mainpower

ASSET MANAGEMENT PLAN

1 APRIL 2025 – 31 MARCH 2035

CHIEF EXECUTIVE'S MESSAGE

As our customers' needs and expectations evolve, we see exciting opportunities to support our customers' desire to control and create energy efficiency through technology and renewable energy in their homes and businesses. At MainPower, we are committed to harnessing this potential to create a smarter future that truly benefits our community.

Welcome to MainPower's 2025 Asset Management Plan (AMP). On behalf of the MainPower team, I am proud to present a plan that highlights our dedication to providing a safe, secure, reliable, and sustainable electricity network for homes and businesses across the North Canterbury region.

Our vision is to create a smarter future that delivers local value. The energy industry is changing rapidly, and we understand that consumers want MainPower to facilitate their adoption of energy innovations by providing the necessary services and infrastructure.

To meet these expectations, we are partnering with our customers to better understand their needs and preferences.

Over the past year, we have made significant strides in engaging with our customers to gain insights into their energy requirements. This collaboration has led to improved planning processes and forecasting methodologies, ensuring that our investments align with the growth and resilience of our network.

To deepen our understanding of the risks impacting our network's reliability, we have strategically invested in various data sources, including insights from the National Institute of Water and Atmospheric Research (NIWA) to model climate impacts, and our work with Canterbury Lifelines, which allows us to enhance disaster response. With this knowledge, we have refined our asset replacement, renewal, and resilience plans to effectively address vulnerabilities and strengthen our network against potential disruptions.

As parts of our network approach capacity limits, substantial upgrades will be necessary to support forecasted growth. We have incorporated this additional expenditure into our 2025 AMP forecasts, driven by increased customer engagement and clarity regarding connection projects that will drive demand.

We are actively exploring innovative solutions, including fleet electrification, enabling distributed generation, and smart technology. This AMP outlines our network, management practices, and the foundational assumptions that guide us as responsible custodians of the MainPower electricity distribution network.

Our plan details how we will invest prudently in our electricity distribution network and related services over the next decade, enhancing the delivery of safe, reliable, and sustainable low-carbon energy. Ultimately, our goal is to power our communities while delivering value to the people who own us.

Andy

Andy Lester
Chief Executive
MainPower New Zealand Limited

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INTRODUCTION

1 INTRODUCTION

MainPower New Zealand Limited (MainPower) is a consumer-trust-owned electricity distribution business (EDB) that builds, owns, operates and maintains the electricity distribution network in the North Canterbury region. We provide electricity distribution services to more than 44,000 residential and business connections and play a crucial role in supplying the energy needs of our communities, as well as contributing to the growth of a vibrant and prosperous region.

MainPower is responsible for supplying safe, secure, reliable and sustainable electricity distribution network and energy services to homes and businesses in the North Canterbury region, from north of the Waimakariri River, through the Hurunui, to Kaikōura.

Owing to changes in the sector, our role is also changing. The New Zealand electricity sector is facing significant transformation, driven by decarbonisation, decentralisation and digitalisation (the "New Energy Future"). This requires a new approach and refreshed thinking about our strategic direction to ensure we continue to build and operate an electricity distribution network for the future that is responsive to consumer demand while delivering value to our consumers, the community and our shareholders.

Over the last three years we have focused our efforts on improving the stability of the business and identifying and addressing opportunities to make the business more efficient. A key outcome of this is the continued support of the core network business, ensuring network services will keep up with change within the sector while also delivering value to our consumers and shareholders.

MainPower has reviewed and developed its Network Transformation Roadmap to ensure the electricity distribution network services that MainPower provides change at a rate that matches changing consumer behaviours, considering the advent of new technologies and the national transition to a low-carbon economy. The review also required MainPower to develop key workstreams that address the future impacts of climate change, including adverse weather, sea level rise and wildfires. A key project supporting this is MainPower's Digital Twin, which enables MainPower to model the physical impacts of weather on network assets in a fully integrated environment.

In 2020, MainPower went live with our new advanced distribution management system (ADMS) for the smart operational management of the network. This system was further embedded into our daily operation in 2021. The ADMS is a key part of ensuring our network is ready to support the Network Transformation Roadmap.

We continue to assess our asset management systems, processes and practices against the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT) and against ISO 55001 via independent evaluation. MainPower remains committed to ensuring our asset management maturity is aligned with our organisational goals and objectives, including compliance with ISO 55001.

MainPower's electricity distribution network performance (quality of supply) is affected by the Asset Management Plan (AMP) work programme. The objective of the AMP work programme is to improve long-term network performance, and the AMP supports workstreams that will return network quality of supply to past levels network performance and improve it into the future.

Our AMP describes our network, our management practices and the assumptions that support our obligation as the responsible custodian of the MainPower electricity distribution network. We forecast the likely development, maintenance, and replacement requirements of the network and non-network assets over the next 10 years, from 1 April 2025 to 31 March 2035. However, there is inherent uncertainty in forecasts. Potential large customer developments, distributed generation connections, changing environment, climatic changes and other external factors may inevitably lead us to change our longer-term forecasts.

This AMP was completed for asset management purposes in 2024 and was approved by the MainPower Board of Directors at their December 2024 meeting.

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ASSET MANAGEMENT PLAN

Figure 2.1 MainPower's electricity distribution network region

2.1 OUR ELECTRICITY DISTRIBUTION NETWORK

MainPower owns and operates North Canterbury's electricity distribution network, from the Waimakariri River in the south up to the Puhi Puhi Valley north of Kaikōura, and from the Canterbury coast inland to Lewis Pass (see Figure 2.1). We provide electricity distribution services to more than 44,000 North Canterbury homes and businesses.

Growth in the region, particularly with new subdivisions, has brought us nearly 3,000 new consumers during the past three years. We are committed to contributing to a bright future for our region by delivering an electricity distribution network that is ready for the future.

The MainPower distribution network lines and cables operate at sub-transmission voltages of 33kV and 66kV, at distribution voltages of 11 kV, 22 kV, and 6.6 kV, and at 230 V or 400 V on the low-voltage network.

Our electricity distribution network connects to the New Zealand national grid at voltages of 66 kV, 33 kV and 11 kV via Transpower's transmission grid exit points (GXPs). The national transmission grid carries electricity from generators throughout New Zealand to electricity distribution networks and large, directly connected consumers (see Figure 2.2). GXP assets are owned mostly by Transpower, although MainPower owns circuit-breaker protection and control equipment at some Transpower sites.

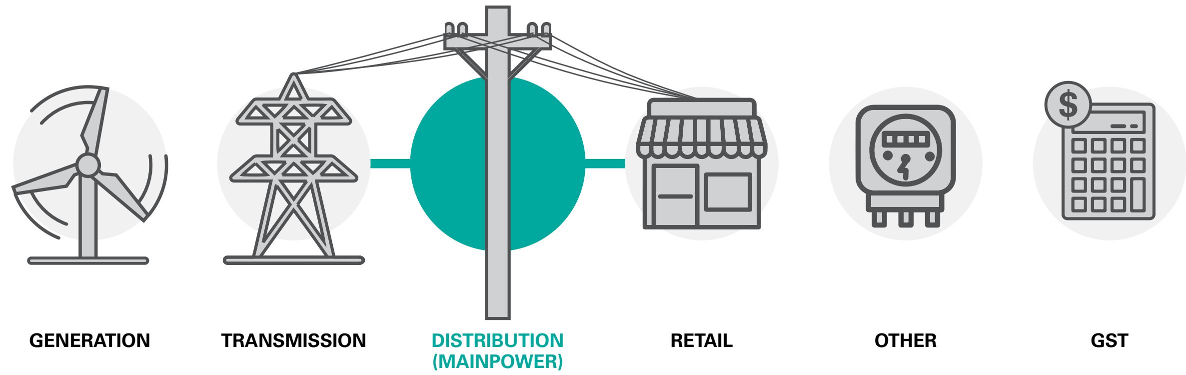


Figure 2.2 MainPower's position within the New Zealand electricity supply chain

2.2 OUR FUTURE NETWORK

The energy landscape is undergoing a significant transformation where new technologies are reshaping the traditional energy production and consumption patterns of our customers. Solar generation and residential battery systems are increasing, reflecting a broader trend towards distributed energy resources. The increasing adoption of electric vehicles (EVs) is creating new demands on the network. This shift not only affects load patterns but also presents opportunities for smart charging solutions to coordinate and optimise individual customer energy patterns and network infrastructure.

We're focused on preparing our network for this future landscape, with our future network objectives to support:

- integration of consumer energy resources (CER) with more active customer participation
- building network resilience to prepare our network for major events and the changing climate
- decarbonisation of New Zealand's economy with electrification of transport and other sectors
- transitioning our network operations to a distribution system operator model with whole-of-system planning
- developing digital and data platforms to provide an open network and enable changing customer needs
- improving our network visibility and control, with a focus on our low-voltage network management.

We want to develop a flexible, resilient, and customer-focused energy environment capable of facilitating the transition to a decarbonised economy while harnessing emerging technologies and data-driven insights.

Collaboration with our industry peers and partners will be crucial in this future energy transition, driving innovation, sharing best practices, and ensuring MainPower is a leader in future energy solutions.

2.2.1 FUTURE NETWORK ROADMAP

The future network roadmap consists of three horizon periods and provides a high-level framework to build the capabilities required to prepare for the future energy landscape. Horizon 1 covers the next 3 years, Horizon 2 extends from years 4 to 10, and Horizon 3 looks beyond the 10-year period to guide our longer-term planning (Table 2.1).

Horizon 1: **Building the foundation**	**Horizon 2:** **Building systems and capability**	**Horizon 3:** **Grow with our customers**
Next 3 years	**Years 4 to 10**	**10 years and beyond**
Gaining a deeper understanding of our network and our customers' energy needs.	Developing new tools, building capability and embedding these across our operations.	Scaling our capability as consumer energy resources (CER) and engagement increases.
• Customer engagement and energy insights • Monitoring the North Canterbury energy landscape and global trends • Network visibility and intelligence • Data and advanced analytics • Advanced asset management • Distribution system operator (DSO) operating models • Advanced scenario modelling	• Digitalisation of the network and our operations • CER integration and optimisation • Flexibility markets and integration • Commercial models • Common standards and communications protocols • Building network resilience • DSO transition	• Improving maturity in mass market coordination • Optimising CER and market solutions with network investment • Continuing to scale our operations to meet consumer requirements • Refining our strategies to reflect local and international energy trends • Continue to build resilience and prepare for the future climate

Table 2.1 Future network roadmap

Our key priority areas for this Asset Management Plan (AMP) cycle over the next 12 months are as follows.

Customer engagement and insights

Understanding our consumers' energy needs and how they may engage with our network through CER and flexibility, along with third-party providers of energy solutions.

North Canterbury energy landscape and global trends

Conduct an environmental scan for North Canterbury and internationally to identify key drivers for change and what we need to support growth in our region.

Network visibility and intelligence

Continuing our project to source low-voltage installation control point (ICP) data and develop analytics tools to understand and model the impacts of CER and changing consumer energy profiles on our network.

Distribution system operator (DSO) operating models

Explore possible future operational models and develop a path into the world of DSOs.

2.2.2 FUTURE SCENARIOS

We have developed three scenarios to understand how our energy environment might evolve. Modelling these pathways provides us with a deeper understanding of the potential range of outcomes and allows us to monitor drivers or trends that may result in a change in pathway. These scenarios use historical data and regional growth information to develop foundational growth projections to then overlay decarbonisation scenarios to understand the possible impacts for each network region. They provide us with a view of possible energy futures, allow us to monitor how we are tracking against the scenarios, and ensure our investment strategies support our region's future.

The scenarios summarised in Table 2.2 relate to a low-carbon future as our region grows and transitions to more renewable energy.

	Description	Customer participation	System coordination
Optimised energy system	High technology adoption and support for whole-of-system coordinated energy management across the energy system. High levels of electrification, offering flexibility solutions to extract value in distributed energy resources with ability to dynamically manage network peaks and match load with lowest cost generation. Requires a high degree of coordination across the full energy system and provides ability to leverage the full range of CER capability and artificial intelligence (AI) for system optimisation.	Engaged	Optimised
Smart sustainable system	Continuation of balanced base energy growth driven by regional development, with consumers embracing a smart, low-carbon energy transition and balanced adoption of technology, accelerating towards 2035. Use of distributed energy resources and flexibility (demand response) services to support New Zealand's decarbonisation journey. Electrification of transport and renewable generation follow New Zealand Government targets.	Balanced	Balanced
Un-coordinated growth	As regional development and technology adoption increases, this scenario describes low support for use of smart technologies or flexibility services (such as grid-connected batteries and distributed energy resources) resulting in growth contributing to network peaks without coordination or ability to centrally manage. Un-coordinated CER makes system stability challenging with increasing two-way energy flows and load variability.	Low	Complex

Table 2.2 Future scenarios

Our staged approach to scenario-based planning is initially focused on defining and monitoring inputs and assumptions to further develop and refine our scenarios, which we then apply to our network to understand possible investment requirements for each scenario. This helps provide context to our long-term plans and investment strategies. We have chosen the Smart Sustainable System scenario as the basis for MainPower's asset management planning.

