whangārei South–Alexander Street oil-filled cable which indicates that the cable is becoming less reliable.

A detailed analysis has been done on the variation of oil pressure in the four oil cable sections. Generally, a drop in oil pressure occurs due to oil leakage or variation in the loading pattern. It has been observed that there were some abnormal variations in oil pressure in the Whangārei South–Alexander Street cable and a consistent drop in average oil pressure.

### Risks

Key risks and mitigation measures are summarised in Table 9.32. While the network's design includes redundancy to mitigate the immediate impact of cable failures, restoration efforts can be time consuming and resource intensive. As we prepare for significant renewal programmes over the next decade, the replacement of the Whangārei South–Alexander Street cable is a key enabler of our network reconfiguration strategy. It will enhance load transfer capability and strengthen operations flexibility during outages, improving resilience and reducing vulnerability to major events.

**Table 9.32: Subtransmission cable risks**

Risk/issue	Type	Risk mitigation	Main risk
Cable strike	All	Member of dial beforeUdig providing location data of the cables for design and excavation works. Maintain cable depth and mechanical protection. Maintain strategic spares. Maintain security levels for subtransmission cables. Damage to cable is limited by differential protection.	Safety Network performance
Leaks in oil-filled cables	Oil-filled	Oil pressure monitoring through SCADA.	Network performance Environment
Fault caused by a dry PILC cable	PILC	Damage to cable is limited by cable differential protection. Maintain security levels for subtransmission cables.	Network performance
Ground level change due to soil erosion or landscaping	All	Regular survey and close monitoring of the subtransmission cable routes.	Network performance
Mechanical damage to the cable or cable termination	All	Routine site inspections. Damage to cable is limited by differential protection. Maintain secure areas for termination of cables.	Network performance Environment
Oil/grease leaks at joints and potheads due to high-head cable installation	Oil-filled/ PILC	Routine site inspections. Damage to cable is limited by differential protection. Maintain secure areas for termination of cables. Maintain security levels for subtransmission cables.	Network performance Environment

Risk/issue	Type	Risk mitigation	Main risk
Poor backfill materials cause overheating or sheath damage, which can cause cable degeneration or failure	All	Using quality products for backfilling as per industry standards.	Network performance
Partial discharge	All	Regular monitoring and testing for early detection of partial discharge.	Network performance
Lack of resilience to major natural disasters	All	Maintain security levels for subtransmission cables. Formulate high impact low probability (HILP) event plans to improve resilience.	Network performance

### Design and build

New subtransmission circuits use single core XLPE cables, which are more cost effective and eliminate the need for water blocking materials<sup>12</sup> required in three core cables.

Cable sizing is based on projected load growth and transfer options across the network so that the project is economical in the long term. While we are standardising cables, aluminium conductors are preferred over copper due to their lower cost and weight.

In all new subtransmission cable installations, we are moving away from the historical practice of installing two circuits in the same trench due to the risk of common mode failure.

#### Box 9.18: Meeting our portfolio objective – a safe network and network performance

We regularly communicate with the public to increase awareness of the safety risks associated with cable strikes. Separate trenching also helps reduce third-party-caused failures.

Due to the complexities of subtransmission cable projects, specialised service providers are engaged for design, manufacture, and installation. The Whangārei South–Alexander Street cable is scheduled for replacement in FY26–27.

<sup>12</sup> Water block materials are used in three core cables prevent water entering and travelling longitudinally along a cable.

## Operate and maintain

### Preventive maintenance

As subtransmission cables are generally maintenance free, we rarely perform extensive preventive maintenance. Oil-filled cables require more inspections and more frequent interventions to maintain the designed oil pressure in the cable. Table 9.33 lists the regular inspection and tests to determine the condition of the cable as part of the preventive maintenance routine.

**Table 9.33:** Preventive maintenance subtransmission cables

Maintenance and inspection task	Frequency
Subtransmission cable route inspection	Yearly
Oil pressure readings and visual inspection	Monthly
Subtransmission cable sheath voltage limiter (SVL) testing, check cross bonding links and cable serving tests	Three yearly

Apart from these periodic inspections, we also carry out HV electrical testing on these cables to ensure the insulation is still in good condition. The polarisation–depolarisation test results have highlighted some relatively minor electrical degradation in these cables.

We are hesitant to carry out detailed testing on old cables as the high test voltage required to perform the test could damage the cable insulation.

### Corrective maintenance

Corrective maintenance in the subtransmission cable asset fleet is mainly related to joints, terminations, and sheath integrity. We monitor the oil pressure in our oil-filled cables using SCADA, ensuring any top-up of oil is performed before the oil pressure drops too low.

Ancillary components, such as pressure gauges, alarm contacts, joints, or terminations, are periodically inspected and maintained or replaced as required.

### Reactive maintenance

The work necessary to restore the cable back into service after a fault, whether the fault was unforced or forced, is included in reactive maintenance. Fault-finding and repair of underground cable faults can be expensive and time-consuming. Specialist resources are required to assist with this work.

## Spares

Due to their criticality, we maintain strategic spares to ensure we can quickly return cables to service after a failure. It is becoming increasingly difficult to source spares for oil-filled and PILC cables. Spares for XLPE cables are not difficult to source as these are current technology. By replacing the aged PILC and oil-filled cables, the risk of sourcing and maintaining obsolete spares can be reduced.

## Renew or dispose

Table 9.34 provides a summary of the renewal strategy for subtransmission cables.

**Table 9.34:** Renewal strategy for subtransmission cables

CABLE TYPE	RENEWAL STRATEGY
Subtransmission	All cables reaching an asset health index of H2 are subject to more detailed assessment, including condition assessment and an options analysis.  Oil-filled cables are replaced with XLPE cables.  Replace cable terminations upon premature failure or when cables exhibit visible deterioration that may lead to failure.

During this AMP period we will start replacing ageing 33kV oil-filled underground cables with modern XLPE cables, where the circuit needs to be retained. This includes three 33kV oil-filled cable circuits with a total length of 5.3km that form part of the Whangārei city subtransmission network. These cable circuits are approaching end of life, the oldest of them was commissioned in 1965.

### Renewals forecasting

Subtransmission cables are identified for renewal based on age, condition, obsolescence, and consequence of failure drivers. When a subtransmission cable is identified as being at end of life, a complete options analysis is carried out. Once a preferred option is selected, a desktop study is carried out to determine the approximate scope, cost, and timing of the project.

These projects form the basis of our forecast.

### Options analysis

Renewal of subtransmission cables is high-cost, time-consuming and can have an impact on network security if the cable needs to be removed before laying a new one. When a subtransmission cable is identified as being at end of life, a full options analysis is carried out to determine the preferred replacement solution.

Options for subtransmission cable replacement include:

1. refurbishment of the existing cable and associated equipment
2. like-for-like replacement of the subtransmission cable
3. review of the network architecture to improve network security and align with long-term network development plans. This can include creating meshed or ring architecture for a more reliable, resilient network
4. decommissioning of the cable.

#### Box 9.19: Meeting our portfolio objectives – network performance

We are assessing a meshed network of zone substations interconnected by subtransmission cables which would enable load transfer between substations. This would play a key role in strengthening network resilience around the Whangārei area and allowing load transfer between Kensington and Maungatapere regional substations.

### Use of criticality in works planning and delivery

The criticality framework for subtransmission cables is being refined. At present, projects are planned on a case-by-case basis, with criticality considered during options analysis. The main factors considered are network performance, reliability, and environment.

### Disposal

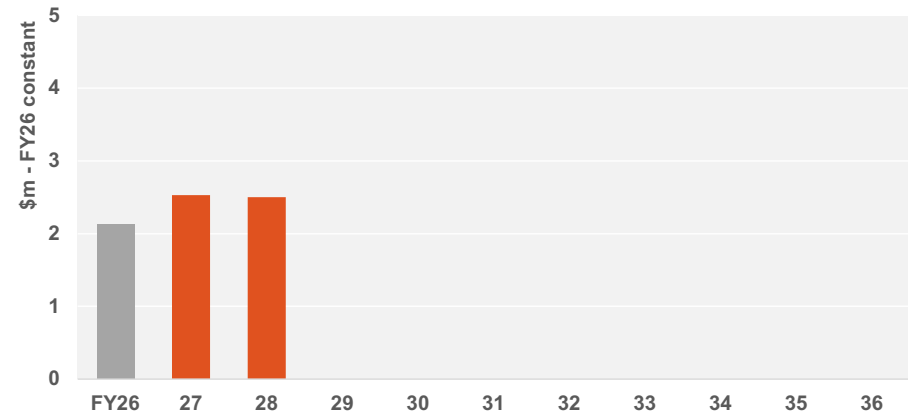
Due to the significant cost involved in retrieving the cables, we often leave the cables in situ. With oil-filled cables, the oil is drained out to prevent it leaking into surrounding soil.

### Coordination with other works

Renewal needs are coordinated with our long-term growth-related plans to ensure the solution is optimal for future requirements. We also consider laying ducts in conjunction with local roading infrastructure works where a cable may be required in the future.

## Subtransmission cable expenditure forecast

Figure 9.34: Forecast subtransmission cable capex



Over the planning period, we have scheduled only one subtransmission cable for replacement, the Whangārei South to Alexander Street cable. This is currently set for FY26–FY28. Other cable initiatives are outlined in Chapter 8, Network Development.

### Benefits

The primary benefit of our planned subtransmission cable renewal work is maintaining the current network performance levels and reducing environmental risk.

#### Box 9.20: Meeting our portfolio objectives – environmental and sustainability

Leaking oil-filled cables are being replaced with XLPE cables to manage oil-related environmental risk.

### 9.5.3 Distribution and LV cables

#### Distribution and LV cables fleet overview

This section describes our portfolio of underground distribution and LV cables. These assets also include joints, terminations, and other ancillary cable equipment. Different types of cable insulation have been used over the years, including XLPE, PILC, and PVC. XLPE is now the standard cable type used on our underground LV and distribution networks.

Oil-filled or insulated PILC cables are no longer installed but remain in service. Cables can be single-multi cores and may have armouring depending on the application. Most older cable installations were direct buried, while the most recent ones are installed inside ducts.

Distribution cables operate at 11kV to transport electricity from our zone substations to distribution substations. Our network includes approximately 320km of these cables. The distribution network has expanded significantly over the last 30 years, and these assets are relatively young compared to their expected life, which means renewal requirements remain low. Our LV cables operate at 400/230V, transmitting electricity from our distribution substations to customers and streetlights. We have approximately 1,130km of LV cables. Due to voltage drop limitations, LV cable sections tend to be much shorter compared to HV distribution cables. As these are younger assets, failures are infrequent and we manage these assets reactively.

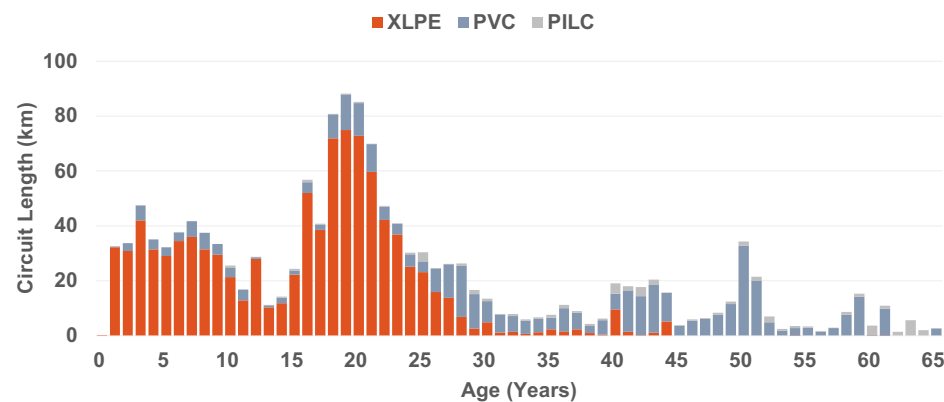
### Population and age

Table 9.35 summarises our population of distribution and LV cables.

**Table 9.35: Distribution and LV cable population by type**

Cable type	Distribution (km)	Low voltage (km)
XLPE	275.9	695.4
PVC	0.5	421.4
PILC	43.3	11.4
<b>Total</b>	<b>319.7</b>	<b>1,128.2</b>

**Figure 9.35: Distribution and LV cable age profile**



Overall, distribution and LV cable asset age is relatively young compared to expected lives. The average age of our distribution cables is 19 years and that of LV cable is 23 years.

## Condition, performance, and risks

### Condition

In general, our distribution and LV cables are relatively young and in good condition. However, there are some specific design and installation issues that are being addressed.

Underground cables condition is impacted by numerous factors: insulation type, outer sheath design, corrosion, soil type/environment, installation type, age, third-party damage, and loading history.

In earlier years, the LV XLPE insulation layer was not UV stabilised. When exposed to above-ground environmental conditions, the insulation can become brittle and crack, allowing moisture ingress over time. This was particularly true where cables were located along poles to connect to the overhead networks. We currently install UV-stabilised tubes over the cable installations to protect them from direct sunlight.

We have also identified some older underground breach or tee joints showing increasing failure rates, due to moisture ingress through the epoxy joint. This issue is not widespread, however, we are closely monitoring where this is happening. A replacement programme has been initiated to identify and replace the joints when required.

### Performance

We assess the reliability and performance of LV and distribution cable networks based on historical outage data.

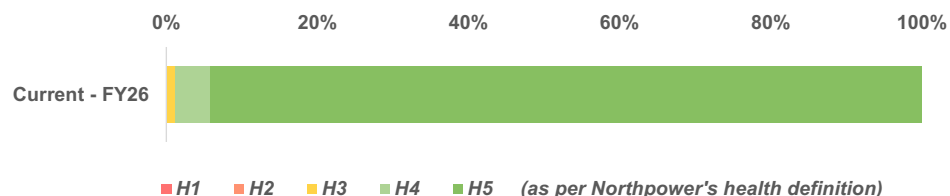
Our distribution cables are performing well overall, although we have experienced a few failures in older PILC cables within the Whangārei CBD. Currently, we have one cable schedule for replacement over the next couple of years to restore full network flexibility and capacity. Despite these isolated issues, the CBD has a high level of security so failures in this area rarely result in significant outages.

Our ability to analyse LV performance is limited. However, we are improving our historical outage data to include more detail on LV faults so we can better analyse them in future. Based on current data, the LV cable network is performing well. Most LV cable failures are caused by third-party activity and ground movement. Older PILC cables are susceptible to damage when moved, so ground disturbance can cause damage and lead to failure.

### Asset health

The AHI for the distribution and LV cables is given below. Our fleet is relatively young, so our distribution and LV cables are in good overall health condition.

**Figure 9.36:** Distribution and LV cable current asset health



We expect to replace approximately 1% of distribution and LV cable over the next 10 years.

## Risks

**Table 9.36:** Distribution and LV cable risks

Risk/issue	Risk mitigation	Main risk
Cable strike – external factors	beforeUdig service.	Safety
	Following installation standards.	Network performance
	Cable depth requirements.	
	Maintaining strategic spares.	
Overloading of cable	Monitor voltage and power quality.	Network performance
	Sizing of cables considering load growth.	
Cast-iron cable termination explosive failure	Targeted replacement programme.	Safety
		Network performance
Damage in UG – overhead cable termination – UV damage	Fitting of UV-stabilised tubes.	Safety
	Monitored during pole inspection.	Network performance
Damage to cable during installation	Use of quality backfill materials.	Network performance
	Appropriate installation procedure.	

## Design and build

Our preferred cable type is XLPE, which we use in different configurations depending on the application. We use single core XLPE for shorter runs and three core XLPE for longer runs. When replacing legacy pole mounted equipment such as cast-iron potheads, significant work is often required to meet modern clearance standards on poles. In some cases, this involves installing new XLPE cable tails down the pole and joining them to the existing PILC cable below ground.

The design and construction standards that we follow for LV cables are similar to those for distribution conductors. We normally use three core aluminium XLPE cables with neutral screen for the installation of LV cables. The cables are sized to maintain the regulatory voltage and required current rating to the furthest customer from the distribution transformer.

We have instances of cable strikes due to third-party works reducing ground levels. When these occur, the affected cable sections are re-laid to a correct depth. Most of the construction activities around digging and re-laying of underground cables include significant civil works, and we often employ external contractors to complete these tasks. We have an in-house design team that carry out scoping, design, project engineering, and standards development.

## Operate and maintain

### Preventive maintenance

The preventive maintenance regime for distribution and LV cables is summarised in Table 9.37.

**Table 9.37:** Distribution cable preventive maintenance tasks

Maintenance and inspection task	Frequency
Visual inspection and thermal testing of HV cable terminations as part of ground-mounted distribution substation inspection.	Two yearly
Visual inspection and thermal testing of LV cable terminations as part of ground-mounted distribution substation inspection.	Two yearly
Visual inspection and voltage testing of LV pillars.	Four yearly

### Corrective maintenance

Corrective maintenance of distribution and LV cables is planned work to fix defects identified during preventive maintenance, or as a second response works after a fault. Replacement of joints or terminations is also carried out as corrective maintenance.

## Reactive maintenance

Reactive maintenance on distribution and LV cables includes restoring the cables to service following a fault. Faults in cables can occur due to an inherent problem with the cable, ground movement, or third-party interference. Locating and repairing cable faults can be significantly more expensive and time-consuming than repairing faults on overhead lines.

## Spares

We maintain spares on hand in order to quickly respond to faults. Having standardised cable sizes enables more effective spares management.

## Renew or dispose

Distribution cable expenditure is mostly reactive in response to a failed test result or a fault. We use industry-standard life expectancy to forecast expenditure requirements. We have an ongoing programme to replace cast-iron cable terminations based on public safety criticality.

## Renewals forecasting

We use a repex approach to forecast distribution and LV cable renewals. We use different expected lives depending on the type of cable, generally aligned with industry. Unit rates are based on the expected average cost to replace a kilometre of cable.

## Options analysis

Our options for managing LV and distributions cables are currently limited to replacing or repairing sections of damaged cable and/or terminations, or replacement of the entire cable.

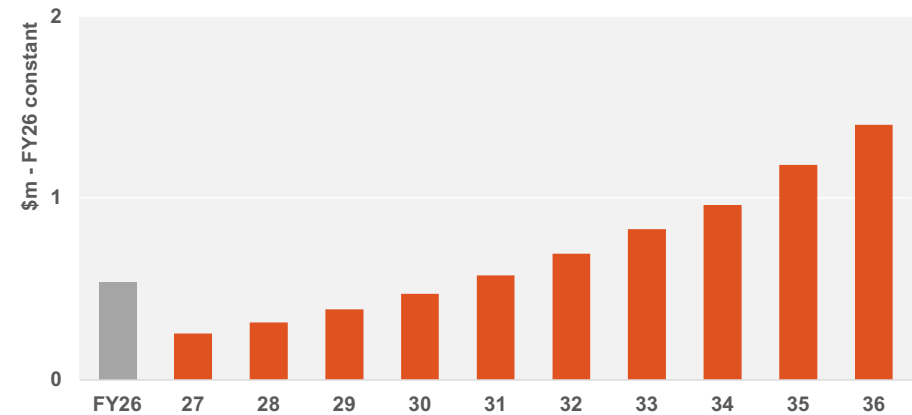
## Use of criticality in works planning and delivery

We do not use criticality for distribution and LV cable replacements.

## Distribution and LV cable expenditure forecast

Due to the young age of our distribution and LV cables our historical spending has been low. We expect to slowly ramp up expenditure as the fleet ages. Our forecast of LV and distribution cables for the planning period is shown in Figure 9.37.

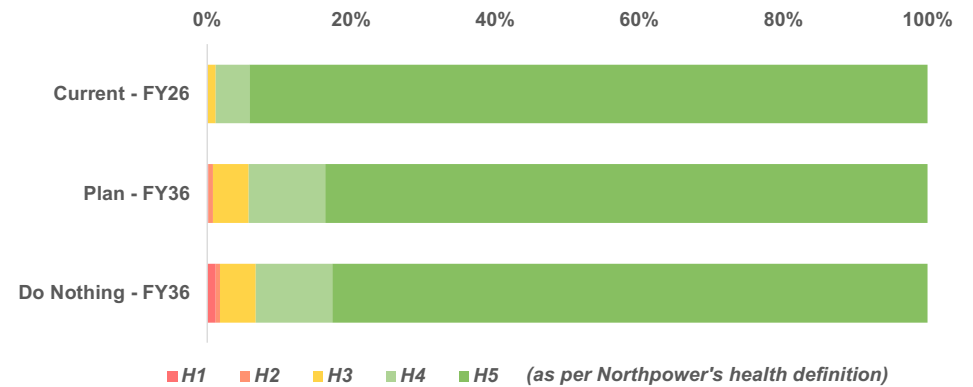
Figure 9.37: Forecast distribution cable capex



## Benefits

Figure 9.38 compares current asset health with projected asset health in 2036 following planned renewals, as well as a do nothing scenario.

Figure 9.38: Projected distribution and LV cable asset health



## 9.6 Distribution equipment

This section describes the distribution equipment portfolio and the asset management plan associated with these asset fleets. This portfolio includes four asset fleets:

- distribution transformers
- ground-mounted switchgear
- LV distribution enclosures
- pole-mounted switchgear.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational, and maintenance approaches and provides expenditure forecasts for the planning period.

### Box 9.21: Portfolio Summary

We expect to increase our investment in distribution equipment to \$388 million over the planning period. Mainly for renewal of our distribution transformer and switchgear assets.

We have forecast this portfolio based on age, condition, and known type issues. Our distribution equipment focus is on maintaining our network performance as our fleets age and managing any environmental and safety risk associated with these assets.

As part of our programme, we will also improve our remote switching capability as we carry out renewals of our distribution switchgear to improve the reliability of our network.

### 9.6.1 Distribution equipment portfolio objectives

Our portfolio objectives for the distribution equipment portfolio are listed in Table 9.38.

Table 9.38: Distribution equipment portfolio objectives

Objective area	Portfolio objectives
A Safe Network	No injuries or fatalities from explosive failures or maloperation of switchgear or fires from distribution transformers. Installations comply with seismic standards. Phasing out our larger pole-mounted transformers in favour of ground-mounted equivalents to limit seismic and working at heights risk exposure.
Network Performance	Increase use of remote switching capable equipment to improve fault isolation and restoration times for customers. Downward trend in distribution equipment failures. Minimise planned interruptions by coordinating with other works.
Community Support	Reduce fleet diversity over time to optimise asset whole-of-life costs.
Sustainability	No uncontained oil spills or significant SF <sub>6</sub> leaks from our distribution equipment assets. Removal of graffiti from assets caused by third parties. Phasing out SF <sub>6</sub> distribution equipment assets as technology improves and becomes economic.

### 9.6.2 Distribution transformers

#### Distribution transformers fleet overview

Distribution transformers can be pole or ground mounted. They typically transform voltage from 11kV to 400/230V to supply consumers. A typical modern ground-mounted transformer is shown in Figure 9.39. Distribution transformer sizes depend on the downstream load they supply. Pole-mounted transformers are typically smaller than ground mounted.

**Figure 9.39:** Ground-mounted distribution transformer



As most distribution transformers are oil filled, they pose environmental and fire hazards. Appropriate lifecycle management, including disposal when decommissioned, is critical for protecting the public and limiting any environmental impacts.

Some of our distribution feeders cover relatively large distances. For these very long overhead feeders, voltage regulators are installed at intervals along the line to maintain the voltage to acceptable levels.

### Population and age

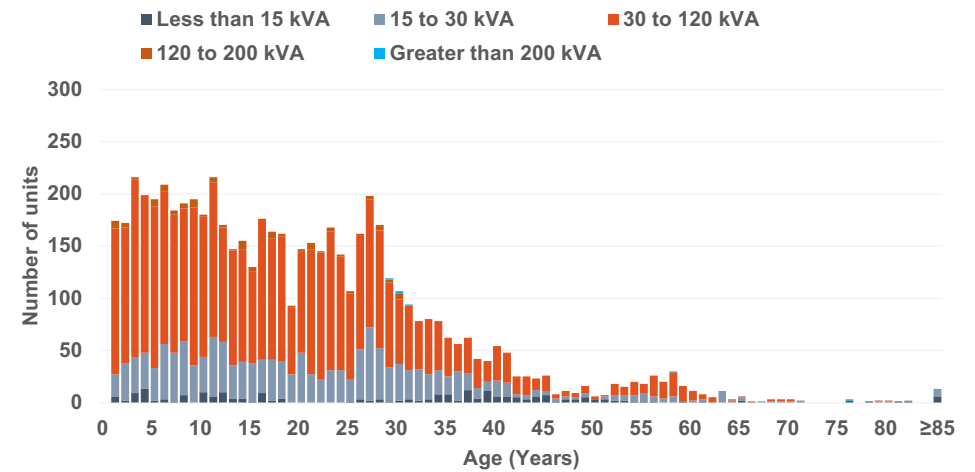
#### Pole-mounted distribution transformers

There are approximately 6,000 pole-mounted transformers on our network. The capacity ranges from less than 5kVA to 300kVA. Most of them are in between 30kVA to 120kVA in size and typically supply a few houses in a rural area.

**Table 9.39:** Pole-mounted distribution transformer population by rating

Rating (kVA)	Number of transformers	Percentage
<15	231	4%
15 to <30	1,457	24%
30 to <120	4,230	70%
120 to <200	116	2%
≥200	6	~0.1%
<b>Total</b>	<b>6,040</b>	<b>100%</b>

**Figure 9.40:** Pole-mounted distribution transformer age profile



These units normally have a life expectancy of 45 to 55 years. Our pole-mounted transformer fleet is still relatively young, with the majority less than 30 years old. The average age is 19 years. There are a few older units across the network that are reaching end of life and will require replacement during the planning period.

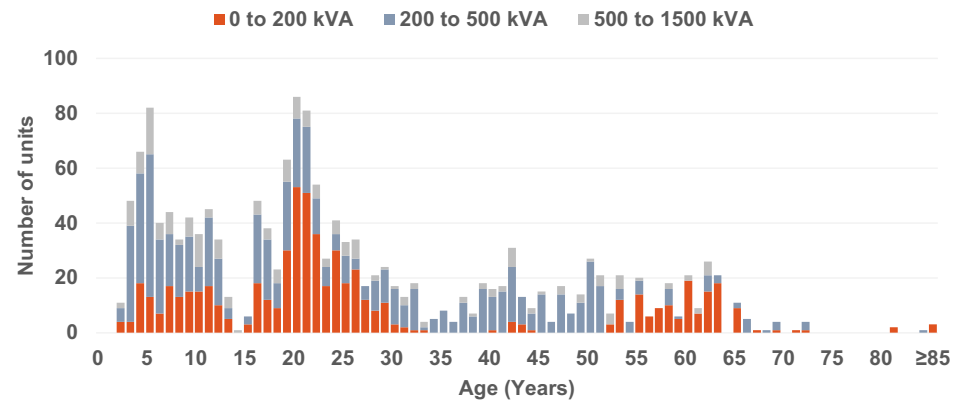
#### Ground-mounted distribution transformers

Our network has about 1,600 ground-mounted distribution transformers. These are usually located in suburban and CBD regions with underground networks, or they serve larger commercial or industrial sites. Most of our ground-mounted transformers are <500 kVA. We have around 210 ground mounted transformers between 500 kVA and 1,500kVA serving higher capacity installations or larger groups of customers.

**Table 9.40:** Ground-mounted distribution transformer population by rating

Rating (kVA)	Number of transformers	Percentage
0 to <200	621	39%
200 to <500	760	48%
500 to 1500	210	13%
<b>Total</b>	<b>1,59</b>	<b>100%</b>

**Figure 9.41:** Ground-mounted distribution transformer age profile

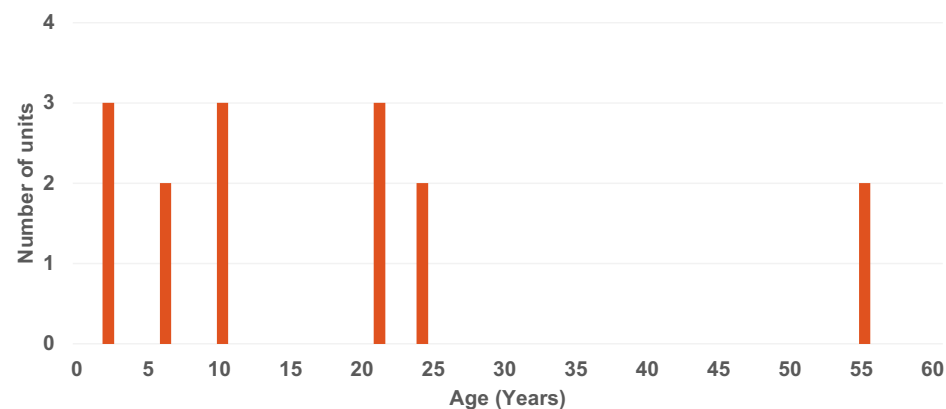


Most ground-mounted transformers are at mid-life with an average age of 25 years. Generally, ground-mounted transformers have a longer life expectancy than pole-mounted units, of around 50 to 60 years. Some older units on the network are nearing the end of their service life and will be replaced during the planning period.

### Voltage Regulators

We have seven voltage regulators. The life expectancy of voltage regulators is 60 years, and the current average age is 14 years. We have two 3-phase voltage regulators nearing the end of their service life that will likely require replacement within the current AMP period.

**Figure 9.42:** Voltage regulator age profile



## Condition, performance, and risks

### Condition

Failure of distribution transformers can have safety, environmental, and reliability consequences. Corrosion on distribution transformers can lead to oil leaks.

The primary drivers for condition-based replacement of distribution transformers are age, corrosion, and failures triggered by third-party interferences or lightning strikes. Factors contributing to degradation are moisture, consistent overloading, oil leaks, and corrosion.

We normally do not perform detailed tests on pole-mounted transformers. Defects are picked up with five-yearly visual inspections. We do not currently hold detailed condition data for our distribution transformers.

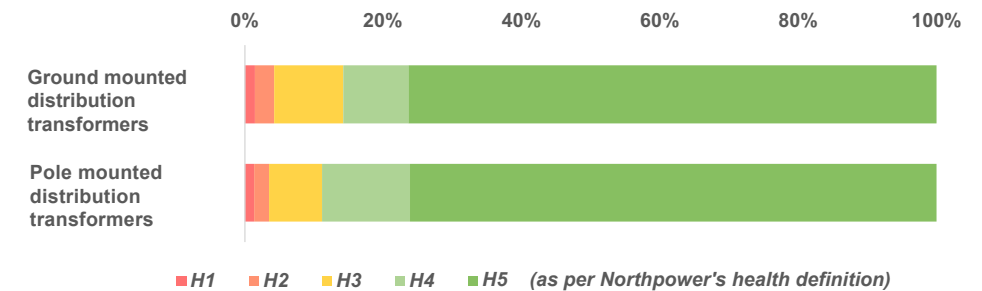
### Performance

Our distribution transformers have generally performed well in the past, with relatively few failures. Overloading and voltage rise issues have emerged in some parts of the network, particularly as a result of growing renewable energy penetration. We are monitoring these transformers to determine whether they need to be upgraded.

### Asset health

The distribution transformer fleet health is generally good, with a small number of assets categorised as H1. We have a further 11% of pole-mounted distribution transformers and 14% of ground-mounted distribution transformers classified as H1 to H3 – requiring intervention over the planning period.

**Figure 9.43:** Distribution transformer current asset health



## Risks

Table 9.41 sets out the key risks identified in the distribution transformer fleet.

**Table 9.41: Distribution transformer risks**

Risk/issue	Risk mitigation	Main risk
Overloading of distribution transformers	Inspections and MDI reading.	Reliability
Oil leaks	Maintenance and asset renewal.	Environment and sustainability
Damage caused by third party	Installation of warning signs. Sensible transformer location.	Safety
Internal failure	Maintaining strategic spares. Preventive maintenance.	Network performance
Transformer noise due to ferro-resonance	Inspection and follow up actions. Replacement plans.	Environment and sustainability
Distribution transformer explosion – active part failure, bushing failure, cable box failure	Safety in design solutions. Preventive maintenance.	Network performance Environment and sustainability Safety
Vegetation growth around transformers	Regular inspections and corrective maintenance.	Network performance
Issues with transformer earthing	Periodic testing of earth resistance. Corrective maintenance.	Safety
Seismic risks	Pole- to ground-mounted conversion. Renewal plans.	Safety
Electrocution risks	Signage to inform associated risks.	Safety
Flooding	Avoid flood-prone areas during installation.	Network performance Safety

## Design and build

Our standard design of pole-mounted transformers uses HV outdoor bushings, allowing direct connection to the overhead line through a drop-out fuse and lead arrangement. The LV 400/230V side of the transformer is connected through a set of fuses to the LV lines that are located below the high voltage ones.

Ground-mounted transformers distribute electricity to consumers by underground cables and are typically mounted on the ground in the road reserve or in front of the customer's premises. The HV is supplied to the ground-mounted transformer by a cable through fuses connecting to the HV overhead network, or from a ring main unit. The LV side of the transformer includes fuse switches which connect to the LV cables supplying consumers.

We have standardised ground-mounted transformer sizes to simplify maintenance and spare management. We continuously monitor the load and renewable energy penetration on each distribution transformer to avoid voltage issues. Hazards like third-party interference, vehicle traffic, and fire risks are addressed during the design process.

To ensure that transformers are seismically compliant, the general practice is to ground mount any pole-mounted transformers above 300kVA. We ensure the support structures for our ground-mounted transformers are complaint with existing seismic standards. During the installation of distribution transformers, care is taken to ensure that ECP34 clearance and safety requirements are met.

## Operate and maintain

### Preventive maintenance

Pole-mounted transformers do not require frequent maintenance. In most instances, maintenance is limited to visual checks, with repair or replacement due to poor condition.

Ground-mounted transformers are more accessible to the public and generally have a higher criticality than pole-mounted transformers. Ground-mounted transformers have more rigorous visual inspections as they are more accessible. Components such as switchgear, fuses, underground cable connections, and terminations are included in these inspections.

Preventive maintenance of distribution transformers highlights deterioration issues requiring remedial action. Depending on the priority of the identified defect, these are addressed as corrective maintenance.

**Table 9.42: Distribution transformer preventive maintenance tasks**

Maintenance and inspection task	Frequency
Visual inspection of ground-mounted and pole-mounted voltage regulators and thermal image survey.	Yearly
Voltage regulator acoustic emission survey.	Two yearly
Voltage regulator controller, communication and regulating relay testing.	Two yearly
Visual inspection of ground-mounted transformers including detailed condition assessment including thermal testing, partial discharge, and acoustic emission testing.	Two yearly
Voltage regulator oil change.	Four yearly
Visual inspection of pole-mounted transformers as part of overhead network inspections.	Five yearly

### Corrective maintenance

Typical corrective work on a pole-mounted transformer includes the replacement of corroded hanger arms and topping up oil. Severely rusted pole-mounted transformers that have not reached end of life may be repaired in the workshop.

Common corrective maintenance on ground-mounted transformers is levelling base pads where there has been land movement, removal of vegetation, and removal of graffiti. As with pole-mounted transformers, we repair transformers where it is cost effective.

### Reactive maintenance

The most common reactive maintenance activity is replacement of fuses and surge arrestors after a fault. There have been instances of car versus transformers, and cases of internal, tank, or bushing damage, which require a new transformer.

### Spares

We keep spare distribution transformers in stock. We have standardised ratings, which makes spares management easier. Spares for some legacy units are sourced when required. Units swapped under corrective maintenance, depending on spares availability and population, are evaluated to determine whether repair is cost effective. If so, the unit can be kept as a spare.

### Renew or dispose

Pole-mounted transformer replacement is generally driven by condition. For efficiency, the pole, crossarm, and other components are considered for replacement at the same time. Some larger pole-mounted transformer structures are not seismically compliant. The single or H-pole mounted structures that do not meet the ECP34 clearance and safety requirements are replaced with compliant pole-mounted or ground-mounted units.

Ground-mounted transformer replacements are based on condition. For indoor units, the condition of the building is also assessed for suitability of the replacement transformer.

Voltage regulators are replaced on condition. This can also be driven by how many operations it has carried out.

### Renewals forecasting

We forecast ground-mounted and pole-mounted transformer renewals using the repex methodology, using standard expected lives for each type of transformer. Our unit rates are based on the expected average cost to replace either a pole- or ground-mounted unit.

Our voltage regulator expenditure is forecast based on an individual assessment of the assets in our fleet. We use a standard unit rate to estimate the cost of replacement.

### Options analysis

When a pole-mounted transformer is identified as end of life, options are considered, such as like-for-like replacement, replacing with a ground-mounted transformer, or repair. Generally, the preferred option is to replace the transformer with the modern equivalent in line with current design standards.

For ground and pole-mounted transformers, options such as like-for-like replacement, repair, and replacement are considered. It is generally cost effective to replace pole-mounted transformers when they are approaching end of life rather than refurbishing to extend its life. Load growth and distributed energy resources (DER) penetration are considered when sizing a replacement.

For voltage regulators identified as end of life, a review of need is carried out. Considered options include like-for-like replacement, relocation, refurbishment, and retirement.

### Coordination with other works

We coordinate transformer replacements with other distribution equipment replacements where possible. This is done to reduce required outages and associated traffic management costs.

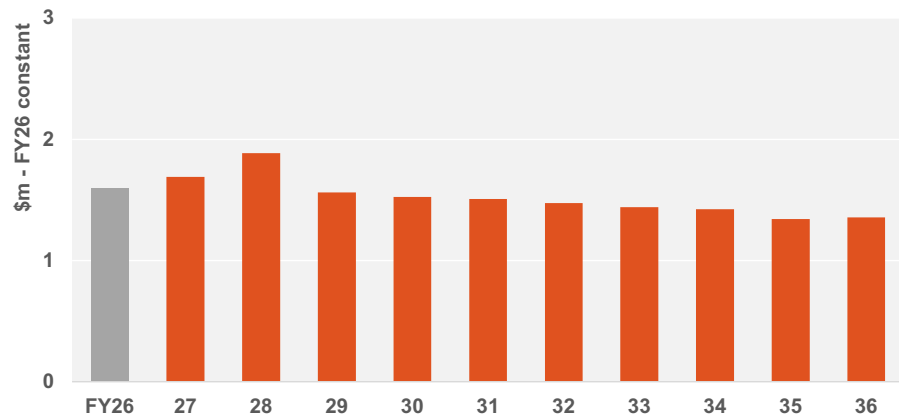
### Disposal

If it is the most economic option, we dispose of distribution transformers at end of life. These are generally recycled after disposing of the transformer oil appropriately.

### Distribution transformer expenditure forecast

The expenditure forecast for the distribution transformer fleet is shown in Figure 9.44.

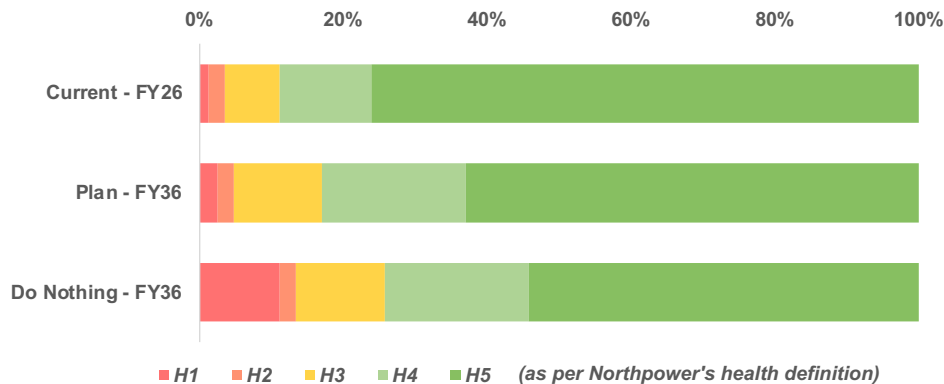
**Figure 9.44:** Forecast distribution transformer capex



### Benefits

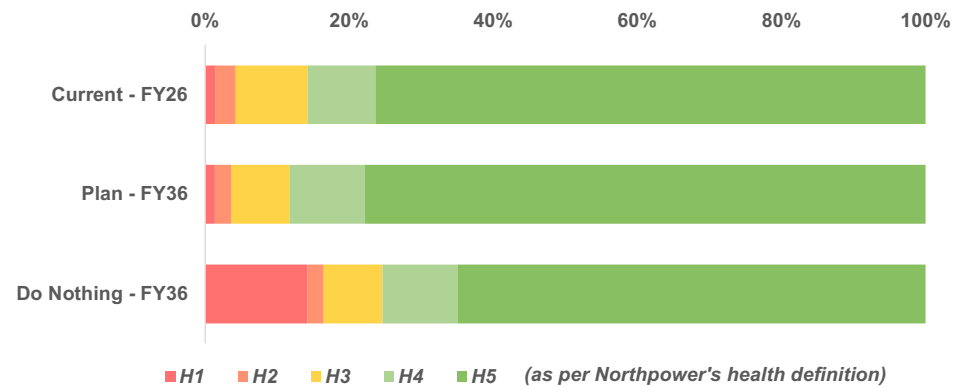
The main benefit of our investment over the AMP period is to ensure volumes of assets classified as H1 remain low. The do nothing scenario presents the counterfactual. If no investment was made, a significant portion of our pole-mounted transformers would be in poor health by FY36.

**Figure 9.45:** Projected pole mounted distribution transformer asset health



The benefit of ground-mounted renewals is similar to pole-mounted. Investing in this fleet enables us to keep the number of assets classified as H1 at a low level. If no investment was made the proportion of H1s would climb to 14%.

**Figure 9.46:** Projected ground mounted distribution transformer asset health



Ensuring the number of assets in poor health is kept low decreases the probability of failures occurring and reduces the risks associated with these assets.

### 9.6.3 Ground-mounted switchgear

#### Ground-mounted switchgear fleet overview

Ground-mounted switchgear offers isolation, protection, and switching options in distribution networks. Assets included in the ground-mounted switchgear are ring main units (RMUs), switches, fuse switches, links, and associated enclosures.

RMUs perform switching and isolation functions between cable circuits. In addition, they provide fuse protection and isolation functionality to distribution transformers. Before the mid-2000s we used oil-filled switchgear (RMUs and ground-mounted switches), but we no longer purchase these due to obsolescence and safety risk concerns. We now predominantly install SF<sub>6</sub> insulated switchgear. Generally, these are arc contained.

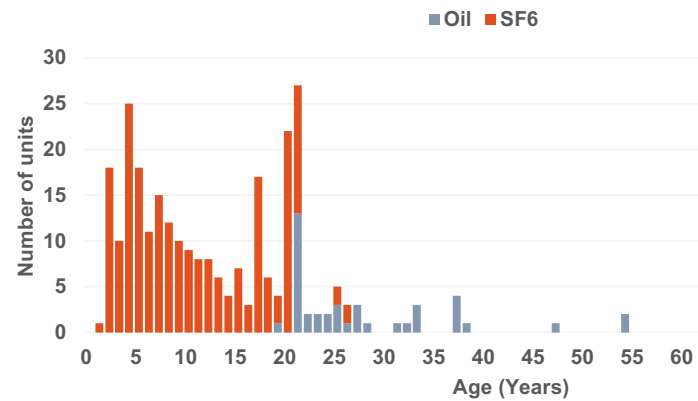
#### Population and age

Table 9.43 lists numbers of ground-mounted RMU by insulation medium. Most of the fleet uses SF<sub>6</sub> as insulation medium, and most of the older units use oil.

**Table 9.43: Ground-mounted RMU by insulation medium**

Ground-mounted switchgear – insulation medium	Number of RMU	Percentage
Oil	41	15%
SF <sub>6</sub>	231	85%
<b>Total</b>	<b>272</b>	<b>100%</b>

**Figure 9.47: Ground mounted switchgear age profile**



Our ground-mounted switchgear fleet is relatively young, with an average age of 13 years. Oil switchgear has an average age of 28 years, and SF<sub>6</sub> switchgear average is 11 years.

### Condition, performance, and risks

Failure of ground-mounted switchgear in service can be a significant safety concern, as it can be near the public and pose electrocution and arc flash risk. It also poses a reliability risk, as failure often results in a loss of supply to customers. It is critical that ground-mounted switchgear failure modes are identified and mitigated.

### Condition

Older oil-filled ground-mounted switchgear installed from the early 1960s to the mid-2000s has the highest safety risk and failure consequence. It does not have arc fault containment, and its oil can increase the risk of a fire if there is a fault. A significant proportion of our ground-mounted switchgear fleet is located outdoors. Switchgear degrades faster in outdoor environments because of rust, particularly in coastal areas of the network, and this makes

these models susceptible to failure from moisture ingress. The older indoor RMUs in the network, which are normally housed in a kiosk or building, are generally in good condition for their age. Newer SF<sub>6</sub> switchgear models are in good condition.

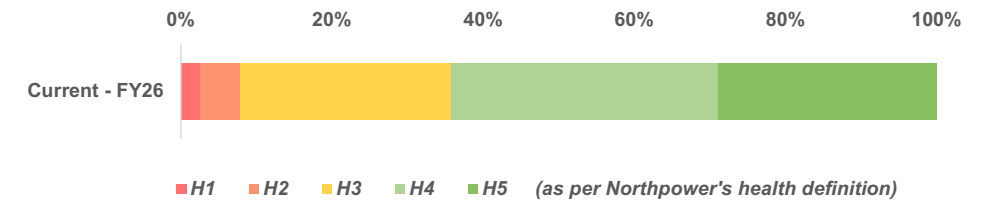
### Performance

After a series of recent operating incidents in our industry, we are planning to phase out oil insulated switches from the network. We have also experienced failures on existing operating mechanisms in oil-filled switchgear. We have an existing programme to upgrade these while we are investigating further actions and replacement options.

### Asset health

We have formulated AHI for ground-mounted switchgear based on the remaining life of the asset. Around 2% of our ground mounted switchgear has reached end of life (H1) and is scheduled for replacement. The predominant driver for this is ageing oil switchgear. We expect 36% of ground-mounted switchgear to be replaced over the next 10 years.

**Figure 9.48: Ground-mounted switchgear current asset health**



## Risks

Table 9.44 discusses risks associated with the ground-mounted switchgear fleet.

**Table 9.44: Ground-mounted switchgear risks**

Risk/issue	Risk mitigation	Main risk
Safety concerns – oil-filled RMUs	Operating procedures. Renewal programmes.	Safety
Risk of potential arc flash	Remote operation through SCADA wherever applicable. Maintenance undertaken while de-energised. New ground-mounted switchgear replacements are arc flash contained.	Safety
Damage caused by third party	Installation of warning signs. Inspection and replacement of lock. Choice of location during installation.	Safety
SF <sub>6</sub> leakage	Periodic checking of pressure gauge. Trained person to handle SF <sub>6</sub> .	Environment and sustainability

## Design and build

All new ground-mounted switchgear is suitably rated to contain arc flash failures. New switchgear can also be remotely operated. The remote operation may shorten the time needed to restore service following an outage, as well as improve worker safety.

We moved away from installing ground-mounted oil-switchgear in the mid-2000s. Currently, all new ground-mounted switchgear installations are of SF<sub>6</sub> type due to its arc quenching properties and reliability. For environmental reasons, we are moving away from SF<sub>6</sub> type switchgear where economic and are exploring other options.

## Operate and maintain

### Preventive maintenance

To ensure the safe operation of our network, regular inspection and maintenance of ground-mounted switchgear is vital. Switchgear enclosures must always be locked and secured as they are often located in public areas. Preventive maintenance tasks are summarised in Table 9.45.