2.2.3 CLIMATE CHANGE IMPACT

Climate change poses significant challenges for MainPower's electricity distribution network, as it will increase wear and tear on network assets and exposes infrastructure to more frequent and severe damage from extreme weather events.

Increased wear and tear on network assets

Rising temperatures, changing weather patterns, and fluctuating environmental conditions may cause accelerated degradation of equipment.

Higher incidence of severe weather damage

The growing frequency and intensity of storms, floods, and other extreme weather events could lead to more disruptions and damage across the network.

Altered urban landscapes

Areas with increased flood risk and rising sea levels may require infrastructure relocation, redesign, or protective measures to safeguard assets and maintain reliable energy supply.

Modified asset performance

Changing environmental factors, such as higher temperatures, can affect the capacity and performance of certain types of equipment, making it necessary to adapt or upgrade systems to cope with the evolving climate.

Elevated fire risk

Rising air temperatures, coupled with drier conditions, can increase the likelihood of wildfires, threatening network assets and requiring enhanced fire-prevention measures.

As climate change continues to intensify, these factors will put more pressure on MainPower's infrastructure, requiring proactive investments in climate-resilient technologies and adaptive strategies to ensure the long-term sustainability and reliability of our network.

Across North Canterbury, climate change is expected to increase mean wind speeds, predominantly in inland areas where north-westerly winds have historically been more damaging to our network. This can lead to more customer outages, often caused by debris or vegetation impacting our lines. MainPower's network area is likely to experience hotter, windier summers and wetter winters, with intensified rainfall events and elevating flood risk. This change in our environment drives our strong focus on resilience and preparing our network for this future environment.

2.2.4 NETWORK RESILIENCE ROADMAP

We need to fully understand the vulnerability of our network to extreme weather, a changing climate and potential high-impact low-probability (HILP) events across North Canterbury. Our resilience strategy and roadmap (Table 2.3) will guide us in developing this deeper understanding and allow us to proactively adapt our planning, operations and response plans to minimise the impact of these events and climatic changes on our network.

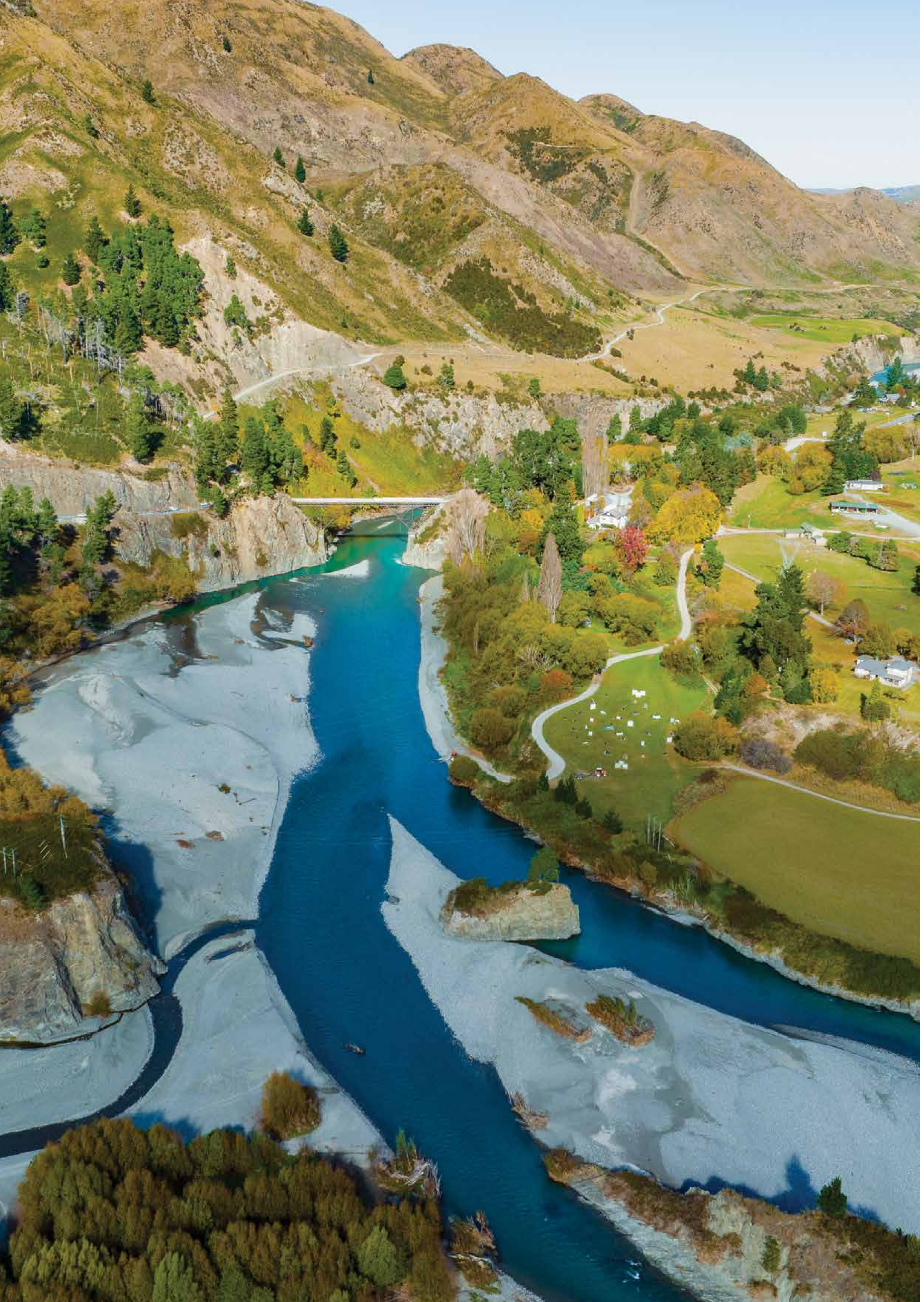
Horizon 1: **Data, modelling and planning**	**Horizon 2:** **Network readiness**	**Horizon 3:** **Monitor and adapt**
Next 3 years	**Years 4 to 10**	**10 years and beyond**
Gaining a deeper understanding of North Canterbury climatology, our changing climate, the impact of major events on our assets and how we can change our operations and plans.	Ensuring our infrastructure is prepared to withstand different types of future events.	Continuing our investment in prioritised resilience initiatives, monitoring our changing environment and making use of more advanced modelling capability.
• Strategic partnerships • Data acquisition and improvement • Network resilience modelling • Network vulnerability analysis • Stakeholder engagement • Engineering standards • Network architecture • Network readiness and response plans • Prioritised resilience investment plan	• Implement, embed and optimise network readiness and response plans • Progressively implement new engineering standards and architecture changes • Coordinate with asset management investment (end-of-life replacement) • Update and refine network resilience and vulnerability analysis • Monitor our changing environment	• Continue to invest in prioritised resilience driven initiatives • Improve resilience modelling with new technology, capability and data • Monitor climate-related trends and adapt our forward plans as needed

Table 2.3 Network resilience roadmap

In FY25 and continuing into FY26 we are developing partnerships with NIWA, Civil Defence/Canterbury Lifelines and a local organisation to gain insight into our region's changing climatology, and model climate risk through a "Resilience Explorer" model that includes risks such as coastal erosion, coastal flooding, rising groundwater, river flooding and wind. Through testing different scenarios we're developing an understanding of the most effective areas to make proactive investments to improve our network resilience.

A more resilient network will limit the initial impact of a major adverse event, enabling faster than otherwise restoration of power for those customers experiencing outages, and it will be adaptable enough to reduce the time to recover from a major event.

MainPower will be able to proactively reinforce network areas that are potentially vulnerable to the impacts of climate change, and to improve network resilience to adverse weather-related events.



2.3 ASSET MANAGEMENT

This AMP covers a 10-year planning period, from 1 April 2025 to 31 March 2035. This is a subset of our internal plan to manage our assets over their entire lifecycle. An individual asset may last for up to a century, and hence require planning with a long horizon.

The purpose of asset management at MainPower is to:

- specify the requirements for establishing, implementing, maintaining and improving MainPower's Asset Management System
- develop a strategic asset management culture within MainPower
- define the purpose and contents of key Asset Management System documentation under the Asset Management Framework
- define the accountabilities and responsibilities for key documents and processes in the Asset Management System
- describe the application of relevant external standards (see Figure 2.3)
- ensure the Asset Management System aligns with MainPower's requirements, other business management systems, and company objectives and policies.

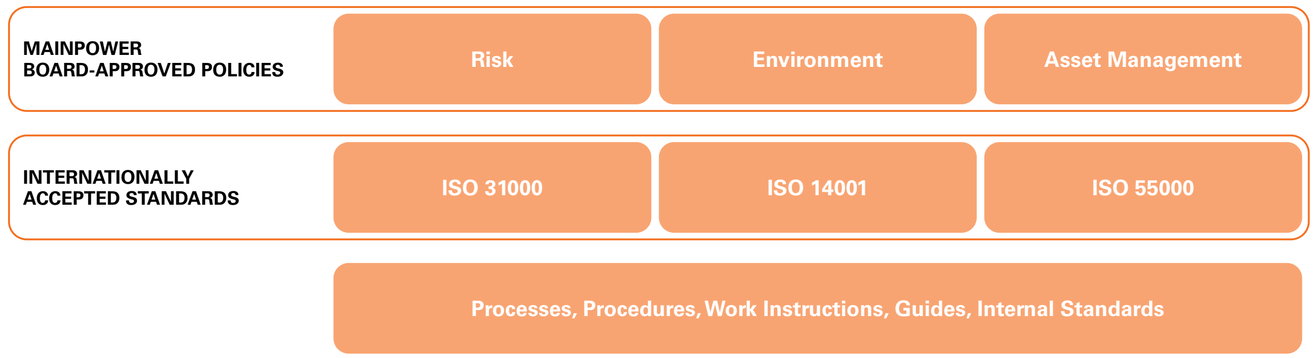


Figure 2.3 Asset Management Standards

2.3.1 ASSET MANAGEMENT POLICY

Our Asset Management Policy supports our corporate vision, values and strategic objectives. It provides a framework for asset management practices to consistently deliver safe, secure, and sustainable electrical distribution network services for current and future generations. The Asset Management Policy describes our commitment to asset management, and our AMP sets out how we implement this policy. We are committed to regular review of our processes and systems to ensure continual improvement. This Policy is supported by the Asset Management Implementation and Audit Guide, which contains detailed deliverables of what is expected for each asset management element.

Underpinning everything we do are MainPower's values. They define who we are and what we strive to achieve through our operations. Figure 2.4 shows how our values impact day-to-day asset management operations.

- Ensure compliance with laws, regulations, standards, and industry codes of practice.
- Ensure consumer engagement and experience effectively informs asset management.
- Provide resources that ensure asset management objectives can be delivered.
- Contribute to a net carbon zero energy future at lowest sustainable cost to consumers.
- Support environmental sustainability.

- Apply quality management systems and strive for continuous improvement and innovation.
- Apply industry best practice, systems, methodologies, and technologies.
- Apply performance monitoring and benchmarking against industry peers.
- Apply a risk-based approach to managing our assets, balancing cost, performance, and risk.
- Ensure network growth delivers consumer requirements while facilitating sustainability.
- Understand and manage the physical and behavioural impacts of climate change on our network.

- Manage competency and training.
- Optimise operational plans and activities and do it right the first time.
- Deliver our AMP.

- Apply effective business systems and processes, roles, and responsibilities.
- Collaborate to drive strategic change within the industry delivering real value to our consumers and market efficiency through transparency.

Figure 2.4 MainPower's Asset Management Policy

2.3.2 ASSET MANAGEMENT FRAMEWORK

Figure 2.5 and Table 2.4 describe the framework that supports asset management at MainPower.