**Table 9.45: Ground-mounted switchgear preventive maintenance tasks**

Maintenance and inspection task	Frequency
Visual inspection of ground-mounted switchgear including detailed condition assessment, thermal testing, partial discharge, and acoustic emission testing.	Two yearly
Service ground-mounted oil filled HV switches.	Eight yearly

### Corrective maintenance

Components in switchgear deteriorate with time due to environmental exposure and system conditions, including switching operations performed. Older oil-type ground-mounted switchgear requires more rigorous and frequent maintenance than SF<sub>6</sub> switchgear. Common corrective maintenance activities for ground-mounted switchgear include oil replacement, internal inspection, and minor repairs to ensure the fleet operates safely. Normally ground-mounted switchgear is berm mounted and is exposed to weather and vegetation growth.

### Reactive maintenance

Replacement of fuses after a fault is the most common reactive maintenance. Other damage to ground-mounted switchgear may require component or unit replacements.

### Spares

Most of our oil-filled ground-mounted switchgear is now obsolete and has no support from the manufacturers for the supply of spares. We maintain a limited number of critical spares for these models. Once a unit is removed from service it is either scrapped, refurbished, or maintained as a spare. The general strategy around spares management is to maintain spares for items with long lead times or that are not part of the standard inventory.

### Renew or dispose

Renewal decisions are based on risk priority, which combines likelihood and consequence of failure, public and field personnel safety, and environmental considerations. This approach ensures expenditure is directed toward equipment with the highest risk. In addition to risk-based renewals, our corrective capex programme targets assets where condition issues are detected, such as partial discharge (PD) in cable terminations or boxes. PD can lead to ionisation within the mechanism, increasing the risk of failure. As a result, some RMUs are replaced or refurbished based on condition rather than age, meaning certain units are retired earlier or later than their nominal useful life.

## Renewals forecasting

We use a Repex approach to forecast renewal of ground-mounted switchgear. We use different expected lives depending on the type of switch, generally in alignment with others in the industry. Our unit rates are based on the expected average cost to replace a ground-mounted switch.

## Options analysis

When a ground-mounted switchgear asset requires replacement, we analyse options and invest in the most long-term cost-effective solution. Replacement, repair, or network reconfiguration are the most common options available. We install modern equivalent SF<sub>6</sub> RMUs because they have modern safety features and require less ongoing maintenance.

## Disposal

Once a ground-mounted switch is decommissioned, it is either kept as a spare or scrapped. The decision is taken on case-by-case basis. Factors such as model, number of units on the network, and age of the unit are considered. Components like steel, copper, and oil are recycled and SF<sub>6</sub> from the RMUs is removed so specialists can safely dispose of it.

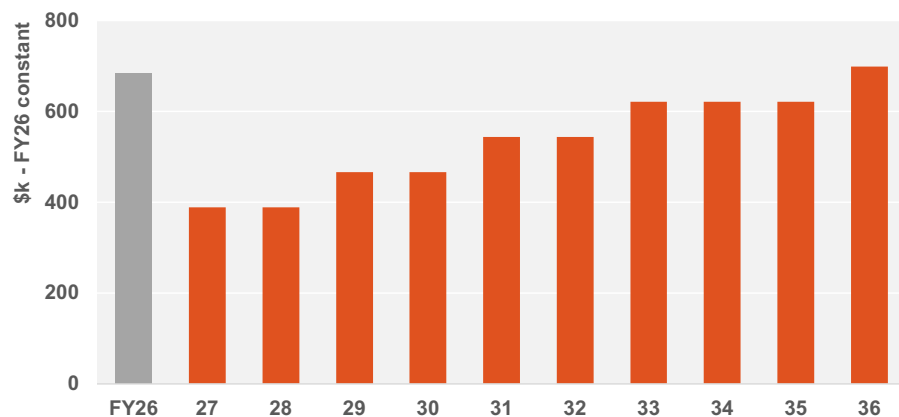
## Coordination with other works

We coordinate replacements with underground cable or ground-mounted transformer renewals wherever possible. This reduces required outages and costs.

## Ground-mounted switchgear expenditure forecast

The expenditure forecast for the ground mounted switchgear fleet is shown in Figure 9.49.

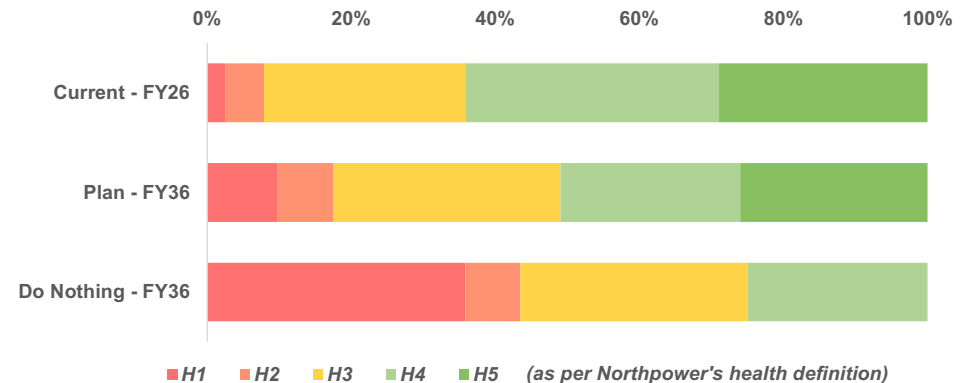
**Figure 9.49:** Forecast ground-mounted switchgear capex



## Benefits

The main benefit of our planned investments is that it will mitigate safety and operability risks associated with obsolete models. It will also phase out oil ground-mounted switchgear. Figure 9.50 compares the projected AHI in FY36 following planned renewals, with a counterfactual do nothing scenario. This comparison illustrates the benefit of the renewals.

**Figure 9.50:** Projected ground-mounted switchgear asset health



Our planned investments will strengthen overall fleet health and actively manage the risks associated with asset failure. Currently, around 2% of our ground-mounted switchgear fleet is classified as H1. Following our planned programme, this figure is expected to rise to approximately 10% by FY36. While this represents an increase, it is a controlled and strategic outcome driven by the replacement of complex, high-impact assets that deliver the greatest risk reduction, even if this means deferring some lower-risk replacements.

Importantly, under a hypothetical do-nothing scenario, H1 assets would increase to 36% by FY36, dramatically increasing risk exposure. By implementing our renewal programme, we limit this growth to a manageable level, ensuring that our fleet remains safer, more reliable and better aligned with future operational standards.

### 9.6.4 Low voltage distribution enclosures

#### LV distribution enclosures fleet overview

The LV distribution enclosures fleet is made up of cabinets and pillars. The customer service cable runs between the customer switchboard and the pillar box, which is usually located on the property boundary. Distribution pillars and cabinets are installed on the LV distribution network to enclose links, fuses, and joints. These also link distribution circuits, disconnection points for distribution circuits, and service fuses for customer connection.

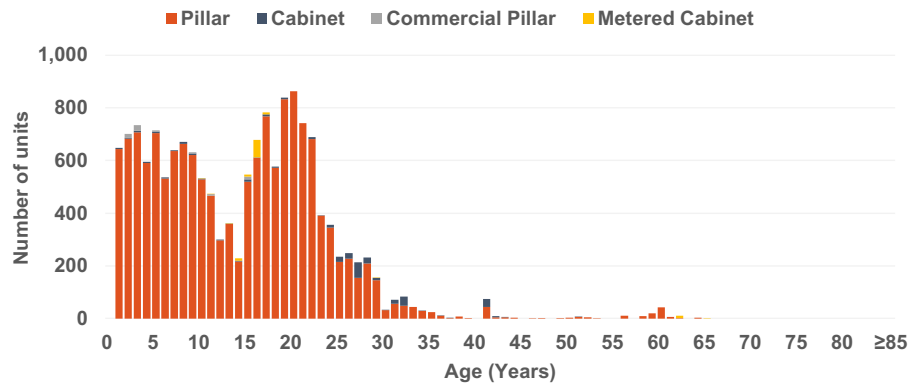
## Population and age

Detailed data on the LV fleet is incomplete, as the age or year of manufacture has not typically been recorded. We are capturing data to fill these gaps. Currently, we have 15,296 LV distribution enclosures, with approximately 97% of the asset population being pillars and the remaining units being cabinets and metered cabinets.

**Table 9.46:** LV distribution enclosures population by type

Distribution enclosure type	No of enclosures	Percentage
Pillar	14,801	97%
Cabinet	328	2%
Commercial pillar	61	-0.4%
Metered cabinet	106	-0.7%
<b>Total</b>	<b>15,296</b>	<b>100%</b>

**Figure 9.51:** LV distribution enclosures age profile



The assets have a relatively young age profile, with an average age of 15 years.

## Condition, performance, and risks

### Condition

Regular inspections and condition assessments on pillars and cabinets have highlighted some corrosion issues requiring remedial action or replacement. We are addressing these issues as defects. We have also identified type issues with some model and material. These enclosures become brittle, which could compromise their structural integrity. These type issues assets will be replaced proactively.

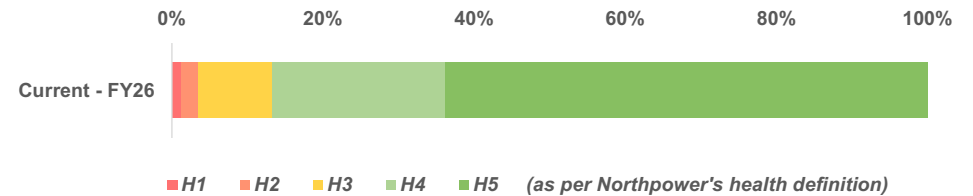
### Performance

Overall, our LV distribution enclosure fleet performs well. Many of the identified faults result from damage caused by vehicles. Although an LV box may be installed in a safe position initially, further development in the area might make it vulnerable to third-party damage. Relocation, underground distribution pits, or protective concrete blocks can prevent future failures.

### Asset health

Figure 9.52 shows the asset health of our LV distribution enclosure fleet.

**Figure 9.52:** LV distribution enclosure current asset health



Around 1% of H1 assets have been tagged as end of life and are identified for replacement within a year. We expect to replace 5% of LV distribution enclosures over the next 10 years.

## Risks

Table 9.47 summarises the key risks identified on our LV distribution enclosure fleet.

**Table 9.47: LV distribution enclosures risk**

Risk/issue	Risk mitigation	Main risk
Water ingress on pillars and cabinets	Safety risk control. Metallic structures can be live due to high impedance faults led by distribution network operator (DNO). Test before touching the equipment.	Safety
Inspection programme	Corrective maintenance to retrofit plastic lids. Replacement programme.	Safety
Third-party damage	Regular inspection programme. Public reporting. Corrective maintenance. Replacement programme.	Safety Network performance
More frequent and severe extreme events (such as floods, droughts, high winds)	Implement more rigorous structural standards.	Safety Network performance

## Design and build

We require pillars and cabinets to be manufactured from suitably rated non-conductive material, removing the risk of internal faults livening the box. The position of the pillar must be carefully considered to reduce the risk of vehicle impacts and pedestrian movements.

## Operate and maintain

### Preventive maintenance

The focus of preventive maintenance of the LV distribution enclosure fleet is inspection of LV pillars and cabinets. We also conduct detailed condition inspections. Table 9.48 summarises the inspections of the LV distribution fleet.

**Table 9.48: LV distribution enclosures preventive maintenance tasks**

Maintenance and inspection task	Frequency
Visual inspection and voltage testing of LV pillars.	Two yearly

### Corrective maintenance

Corrective maintenance of LV enclosures includes changing fuses or re-terminating LV cables that show signs of overheating. Other activities include replacing seals, remounting loose plastic lids, renewing or applying labels, and fixing ground connections. We also replace the metal enclosures with plastic to limit the risk of the enclosures being energised.

### Reactive maintenance

Vehicle damage is the most common cause of reactive maintenance in the LV distribution fleet. If this causes irreparable damage, the entire asset will be replaced.

### Spares

We normally do not maintain spares for the LV distribution fleet as these are readily available. Where there is physical damage to the structure, we replace the entire unit.

### Renew or dispose

We carry out LV distribution enclosure renewals following visual inspection or reactively.

### Renewals forecasting

We use a repex approach to forecast renewals, applying different expected lifespans depending on the enclosure type. Unit rates are based on the expected average cost of replacement.

In addition to repex forecast, we have considered an emerging requirement recently identified, this is the need to replace LV enclosures of a specific type and configuration. The material in these enclosures is becoming brittle, which could compromise their structural integrity and enclosure capabilities. These assets are primarily located in town areas and have become the focus of the next couple of years. We have already scheduled some replacements to better understand the implications and costs, enabling us to refine our response plan.

### Options analysis

Limited options are available for LV distribution enclosure renewals — they are generally like-for-like (with a modern equivalent) or replacement in a better location.

### Disposal

LV distribution enclosures have no special disposal requirements. Metal parts are normally recycled, and the plastic is disposed of.

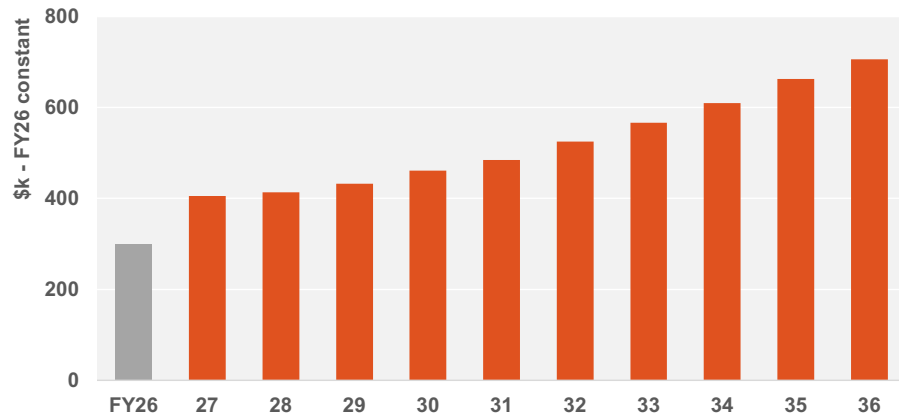
## Coordination with other works

LV distribution assets can generally be replaced with minimal disruption to the network, so there is usually limited need to coordinate with other works. However, some LV distribution enclosures targeted during this planning period are located in central and busy areas of CBDs where coordination becomes essential to minimise costs and reduce the impact on normal town operations.

## LV distribution expenditure forecast

The expenditure forecast for the LV distribution switchgear is shown in Figure 9.53.

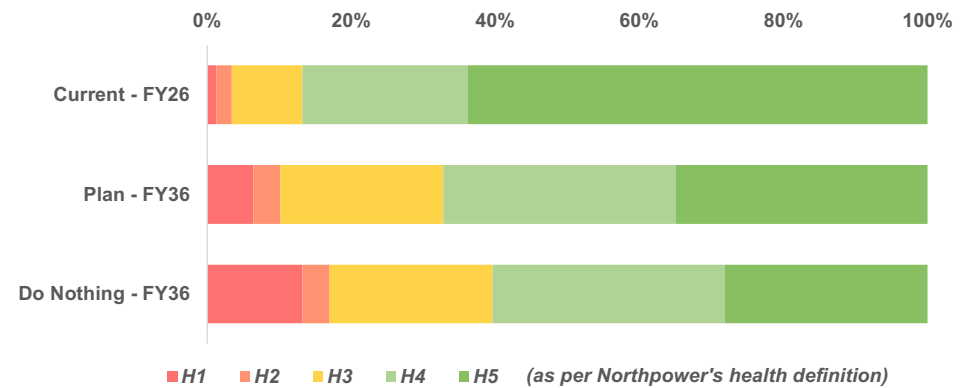
**Figure 9.53:** Forecast LV distribution enclosure capex



## Benefits

The key benefit of our planned renewal programme is reduced safety risk. Figure 9.54 compares the projected asset health in FY36 following our planned renewal programme, along with a counterfactual do nothing scenario.

**Figure 9.54:** Projected LV distribution enclosure asset health



Around 1% of our LV distribution enclosure fleet have been identified as being H1 and will require replacement over the next few years. If this programme of work was not undertaken, asset health would deteriorate, producing a substantially greater level of H1s by the end of FY36. This highlights the benefits of our planned asset replacements.

## 9.6.5 Pole-mounted switchgear



### Pole-mounted switchgear fleet overview

Pole-mounted distribution switchgear consists of switching devices that are typically mounted on poles located on our distribution network and are at different voltage levels. The device can be used for isolation or both protection and isolation. The portfolio includes links, fuses, switches, reclosers, and sectionalisers.

Pole-mounted fuses protect and isolate distribution transformers and, in rural areas, provide fault isolation for tee-offs supplying low customer density spur lines or cables. HV fuses and links are installed in the overhead distribution network to isolate 11kV transformers and spur lines. Fuses provide short-circuit protection for the equipment or reticulation beyond.

For pole-mounted switches on our network, SF<sub>6</sub> is commonly used as the insulating medium. Some of the pole-mounted switches can be operated either manually or remotely through SCADA. Pole-mounted switches are also used to assist with fault-finding on long rural networks. They are mainly operated during planned or unplanned outages to isolate a section of the network that has experienced a fault or to shift customers onto alternate feeds and isolate a section of the network for planned outages.

Reclosers and sectionalisers are devices that increase reliability by reducing the area impacted by faults. A recloser functions as pole-mounted circuit breaker equipped with integrated protection and control capabilities. Its primary role is to detect and interrupt fault currents, automatically attempting to reclose the circuit, typically up to three times within 60 seconds of the initial tripping. This allows for the restoration of supply in cases of transient faults, minimising unnecessary outages.

Sectionalisers work in conjunction with an upstream recloser and requires coordination between the control settings in both the sectionaliser and recloser. The sectionaliser will detect a fault current passing through it and will wait for the upstream recloser to isolate the fault. The sectionaliser will then operate and disconnect the faulted section of the network, allowing the upstream recloser to re-energize the network up to the point of the sectionaliser. Sectionalisers allow us to minimise the impact of network faults by limiting the number of customers left offline.

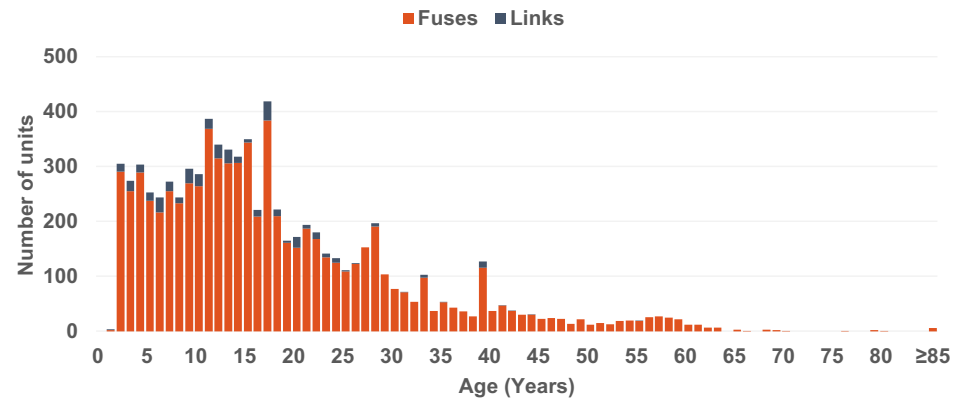
### Population and age

We have approximately 8,600 pole-mounted switchgears units on the network.

**Table 9.49:** Pole-mounted switchgear population by type

POLE-MOUNTED SWITCHGEAR	SUBTRANSMISSION	DISTRIBUTION	TOTAL
Links	10	392	402
Fuses		7,521	7,521
Overhead switches	7	680	687
Reclosers	1	32	33
Sectionalisers		2	2
<b>Total</b>	<b>18</b>	<b>8,627</b>	<b>8,645</b>

**Figure 9.55: Links and fuses age profile**



Compared to the average expected age for links and fuses, most of our pole-mounted links are near mid-life, while our pole-mounted fuses have a relatively young age profile. The average age of our links and fuses is 18 years (14 years and 18 years respectively).

**Figure 9.56: Overhead switches age profile**

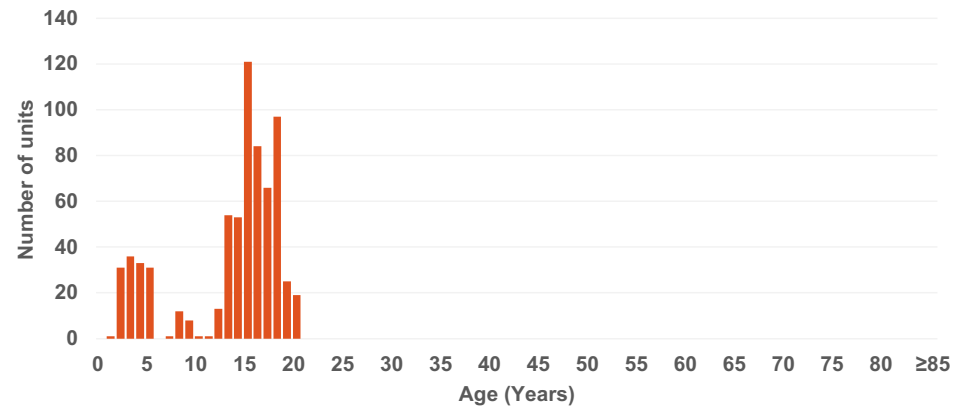


Figure 9.56 illustrates the age distribution of overhead switches. Compared to the expected age of overhead switches, the majority of the units have passed mid-life. The average age of overhead switches is 13 years.

**Figure 9.57: Reclosers and sectionalisers age profile**

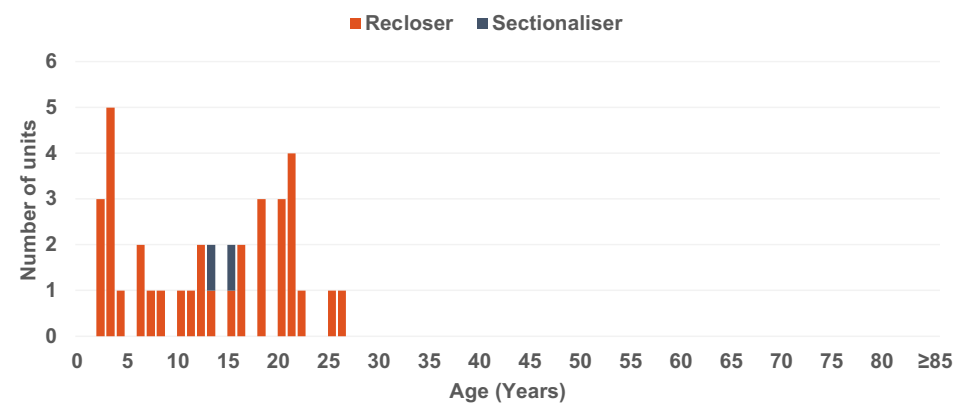


Figure 9.57 shows the age distribution of pole-mounted reclosers and sectionalisers. Compared to the expected age of reclosers and sectionalisers, the assets have a young age profile. The average age of our reclosers and sectionalisers is 13 years.

## Condition, performance, and risks

### Condition and performance

We do not undertake detailed condition assessment of fuses. Any failure or malfunction normally results in replacement of fuse. Whenever a type defect, corrosion, or failure of older fuse models is detected, the entire fuse assembly, including mounts, is replaced with its modern equivalent. Pole-mounted fuses are generally in good condition.

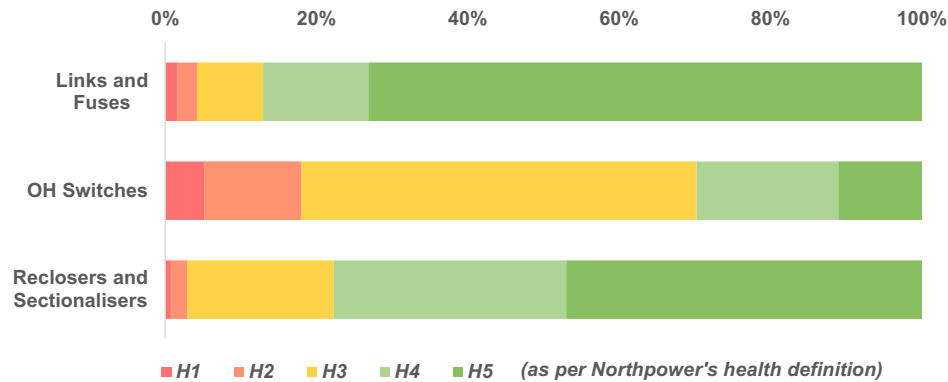
Overhead switches follow a similar approach, with no extensive maintenance programme or condition assessment. Units that experience maloperation or damage during operation are DNO-tagged (do not operate) and repaired or replaced. While most switches perform adequately, recurring issues have been observed, including corrosion on external components and water ingress into operating mechanisms, which can cause moving parts to seize. These factors increase maintenance requirements and operational risks, making early replacement necessary in some cases to maintain network resilience.

The performance of the reclosers and sectionalisers in the network has been satisfactory. Older models have issues with their ability to clear faults, which extends restoration times. As these issues arise, we plan to replace these with modern equivalents.

## Asset health

AHI for the pole-mounted switchgear is based on expected remaining life.

**Figure 9.58:** Pole-mounted switchgear current asset health



## Risks

Table 9.50 summarises the key risks identified in our pole mounted switchgear fleet.

**Table 9.50:** Pole-mounted switchgear risk

Risk/issue	Risk mitigation	Main risk
Condition based failures	Renewal programme.	Network performance
SF <sub>6</sub> leaks	Inspection and maintenance.	Environment and sustainability
	Replacement programme.	
	Network performance.	
Water ingress causing seizing up of moving parts	Inspection and maintenance.	Network performance
	Replacement programme.	
Risk of vegetation fire when auto reclosers operate	Maintaining restrictions during seasons of fire risk.	Safety
		Environment and sustainability

## Design and build

Pole-mounted fuses are selected based on the network's specific protection and operational requirements. When a distribution line is renewed, we consider replacing fuses supplying spur lines with more effective devices, such as reclosers or sectionalisers. This improves network reliability and reduces outage downtime. Before a new type of fuse can be used on the network it is thoroughly assessed for suitability.

We use SF<sub>6</sub> switches in corrosion-prone areas instead of standard air break switches. Although these switches are more expensive, they require less intrusive maintenance, can interrupt higher load currents than standard ABS, and can be made remotely operable. SF<sub>6</sub> switches are available in automation-ready configurations. The installation of automation-ready switches at critical interconnection points increases remote control operations.

Reclosers and sectionalisers are critical for maintaining network reliability and minimising disruptions. When new equipment enters the market, it is subjected to a thorough assessment to ensure it is fit for purpose. This includes construction material checks, such as stainless steel grades, which have proven critical in ensuring assets reach expected life.

## Operate and maintain

Our pole-mounted switchgear fleet is inspected as part of our overhead line inspections, which look for damage, corrosion, and deterioration. Other key preventive maintenance activities like oil change, topping up of SF<sub>6</sub> gas, thermal imaging, and battery checks are carried out at set maintenance intervals.

## Preventive maintenance

The preventive maintenance inspection task and frequencies are summarised in Table 9.50.

**Table 9.51:** Pole-mounted switchgear preventive maintenance tasks

Maintenance and inspection task	Frequency
Aerial inspection of overhead switches and links including rapid inspections of subtransmission circuits and express lines, checking for key defects.	Yearly
Visual inspection and backup battery change of remote-controlled overhead switches, reclosers, and sectionalisers.	Two yearly
Control battery change of remote-controlled reclosers and sectionalisers.	Four yearly
Visual inspection of pole-mounted hardware as part of overhead network inspections, completing a detailed condition assessment.	Five yearly
Recloser oil change and refurbishment.	Eight yearly

## Corrective maintenance

We generally do not undertake any corrective maintenance on fuses as they are replaced if issues are found. We only undertake simple corrective maintenance on pole-mounted switches, such as fixing minor corrosion and alignment of contacts. Recloser corrective maintenance includes adjusting settings outside of preventive maintenance due to network changes and resolving communication issues.

## Reactive maintenance

Reactive maintenance includes the replacement of fuses when they clear faults. The most common recloser and sectionalisers defects are with either the controller or the communication system, with fewer failures occurring within the device itself. Depending on the nature of the fault, it may be repaired on site, or a spare may be used to replace defective parts. If the primary device fails, a unit swap is required.

## Spares

We manage and maintain an inventory of spare pole-mounted fuses, switches, reclosers, and sectionalisers to ensure defects can be quickly cleared by swapping devices.

## Renew or dispose

Pole-mounted fuse renewal is based on condition and known type issues. We replace pole-mounted fuses during routine inspections due to condition, obsolescence, and reactively following faults. Some models of expulsion drop-out fuses and link holders are susceptible to corrosion and reliability issues. These are usually replaced during related works.

Pole-mounted switches are mostly replaced due to poor condition. Switches with identified defects are scheduled for replacement as part of defect management. The replacement trigger for a recloser is normally its operation count. Whenever a recloser reaches its limit or is found to be significantly degraded or malfunctioning, replacement is planned as part of our defect management process.

Reclosers and sectionalisers are individually assessed for replacement based on age, condition, and any other known issues.

## Renewals forecasting

We use a repex methodology for the forecasting of pole mounted switchgear. We use different expected lives depending on the type of switchgear. Our unit rates are based on the expected average cost to replace each type of switchgear.

## Options analysis

When pole-mounted switchgear is identified as being at end of life, we consider options such as like-for-like replacement, upgrade to switchgear with more functionality, relocation, and decommissioning.

## Disposal

Pole-mounted switchgear has no specific disposal requirements. Metal parts such as copper or aluminium are recycled, and oil is disposed of responsibly.

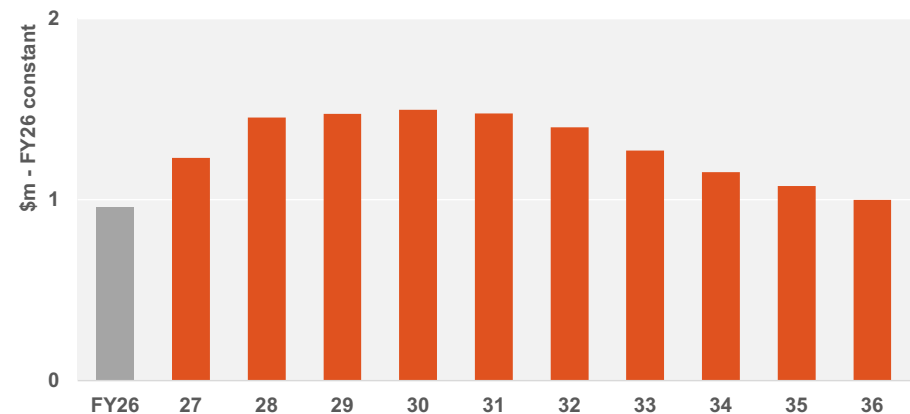
## Coordination with other works

Renewal of pole-mounted switchgear is often coordinated with other replacement and maintenance work to ensure outage times are minimised. For efficiency, switchgear such as fuses can be replaced during pole or transformer replacement.

## Pole-mounted switchgear expenditure forecast

We forecast \$13 million of pole-mounted switchgear renewal during the planning period. Expenditure and replacement rates will be higher in the first half of this period as we accelerate work to address recurring issues within part of the fleet, including corrosion, water ingress and premature deterioration of insulation and operating mechanisms. These issues are reducing reliability and limiting network operability, making early replacement essential to maintain performance, improve resilience and minimise the risk of unplanned outages.

Figure 9.59: Forecast pole-mounted switchgear capex



## Benefits

The main benefit of our planned renewal programme is that it will ensure reliable network performance by eliminating operational issues and associated safety risks.

**Figure 9.60:** Projected links and fuses asset health

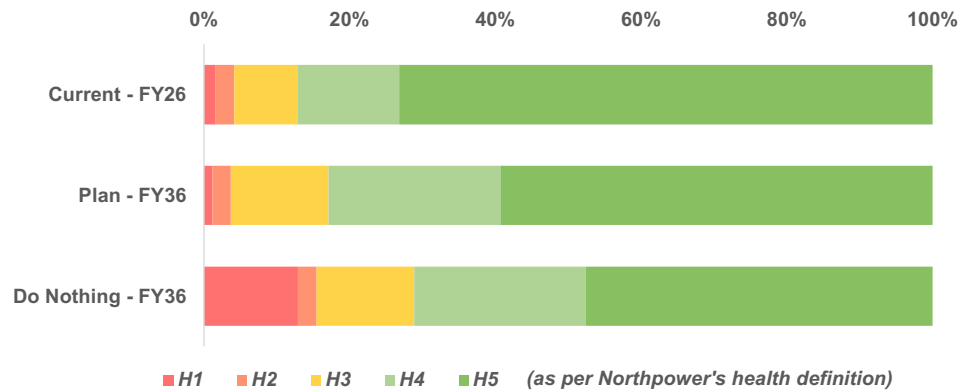


Figure 9.60 compares AHI in FY26 with the projected estimate in FY36 following our programme of renewals, with a counterfactual do nothing scenario. If no investment was made, around 13% of our links and fuses assets would be end of life by FY36. Our investment programme reduces this to 1%. This highlights the benefits of the replacement programme.

**Figure 9.61:** Projected overhead switches asset health

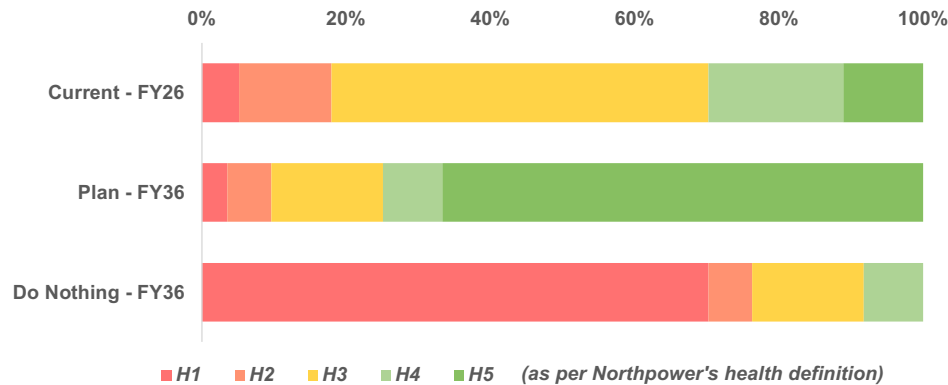


Figure 9.61 compares the AHI in FY26 with the projected AHI in FY36 following our programme of renewals, with a counterfactual do nothing scenario. If we undertook no replacements, we expect the proportion of H1 overhead switches to be approximately 70% by FY36, compared to 4% H1 assets under our proposed replacement programme.

**Figure 9.62:** Projected reclosers and sectionalisers asset health

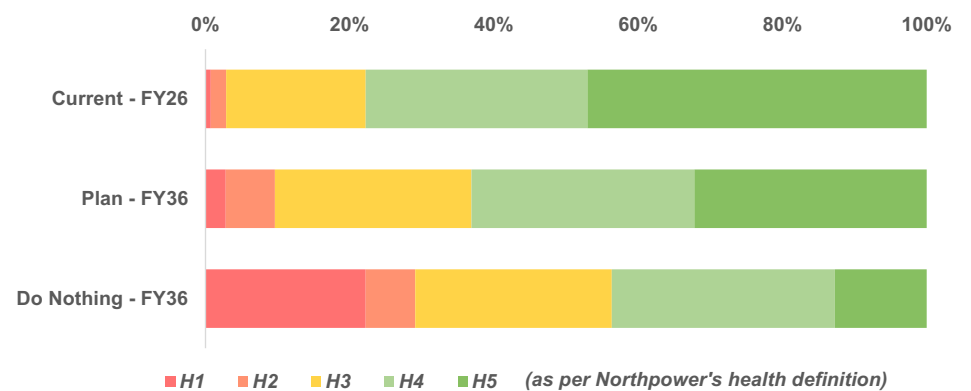


Figure 9.62 compares the AHI in FY26 with the projected AHI in FY36 following our programme of renewals, with a counterfactual do nothing scenario. Currently there are approximately 1% of our assets in the H1 category. However, over the next 10 years we would expect to have 22% of assets in the H1 category if we made no investment.

## 9.7 Secondary systems and other assets

This section describes in detail the secondary systems portfolio, which includes eight asset fleets:

- protection systems
- automatic voltage regulators
- auxiliary power supply systems
- capacitor banks
- load control
- SCADA system
- automation and control systems
- communication.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational and maintenance approaches, and provides expenditure forecasts for the planning period.

### Box 9.22: Portfolio summary

We plan to invest an average of \$1.2 million per year over the planning period, focusing on protection systems, communication network and auxiliary power supplies. Many of our protection relays are ageing and becoming obsolete, posing safety and network performance risk. Our programme prioritises relay replacement based on age and type to maintain network reliability and operational safety.

Secondary systems are crucial for the safe and reliable operation of our network, as they power and control primary equipment such as reclosers and circuit breakers. The portfolio includes assets that are generally relatively low cost, however, they have much shorter lives compared to the primary assets they power and control.

Protection systems detect network faults or abnormal power system conditions and operate equipment to isolate the faulted part from the rest of the system. This maintains system stability and prevents further harm to people and assets. Protection systems are typically located in our substations but also include field systems that operate our reclosers.

Auxiliary power systems provide reliable backup power supplies to vital equipment in our substations. These systems typically comprise batteries and chargers that provide power to ensure continued operation of equipment after AC supply is lost to substations.

Capacitor banks are employed to manage the supply voltage on our network where long lines or large inductive loads exist.

Load control systems are currently used to manage network constraints by remotely switching off controllable residential hot water systems, during periods of peak demand. We recognise that the landscape of load control is evolving. Emerging technologies such as smart meters, DER and home automation systems are introducing new capabilities and shifting customer expectations. We are actively monitoring these developments to understand their potential impact on traditional load control practices and to inform future strategies.

Communications, automation and control, and SCADA systems work together to provide remote visibility and control. They enable our operations team to manage the network in real time.

## 9.7.1 Portfolio objectives

Portfolio objectives are listed in Table 9.52.

Table 9.52: Secondary systems and other assets objectives

Objective area	Portfolio objectives
A Safe Network	No injuries or fatalities resulting from protection maloperation <sup>13</sup> . SCADA system always allows for reliable control and accurate visibility of the network.
Network Performance	No protection maloperation causing a loss of supply or that renders primary equipment unserviceable. DC systems provide adequate carry-over time during AC loss of supply events.
Community Support	Coordinate protection replacements with other zone substation upgrade, where practicable, to optimise costs and disruption.
Sustainability	Dispose of lead acid batteries in a responsible manner.

## 9.7.2 Protection systems

### Protection systems fleet overview

Protection systems are installed in substations to detect faults and operate circuit breakers to isolate faults. Protection systems must be able to discriminate between faults occurring in other locations versus faults on parts they are deployed to protect. This minimises the network outage footprint and improves fault clearance times. Protection systems typically consist of relays, test blocks, switches, wiring, panels, communication interfaces, and junction boxes. Protection relays have evolved over time but can be described as two main technologies: electromechanical and static relays and numerical relays.

### Electromechanical and static relays

Electromechanical and static relays are legacy technologies that, while historically reliable, are now largely obsolete. Electromechanical relays operate using coils and electromagnets



<sup>13</sup> Protection maloperation happens when the protection system fails to clear a fault due to a software or hardware fault. This does not include issues due to incorrectly applied settings or discrimination issues.

to drive mechanical components such as rotating discs, triggering protection functions under specific conditions. Static relays, in contrast, use analogue electronics without moving parts to achieve similar functionality.

Both types are limited in scope, typically requiring multiple units to deliver comprehensive protection, for example, up to three electromechanical relays may be needed for line differential protection, whereas a single numerical relay can perform the same task. These older relays lack modern features such as flexible configuration, self-monitoring, and remote access. Spare parts are increasingly unavailable, and repairs are often uneconomical.

### Numerical relays

Numerical relays use digital technology and are fully programmable, offering high flexibility in configuration and application. They support multiple analogue and digital inputs/outputs, integrate with SCADA, enable remote engineering access, and store real-time and historical data for fault analysis. Their self-monitoring capabilities allow component failure to be reported back to SCADA, enabling timely maintenance response.

Numerical relays are now the industry standard for protection systems. However, their use requires ongoing staff training, particularly for service technicians and protection engineers, to stay current with evolving protocols, firmware updates, and configuration software provided by manufacturer.

### Population and age

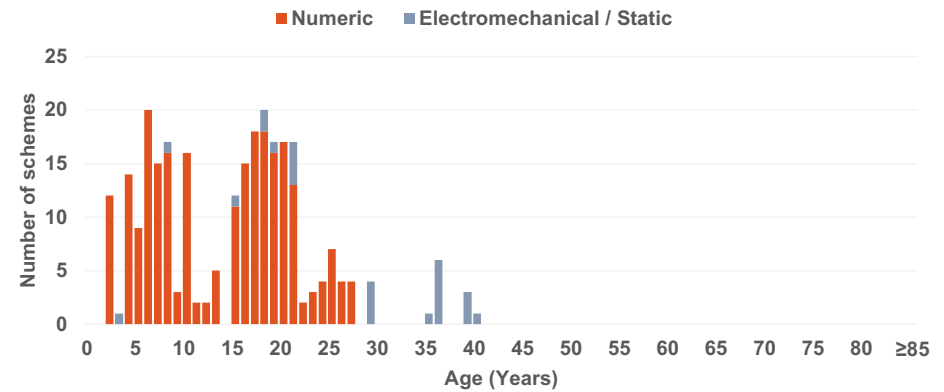
Table 9.53 summarises our population of protection schemes by function and relay type. Each protection scheme comprises one or more relays. We count schemes because a modern equivalent scheme may comprise fewer relays than the schemes it is replacing

**Table 9.53: Protection function and relay types (number of schemes / number of relays)**

Function	Electromechanical & static	Numerical	Total
Arc flash	0/0	4/4	4/4
Automatic under frequency load shedding (AUFLS)	0/0	10/10	10/10
Bus coupler	2/3	9/9	11/12
Bus zone	2/26	2/3	4/29
Feeder	2/2	112/112	114/114
Subtransmission	9/13	75/75	84/88
Transformer	10/47	34/34	44/81
<b>Total</b>	<b>25/91</b>	<b>246/294</b>	<b>271/385</b>

Protection is generally named for the primary plant the relays are protecting, with the exception of arc flash and AUFLS protection. Arc flash relays primarily use light detection, alongside current measurements, to sense an arc in indoor switchgear. It can quickly isolate the supplies to the switchboard to limit arcing, which reduces equipment damage and potential harm to personnel. AUFLS is a special type of protection that maintains system stability by shedding load automatically when an under-frequency event is detected.

**Figure 9.63: Protection systems age profile**



We have replaced many of our electromechanical and static relays with numerical types over the last 20 years. Schemes are replaced when they become obsolete, for example, they are no longer supported by the manufacturer or when there is lack of spares. The expected life of electromechanical and static schemes is 40 years, and 20 years for numerical schemes.

The average age of our relays is 17 years (14 years for numeric and 30 years for electromechanical/static). Some of our first-generation numerical schemes have now reached or exceeded their 20-year life. Many of our electromechanical schemes will reach their expected life by the end of the planning period. We will phase these out and replace them with numerical schemes.

## Condition, performance, and risks

### Condition and performance

Our electromechanical relay fleet has a proven record of good performance. However, as these relays near their expected life of 40 years, the mechanical parts become overly worn, allowing the relay calibration to drift. This drift may cause the relay to operate incorrectly or fail to clear a fault quickly. To mitigate this, we calibrate them during scheduled maintenance and replace parts. Another issue is that spares and parts for electromechanical relays are becoming more difficult to source as several types are no longer manufactured.

Our numerical relay fleet has had relatively good performance; however, we have previously deployed fast bus blocking (FBB) schemes that use a specific type of numerical relay which is unreliable and is now obsolete. FBB schemes are a relatively simplistic form of bus zone protection, which utilises feeder and transformer relays connected in series. FBB protection is relatively cost-effective to install, however, if one of the relays is temporarily removed from service for maintenance, this disables the scheme and poses safety risks to our staff working in the area. These relays are also relatively old, with most nearing the 20-year expected life.

We have observed several protection discrimination issues. These occur when protection systems do not act in a coordinated manner — either tripping load unnecessarily, or not selectively clearing the fault using the device installed immediately upstream of that fault. Most of these instances happen because settings are applied incorrectly or have become out of date (as the network load grows, settings need to be updated, otherwise it will inadvertently trip that load). We are exploring options to more tightly control our protection settings and avoid these incidents.

### Risks

Table 9.54 sets out the key risks and mitigations we have identified for our protection systems.

**Table 9.54:** Protection system risks

Risk/issue	Risk mitigation	Main risk
Protection relay fails to detect and isolate faults correctly	Settings are reviewed regularly and any gaps identified are quickly addressed. Replacement programme. Implementation of local or remote backup protection.	Safety Network performance
Obsolete relays fail with no spares available, resulting in prolonged equipment outage.	Contingency plan enacted to replace relay with a different model. Replacement programme. Spares purchased where available.	Safety Network performance
Cybersecurity breach resulting in unnecessary tripping or equipment damage	Install firewalls where appropriate and ensure firmware updates are regularly applied. Access restrictions to network control.	Safety Network performance
Complicated scheme implementation, resulting in extended outages during fault-finding and analysis	Technicians and staff are regularly trained and competent. Standard network protection philosophy and protection arrangements.	Network performance

### Design and build

The main objective for our protection system design is to correctly identify faults and isolate them effectively. This requires balancing several competing requirements such as:

- coordination with other protection in the immediate area in terms of primary plant coverage, clearance speed, and sensitivity
- stability of the protection equipment and ability to operate normally during power swings or current reversals
- availability and accuracy of current transformer (CT) cores could drive the type of scheme implemented, such as differential bus zone versus bus coupler overcurrent protection
- simplicity of the protection scheme — the simpler it is, the easier it is to maintain and undertake fault analysis; however, this may sacrifice discrimination capability
- lifecycle cost, as the goal is to select a scheme type that addresses network safety and reliability risk, consistently balanced with being cost effective

- availability of local or remote backup protection, consistent with our protection philosophy that addresses our network risk
- applying remote engineering access (REA), particularly for remote / difficult to access areas of our network. However, REA requires new infrastructure to be developed, and its cost-effectiveness will be considered on a case-by-case basis.

We have recently completed our protection philosophy document. This is a key document which will drive consistency and standardisation of our protection scheme designs going forward.

Simple protection design, such as ad hoc feeder protection replacements, are typically completed by our in-house team and the installation works carried out by our contracting division. Larger, more complicated projects such as bus zone protection, are generally outsourced for design. Installation is carried out by our contracting division.

## Operate and maintain

### Preventive maintenance

We regularly inspect, test, and maintain our protection assets to ensure they operate reliably. Our electromechanical relays require frequent calibration and detailed inspections and testing compared to numerical relays. Numerical relays, though more complicated, can self-diagnose performance with interval-based inspections covering any other gaps. Our approach is summarised in Table 9.55.

**Table 9.55: Protection systems preventive maintenance tasks**

Maintenance and inspection task	Frequency
Visual inspection of relays as part of zone substation equipment inspection	Two monthly
Detailed condition assessment and operational checks for electromechanical and static relays	Two yearly
Detailed condition assessment and operational checks for numerical relays	Four yearly

### Corrective maintenance

Corrective maintenance on protection systems is limited to component replacements and changes necessary to relay settings that arise from protection review or fault analysis.