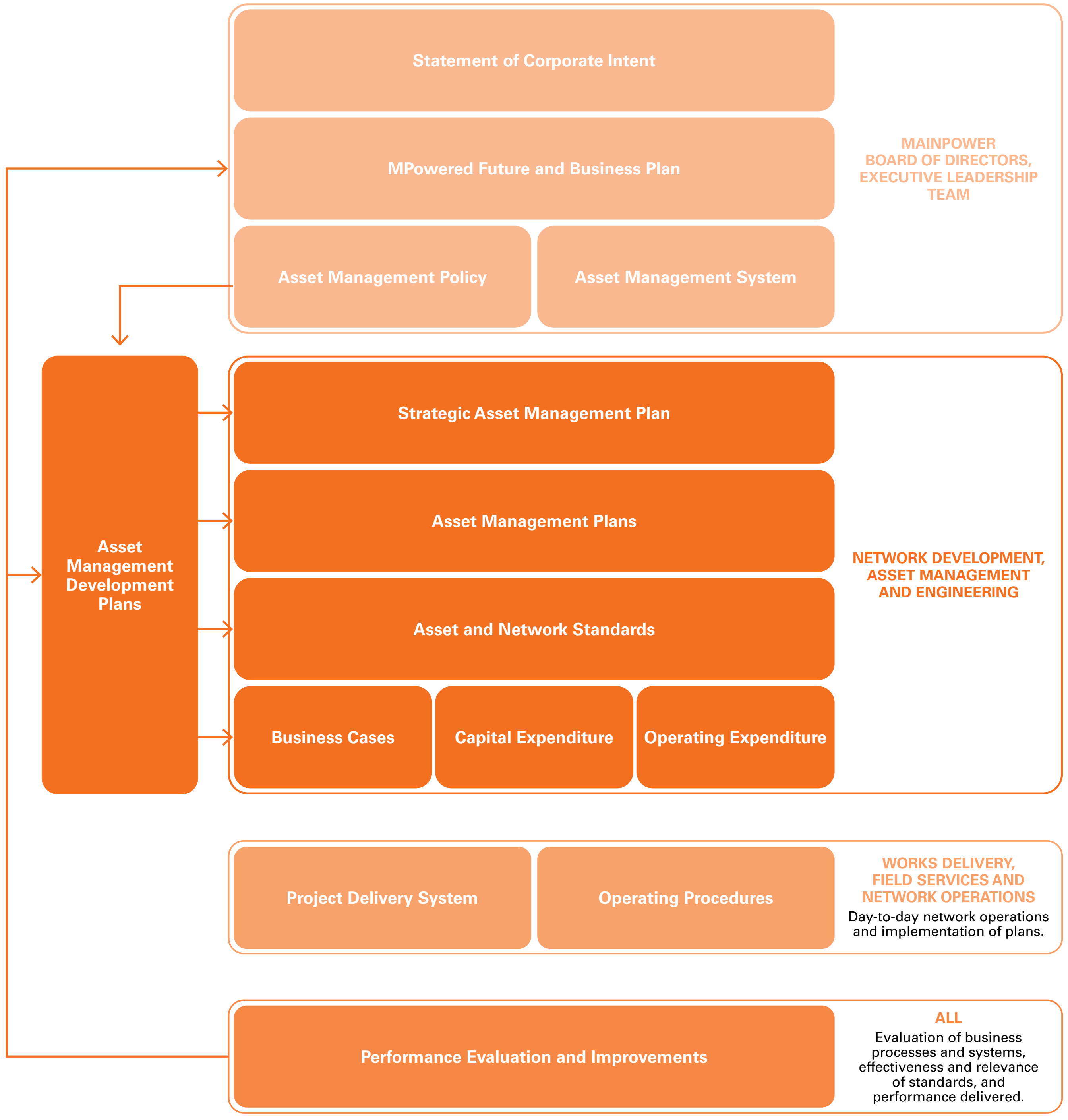


Figure 2.5 Asset Management Framework

Framework components	Description
Statement of Corporate Intent	Presents the strategic direction and operational environment of the organisation
MPowered Future and Business Plan	MPowered Future articulates the strategic intent of the organisation and its business goals. The Business Plan articulates the objectives and how the business is going to achieve the goals.
Asset Management Policy	Defines the key principles, responsibilities and approach to asset management
Asset Management System	System used to manage MainPower's assets
Strategic Asset Management Plan	Optimises value by making appropriate trade-offs between risk, cost and performance
Asset Management Plans	Detail MainPower's plans for managing its assets to deliver an agreed standard of service
Standards	Documents that detail the quality or achievement of assets
Business Cases	Used in the project-approval process to deliver works detailed in this document through a capital sanction process (this AMP document is not an authorised work programme)
Capital and Operating Plan and Expenditure Reports	Used throughout the year to monitor delivery costs against the original plan
Project Delivery Systems	Used to govern and manage the delivery of projects
Operating Procedures	Used to document the safe operation of plant and equipment
Performance Evaluation	Reviews the performance of the asset management system, including service levels to consumers

Table 2.4 Asset Management Framework components

2.3.3 ASSET LIFECYCLE

MainPower has adopted a lifecycle asset management process structured on a total lifecycle cost of asset ownership. The framework has its foundation in the activities that occur over the lifetime of the physical asset (see Figure 2.6 and Figure 2.7).

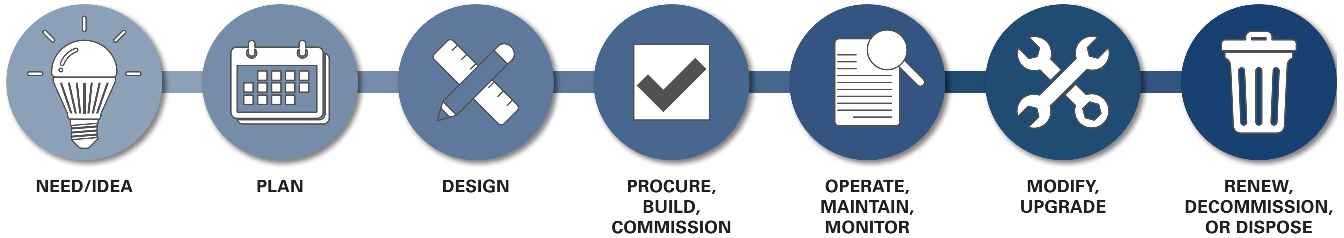


Figure 2.6 Asset lifecycle planning

The steps of the process are as follows.

1. **Develop a need or idea**

   The need or idea typically details a high-level view of the intent or requirement of a given project.

2. **Plan a project**

   The project plan sets out the specific requirements of the project. This includes a definition of the requirements, timelines, resourcing, procurement and risk.

3. **Design phase**

   The design phase includes identifying detailed requirements and how a solution could be delivered, and developing this into a design (or designs), which are then reviewed until a construction-ready design is available.

4. **Procure, build, and commission**

   The construction phase involves all steps to deliver the works and project on time, on budget, and up to quality standards. This starts with procurement and finishes when the asset is handed over post-commissioning.

5. **Operate, maintain, and monitor**

   Operating and maintaining the assets is based on a range of processes, procedures, and standards that govern how MainPower runs its asset fleets in accordance with our management systems.

6. **Modify and upgrade**

   Assets are assessed against service levels. Sometimes this assessment highlights the need to modify or upgrade an asset. Assets could be upgraded because of issues such as changes in legislation and safe working procedures, growing network load, or changing consumer preferences.

7. **Renew, decommission, or dispose**

   All asset lifecycles have an endgame. Assets may be replaced if they are still required, or the needs may have changed. If renewal is preferred, an asset's condition and its level of criticality can inform the decision, which is assessed against the costs and the risk.

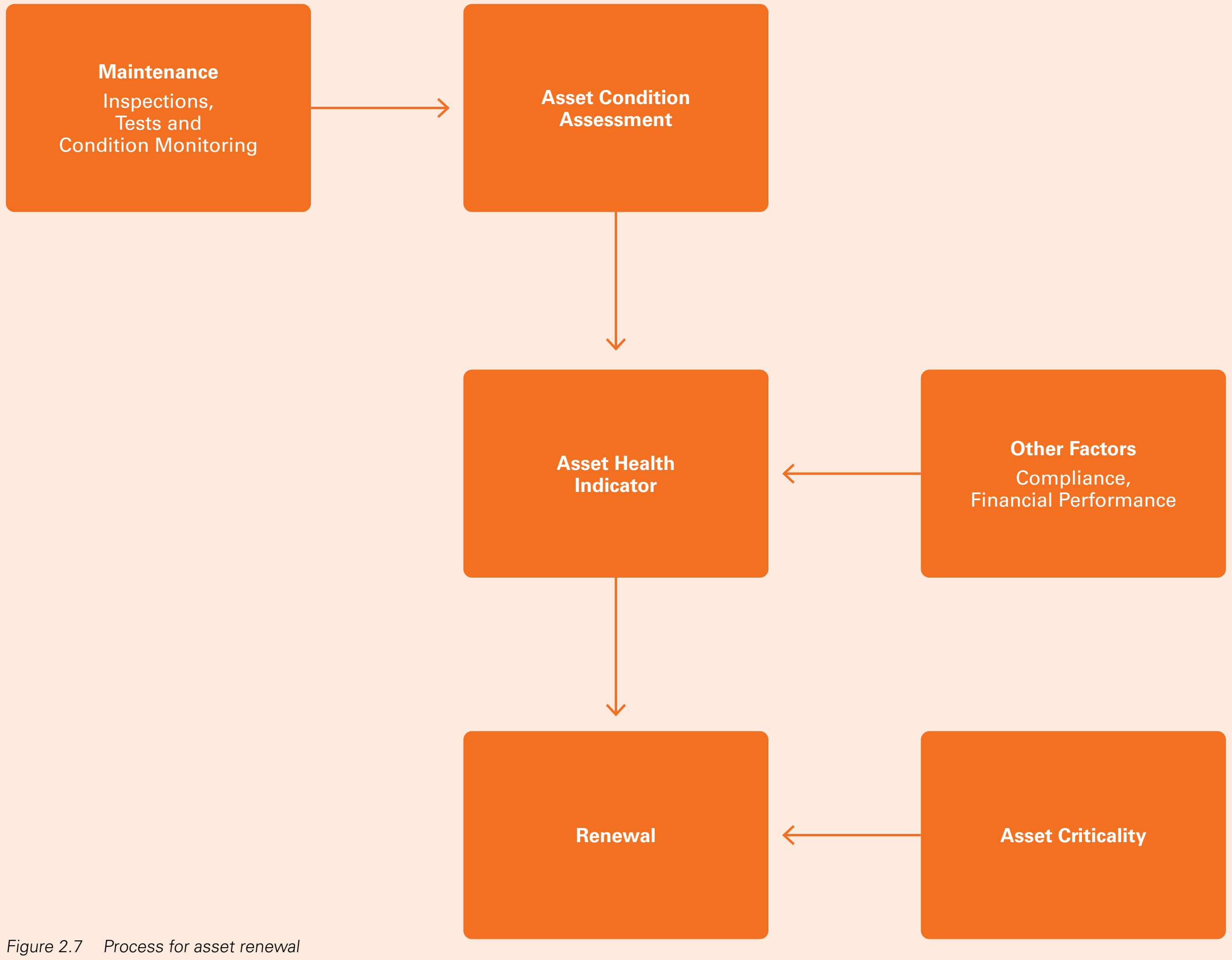


Figure 2.7 Process for asset renewal

2.4 OUR STAKEHOLDERS

Defining and understanding the needs and desires of our stakeholders allows us to structure our strategic objectives and define service levels in a way that is meaningful and relevant. Figure 2.8 shows our stakeholder groups.

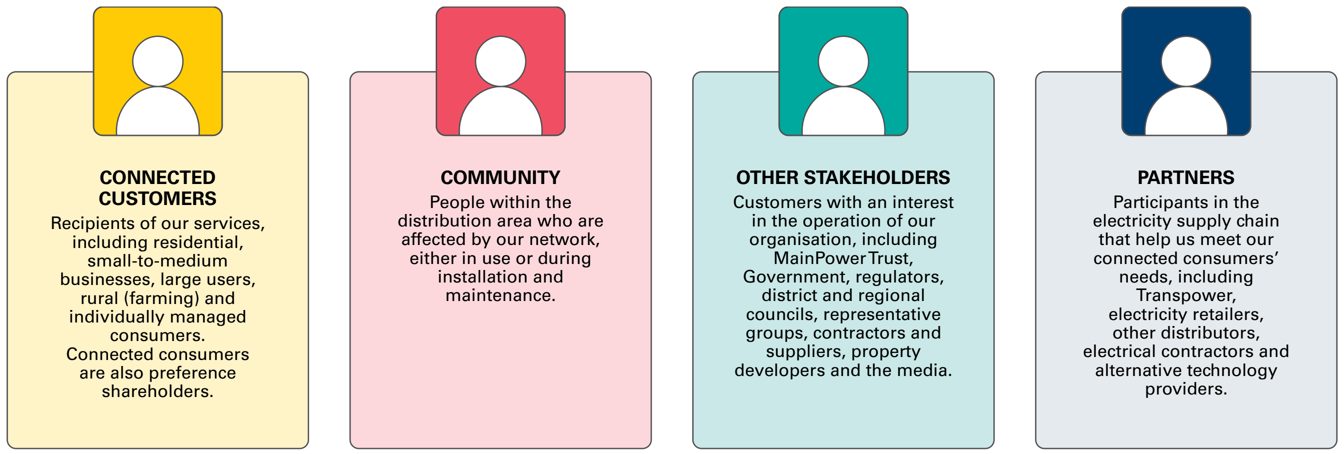


Figure 2.8 MainPower's stakeholder groups

2.4.1 MAINPOWER'S CONSUMERS AND CUSTOMERS

Primarily, the link between MainPower's consumers and our customers is through our Use of System Agreement and Connection Agreement. Under Part 12A of the Electricity Industry Participation Code, the Use of System Agreement with our retailer customers is based on conveyance. MainPower's consumers are also our customers for the provision of lines services, and this relationship is governed by our Connection Agreement. For the purposes of this AMP, MainPower also refers to our customers as "consumers".

2.4.2 STAKEHOLDER ENGAGEMENT

We identify the expectations and requirements of our stakeholders through a wide range of engagement activities, including consultation, correspondence and online feedback via our website. Our other methods of identification are summarised in Table 2.5.