### Reactive maintenance

We undertake reactive maintenance on protection systems in response to callouts for alarms, gather data from relays for fault analysis, and respond to relays that fail in service.

## Renew or dispose

Protection renewals are guided by the following principles.

- **Safety:** protection schemes are critical in detecting and isolating faults. Maloperation poses a significant safety risk to our workers and the public. We have also identified a specific type of relay (FBB schemes) that has a safety vulnerability.
- **Obsolescence:** relays that are no longer supported and have limited spares available pose a risk to reliable network supply. Our protection technicians are also finding it difficult to sustain the skills and software necessary to maintain these relays.
- **Functionality:** modern numerical relays provide significant functionality that enables us to carry out fault analysis in a more efficient manner, provide greater fault discrimination, and better control and operation of the network.

Our protection philosophy and subsequent gap analysis of our protection system against our design guidelines and philosophy, set out several recommendations to:

- replace FBB schemes.
- review inadequate transformer protection settings, such as LV overcurrent protection resulting in longer than necessary bus fault clearance times. This could introduce or increase arc flash hazards on site.
- install circuit breakers and RMUs and associated protection on buses and long feeders.
- review supply loss and safety risk at areas where we lack local backup protection and we rely on remote protection. This reliance increases fault clearance times (safety risk) and can result in a wider than necessary outage footprint.

These recommendations are currently being addressed. Our renewal programme will progressively replace FBB schemes when they become due for replacement. Some of our major zone substation projects, both renewal and growth, will directly address some of these recommendations and are included in their respective portfolios.

### Box 9.23: Meeting our portfolio objectives — a safe network and network performance

As we continue to renew and replace our protection relays, the overall system reliability will improve. This approach will reduce safety and reliability risks by minimising the likelihood of protection maloperations and hardware failures.

**Table 9.56:** Summary of protection systems renewals approach

Aspect	Approach used
Renewal trigger	Obsolescence, age (versus expected life)
Forecasting approach	Obsolescence (age/type based)
Cost estimation	Volumetric

### Renewals forecasting

We forecast renewals based on our strategy to replace all relays that are obsolete or have reached end of life. We size our programme to be consistent with resource constraints.

### Options analysis

Options for replacing protection schemes include lifting protection discrimination capability, such as applying differential protection rather than simple overcurrent. Another consideration is the application of inter-trips for interconnected areas where faults can be fed from multiple sources. Combinations of different types of schemes are considered on a network basis.

### Disposal

Relays and associated parts that can be re-used are retained and kept as spares. Disposal requirements for relays are similar to other electronic devices. Where mercury is present (typically sourced from old Buchholz relays), it will be disposed of in an appropriate manner.

### Coordination with other works

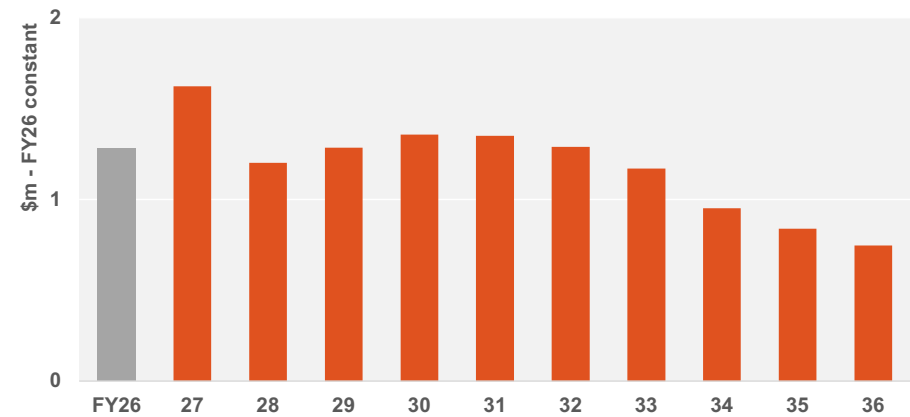
Protection systems projects are coordinated with substation projects, whether they are growth or renewal projects. This practice will reduce overall costs and equipment downtime.

#### Protection systems expenditure forecast

We forecast renewals using a volumetric approach. Unit rates vary by scheme type, with bus zone differential and arc flash protection having higher unit costs compared to others.

We plan standalone protection renewal capex of \$11.8 million over the forecast period.

**Figure 9.64:** Forecast protection systems capex



We will continue to sustain our protection delivery over the coming years, targeting the resolution of our backlog of end-of-life relays by FY33, ensuring our fleet is aligned with modern protection standard.

### Benefits

The key benefits of our renewal programme are mitigating in-service relay failures, minimising maloperation risk, and increasing protection functionality. This allows us to better manage the network and resolve faults more quickly.

## 9.7.3 Automatic voltage regulators (tap changer controls)

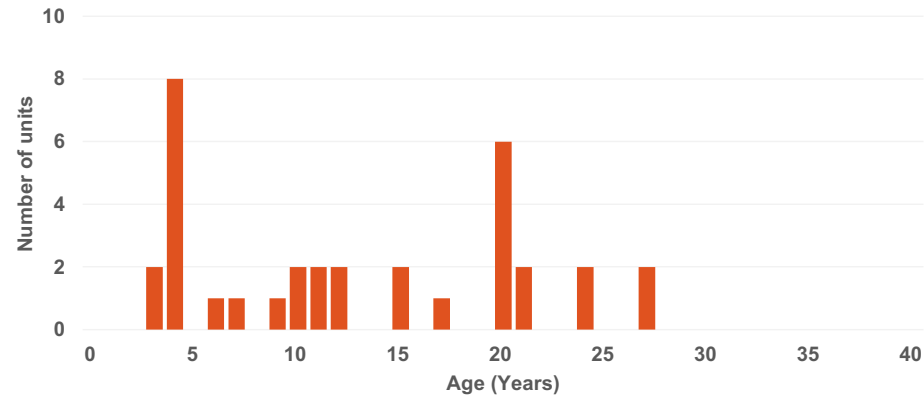
### Automatic voltage regulator fleet overview

Automatic voltage regulators (AVR) are electronic devices used to maintain a constant voltage output from a power source, such as a generator or transformer. A tap changer controller is a type of AVR that regulates the voltage by adjusting the tap setting on the transformer. These are essential in power distribution systems as they ensure the voltage output remains stable, preventing damage to equipment and ensuring reliable performance.

### Population and age

Figure 9.65 shows the fleet of tap changer controllers in our network. We have 34 controllers, with service life ranging from new to 27 years in service.

**Figure 9.65:** Age profile of AVR fleet



## Condition, performance, and risks

### Condition and performance

Our AVRs have generally performed well in the past and the condition of the fleet is reasonable. We plan to align these replacements with our transformer and transformer relay replacements and larger substation projects.

### Risks

The AVR is critical to the proper functioning of our network, ensuring we meet our power quality obligations. Therefore, failure risk needs to be effectively managed.

**Table 9.57:** Risks associated with AVR fleet

Issue	Risk mitigation	Main risk
Failure of AVR leading to inadequate voltage control	Periodic inspection. Maintain spares inventory.	Network performance

## Operate and maintain

### Preventive maintenance

We have recently included a four-yearly maintenance task as part of the routine inspection of AVRs. Settings and functionality are checked as part of this task.

**Table 9.58:** AVR preventive maintenance tasks

Task	Frequency
Tap changer controller	Four yearly
Routine equipment inspections and checks.	Four yearly

### Corrective maintenance

The manufacturer recommends replacing the battery every 6 or 10 years based on duty cycle. When this task is performed it is standard practice to back up the parameters in use.

Over time, the equipment may require software updates or upgrades which are also carried out under corrective maintenance.

### Reactive maintenance

Reactive maintenance is carried out in response to unexpected equipment failure. This may require emergency replacement of the AVRs or other associated equipment. We maintain a spare unit of our preferred controller to have available if there is a failure.

### Design and build

There are many types of voltage regulators on the market. Our standard design is now an Eberle Reg-D tap changer controller. This ensures that we can keep our spares holdings down and minimise the range of controllers our technicians need to be familiar with.

### Renew or dispose

We generally replace our AVRs based on age or obsolescence. We try to align these replacements with our transformer and transformer relay replacements.

### Options analysis

There are minimal options available when replacing our tap changer controllers. We generally replace them with a modern equivalent.

### Dispose

Material disposal is done separately when disassembly is possible, considering metals and plastics as recyclables while treating disposed electronic circuits as electronic waste.

## Automatic voltage regulators expenditure forecast

We do not currently have a standalone forecast for AVR. This capex is combined with transformer or transformer protection replacements.

### 9.7.4 Auxiliary power supply systems



#### Auxiliary power supply systems overview

The auxiliary power supply systems provide secure and reliable DC power to essential equipment at substations and communication sites. Devices such as protection relays, circuit breaker controls, emergency lighting, and radio systems rely on DC power to remain operational during and after faults, when AC power may be unavailable.

The two main components of these systems are the battery bank and the battery charger. The DC voltage level depends on the application, for instance, protection equipment are normally supplied at 110V, and communication sites are supplied at 48V.

To achieve 110V DC, battery banks typically consist of nine 12V batteries. In two substations we use 54 individual 2V batteries connected in series to form a 110V bank. Sealed lead acid batteries are currently the most common and preferred type for replacing old units.

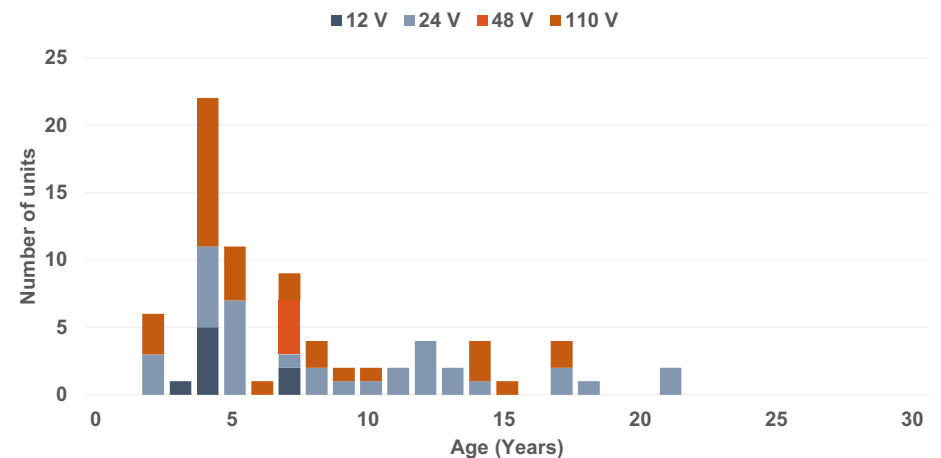
#### Population and age

Table 9.59 categorises our auxiliary power fleet by system purpose and battery voltage.

**Table 9.59:** Auxiliary power system fleet

SYSTEM PURPOSE	VOLTAGE	BATTERY BANKS
Protection systems	110 V	31
Telecommunications fibre	48 V	4
Telecommunications radio	12 V	8
SCADA	24 V	35
<b>Total</b>		<b>78</b>

**Figure 9.66:** Auxiliary systems age profile



We have battery banks which are beyond their 10-year life expectancy. These will be addressed during the planning period.

#### Condition, performance, and risks

##### Condition and performance

Our battery banks are in reasonable condition, although some have surpassed their expected life. Regular inspection and testing are carried out, and defective cells are replaced as needed. This proactive approach keeps short-term failure risk low.

## Asset health and criticality

Battery banks identified as end of life will be prioritised for replacement during the AMP period. Auxiliary systems are critical for safe and reliable network operation and are treated as high priority assets.

### Risks

We have identified two main risks related to auxiliary power systems:

- auxiliary system failing in service
- catastrophic battery failure.

Both risks pose safety and reliability concerns. To mitigate them, we conduct regular inspections and testing, and replace batteries based on age and condition.

### Design and build

The capacity required from each individual battery bank is site specific and designed to industry standards. A single tripping and re-closing operation of all circuit breakers plus all standing loads are used to determine the substation total load (continuous and momentary) for a set standby period and number of operations. The main factors are the load connected to it and the time the auxiliary power system is expected to supply the load if AC power is lost. This is called 'carry-over time', and it is a function of load and response time.

## Operate and maintain

### Preventive maintenance

Auxiliary power systems are critical assets. As such, they are regularly inspected and tested. Table 9.60 shows our preventative activities and frequency.

**Table 9.60:** Auxiliary power supply system preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Zone substation battery inspection and test	Two monthly

### Corrective maintenance

After a battery cell is diagnosed as defective, it is immediately replaced. Diagnosis occurs during testing or routine inspection.

### Renew or dispose

Battery banks are replaced based on age and condition. Where feasible, replacements are aligned with major primary plant upgrades to ensure compatibility with new load designs are installation standards.

## Options analysis

We aim to standardise battery banks and chargers to improve spare parts management and simplify installation. This includes standardising mounting racks, electrical connections, and communication cables.

Replacements will be coordinated with other substations projects, but due to their critical nature, auxiliary power systems requirements will be prioritised when a conflict may arise.

### Disposal

Depleted batteries are stored in covered area with spill trays to contain any leaks. They are transported in appropriately sized spill trays and delivered to certified recycling facilities for responsible disposal.

### Auxiliary power supply systems forecast expenditure

Over the planning period, we plan to spend approximately \$197k per annum on battery bank and charger replacements. This is to cover targeted replacements and corrective replacements following preventive maintenance checks.

## 9.7.5 Capacitor banks



### Capacitor banks fleet overview

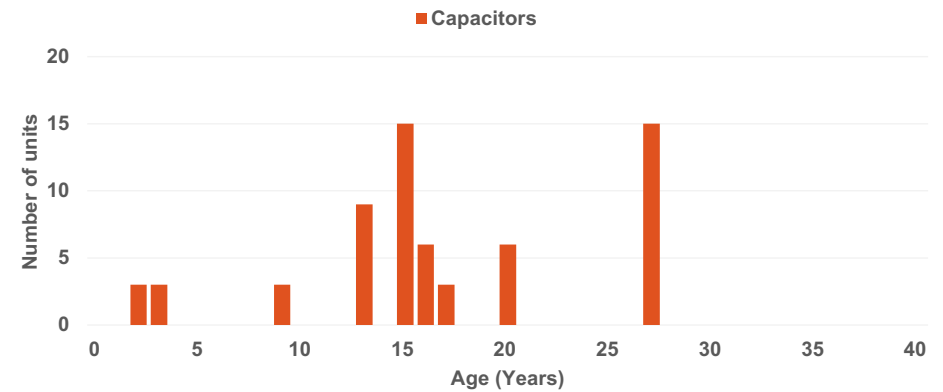
Capacitor banks are used to counteract the effects of large inductive loads, helping improve power factor, network voltage levels and enhance current carrying capacity. Inductive loads typically include large motors, although transmission circuits also contribute to the overall inductive load on the network.

In our network, 750kVAr capacitor banks are strategically placed at selected substations and feeders to provide localised reactive power support. Additionally, 150kVAr capacitors are installed at approximately the midpoint of a long 11kV feeder, where it continues to support voltage regulation and maintain service quality across its length.

### Population and age

Our capacitor fleet age is shown in Figure 9.67.

Figure 9.67: Capacitor banks age profile



In total we have 63 capacitors installed at 20 banks on our distribution network.

### Condition, performance, and risks

#### Condition and performance

Condition assessments indicate our capacitor banks are in satisfactory condition. To mitigate failure risk associated with ageing assets, an age-based replacement strategy is in place. The current age profile means minimal replacements are expected over the next 10 years.

#### Asset health and criticality

The overall health of the capacitor fleet is good, with no immediate end-of-life drivers identified.

#### Risks

Capacitors play a crucial role in maintaining system voltage within allowable limits. Table 9.61 summarises the key risks associated with the capacitor fleet.

**Table 9.61:** Capacitor bank risks

Risk/issue	Risk mitigation	Main risk
Condition based failures of equipment	Renewal programme.	Network performance
Stored energy	Appropriately discharge before work.	Safety
Explosive failure	Renewal programme.	Network performance

## Design and build

Capacitor banks are typically pole-mounted and constructed using three single phase capacitors configured in an ungrounded star connection. Each capacitor is protected by a high voltage dropout fuse, and the bank is switched using a 3-phase overhead switch.

In substations, capacitors may be directly connected to a circuit breaker as standalone units, in which case fusing is not required. Surge arrestors are installed on the incoming line connection to protect against lightning strikes.

Capacitors are filled with dielectric fluid and feature porcelain bushings hermetically sealed to the tank. Adequate corrosion protection is essential to prevent seal failure.

## Operate and maintain

### Preventive maintenance

Our capacitor bank preventive maintenance programme is shown in Table 9.62.

**Table 9.62:** Capacitor bank preventive maintenance

Preventative maintenance	Frequency	Scope of work
Pole-mounted/substation capacitor banks	Five yearly	Visual inspection

### Corrective maintenance

Typical corrective maintenance activities include cleaning of bushings or repair of overheated joints. We replace capacitors with dielectric leaks or corrosion that cannot be repaired.

### Reactive maintenance

Failed capacitors are replaced promptly to maintain system performance.

### Renew or dispose

Capacitors are scheduled for replacement based on age and condition.

## Options analysis

Typical options considered when a capacitor is found to be at end of life include:

- like-for-like replacement
- decommissioning
- replacement with a different type of reactive power support.

## Disposal

Removed capacitors are disposed of responsibly, with disposal methods targeted to the material of each component.

## Capacitor banks forecast expenditure

Over the AMP period we have forecast \$40k in expenditure for this asset fleet.

### 9.7.6 Load control

#### Load control fleet overview

We use ripple plants to manage load across the network. These plants generate and transmit signals that are received by ripple control relays, which then execute programmed actions. Signals are sent either according to predefined schedules or in response to specific events.

Our network uses the Decabit ripple protocol, which is considered reliable, secure, and fast.

Load control signalling is used to manage:

- hot water cylinders
- streetlights
- HVAC (very limited).

We operate six load control plants, as outlined in Table 9.63.

**Table 9.63:** Load control relays

Ripple plant location	Injection voltage	Transmitter ratings
Maungatapere	33kV	200kVA
Tikipunga	33kV	200kVA
Maungaturoto	33kV	80kVA
Dargaville	11kV	40kVA
Bream Bay	11kV	40kVA
Ruakākā	11kV	40kVA

The main components of each system include the transmitter, coupling cell, and receiver.

### Population and age

Our load control fleet is ageing, and medium-term action is required to manage the associated risks.

**Table 9.64:** Load control relays ages

Load control plant (SFC)	Age (years)
Maungatapere	18
Tikipunga	3
Maungaturoto	15
Dargaville	8
Bream Bay	18
Ruakākā	16

## Condition, performance, and risks

### Condition and performance

Condition assessments indicate that all ripple plants are currently in satisfactory condition. To mitigate the risk associated with ageing assets, we are implementing a replacement strategy based on age and condition. Historically, the fleet has performed well, with only minor corrective maintenance required.

### Asset health and criticality

Some ripple plants have been identified for replacement to prevent increased risk and maintain system reliability.

### Risks

The primary risk is failure to manage load effectively, which could result in manual load shedding of feeders.

### Design and build

The ripple plant consists of several individual assets, including:

- transmitter
- isolating transformer
- tuning coils
- capacitors

The system is modular, allowing individual components to be replaced as needed. The equipment is typically robust, with similar life expectancies across components. Units or systems are replaced at end of life.

Our current approach involves replacing older transmitter with modern insulated-gate bipolar transistor (IGBT) power electronics, which offer enhance features such as fault logging and real time output current and voltage monitoring.

## Operate and maintain

### Preventive maintenance

Load control plants are inspected and tested by specialist contractors on a scheduled basis, as described in Table 9.65.

**Table 9.65: Load control preventive maintenance**

Load control plant	Frequency	Scope of work
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Equipment test	Annual	Check operation and signal strength.

### Corrective maintenance

We maintain a contract with specialist contractors to repair components as required.

### Reactive maintenance

A contract is in place with specialist contractors who hold key spare parts to support reactive maintenance needs.

### Renew or dispose

Load control units are replaced at end of life, based on age and condition of the asset. This ensures continuity of service, while maintaining system reliability and performance.

### Options analysis

When load control units reach end of life, they will be replaced with modern equivalents to maintain service continuity. However, we are actively monitoring emerging technologies impacting this field, such as smart meters, price responsive appliances, and home automation systems.

While some of them are consumer driven, they influence network demand patterns. We will assess their impact and adapt our replacement strategy as needed. Where appropriate, we may also support or incentivise adoption to enhance load flexibility.

### Disposal

Disposal methods vary depending on the material type of each component. All components are disposed of responsibly in accordance with environmental and safety standards.

## 9.7.7 SCADA system

### SCADA system overview

Northpower's GE PowerOn advanced distribution management system (ADMS) system provides Supervisory Control and Data Acquisition (SCADA) capability for network visibility and remote-control operations. It allows our network operators to efficiently manage our network.

**Table 9.66:** Modules and subsystems description

Modules/sub systems and descriptions	Modules/sub systems and descriptions
<p><b>SCADA</b></p> <p>At the heart of our ADMS is a SCADA system which provides a real-time view of tele controlled parts of the network, including switch position and energisation, loading and voltage levels, and event logs. This is dynamically generated using graphical displays of network schematics combined with active tables and charts.</p> <p>The core SCADA system comprises:</p> <ul style="list-style-type: none"><li>- <b>remote terminal units (RTUs):</b> field devices concentrating sensor/actuator information (refer to automation and control section)</li><li>- <b>communications network:</b> provides the link between the field and central server, comprising fibre, radio links and associated switching facilities (refer to communications section)</li><li>- <b>servers:</b> the system runs four real-time application nodes across our head office and disaster recovery sites, providing a very high level of redundancy</li><li>- <b>SCADA workstations:</b> provides the human machine interface (HMI).</li></ul> <p>The system is a bespoke design. It was implemented with cybersecurity in mind, minimising the likelihood of any potential security breach. Redundancy is another core design principal, with all parts of the system allowing for failures without impacting operations.</p>	<p><b>Network access request system (EDNAR)</b></p> <p>EDNAR network access permit system manages permit planning processes, allowing approved staff and contractors to request access to work on our network. Planners can automatically create planned orders in our ADMS system, and manage the flow of documentation back to applicants following planning.</p> <p><b>Outage management system (OMS) and advanced applications</b></p> <p>Our OMS is a fully integrated solution that provides centralised visibility, management and reporting of network outages in the ADMS as well as full visibility of outages in our Salesforce CRM to support call taking and dispatch, and near real time accurate reporting of outages to our data platforms and website. In the process of implementing the OMS, we have improved fault cause capture and automated regulatory reporting.</p> <p><b>Inter Control Centre Protocol interfaces (ICCP)</b></p> <p>ICCP interfaces have been commissioned, linking our ADMS system to Transpower. This interfaces serves two purposes, it allows visibility across control centres of key assets at our points of interconnection, and it supports generators attached to our network to securely communicate with the system operator.</p> <p><b>Advanced Applications</b></p> <p>We have recently enabled Distribution Power Flow (DPF) and Switching Advisor (SA) applications, as initial steps towards enabling even more advanced functionality, and have created load profiles across the network based on smart meter data. Real time and forecast modelling of power flows are now available enabling the system to automatically recommend switching sequences to planners and operators.</p>
<p><b>Load management system (LMS)</b></p> <p>The Catapult on-demand load control subsystems automatically control interruptible load on the network. This system curtails load when substation constraints are breached, helps control streetlights and tsunami sirens, and ensures minimum disruptions for our consumers.</p>	
<p><b>Distribution management system (DMS)</b></p> <p>The SCADA system is integrated with our GIS, allowing non-remote-controlled parts of the network to be included and enabling us to electronically manage supporting processes, and issue access permits. We can simulate outage impacts, and the system prevents unsafe operation of the network, reducing the possibility of switching related incidents.</p>	

## Population and age

Our SCADA system was initially implemented in 2020, and is being incrementally patched and upgraded, therefore, it is still relatively young.

## Condition, performance, and risks

### Condition and performance

The ADMS software has been through one upgrade cycle, and another upgrade is underway in FY26 (uplifting the operating systems (OS), databases (DB) and applications). The hardware is scheduled for replacement in FY27. Implementation is ongoing and is being upgraded and patched regularly. The system is designed and managed with high availability and cybersecurity as key architectural principals.

### Asset criticality

The SCADA system is important to support safe day to day operation of the network.

### Risks

The following risks have been identified

**Table 9.67:** SCADA System risks

Risk/issue	Risk mitigation	Main risk
Loss of visibility and control	Diverse communication paths. Manual operation. Preventive maintenance.	Network performance
Cyberattack resulting in third-party gaining control	Cybersecurity preventive measures. Preventive maintenance (patching software).	Network performance

## Design and build

GE's ADMS is quickly becoming the de facto standard, being used by many of the largest EDBs in New Zealand. We have used the New Zealand EDB model, which includes standardised symbology and configuration.

## Operate and maintain

Our new ADMS system is kept patched and cyber secure, with regular updates provided by the vendors. A software upgrade is underway this financial year, and hardware replacement is scheduled for FY27. Other older subsystems are monitored, vendor support contracts are in place, and systems are flagged for replacement when necessary.

### Preventive maintenance

Our control systems and digital teams actively monitor, upgrade, and patch ADMS software as required. Application, DB, and OS critical security updates are applied soon after release.

### Corrective maintenance

Our control systems and digital teams manage corrective issues — that is, problems raised by our NOC, based on priority.

### Reactive maintenance

High availability provides redundancy for any hardware failures. Vendor support contracts are in place for hardware, and issues are dealt with as they arise.

### Renew or dispose

Vendor certification drives decisions regarding our ability to patch or upgrade versus the need to replace or re-implement. Our objective for SCADA systems and hardware is to keep it patched and upgraded to support cybersecurity and extend the lifetime of the solution.

We anticipate a life of over 20 years for the ADMS, so will continue to schedule upgrades and hardware replacements as they become due.

### Options analysis

A complete replacement/re-implementation of SCADA systems is significant. This would see options analysis and project decision papers being escalated for consideration.

### Disposal

Hardware is securely disposed of by our Digital team.

## 9.7.8 Automation and control systems

### Automation and control systems fleet overview

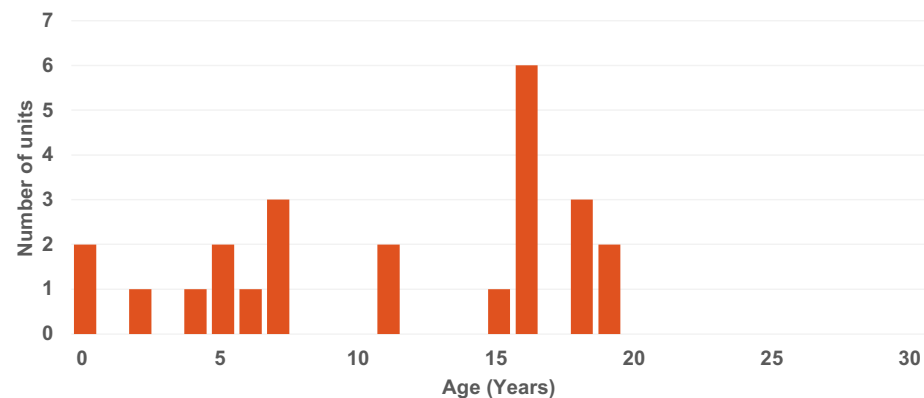
#### Remote terminal unit (RTUs)

RTUs are an essential component of our SCADA and telemetry infrastructure. Within zone substation, RTUs interface with Intelligent Electronic Devices (IEDs) to facilitate data exchange and control functions. Communication between the central master station and RTUs is achieved through a combination of radio, microwave, and fibre optic links.

#### Population and age

There are 27 RTUs currently deployed across the network. Figure 9.68 shows the age profile of the RTU fleet.

**Figure 9.68:** RTU age profile



RTUs have an expected service life of 15 years. Several units have already reached or exceeded this threshold and will require replacement during the planning period. The average age of the fleet is 11 years.

#### Condition, performance, and risks

##### Condition and performance

RTUs are electronic devices, so obtaining accurate condition information is not practical. We instead use age as a proxy for health. Replacements are influenced by other factors, for example, functionality, obsolescence, and supportability. We manage the risk of unplanned failures through spares if a manufacturer discontinues support for a specific hardware model.

Our RTUs have generally performed well. Where failures do occur, they immediately become visible to the operations centre and we replace the unit reactively.

#### Asset health and criticality

As we do not have much data for this asset fleet, we do not have an RTU asset health model yet. Once the data capture exercise is complete, an AHI model similar to that of the other asset fleets will be developed.

#### Risks

Table 9.68 sets out key risks and mitigations we have identified for our RTU fleet.

**Table 9.68:** Automation and Control System risks

Risk/issue	Risk mitigation	Main risk
Malfunction and failure of RTU	Following regular inspection and maintenance regime.	Safety
	Network performance.	
Communications failure	Regular inspection and monitoring of the optical fibre connectivity.	Safety
	Establish strong microwave/radio modes of connectivity.	Network performance
Risk of cyberattack	Continuous improvement of security levels in the SCADA system.	Safety
		Network performance

#### Design and build

We have standardised RTU designs, and installations are now carried out through approved manufacturers. This reduces required spares and lowers total cost of ownership. Detailed design and mapping of RTUs is done during pre-commissioning activities of a substation.

#### Operate and maintain

##### Preventive maintenance

RTUs and remote HMIs are regularly inspected and functionally tested as part of regular zone substation maintenance to ensure their ongoing reliability. Being electronic devices, RTUs do not need extensive maintenance.

### Corrective maintenance

Corrective maintenance on RTUs and remote HMIs is often limited to system rebooting and software upgrades.

### Reactive maintenance

Limited reactive maintenance can be performed for individual components, and obsolete units are typically replaced during substation projects.

### Renew or dispose

RTU renewal is typically carried out as part of zone substation projects. RTU replacements outside of the zone substation programme are limited.

### Options analysis

During the planning period, we will replace RTUs as part of zone substation upgrades. We also replace RTUs as they become technologically obsolete. Once RTUs reach end of life, or when they are planned for renewal, there are limited alternatives available.

### Disposal

RTUs and remote HMI modules that can be used as spares are kept. The disposal requirements are minimal, and they are handled in the same way as other electronic devices.

### Automation and control expenditure forecast

Over the AMP period, we forecast an annual expenditure of approximately \$150k on RTU replacements. This covers works associated with substation replacements, ad hoc replacements of obsolete units, and reactive replacements as required.

## 9.7.9 Communications

The following sections describe our communications fleet. We are currently updating our communications strategy to ensure a consistent lifecycle approach is applied to this fleet. We manage our communications assets through corrective and reactive programmes.

### Communications fleet overview



### Radio and fibre

Over time, we have built up our fibre and radio (VHF and UHF) capability to cover the entire Northpower region. There are six dedicated VHF voice repeater sites, and six dedicated VHF data sites. We operate a structured voice and data radio access network (RAN). The network is a mixture of VHF and UHF analogue voice, data, repeater, and linking equipment located at the various radio and substation sites. In addition to the repeater sites, we have five substation sites connected by a data RAN. We use fibre to connect to various substations within the access network.

## Network resilience

Communication systems play a critical role during and after a hazard event. It is critically important that we have systems in place to ensure the network has sufficient resilience to perform as required during and after these events. Typical examples are as follows.

- Where possible, RAN sites are located on fibre or radio ring protected circuits.
- Dual connection paths are made available for mission critical sites.
- Quality power backup systems give additional up time during power failures.
- Critical sites should have power generator capability.
- N-1 systems are used for remote access sites within the access network.
- Sufficient sparring is held to ensure quick replacement during failure.
- Network management systems are in place to ensure faults and failures are quickly dealt with during an emergency.

## Voice network

We own and operate our own private land mobile radio network. This provides a radio telephone (RT) service for the exclusive use of our network staff and contractors. The network consists of six VHF repeaters linked through a radio dispatch system at the Whangārei depot. The Whangārei control centre is connected to the radio dispatch hardware by an ethernet local area network (LAN). The backup control room is connected to the radio dispatch hardware by fibre. These repeaters provide a 90% coverage of our distribution area.

There are approximately 150 mobile radios installed in our vehicles and another 21 RT radios located at substations.

## Point to multipoint data radio network

We own and operate three point to multipoint (P-MP) networks, which are used to carry control data to remote hardware. The largest of the P-MP networks uses RT technology to link SCADA gateways (located at communications sites) to RTUs on remote hardware. There are 36 reclosers, regulators, and sectionalisers, and 104 switches on this network.

The second network uses a similar RT topology but differs in the solution used for remote RTUs. This network has 26 switches.

The third P-MP network uses VHF utility radios, which are designed specifically to carry control data. This network has completed its pilot and is undergoing a hardware update before additional connections are made. Four reclosers are currently connected to the network.

## Point to point radio (WAN radio)

We own and operate 12 point to point radio links which form a radio WAN. The radio WAN connects to a central communications node. The node is connected to our control by fibre. The links carry SCADA, security, management data for substations; the radio WAN also carries management data for radio communications huts. Digitised voice data is carried on one point to point link contained within the WAN. This data facilitates the voice service in the Dargaville region. Ten of the point to point links provide an ethernet interface. One link is being updated to provide an ethernet interface and the remaining link is earmarked for decommissioning.

## WAN (fibre)

Twelve substations have distributed fibre connections. We have a leased fibre connection which terminates at Dargaville radio site, and a fibre connection to carry data from the radio site to Dargaville substation.

## LAN (substations)

The substation SCADA LANs are standardised with an IP LAN and copper or optical ethernet interfaces. The SCADA LAN is managed by substation engineering. The SCADA LAN is connected into the substation communications LAN by an ethernet switch.

## LAN (communications sites)

There are seven communications sites. Six sites have a standard IP LAN with copper or optical ethernet interfaces. The remaining site will be upgraded in the future.

## Communications expenditure forecast

Over the planning period we expect to spend approximately \$400k per year on our communications network.





## Chapter 10

# Supporting Activities

## 10.1 Introduction

This chapter discusses the business functions and non-network assets that support our electricity network. This includes supporting functions (for example, human resources, digital, and commercial) and the staff that directly support our day-to-day asset management activities. Facilities and motor vehicles are also included in this category.

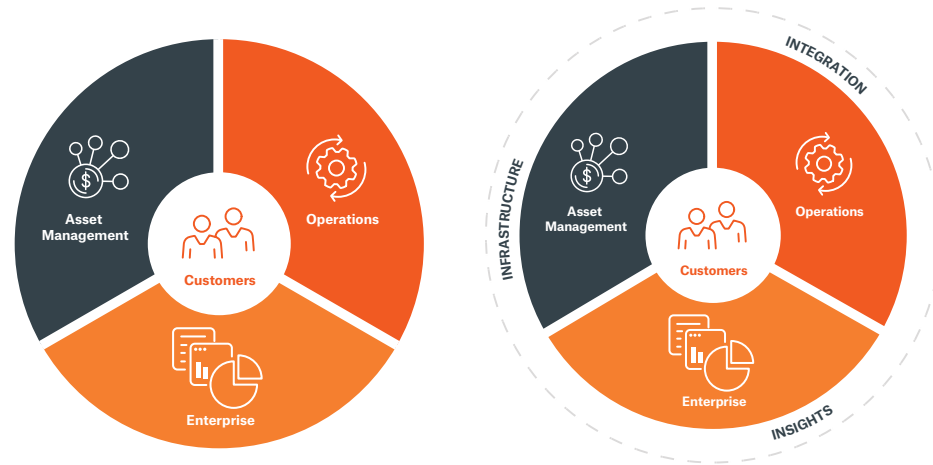
## 10.2 Business focus areas

We have taken the approach of architecting core platforms by business focus areas:

- asset management
- customer
- operations and Distribution System Operator (DSO)
- commercial and regulatory
- enterprise, data and insights

Efficient, clear, and effective business processes are critical to delivering innovative services quickly, at the least possible cost. The following outlines Northpower’s multi-layered view of key business processes and how these are supported by effective integration, infrastructure, and business insights.

**Figure 10.1:** Business process framework



## 10.3 Core digital platforms to support process areas

We continue to invest in quality, industry leading digital solutions to support key focus areas around customers, operations, assets, commercial and regulatory, and data insights.

These investments have:

- set us up with a solid foundation to build upon
- leveraged the capabilities of each of these platforms
- positioned us well to adapt to future change.

Digital teams provide resources to continue to support and respond to changing business needs. They supply design and solution expertise, develop and enhance functionality, improve quality of data, and provide technical support.



**Table 10.1:** Description of core asset management platforms

Platform	Description
<b>Design</b>	Construction plans are prepared using AutoCAD and templates.
<b>Engineering drawings management</b>	Introduced Autodesk Vault for the management of substation and communication drawings in 2025. This will be extended to include a wider range of network drawings.
<b>Network modelling</b>	SINCAL is used for high voltage (HV) load flow studies and Future Grid to analyse and provide insights from low voltage (LV) Network Operational Data.
<b>Geospatial information</b>	Core GIS is Hexagon G/Technology, with an ESRI ArcGIS application layer. Plans are underway to re-platform the aging core GIS over the next three calendar years.
<b>Asset information Management</b>	We’re progressing with the transition to the IBM Maximo EAM platform. Design is complete, and implementation is planned across the 2026 and 2027 calendar years. Combined, the EAM and GIS ensure the quality and accuracy of asset management information.
<b>MODLA</b>	MODLA is utilised as an optimisation and modelling platform, supporting volumetric asset analysis to enhance investment strategies and inform asset replacement planning decisions.
<b>Quality management</b>	Q-Pulse is used to track Health, Safety, Quality and Environmental (HSQE) actions. Controlled documents are managed in SharePoint Quality Management System (QMS).

## Initiatives

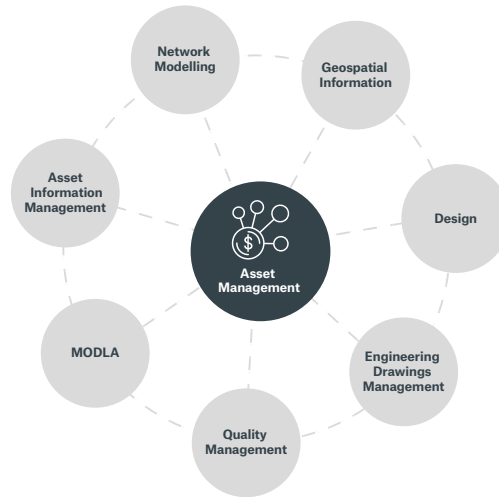
Our existing legacy asset management system EMS WASP is end-of-life, and we are replacing it with the IBM Maximo asset management suite. We are currently undertaking a design exercise, with a view to implementing in the 2026 and 27 calendar years.

We will take a similar approach to this project as we did with our successful customer relationship management (CRM) implementation, focusing on our core requirements first, and iteratively learn, grow, and develop over time.

MODLA is utilised as both a modelling and optimisation platform to support data-driven decision making across our asset portfolios. It enables causal asset modelling, lifecycle cost analysis, and strategic optioneering to inform and enhance targeted investment planning.

Since 2023, MODLA has been progressively integrated into our asset management approach including:

- development of failure mode, effects and criticality analysis (FMECA) models for eight volumetric fleet asset classes
- implementation of an optimiser tool to evaluate multiple investment scenarios across a broad range of assets
- integration of network consequence modelling within HV overhead networks, enabling initial asset risk quantification.



### 10.3.1 Customer platforms

Our CRM platform is now firmly embedded into our business. It plays a key role in supporting a number of processes and underpins all interactions with our customers. The building blocks of our modern CRM platform are strong, and knowledge and expertise in the platform has grown. This positions us well to develop further functionality into the platform.



**Table 10.2:** Description of core customer platforms

Platform	Description
<b>Customer relationship management</b>	Customer information and core customer processes are embedded into Salesforce CRM.
<b>Customer communications management</b>	Customer notification management leverages our Salesforce platform with custom extensions. Call centre telephony has been replaced with a Genesys solution.
<b>Service delivery and advisory</b>	Our Salesforce CRM supports these processes.
<b>ICP management</b>	Our Axos Billing system and associated interfaces provide a robust link between the electricity registry and a number of our core systems.
<b>New connections</b>	Salesforce is used to manage new connections.

## Initiatives

Improvements to our customer solutions are ongoing. They include future-proofing, and automating previously manual or paper processes. Integration with operational and registry information provides customers with visibility and tracking of work and interactions with our business.

Key focus areas:

- Customer transaction portal improvements — future proofing and refreshing the customer experience.
- Website outage centre improvements — improved proactive customer communication and transparency of information, including utilising short messaging service (SMS) for customers impacted by planned and unplanned outages.
- Operational Excellence portal — ensuring easy self-serve access to our Network Standards by staff and Network Approved Contractors.
- Publishing a capacity map to enable customers to understand available capacity at their chosen project location.
- Respond to Electricity Authority (EA) regulatory changes, implementing system changes to ensure continued regulatory compliance.

### 10.3.2 Operations platforms

Northpower’s advanced distribution management system (ADMS) is a mature, modern platform that has the capability to evolve over time to meet the challenges facing the industry. It has been designed and commissioned with cybersecurity, digital integration, paperless processes and seamless reporting capabilities in mind.

Following the SCADA HV network implementation, and the 2022 commissioning of the Distribution Management System (DMS), an integrated Outage Management System (OMS) with a modern data platform solution was commissioned in 2024.



**Table 10.3:** Description of core operations platforms

Platform	Description
<b>Data Historian</b>	Our OSIsoft PI Historian keeps time series data from telemetered points on the network.
<b>SCADA</b>	The core of our ADMS platform is our GE PowerOn SCADA system. We have an Inter-control Centre Communications Protocol (ICCP) interface to Transpower to support management of inter-connectivity and dispatch of hosted HV distributed energy resources (DER).
<b>Distribution management</b>	We use a GIS to ADMS CIM interface to keep our distribution network data up to date in GE PowerOn, a fully electronic distribution mimic with geographic views, switching management with safety logic.
<b>Load management</b>	The Catapult OnDemand system provides control of ripple-controlled plant for demand response, tsunamis, and streetlight control.
<b>Network access management</b>	The ADMS integrated Zepben electrical distribution network access request (EDNAR) system allows applicants to raise work requests on the network using the built-in ADMS network viewer. They can then access permits prepared by Network Operations Centre (NOC).
<b>Outage management</b>	We have an end-to-end integrated system, from customer calls and dispatch in Salesforce, outages in GE PowerOn, our in-house NORA platform for website and telephony integration, and Click in the field.

### Operations Reporting

In 2025, Northpower implemented a managed data platform. Fivetran ingests ADMS data into Snowflake with near-real-time capability, the data is transformed within the platform.

Reporting tools such as PowerBI consume this data to produce near real time regulatory reporting and dashboards.

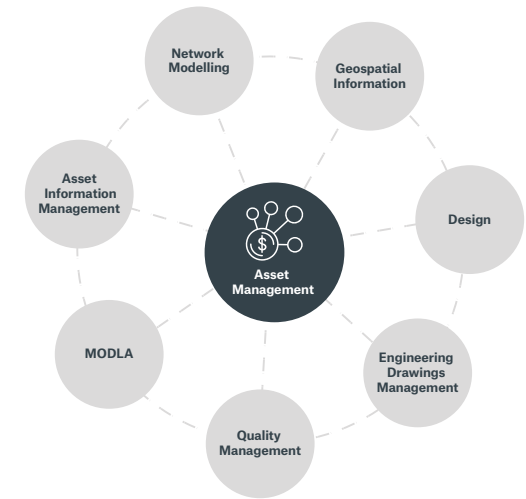
### Initiatives

Northpower is actively preparing for a future DSO model by building the necessary data infrastructure, tools, and capabilities to manage the increasing integration of DER and enable greater flexibility in both load management and generation.

Key focus areas:

- Adaptive Network Management (ANM) — manage DER HV network congestion.
- Developing advanced control systems to actively manage DER. Initially, ANM will focus on managing high-risk or constrained areas to help Northpower maximise the use of existing assets and avoid expensive upgrades.
- Low voltage visibility and monitoring.
- Enhancing the ability to monitor and manage the LV network in real-time. This will improve safety, reliability, and coordination with DER, ensuring efficient integration of renewable energy sources.
- Communications and data infrastructure.
- Implementing secure, high-speed data platforms such as ICCP to enable real-time data exchange between the System Operator, DER participants, and network operators. This infrastructure will support timely decision making and seamless network management.

These areas are integral to Northpower’s DSO roadmap, which is designed to enable a flexible and responsive network capable of meeting future challenges and supporting Northland’s low-carbon transition.



### 10.3.3 Enterprise and insights platforms

Our enterprise and insights applications support all business units and provide core systems for numerous processes. The focus in the asset management space is data sharing, and a number of proof-of-concept initiatives are planned to remove data silos, improve data access, and enhance datasets to support identification and analysis for asset risk and criticality.



**Table 10.4:** Description of enterprise and insights platforms

Platform	Description
<b>Records and document management</b>	SharePoint is used as the document management system across Northpower.
<b>IT service desk software</b>	Jira and Jira Service Desk manages interactions with users and IT resources, based on ITIL framework.
<b>Financial management</b>	Northpower’s JDE ERP provides core financials and supply chain functions for all Northpower divisions.
<b>Purchasing</b>	Coupa is used for requisitions and purchase orders.
<b>Field force automation</b>	Provided by Northpower’s network contractors.
<b>Human resource management</b>	Cornerstone provides eLearning portals and is used for tracking competencies, qualifications and managing recruitment. PayGlobal is used for remuneration.

### Initiatives

Our enterprise and insights applications support all business units and provide core systems for numerous processes.

The focus in the asset management space is data access and analysis support. To this end, a number of initiatives are planned or underway to remove data silos, improve data access, and enhance datasets to support identification and analysis for asset risk and criticality.



## 10.4 Digital expenditure

Northpower continues to mature its digital investment decision making and lifecycle management by strengthening related governance and supporting digital strategies. Our strategy aims to ensure digital resources and solutions are provided and managed in a way that supports the business, with an emphasis on reliability, cybersecurity, and cost efficiency.

Like our network expenditure, digital investments require robust governance and portfolio management to ensure projects are selected and executed in a prudent and efficient manner. We have established clear structures, processes, and oversight mechanisms to ensure our digital expenditure delivers value to the business.

Through platform-centric delivery, data-driven decision making, a focus on cybersecurity, and innovation, Northpower’s digital strategy ensures that every investment in technology contributes to our purpose, impact, and long-term aspirations. We adopt a principle of platform-centric enterprise with business capabilities delivered through, oriented around and aligned with our strategic enterprise platforms (including GE PowerOn, Salesforce, Maximo, JDE, and Snowflake).

### 10.4.1 Expenditure Overview

Our Digital team delivers the infrastructure, servers, applications, and tools that support our distribution network operations. Key drivers for our expenditure include:

- **capability development:** development of capabilities identified by business owners (internal customers) subject to digital governance and system/vendor capacity. There is an increasing focus on providing cybersecurity capability to safeguard the network and assets.
- **system maintenance:** servers and systems are regularly patched and tested for security and reliability (disaster recovery capability, where applicable). This is covered by Northpower's Cyber and Information Security Policy.
- **renewal:** digital hardware and operating systems are upgraded or replaced as they become unsupported, typically every five to seven years.
- **ICT Opex:** includes software as a service (SaaS) and cloud infrastructure costs to keep our systems running. New platforms and capabilities often require an ongoing support agreement or maintenance contract. As our application portfolio grows, the aggregate support costs rise.
- **technology:** to support scalable, secure, and future-ready operations, Northpower has adopted a 'cloud-first' architecture approach.

### 10.4.2 Cybersecurity

We have completed a comprehensive cybersecurity review and penetration testing programme, with remedial actions already underway. Development of a formalised Disaster Recovery Plan is progressing, ensuring clearer processes for continuity and recovery.

Our defensive posture has been enhanced with Distributed Denial of Service (DDoS) protection in place, and we are actively assessing additional vulnerability detection options. Supplier risk management has been uplifted through the introduction of a new tool that improves visibility, monitoring, and remediation of third-party risks.

We have established a formal incident recovery process and a comprehensive cyber roadmap. Ongoing security awareness efforts include multiple learning modules launched and phishing simulations providing valuable insight into behavioural risk.

By investing in the cybersecurity and resilience capability, Northpower will be better protected against data breaches, service disruptions, and other technology-related risks.

## 10.5 Non-network functions

In addition to our operations, delivery, and engineering functions, see Chapter 2, we rely on the wider teams within Northpower to ensure we effectively deliver electricity distribution services to our customers. These supporting functions include our corporate teams, such as Finance, and the People and Capability team.

### 10.5.1 Business support activities

Business support activities are part of our non-network operating expenditure. These include direct and indirect staffing costs as well as advice we use to complement our internal resource. The key functions supported by this non-network Opex include:

- **people and capability:** attracting and retaining capable and effective people, managing skills and competency development, and fostering a positive working environment. This will be increasingly important as we grow our capability and competency levels over the planning period.
- **finance:** includes managing our working capital and debt, purchasing and transaction functions, financial analysis, corporate reporting, and advice.
- **health, safety, quality, and environment:** providing support and coordination of safety and environmental policies and approaches in support of our operational teams.
- **commercial and regulatory:** managing our relationships with regulators and retailers, setting our pricing and commercial direction.
- **customer experience:** managing our day-to-day customer interactions, stakeholder engagement, consultation, and general communications.
- **digital platforms:** managing, supporting and developing the digital platforms used to support the electricity network.
- **business change portfolio:** managing our internal business improvement projects and programmes to support the electricity network.

These functions all support our electricity asset management activities. Some of the key drivers for this expenditure over the planning period include:

- **staff numbers:** directly impacts business support costs. Salary and indirect costs (for example, consumables) are driven by overall staffing levels.
- **external labour market:** staff salaries and other benefits are influenced by the general employment market. Demand for skilled staff, particularly in the regions, will impact the level of competitive salaries.
- **business support requirements:** as our network work programme expands, work volumes for areas of support functions will increase.
- **digital capability:** licence agreements and costs for third party support and hardware.

These functions play a key role in supporting our operations and ensuring we have the capability and resources necessary to be effective asset managers.

### 10.5.2 Non-network assets

In addition to our digital assets we own or lease a range of other non-network assets used to support our day-to-day asset management activities. These include:

- **offices and facilities:** Northpower owns or leases a number of facilities including office buildings and depots. We aim to ensure that our offices and stores are safe and secure for our employees, are functional and fit for purpose, support improved productivity and efficiency, and are cost-effective to procure and operate. They must also be sized to support future staff growth and materials storage requirements.
- **office equipment:** offices are fitted out with workstations to accommodate our employees. Our offices also host meeting spaces and equipment that is required to operate effectively. These assets include desktop and laptop hardware, video conferencing equipment, and peripherals (such as printers).
- **vehicles:** we have a fully maintained fleet of vehicles that are leased over a range of terms. An increasing proportion of these are plug-in hybrids or battery EV. We plan to increase this proportion over time in support of emission reduction targets. Our fleet includes vehicles that fit defined criteria, including that vehicles must have a five-star ANCAP safety rating and be fit for purpose, for example, all-wheel-drive and with suitable ground clearance. Our approach to managing our vehicle fleet is set out in a policy which specifies how we procure vehicles and associated utilisation rules.



## Chapter 11

# Forecast Summary

## 11.1 Introduction

This chapter sets out a summary of our expenditure forecasts over the AMP planning period. The information presented summarises the investments discussed in earlier chapters. It provides further commentary and context for our forecasts, including key assumptions. It discusses the assumptions used and the uncertainties inherent in developing a 10-year forecast. It should be read in conjunction with the relevant expenditure chapter.

Our AMP includes our current best forecasts, based on our asset management strategies, and using available network information. We expect this profile, particularly later in the period, to be refined as we further enhance our modelling approaches and improve our underlying asset management capability. These refinements will be reflected in subsequent updates of our AMP.

The expenditure forecasts presented are broadly aligned with information disclosure categories and is consistent with the amounts set out in Schedules 11a and 11b in Appendix B.

We summarise our capex and opex forecasts for the AMP period, together with cross references to chapters where more detailed information is provided.

## 11.2 Capex

As discussed in Chapter 6, we have adopted a lifecycle-based approach to managing our electricity distribution assets. We reflect these stages in the categories we use to explain our investments in network assets. In addition, we use the term 'non-network capex' to describe investment in assets that support our electricity distribution service.

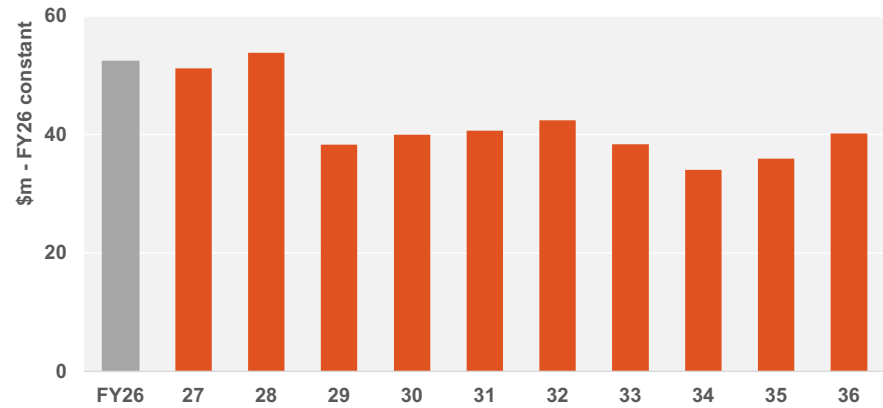
### 11.2.1 Total capex

Overall capex includes the following categories:

- **Network development capex:** relates to capital investments that increase the capacity, functionality, or size of our network. These are discussed in Chapter 8.
- **Customer connections capex:** the cost of connecting new customers to our network. These are discussed in Chapter 8.
- **Asset lifecycle management capex:** expenditure used to replace or refurbish existing assets on our networks. Our approach to asset lifecycle management is discussed in Chapter 9.
- **Other network capex:** the cost of relocating our assets to facilitate third-party developments, and specific initiatives to improve safety or reliability or to reduce the environmental impact of our assets. These are discussed in Chapter 9.
- **Non-network capex:** our investment in those assets that support and enable our asset management activities. The drivers for these investments are discussed in Chapter 10.

In Figure 11.1, we set out our total capex for the planning period.

Figure 11.1: Forecast total capex over the planning period (net of contributions)

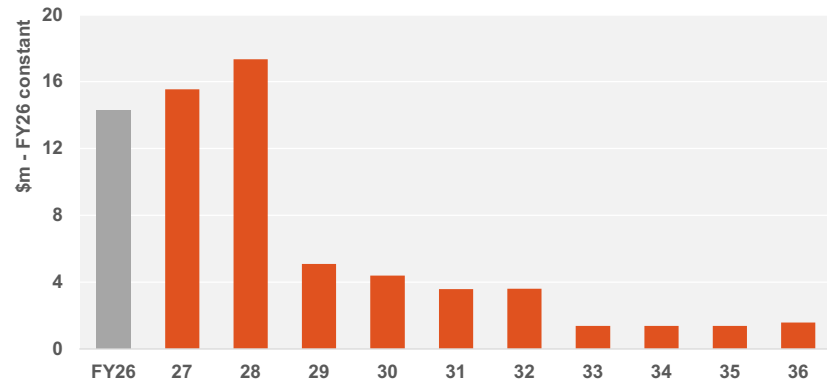


Our planned capital expenditure on the network for the 10-year planning period from FY27 to FY36 is \$414.7 million. This continues the trajectory outlined in our previous year's forecast update. Over the next three years, we anticipate elevated capex driven by several major subtransmission projects. Throughout the period, our priority remains on targeting assets for renewal and upgrade based on sound justification, while also enabling network growth. We are experiencing significant cost pressures on our capital programme, and we are focused on proactively managing network risk. We continue to seek opportunities to deliver necessary network upgrades efficiently, ensuring prudent cost management.

### 11.2.2 Network development

Investments to develop our network are primarily driven by load growth and the changing behaviours and needs of our customers. Developments at the subtransmission level tend to be more predictable than those at distribution level, which allows these projects to be planned further out. Projects at distribution level are more closely linked to shorter-term economic activity, such as housing development and changes in consumer demand, with the result that we expect some flexibility in our short-term plans. These investments are covered in more detail in Chapter 8.

**Figure 11.2:** Forecast network development capex over the planning period

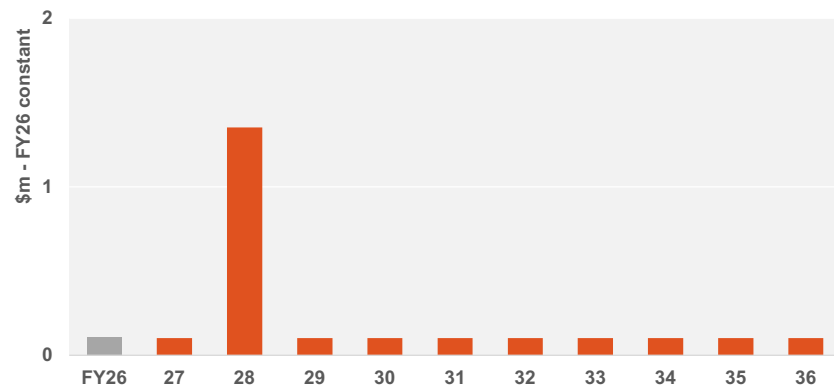


In the initial years of the period, we will carry out some large growth projects. This includes upgrading the completion of Kensington substation, constructing a new 33kV overhead line to Mangawhai and the upgrade of the 110/33kV transformers at Maungatapere. These larger investments are expected to drop off in the middle of the planning period. Beyond the AMP period, we continue to assess load growth in the Waipū and Ruakākā regions, with plans underway for the establishment of a new zone substation at Waipū and the construction of a line connecting Ruakākā to Waipū. For more detail on the planned projects, refer to Chapter 8 and Appendix C.

### 11.2.3 Customer connections

Customer connections expenditure includes expenditure Northpower incurs when connecting new customers to its network.

**Figure 11.3:** Forecast customer connections capex over the planning period (net of contributions)

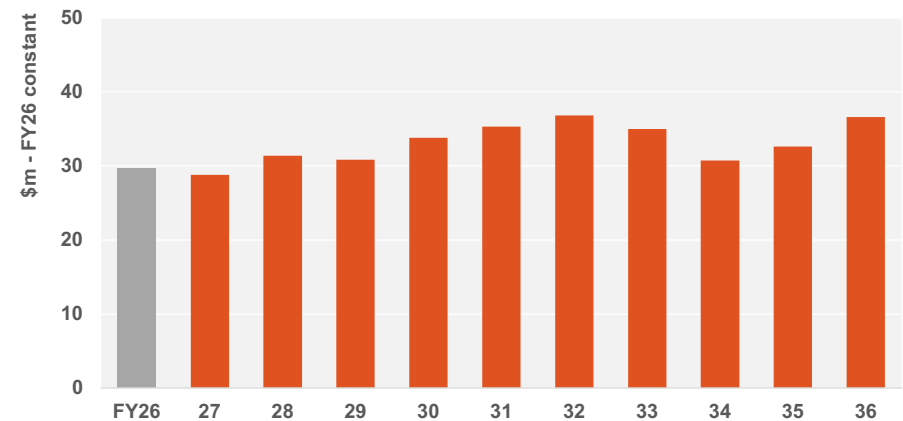


Our forecast over the 10-year period in the customer connections expenditure category is relatively low. This is due to the recent change in our customer contribution policy, meaning that expenditure on new connections is largely covered by developers, with some small exceptions for single dwelling connections. Budget has been included for the asset procurement at Maungaturoto grid exit point (GXP), changing our point of connection.

### 11.2.4 Renewals

Our renewals expenditure category includes expenditure to replace and refurbish our existing assets. This is our largest expenditure category and we expect it to ramp up over the planning period as we address our ageing asset base. This category is covered in more detail in Chapter 9.

**Figure 11.4:** Forecast renewals capex over the planning period



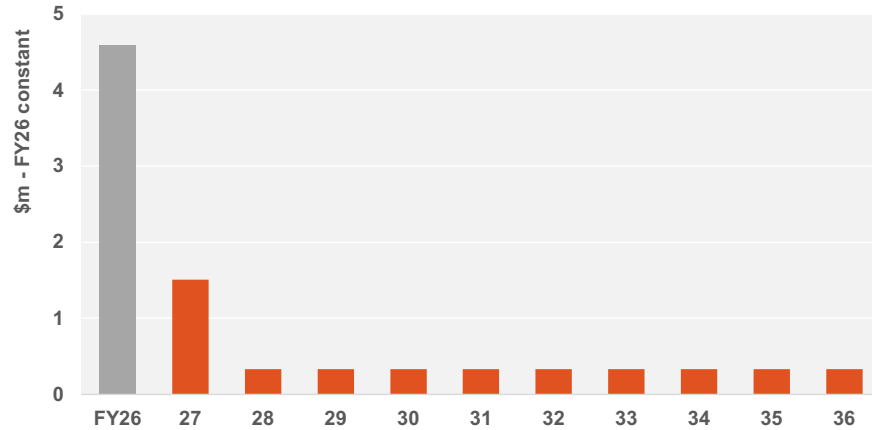
We are continuing with a consistent approach to replace our asset fleets as they are reaching end of life. There is some escalation in some of our larger projects (feeder board upgrades and oil cable replacements), which is offset through our volumetric programmes.

Over the 10-year period, the largest proportion of forecast spend is in the overhead lines portfolio, with 65% of the expenditure forecast on these assets. This is followed by 13% for zone substations and 12% for distribution equipment. There are several 33kV switchgear projects scheduled within the planning period, and we are also making ongoing enhancements to our field inspection data to further strengthen our asset condition assessments. In conjunction with our transition to a risk-based approach, as outlined in Chapter 6, we anticipate ongoing refinements in future years, which will be communicated as appropriate in due course.

### 11.2.5 Other network capex

Our other network capex category includes the Commerce Commission categories of asset relocations, and reliability, safety, and environment.

**Figure 11.5:** Forecast other network capex over the planning period



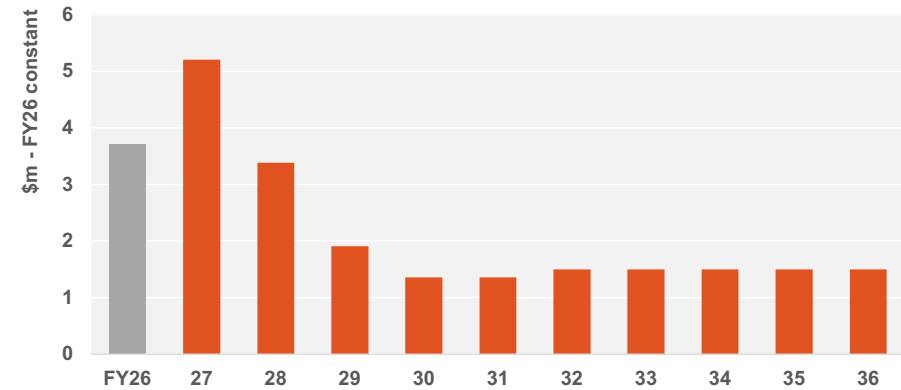
The primary focus for reliability, safety, and environmental investment in the near term is the completion of the 110kV bus at Kensington substation, along with the reconfiguration of an 11kV feeder at Ruakākā substation. In addition to these projects, we have initiated a programme to install mid-point and tie-point remotely controllable switches to enhance network performance and supply recovery, with completion expected during FY27. The remainder of the period includes expenditure on LV visibility.

Asset relocations spend includes the portion of the cost that Northpower covers to relocate assets following customer requests. By its nature, asset relocations expenditure is difficult to predict with certainty.

### 11.2.6 Non-network capex

Our non-network capex category includes expenditure on digital systems and other non-network assets that support the network and our asset management activities.

**Figure 11.6:** Forecast non-network capex over the planning period



In the early years of the planning period, we have allocated funding for several digital initiatives. These include the implementation of a new Asset Management Information System (AMIS) and the replacement of our Geographic Information System (GIS). Looking ahead to FY28 and FY29, our plans include the development of a digital twin for the network, supported by LiDAR data capture. To ensure we fully leverage the benefits of the LiDAR programme, its deployment has been deferred until the GIS upgrade is complete in FY28. This initiative will be delivered alongside the new Line Design Tool, which has been established as a separate project within the programme.

Furthermore, a number of interrelated projects have been integrated into a single programme, with a dedicated focus on strengthening data integrity, governance, and workflow processes. Further information has been provided in the Asset Management Plan, including how these projects strategically support the advancement of our asset management practices.

We have also allowed for the necessary work to meet regulatory disclosure obligations, the development of capacity maps, and an upgrade to the Customer Services Portal to enhance service delivery and improve access to information for our customers. For the remainder of the planning period, we have included provision for smaller projects aimed at process and analytics improvements.

## 11.3 Opex

Our opex forecast includes our expenditure across five portfolios:

- routine, corrective maintenance and inspections
- asset replacement and renewal
- service interruptions and emergencies
- vegetation management
- non-network.

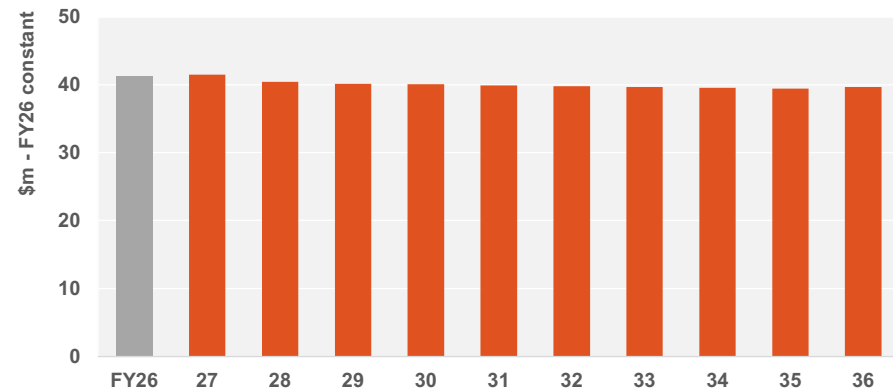
The following sections set out our planned Opex for each of the five portfolios. Further information on the forecasts can be found in Chapters 9 and 10.

We carry out a range of maintenance activities to ensure our network assets provide the required capability in a safe and reliable manner throughout their useful life. Our internal maintenance categories differ from those used in information disclosure. However, for consistency, we have set out our forecasts here to align with our disclosure in Schedule 11b (see Appendix B). An explanation of our internal maintenance categories is included in Chapter 6.

### 11.3.1 Total opex

In Figure 11.7, we set out forecast for total opex during the AMP planning period.

**Figure 11.7:** Forecast total opex over the planning period

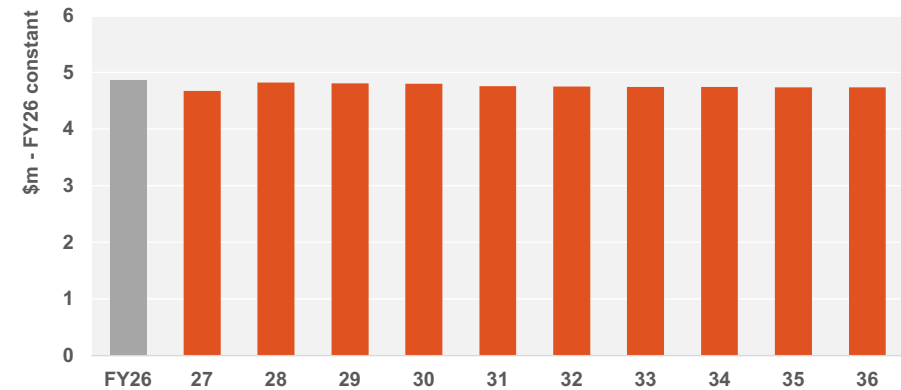


Our total opex forecast is relatively stable over the planning period, FY27–FY36, with our total 10-year expenditure at \$400 million.

### 11.3.2 Routine, corrective maintenance and inspections

Routine, corrective maintenance and inspections (RCI) includes preventive maintenance activities. It is scheduled work, including servicing to maintain asset integrity, and inspections to compile condition information for subsequent analysis and planning. Our programmes reflect industry norms relating to inspection, and we are increasingly moving to an approach based on condition and criticality in these areas. RCI is our most regular asset intervention and is a key input into our asset management decision making.

**Figure 11.8:** Forecast RCI opex over the planning period



Over the 10-year AMP period we plan to spend \$47.6 million on routine, corrective maintenance, and inspections. Under this expenditure category we also undertake value-added maintenance — activities carried out by Northpower to ensure the safety of the public. These include cable location, high load management, safety disconnects, and corrective activities on service lines. Our highest forecast spend is in this area. Of the portfolio-specific spend, the largest proportion is in overhead lines, making up approximately 26% of the portfolio maintenance. The breakdown of the expenditure is shown in Table 11.1.

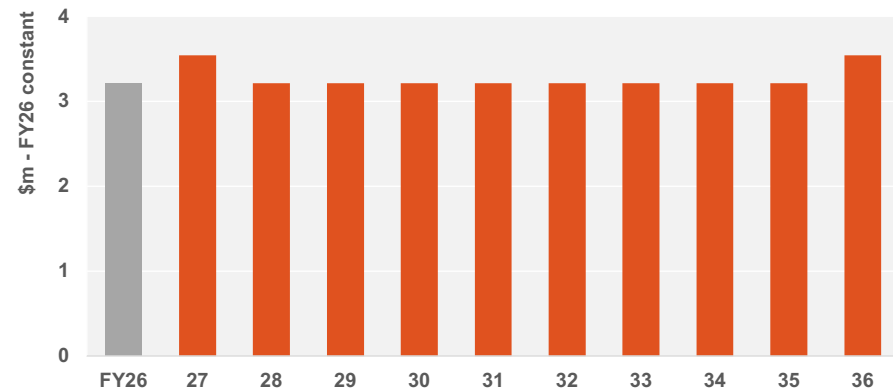
**Table 11.1:** Forecast RCI Opex broken down by portfolios

Portfolio	10 year total expenditure (\$)
Overhead lines	12.5m
Substation equipment	6.0m
Distribution equipment	7.8m
Cables	3.2m
Earthing systems	4.3m
Secondary systems	1.0m
Auxiliary systems	0.2m
Other	12.5m
<b>Total</b>	<b>47.5m</b>

### 11.3.3 Service interruptions and emergencies maintenance

Service interruptions and emergencies (SIE) opex includes expenditure incurred in response to network faults and other incidents. This is reactive work with no advanced scheduling other than ensuring that there are sufficient resources on standby to respond to network faults. SIE maintenance focuses on safely restoring supply to customers. It is especially prevalent during and after large events such as major storms.

**Figure 11.9:** Forecast SIE Opex over the planning period



Over the period we expect to spend \$32.8 million on SIE. SIE is difficult to forecast with certainty as it is based on fault numbers, which are influenced by external drivers such as weather and third-party interference. The flat forecast is consistent with maintaining levels of historical reliability. The breakdown by portfolio is shown in Table 11.2.

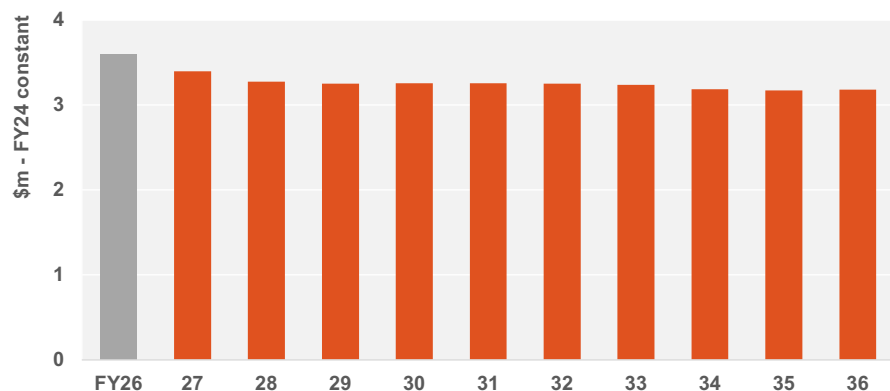
**Table 11.2:** Forecast SIE Opex broken down by portfolios

Portfolio	10 year total expenditure (\$)
Overhead lines	17.5m
Substation equipment	1.2m
Distribution equipment	1.4m
Cables	3.6m
Earthing systems	0.1m
Secondary systems	0.5m
Auxiliary systems	0.9m
Other	7.7m
<b>Total</b>	<b>32.9m</b>

### 11.3.4 Asset replacement and renewal maintenance

Asset replacement and renewal (ARR) opex relates to corrective maintenance. It is generally undertaken to rectify defects and ensure assets continue to provide reliable service throughout their useful life.

**Figure 11.10:** Forecast ARR opex over the planning period



Over the 10-year AMP period we expect to spend \$32.5 million on ARR. The largest proportion of forecast spend is in the overhead lines portfolio, making up approximately 43% of the budget. The breakdown of expected spend by portfolio is shown in Table 11.3.

**Table 11.3:** Forecast ARR opex broken down by portfolios

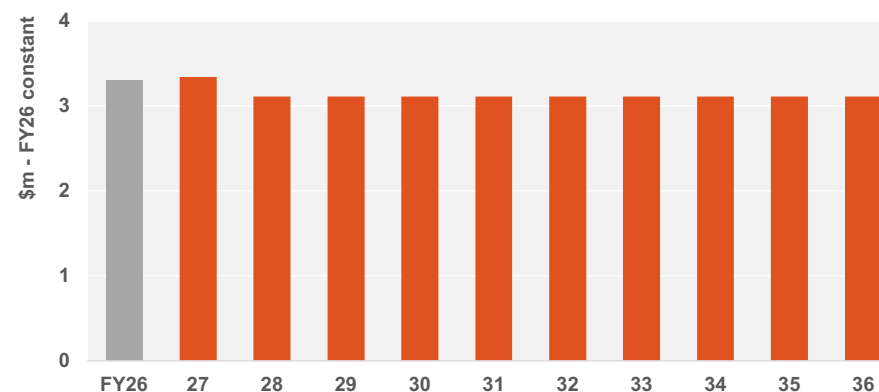
Portfolio	10 year total expenditure (\$)
Overhead lines	14.1m
Substation equipment	6m
Distribution equipment	9m
Cables	0.4m
Earthing systems	0.4m
Secondary systems	0.6m
Auxiliary systems	0.4m
Other	1.6m
<b>Total</b>	<b>32.5m</b>

### 11.3.5 Vegetation management

We undertake vegetation management to keep trees clear of overhead lines. This is necessary to minimise vegetation-related outages and meet our safety and statutory obligations. The main activities we carry out are inspections to determine the amount of work required, liaison with landowners when work is required, and subsequent follow-up tree trimming and removal.

The following chart below shows our forecast vegetation management Opex during the planning period.

**Figure 11.11:** Forecast vegetation management opex over the planning period



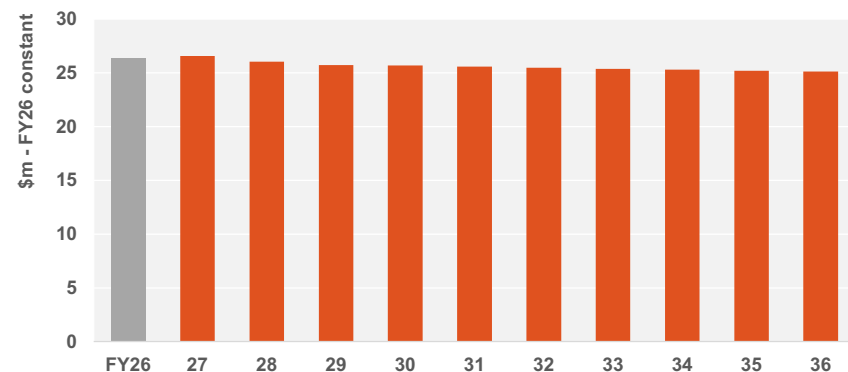
Over the 10-year AMP period, we plan to spend \$31.3 million on vegetation management. As illustrated in Figure 11.11, following the completion of our rapid inspection programme in FY27, Northpower will transition to a structured three-year cycle for vegetation inspection and clearance where the expected forecast expenditure will be constant.

### 11.3.6 Non-network opex

Non-network Opex includes two main expenditure categories as defined in information disclosure.

- **Business support:** includes the costs associated with support functions such as human resources and finance, as well as ICT-related opex. This is discussed further in Chapter 10.
- **System operations and network support:** indirect network opex where the primary driver is the management of the network. It includes expenditure relating to engineering staff, network operations centre (NOC), and system operations.

**Figure 11.12:** Forecast non-network opex over the planning period



Over the 10-year planning period we plan to spend \$255.9 million on non-network opex.

## 11.4 Underlying assumptions

The following inputs and assumptions have informed our overall forecasting approaches.

### 11.4.1 Forecasting uncertainties

Our AMP includes our current best forecasts based on our asset management strategies and using available network information. In subsequent updates, we expect the profiles, particularly later in the period, to be further refined as we collect improved asset information. By combining this higher-value information with improved field inspection methods and techniques, we have further enhanced our modelling approaches.

The following are some examples of the assumptions underpinning our forecasts for the planning period. Further assumptions are discussed in relevant chapters.

- We use available asset information and applied assumptions to develop our renewal forecasts. There is known uncertainty in both the data and assumptions, but we expect that the overall level of expenditure is forecast at the right level. We will continue to refine our asset information and assumptions to improve the accuracy of these forecasts.
- Distributed Energy Resources (DER) uptake will not have a material impact on network investment needs in the planning period. We have assumed that the installation of photovoltaic (PV) and energy storage will not materially affect peak load growth or related investment requirements over the planning period. We will review this assumption as the period progresses.
- Customers are happy with current reliability levels and do not expect performance to degrade over the long term. We will continue our engagement with customers to assess whether this remains the case.

- We are currently facing significant escalation pressures within our capex replacement programme. In response, we have updated our substation unit rates. While historical unit rates have generally been suitable for volumetric forecasting, we are now actively reviewing these rates and identifying opportunities to enhance efficiency and maintain control over costs.
- Relationships between growth drivers and future demand will continue to apply in the short term — for example, installation control point (ICP). In the medium term, the increasing adoption of new technologies may alter these relationships, and we are monitoring these trends carefully.

In developing forecast and investment strategies over a 10-year AMP period there needs to be flexibility. For example, using scenarios to support planning decisions. In future AMPs we will provide further detail on these scenarios.

### 11.4.2 Cost estimation

Good practice cost estimation uses a range of qualitative and quantitative methods to establish the most likely expenditure at project or programme level, depending on the nature of the work. The development of estimates can be complex, leading to a degree of uncertainty and estimation risk, especially for longer-term forecasts.

Investments are estimated using our cost estimation process which differs depending on the type of project. The two main estimate types are:

- **volumetric projects:** for large-volume, low-cost replacement programmes, a volumetric unit rate is used to estimate the programme costs. We use P50<sup>1</sup> unit rates derived using historical out-turn costs.
- **customised estimates:** for low-volume and one-off projects, a desktop study of the project is used to determine an estimate and a breakdown of the scope, to which unit rates are applied. As the project moves into delivery, the scope and cost estimate become more accurate through further engineering investigation and detailed design. We have also recently included our non-network projects through a similar customised estimation process.

### 11.4.3 Historical unit rates

In general, historical unit rates reflect future volumetric work scopes and risks at an aggregate or portfolio level. While we continue to aim for efficiency in all aspects of our work delivery, our experience has shown that increased efficiency tends to be offset by increased safety-related costs (such as traffic management) and costs associated with accessing the road corridor and private land.

<sup>1</sup> A P50 cost is an estimate of a cost based on a 50% probability that the cost will not be exceeded.

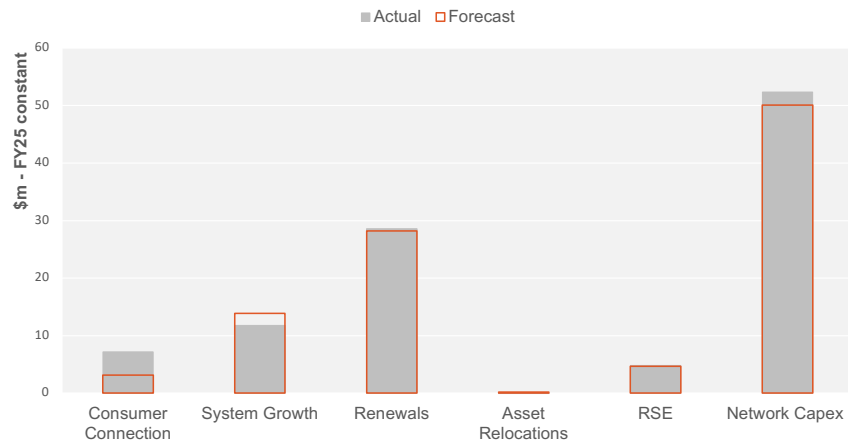
### 11.4.4 Price escalation

There are a number of inputs and assumptions underpinning our forecasts for the planning period. These include our approach to escalating our forecasts to nominal dollars. Over the AMP period, we expect to face different input price pressures to those captured by a general measure of inflation such as consumers price index (CPI). We expect that the input price increases we face over the planning period will be greater than CPI, due to factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.

## 11.5 Financial progress against plan

Total expenditure on our network in FY25 was largely in line with the FY25 AMP forecast. There are some variances between categories as shown in Figure 11.13.

Figure 11.13: Comparison between actual FY25 network capex and our AMP25 forecast

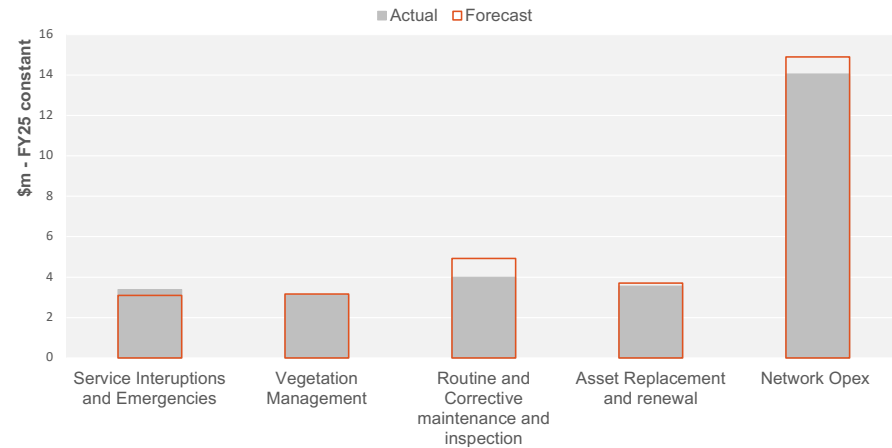


Overall, we delivered close to the budgeted levels of network Capex in FY25. The largest variance in spend was in the consumer connection portfolio, which exceeded our projected budget resulting in an over expenditure in total Capex. This is a difficult expenditure category to forecast as it is largely driven by third-party decisions and other external factors. We saw a larger number of customer connections in FY25 than expected.

We delivered marginally more in the replacement and renewal category than expected and less in the system growth categories.

These adjusted out-turns were largely driven by timing shifts to large projects. These included adjustments due to changing supplier lead times and materials availability. Examples of these projects included a switchgear installation project at Bream Bay and a transformer upgrade project at Maungatapere.

Figure 11.14: Comparison between actual FY25 network opex and our AMP25 forecast



Overall, our FY25 network Opex was slightly below our budgeted network Opex, with some minor variances in each category. The largest variance was in the routine and corrective maintenance area where we delivered less than originally forecast. This was primarily due to a reduced backlog of lower priority tasks and a more targeted maintenance programme, which reduced the overall volume of required maintenance activity.

## 11.6 Overall AMP forecast comparison

The following table explains the variances in our overall expenditure forecasts since our last AMP disclosure in 2025. These reflect changes in forecast expenditure (by information disclosure category) during the overlapping period, FY27 to FY35 inclusive. All amounts are in nominal dollars.

**Table 11.4:** Expenditure profile comparison (nominal, 000's)

	AMP25	AMP26	% Change	Comments
<b>Capex</b>				
Consumer connection (gross)	51,670	66,939	30%	We have updated our consumer connection forecast based on recent expenditure and expected future connections. Cost includes large DG connections within the initial period
System growth	57,755	57,834	No change	There has been no material change in our network development projects. We are continuously monitoring developments and will make future updates when large load demands materialise.
Asset replacement and renewal	323,727	332,114	3%	Updated renewals modelling, resulting in ups and downs throughout asset portfolios with small uplift.
Asset relocations (gross)	1,236	1,255	2%	No material change.
Reliability, safety, and environment	4,422	3,311	-25%	Finalisation on underground conversion program of two pole transformers to ground mount units
Expenditure on non-network assets	19,91	21,1	6%	Updated costs and scope for the AMIS, GIS and Field inspection tools to be implemented resulting in increased expenditure.
<b>Opex</b>				
Service interruptions and emergencies	31,969	32,805	3%	Minor adjustments.
Vegetation management	30,805	31,676	4%	Minor adjustments.
Routine and corrective maintenance and inspection	50,489	48,091	-5%	Minor adjustments to accommodate efficiency in maintenance practices.
Asset replacement and renewal	33,041	32,844	1%	Minor adjustments.
Non-network	249,150	256,138	3%	Increased costs in SCADA and digital opex.

Overall, there is no significant change in Capex. We continue to face cost pressures that exceed the rate of inflation, prompting an ongoing focus on initiatives to manage and contain expenditure wherever possible. Over the past year, we have updated our unit rates for zone substations and commenced a review of our distribution fleet, with changes from this work expected to be reflected in future budgets. Within non-network projects, we have incorporated a 4% increase in budget forecasts.

Key projects underway include the replacement of both our asset management information system and GIS, alongside the introduction of a new field inspection methodology and the acquisition of an enhanced field data capture tool. These initiatives are scheduled for completion within the first three years of the AMP period. Additionally, the conversion of two-pole transformers has been finalised, resulting in a reduction in expenditure within the Reliability, Safety and Environment category.

In network opex, there are various small uplifts and downtrends within the budget, resulting in no material change. New inspection techniques are replacing our existing methodology and we made savings in optimising our LV pillar inspection methodology.

In non-network opex, we have forecast increased requirements, reflecting the need for more capability to manage the network and meet the new challenges outlined in this AMP. This includes the uplift in renewals as our asset base ages, improving resilience, addressing climate change risk, improving asset management capability, and adapting to meet new customer technology demands.



## Chapter 12

# Appendices

## Appendix A. Glossary

Acronym / terms	Meaning
<b>ABS</b>	Air break switch
<b>AAAC</b>	All aluminium alloy conductor
<b>AAC</b>	All aluminium conductor
<b>ACSR</b>	Aluminium conductor steel reinforced (cable)
<b>ADMS</b>	Advanced distribution management system
<b>AHI</b>	Asset health indicator
<b>AMIS</b>	Asset management information system
<b>AMMAT</b>	Asset management maturity assessment tool
<b>AMP</b>	Asset Management Plan
<b>ANCAP</b>	Australian new car assessment programme
<b>ANM</b>	Adaptive Network Management
<b>AXOS</b>	Network billing system
<b>BCP</b>	Business continuity planning
<b>CB</b>	Circuit breaker
<b>CAIDI</b>	Consumer average interruption duration index
<b>Capex</b>	Capital expenditure
<b>CIMP</b>	Coordinated incident management plan
<b>CRM</b>	Customer Relationship Management system
<b>Cu</b>	Copper
<b>DER</b>	Distributed energy resources
<b>DG</b>	Distributed generation
<b>DGA</b>	Dissolved gas analysis
<b>DPP</b>	Default price-quality path
<b>DSM</b>	Demand side management
<b>DSO</b>	Distribution System Operator
<b>EDB</b>	Electricity distribution business
<b>EDO</b>	Expulsion dropout (HV fuse or link)
<b>EDNAR</b>	Electrical Distribution Network Access Request
<b>EEA</b>	Electricity Engineers' Association of New Zealand

Acronym / terms	Meaning
<b>EV</b>	Electric vehicle
<b>FY</b>	Financial year
<b>GIS</b>	Geospatial Information System
<b>GWh</b>	Gigawatt hour
<b>GXP</b>	Grid exit point
<b>HILP</b>	High impact low probability (events)
<b>HR</b>	Human resources
<b>HV</b>	High voltage
<b>ICP</b>	Installation control point
<b>IEDs</b>	Intelligent electronic devices
<b>ISO</b>	International Standards Organisation
<b>KPI</b>	Key performance indicator
<b>km</b>	Kilometre
<b>kV</b>	Kilovolt
<b>kVA</b>	Kilovolt ampere
<b>kVAr</b>	Kilovolt ampere reactive
<b>kW</b>	Kilowatt
<b>LiDAR</b>	Light Detection and ranging
<b>LV</b>	Low voltage
<b>Maximo</b>	IBM Enterprise Asset Management (EAM) system
<b>MODLA</b>	Modelling and Optimisation for Distribution Load Analysis
<b>MVA</b>	Mega volt-ampere
<b>MVAr</b>	Mega volt-ampere reactive
<b>MW</b>	Megawatt (one million watts)
<b>N security</b>	Unable to take full load with loss of a single element
<b>N-1 security</b>	Able to take full load with loss of a single element
<b>NEPT</b>	Northpower Electric Power Trust
<b>NOC</b>	Network operations centre
<b>NPV</b>	Net present value

Acronym / terms	Meaning
<b>NZTA</b>	New Zealand Transport Agency
<b>NBS</b>	New Building Standard
<b>OLTC</b>	On load tap changer
<b>Opex</b>	Operational expenditure
<b>PILC</b>	Paper insulated lead cable
<b>PV</b>	Photovoltaic
<b>PVC</b>	Poly vinyl chloride
<b>RAS</b>	Risk appetite statement
<b>RC</b>	Replacement cost
<b>RMU</b>	Ring Main Unit (distribution switchgear)
<b>RSE</b>	Reliability, Safety and Environment (Capex)
<b>RTU</b>	Remote Terminal Unit
<b>QMS</b>	Quality Management System
<b>SAIDI</b>	System average interruption duration index (minutes)
<b>SAIFI</b>	System average interruption frequency index
<b>SCADA</b>	Supervisory Control and Data Acquisition System
<b>SCI</b>	Statement of corporate intent
<b>SF6</b>	Sulphur hexafluoride
<b>SINCAL</b>	Power system simulation software
<b>SLA</b>	Service level agreement
<b>UG</b>	Underground
<b>V</b>	Volt
<b>VAR</b>	Volt Ampere (reactive)
<b>VLI</b>	Very large industrial customer
<b>VoLL</b>	Value of Lost Load
<b>WASP</b>	Works, assets, solutions, and people (maintenance management system)
<b>XLPE</b>	Cross linked polyethylene cable

## Appendix B. Disclosure Schedules

This appendix includes the following Information Disclosure schedules:

- Schedule 11a: report on forecast Capital Expenditure
- Schedule 11b: report on forecast Operational Expenditure
- Schedule 12a: report on asset condition
- Schedule 12b: report on forecast capacity
- Schedule 12c: report on forecast network demand
- Schedule 12d: report on forecast interruptions and duration
- Schedule 13: report on asset management maturity
- Schedule 14a: commentary on differences between forecast capex (schedule 11a) and opex (schedule 11b) in nominal and constant prices

## Schedule 11a: report on forecast Capital Expenditure

Company Name **Northpower**  
 AMP Planning Period **1 April 2026 - 31 March 2036**

### SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions). EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes). This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7												
8												
9	<b>11a(i): Expenditure on Assets Forecast</b>	<b>\$000 (in nominal dollars)</b>										
10	Consumer connection	19,452	16,763	5,386	4,561	5,116	6,747	6,882	7,020	7,160	7,304	7,450
11	System growth	14,306	16,099	18,321	5,497	4,830	4,019	4,126	1,615	1,647	1,680	1,970
12	Asset replacement and renewal	29,637	29,826	33,169	33,223	37,164	39,588	42,127	40,850	36,576	39,590	45,336
13	Asset relocations	120	129	131	134	137	139	142	145	148	151	154
14	Reliability, safety and environment:											
15	Quality of supply	3,267	1,069	-	-	-	-	-	-	-	-	-
16	Legislative and regulatory	56	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,145	364	219	223	228	232	237	242	246	251	256
18	<b>Total reliability, safety and environment</b>	<b>4,469</b>	<b>1,433</b>	<b>219</b>	<b>223</b>	<b>228</b>	<b>232</b>	<b>237</b>	<b>242</b>	<b>246</b>	<b>251</b>	<b>256</b>
19	<b>Expenditure on network assets</b>	<b>67,984</b>	<b>64,251</b>	<b>57,226</b>	<b>43,638</b>	<b>47,474</b>	<b>50,726</b>	<b>53,514</b>	<b>49,871</b>	<b>45,777</b>	<b>48,976</b>	<b>55,166</b>
20	<b>Expenditure on non-network assets</b>	<b>3,708</b>	<b>5,385</b>	<b>3,574</b>	<b>2,056</b>	<b>1,491</b>	<b>1,520</b>	<b>1,717</b>	<b>1,751</b>	<b>1,786</b>	<b>1,822</b>	<b>1,858</b>
21	<b>Expenditure on assets</b>	<b>71,692</b>	<b>69,635</b>	<b>60,800</b>	<b>45,694</b>	<b>48,965</b>	<b>52,246</b>	<b>55,231</b>	<b>51,622</b>	<b>47,563</b>	<b>50,798</b>	<b>57,024</b>
22												
23	plus Cost of financing	1,210	1,234	1,269	1,047	1,110	1,145	1,144	1,054	956	1,138	1,297
24	less Value of capital contributions	19,352	16,752	5,276	4,449	5,002	6,631	6,764	6,899	7,037	7,178	7,322
25	plus Value of vested assets											
26												
27	<b>Capital expenditure forecast</b>	<b>53,551</b>	<b>54,117</b>	<b>56,793</b>	<b>42,292</b>	<b>45,073</b>	<b>46,760</b>	<b>49,611</b>	<b>45,777</b>	<b>41,482</b>	<b>44,758</b>	<b>50,999</b>
28												
29	Assets commissioned	45,088	55,419	79,851	37,987	45,996	41,232	50,932	47,668	42,356	41,582	51,599
30												
31												
32												
33		<b>\$000 (in constant prices)</b>										
34	Consumer connection	19,452	16,196	5,096	4,231	4,653	6,017	6,017	6,017	6,017	6,017	6,017
35	System growth	14,306	15,555	17,338	5,100	4,393	3,584	3,607	1,384	1,384	1,384	1,591
36	Asset replacement and renewal	29,637	28,818	31,388	30,823	33,803	35,302	36,829	35,013	30,735	32,615	36,617
37	Asset relocations	120	124	124	124	124	124	124	124	124	124	124
38	Reliability, safety and environment:											
39	Quality of supply	3,267	1,033	-	-	-	-	-	-	-	-	-
40	Legislative and regulatory	56	-	-	-	-	-	-	-	-	-	-
41	Other reliability, safety and environment	1,145	352	207	207	207	207	207	207	207	207	207
42	<b>Total reliability, safety and environment</b>	<b>4,469</b>	<b>1,385</b>	<b>207</b>	<b>207</b>	<b>207</b>	<b>207</b>	<b>207</b>	<b>207</b>	<b>207</b>	<b>207</b>	<b>207</b>
43	<b>Expenditure on network assets</b>	<b>67,984</b>	<b>62,078</b>	<b>54,154</b>	<b>40,485</b>	<b>43,181</b>	<b>45,234</b>	<b>46,784</b>	<b>42,745</b>	<b>38,466</b>	<b>40,347</b>	<b>44,556</b>
44	<b>Expenditure on non-network assets</b>	<b>3,708</b>	<b>5,202</b>	<b>3,382</b>	<b>1,907</b>	<b>1,356</b>	<b>1,356</b>	<b>1,501</b>	<b>1,501</b>	<b>1,501</b>	<b>1,501</b>	<b>1,501</b>
45	<b>Expenditure on assets</b>	<b>71,692</b>	<b>67,280</b>	<b>57,536</b>	<b>42,392</b>	<b>44,537</b>	<b>46,590</b>	<b>48,285</b>	<b>44,246</b>	<b>39,967</b>	<b>41,848</b>	<b>46,056</b>
46	<b>Subcomponents of expenditure on assets (where known)</b>											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											
50												
52												