Stakeholder	How we identify the expectations and requirements of stakeholders
All stakeholders	• Consultation and correspondence
Connected consumers	• Consumer discussion groups • Consumer research (quantitative and qualitative methods) • Consumer feedback/interactions • Events (including the Annual Meeting) • Informal contact/discussions • Public meetings and information sessions • Submissions on discussion papers
Community, representative groups	• Consumer feedback/interactions • Forums and working groups • One-on-one meetings • Submissions on discussion papers
MainPower Trust (ordinary shareholders)	• Direct feedback/interaction • Events (including the Annual Meeting) • Operational interface • Other engagement activities
Government	• Disclosure requirements • Submissions on discussion papers
Regulators	• Adherence to corporate policies • Disclosure requirements • Operational interface
District and regional councils	• Disclosure requirements
Contractors and suppliers	• Customer feedback/interactions • One-on-one meetings
Media	• Media monitoring and editorial opportunities • Public meetings and information sessions • Sponsorship involvement
Transpower	• Operational interface • Submissions on discussion papers
Electricity retailers	• Customer feedback/interactions • Industry collaboration • Informal contact/discussions • One-on-one meetings
Electricity industry	• Forums and working groups • Informal contact/discussions • One-on-one meetings • Open days • Participation in industry (including membership) • Public meetings and information sessions • Submissions on discussion papers

Table 2.5 How we identify the expectations and requirements of our stakeholders

2.4.3 SUMMARISING THE INTERESTS OF OUR STAKEHOLDERS

The expectations of our stakeholders are summarised in Table 2.6.

Stakeholder	Expectations
Connected consumers	• Accessibility – easy to contact provider when necessary • Consistency of service delivery (including response time) • Continuity of supply – keeping the power on • Future innovation • Health, safety and the environment • Price – keeping costs down • Quality – keeping flickering or dimming lights to a minimum • Restoration of supply – reducing the length of time that the power is off • Transparent communication (including outage information)
Community, representative groups	• Community focus • Corporate social responsibility • Engagement and consultation • Public safety around electricity
Other stakeholders	
MainPower Trust (ordinary shareholder)	• Delivery of a secure and reliable power supply • Effective and efficient incident response • Future innovation • Health, safety and the environment • Maintaining shareholder value • Prudent risk management • Statutory/regulatory compliance
Government	• Appropriate investment in infrastructure • Delivery of a secure and reliable power supply • Future innovation • Health, safety and the environment • Industry collaboration
Regulators	• Contribution via industry consultations/submissions • Cost-reflective pricing methodology • Delivery of a secure and reliable power supply • Health, safety and the environment • Future innovation • Statutory/regulatory compliance
District and regional councils	• Appropriate investment in infrastructure • Collaboration on shared service upgrades • Contributing towards a vibrant and prosperous region • Contribution to planning via consultations/submissions • Delivery of a secure and reliable power supply • Engagement and consultation • Health, safety and the environment • Future innovation
Contractors and suppliers	• Effective contractor management • Health, safety and the environment
Media	• Effective relationship management • Timely access to information
Partners	
Transpower	• Appropriate investment in infrastructure • Collaboration and effective relationship management • Engagement and consultation • Health, safety and the environment • Transparent communication (including outage information)
Electricity retailers	• Continuity and security of supply • Effective systems and processes • Health, safety and the environment • Transparent communication (including outage information)
Electricity industry	• Collaboration • Future innovation • Health, safety and the environment • Industry participation • Information and knowledge sharing
Bankers and insurers	• Accurate and timely performance information • Confidence in Board and leadership • Good governance • Prudent risk management • Sufficient revenue to maintain asset efficiency and reliability

Table 2.6 What our stakeholders expect from us

We assess the performance of our electricity distribution network against what our consumers are telling us they want.

2.4.4 MANAGING STAKEHOLDER INTERESTS WHEN THEY CONFLICT

Where stakeholder conflicts arise, the priorities for managing the conflicts are ranked as follows.

1. Safety
2. Compliance
3. Service quality
4. Risk management
5. Efficiency and effectiveness

2.4.5 COMMUNICATION AND PARTICIPATION

MainPower communicates its asset management strategy, objectives and outcomes to stakeholders as outlined in Table 2.7.

Reporting from/to	Reporting type
MainPower Trust to consumers and the wider community	• Consultation on the Trust's Letter of Expectation to the MainPower Board • MainPower Trust's Annual Report and audited accounts
MainPower Board to MainPower Trust	• Statement of Corporate Intent • Company Annual Report, including Chair and Chief Executive's statements and audited accounts • Annual information disclosure • Twice-yearly presentation, including financial and operational performance
Chief Executive to MainPower Board	• Chief Executive's statement in the Annual Report, including narrative of the year's highlights • Monthly MainPower Board report, including progress on capital and maintenance programme • Monthly update on network performance and major incidents
Chief Assets and Operations Officer to Chief Executive and MainPower Board	• Annual report on budget and major projects • Monthly report, including year-to-date performance and progress against budget • Individual reports on major projects • Daily updates on areas of concern, including health and safety
Managers	• Weekly direct reporting from team meetings • One-on-one discussion with direct managers • Daily updates during briefing meetings, including health and safety updates • Monthly management accounting reports
Field Services Supervisors	• Weekly progress reports • Monthly meetings on progress in relation to budget
External contractor to General Manager Field Services	• Weekly progress reports • Monthly meetings on progress

Table 2.7 Reporting on asset management

2.5 ACCOUNTABILITIES AND RESPONSIBILITIES

Our electricity distribution network is managed and operated from our Rangiora office at 172 Fernside Road. Our ownership, governance and management structure is outlined in Figure 2.9.

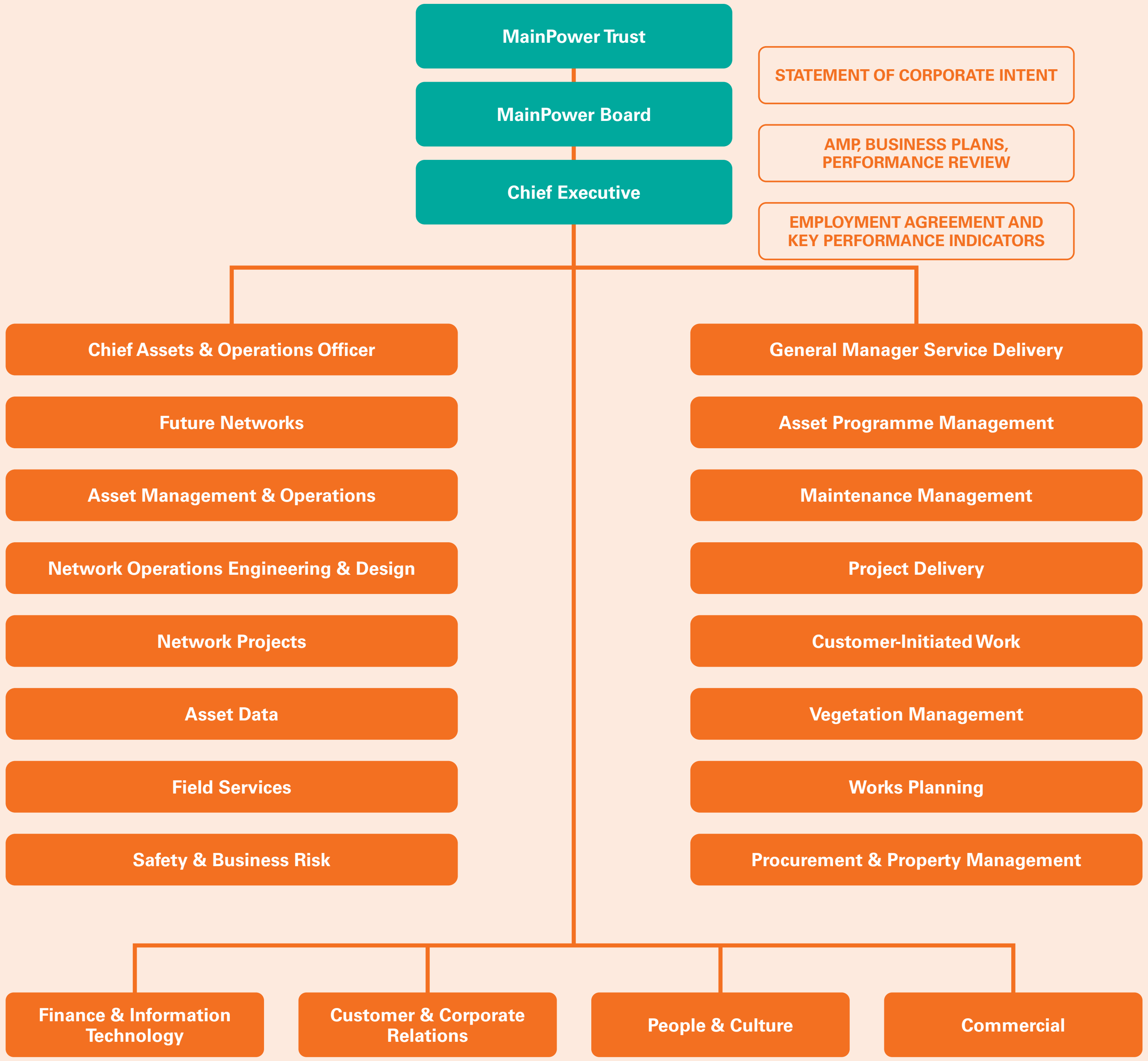


Figure 2.9 Organisational management structure

2.5.1 OWNERSHIP

We are 100% shareholder owned by the MainPower Trust, which holds shares in the company on behalf of preference shareholders. The Trust appoints the MainPower Board of Directors and agrees the Statement of Corporate Intent. They also provide input, on behalf of their beneficiaries, on matters of relevance to asset management planning, such as price, quality and performance.

The Trust also requires MainPower to measure and compare its performance against a selected sample of other electricity distribution businesses (EDBs) in terms of profits, price, expenditure and electricity distribution network reliability.

2.5.2 GOVERNANCE AND EXECUTIVE LEADERSHIP

2.5.2.1 ROLE OF THE BOARD

The Board is responsible for the overall corporate governance of MainPower. The Board guides and monitors the business and affairs of MainPower on behalf of both the ordinary shareholders, the MainPower Trust, to whom it is primarily accountable, and the preference shareholders of the company (i.e. the qualifying customers in the region).

The Board's primary objective is to satisfy the shareholders' wish of enhancing shareholder value through a commitment to customer service and regional prosperity.

Customer service is measured in terms of both financial return and MainPower's ability to deliver excellence in electricity distribution system security and reliability, responsiveness to customers, quality and price competitiveness.

Regional prosperity is measured in terms of MainPower's role in leading and/or supporting regional initiatives for economic development.

The Board aims to ensure that MainPower is a good employer and corporate citizen.

2.5.2.2 THE ASSET MANAGEMENT PLAN

The AMP serves to communicate to the Board the business' approach to asset management. Corporate objectives, expenditure, and electricity distribution network and asset management performance are reported to the Board monthly.

2.5.2.3 STRATEGIC ASSET MANAGEMENT STEERING GROUP

MainPower has a Strategic Asset Management steering group to oversee the strategic direction of asset management and enhance the link between the Board and the asset management function at MainPower.

2.5.3 FIELD SERVICES

All field services are managed both internally and externally. The work programme is assessed and where resourcing gaps are identified or where MainPower does not have the in-house capability, the works are outsourced. Typically, outsourcing is achieved via a Request for Proposal process. Costs are used to benchmark internal costs. The primary objective is to deliver the work programme detailed within the AMP while ensuring that MainPower benchmarks its service delivery against the market in terms of price and quality.

2.6 OVERALL AMP ASSUMPTIONS

2.6.1 SIGNIFICANT ASSUMPTIONS MADE

The following assumptions have been made in the preparation of this AMP.

Business drivers

- Regulatory and legislative requirements will change over the period of the AMP and will have a significant impact on electricity distribution businesses. New compliance and reporting requirements are being introduced, and regulatory reviews are considering the future role of electricity distribution networks in the electricity market. Regulatory projects that will impact MainPower during the planning period include, but are not limited to:
  - amendments to the information disclosure requirements
  - review of the input methodologies
  - the Commerce Commission's consideration of electricity distributors' role in emerging contestable services
  - New Zealand's National Energy Strategy and Emission Reduction Plan.

Climate change

- During the planning period, our electricity distribution network will be exposed to increasing climatic variation that is consistent with our experience in recent years, and includes increased annual temperature, decreased average annual rainfall, and increased likelihood of significant rain and wind events.

Asset lifecycle management

- During the planning period, no significant asset purchases/divestments will occur.
- Historical asset renewal rates remain constant for fleets not managed by a Condition-Based Risk Management (CBRM) or Asset Health Indicator (AHI) model.

Growth

- Seasonal load profiles will remain consistent with recent historical trends.
- EV-charging loads will impact electricity distribution network constraints within the planning period.
- Customer connections will continue in line with population growth.
- Major industrial plants will maintain similar load and demand characteristics over the next five years.
- Regional development, investment, and growth will continue at approximately the same rate.

Network development

- Transpower will continue to provide sufficient capacity to meet MainPower's requirements at the existing GXPs and will undertake additional investment required to meet future demand, as specified in the development plan.
- Small grid-connected distributed generation (DG) will increase throughout the planning period, impacting financial growth but not causing significant electricity distribution network constraints.
- Large-scale solar/wind connections are likely to occur during the planning period.