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
<b>Difference between nominal and constant price forecasts</b>	<b>\$000</b>										
Consumer connection	-	567	289	329	463	731	865	1,003	1,144	1,287	1,433
System growth	(0)	544	984	397	437	435	519	231	263	296	379
Asset replacement and renewal	(0)	1,009	1,781	2,400	3,361	4,286	5,298	5,837	5,841	6,975	8,720
Asset relocations	-	4	7	10	12	15	18	21	24	27	30
Reliability, safety and environment:											
Quality of supply	-	36	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	12	12	16	21	25	30	35	39	44	49
<b>Total reliability, safety and environment</b>	-	48	12	16	21	25	30	35	39	44	49
<b>Expenditure on network assets</b>	(0)	2,173	3,072	3,153	4,293	5,492	6,730	7,126	7,311	8,629	10,610
Expenditure on non-network assets	-	182	192	149	135	165	216	250	285	321	357
<b>Expenditure on assets</b>	(0)	2,355	3,264	3,301	4,428	5,657	6,946	7,377	7,596	8,949	10,968
<b>Commentary on options and considerations made in the assessment of forecast expenditure</b>	<i>EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15</i>										
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5					
<b>11a(ii): Consumer Connection</b>	<b>\$000 (in constant prices)</b>										
<i>Consumer types defined by EDB*</i>											
Consumer connections (gross)	19,436	16,186	3,837	4,221	4,643	6,007					
Easements (Consumer Connections)	10	10	10	10	10	10					
Vested Assets (Connections)	6	-	1,249	-	-	-					
<i>*include additional rows if needed</i>											
<b>Consumer connection expenditure</b>	19,452	16,196	5,096	4,231	4,653	6,017					
less Capital contributions funding consumer connection	19,346	16,092	3,744	4,128	4,550	5,913					
<b>Consumer connection less capital contributions</b>	106	103	1,353	104	104	104					
<b>11a(iii): System Growth</b>											
Subtransmission	4,400	8,291	9,215	3,724	3,017	2,231					
Zone substations	7,210	5,911	6,770	24	24	-					
Distribution and LV lines	877	104	104	104	104	104					
Distribution and LV cables	232	-	-	-	-	-					
Distribution substations and transformers	1,256	1,249	1,249	1,249	1,249	1,249					
Distribution switchgear	332	-	-	-	-	-					
Other network assets	-	-	-	-	-	-					
<b>System growth expenditure</b>	14,306	15,555	17,338	5,100	4,393	3,584					
less Capital contributions funding system growth											
<b>System growth less capital contributions</b>	14,306	15,555	17,338	5,100	4,393	3,584					

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Current Year CY CY+1 CY+2 CY+3 CY+4 CY+5

**11a(iv): Asset Replacement and Renewal**

\$000 (in constant prices)						
Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	
3,230	3,917	3,693	515	520	1,225	
8,221	7,784	4,058	3,778	6,313	8,298	
13,953	12,987	19,017	22,045	22,382	21,031	
682	254	316	387	474	574	
1,448	1,688	1,884	1,561	1,525	1,505	
2,018	2,100	2,332	2,449	2,501	2,580	
85	88	88	88	88	88	
<b>29,637</b>	<b>28,818</b>	<b>31,388</b>	<b>30,823</b>	<b>33,803</b>	<b>35,302</b>	
<b>29,637</b>	<b>28,818</b>	<b>31,388</b>	<b>30,823</b>	<b>33,803</b>	<b>35,302</b>	

**11a(v): Asset Relocations**

Project or programme*
Asset relocations (gross)

\$000 (in constant prices)						
Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	
120	124	124	124	124	124	
<b>120</b>	<b>124</b>	<b>124</b>	<b>124</b>	<b>124</b>	<b>124</b>	
<b>120</b>	<b>124</b>	<b>124</b>	<b>124</b>	<b>124</b>	<b>124</b>	

\*include additional rows if needed  
All other project or programmes - asset relocations

**11a(vi): Quality of Supply**

Project or programme*
All QoS projects

\$000 (in constant prices)						
Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	
3,267	1,033					
<b>3,267</b>	<b>1,033</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	
<b>3,267</b>	<b>1,033</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	

\*include additional rows if needed  
All other projects or programmes - quality of supply



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Current Year CY    CY+1    CY+2    CY+3    CY+4    CY+5

**11a(vii): Legislative and Regulatory**

Project or programme\*

4-Block AUFLS

\$000 (in constant prices)

56					

\*include additional rows if needed  
All other projects or programmes - legislative and regulatory  
**Legislative and regulatory expenditure**  
less Capital contributions funding legislative and regulatory  
**Legislative and regulatory less capital contributions**

56	-	-	-	-	-
56	-	-	-	-	-

Current Year CY    CY+1    CY+2    CY+3    CY+4    CY+5

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

Project or programme\*

All ORSE projects

\$000 (in constant prices)

1,145	352	207	207	207	207

\*include additional rows if needed  
All other projects or programmes - other reliability, safety and environment  
**Other reliability, safety and environment expenditure**  
less Capital contributions funding other reliability, safety and environment  
**Other reliability, safety and environment less capital contributions**

1,145	352	207	207	207	207
1,145	352	207	207	207	207

Current Year CY    CY+1    CY+2    CY+3    CY+4    CY+5

**11a(ix): Non-Network Assets**

**Routine expenditure**

Project or programme\*

Routine expenditure

\$000 (in constant prices)

140	368	228	228	155	155

\*include additional rows if needed  
All other projects or programmes - routine expenditure

140	368	228	228	155	155

**Atypical expenditure**

Project or programme\*

Atypical expenditure

3,568	4,835	3,154	1,680	1,201	1,201

\*include additional rows if needed  
All other projects or programmes - atypical expenditure

3,568	4,835	3,154	1,680	1,201	1,201

**Expenditure on non-network assets**

3,708	5,202	3,382	1,907	1,356	1,356
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## Schedule 11b: report on forecast Operational Expenditure

Company Name **Northpower**  
 AMP Planning Period **1 April 2026 - 31 March 2036**

### 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.

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
<b>Operational Expenditure Forecast</b>	<b>\$000 (in nominal dollars)</b>										
Service interruptions and emergencies	3,213	3,666	3,395	3,463	3,532	3,603	3,675	3,748	3,823	3,900	4,385
Vegetation management	3,304	3,460	3,287	3,353	3,420	3,489	3,558	3,630	3,702	3,776	3,852
Routine and corrective maintenance and inspection	4,860	4,834	5,096	5,183	5,280	5,338	5,431	5,537	5,641	5,751	5,866
Asset replacement and renewal	3,600	3,517	3,459	3,503	3,581	3,650	3,720	3,777	3,788	3,850	3,938
<b>Network Opex</b>	<b>14,977</b>	<b>15,476</b>	<b>15,237</b>	<b>15,502</b>	<b>15,813</b>	<b>16,080</b>	<b>16,385</b>	<b>16,691</b>	<b>16,954</b>	<b>17,277</b>	<b>18,041</b>
System operations and network support	14,049	14,781	14,606	14,582	14,841	15,014	15,187	15,361	15,593	15,770	16,008
Business support	12,248	12,396	12,584	12,836	13,092	13,354	13,621	13,894	14,172	14,455	14,744
Non-network solutions provided by a related party or third party	-	35	36	36	37	38	39	39	40	41	42
<b>Non-network opex</b>	<b>26,297</b>	<b>27,212</b>	<b>27,225</b>	<b>27,454</b>	<b>27,971</b>	<b>28,406</b>	<b>28,847</b>	<b>29,294</b>	<b>29,805</b>	<b>30,266</b>	<b>30,794</b>
<b>Operational expenditure</b>	<b>41,274</b>	<b>42,688</b>	<b>42,463</b>	<b>42,956</b>	<b>43,784</b>	<b>44,485</b>	<b>45,231</b>	<b>45,985</b>	<b>46,759</b>	<b>47,543</b>	<b>48,835</b>
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	<b>\$000 (in constant prices)</b>										
Service interruptions and emergencies	3,213	3,542	3,213	3,213	3,213	3,213	3,213	3,213	3,213	3,213	3,542
Vegetation management	3,304	3,343	3,111	3,111	3,111	3,111	3,111	3,111	3,111	3,111	3,111
Routine and corrective maintenance and inspection	4,860	4,670	4,822	4,809	4,802	4,760	4,748	4,745	4,740	4,738	4,738
Asset replacement and renewal	3,600	3,398	3,273	3,250	3,257	3,253	3,252	3,237	3,183	3,171	3,180
<b>Network Opex</b>	<b>14,977</b>	<b>14,953</b>	<b>14,419</b>	<b>14,382</b>	<b>14,383</b>	<b>14,339</b>	<b>14,324</b>	<b>14,306</b>	<b>14,247</b>	<b>14,233</b>	<b>14,571</b>
System operations and network support	14,049	14,416	13,951	13,655	13,626	13,514	13,401	13,289	13,226	13,114	13,050
Business support	12,248	12,093	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025	12,025
Non-network solutions provided by a related party or third party	-	34	34	34	34	34	34	34	34	34	34
<b>Non-network opex</b>	<b>26,297</b>	<b>26,543</b>	<b>26,010</b>	<b>25,714</b>	<b>25,684</b>	<b>25,572</b>	<b>25,460</b>	<b>25,348</b>	<b>25,284</b>	<b>25,172</b>	<b>25,109</b>
<b>Operational expenditure</b>	<b>41,274</b>	<b>41,496</b>	<b>40,429</b>	<b>40,096</b>	<b>40,067</b>	<b>39,911</b>	<b>39,784</b>	<b>39,654</b>	<b>39,531</b>	<b>39,405</b>	<b>39,680</b>
<b>Subcomponents of operational expenditure (where known)</b>											
Energy efficiency and demand side management, reduction of energy losses											
Direct billing*											
Research and Development											
Insurance											
* Direct billing expenditure by suppliers that direct bill the majority of their consumers											
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
<b>Difference between nominal and real forecasts</b>	<b>\$000</b>										
Service interruptions and emergencies	-	124	182	250	319	390	462	536	611	687	843
Vegetation management	-	117	176	242	309	378	447	519	591	665	741
Routine and corrective maintenance and inspection	-	163	274	374	477	578	683	791	901	1,013	1,128
Asset replacement and renewal	-	119	186	253	324	395	468	540	605	678	757
<b>Network Opex</b>	<b>-</b>	<b>523</b>	<b>818</b>	<b>1,120</b>	<b>1,430</b>	<b>1,741</b>	<b>2,060</b>	<b>2,385</b>	<b>2,708</b>	<b>3,044</b>	<b>3,470</b>
System operations and network support	-	366	654	927	1,216	1,500	1,785	2,072	2,368	2,657	2,958
Business support	-	302	559	811	1,068	1,330	1,597	1,869	2,147	2,431	2,720
Non-network solutions provided by a related party or third party	-	1	2	2	3	4	5	5	6	7	8
<b>Non-network opex</b>	<b>-</b>	<b>669</b>	<b>1,215</b>	<b>1,740</b>	<b>2,286</b>	<b>2,833</b>	<b>3,387</b>	<b>3,946</b>	<b>4,521</b>	<b>5,094</b>	<b>5,685</b>
<b>Operational expenditure</b>	<b>-</b>	<b>1,192</b>	<b>2,033</b>	<b>2,860</b>	<b>3,716</b>	<b>4,574</b>	<b>5,447</b>	<b>6,331</b>	<b>7,228</b>	<b>8,138</b>	<b>9,155</b>
<b>Commentary on options and considerations made in the assessment of forecast expenditure</b>	EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.										

## Schedule 11c: report on forecast cybersecurity expenditure forecast

Company Name **Northpower**  
For Year Ended **31 March 2026**

### SCHEDULE 11c: REPORT ON CYBERSECURITY EXPENDITURE FORECAST

This schedule requires details on the cybersecurity expenditure for various categories.

11c Expenditure Forecast		\$000 (in constant prices)										
		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
23	<b>Capex Forecast</b>											
24	Cybersecurity (Commission only)											
25	<b>Opex Forecast</b>											
26	Cybersecurity (Commission only)	56	62	68	74	80	86	93	99	105	111	117

## Schedule 12a: report on asset condition

Company Name **Northpower**  
AMP Planning Period **1 April 2026 – 31 March 2036**

### 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.

		Asset condition at start of planning period (percentage of units by grade)										
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												
9	All	Overhead Line	Concrete poles / steel structure	No.	0.33%	0.70%	4.44%	9.74%	84.80%		2	2.03%
10	All	Overhead Line	Wood poles	No.	3.54%	6.41%	21.38%	24.29%	44.37%		2	18.78%
11	All	Overhead Line	Other pole types	No.	-	-	-	-	-			-
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.43%	3.18%	16.63%	21.28%	57.49%		3	5.34%
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	0.11%	0.35%	4.92%	17.93%	76.69%		3	0.64%
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	3.69%	60.31%	36.00%		3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	98.87%	1.13%	-		4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-			-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-		4	-

Asset condition at start of planning period (percentage of units by grade)

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	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	100.00%	-	4	-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	100.00%	-	-	4	-	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	4.55%	-	45.45%	40.91%	9.09%	4	-	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-	4	-	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	29.79%	-	70.21%	4	12.77%	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	1.75%	-	14.04%	42.11%	42.11%	4	8.77%	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	71.43%	11.43%	17.14%	2	-	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	59.66%	36.93%	3.41%	2	-	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-	4	-	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	16.67%	-	83.33%	-	2	16.67%	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	1.16%	-	4.62%	5.20%	89.02%	4	-	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	-	-
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2.04%	-	10.20%	24.49%	63.27%	4	30.61%	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.86%	3.80%	8.42%	6.09%	78.82%	4	7.07%	-
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	-	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.11%	0.28%	3.13%	14.26%	82.23%	3	0.95%	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.15%	0.41%	3.97%	11.06%	84.41%	2	0.20%	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	100.00%	3	-	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.73%	2.12%	19.39%	30.74%	47.02%	4	5.56%	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	-	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.89%	3.41%	12.20%	14.29%	68.22%	3	8.04%	-
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	-	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.50%	5.40%	28.05%	35.33%	28.72%	4	12.13%	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.33%	2.21%	7.66%	12.72%	76.09%	3	4.08%	-
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.47%	2.81%	9.99%	9.42%	76.32%	3	6.91%	-
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	13.33%	66.67%	20.00%	4	-	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	23.21%	4.46%	36.61%	32.14%	3.57%	4	5.03%	-
55	LV	LV Line	LV OH Conductor	km	0.64%	1.23%	5.02%	6.37%	86.74%	4	2.84%	-
56	LV	LV Cable	LV UG Cable	km	0.01%	0.04%	0.47%	2.05%	97.42%	2	0.11%	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	21.17%	24.77%	10.52%	37.43%	6.10%	2	-	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	100.00%	3	-	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	20.31%	13.79%	22.99%	40.61%	2.30%	3	35.63%	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	4	-	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	22.73%	63.64%	13.64%	4	-	-
62	All	Load Control	Centralised plant	Lot	66.67%	33.33%	-	-	-	4	41.67%	-
63	All	Load Control	Relays	No.	26.76%	5.17%	45.24%	20.12%	2.70%	3	-	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-

# Schedule 12b: report on forecast capacity

Company Name: **Northpower**  
AMP Planning Period: \_\_\_\_\_

**SCHEDULE 12b: REPORT ON FORECAST CAPACITY**  
This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. 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.

**12b(i): System Growth - Zone Substations**

Existing Zone Substation	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 + 5 years (%)	Installed Firm Capacity + 5 years (constraint)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (Type)	Current constraint type	Current available capacity (MVA)	Peak load period < 5 yrs	Available capacity < 5 yrs (MVA)	Security of supply classification < 5 yrs (Type)	Peak load period > 5 yrs	Min. available capacity > 10 yrs (MVA)	Max. available capacity > 10 yrs (MVA)	Security of supply classification > 10 yrs (Type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution timeline	Temporary constraint solution remaining lifespan	Explanation	
					%	%																							
Manawhanga Regional	8.5								[Select one]	Winter	5.0	N-1 switched	Security		0.0	Winter	22.0	N-1	Winter	29.0	25.0	N-1	Security	1	Transformer	Network upgrade	Stage	< 1 year	
Alexander Street	1.1								[Select one]	Winter	1.5	N-1	No constraint		4.4	Winter	4.3	N-1	Winter	3.0	3.0	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Hikurangi	7								[Select one]	Winter	10	N-1	No constraint		2.0	Winter	2.1	N-1	Winter	1.5	1.0	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Rangitikei	1.3								[Select one]	Winter	1.5	N-1	No constraint		2.0	Winter	0.8	N-1	Winter	0.0	0.0	N-1 switched	Security	9	Transformer	Undecided	Planning stage	> 3 years	
Ngaurunui	3								[Select one]	Winter	5	N	No constraint		2.0	Winter	3.3	N	Winter	1.0	1.1	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Ohauwhiri	7								[Select one]	Winter	15	N-1 switched	No constraint		8.4	Winter	7.0	N-1 switched	Winter	7.1	7.1	N-1 switched	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Pohokura Bay	4								[Select one]	Winter	5	N	No constraint		1.2	Winter	1.0	N	Winter	0.8	0.8	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Tekeapa	17								[Select one]	Autumn	20	N-1	No constraint		2.8	Winter	1.8	N-1	Winter	0.0	0.0	N-1	No constraint	10*	Not applicable	Not required	Not applicable	Not applicable	
Whareroa Bay	3								[Select one]	Winter	10	N	Security		4.7	Winter	2.0	N-1	Winter	1.0	1.0	N-1	Security	2	Overhead transmission line	Network upgrade	Stage	1 - 3 years	
Whakapu	8								[Select one]	Winter	10	N-1	No constraint		1.7	Winter	1.1	N-1	Winter	0.7	0.7	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Manungatapu Regional	4.5								[Select one]	Winter	30	N-1 switched	Security		0.0	Winter	57.0	N-1	Winter	56.0	56.0	N-1	Security	1	Transformer	Network upgrade	Stage	> 1 years	
Manungatapu	6								[Select one]	Winter	8	N-1	No constraint		1.0	Winter	1.4	N-1	Winter	1.2	1.2	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Maunatu	4								[Select one]	Winter	10	N	No constraint		6.2	Winter	5.7	N	Winter	5.0	5.1	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Manawa	9								[Select one]	Winter	20	N-1	No constraint		10.8	Winter	10.4	N-1	Winter	10.2	10.1	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Poneto	3								[Select one]	Winter	10	N	No constraint		6.0	Winter	6.3	N	Winter	6.1	6.1	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Whanganui South	11								[Select one]	Winter	10	N-1 switched	Security		0.0	Winter	0.0	N-1 switched	Winter	8.8	8.8	N-1	Security	3	Transformer	Network upgrade	Confirmed	> 3 years	
Waipapakura	12								[Select one]	Winter	15	N-1	No constraint		3.0	Winter	2.7	N-1	Winter	2.2	2.1	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Manungatapu	4								[Select one]	Spring	10	N-1	No constraint		3.0	Winter	3.0	N-1	Winter	3.1	3.1	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Whareroa	3								[Select one]	Winter	5	N	No constraint		1.7	Winter	1.3	N	Winter	1.0	1.0	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Whareroa	4								[Select one]	Winter	5	N	No constraint		1.2	Winter	0.9	N	Winter	0.7	0.7	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
Manungatapu	5								[Select one]	Winter	10	N	Security		4.2	Winter	3.2	N-1 switched	Winter	2.9	2.9	N-1 switched	Security	None	Not applicable	Network upgrade	Stage	1 - 3 years	
Manungatapu Central	7								[Select one]	Winter	15	N	Security		12.2	Winter	12.2	N-1 switched	Winter	11.8	11.8	N-1 switched	Security	None	Not applicable	Network upgrade	Stage	1 - 3 years	
Manurewa	9								[Select one]	Winter	5	N	No constraint		2.0	Winter	1.7	N	Winter	1.0	1.0	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	

\* Exceed table as necessary to disclose all capacity and constraint information by each zone substation

## Schedule 12c: report on forecast network demand

Company Name **Northpower**  
 AMP Planning Period

### SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

#### 7 12c(i): Consumer Connections

8 Number of ICPs connected during year by consumer type

	Number of connections					
	Current Year CY 31 Mar 26	CY+1 31 Mar 27	CY+2 31 Mar 28	CY+3 31 Mar 29	CY+4 31 Mar 30	CY+5 31 Mar 31
<i>Consumer types defined by EDB*</i>						
Very large industrial	1					
Commercial and Industrial	2	2	2	2	2	2
Mass market	609	606	604	624	618	608
[EDB consumer type]						
[EDB consumer type]						
<b>Connections total</b>	<b>612</b>	<b>608</b>	<b>606</b>	<b>626</b>	<b>620</b>	<b>610</b>

18 \*include additional rows if needed

#### 22 Distributed generation

23 Number of connections made in year

24 Capacity of distributed generation installed in year (MVA)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Number of connections made in year	442	445	449	452	456	461
Capacity of distributed generation installed in year (MVA)	41.81	113.65	27.68	7.22	3.76	3.80

#### 25 12c(ii): System Demand

##### 27 Maximum coincident system demand (MW)

28 GXP demand

29 plus Distributed generation output at HV and above

30 Maximum coincident system demand

31 less Net transfers to (from) other EDBs at HV and above

32 Demand on system for supply to consumers' connection points

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
GXP demand	146	121	122	123	124	125
Distributed generation output at HV and above	6	33	33	33	33	33
Maximum coincident system demand	152	154	155	156	157	158
Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
Demand on system for supply to consumers' connection points	152	154	155	156	157	158

##### 33 Electricity volumes carried (GWh)

34 Electricity supplied from GXPs

35 less Electricity exports to GXPs

36 plus Electricity supplied from distributed generation

37 less Net electricity supplied to (from) other EDBs

38 Electricity entering system for supply to ICPs

39 less Total energy delivered to ICPs

40 Losses

42 Load factor

43 Loss ratio

Electricity supplied from GXPs	776	602	576	576	581	586
Electricity exports to GXPs	1.01	0.94	1.83	2.02	1.99	1.96
Electricity supplied from distributed generation	53.55	208	241	246	246	246
Net electricity supplied to (from) other EDBs	-					
Electricity entering system for supply to ICPs	829	809	816	820	825	830
Total energy delivered to ICPs	783	765	770	775	780	785
Losses	46	44	46	45	45	45
Load factor	62%	60%	60%	60%	60%	60%
Loss ratio	5.5%	5.4%	5.6%	5.5%	5.5%	5.4%

Schedule 12d: Report on forecast interruptions and duration

Company Name **Northpower**

AMP Planning Period

Network / Sub-network Name

**SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION**

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

*sch ref*

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8							
9							
10	<b>SAIDI</b>						
11	Class B (planned interruptions on the network)	105.0	178.3	178.3	178.3	178.3	178.3
12	Class C (unplanned interruptions on the network)	115.0	98.0	98.0	98.0	98.0	98.0
13	<b>SAIFI</b>						
14	Class B (planned interruptions on the network)	0.60	0.80	0.80	0.80	0.80	0.80
15	Class C (unplanned interruptions on the network)	2.90	2.40	2.40	2.40	2.40	2.40

## Schedule 13: Report on asset management maturity

<div style="text-align: right;">                     Company Name <b>Northpower</b>                      AMP Planning Period                      Asset Management Standard Applied                 </div>								
<b>SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY</b> 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/document Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.5	Asset Management Policy is approved by COO - Network and forms part of our controlled document (managed through our Quality Management System). It is an overarching policy which is intended to inform our asset management strategies, and be considered in investment decisions. Our AM Policy is embedded in every day asset management activities such as Asset Fleet strategies and Business Case assessments. Our Policy also aligns with our Company Strategic Objectives and Business Plan.		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	Our electricity network strategy, outlined in the AMP, has at its core delivering a consistent, safe and cost effective supply of electricity to our customers by using good asset management practices. The strategy gives effect to our shareholders' expectations (as set out in our SCI), as well as our risk management policy. We consider stakeholder feedback, including through informal and formal channels, in developing our strategy. Our common management systems are certified to ISO 9001, ISO 14001 and we have developed an asset management maturity roadmap to align our approach to ISO55001.		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 policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	We have a documented asset management strategy with an approach aimed at managing the asset lifecycle of our assets. We have developed a number of individual asset class strategies defining individual asset lifecycles, performance expectations aligned with our Asset Management Strategy.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Our asset management work plan is documented in broad terms within our AMP. Detailed work plans are documented in the annual work plan, project definition documents, detailed project scopes and in our preventative and corrective maintenance plans. Asset management plan documents are made available to stakeholders as appropriate to their role within the asset management system. Key documents including (AMP, work plans, detailed business cases and work scopes) are stored in controlled document repositories for version control enabling easy stakeholder access.		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).

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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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	Our AMP is communicated through our intranet and published on our website. A one page visual summary of plans are published annually in print and on social media with links to full AMP. This is used as a key tool for communication with internal and external stakeholders. The 10 year plan, is continuously updated through dashboards with weekly updates to affected teams.		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	Overall responsibility for AMP delivery rests with the COO – Network, with roles further detailed in Chapter 2 of the AMP. The Delegated Authorities Policy defines financial authority for the AMP delivery program. The Network Governance Framework establishes structures, roles, and approval processes. The Project Management Framework provides the systems and processes to deliver projects in a structured manner.		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	We have a formal SLA in place with our principal contractor. A strong governance structure supports monthly progress reporting against plans. Supplier arrangements are secured for key equipment and materials. Competitive procurement processes for large projects and critical network assets are well established. We have increased resource capability and restructured the team to provide focused attention on asset planning, design, and project delivery. The procurement function within the Delivery team has been strengthened, and a framework has been introduced to enable ordering of long-lead equipment through secure supply channels to minimize project implementation delays.		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. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Northpower has well documented emergency and incident response procedures, including: a Co-ordinated Incident Management Plan for major events impacting network operations; a suite of network contingency plans used to assist in major unplanned events that significantly disrupt supply; a revised Business Continuity plan and processes for events which disrupt business operations. We are an active member of the Northland Lifelines group and the regional CDEM group. We regularly review and update our contingency and disaster recovery plans to ensure they remain relevant and appropriate. We have adequate staff and contractor resources available for events (via the wider Northpower Group), standby generators available, a backup control centre at a remote location. Most staff can work remotely if required.		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.

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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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)?	2.5	The COO - Network is responsible for delivering the requirements of the asset management strategy, objectives and plans. In turn, responsibilities are delegated to members of the network leadership team. These responsibilities are supported by a delegated authorities policy, with clearly defined levels of financial authority. Most delivery activities are contracted out to experienced field service providers, and governed through service level agreements that define accountabilities and responsibilities. Roles and responsibilities are well defined in both Management and team roles within the affected teams.		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	Executive-level management oversight monitors the achievement of asset management activities, with key delivery and performance metrics reported monthly to the Board. We have significantly increased internal resourcing in recent years, enhancing our capability to deliver the Capex Plan at higher levels. There is a clear separation between Engineering and delivery teams. At Senior Management the operational and System Control functions have been separated from Engineering and Design.		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?	3	We have aligned our electricity strategy with our asset management strategy. A range of strategies are employed to communicate the importance of meeting asset management requirements and delivering the outcomes to our customers. This includes monthly reporting against performance targets, weekly meetings with senior leadership teams to discuss asset management requirements and ensure we are on plan, regular meetings with our delivery contractor at which asset management requirements are discussed. Key deliverables and progress against plan, as well as core asset management issues are communicated at regular Steerco meetings.		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-about 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	Compliance is ensured by service level agreement (SLA) and contracts for field services and construction works. The majority of outsourced work is undertaken by Northpower Energy Services under a SLA which outlines respective responsibilities and KPI's to support performance. Control processes include formal project specifications and documentation, HSQE audits. Programme managers are accountable for ensuring compliant delivery of outsourced activities. The Network Delivery Manager is accountable for assessing performance of contractors under the relevant agreements. We are working on ensuring our contracts and processes are robust for all external contractors.		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.

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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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	Department managers determine human resource requirements, with key competencies captured in job profiles and assessed through performance reviews. Training budgets are allocated, and every employee is encouraged to maintain a personal development plan. We have invested in engineering cadet training to build future capability and our Energy Services partner continue to do so. Over the past five years, we have scaled up staffing to support our commitment to strengthen asset management and manage increased workload. Recognizing further resourcing needs, we have established approved contractor frameworks to enable additional network support. We are developing a competency framework aligned with the EEA Common Competency Framework and our Asset Management standards.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.5	As per question 48 above. Competencies are identified in the job design process, and included in position descriptions. Competency is regularly reviewed against the requirements of the job profile and training needs identified. Competencies are defined for certain field based activities, and managed through our Learning Management System (this includes records of learning and verifications). Specialised training is provided for control operators. Staff or contractors not holding the mandatory competencies are unable to undertake the associated activities. Asset management specific competency requirements and training is currently being developed. In 2024, we launched a scholarship program and continue to employ graduate engineers to secure the next generation of skilled resources. We have over the past two years trained a number of Managers and staff through our talent development programme lifting leadership capability.		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	Service provider training and competence is managed through established competency frameworks. These are subject to regular audit. Asset management skills and competencies are documented in job descriptions and reviewed during annual performance reviews. Staff are encouraged to have a personal development plan and development and training opportunities are discussed with each employee. Staff are expected to attend relevant courses or seminars to upskill as needed. Staff new to the industry are assisted with their development by exposure to engineering projects and related tasks under the guidance of senior staff. Asset management specific competency requirements and training is currently being worked through.		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	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.

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 in 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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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	Publication and availability of the AMP on our website, relevant information is included in print and social media advertising; quarterly updates are provided to the shareholder trustees. The contractor has access to asset information and reports through GIS and WASP. Technical and operational standards are available to all contractors through our QMS system, with some key documents also externally available through our website. (e.g.: policies that help define asset ownership, standards to assist designers of subtransmission and distribution assets, network planning standards and asset fleet strategies). A technical advisory team within the customer services team assists external stakeholders to understand key network and asset management requirements. We are developing a communications plan to ensure we communicate the right information to our stakeholders.		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?	2.5	We have in place some of the key elements of an asset management system - documented in our asset management policy, our AMP, our asset strategies, and our network standards framework and documents. We have made progress in the development our asset management documentation suite as set out in Chapter 4.		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	We have developed an Asset Information Strategy and are documenting current and future data capture rules within formal data standards. These standards, published in the Quality Management System, define capture requirements for each asset class. As asset modelling evolves, we will continue to refine and strengthen these requirements. Asset data is mastered in GIS and made accessible through various viewers and analytical tools. Historical data, including corrective maintenance, tests, and inspections, is stored in the Works Management System and supports operations, maintenance, and replacement decisions. One major strategic initiative, the AMIS upgrade implementation will drive further enhancements to data requirements. The AMIS upgrade design phase is complete.		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	Our asset information team maintain asset information in various systems - primarily our GIS and WASP system. They take steps to ensure data quality and accuracy and look for areas where to improve this. Data quality is continuously improved by way of ongoing field capture, sample audits and data analysis. We have introduced an assurance program within the GIS team reviewing data accuracy and quality of as-build drawings and data capture. With the implementation of the AMIS and GIS upgrade projects, our legacy data will undergo profiling, cleansing and enrichment before being migrated to		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.

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 is 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.

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	The pairing of GIS as the core system of record for asset data and EMS WASP for works management and asset history have supported asset management functions to date. However we recognise that understanding asset condition and performance as well as managing defect information and supporting root cause analysis. This will require further improvements in the capability of the information systems used to support asset management. We recognise that we must continue to meet growing stakeholder expectations of asset information including regulatory, customers, shareholders, landowners, service providers and asset managers. We are in the process of ensuring our data capture requirements are relevant to our needs. Our Data transformation initiatives is captured within Chapter 10 and has been allocated within this AMP Capex program.		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	Chapter 7 details the overall approach to risk, systems utilised, documents and risk management plans. We regularly review our key risks and improvement actions. We have an audited safety management system (SMS) in accordance with NZS 7901. ISO 9001 and ISO 14001 also used to identify risks. We undertake post incident reviews to ensure lessons learned and continuous improvement. Actions arising from incidents are logged and tracked in our QPulse system. Asset risk is managed through documented procedures including inspection and maintenance standards. We are building a better understanding of our asset risks through the development of asset health and criticality modelling. We will be implementing a new inspection standard and methodology for overhead networks, starting in 2026 and have completed the consequence models for overhead networks to support our risk models.		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	Risks are identified and mitigated, and controls are linked to resourcing, competencies, and training plans. Investment plans are built up based on known asset risks. Our learning management system manages competencies, and we engage regularly with our field service providers to ensure the right levels of competencies are held and maintained for staff working on the network. Where risks or incidents have identified competencies and/or training improvements are required, these are followed up on. We are developing an asset management competency framework to ensure that we have the right competencies in the team to manage risk.		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	We have a legal compliance programme, which includes a register of all material obligations and regular surveys run through Comply With, where all responsible persons are required to attest to the state of compliance in their business area. Results are reviewed by the executive and reported to the Audit and Risk Committee. In house legal counsel support with advice on legal and compliance issues. The Network Commercial and Regulatory Manager is responsible for oversight of regulatory compliance obligations. The AMP is reviewed by leadership team and an external specialist assesses compliance to support director certification. Staff have clear PDs and understand their area of responsibilities and authority.		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

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.

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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.5	The AMP includes an annual programs of capital and operations activities. Approved annual capital and maintenance budgets reflect operational plans for programs of work (such as asset inspection, maintenance and asset renewals) and project works, such as power transformer replacements and upgrades. Work is overseen by the delivery team, and includes dedicated project managers. Work is issued to the field service providers and the program of works is governed by the SLA or other relevant contracts. Network standards and procedures define the requirements for design, equipment procurement, construction, commissioning, operation and ongoing inspection and maintenance. We continue to refine our processes and documentation in some areas		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg. PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.5	There are defined processes for inspections, recording defects and maintenance and other work on assets. We have refined some of these to provide better clarity on the classification of defects. We have defined timeframes for when each category of defect needs to be remediated. Progress against defect remediation is closely monitored and we continue to review our systems for areas for improvement. We audit the quality of work performance by our service providers. Our SLAs define clearly the requirements to be delivered. We are currently reviewing our asset lifecycle activities to ensure they are consistent with our asset management strategy and control cost, risk and performance as we develop our asset class strategies.		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	Asset performances is monitored via reliability reporting, inspections, unplanned outages, major weather events and incidents. We have developed asset strategies which for major fleets define performance requirements across safety, reliability, cost and environment. We plan to further develop reporting across these metrics. Investigations are conducted for major asset failures to identify improvement opportunities. Debriefs are held following weather events and other incidents to identify improvement opportunities for asset selection, configuration and operational response. We have developed guidelines for Component failure analysis and Chronic asset failures to better understand asset behaviours and faults recorded. We are refining asset class strategies, data requirements. We have developed a suite of models to assist with the probability of failure analysis of our large volumetric fleets, focussing on failure modes and the likelihood of causing overall asset failure.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to-end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Requirements for reporting and handling of incidents, emergencies and non-conformances is outlined in written procedures and standards. Some are groupwide (e.g. Health and Safety Incident reporting), others are network specific (e.g. outage reporting, incident management plan). Responsibilities are outlined in those documents, as well as in the objectives and duties of the relevant staff. A companywide reporting system (NPSAFE) is used to report and follow up on HSQE incidents. Outages are reported in the faults Database, and results and trends monitored and reported monthly. Serious incidents are subject to ICAM investigation, either by internal staff or an independent investigator. QPulse is used to capture actions and non conformances to monitor progress of assigned actions. The leadership team undertakes weekly reviews of incidents and actions. Findings from investigations are shared across the organisation and other EDBs where warranted. We are improving our event management process and part of this will ensure clarity of responsibilities and authorities.		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.

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))?	1	We are certified to ISO9001:2015 which supports our quality management system. We are also certified to ISO14001:2015 for our Environmental Management System, and ASNZS 4801 for our Health and Safety Management System, and NZS 7901 Electricity and Gas Industries - Safety Management System for Public Safety. We undertake regular internal audits against these systems. HSQE audits are undertaken by staff to ensure contractors are delivering to our requirements. An area for improvement is to systemise audits of other key asset management processes. We are working on expanding our asset management framework and will ensure that an audit process is established to cover our entire asset management system.		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	Our corrective action processes are actively managed through normal business activities, roles and responsibilities and contractor management process. The outage review process investigates significant outages and equipment failure events. The incident review process is used to investigate what defences failed and recommended corrective or improvement actions. There is weekly operations meeting with key departments where we discuss and actively manage network performance. All staff and contractors are aware that they must report all incidents and non-conformances. We have improved our incident management process, part of this will ensure that corrective/preventive actions are clearly captured and followed through.		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 business's 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?	1.5	We have some feedback loops to inform our continual improvement requirements and are in the process of improving our event management processes to ensure that continuous improvement is embedded in our operating model and part of BAU. Current improvements are identified through our business planning process and delivered through structured projects or programmes. We have set up delivery governance and investment governance committees to oversee our asset management processes to drive improvement. We have developed risk models for key asset models and an optimiser tool to identify prioritised risk, formulate work packages and optimise costs for large replacement projects.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.5	We source improvement information from several sources, both internal and external, including - equipment suppliers - Industry partners, including EDBS and the EEA, industry conferences, forums and trade shows. - engagement of consultants - Learnings from our field service provider, which is one of the largest electricity supply contractors in NZ, and works for a number of other network companies. Our staff participate in a range of industry groups and conferences, on issues topical to the management of our assets and the integration of new technologies. Testing of materials takes place 'in the field'. And is reported on.		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.

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.

## Schedule 14a: Mandatory explanatory notes on forecast information

- 1) This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

*Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)*

- 2) In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

**Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts**

The difference between constant and nominal prices is based on the New Zealand Institute of Economic Research (NZIER) September 25 forecast with an increase of 3.5% for FY27, after which it is based on an escalation of 2%.

*Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)*

- 3) In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

**Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts**

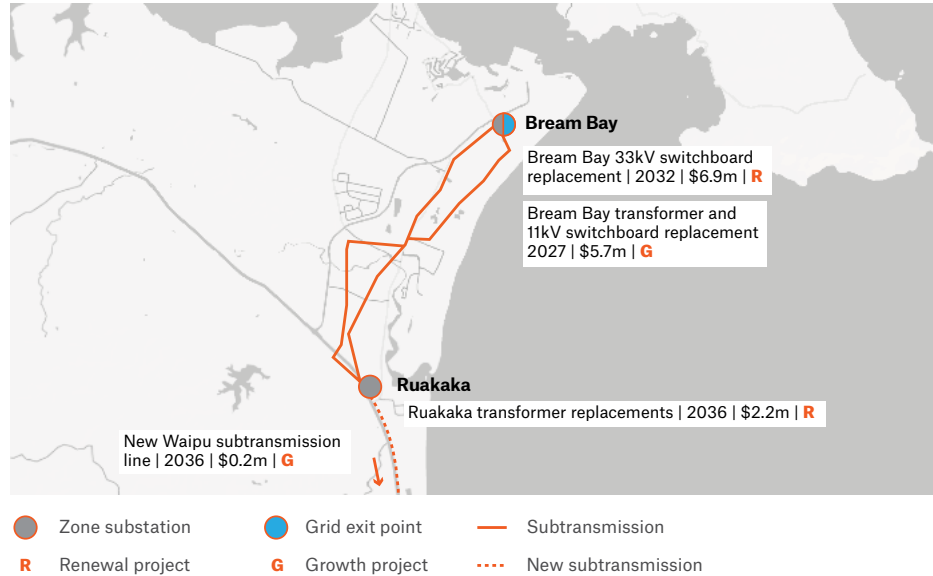
The difference between constant and nominal prices is based on the New Zealand Institute of Economic Research (NZIER) September 25, with a 3.5% increase for maintenance and 2.5% for other costs forecast for FY27, after which it is based on an escalation of 2%.



## Bream Bay GXP

The following map shows the key investments in the areas supplied by Bream Bay GXP.

### Bream Bay GXP key investments



The most significant project in this region over the planning period is the replacement and upgrades at the Bream Bay substation. Works include the installation a second transformer, as well as the replacement of both the 11kV and 33kV switchboards.

## Zone substation investments and overview

This section covers some of the key information about each zone substation and the investments covered over the planning period.

### Bream Bay zone substation

#### Substation overview

This substation supplies a mixture of industrial, commercial, and residential load. The potential for growth in the surrounding area is very high, with the district council designating large areas of land for heavy industry, service industry, and residential development.

The present 11kV load is increasing and is expected to increase substantially in the medium to long term due to a newly established marina in the One Tree Point area, and other interests in large developments.

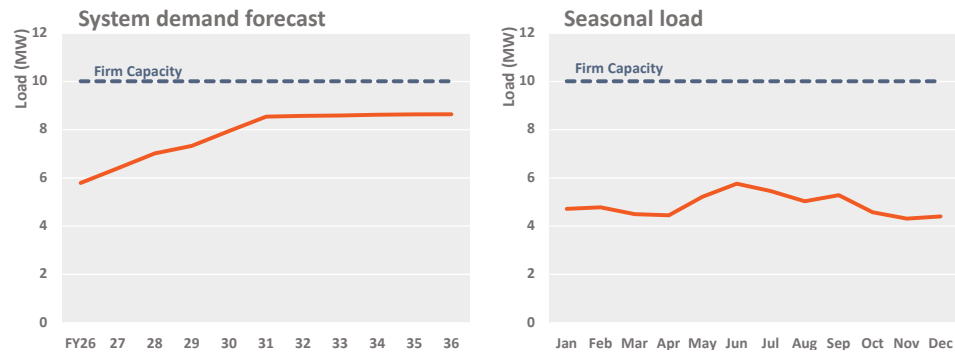
We currently have a project in progress that will installation of a second transformer and replace the 11kV switchboard. This will increase security of supply and allow for the expected load growth. More information on this project is discussed in Chapter 8.

#### Bream Bay zone substation technical summary

Bream bay zone substation profile				
Transformer capacity	1 unit 7.5MVA ONAN/10MVA OFAF			
Peak load	6MW			
Total number of customers supplied	1,759			
Feeder	CB	ICPs	Lines	Customer type
Marsden Bay	1107	1,586	Overhead	Residential
Port Feeder	1110	80	Underground	Industrial
Marsden South	1111	93	Overhead	Residential/ Commercial mix

## Substation demand

Bream Bay zone substation forecast system demand and seasonal load

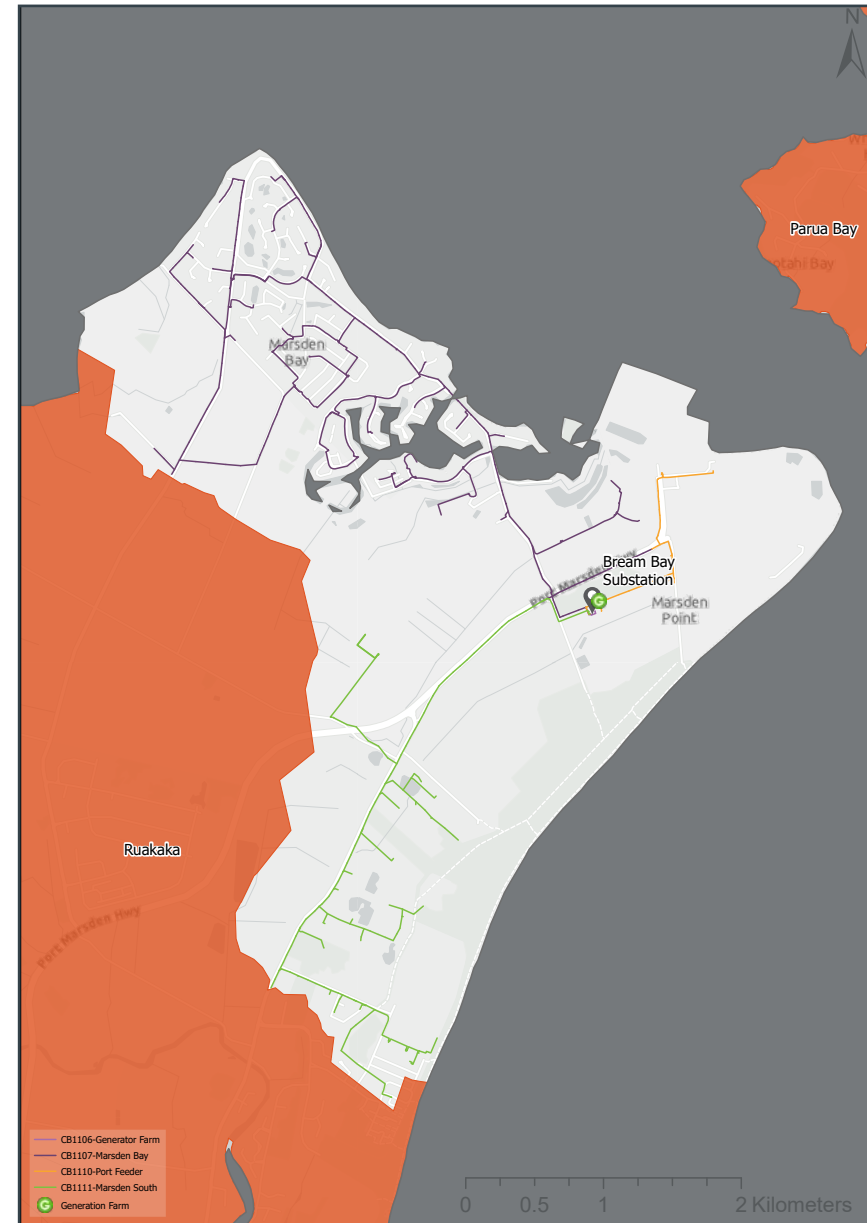


## Forecast capital investment

Bream Bay zone substation key capex projects

Growth projects	Timing
<b>Bream Bay T2 and 11kV switchgear upgrade</b>	FY27
This project will install an additional 15MVA transformer to provide N-1 security to Bream Bay zone substation and meet growing demand. In conjunction, the existing 11kV switchboard will be upgraded.	
Renewal projects	Timing
<b>Bream Bay 33kV switchboard replacement</b>	FY30-32
The project will replace a an approximately 40-year-old switchboard which contains 12 circuit breakers (CB). The switchboard is a known arc flash hazard and lacks arc containment, which do not comply with the latest industry design standards.	