Supply chain

- Access to services, goods, and a recruitable workforce remains the same.
- All financial budgets when compared with actual project costs will vary due to uncertainty in the supply chain, exchange rate fluctuations and inflation.

2.6.2 SOURCES OF INFORMATION

The principal sources of information relevant to this AMP are:

- MainPower's strategic planning documents, including the Statement of Corporate Intent and the Annual Business Plan and Budget
- MainPower's Asset Management Policy
- MainPower's Business Continuity Plan
- ongoing consumer surveys
- maximum electricity demand at each GXP
- regional population data and forecasts sourced from Stats NZ and the Waimakariri, Hurunui and Kaikōura district councils
- interaction with consumers and the community in relation to possible future developments within the electricity distribution network region.

2.6.3 FORECASTING CERTAINTY

MainPower considers how contextual factors may lead to material differences in actual outcomes versus planned outcomes. As the AMP is updated annually, any differences would likely exhibit as a linear change (i.e. not a step change) and would be anticipated in advance through monitoring trends.

Changes in demand can affect the timing of future development plans. Growth that is higher than forecast may drive the need to either bring forward investment in capacity and security or provide opportunities to deploy tactical solutions such as flexibility services. Growth that is lower than expected can sometimes allow development plans to be re-prioritised. Changes in operational factors may require us to reprioritise or reallocate our planned operating expenditure in the short term and increase or decrease operating expenditure or renewals allowances in the medium term. Uncertainties within our demand, service level and operational plan assumptions are identified in Table 2.8.

	Uncertainty	Drivers
Electricity demand	The rate of growth in demand could significantly accelerate or decelerate within the planning period. Land-zoning changes may be implemented within the region.	• Economic conditions • Government policies • Local council plans
	Load patterns could change within each region, resulting in a movement from summer to winter peaks or vice versa. Dry/wet years could affect irrigation demand.	• Abnormal weather • Changes in climate • Technology adoption
	Significant new loads may require supply increases.	• Economic conditions • Government policies • Decarbonisation • Consumer behaviour
	Large existing loads may decline or cease their demand.	• Economic conditions • Government policies
	Significant generation connections may be commissioned.	• Economic conditions • Government policies • Decarbonisation
Service levels	Consumers could change their requirements for reliability and/or their willingness to pay for higher/lower levels of service.	• Consumer behaviour and expectations • Economic conditions • Major weather events
Operational plans	The electricity distribution network could experience major natural disasters such as earthquake, flood, tsunami or extreme storm. Significant storm events could divert resources from scheduled maintenance.	• Weather and major natural disasters
	Significant equipment failure could require significant repair or replacement expenditure. Improvements in lifecycle asset management could generate replacement or maintenance requirements that significantly differ from those currently forecast.	• Asset management
	Regulatory requirements could change, requiring MainPower to achieve different service standards, health and safety standards, or design or security standards.	• Government policies and regulations

Table 2.8 Forecasting uncertainty

2.6.4 ESCALATION INDEX

Our input prices are subject to a range of cost pressures, including those that apply to skilled and unskilled labour, material components (e.g. copper, aluminium, steel), New Zealand dollar exchange rates, and other inputs such as fuel. We have applied the Westpac Economics Forecast Summary Spreadsheet values for the purpose of converting our constant price forecasts to nominal terms, as shown in Table 2.9.

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Index	1.00	1.02	1.04	1.06	1.09	1.11	1.14	1.17	1.20	1.23

Table 2.9 Escalation index based on Westpac Economics Forecast Summary Spreadsheet 25 October 2024

2.7 SYSTEMS AND INFORMATION MANAGEMENT

The core of all MainPower's asset management is our TechnologyOne enterprise resource planning (ERP) system and our Smallworld geographic information system (GIS). These tools are designed to support project and programme delivery, financial reporting, asset management, and human resources management.

2.7.1 ASSET LIFECYCLE MANAGEMENT – MAINTENANCE AND REPLACEMENT

Preventative maintenance programmes are detailed in MainPower's Asset Maintenance Standards. These are developed for all MainPower asset fleets. The Asset Maintenance Standards are continually reviewed, based on the life and performance analysis of the asset fleets. The backbone of the analysis is asset data. The data (inspection, condition and defects) is collected when carrying out maintenance activities and informs asset health and replacement strategies (see Figure 2.10).

The asset data is collected and stored in several locations, such as the ERP, GIS and data warehouse systems. This currently presents a risk to the organisation in terms of the integrity of the data and the ability to make good asset management decisions. The aim is to develop a single source of the truth for all asset data within the ERP system, including the implementation of strategic asset management. Currently, renewals are informed primarily by defects and age. The future includes implementing a targeted, scheduled replacement programme informed by asset condition, criticality and risk.

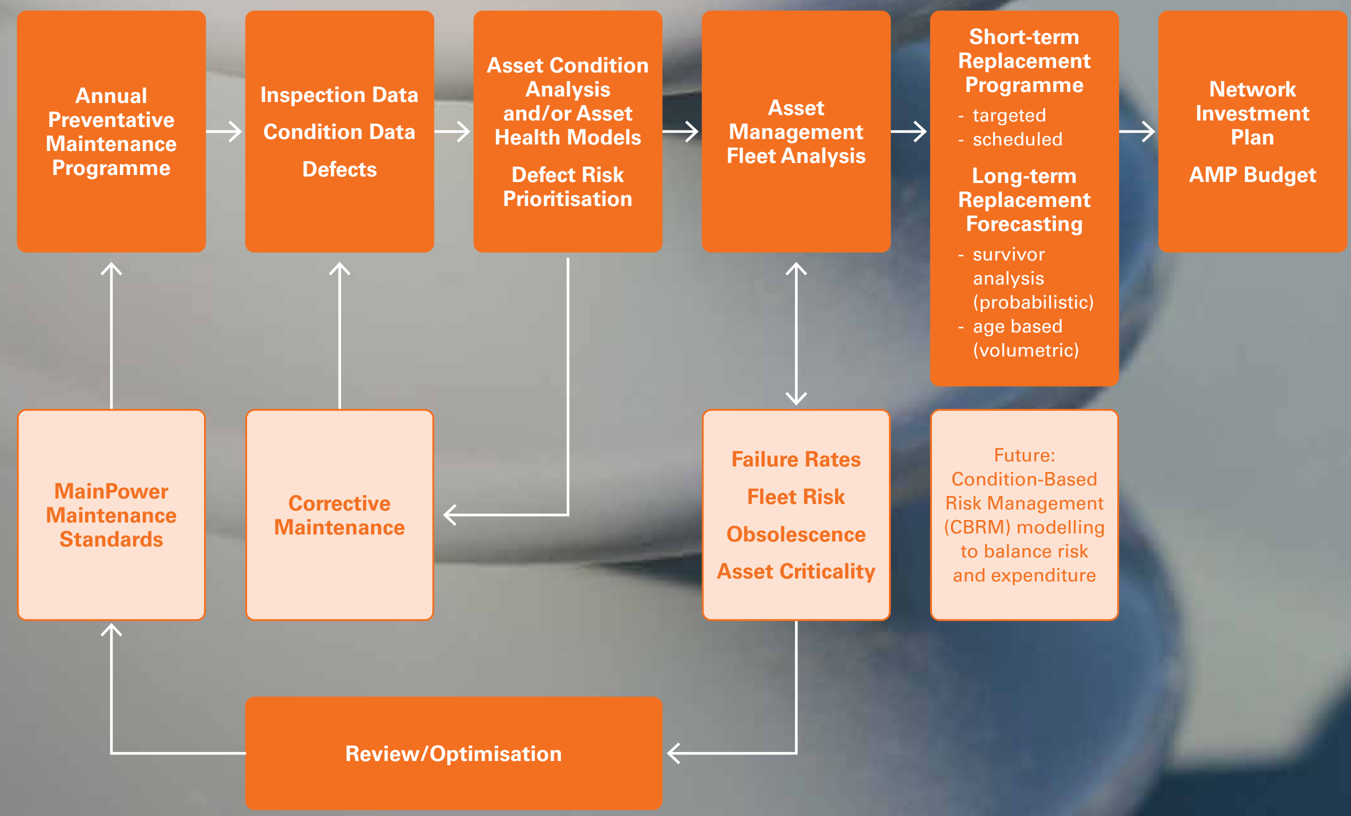


Figure 2.10 Asset lifecycle management

2.7.2 LIMITATION OF ASSET DATA AND IMPROVEMENTS

MainPower holds good information on our assets. The focus in the future is to centralise asset data into a single source of information: TechnologyOne Enterprise Asset Management. A project to achieve this is underway and will provide the foundation for the automated logging of maintenance and condition assessment of all maintenance activities. All maintenance activities allow for asset data to be updated through inspections or routine maintenance.

MainPower has completed a review of our asset data, including consistency of data across multiple systems and the ability of data to support future strategic asset management. While the data currently supports MainPower's AMP and work programme, we aim to improve the quality and consistency of our data.

MainPower also has a specific workstream to improve data governance, ownership, and management across our organisation.

2.7.3 ELECTRICITY DISTRIBUTION NETWORK PLANNING

MainPower's network planning process has been developed to meet our Security of Supply, Quality of Supply and Power Quality requirements while adapting to an uncertain future energy landscape. This method uses data about our customers, network topography and energy loads combined with regional datasets and projections to develop regional demand models. This captures locational differences, in which we overlay a range of future scenarios to test how our network will perform and identify potential constraints. Our planning approach allows early identification of emerging customer behaviours and technology adoption trends, which allows us to focus our customer engagement. Once potential constraints are identified, we consider traditional infrastructure solutions (cables, lines, transformers) as well as incorporating innovative, flexible (non-wires) alternatives such as smart load control, solar and battery energy systems and intelligent EV charging. This allows us to prioritise and implement cost-effective solutions and aligns with our overall network strategy. The network planning process is illustrated in Figure 2.11.

2.7.4 MEASURING ELECTRICITY DISTRIBUTION NETWORK PERFORMANCE

MainPower maintains an ISO 9001-certified quality assurance programme and continues to develop, implement and internally audit the programme in accordance with this commitment. Relevant standards for asset management planning include design, purchasing, document and record management, and environmental management. MainPower maintains a document control system under this certification.

The ISO 9001 certification ensures annual review and continual improvement of the documentation systems.

Where asset management design and construction are outsourced, contractors must comply with our asset management processes, controls and documentation systems. All maintenance tasks and asset data collection are maintained within the MainPower computerised maintenance management system (CMMS) against the applicable asset. Costs associated with the maintenance are linked back to the asset via the work order.

MainPower measures network performance by trending information reported in the annual Electricity Distribution Information Disclosure Determination 2012.

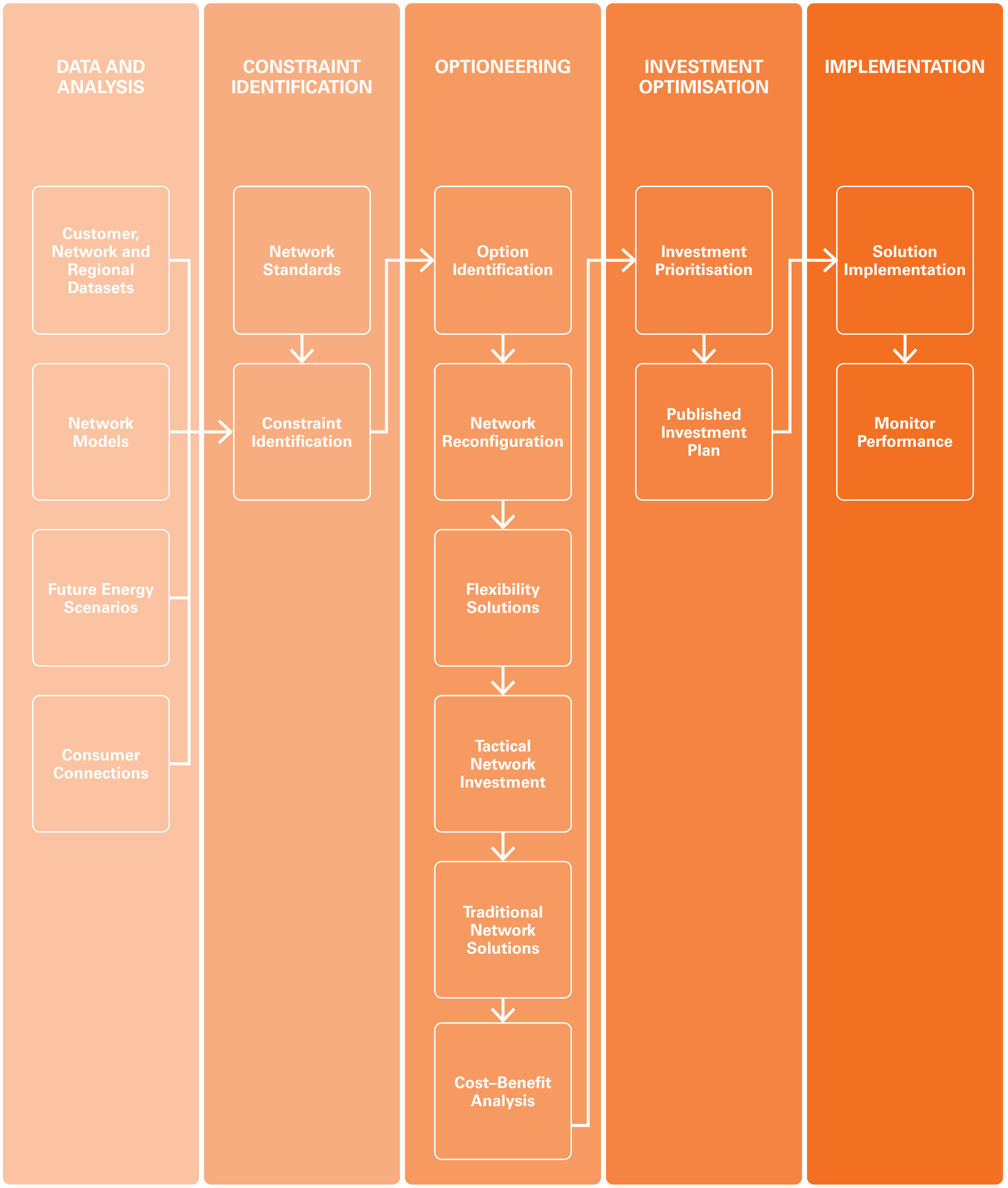


Figure 2.11 Electricity distribution network planning process

3
SERVICE LEVELS AND PERFORMANCE EVALUATION

MainPower's electricity distribution network, business service levels, and performance achieved are an integral part of the decision-making processes throughout the organisation. We are committed to listening to our customers and stakeholders to better understand their needs and to monitor and improve the services we provide.

We use a range of engagement methods to find out what customers expect of MainPower and their vision for the future. We believe we have balanced legislative, regulatory, and stakeholder requirements in our defined service levels. This section outlines how we engage with our customers, what they expect from us, and how this translates through to our service levels.

3.1 CUSTOMER ENGAGEMENT

We provide electricity distribution services to more than 44,000 homes and businesses across the Waimakariri, Hurunui and Kaikōura regions in the South Island of New Zealand. Types of consumers include residential, commercial, large commercial or industrial, irrigators, council pumps, streetlights and individually managed consumers (see Table 3.1).

Understanding customer expectations, monitoring, and improving the service MainPower provides are all vital if we are to establish and maintain trust and goodwill with our customers and stakeholders throughout the region. We do this by actively consulting with our customers via surveys conducted by MainPower and by research agencies. This information is important to our forward planning, as the electricity industry is entering a time of transformation as emerging technologies change the way consumers use and manage energy.

Consumer type	Average number of ICPs	% of ICPs	Units delivered (GWh)	% of units delivered
Residential	37,177	82.0%	309	48.3%
Commercial	5,918	13.2%	130	20.4%
Large commercial or industrial	41	0.9%	56	8.8%
Irrigators	1,462	3.2%	91	14.2%
Council pumps	209	0.5%	14	2.1%
Streetlights	110	0.2%	4	0.6%
Individually managed consumer	1	0.0%	36	5.6%
Total	**44,918**	**100%**	**640**	**100%**

Note: ICPs = installation control points
GWh = gigawatt-hours

Table 3.1 Electricity consumption, by consumer category (FY24)

3.1.1 CUSTOMER ENGAGEMENT PROGRAMME

MainPower undertakes a comprehensive suite of customer engagement initiatives every year to collect feedback and information from our customers across a variety of areas, as detailed in Table 3.2.

MainPower Customer Engagement Programme

Engagement type	Frequency	Numbers	Purpose
Asset Management Plan (AMP) Customer Satisfaction Survey	Ongoing	All customers who have interacted with MainPower's Customer-Initiated Works, Network Services Representative, and Vegetation teams are invited to participate at trigger points during their customer journey.	To gather AMP performance statistics on customers who have engaged with MainPower for customer-initiated work, including new connections, new power supplies or changes to power supplies. Measurements include: • engagement effort – how easy it is to do business with MainPower • staff friendliness – to ensure the engagement is proactive and results oriented • quality of work – to ensure we deliver a standard of work that is aligned with our consumers' expectations • timeliness – to ensure work is delivered in accordance with our consumers' expectations • communication – to ensure we communicate with our consumers proactively • staff reliability – to ensure our staff deliver services to our consumers as agreed • price – to ensure our pricing is fair.
Customer Pulse Survey	Annual	Minimum of 200 phone and 200 online survey completions.	To gather customer perceptions of MainPower. Same focus areas each year covering overall satisfaction, brand awareness, outage communications, community support and effectiveness of safety campaigns.
AMP Customer Engagement Sessions – World-Café Style	Every two years (alternates with AMP Future Networks Survey)	20–24 attendees per session (4–6 per group rotating around four stations). Three sessions held – Waimakariri, Hurunui and Kaikōura.	Receiving qualitative feedback from residential, rural and commercial/business customers in each main region (Waimakariri, Hurunui and Kaikōura). Covering reliability, future technology, resilience and safety. Opportunity to include other topical subjects (e.g. pricing).
AMP Customer Engagement Survey	Every two years (alternates with AMP Future Networks Survey)	Minimum of 1,000 online responses.	Receiving quantitative feedback from residential, rural and commercial/business customers in each main region (Waimakariri, Hurunui and Kaikōura). Covering reliability, future technology, resilience and safety. Opportunity to include other topical subjects (e.g. pricing, environment and community sponsorships).
AMP Future Networks Survey	Every two years (alternates with AMP Customer Engagement Sessions and Survey)	Minimum of 1,000 online responses.	To gather information on topics related to future network planning (e.g. technology adoption). This information is used to help inform the AMP.

Table 3.2 MainPower Customer Engagement Programme

3.2 WHAT CUSTOMERS HAVE TOLD US

According to the feedback from the FY24 surveys, MainPower customers have high satisfaction levels overall.

54%

rated MainPower's performance and services as positive.

86%

rated their electricity as "reliable" or "very reliable".

Satisfaction with most of MainPower's services remained stable in FY25.

Satisfaction with price remained below half (44%) for the second consecutive year.

Recall of outages reached an all-time high in FY24. This reflects the more intensive maintenance programme MainPower had undertaken.

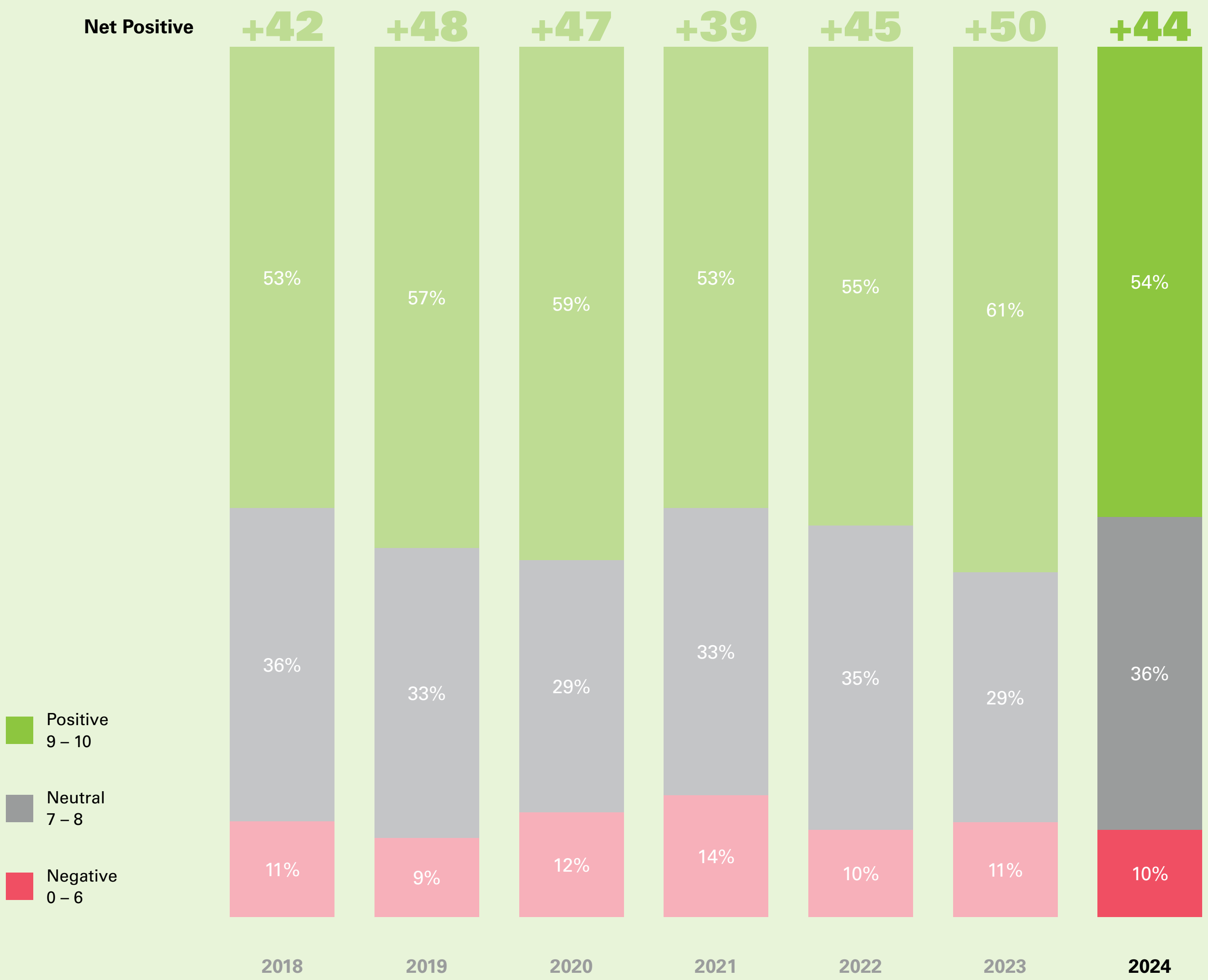
- 64% of respondents could recall at least one outage.
- Outage recall was particularly high among rural residents and customers located in Hurunui.

Notice of planned outages was high (92%). This aligns with MainPower's efforts to improve customer engagement in relation to outages, including when outages are changed or cancelled (acknowledging the retailer is not always able to communicate these changes to their customers). Other research projects conducted by the same research agency have found decreasing satisfaction levels in surveys across all industries. This, along with anecdotal evidence and the results of an environmental scan, suggests that there are levels of fatigue in the nation that may be reflected in satisfaction survey results. The continued stable nature of MainPower's high scores is a sign of success.

3.2.1 CONSUMERS – PERFORMANCE AND SERVICE

Customers remain positive about MainPower's performance and service, as illustrated in Figure 3.1.

MAINPOWER'S PERFORMANCE AND SERVICE



Source: MainPower's Customer Pulse Surveys FY18–FY25

Figure 3.1 MainPower consumers' perceptions of our performance and service

3.2.2 CONSUMERS – RELIABILITY

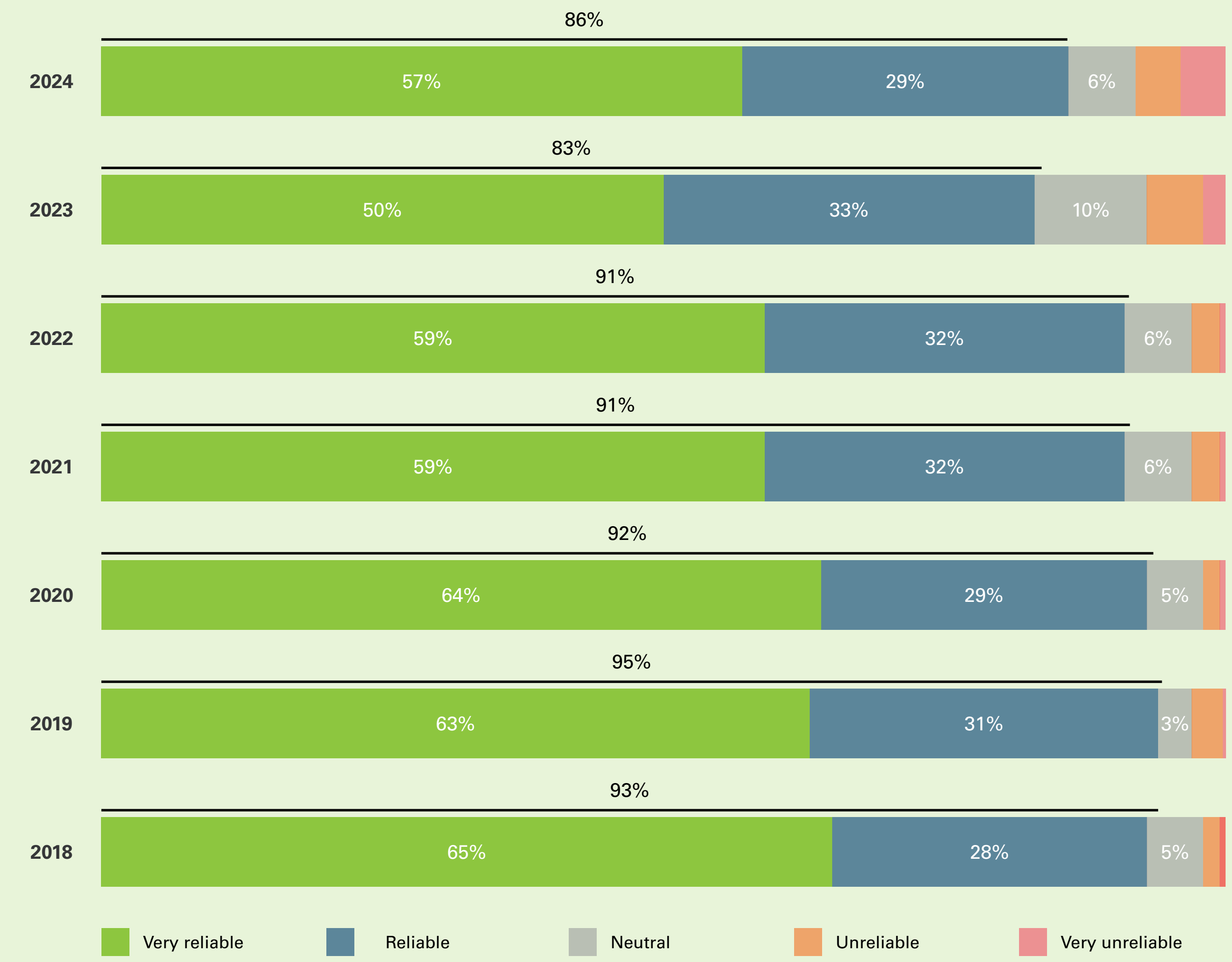
Perceived reliability is on the rise – recovering from the 2023 decline.