Figure C.5: Bream Bay zone substation feeder map



## Ruakākā zone substation

### Substation overview

This substation is centred around the Ruakākā township and also supplies the surrounding rural dairying area, Waipū township, and the south-east coast holiday resort area. The rural area is becoming more lifestyle in nature and significant subdivision activity and growth is expected in the future. The switchboard incorporates a spare feeder for the anticipated future growth. In FY35–FY36, we plan on replacing one of the transformers due to its condition. A project to increase the capacity of Marsden Point CB1 by offloading customers onto One Tree Point CB6 was completed in FY26.

A voltage regulator was installed on the Waipū feeder in 2016 to support the growing load in the area. We have recently identified an approaching capacity constraint for this regulator, and a feeder reconfiguration has been completed that has deferred this constraint. This feeder reconfiguration has also provided additional back-feed capacity to the Mangawhai substation.

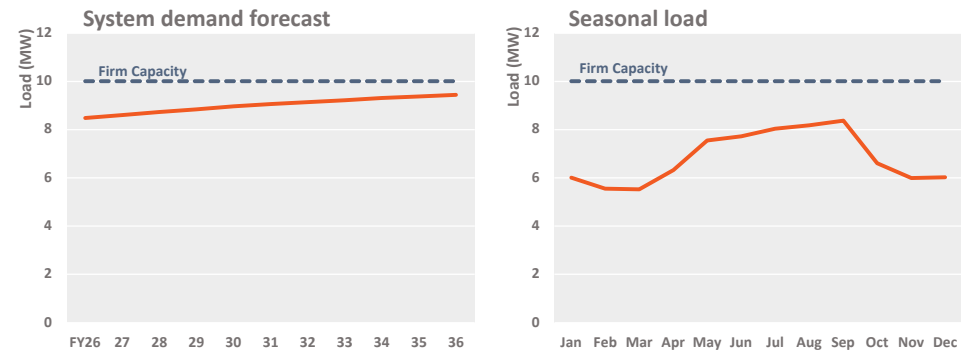
We have identified the need for a future zone substation in the Waipū area. The timing of this substation will allow for future anticipated load growth and development. This substation will also improve supply resilience in the area and provide greater backstop capability to Mangawhai and Ruakākā substations.

### Ruakākā zone substation technical summary

Ruakākā zone substation profile				
Transformer capacity	2 units 10MVA			
Peak load	8.5MW			
Total number of customers supplied	4,304			
Feeder	CB	ICPs	Lines	Customer type
Marsden Pt	1	1,393	Overhead	Residential
Waipu	2	970	Overhead	Residential
Mata	3	432	Overhead	Residential
One Tree Point	6	394	Overhead	Residential
North River	7	1,115	Overhead	Residential

## Substation demand

### Ruakākā zone substation forecast system demand and seasonal load



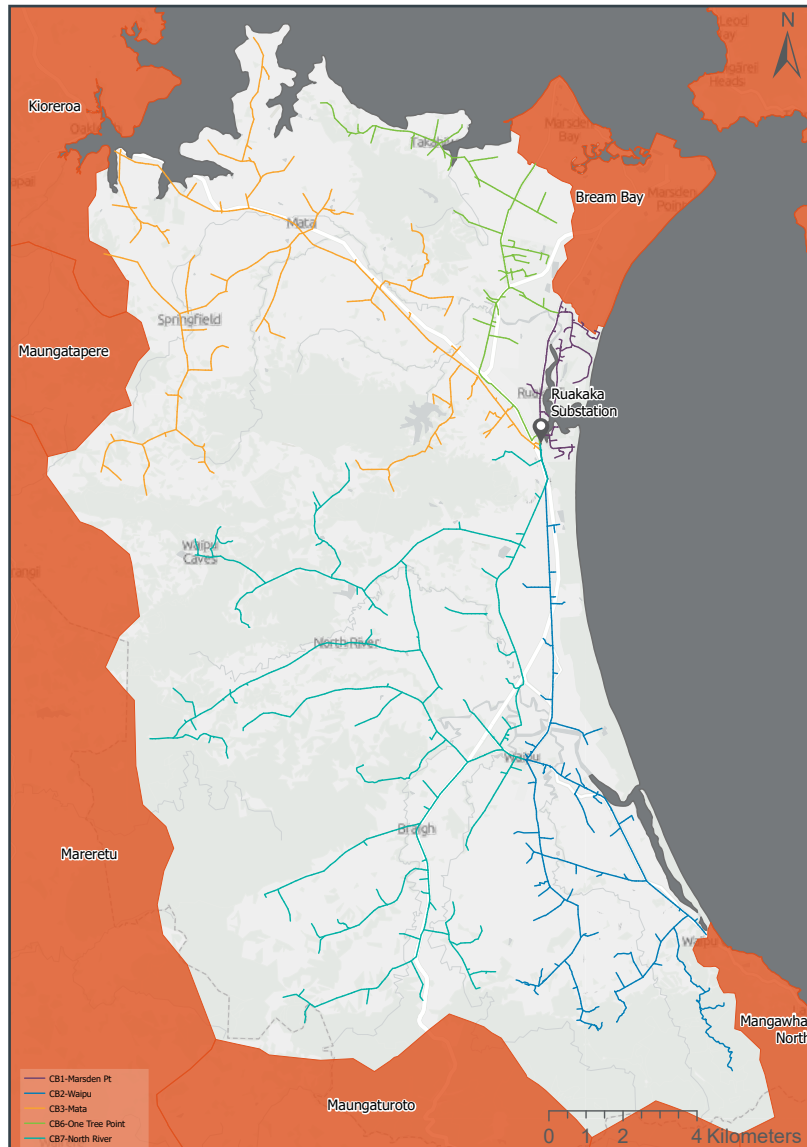
## Forecast capital investment

### Ruakākā zone substation key capex projects

Renewal projects	Timing
<b>Ruakākā T2 replacement</b>	FY35-36
Replacement of a 10MVA transformer which is in relatively poor condition. The transformer has relatively low paper degree of polymerisation (DP) <sup>2</sup> readings, ranging from 200 to 500. The transformer also has poor insulation resistance readings.	

<sup>2</sup> A DP reading of 200 would warrant urgent replacement.

## Ruakākā zone substation feeder map



## Dargaville zone substation

### Substation overview

This substation supplies a large rural area (mainly dairy farming) centred around Dargaville township. The meat works on the outskirts of the town and a sawmill to the north form the only significant industrial loads. Load growth has historically been very low, although there is a small amount of seasonal growth due to subdivision activity along the west coast, north of Dargaville.

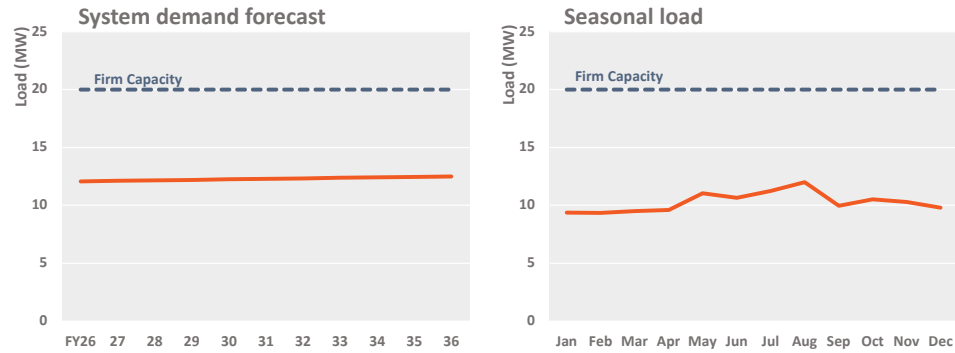
The most likely sector for significant future load growth is forestry, as the large plantations to the north of Dargaville mature. The growth in the medium to longer term is expected to be low. This area has attracted high interest for large-scale distributed energy resource (DER) developments to the network.

### Dargaville zone substation technical summary

Dargaville zone substation profile				
Transformer capacity	2 units 20MVA			
Peak load	12MW			
Total number of customers supplied	5,772			
Feeder	CB	ICPs	Lines	Customer type
North Dargaville	1	816	Overhead	Residential/Commercial mix
Te Kōpuru	2	913	Overhead	Residential
Town Dargaville	3	870	Overhead	Residential/Commercial mix
Awakino Point	4	360	Overhead	Residential
Coast	6	714	Overhead	Residential
Hokianga Rd	7	1,105	Overhead	Residential
Tangowahine	8	530	Overhead	Residential/Commercial mix
Turiwiri	9	464	Overhead	Residential/Commercial mix

## Substation demand

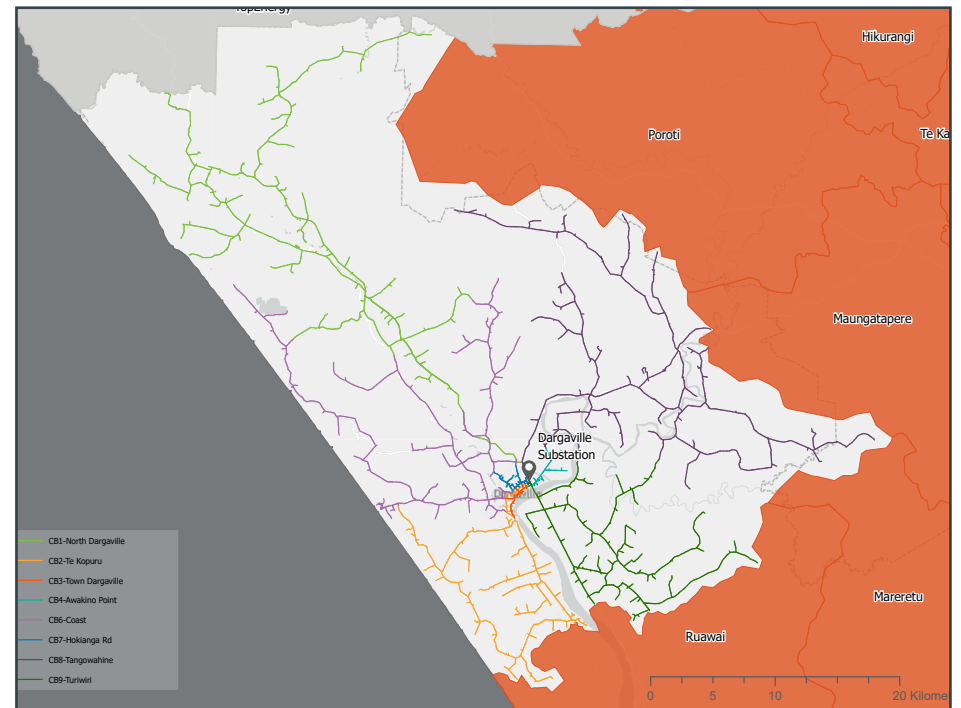
### Dargaville zone substation forecast system demand and seasonal load



### Forecast capital investment

No capital investment is forecast at Dargaville at this time.

### Dargaville zone substation feeder map



## Alexander Street zone substation

### Substation overview

This substation supplies the Whangārei CBD and the central residential areas. The substation is supplied directly from Kensington 110/33kV regional substation.

The long-term load growth in the area is expected to be moderate as business expansion taking place in Whangārei tends to be outside the current supply area for the zone substation.

Some residential load was transferred from this station to the new Maunu substation, thus providing further capacity. The Maunu substation was constructed to address the growing needs in Maunu and provide contingency supply to Alexander Street, Whangārei South, and Maungatapere zone substations. The 33kV switchboard is scheduled for replacement in FY32-FY34 due to age.

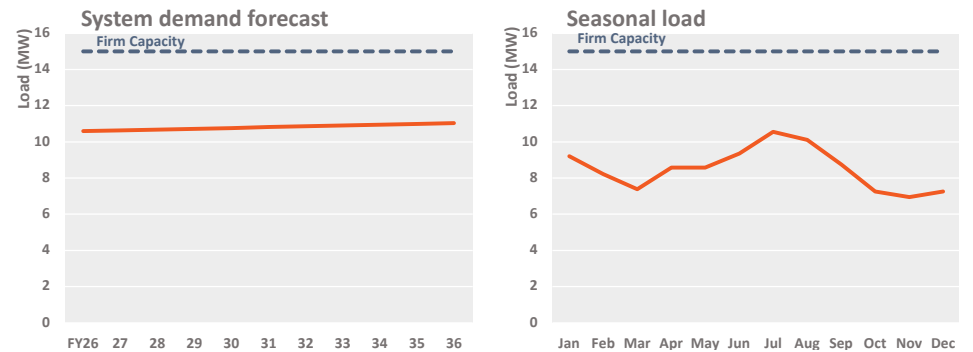
Alexander Street substation is an important backstop for any contingency at Whangārei South or Tikipunga substations. Alexander Street substation has high restorability through the 11kV network.

### Alexander Street zone substation technical summary

Alexander street zone substation profile				
Transformer capacity	2 units 7.5MVA ONAN/15 MVA OFAF			
Peak load	10MW			
Total number of customers supplied	3,570			
Feeder	CB	ICPs	Lines	Customer type
Norfolk St	1	1 2	Underground	Commercial
Forum North	2	367	Underground	Residential/Commercial mix
Second Ave	3	1,078	Underground	Residential
Bank of NZ	6	450	Underground	Residential/Commercial mix
Western Hills Dr	7	895	Overhead	Residential
Kensington	8	768	Overhead	Residential

## Substation demand

### Alexander Street zone substation forecast system demand and seasonal load

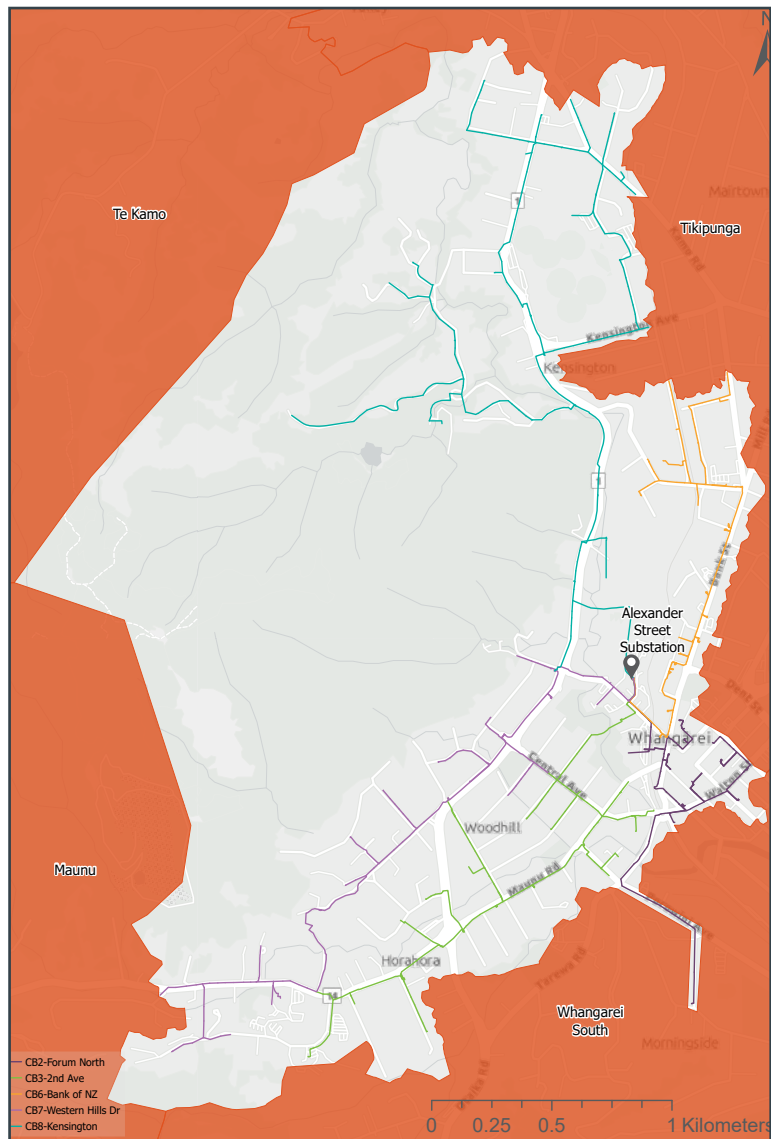


## Forecast capital investment

### Alexander Street zone substation key capex projects

Renewal projects	Timing
<b>Alexander Street 33kV switchboard replacement</b>	FY32-34
Replacement of an approximately 35-year-old switchboard which contains five CBs. The switchboard has relatively high arc flash hazards and lacks spare parts for maintenance as the switchgear is now obsolete.	

Alexander street zone substation feeder map



## Hikurangi zone substation

### Substation overview

The mainly dairy farming rural load surrounding Hikurangi township dominates the area supplied by this substation, although there is also some light industrial load in the township. The substation also supplies a large flood-pumping scheme in the Hikurangi swamp area (that occasionally operates) as well as the coastal holiday living areas along the east coast as far north as Bland Bay.

The most likely prospect for growth is lifestyle sections and holiday development in the scenic east coast area. Hikurangi town itself could also see development as an overflow from Whangārei. To date, most of the coastal growth has been south of Whangārei and, to a lesser extent, in the Tutukaka area. As these areas become more populated it is expected that the demand for coastal properties north of Whangārei will increase.

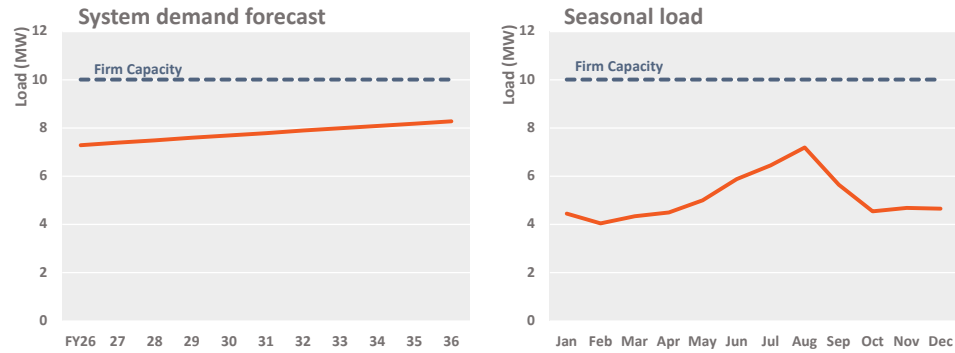
Load growth in the short to medium term is likely to be moderate but could increase in the longer term alongside growth in Whangārei. We have plans in place to upgrade and strengthen the 11kV network feeding the Helena Bay, Oakura, and Bland Bay areas. This will go ahead when the capacity of the existing network needs to be increased. The transformers were replaced with two 10MVA units in 2021, as well as the 11kV switchboard, thus providing capacity for the area for the foreseeable future.

### Hikurangi zone substation technical summary

Hikurangi zone substation profile				
Transformer capacity	1 unit 7.5MVA ONAN/10MVA OFAF			
Peak load	5MW			
Total number of customers supplied	3,516			
Feeder	CB	ICPs	Lines	Customer type
Whakapara	1112	938	Overhead	Residential
Town Hikurangi	1082	824	Overhead	Residential
Jordan Valley	1102	464	Overhead	Industrial
Swamp South	1092	23	Overhead	Residential/Commercial mix
Otonga	1032	575	Overhead	Residential
Marua	1022	310	Overhead	Residential
Swamp North	1042	382	Overhead	Residential/Commercial mix

## Substation demand

Hikurangi zone substation forecast system demand and seasonal load



## Forecast capital investment

No capital investment is forecast at Hikurangi at this time.

Hikurangi zone substation feeder map



## Kamo zone substation

### Substation overview

Located on the northern boundary of Whangārei city, this substation supplies a mixture of industrial, commercial, residential, and rural load.

The industrial and commercial load is minimal, with the main growth occurring in the residential segment through a large number of lifestyle blocks and new residential developments. This trend is likely to continue with planned development to the west. Council planning indicates a relatively high rate of residential growth is anticipated over the next five to 10 years, with moderate increases in commercial and light industrial demand also expected.

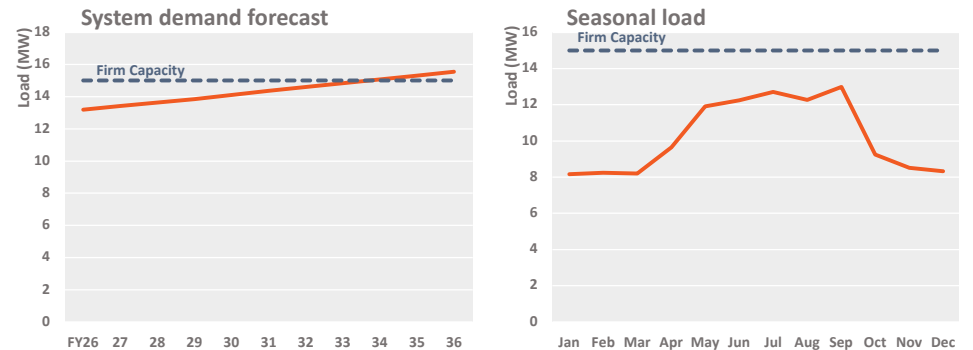
The 15MVA firm capacity at Kamo substation is adequate for the medium term, however, it is possible due to the large development plans from the council that capacity upgrades will be required to meet long-term demand. We are currently scoping out options to increase the capacity of the area and will be included into the capex forecast once more certainty is achieved. The preferred solution will consider non-network options as well as upgrading existing network assets.

### Kamo zone substation technical summary

Kamo zone substation profile				
Transformer capacity	2 units 7.5MVA ONAN/15 MVA OFAF			
Peak load	13MW			
Total number of customers supplied	6,030			
Feeder	CB	ICPs	Lines	Customer type
Springs Flat	1	1,013	Overhead	Residential
Charles St	2	1,086	Overhead	Residential
Three Mile Bush	3	877	Overhead	Residential
Ruatangata	6	721	Overhead	Residential
Kamo Town	7	1,020	Overhead	Residential
Ōnoke	8	1,313	Overhead	Residential

## Substation demand

### Kamo zone substation forecast system demand and seasonal load

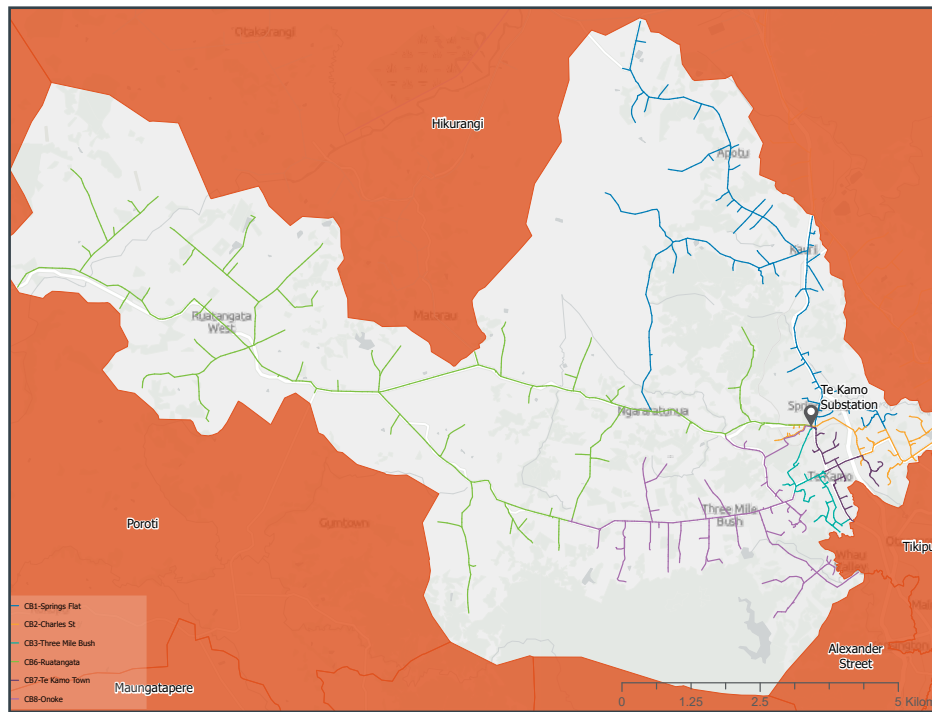


### Forecast capital investment

Renewal projects	Timing
<b>Kamo 33kV circuit breaker replacements</b>	FY28

Replacement of two 33kV CB, both units are being replaced due to age and condition.

## Kamo Zone Substation feeder map



## Ngunguru zone substation

### Substation overview

This substation supplies the Ngunguru township, Tutukaka, and Matapouri areas, made up mainly of residential load. Load growth has been fairly low, A new 5MVA transformer and 11kV switchboard was installed in 2021. The new transformer will have enough capacity to meet growth for the foreseeable future.

An 11kV reinforcement project has been completed, enabling improved backfeeding capability to the area and resolving a security of supply constraint.

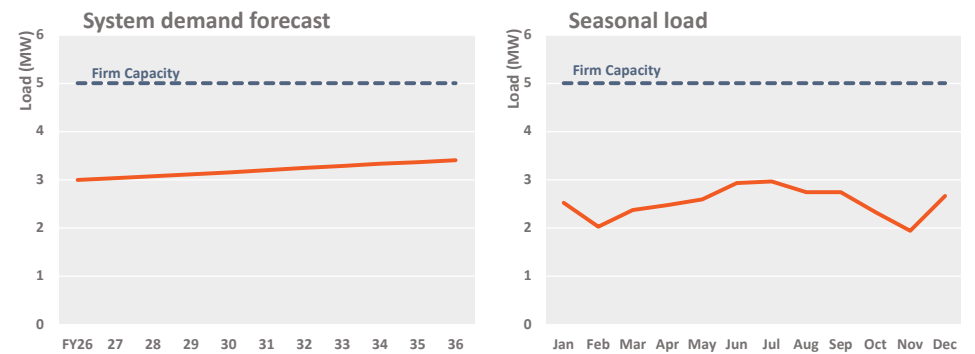
### Ngunguru zone substation profile summary

#### Ngunguru zone substation profile

Transformer capacity	1 unit 5MVA
Peak load	3MW
Total number of customers supplied	2,116

Feeder	CB	ICPs	Lines	Customer type
Tutukaka Block	1082	658	Overhead	Residential
Kaiatea	1072	676	Overhead	Residential
Matapouri	1032	782	Overhead	Residential

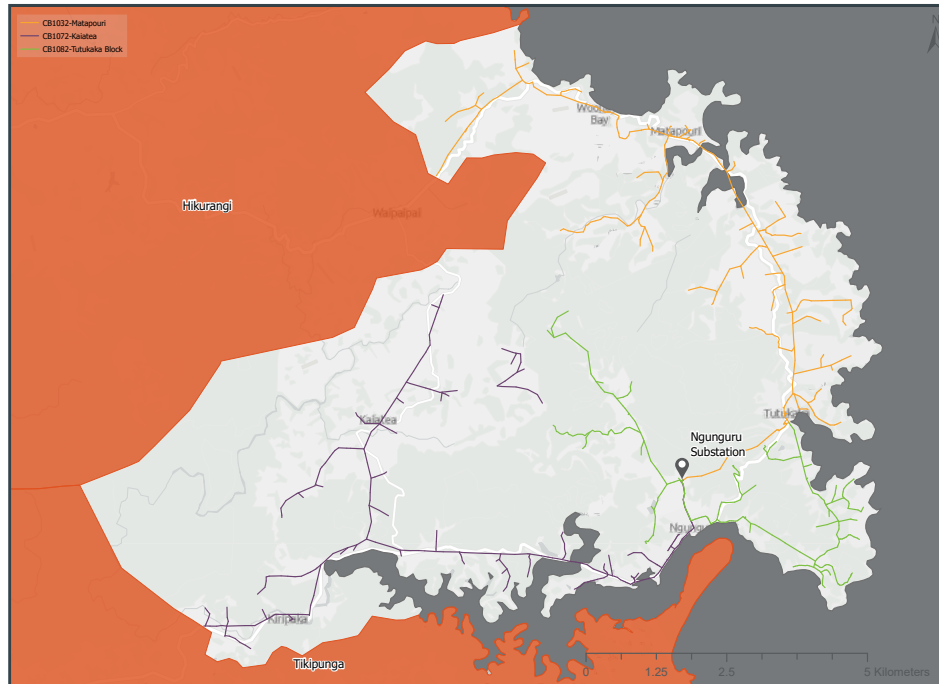
### Ngunguru zone substation forecast system demand and seasonal load



### Forecast capital investment

No capital investment is forecast at Ngunguru at this time.

## Ngunguru zone substation feeder map



## Onerahi zone substation

### Substation overview

This substation supplies the suburb of Onerahi which is mainly residential with some commercial load. The 11kV network also stretches out to the residential areas of Tamaterau, Manganese Point, and part of Riverside. There is a moderate amount of residential development in the area supplied from this substation and this is expected to continue.

Over the past 10 years, we have replaced end-of-life assets as well as upgraded the transformer capacities, we are not forecasting any capital investment will be required for this zone substation for the foreseeable future.

### Onerahi zone substation technical summary

#### Onerahi zone substation profile

Transformer capacity 2 units 15MVA

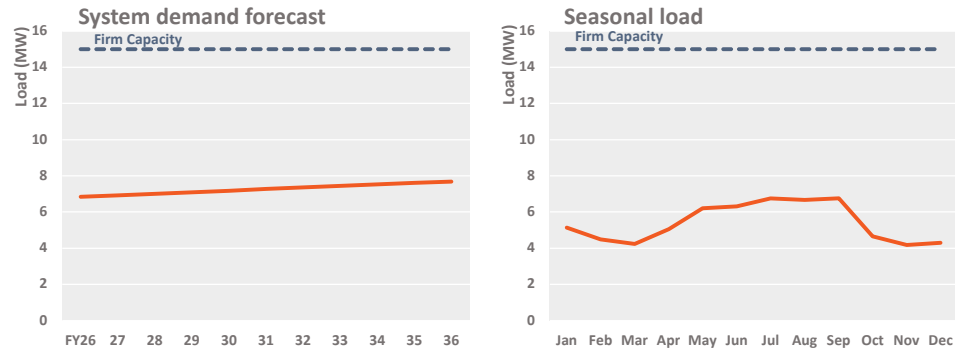
Peak load 7MW

Total number of customers supplied 4,044

Feeder	CB	ICPs	Lines	Customer type
Beach Road	2	647	Overhead	Residential
Alamein Ave	3	1,018	Overhead	Residential
Cartwright Rd	6	798	Overhead	Residential
Tamaterau	7	553	Overhead	Residential
Montgomery Ave	8	1,028	Overhead	Residential

## Substation demand

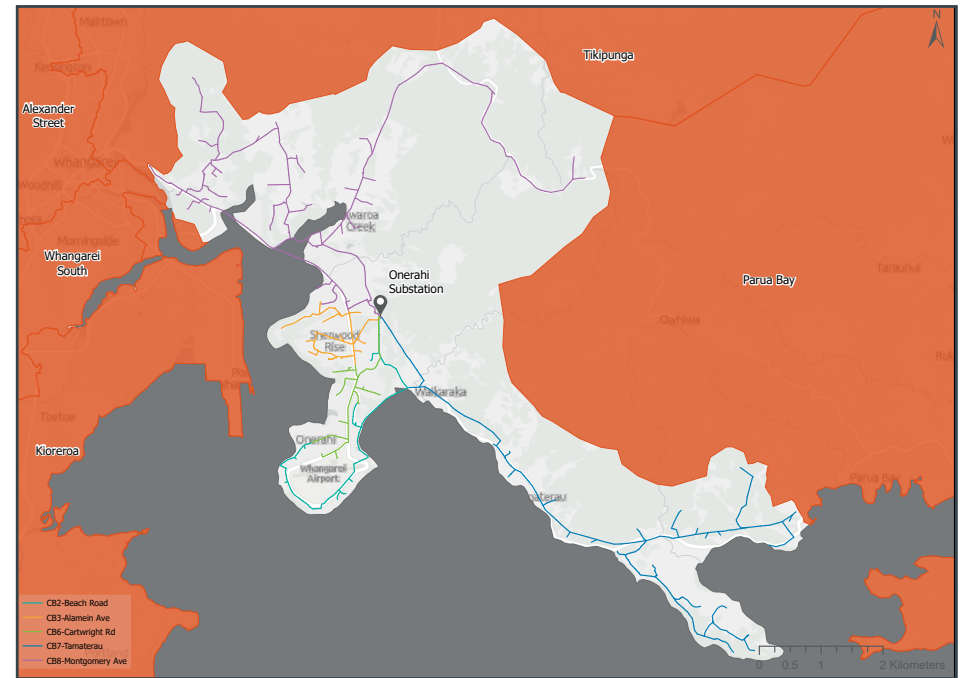
### Onerahi zone substation forecast system demand and seasonal load



### Forecast capital investment

No capital investment is forecast at Onerahi at this time.

### Onerahi zone substation feeder map



## Parua Bay zone substation

### Substation overview

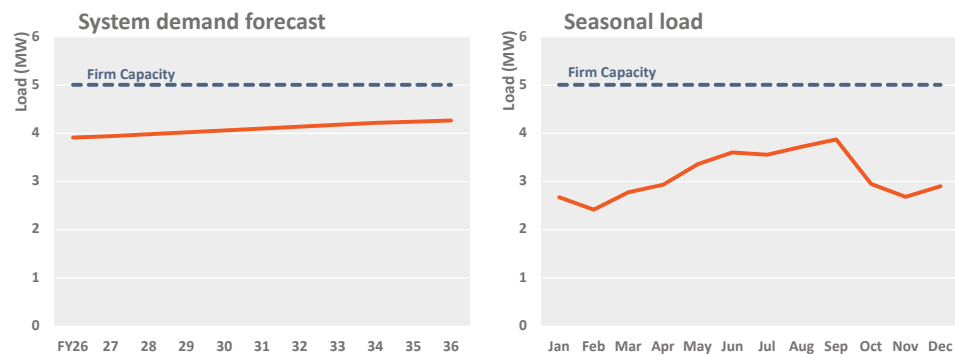
This substation supplies the Parua Bay, McLeod's Bay, Whangārei Heads, and Pataua areas, comprising mainly residential load. Historical growth trends have been fairly low. The transformer was replaced with a 5MVA unit in 2022 due to the asset being end of life, we are expecting that the new transformer will meet the long term growth forecasts for the area. An 11kV back feeding upgrade is planned for FY27 to address an existing security of supply constraint.

### Parua Bay zone substation technical summary

Parua Bay zone substation profile				
Transformer capacity	1 unit 5MVA			
Peak load	4MW			
Total number of customers supplied	2,296			
Feeder	CB	ICPs	Lines	Customer type
Pataua	1	935	Overhead	Residential
Parua Bay	2	575	Overhead	Residential
Whangārei Heads	3	786	Overhead	Residential

## Substation demand

### Parua Bay zone substation forecast system demand and seasonal load



## Forecast capital investment

Reliability, safety & environment projects

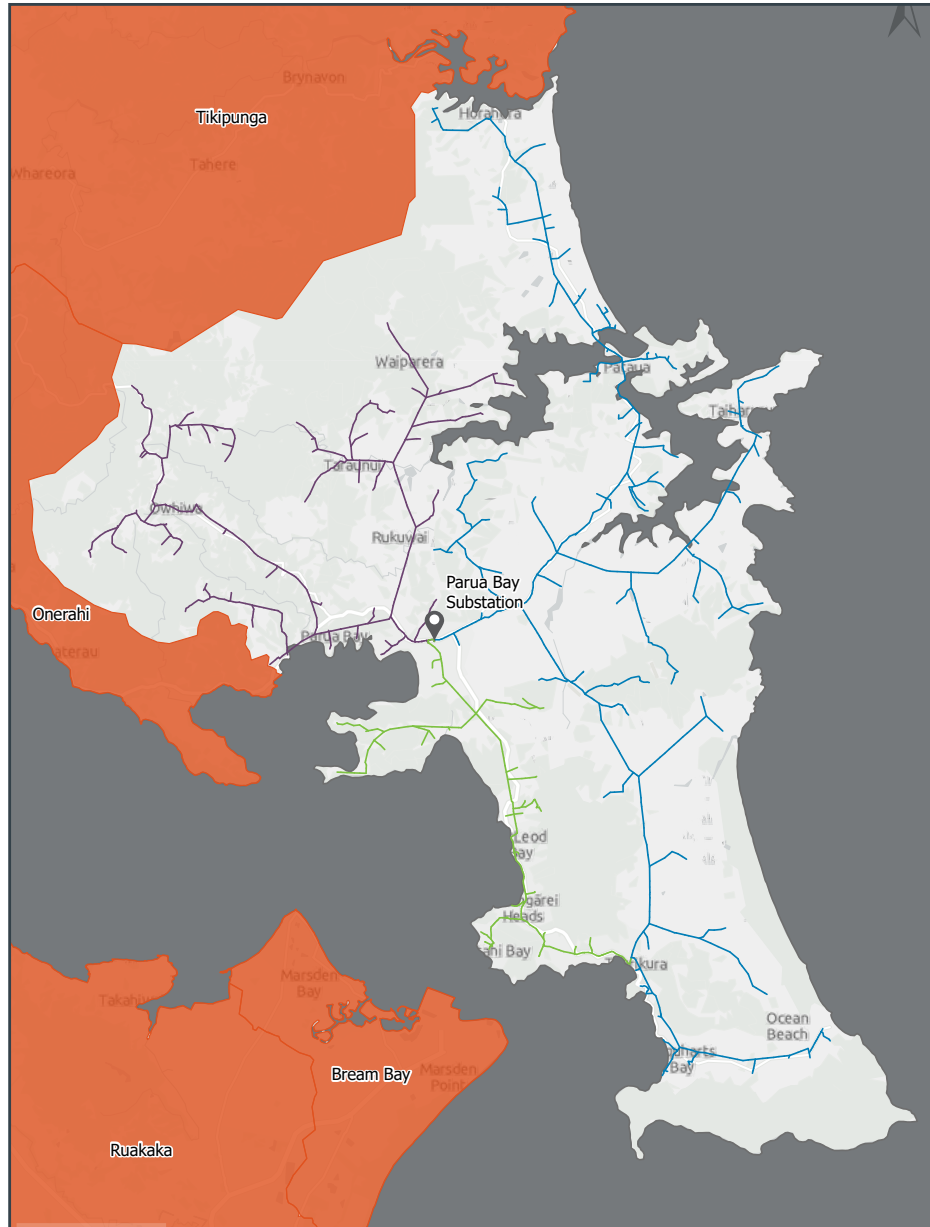
Timing

### Parua Bay back-feed constraint mitigation

FY27

The project proposes an installation of a switchable capacitor bank at the zone substation which will allow for additional back-feed capacity to the Parua Bay substation. This project will ensure all N security substations meet our security of supply criteria

## Parua Bay zone substation feeder map



## Tikipunga zone substation

### Substation overview

This is Northpower's largest zone substation based on number of premises connected. Feeders supply the residential areas to the north of the CBD as well as the rural area to the north-east of Whangārei. Load growth is moderate, driven primarily by residential growth in the Kensington and Tikipunga suburbs, due to urban infill. Development is expected to continue in the area to the north and east of the substation.

The transformers were upgraded to two 20MVA units in 2009 and are expected to meet the demand forecasts for the current planning period.

### Tikipunga zone substation technical summary

#### Tikipunga zone substation profile

Transformer capacity	2 units 20MVA
Peak load	17MW
Total number of customers supplied	7,362

Feeder	CB	ICPs	Lines	Customer type
Whau Valley	1	1,280	Overhead	Residential
Mains Ave	2	884	Overhead	Residential
Tikipunga Hill	4	801	Overhead	Residential
Cairnfield Rd	5	1,188	Overhead	Residential
Paranui	6	723	Overhead	Residential
Otangarei	7	1,013	Overhead	Residential
Kiripaka Rd	8	1,258	Overhead	Residential



## Maungatapere zone substation

### Substation overview

The substation supplies a predominantly rural area of dairy and fruit farming. It supplies Maungatapere village as well as Maungakamea, Poroti, Tangiteroria, Puwera, and Mangapai.

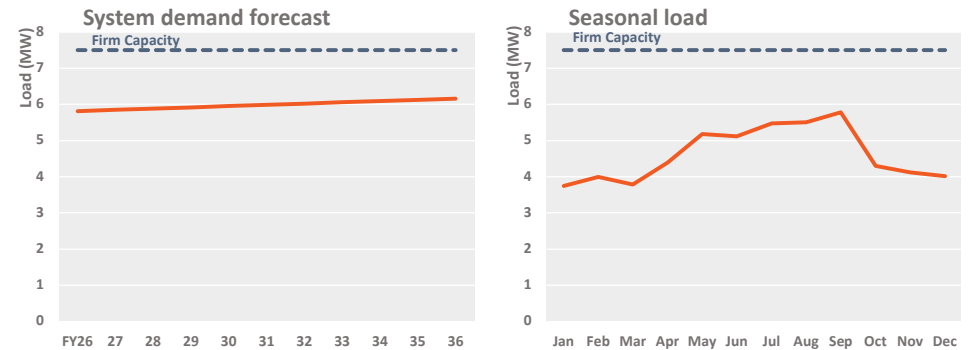
In recent years, some load has been shifted onto the Maunu zone substation. Historically the majority of the growth occurred in the Maunu area. However, now the Maunu zone substation is operational, the growth on the Maungatapere zone substation has been low.

### Maungatapere zone substation technical summary

Maungatapere zone substation profile				
Transformer capacity	2 units 7.5MVA			
Peak load	6MW			
Total number of customers supplied	2,793			
Feeder	CB	ICPs	Lines	Customer type
Maunu Mountain	1	261	Overhead	Residential
Poroti	2	599	Overhead	Residential
Maungakamea	3	585	Overhead	Residential
Maungatapere dairy factory	6	283	Overhead	Residential
Puwera	7	454	Overhead	Residential/Commercial mix
Whatitiri	8	611	Overhead	Residential

## Substation demand

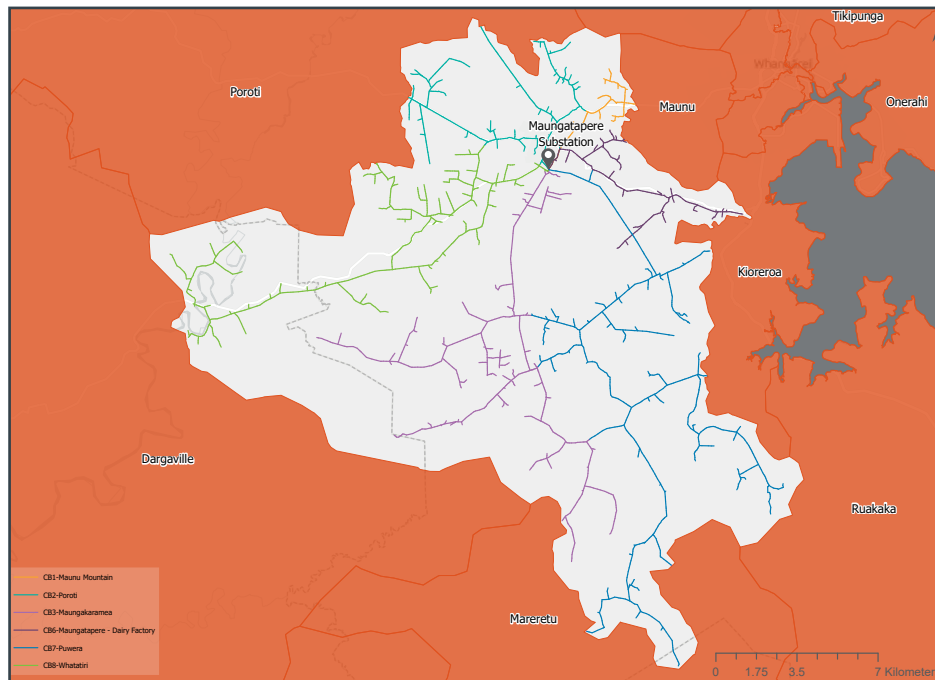
### Maungatapere zone substation forecast system demand and seasonal load



### Forecast capital investment

No capital investment is forecast at Maungatapere at this time.

## Maungatapere zone substation feeder map



## Maunu zone substation

### Substation overview

Maunu zone substation was constructed in FY22 and supplies a predominant residential area to the west of Whangārei city. There is a significant amount of lifestyle development in the rural areas, and this trend is expected to continue.

Maunu substation also offloaded parts of Whangārei South and Alexander Street substations. Maunu substation gives Whangārei hospital an extra level of security as it can be used as an additional supply if needed.

A large amount of upmarket subdivision activity is expected in the Maunu area as Whangārei city spreads westward. This is expected to result in substantial residential load growth in the medium to long term .