It is positive to note the significant increase in customers stating their power supply was 'Very Reliable' in 2024 (57% – a 7% increase from 2023).

Several customer groups were found to have differing reliability perceptions:

- Hurunui residents continue to be less likely to state that their power supply is 'reliable' (76%) compared to residents based in Waimakariri and Kaikōura (88%).
- Recall of three or fewer outages had little to no impact on their perceived reliability (92%), particularly compared to customers who experienced four or more (70%).

PERCEIVED RELIABILITY



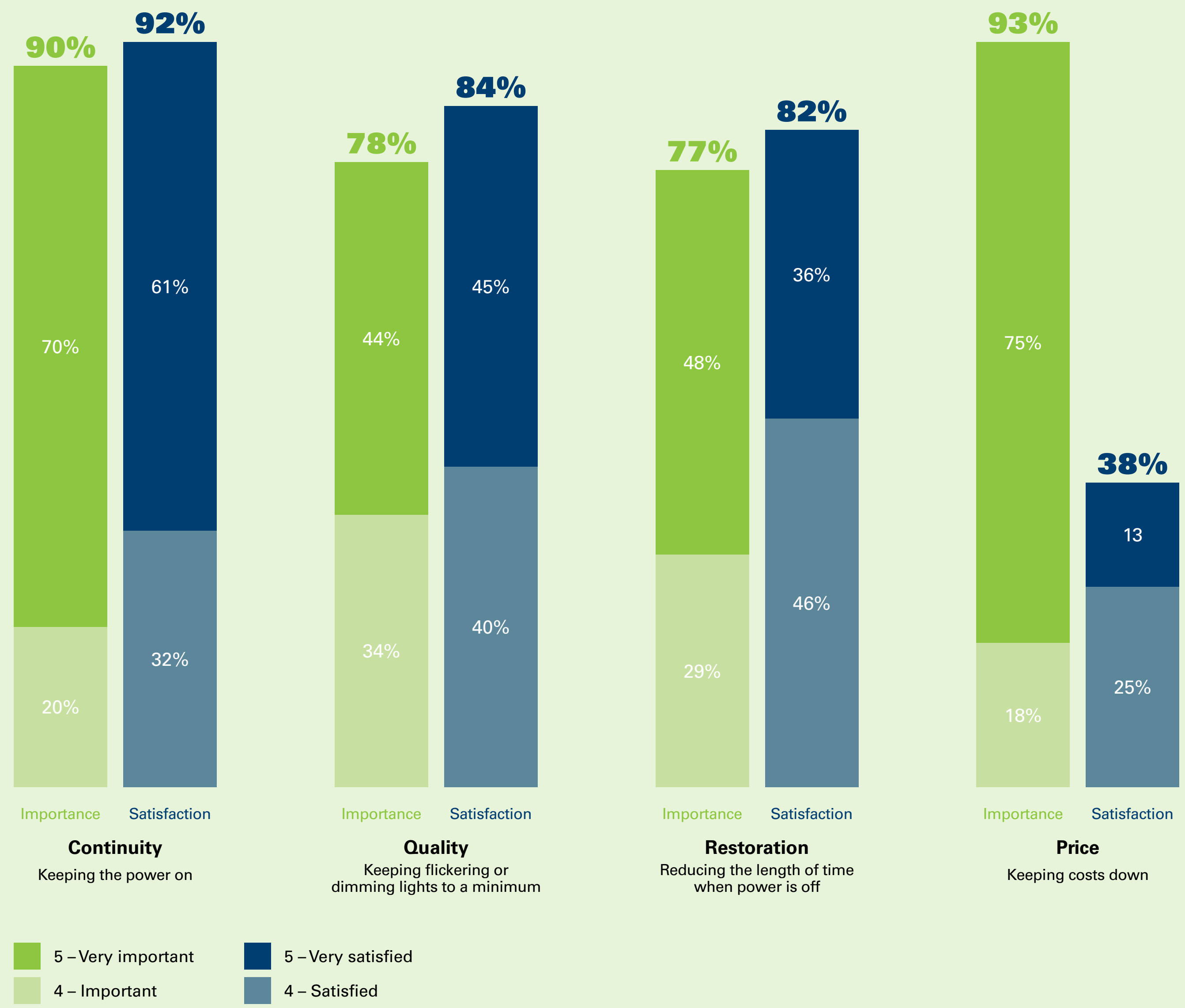
Source: Customer Pulse Surveys FY18–FY25

Figure 3.2 MainPower customers' scores for our reliability

3.2.3 CUSTOMERS – SUPPLY CONTINUITY, QUALITY, RESTORATION AND PRICE

MainPower delivers strongly in all important service areas, except for price. Keeping costs down is perceived as vital, but satisfaction with price was low (see Figure 3.3).

IMPORTANCE VS. SATISFACTION



Source: Customer Pulse Survey FY25

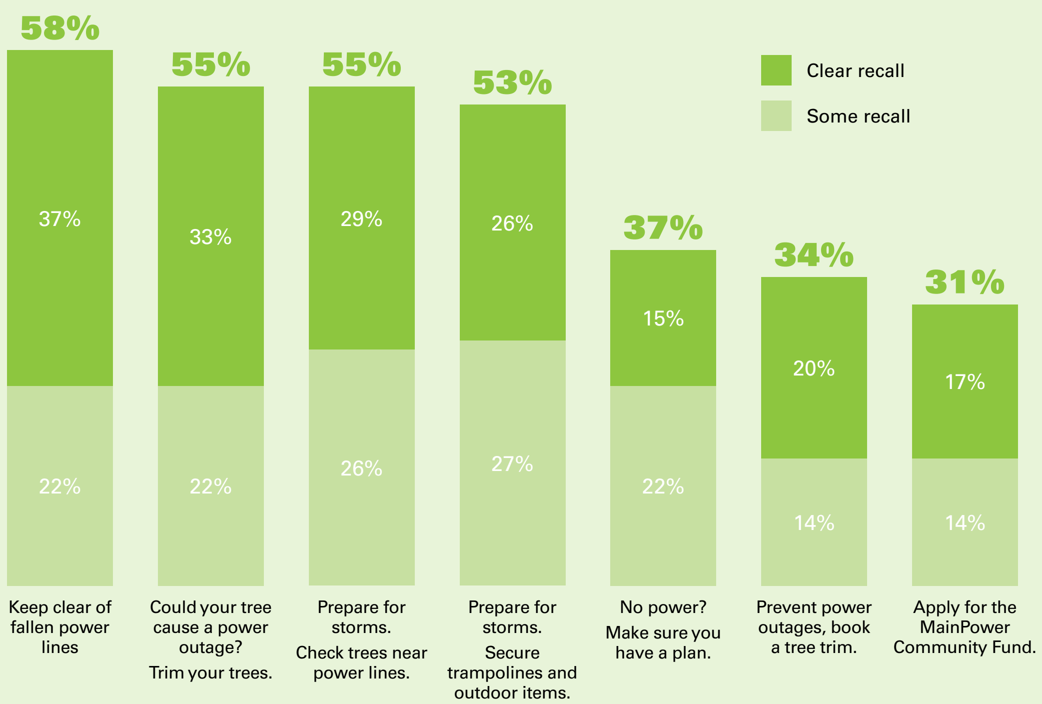
Figure 3.3 MainPower customers' scores regarding importance and satisfaction across service areas

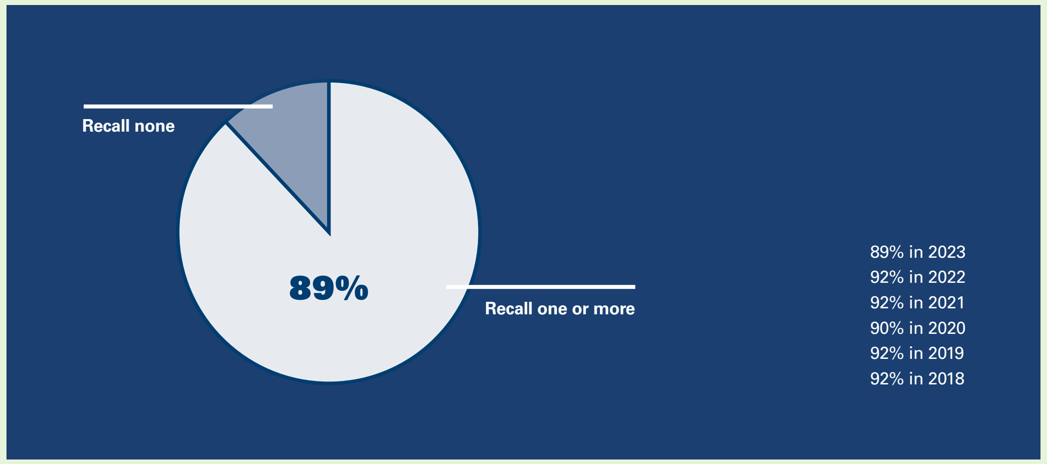
3.2.4 CUSTOMERS – SAFETY MESSAGING RECALL

Prompted recall of safety messages remains very high and is similar to previous years (see Figure 3.4).

Overall recall of safety messaging was consistently high among all districts and customer groups.

MESSAGING RECALL





Source: Customer Pulse Survey FY25

Figure 3.4 MainPower customers' recollection of safety messaging

3.2.5 ASSET MANAGEMENT PLAN CUSTOMER SATISFACTION SURVEY

In 2024, MainPower began surveying customers engaging with our Customer-Initiated Works, Network Services Representative and Vegetation teams using marketing automation. The surveys give us a real-time insight to our customers' perception of the service they have received. It measures their satisfaction with our online tools, staff interactions, timeliness of work, quality of work and the effort required from them to complete the work.

We are currently trialling this survey as a potential replacement for the previously undertaken AMP Service Experience Survey.

We send surveys to our customers at set points during their customer journey with MainPower. Initial feedback from March–September 2024 demonstrates an 85% overall satisfaction rating of interactions with MainPower.

Measurements include:

- Communication – to ensure we communicate with our customers proactively
- Timeliness – to ensure work is delivered in accordance with our consumers' expectations
- Staff friendliness – to ensure the engagement is proactive and results oriented
- Quality of work – to ensure we deliver a standard of work that is aligned with our consumers' expectations
- Website – to ensure the website application process is optimised for the user
- Price – to ensure our pricing is fair
- Engagement effort – how easy it is to do business with MainPower.

Please note, MainPower prefers to use an engagement effort measurement over the Net Promoter Score. Customers do not have a choice as to whether they can change their lines company, so we believe the customer effort question better reflects the satisfaction perceptions of the customer compared to the standard Net Promoter Score question.

Customer satisfaction is measured on a scale of 0–10 (0 being very dissatisfied and 10 being very satisfied; for engagement effort, 0 is very difficult and 10 is very easy to get the work completed or enquiry resolved).