### Maunu zone substation technical summary

#### Maunu zone substation profile

Transformer capacity 1 unit 10MVA

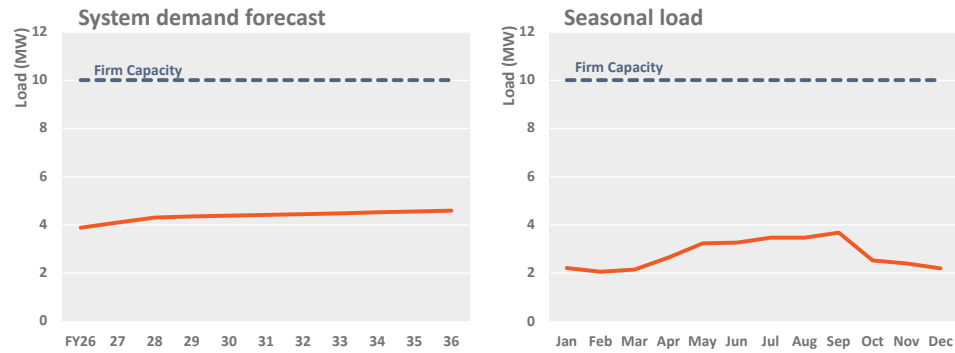
Peak load 4MW

Total number of customers supplied 1,736

Feeder	CB	ICPs	Lines	Customer type
Te Hihi	1022	363	Overhead	Residential
Maunu	1032	883	Overhead	Residential
Austin Road	1072	410	Overhead	Residential
Pompallier	1082	80	Overhead	Residential

## Substation demand

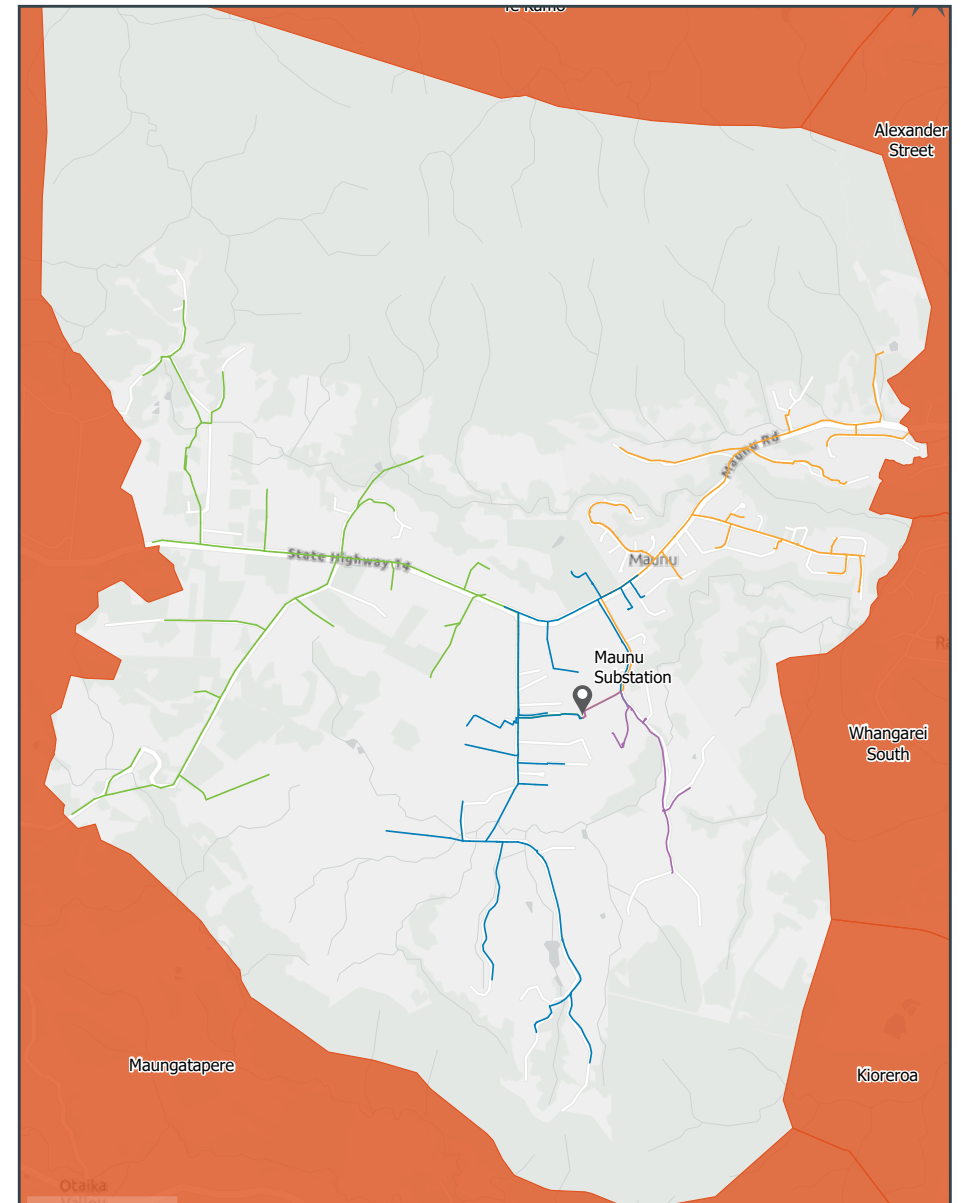
### Maunu zone substation forecast system demand and seasonal load



### Forecast capital investment

No capital investment is forecast at Maunu at this time.

### Maunu zone substation feeder map



## Kioreroa zone substation

### Substation overview

The area supplied by this substation is dominated by heavy industry loads with associated light industrial and commercial loads. The Portland area to the south of Whangārei is also supplied from this substation and includes some rural residential load. Load growth has been high in the past, due to the expansion of some industries, but has been marginal in recent years. With the development of Port Road, we expect a significant amount of future growth as more land will become available for development.

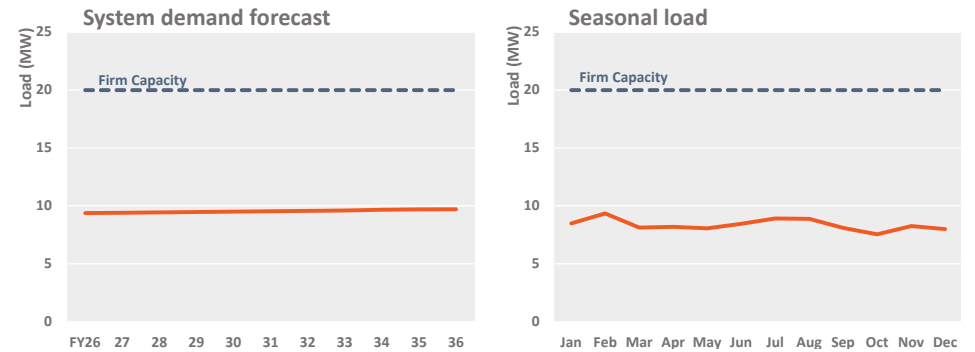
Load forecasting can be unpredictable for this substation due to the large industrial supply area. However, the two 15/20MVA transformers are expected to meet the long term growth forecasts for the area.

### Kioreroa zone substation technical summary

Kioreroa zone substation profile				
Transformer capacity	2 units 15MVA ONAN/20 MVA ONAF			
Peak load	10MW			
Total number of customers supplied	1,141			
Feeder	CB	ICPs	Lines	Customer type
Union East	1	137	Overhead	Residential/Commercial mix
Treatment	2	219	Overhead	Residential/Commercial mix
CHH Supermill	3	1	Underground	Industrial
Fraser	5	71	Overhead	Industrial
Fert. Works	6	113	Overhead	Industrial
ToeToe Rd	7	600	Overhead	Residential

## Substation demand

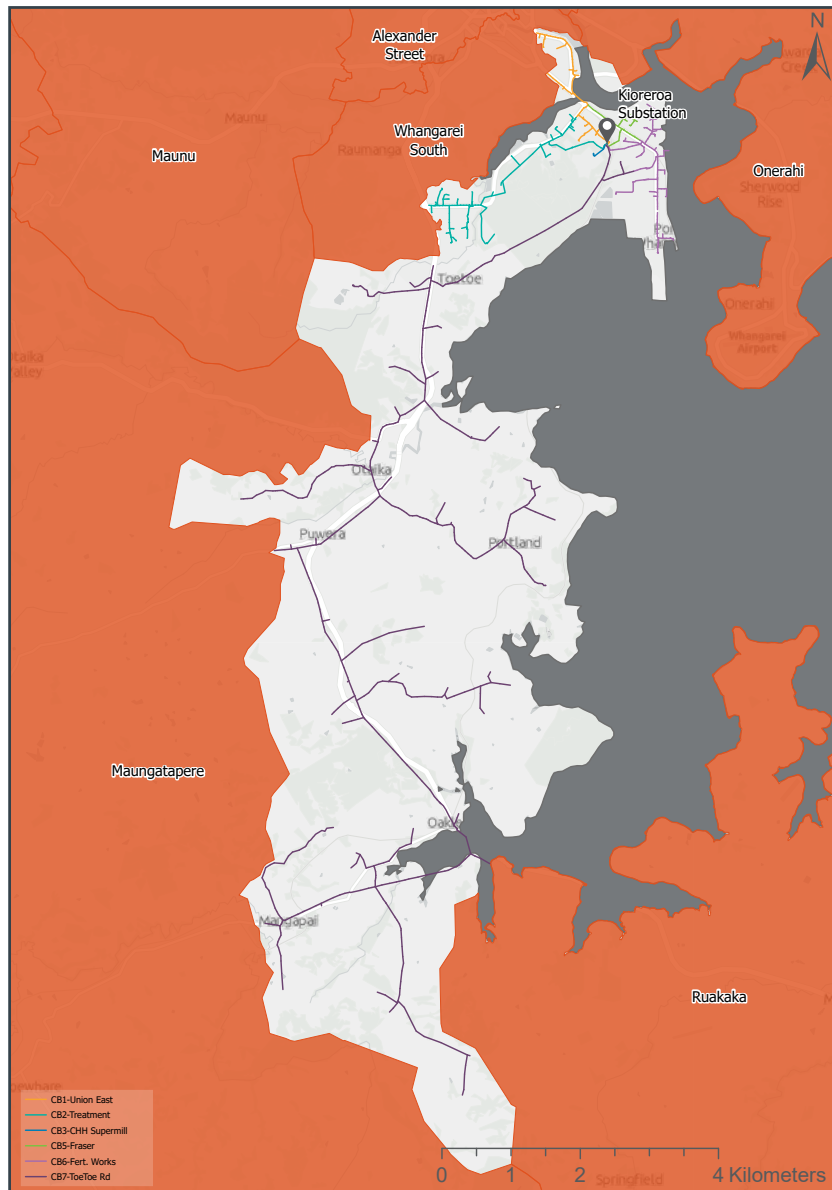
### Kioreroa zone substation forecast system demand and seasonal load



### Forecast capital investment

Renewal projects	Timing
<b>Kioreroa feederboard renewal</b>	FY35-36
Replace feederboard due to age and condition.	

## Kioreroa zone substation feeder map



## Poroti zone substation

### Substation overview

This substation supplies a predominantly rural region with no significant urban centres other than Titoki village. The substation covers a large area with a relatively small total load. Load growth is low with no signs of development, future growth is also expected to be low.

Residential and lifestyle growth is relatively low, and any significant growth is more likely to come from additional irrigation schemes. In FY25, the transformer was replaced with a 10MVA unit due to the age and condition of the asset.

### Poroti zone substation technical summary

#### Poroti zone substation profile

Transformer capacity 1 unit 10MVA

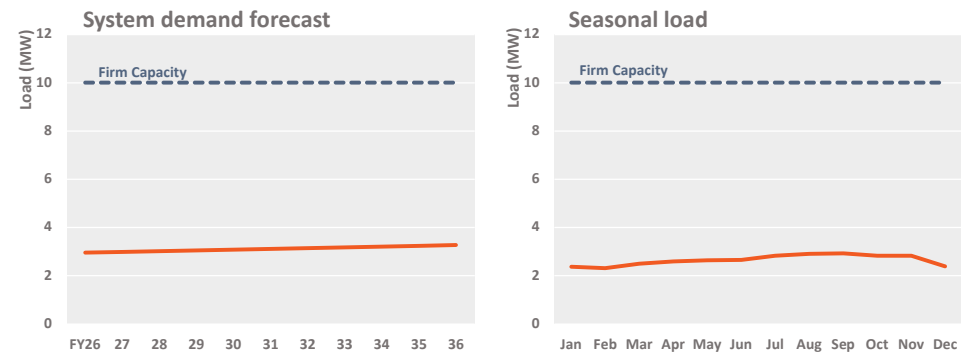
Peak load 3MW

Total number of customers supplied 1,297

Feeder	CB	ICPs	Lines	Customer type
Titoki	1032	708	Overhead	Residential/Commercial mix
Hotel	1052	118	Overhead	Commercial
Wharekohe	1062	71	Overhead	Residential/Commercial mix
Kokopu	1022	400	Overhead	Residential

### Substation demand

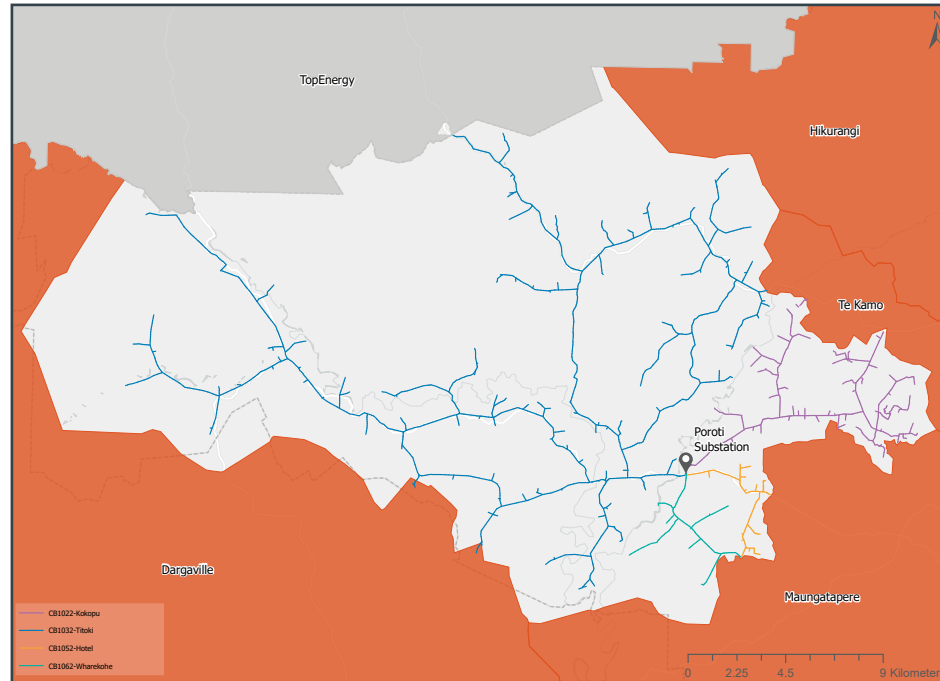
#### Poroti zone substation forecast system demand and seasonal load



## Forecast capital investment

No capital investment is forecast at Poroti at this time.

### Poroti zone substation feeder map



## Whangārei South zone substation

### Substation overview

This substation is situated to the south of Whangārei CBD and supplies a mixture of residential, commercial, and light industrial load. Two major customers are supplied from Whangārei South: Whangārei Hospital and Northland Polytechnic.

The peak load currently exceeds the transformer N-1 capacity. However, due to the close proximity of Alexander Street and Kioreroa substations, it is possible to transfer load if needed. We plan to replace these transformers in FY29–FY31 due to condition, using this opportunity to replace these units with two 20MVA transformers which will reinstate N-1 security.

The new Maunu zone substation that was completed in FY22 allowed a transfer of some residential load lying to the west of Whangārei South. This has freed up some capacity to accommodate anticipated new load to the south, as well as some marginal growth of existing load.

### Whangārei South zone substation technical summary

#### Whangārei South zone substation profile

Transformer capacity 2 units 10MVA

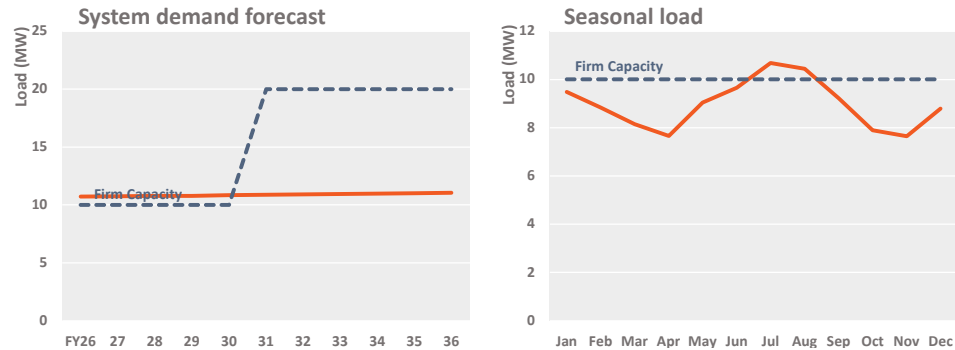
Peak load 11MW

Total number of customers supplied 3,319

Feeder	CB	ICPs	Lines	Customer type
Otaika	1042	80	Overhead	Residential
Kaka St	1032	364	Overhead	Residential/Commercial mix
Te Mai	1102	923	Overhead	Residential
Rewa Rewa Rd	1082	925	Overhead	Residential
Okara Drive	1092	467	Overhead	Residential
Walton St	1022	560	Overhead	Residential

## Substation demand

### Whangārei South zone substation forecast system demand and seasonal load

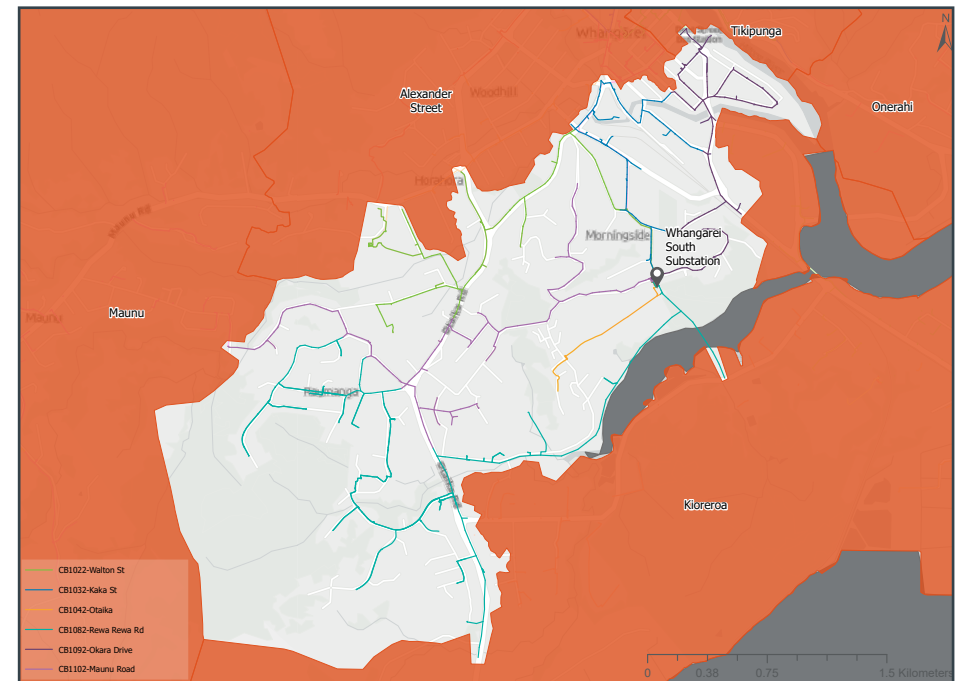


## Forecast capital investment

### Whangārei South zone substation key capex projects

Renewal projects	Timing
<p><b>WHG to ALX 33kV oil cable replacement</b></p> <p>The WHG to ALX cable circuit comprises a 56-year-old oil cable that runs for 2.2km. This cable has leaked extensively in the past and oil pressure has consistently dropped, which increases its risk of insulation failure. The cable is predominantly used for back-feed purposes. We anticipate the back feed will be required more frequently in the future due to increasing extreme weather events. Replacing this cable will make the 33kV subtransmission network around the Whangārei area more resilient against these events.</p>	FY26-28
<p><b>Whangārei South transformer replacements</b></p> <p>There are two transformers feeding the Whangārei South zone substation. One of the transformers has poor winding condition and recent impedance testing indicate that there is deformation. The other transformer also has low insulation resistance test results and there is a risk of catastrophic failure for both transformers. Replacing these transformers will address this risk.</p>	FY29-31

### Whangārei South zone substation feeder map



## Maungaturoto zone substation

### Substation overview

The load on this substation is dominated by the local dairy factory, which accounts for approximately 75% of the substation's maximum demand. The remainder of the load comprises Maungaturoto township and large surrounding rural area, in which the load is predominantly dairy farming. Maungaturoto substation is an important backstop for Kaiwaka and Mareretu single transformer substations.

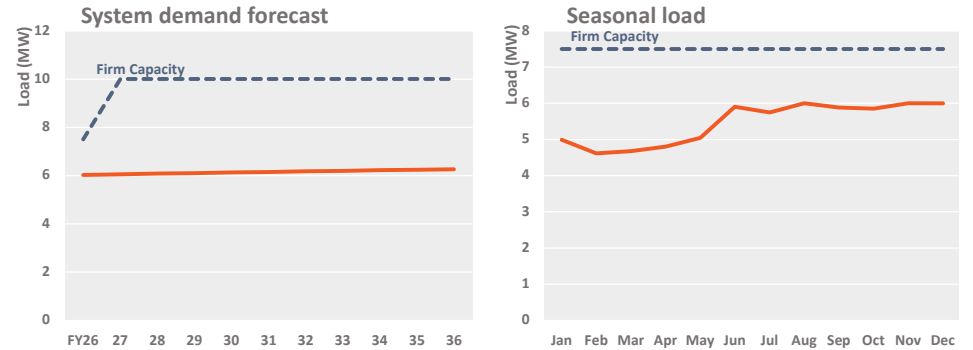
Growth in the township and surrounding area is low. Future load growth potential is mainly driven by the possible expansion of the dairy factory in the longer term. The 10-year plan makes provision for upgrading the 11kV switchboard and replacing the transformers in FY26 to FY27 for age reasons, during this time we will install two 10MVA units which will provide enough capacity for the foreseeable future.

### Maungaturoto zone substation technical summary

Maungaturoto zone substation profile				
Transformer capacity	2 units 7.5MVA			
Peak load	6MW			
Total number of customers supplied	941			
Feeder	CB	ICPs	Lines	Customer type
Brynderwyn	1	180	Underground	Residential/Commercial mix
Bickerstaff	2	758	Overhead	Residential
Maungaturoto dairy factory	4	3	Overhead	Industrial

## Substation demand

### Maungaturoto zone substation forecast system demand and seasonal load

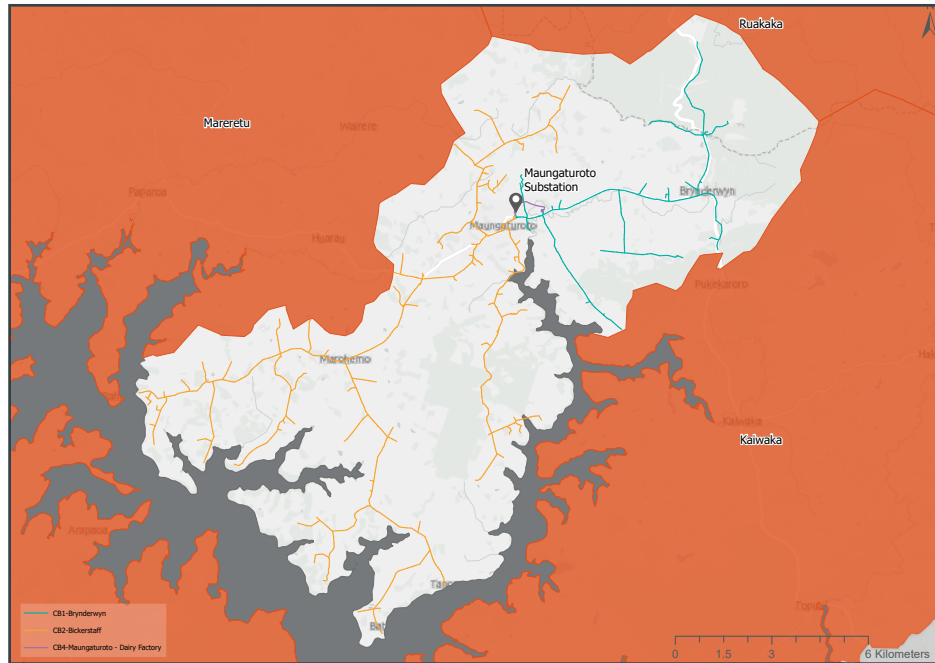


### Forecast capital investment

#### Maungaturoto zone substation key capex projects

Renewal projects	Timing
<b>Maungaturoto transformer replacement</b>	FY26-28
This project will replace two transformers that have poor internal winding condition. Recent tests have failed insulation resistance between HV and LV windings, despite a mid-life overhaul being undertaken.	
<b>Maungaturoto 11kV switchboard replacement</b>	FY26-28
The 11kV switchboard at Maungaturoto is around 50 years old and is made up of five oil filled switchgear. This switchboard has relatively high arc flash incident energy which elevates worker safety risks. The switchboard is also obsolete as spare parts are becoming scarcer to source and we will replace this switchboard at the same time as the transformers.	

## Maungaturoto zone substation feeder map



## Kaiwaka zone substation

### Substation overview

This substation supplies Kaiwaka township and the surrounding rural area, which is predominantly dairy farming loads. There is, however, an increasing amount of lifestyle block developments towards the east near the Mangawhai area. The demand for lifestyle properties is expected to continue or even increase as Mangawhai expands.

### Kaiwaka zone substation technical summary

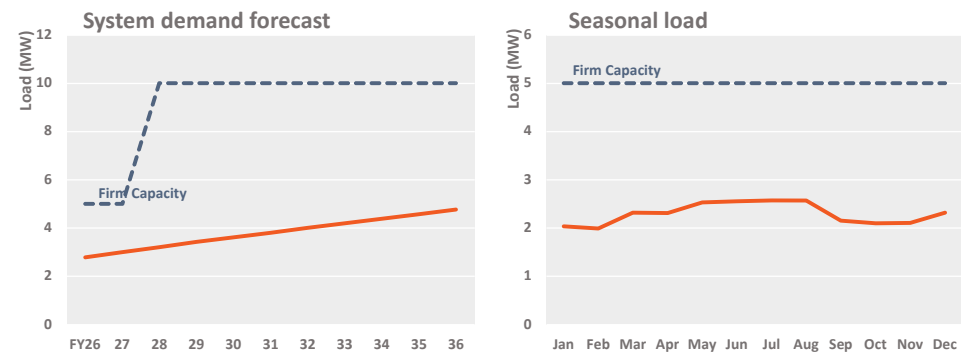
#### Kaiwaka zone substation profile

Transformer capacity	1 unit 5MVA
Peak load	3MW
Total number of customers supplied	2,095

Feeder	CB	ICPs	Lines	Customer type
North Kaiwaka	1022	222	Overhead	Residential
Kaiwaka town	1062	514	Overhead	Residential
Hakaru	1032	849	Overhead	Residential
Kaiwaka South	1072	510	Overhead	Residential

### Substation demand

#### Kaiwaka zone substation forecast system demand and seasonal load



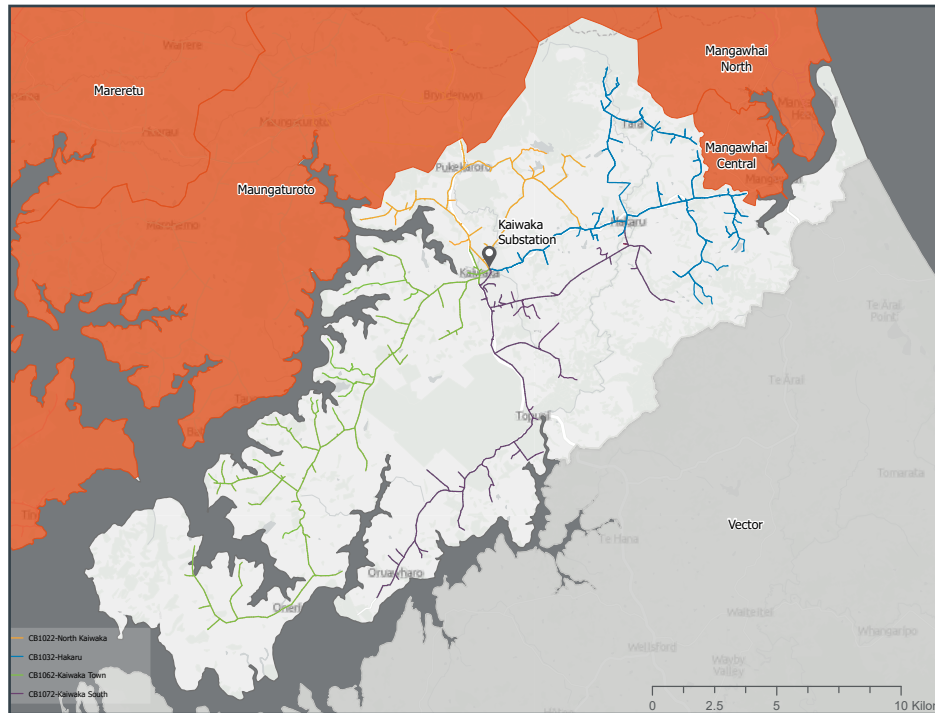
## Forecast capital investment

### Kaiwaka zone substation key capex projects

Renewal projects	Timing
<b>Kaiwaka 11kV transformer replacement</b>	FY30

The project will replace a 62-year-old power transformer. This transformer has exceeded its typical service life, increasing the likelihood of failure and posing a risk to network reliability. The proposed replacement will be a new 10MVA unit.

### Kaiwaka zone substation feeder map



## Mangawhai North zone substation

### Substation overview

The load on this substation is made up primarily of coastal residential, with holiday homes and rural lifestyle dominating. The urban areas include Mangawhai Heads, Langs Beach, and Waipū Cove. The load has grown at a significant rate in recent years compared to other parts of Northpower's distribution network. Further growth is expected in the future which is also aligned with the council's development plans.

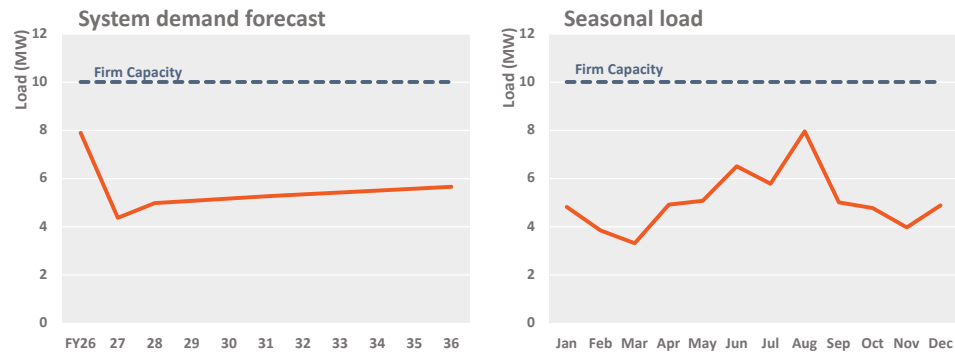
A new substation was commissioned in 2024 to provide more capacity in the area and address the rapid development of the area. In addition, a new 33kV line from Maungaturoto GXP to Mangawhai is currently under construction which will address existing security and reliability constraints.

### Mangawhai North zone substation technical summary

Mangawhai North zone substation profile				
Transformer capacity	2 units 5MVA			
Peak load	8MW			
Total number of customers supplied	3,546			
Feeder	CB	ICPs	Lines	Customer type
Mangawhai Heads	1	1,368	Overhead	Residential
Tara	2	304	Overhead	Residential
Langs Beach	3	797	Underground	Residential
Moir Point	4	1,077	Overhead	Residential

## Substation demand

### Mangawhai North zone substation forecast system demand and seasonal load

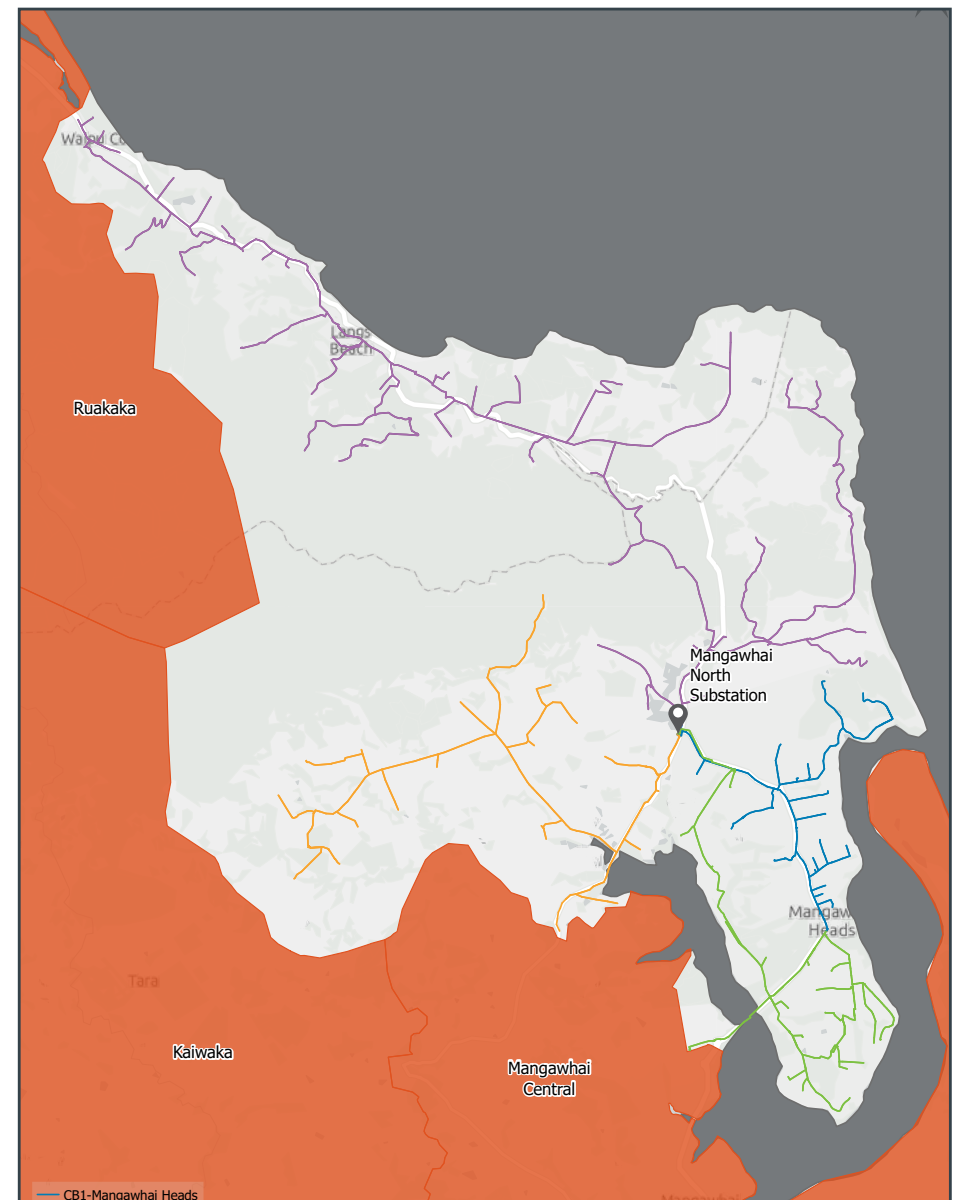


## Forecast capital investment

### Mangawhai North zone substation key capex projects

Growth projects	Timing
<p><b>Maungaturoto to Mangawhai new 33kV line</b></p> <p>The project will install a new 28km subtransmission cable/line from Maungaturoto GXP to Mangawhai substation to improve the reliability and security of supply to Kaiwaka and Mangawhai zone substations. This will also support the growing demand in the Mangawhai area and provide contingency supply under planned outages to perform asset renewal and maintenance. The design is complete and project is underway.</p>	FY26-28
<p><b>Upgrade existing Kaiwaka to Mangawhai 33kV line</b></p> <p>This project proposes a conductor upgrade on the existing 33kV line supplying the Mangawhai area. To ensure N-1 security is maintained to meet the future demand growth a capacity upgrade of the existing line is required.</p>	FY28-30

### Mangawhai North zone substation feeder map



## Mangawhai Central zone substation

### Substation overview

Mangawhai Central is Northpower's newest zone substation, constructed in 2024 to address the rapid growth rate of the area. This substation supplies mostly urban living and commercial areas within Mangawhai as well as some rural lifestyle blocks.

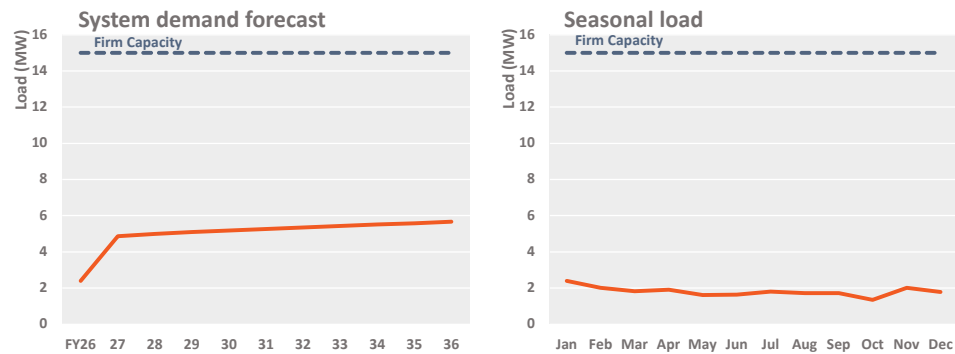
As Mangawhai central develops addition feeders will be constructed which will allow further load transfers from Mangawhai North. In addition, a new 33kV line from Maungaturoto GXP is currently under construction which will address existing security and reliability constraints.

### Mangawhai Central zone substation technical summary

Mangawhai Central zone substation profile				
Transformer capacity	1 unit 15MVA			
Peak load	2MW			
Total number of customers supplied	1,151			
Feeder	CB	ICPs	Lines	Customer type
Commercial	1042	877	Overhead	Residential
Tara Road	1092	274	Overhead	Residential

### Substation demand

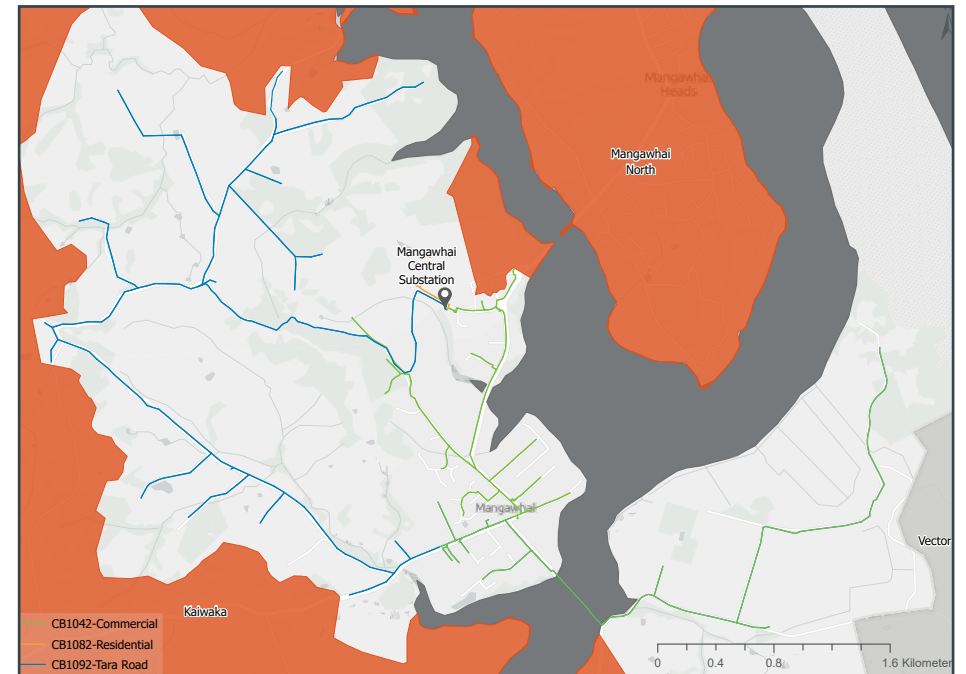
#### Mangawhai Central zone substation forecast system demand and seasonal load



## Forecast capital investment

No capital investment is forecast at Mangawhai Central at this time.

### Mangawhai Central zone substation feeder map



## Mareretu zone substation

### Substation overview

The load on this substation is predominantly rural dairy farming with no significant urban centres other than Paparua village. The substation supplies a large area, although the total load is relatively small. Load growth is low, with no sign of significant development in the short to medium term.

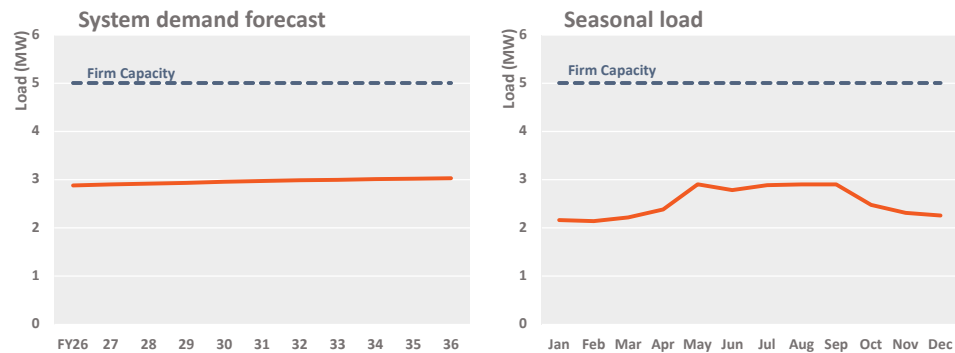
In FY33, the 11kV switchboard is forecasted for replacement due to condition.

### Mareretu zone substation technical summary

Mareretu zone substation profile				
Transformer capacity	1 unit 5MVA			
Peak load	3MW			
Total number of customers supplied	2,031			
Feeder	CB	ICPs	Lines	Customer type
Taipuha	1	422	Overhead	Residential/Commercial mix
Ararua	2	636	Overhead	Residential
Wairere	5	400	Overhead	Residential

## Substation demand

### Mareretu zone substation forecast system demand and seasonal load

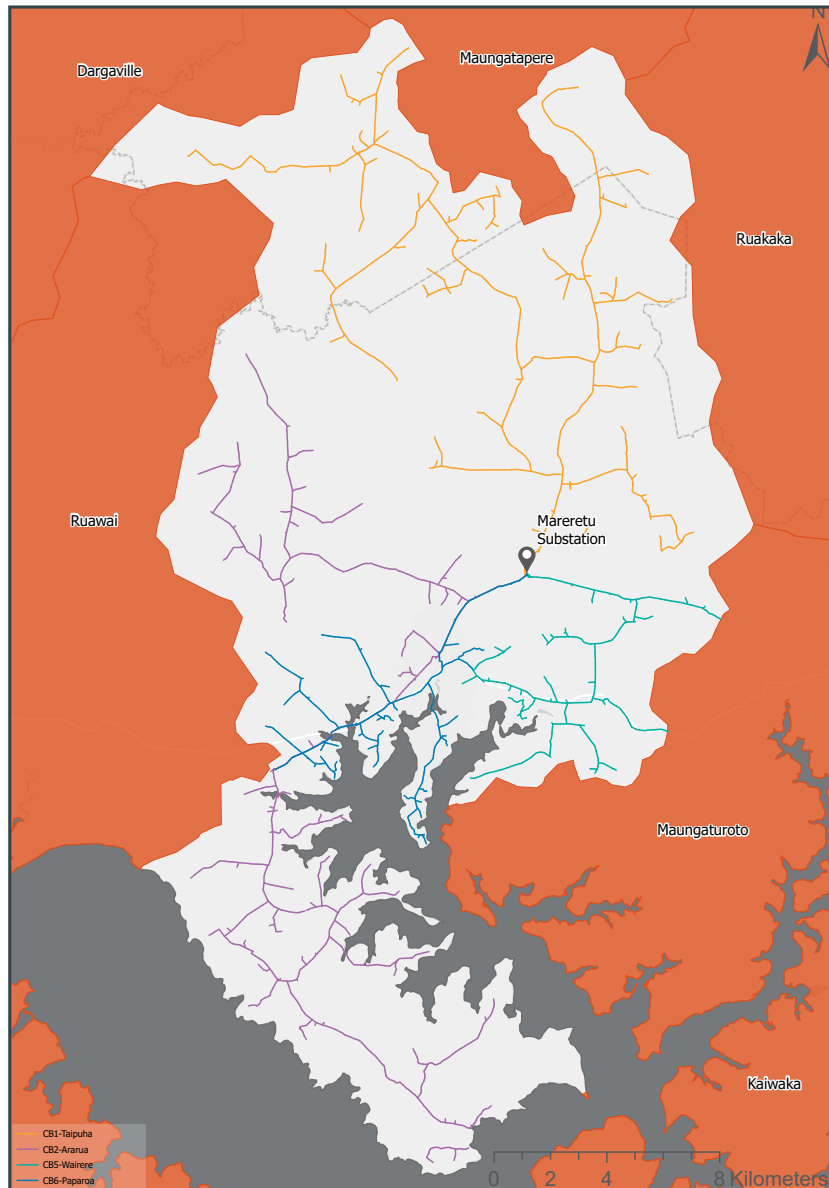


## Forecast capital investment

### Mareretu zone substation key capex projects

Renewal projects	Timing
<b>Mareretu 11kV switchboard replacement</b>	FY34-36
The Mareretu 11kV switchboard comprises five oil filled switchgear which are now around 40 years old. The switchboard is also obsolete and there are no spare parts available. We are replacing this switchboard in order to address its failure and obsolescence risk.	
<b>Mareretu transformer replacement</b>	FY35-36
The project will replace an aging power transformer which has exceeded its typical service life, increasing the likelihood of failure and posing a risk to network reliability.	

Mareretu zone substation feeder map



## Ruawai zone substation

### Substation overview

This substation supplies Ruawai town, with demand dominated by the surrounding rural dairy farming area. Growth is low and this trend is expected to continue into the foreseeable future.

In 2024 the 11kV switchboard and transformer was replaced due to the assets reaching the end of their service life, we have also installed a switchable capacitor bank at the zone substation to address a security of supply constraints.

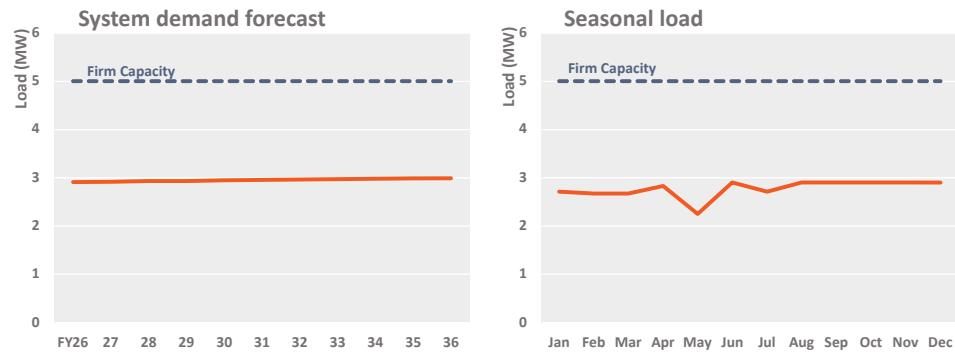
An embedded 4.2MW solar farm was commissioned during 2025 onto the Dunns Rd feeder. During the day, generation exceeds local demand and causes reverse power flow through the Ruawai substation.

### Ruawai zone substation technical summary

Ruawai zone substation profile				
Transformer capacity	1 unit 5MVA			
Peak load	3MW			
Total number of customers supplied	1,676			
Feeder	CB	ICPs	Lines	Customer type
Dunns Rd	1082	368	Overhead	Residential/Commercial mix
Ruawai town	1072	312	Overhead	Residential
Tangaihe	1032	610	Overhead	Residential/Commercial mix
Access Rd	1022	300	Overhead	Residential/Commercial mix

## Substation demand

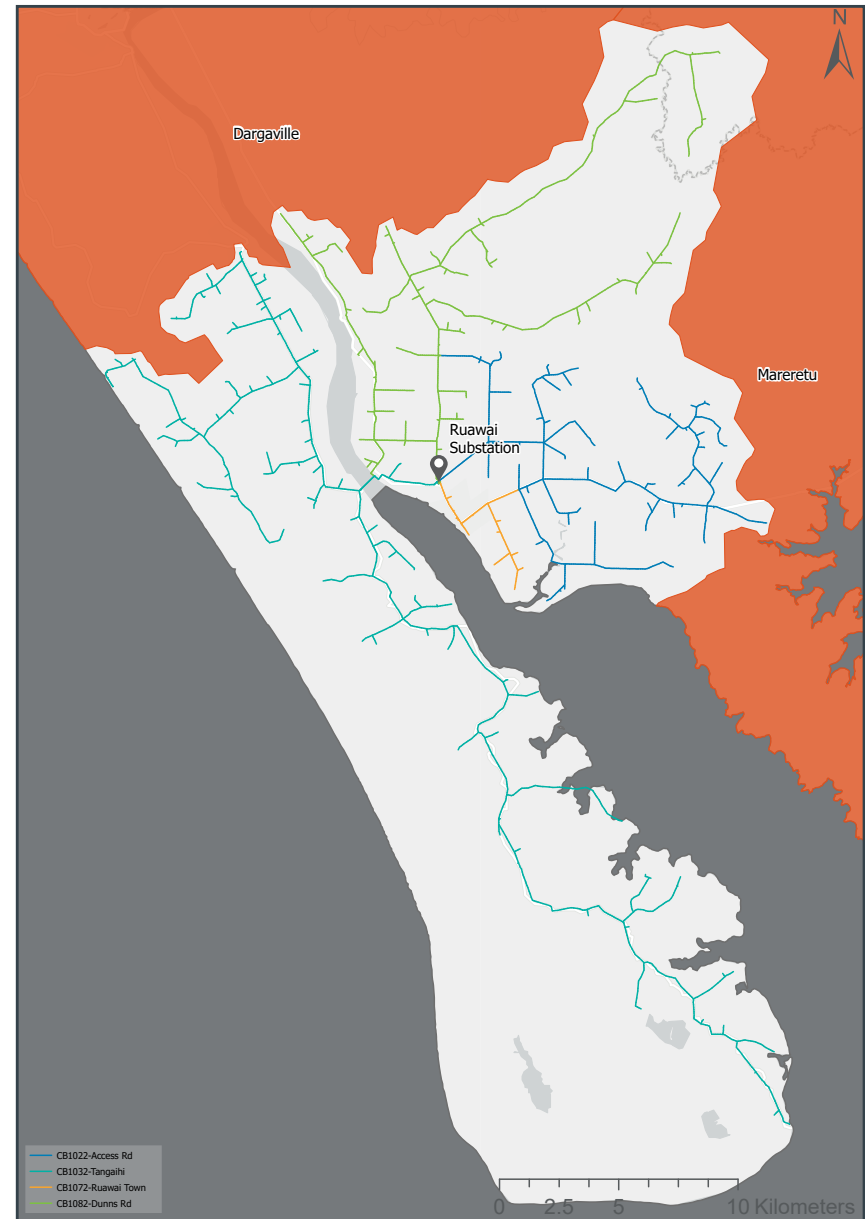
Ruawai zone substation forecast system demand and seasonal load



## Forecast capital investment

No capital investment is forecast at Ruawai at this time.

Ruawai zone substation feeder map



## Significant projects investment analysis

The following section covers more detail on the significant network development projects and the options analysis undertaken to identify the preferred option.

### Maungatapere 110/33kV transformer upgrade

#### Preferred option identified:

Replace both transformers with 100 MVA units.

#### Alternative options considered:

We reviewed six different options to address the capacity and security of supply needs. Two of these options were subsequently shortlisted for detailed costing and economic analysis, as summarised in the following table.

The status quo option was not shortlisted, as compromising security is not a feasible solution. We did not shortlist the option of deferring the upgrade as these transformers are nearing end of life and are critical for supplying several large zone substations.

A non-network solution was considered, using a mixture of battery storage and diesel generation as peak lopping to reduce the load of the existing transformers, however this is not a long term solution and there for not shortlisted.

The recommended option to replace both transformers with 100 MVA units was preferred as this option provides appropriate capacity to meet the long-term needs of the network as well as providing capacity for various decarbonisation scenarios. Replacing these transformers with 100 MVA units also reduces the impact of a high impact low probability (HILP) event occurring at the Kensington 110/33kV regional zone substation.

### Overview of the economic analysis of the short-listed options

Options	NPV costs (\$)		
	CAPEX	OPEX	TOTAL
Replace both transformers with 100 MVA units.	\$10m	-	\$10m
Replace both transformers with 75 MVA units.	\$9.1m	-	\$9.1m
<b>Recommended</b>	\$10m	-	\$10m
Replace both transformers with 100 MVA units.			

### Maungaturoto to Mangawhai 34km 33kV subtransmission line

#### Preferred option identified:

Construct a new 33kV cable from Maungaturoto - Mt. Rd - SH1 - KAI - Mangawhai Central.

#### Alternative options considered:

We reviewed 14 different options to address the constraint, with four options shortlisted for costing and economic analysis, as summarised in the following. The status quo option (i.e. do nothing) was not shortlisted, because investment is required in the near term to meet the N security constraint. Therefore, in this analysis, we are looking for the lowest-cost option to address the network constraint.

The analysis shows that the lowest-cost option is to construct a new 33kV cable/line between Maungaturoto and Mangawhai. The expected upfront cost of the overhead line is lower; however, due to the lower ongoing reliability risk associated with a cable and higher maintenance costs associated with an overhead line, the whole-of-life costs of a cable are lower.

Due to the uncertainty in the estimates (in particular consenting costs), the solution will likely be a mix of overhead line and underground cable where it works practically, and where easement costs can be minimised.

A non-network solution was considered using a mixture of battery storage and diesel generation as peak lopping to reduce the load of the existing substation. This would not improve reliability or security of supply to Mangawhai so it was not shortlisted.

Overview of original economic analysis conducted in 2021.

Options	NPV costs (\$)			
	CAPEX	Reliability	OPEX	TOTAL
Construct a new 33kV line from Maungaturoto to Mangawhai via KAI largely following the route of the existing 33kV line and pass through future growth areas (30km)	\$13.4m	\$4.3m	\$1.9m	\$19.6m
Construct a new 33kV line from Maungaturoto - Mt. Rd - SH1 - KAI - MWI South - Mangawhai	\$14.3m	\$1.3m	\$0	\$15.6m
Construct a new 33kV cable from Maungaturoto - SH12 - SH1 - Bld. Rd - Mangawhai South - Mangawhai bypass KAI	\$14.3m	\$2.7m	\$1.9m	\$18.9m
<b>Recommended</b>	\$17.2m	\$1.3m	\$0	\$18.5m
Construct a new 33kV cable from Maungaturoto - Mt. Rd - SH1 - KAI - Mangawhai Central				

### Kensington 110 kV bus reconfiguration

**Preferred option identified:**

Install a 110kV bus arrangement with bus section CB.

**Alternative options considered:**

The current 110kV arrangement at Kensington means that each of the two incoming lines feed one transformer each. Without a bus on the 110kV, both lines cannot feed one transformer (or one line cannot feed both transformers). If a transformer is out of service for an extended period and the opposite line has a significant fault, supply to all of the downstream customers would be lost until the line and transformer can be restored. This would have a significant impact on our network. This event is a HILP risk and the consequence of this event occurring is not acceptable. We have chosen to mitigate this risk by creating a 110kV bus. Therefore, the do nothing option was not considered.

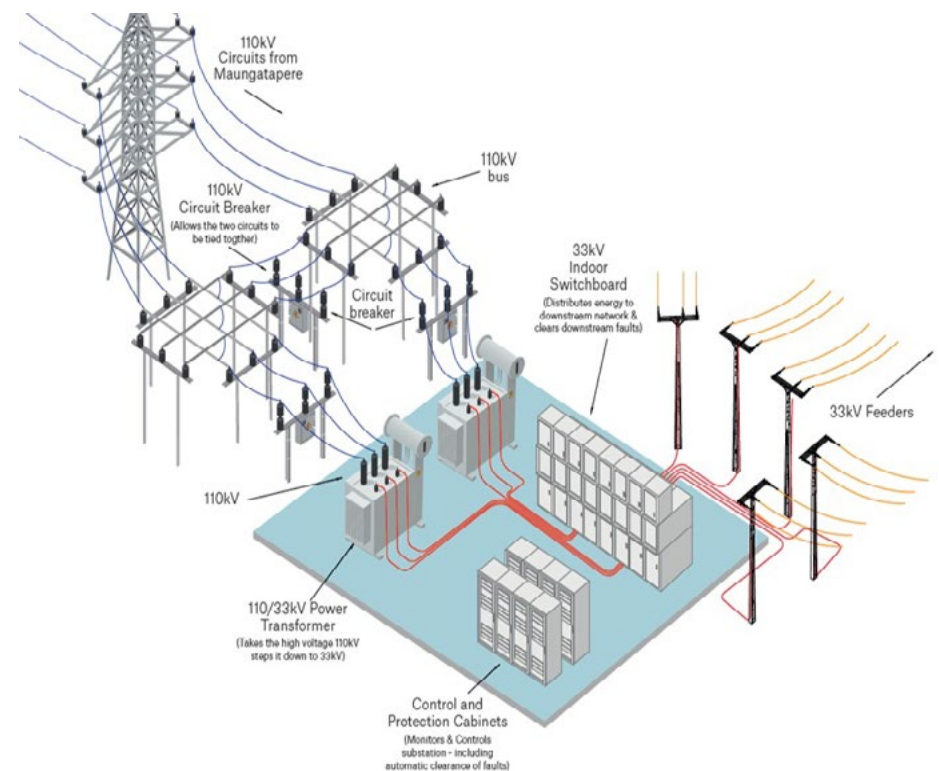
The options identified to address this risk were:

- install a bus arrangement with a bus section disconnecter
- install a bus arrangement with a bus circuit breaker.

The bus circuit breaker was chosen as the preferred option as it only has marginally higher

costs than the disconnecter and would allow switching to occur remotely and without an outage, minimising downtime on the network. This would also give flexibility to keep the other assets in service during an outage of either line or either transformer and effectively remove the possibility of this high-consequence event. Having circuit breakers on the 110kV bus would have the added benefit that the protection system would not rely on a communications link back to Transpower Maungatapere substation circuit breakers.

Kensington substation with 110kV bus arrangement installed (simplified for illustrative purposes)



## Appendix D. Further risk information

High Impact Low Probability (HILP) events are rare, but when they do occur, they have a more significant impact than that is usually catered for in our security of supply criteria. They include extended outages and major common mode failure events. The following sections discuss externally driven and asset specific HILP risks.

### Externally driven HILP risks

We have identified the following list of low-probability, externally driven events that could have unacceptable consequences on our operations.

#### Externally Driven HILP Risks

Event description	HILP scenario	Immediately available actions (operational)	Investment options for risk reduction	Actions: FY24 – 26
Major natural disaster, such as earthquake, tsunami, cyclone	Multiple parts of the network damaged and widespread outages. Increasing impacts of climate change, for example, severe flooding.	Repair and restoration through emergency response. Backfeed where possible through parts of network where supply was maintained. Civil Defence and Emergency Management (CDEM) responses.	Systems to support restoration activities. Network ‘hardening’. Changes to standards and security of supply criteria.	Continue our active role in CDEM to ensure appropriate planning has taken place. Deployment of ADMS and outage management system completed. Development of formal climate change and resilience.
Catastrophic incident at transmission level	Loss of majority or all of network supply.	Engagement with Transpower and provide support in restoration activities.	Engage with Transpower to provide resilience of supply to the upper North Island.	Engage with Transpower to understand vulnerabilities and look at investment options.
Pandemic	Widespread lockdowns, minimal ability to work.	Staff who can work from home, work from home. Implement working “bubbles” to minimise transmission between staff. Follow public health advice.	Investment in systems to enable and improve remote working ability.	Continue to move paper-based processes online to be able to be carried out remotely. Continue to improve remote-working tools and management.
Major cybersecurity attack	Loss of control of network, widespread loss of supply.	Disconnect comprised systems from the network. Manual operation of equipment. Engage external specialists to assess and control the situation.	Continued investments in cybersecurity capability. Continued investment in lifecycle renewals and removal of legacy systems.	Completion of a cybersecurity review and penetration tests, progressing remedial actions. The development of a formalised disaster recovery plan. Distributed Denial of Services (DDOS) protection is in place and we are investigating vulnerability detection options.

## Asset specific HILP risks

The following are asset-specific high consequence events that could occur. These events have very low probability of occurring. However, the consequence of these occurring is not acceptable. We are working to put in place appropriate plans to mitigate these risks over the coming years.

### Asset specific HILP risks

Asset description	HILP scenario	Immediate actions (operational)	Investment options for risk reduction (CAPEX)	Other response options	Actions: FY26 – FY29
2 x 110kV lines Maungatapere (MPE) to Kensington (KEN)	Loss of one or multiple towers resulting in loss of double circuit.	Perform 33kV switching to transfer load to MPE. This has limited capability in high load times.	Build one new 110kV line from MPE to KEN. Build stronger interconnections in the 33kV network to backup from MPE.	Deploy emergency response system (Lindsay Towers) as a temporary measure to reinstate 110kV supply to KEN. Assess and commence works to rebuild tower(s).	<ol style="list-style-type: none"> <li>1. Improve transfer capacity between MPE &amp; KEN.</li> <li>2. Assess for each tower site: access, stability, vulnerability, suitability for the deployment of emergency response system.</li> <li>3. Define scope of works to improve any shortfalls in 1.</li> <li>4. Improve asset management approach of towers.</li> </ol>
Kensington (KEN) 110/33kV transformers	Loss of both 110kV/33kV transformers at KEN.	Perform 33kV switching to transfer load to MPE. Deploy generators to restore load.	Purchase a spare transformer. Enter into an agreement with other utilities to share a 110/33 kV spare.	Repair transformer.	<ol style="list-style-type: none"> <li>1. Install identical transformers at MPE GXP to ensure interchangeability.</li> <li>2. Improve transfer capacity between MPE &amp; KEN.</li> <li>3. Assess risks associated with KEN site and mitigate as far as practicable.</li> </ol>
Kensington (KEN) 33kV bus	Loss of entire 33kV bus	Perform 33kV switching to transfer load to MPE. Deploy generators to restore load.	Upgrade 33kV switchboard to have two separate 33kV buses. Upgrade 33kV interconnections to MPE.	Carry out sufficient repairs to get half the bus operational.	<ol style="list-style-type: none"> <li>1. Upgrade 33kV switchboard is underway, project planned for completion by FY27.</li> <li>2. Improve transfer capacity between MPE &amp; KEN.</li> </ol>
Maungatapere (MPE) regional substation 110/33kV transformers	Loss of all 110/33kV transformers.	Perform 33kV switching to transfer load to MPE. Deploy generators to restore load.	Install third 110/33kV transformers in nearby location as a backup that are seismic rated.	Repair transformer.	<ol style="list-style-type: none"> <li>1. Install identical transformers at MPE GXP to ensure interchangeability</li> <li>2. Improve transfer capacity between MPE &amp; KEN.</li> <li>3. Assess risks associated with MPE site and mitigate as far as practicable.</li> </ol>

Asset description	HILP scenario	Immediate actions (operational)	Investment options for risk reduction (CAPEX)	Other response options	Actions: FY26 – FY29
Maungatapere 33kV bus (MPE)	Loss of entire 33kV bus.	Perform 33kV switching to transfer load to KEN.  Deploy generators to restore load.	Install a modern indoor 33kV switchboard that has fast acting protection and 2 separate bus sections.  Upgrade 33kV interconnections with KEN.	Ensure spares are available and repair any damage to the 33kV bus.	<ol style="list-style-type: none"> <li>1. Install an indoor 33kV switchboard at MPE, planned for completion in FY33.</li> <li>2. Improve transfer capacity between MPE &amp; KEN.</li> </ol>
2 x 66kV lines Maungatapere (MPE) to Dargaville (DAR)	Loss of one or multiple towers resulting in loss of both 50kV circuits.	Perform 11kV switching to transfer load.  Deploy generators to restore load.	Build new 66kV line from MPE to DAR to establish an alternate 66kV ring.  Reinforce 11kV to improve backfeed capability.	Assess and commence works to rebuild 66kV lines.	<ol style="list-style-type: none"> <li>1. Assess line route: access, stability, vulnerability, suitability for the deployment of emergency response system.</li> <li>2. Define scope of works to improve any shortfalls in 1.</li> <li>3. Improve asset management approach of 66kV line.</li> </ol>

## Appendix E. Disclosure requirements

This compliance matrix provides a look-up reference for each AMP-related Information Disclosure requirement.

### Disclosure requirements checklist

Regulatory Requirements	AMP Reference
<p>2.6 Asset management plans and forecast information</p>	
<p>2.6.1 Except as provided in clause 2.6.1A, and subject to clause 2.6.3, before the start of each disclosure year commencing with the disclosure year 2014,</p> <p>(1) Each EDB must complete an AMP that—</p> <ul style="list-style-type: none"> <li>(a) relates to the electricity distribution services supplied by the EDB;</li> <li>(b) meets the purposes of AMP disclosure set out in clause 2.6.2;</li> <li>(c) has been prepared in accordance with               <ul style="list-style-type: none"> <li>(i) in Aurora’s case, clauses 1 to 18 of Attachment A; and</li> <li>(ii) in the case of each other EDB, clauses 1 to 17 of Attachment A;</li> </ul> </li> <li>(d) contains the information set out in the schedules described in clause 2.6.6;</li> <li>(e) contains the Report on Asset Management Maturity as described in Schedule 13;</li> </ul> <p>(2) Each EDB must complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13; and</p> <p>(3) Each EDB must publicly disclose the AMP.</p> <p>(4) Each EDB may choose to publicly disclose the information in clauses 17.117.6 of Attachment A in any of the following forms:</p> <ul style="list-style-type: none"> <li>(a) wholly in the EDB’s AMP, in line with clause 2.6.1 above; or</li> <li>(b) wholly in a document(s) separate to the AMP, provided that-               <ul style="list-style-type: none"> <li>(i) the document is made publicly available on the EDB’s website; and</li> <li>(ii) the contents page of the EDB’s most recent AMP includes a hyperlink reference to the website where the document(s) can be located;</li> </ul> </li> </ul>	<p>(1) (a) This is addressed in the Chapter 1.            (b) Refer to 2.6.2 below.            (c) Compliance with clauses 1 to 17 of Attachment A is demonstrated in this compliance matrix.            (d) This information is included in Appendix B.            (e) AMMAT report is included in Appendix B.</p> <p>(2) AMMAT report has been completed for this AMP and is included in Appendix B.</p> <p>(3) We have published the AMP on our website.</p> <p>(4) We have addressed these requirements in the AMP, referencing supporting material, as relevant, on our website.</p>

Regulatory Requirements	AMP Reference
<p>2.6.1A</p> <p>Despite clause 2.6.1</p> <p>(1) Clause 3.11.1(e) and (f) and clauses 12.5-12.7 of Attachment A do not apply in respect of the AMP required to be disclosed before the start of disclosure year 2024;</p> <p>(2) In respect of the AMP required to be disclosed before the start of disclosure year 2024, if an EDB chooses to publicly disclose the information in clauses 17.1-17.6 of Attachment A in a document separate to the AMP in line with clause 2.6.1A(2)(b), the EDB—</p> <p>(a) must publicly disclose that information by 30 June 2023; and</p> <p>(b) is not required to include in its AMP for disclosure year 2024 (publicly disclosed by 31 March 2023) a hyperlink reference to the website where the document(s) can be located.</p> <p>(3) In fulfilling the requirements of clause 2.6.1A(2) above, EDBs are exempt from the director certification requirements set out in clause 2.9 below in respect of the information disclosed in line with the requirements under clauses 17.1-17.6 of Attachment A, contained in either:</p> <p>(a) the EDB’s AMP required to be disclosed before the start of disclosure year 2024; or</p> <p>(b) in a document(s) separate to the AMP, which must be made publicly available on the EDB’s website by 30 June 2023.</p>	<p>Noted.</p>
<p>2.6.2</p> <p>The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP—</p> <p>(1) Must provide sufficient information for interested persons to assess whether-</p> <p>(a) assets are being managed for the long term;</p> <p>(b) the required level of performance is being delivered; and</p> <p>(c) costs are efficient and performance efficiencies are being achieved;</p> <p>(2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets;</p> <p>(3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.</p>	<p>(1) (a) Chapter 2 describes our business, Chapter 3 provides an overview of our network and Chapters 6, 8 and 9 discuss the management of our assets.</p> <p>(1) (b) Our levels of performance are set out in Chapter 5 while Chapter 2 sets out information on customer preferences.</p> <p>(1) (c) We refer to expected efficiencies in a number of sections, including Chapter 11.</p> <p>(2) We have included a glossary in Appendix A which will aid in understanding.</p> <p>(3) Risk management and resilience is discussed in several sections and in Appendix D.</p>

Regulatory Requirements	AMP Reference
<p>2.6.3 Subject to clause 2.6.4, an EDB may elect to complete and publicly disclose an AMP update, as described under clause 2.6.5, before the start of a disclosure year, instead of an AMP, as described under clause 2.6.1(1), unless the start of that disclosure year is—</p> <ul style="list-style-type: none"> <li>(1) one year after the start of the DPP regulatory period; or</li> <li>(2) two years before the start of the next DPP regulatory period.</li> </ul>	<p>We are publishing a full 2026 AMP.</p>
<p>2.6.4 An EDB must not complete and publicly disclose an AMP update instead of an AMP if it has not previously publicly disclosed an AMP under clause 2.6.1.</p>	<p>We are publishing a full 2026 AMP.</p>
<p>2.6.5 For the purpose of clause 2.6.3, the AMP update must—</p> <ul style="list-style-type: none"> <li>(1) Relate to the electricity distribution services supplied by the EDB;</li> <li>(2) Identify any material changes to the network development plans disclosed in the last AMP under clause 11 and clause 17.5-17.7 of Attachment A or in the last AMP update disclosed under this clause;</li> <li>(3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 12 of Attachment A or in the last AMP update disclosed under this section;</li> <li>(4) Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b;</li> <li>(5) Identify any changes to the asset management practices of the EDB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and</li> <li>(6) Contain the information set out in the schedules described in clause 2.6.6.</li> </ul>	<p>Not applicable as we are publishing a full AMP.</p>

Regulatory Requirements		AMP Reference
2.6.6	<p>Each EDB—</p> <p>(1) must, except as provided in subclause 2.6.6(2), before the start of each disclosure year, complete and publicly disclose each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports—</p> <p>(a) the Report on Forecast Capital Expenditure in Schedule 11a;</p> <p>(b) the Report on Forecast Operational Expenditure in Schedule 11b;</p> <p>(c) the Report on Asset Condition in Schedule 12a;</p> <p>(d) the Report on Forecast Capacity in Schedule 12b;</p> <p>(e) the Report on Forecast Network Demand in Schedule 12c;</p> <p>(f) the Report on Forecast Interruptions and Duration in Schedule 12d;</p> <p>(2) for the purposes of the Report on Forecast Capital Expenditure set out in Schedule 11a required under clause 2.6.6(1)(a), and the Report on Forecast Operational Expenditure set out in Schedule 11b required under clause 2.6.6(1)(b),-</p> <p>(a) is not required to publicly disclose information on cybersecurity expenditure, but must provide that information to the Commission; and</p> <p>(b) in respect of disclosures before the start of disclosure year 2024, is not required to-</p> <p>(i) complete and publicly disclose the information on cybersecurity expenditure in these reports; or</p> <p>(ii) provide the information required on cybersecurity expenditure to the Commission); and</p> <p>(3) must, if the EDB has sub-networks, complete and publicly disclose the Report on Forecast Interruptions and Duration set out in Schedule 12d by inserting all information relating to the electricity distribution services supplied by the EDB in relation to each sub-network for the disclosure years provided for in the report.</p>	<p>(1) This information is included in Appendix B.</p> <p>(2) Noted.</p> <p>(3) Not applicable.</p>
2.7	Explanatory notes to disclosed information	
2.7.2	Before the start of each disclosure year, every EDB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	This information is included in Appendix B.
2.9	Certificates	
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	A copy of the certificate is included in Appendix F.

## AMP design

1	<p>The core elements of asset management—</p> <ul style="list-style-type: none"> <li>1.1 A focus on measuring network performance, and managing the assets to achieve service targets;</li> <li>1.2 Monitoring and continuously improving asset management practices;</li> <li>1.3 Close alignment with corporate vision and strategy;</li> <li>1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets;</li> <li>1.5 That responsibilities and accountabilities for asset management are clearly assigned;</li> <li>1.6 An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets;</li> <li>1.7 An emphasis on optimising asset utilisation and performance;</li> <li>1.8 That a total life cycle approach should be taken to asset management;</li> <li>1.9 That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.</li> </ul>	<ul style="list-style-type: none"> <li>1.1 Chapter 5 discusses our service performance.</li> <li>1.2 Recognition of the need to improve our asset management capabilities and results of our AMMAT assessment are included in Chapter 6.</li> <li>1.3 Chapter 4 details group strategy and how that aligns with asset management strategy.</li> <li>1.4 Chapter 4 sets out our business strategies and how these inform asset management practices and performance objectives and targets.</li> <li>1.5 Chapter 2 discusses our governance structures, governance roles and responsibilities.</li> <li>1.6 Chapter 3 provides an overview of our network assets. Chapter 9 includes more detailed information.</li> <li>1.7 Chapters 5 and 8 discuss how we manage asset utilisation.</li> <li>1.8 Chapter 6 explains our lifecycle based approach to managing our assets.</li> <li>1.9 Chapter 8 sets out our approach to using non-network solutions.</li> </ul>
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Regulatory Requirements	AMP Reference
<p>2 The disclosure requirements are designed to produce AMPs that—</p> <p>2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1;</p> <p>2.2 Are clearly documented and made available to all stakeholders;</p> <p>2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets;</p> <p>2.4 Specifically support the achievement of disclosed service level targets;</p> <p>2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment;</p> <p>2.6 Consider the mechanics of delivery including resourcing;</p> <p>2.7 Consider the organisational structure and capability necessary to deliver the AMP;</p> <p>2.8 Consider the organisational and contractor competencies and any training requirements;</p> <p>2.9 Consider the systems, integration and information management necessary to deliver the plans;</p> <p>2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and</p> <p>2.11 Promote continual improvements to asset management practices.</p>	<p>2.1 The elements of asset management identified in clause 1 are referenced above, while further elements are discussed throughout the AMP itself.</p> <p>2.2 Our AMP is made available on our website to all stakeholders.</p> <p>2.3 Our evaluation of our asset management processes is contained in Schedule 13 (Report on Asset Management Maturity) – refer to Appendix B. Asset management capability is discussed in Chapter 6.</p> <p>2.4 Chapter 5 discusses our service performance and supporting initiatives.</p> <p>2.5 Chapter 7 discusses risk management in general. Chapter 9 discusses the performance and risk for each individual fleet.</p> <p>2.6 Works delivery is discussed in Chapters 2 and 6.</p> <p>2.7 Organisational structure is discussed in Chapter 2 and capability is further discussed in Chapter 6.</p> <p>2.8 Chapters 2 and 6 discuss organisational competencies.</p> <p>2.9 Chapter 10 discusses our supporting ICT systems.</p> <p>2.10 We have included a glossary in Appendix A.</p> <p>2.11 Chapter 4 discusses asset management objectives and strategy. Chapter 6 discusses our asset management capability, including our current capability and planned improvements.</p>

Regulatory Requirements		AMP Reference
Contents of the AMP		
3	The AMP must include the following-	
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	3.1 The Executive Summary provides a brief overview and highlights significant information.
3.2	Details of the background and objectives of the EDB's asset management and planning processes;	3.2 Chapters 4, 6 and 9 discuss our management strategy and planning approaches.
3.3	A purpose statement which- <ul style="list-style-type: none"> <li>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;</li> <li>3.3.2 states the corporate mission or vision as it relates to asset management;</li> <li>3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;</li> <li>3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and</li> <li>3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;</li> </ul>	<ul style="list-style-type: none"> <li>3.3.1 Purpose statement is included in Chapter 1</li> <li>3.3.2 Chapter 4 sets out our group strategy and how this relates to asset management</li> <li>3.3.3 Chapter 4 discusses our planning documents.</li> <li>3.3.4 Chapter 4 sets out our document hierarchy.</li> <li>3.3.5 Chapter 4 details our corporate strategy and how this informs the objectives set out in the AMP.</li> </ul>
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;	Chapter 1 details the period covered by the AMP.
3.5	The date that it was approved by the directors;	Chapter 1 includes the date it was approved by directors.
3.6	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates- <ul style="list-style-type: none"> <li>3.6.1 how the interests of stakeholders are identified</li> <li>3.6.2 what these interests are;</li> <li>3.6.3 how these interests are accommodated in asset management practices; and</li> <li>3.6.4 how conflicting interests are managed;</li> </ul>	3.6 Chapters 2 and 4 explain our approach to stakeholder management and addresses these points.

Regulatory Requirements		AMP Reference
3.7	<p>A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-</p> <p>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;</p> <p>3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and</p> <p>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;</p>	<p>Chapters 2 and 6 explain our governance approaches</p> <p>3.7.1 Section 6.4 explains our asset management governance approach.</p> <p>3.7.2 Section 2.2.1 discusses our executive team.</p> <p>3.7.3 Section 2.2.4 discusses service delivery.</p>
3.8	<p>All significant assumptions-</p> <p>3.8.1 quantified where possible;</p> <p>3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including-</p> <p>3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;</p> <p>3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and</p> <p>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;</p>	<p>3.8.1 We comment on the possible impacts of certain assumptions in Chapter 11 and where forecasts are discussed. These assumptions are quantified where feasible.</p> <p>3.8.2 Significant assumptions are discussed throughout the AMP, including in Chapters 8 and 9.</p> <p>3.8.3 Not directly applicable.</p> <p>3.8.4 Sources of uncertainty (and the potential effect of the uncertainty on information) are discussed throughout the AMP. For example, forecast uncertainty in Chapter 11.</p> <p>3.8.5 Chapter 11 and Schedule 14a discuss these assumptions.</p>
3.9	<p>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;</p>	<p>Future disclosed forecasts may vary due to the uncertainty items set out in Chapter 11. More generally there is scope for variance due to efficiency improvements and other improvements to our asset management systems and modelling.</p>

Regulatory Requirements	AMP Reference
<p>3.10 An overview of asset management strategy and delivery;  <i>To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify-</i></p> <ul style="list-style-type: none"> <li>- <i>how the asset management strategy is consistent with the EDB's other strategy and policies;</i></li> <li>- <i>how the asset strategy takes into account the life cycle of the assets;</i></li> <li>- <i>the link between the asset management strategy and the AMP; and</i></li> <li>- <i>processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.</i></li> </ul>	<ul style="list-style-type: none"> <li>- This is set out in Chapter 4 where we explain our strategic framework, our group strategy and asset management policy and related linkages.</li> <li>- This is explained in Chapter 6.</li> <li>- The link between asset management strategy and the AMP is discussed in Chapter 4.</li> <li>- Chapters 6 and 7 discuss our governance and risk management processes respectively. Chapter 5 discusses system performance aspects.</li> </ul>
<p>3.11 An overview of systems and information management data;</p> <p>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-</p> <ul style="list-style-type: none"> <li>(a) <i>the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;</i></li> <li>(b) <i>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;</i></li> <li>(c) <i>the systems and controls to ensure the quality and accuracy of asset management information; and</i></li> <li>(d) <i>the extent to which these systems, processes and controls are integrated</i></li> <li>(e) <i>how asset management data informs the models that an EDB develops and uses to assess asset health; and</i></li> <li>(f) <i>how the outputs of these models are used in developing capital expenditure projections.</i></li> </ul>	<ul style="list-style-type: none"> <li>(a) The role of asset management data in lifecycle management, including its role in renewal forecasting, is discussed in Chapter 9. It discusses information requirements including asset condition, details on inspections and performance reporting.</li> <li>(b) Chapter 10 provides an overview of our asset management data systems. Chapter 9 explains how asset data is used to inform lifecycle-related expenditure forecasts.</li> <li>(c) Asset management systems are discussed in Chapter 10.</li> <li>(d) System integration is discussed in Chapter 10.</li> <li>(e) Overarching approach is discussed in Chapter 6 with specific details included throughout Chapter 9.</li> <li>(f) Overarching approach for forecasting is discussed in Chapter 6 with specific details included throughout Chapter 9.</li> </ul>
<p>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;</p>	<p>Limitations and initiatives (e.g. AMIS) to improve data are both discussed in Chapters 6 and 9.</p>

Regulatory Requirements		AMP Reference
3.13	<p>A description of the processes used within the EDB for-</p> <p>3.13.1 managing routine asset inspections and network maintenance;</p> <p>3.13.2 planning and implementing network development projects; and</p> <p>3.13.3 measuring network performance;</p>	<p>3.13.1 Chapters 6 and 9 set out our operations and maintenance approach in terms of fleet management.</p> <p>3.13.2 Our approach to planning and implementing network development projects is discussed in Chapter 8.</p> <p>3.13.3 Performance is discussed in Chapter 5.</p>
3.14	<p>An overview of asset management documentation, controls and review processes.</p> <p><i>To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-</i></p> <p>(i) <i>identify the documentation that describes the key components of the asset management system and the links between the key components;</i></p> <p>(ii) <i>describe the processes developed around documentation, control and review of key components of the asset management system;</i></p> <p>(iii) <i>where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;</i></p> <p>(iv) <i>where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and</i></p> <p>(v) <i>audit or review procedures undertaken in respect of the asset management system.</i></p>	<p>Chapters 4 and 6 discusses our strategy and governance. In particular:</p> <p>(i) Section 4.5 discusses documentation for our Asset Management System.</p> <p>(ii) Section 4.5 discusses documentation for our Asset Management System</p> <p>(iii) Generally not applicable, relevant instances are discussed in Section 2.2</p> <p>(iv) Generally not applicable, relevant instances are discussed in Section 2.2</p> <p>(v) This is discussed in Section 4.3.4.</p>
3.15	<p>An overview of communication and participation processes;</p> <p>(i) <i>communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and</i></p> <p>(ii) <i>demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.</i></p>	<p>Chapter 2 sets out our communication and engagement processes.</p> <p>(i) Chapter 2 discusses our interactions with external stakeholders</p> <p>(ii) Chapter 2 discusses our internal engagement on the efficient and cost effective delivery of asset management requirements.</p>
3.16	<p>The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and</p>	<p>Expenditure and related charts are set out in constant price New Zealand dollars.</p>
3.17	<p>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.</p>	<p>The AMP has been structured and presented to align with effective disclosure. The structure of the AMP is detailed in Section 1.2.</p>

Regulatory Requirements		AMP Reference
Assets covered		
4	The AMP must provide details of the assets covered, including-	An overview of assets included in Chapter 3, with more detailed information in Chapter 9 and Appendix C.
4.1	<p>a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-</p> <p>4.1.1 the region(s) covered;</p> <p>4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities;</p> <p>4.1.3 description of the load characteristics for different parts of the network;</p> <p>4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.</p>	<p>4.1 Service areas and related loads are discussed in Chapters 3 and 8, and in Appendix C.</p> <p>4.1.1 The regions covered by our network are discussed in Chapter 3.</p> <p>4.1.2 Major customers are discussed in Section 3.4.</p> <p>4.1.3 Load characteristics are discussed in Chapter 8 and Appendix C</p> <p>4.1.4 Set out in Chapter 8.</p>
4.2	<p>a description of the network configuration, including-</p> <p>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;</p> <p>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;</p> <p>4.2.3 a description of the distribution system, including the extent to which it is underground;</p> <p>4.2.4 a brief description of the network's distribution substation arrangements;</p> <p>4.2.5 a description of the low voltage network including the extent to which it is underground; and</p> <p>4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.</p> <p>4.2.7 a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party.</p> <p><i>To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.</i></p>	<p>Network configuration is discussed in Chapter 3 and Appendix C.</p> <p>4.2.1 This information is set out in Section 3.2 and Chapter 8.</p> <p>4.2.2 Chapter 3 describes our subtransmission network. The capacity and security ratings of individual zone substations is set out in Chapter 8.</p> <p>4.2.3 Chapter 3 and Appendix C describe our distribution network.</p> <p>4.2.4 An overview is provided in Appendix C.</p> <p>4.2.5 Section 3.3.4 describes our low voltage network.</p> <p>4.2.6 An overview of secondary systems is provided in Chapter 9.</p> <p>4.2.7 Our approach to non-network solutions and related information is included in Section 8.8.4.</p> <p>Chapter 3 and Appendix C include network maps and a single line diagram.</p>

Regulatory Requirements		AMP Reference
4.3	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	Not applicable.
	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.	4.4 Network assets are detailed in Chapters 3 and 9. 4.4.1 These are provided, where relevant, in Chapter 3. 4.4.2 Chapter 9 provides detailed description for each fleet. 4.4.3 These are described individually for each fleet in Chapter 9. 4.4.4 These are described individually for each fleet in Chapter 9.
4.5	The asset categories discussed in clause 4.4 should include at least the following- 4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); 4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others; 4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.4 other generation plant owned by the EDB.	4.5.1 Chapter 9 discusses our fleets based on our internal categories and explains how categories relate to Schedule 11a. 4.5.2 This is discussed in Section 3.2. 4.5.3 Not applicable. 4.5.4 Not applicable.
Service Levels		
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Chapter 5 sets out our performance indicators and targets. Where applicable we have indicated whether targets apply for the full planning period.
6	Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	These are set out in Chapter 5.
7	Performance indicators for which targets have been defined in clause 5 should also include- 7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and 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.	7.1 We discuss feedback from customers on our performance. Satisfaction measures are broken out into residential and commercial. 7.2 This is discussed in Chapter 5.

Regulatory Requirements		AMP Reference
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.	Chapter 5 discusses our performance targets and strategies.
9	Targets should be compared to historic values where available to provide context and scale to the reader.	Chapter 5 sets out historical performance where this is available and equivalent.
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance. <i>Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.</i>	This is discussed for individual targets in Chapter 5.
Network Development Planning		
11	AMPs must provide a detailed description of network development plans, including—	Network development is discussed in Chapter 8.
	11.1 A description of the planning criteria and assumptions for network development;	Our planning process is discussed in Section 8.3.
	11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Our planning criteria are discussed in Section 8.3.2.
	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;	Cost efficiency is discussed in a number of sections, with relevant approaches included in Chapter 6.
	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; and 11.4.2 the approach used to identify standard designs;	Section 6.2.2 discusses our use of standard designs. Chapter 9 discusses assets and designs that are standardised.
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Section 8.3.3 discusses our use of customer demand management including ripple control.
	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; <i>The criteria described should relate to the EDB's philosophy in managing planning risks.</i>	Section 8.3 discusses how we determine capacity and its role informing investment decisions. Asset and network planning in terms of asset risk management are discussed in Chapter 7.
	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;	Section 6.4 explains how we prioritise investments and how these align with our objectives and vision.

Regulatory Requirements	AMP Reference
<p>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;</p> <p>11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;</p> <p>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;</p> <p>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</p> <p>11.8.4 discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network;</p>	<p>11.8 System demand is discussed, and demand forecasts are provided, in Section 8.4.</p> <p>11.8.1 The methodology used for load forecasting is set out in Section 8.3.1.</p> <p>11.8.2 Load forecasts are set out in Section 8.4.4. Potential uncertainties are discussed in Section 8.3.1.</p> <p>11.8.3 Network constraints are discussed in Section 8.5.</p> <p>11.8.4 This is explained in Section 8.8.4.</p>
<p>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-</p> <p>11.9.1 the reasons for choosing a selected option for projects where decisions have been made;</p> <p>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; and</p> <p>11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;</p>	<p>Major projects are discussed in Section 8.6 and Appendix C.</p>
<p>11.10 A description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-</p> <p>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;</p> <p>11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and</p> <p>11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period;</p> <p><i>For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including a detailed description of the investigations undertaken in respect of the potential for non-network solutions to be more cost effective than network augmentations and vice versa. This should specify if any third parties were approached in relation to non-network solutions, and if so, whether those third parties are related parties. For the purposes of disclosing the information described in clause 11.10.3, an EDB is not required to include commercially sensitive or confidential information.</i></p>	<p>Network development investments and related timeframes are set out and discussed in Section 8.6, in particular Section 8.6.1. Further detail on these projects (including alternative options considered and the reasons for choosing the selected option) is set out in Appendix C.</p>

Regulatory Requirements		AMP Reference
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; and	Distributed generation is discussed in Sections 3.5 and 8.7.
11.12	A description of the EDB's policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; 11.12.2 the potential for non-network solutions to address network problems or constraints; and 11.12.3 how information on current and forecast constraints (both load and injection) is shared with potential providers of non-network solutions. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2 of Attachment A.	Our approach to non-network solutions are discussed in Section 8.8.4
Lifecycle Asset Management Planning (Maintenance and Renewal)		
12	The AMP must provide a detailed description of the lifecycle asset management processes, including—	Our lifecycle management approach is discussed in Chapters 6 and 9.
12.1	The key drivers for maintenance planning and assumptions;	These are discussed in Section 9.2.2
12.2	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	Our approach to maintenance is set out in Chapters 6 and 9. 12.2.1 Chapter 9 explains our approach to inspecting and maintaining each category of assets. 12.2.2 Chapter 9 provides this information for each fleet individually. 12.2.3 Forecast maintenance expenditure is included in Chapter 11.
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 that have deferred asset replacements; 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.	12.3 Our approach to refurbishment and renewal is discussed in Chapters 6 and 9. 12.3.1 Chapter 6 explains the high-level approach while Chapter 9 provides this information for each fleet. 12.3.2 These are addressed in Chapter 9. 12.3.3 This is included in Appendix C. 12.3.4 This is included in Appendix C and overall forecasts in Chapter 9. 12.3.5 This is discussed in Chapter 9 for each fleet.

Regulatory Requirements		AMP Reference
12.4	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Chapter 9 provides this information for each fleet.
12.5	Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of: 12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and 12.5.2 the rationale for using the approach for each asset category.	12.5.1 Approach to developing capital expenditure projections for lifecycle asset management is set out in Chapters 6 and 9. 12.5.2 The approach for individual asset fleets is set out in Chapter 9.
12.6	Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	Our approach to vegetation management is set out in Chapter 9.
12.7	The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	Our overarching approach is discussed in Section 8.8.4.
Non-Network Development, Maintenance and Renewal		
13	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including— 13.1 a description of non-network assets; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; and 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	13.1 Chapter 10 explains our overarching approach to managing our non-network assets. 13.2 Section 10.4 explains our approach to identifying development, maintenance and renewal ICT expenditure. 13.3 Section 11.2.6 discusses material Capex projects during the next five years. 13.4 Chapter 11 set out Capex and Opex related to our non-network assets and activities.

Regulatory Requirements		AMP Reference
Risk Management		
14	<p>AMPs must provide details of risk policies, assessment, and mitigation, including—</p> <p>14.1 Methods, details and conclusions of risk analysis;</p> <p>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;</p> <p>14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and</p> <p>14.4 Details of emergency response and contingency plans.</p>	<p>14.1 Our approach to risk management is discussed in Chapter 7.</p> <p>14.2 We discuss our methodology and key risks in Section 7.4.</p> <p>14.3 We discuss our approach and include planned controls (where identified) in Appendix D.</p> <p>14.4 We discuss emergency response and contingency plans in Section 7.4.</p>
Evaluation of performance		
15	<p>AMPs must provide details of performance measurement, evaluation, and improvement, including-</p> <p>15.1 A review of progress against plan, both physical and financial;</p> <ul style="list-style-type: none"> <li>- <i>referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;</i></li> <li>- <i>commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and</i></li> <li>- <i>commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.</i></li> </ul> <p>15.2 An evaluation and comparison of actual service level performance against targeted performance;</p> <ul style="list-style-type: none"> <li>- <i>in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.</i></li> </ul> <p>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.</p> <p>15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.</p>	<p>This is addressed in Chapter 11.</p> <p>Chapter 5 discuss our network reliability performance, our primary service performance measure. We have also set out updated reliability measures.</p> <p>In Chapter 6 we discuss the implications of our AMMAT result and set our improvement initiatives.</p> <p>Chapters 5 and 6 set out improvement initiatives for performance and asset management capability, respectively.</p>

Regulatory Requirements		AMP Reference
Capability to deliver		
16	<p>AMPs must describe the processes used by the EDB to ensure that-</p> <p>16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and</p> <p>16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.</p>	<p>16.1 Chapter 4 discusses our objectives, strategy and governance practices that guide our decision-making.</p> <p>16.2 An overview of our ownership and governance structure is included in Chapter 2 along with roles and responsibilities.</p>
Requirements to provide qualitative information in narrative form		
17	AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
	17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	We explain our approach to notifying customers about outages in Chapter 2.
Voltage Quality		
	17.2 a description of the EDB's practices for:	
	17.2.1 monitoring voltage, including:	This is discussed in Chapter 8.
	(a) the EDB's practices for monitoring voltage quality on its low voltage network;	This is discussed in Section 8.3.
	(b) work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	This is discussed in Section 8.3.
	(c) how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	This is discussed in Sections 2.4 and 8.3.
	(d) how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	This is discussed in Sections 2.4 and 8.3.
	(e) any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	This is discussed in Sections 2.4.11
	17.2.2 monitoring load and injection constraints, including:	We explain our approach in Chapter 8.
	(a) any challenges, and progress, towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and	Progress in understanding the LV network is discussed in Section 8.8.
	(b) any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	Analysis and modelling of the LV network is discussed in Section 8.8.

Regulatory Requirements		AMP Reference
<i>Customer service practices</i>		
<i>There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places.</i>		
17.3	a description of the EDB's customer service practices, including:	This is discussed in Chapter 2.
17.3.1	the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	We explain our customer satisfaction performance and related activities in Chapters 2 and 5.
17.3.2	the EDB's approach to planning and managing customer complaint resolution;	We explain our approach to customer complaints in Section 2.4.
<i>Practices for connecting new consumers and altering existing connections</i>		
17.4	a description of the EDB's practices for connecting consumers, including:	We explain our approach to customer connections in Chapter 2
17.4.1	the EDB's approach to planning and management of-	We explain how we manage the planning and management of customer connections in Section 2.4
17.4.1(a)	connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and	We explain our approach in Sections 2.4 and 3.5.
17.4.1(b)	alterations to existing connections (offtake and injection connections);	We explain our approach in Section 2.4.
17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections;	We discuss our approach to fair pricing in Section 5.6.1.
17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections;	We explain our approach in Section 2.4.
17.4.4	commonly encountered delays and potential timeframes for different connections; and	This is discussed in Section 2.4.
17.4.5	the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a) of Attachment A.	This is discussed in Section 8.6.3.

Regulatory Requirements		AMP Reference
	<i>New connections likely to have a significant impact on network operations or asset management priorities</i>	
	<i>The following requirements focus on the EDB's capability and risk management regarding demand, generation, or storage capacity that the EDB considers are likely to have a significant impact on its network operations or asset management priorities. The EDB may consider voltage, network location, or other factors in making this assessment.</i>	
17.5	A description of the following:	
17.5.1	how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including:	This is discussed in relation to our load forecasting approach in Chapter 8.
17.5.1(a)	how the EDB measures the scale and impact of new demand, generation, or storage capacity;	This is discussed in relation to our load forecasting approach in Chapter 8.
17.5.1(b)	how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account;	We explain our approach in Section 8.3.1.
17.5.1(c)	how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	We explain our approach in Section 8.3.1.
17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	This is discussed in Section 8.3.
	<i>Innovation practices</i>	
17.6	A description of the following:	
17.6.1	any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	This is discussed in Section 8.8.6
17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	These are primarily based on our 'BAU' desired outcomes discussed in Chapters 4 and 5.
17.6.3	how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;	This is discussed in Section 8.8.6
17.6.4	how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	This is discussed in Section 8.8.6
17.6.5	the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	This is discussed in Section 8.8.6
17.7	For the purpose of disclosing the information required under clauses 17.6.1-17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	Noted

## Appendix F. Director Certification

We, **Mark Trigg** and **Kerry Friend**, being directors of Northpower Ltd certify that, having made all reasonable enquiry, to the best of our knowledge:

- a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.6.1, 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, 11c, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Northpower Limited's corporate vision and strategy and are documented in retained records.

Director:  ..... Director:  .....

Date: 25 March 2026 ..... Date: 25 March 2026 .....