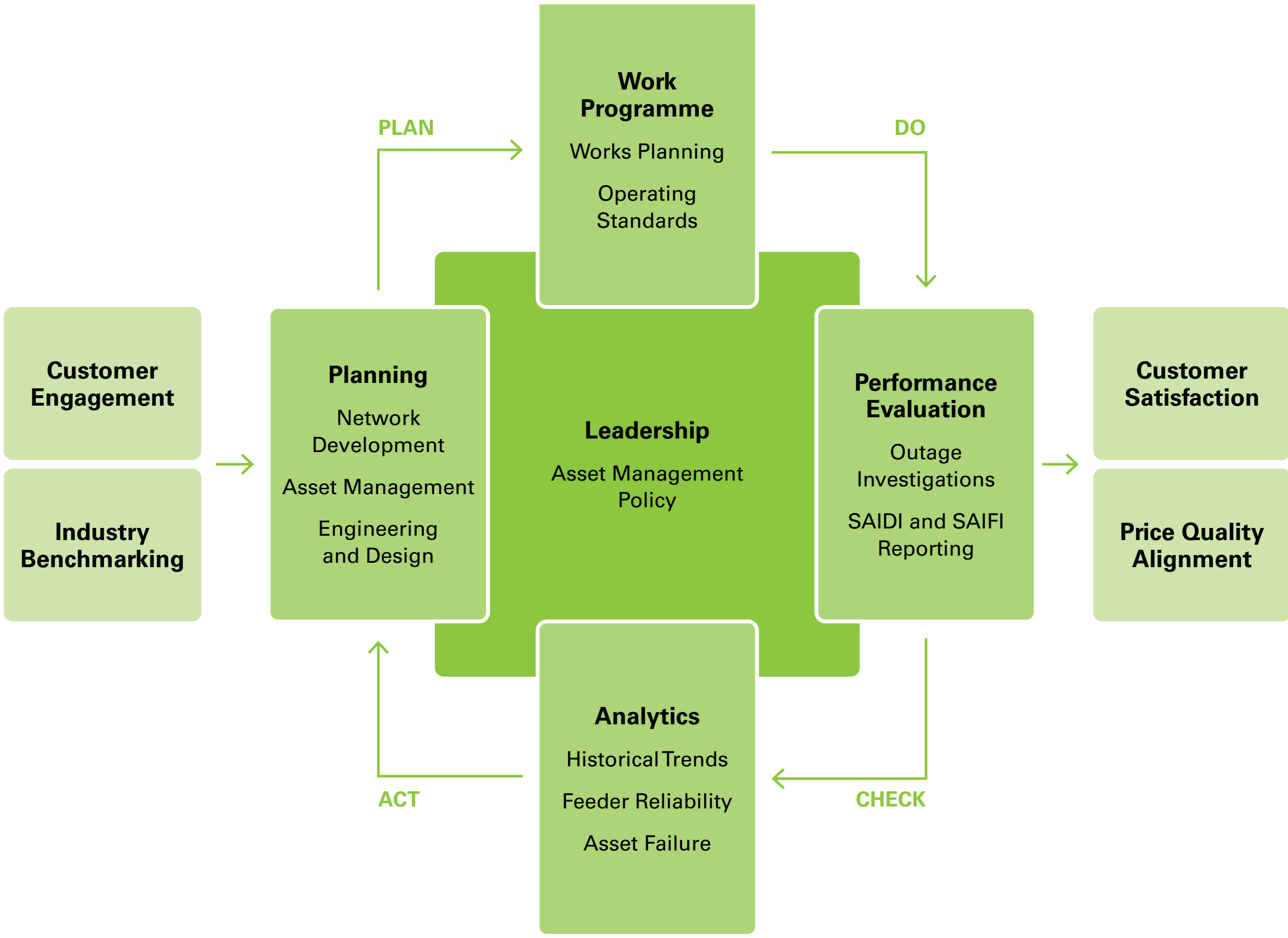
The results in Table 3.3 were collected between 1 October 2024 and 28 February 2025.

	Score	Target
Quotation	2.5	5
Website	5.4	5
Quality	5.3	7
Timeliness	6.4	7
Effort	6.6	7
Communication	6.7	7
Friendliness	7.4	7
Overall satisfaction	**6.6**	**7**

Table 3.3 AMP Customer Satisfaction Survey FY25 results

3.3 MAINTAINING PERFORMANCE INDICATORS

MainPower periodically reviews its performance against its performance indicators in a Plan–Do–Check–Act cycle that is aligned with MainPower's accreditation to ISO 9001, as described in Figure 3.5.



Note: SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Figure 3.5 MainPower's performance indicator continuous improvement process

This continuous improvement process is described in more detail on the following page.

3.3.1 INPUTS

Inputs are based on:

- the customer expectations revealed in the AMP Customer Engagement qualitative and quantitative data (discussed in Section 3.2)
- analysis and industry benchmarking across our peer group (discussed in Section 3.9.7).

3.3.2 PLANNING

Using the above inputs, MainPower's network development and asset management guidelines have been refined to include:

- Security of Supply Standard
- Asset Portfolio Strategies, including Condition-Based Risk Management (CBRM) and Asset Health Indicators (AHIs)
- Project and Works Delivery Planning and Processes
- Network Operating Standards
- Network Architecture Standards
- Network Reliability Strategy.

3.3.3 WORK PROGRAMME

MainPower's asset management guidelines are used to inform a targeted AMP work programme and budgeting/resource planning, including:

- asset replacement/renewals
- reliability and security of supply focused network reinforcement and major capital projects
- a refined and targeted network maintenance programme
- refined network engineering and design practices.

3.3.4 PERFORMANCE MONITORING

Internal data is analysed to monitor historical service levels – including feeder reliability, root cause and common mode failure analysis – and predictive modelling is applied.

Network service-level performance is continuously monitored, with analysis of network outages and monthly reporting of SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) indices to the MainPower Board against year-to-date forecasts, and specific investigations are conducted into the causes of major outages.

3.3.5 ANALYTICS

Continuous improvement principles are employed to feed back the insights from the performance monitoring, data analytics and outage investigations into annual updates of MainPower's electricity distribution network development and asset management documentation. This is combined with other inputs to better understand, inform and refine future service levels.

3.4 CUSTOMER SERVICE PRACTICES – COMPLAINT MANAGEMENT

3.4.1 PLANNING AND MANAGING CUSTOMER COMPLAINT RESOLUTION

Our complaints process is documented for all team members to access. All customer interactions are recorded and managed in MACK, MainPower's customer relationship management (CRM) system.

As well as MainPower employees interacting with customers, MainPower also uses a third-party call centre service called CallCare to answer customer telephone enquiries.

The complaints process aims to provide guidance on how to process complaints submitted to the business and provide a solution to the customers that is fair and reasonable.

The following information is provided to staff via a Promapp complaint process guide.

3.4.1.1 MANAGING CUSTOMER COMPLAINTS

Complaints can be received over the phone, by email, via the MainPower website, in a letter, or in person (e.g. verbally reported to field services while at a job site or if a customer visits the MainPower office).

The goal is for a complaint to be addressed or resolved at the initial point of contact, where possible. Following a resolution, a summary of the interaction is entered into MACK. If the complaint is not resolved during initial contact with the customer, it is reported to the business via MACK and managed via our complaint process.

A complaint investigation is managed by MainPower's Corporate and Customer Relations team. During the investigation key information about the customer and complaint is gathered, including any supporting documentation or images.

Customer complaints must be acknowledged, in writing, to the customer within two working days. The acknowledgement must also include a copy of the complaint resolution process and information about Utilities Disputes – an independent service that assists with complaint resolution.

Following the acknowledgement, MainPower aims to resolve the complaint within five working days. However, if further time is needed to complete a thorough investigation, the process does allow for up to 20 working days with an additional extension of 20 working days by mutual agreement with the customer. Following the investigation, a proposed resolution is approved internally prior to being presented to the customer. If the resolution is accepted by the customer, once the resolution has been processed, the complaint is closed. If the resolution is not accepted, then the complaint is placed in "deadlock" and the customer is advised that they can submit a dispute to Utilities Disputes, if they would like to continue finding a resolution.

If Utilities Disputes accepts the complaint, they will manage MainPower and the customer towards an agreeable resolution.

3.5 PRACTICES FOR NEW CONNECTIONS AND ALTERING EXISTING CONNECTIONS

3.5.1 APPROACH TO PLANNING AND MANAGEMENT OF NEW CONNECTIONS

3.5.1.1 NEW CONNECTIONS

New connections apply to situations where an electricity distribution network connection is already available at the property boundary, in the location where the connection will take place, with adequate capacity. If no power connection is available at the boundary, a separate process must be followed to extend the distribution network and install a new power supply (distribution network electrical infrastructure build).

MainPower's website allows customers to access a range of information about MainPower's new connection process, including making online applications for new connections (offtake and injection connections). All new connection applications must be made online through our website. New connection applications are normally completed by electricians and/or distributed generation (DG) installers who are experienced with the process, on behalf of the customer. MainPower's team of Network Services Representatives are available during business hours to assist customers and electricians with such applications in person, by phone, or by email.

Offtake-only connections are processed quickly using an integration between the website and our internal systems. The application only needs to be reviewed and approved, at which point the system generates a connection advice sheet that instructs the customer/electrician how to connect to the network. Here we provide specific advice intended to be read by the electrician, to avoid some common problems like connecting to the wrong number of phases, connecting to the wrong supply point, or failing to run cabling close enough to the supply point.

MainPower then updates the registry with the trading information for the installation control point (ICP) to be livened and advises the customer's chosen energy retailer. Once the energy retailer accepts the customer/new connection and advises the metering equipment provider (MEP), the livening agent undertakes the final connection, which allows the power to flow. Once MainPower has received the necessary information back from the livening agent to confirm the ICP is live, MainPower then updates the registry to show the ICP has been livened by the network.

There are many parties involved, which complicates the process and can lead to delays if one party fails to complete all their responsibilities in a timely way. This also means the overall timeframe for new connections can vary, although each party works quickly. Early new connection applications are important to ensure consumers are connected within a reasonable time. MainPower works with metering providers and livening agents to ensure this happens, and MainPower has contracted with all the willing livening agents in our area.

Injection connections, also known as DG connections, are more complex, and the processing time varies with the size and compliance considerations of the application. They can only be installed on ICPs that have already completed the above process as a "permanent" connection. Again, all applications must be made online, and assistance is available from our Network Services Representatives. MainPower processes the online DG connection application and confirms it meets the requirements of Part 6 of the Electricity Industry Participation Code. Conforming applications then receive a DG Approval Notice, which is sent to the customer and installer. The installer is subsequently required to supply MainPower with the necessary compliance paperwork and must send the energy retailer a copy of our notice, so they may upgrade the installation's metering to import/export metering at the correct point in the process. One common issue is DG being connected without following the necessary approval processes with the network. MainPower undertakes weekly and monthly checks of registry and billing information to identify those ICPs with DG installed but without a DG Approval Notice issued.

In these situations, we seek retrospective compliance paperwork from the consumer/installer. The one group of DG connections we cannot check for is those where DG is physically installed but no application has been made either to MainPower as distributor or the consumer's retailer.

3.5.1.2 ALTERATIONS TO EXISTING CONNECTIONS

Alterations to existing connections generally follow the same practices as outlined above. Typical alterations to a connection include going from a temporary supply to a permanent supply, upgrading a supply to include DG, or decommissioning an ICP, which follows a different process to all the others explained above.

Decommissioning (permanently disconnecting an ICP from the electrical network) is only completed on request from the energy retailer. Upon request, MainPower dispatches an employee to site, removes the physical electrical connections to the installation, makes those connections safe, and removes the electricity meter. The electricity meter is returned to the MEP. MainPower will then update the registry to show the ICP has been decommissioned, advising the retailer.

3.5.2 MINIMISING COST TO THE CONSUMER

MainPower aims to encourage a competitive commercial environment in our geographic region for services related to connection and livening. We have authorised several different livening agents and set few barriers to entry for new parties. We give customers a choice of livening agent when they connect to our network, and a choice of contractors if they require a network extension.

We actively encourage the use of local electricians whenever possible, in preference to MainPower doing work on-property. We allow a wide range of parties to access and work upon our electrical network connection points, without access costs, subject to a range of standardised safety measures.

MainPower charges consumers a relatively low fixed fee for new connections, which covers our immediate costs of connection. This fixed fee is most often met by the property developers when a subdivision is created (residential/commercial/industrial) prior to electricity consumers becoming involved. MainPower avoids charging consumers for modifying a connection or decommissioning a connection.

3.5.3 COMMUNICATING WITH THE CONSUMER ABOUT NEW OR ALTERED CONNECTIONS

MainPower provides information about the steps involved on our website for consumers to view at their discretion. Additionally, we provide a team of Network Services Representatives who are available to assist consumers.

It is our experience that electricians, DG installers, energy retailers, MEPs and livening agents engage directly with us about new connections, rather than the consumer.

3.5.4 COMMONLY ENCOUNTERED DELAYS AND POTENTIAL TIMEFRAMES FOR DIFFERENT CONNECTIONS

Some of the common issues encountered that result in delays to new connections can be summarised as follows.

- Where the distribution network must be extended to the prospective consumer's property boundary, timeframes vary greatly depending on the location, size, and complexity of the new power supply build. In these situations, the subsequent new connection process cannot be started until the network extension process has been completed.
- Consumers may not be familiar with the connection process.
- Many parties are involved with the new connection process, which creates complexity and opportunities for any party to miss a step.
- The applicant may not have full knowledge of the new connection process, nor be aware of the number of industry participants involved in the process (e.g. distributor, retailer, MEP), which may increase the time required to complete a new connection.
- The livening agent and the MEP are not necessarily the same organisation, which can complicate the scheduling of new connection and livening activities.
- DG being connected without following the complete process and involving the network can result in delays to certain aspects of the process or connecting unapproved DG equipment.

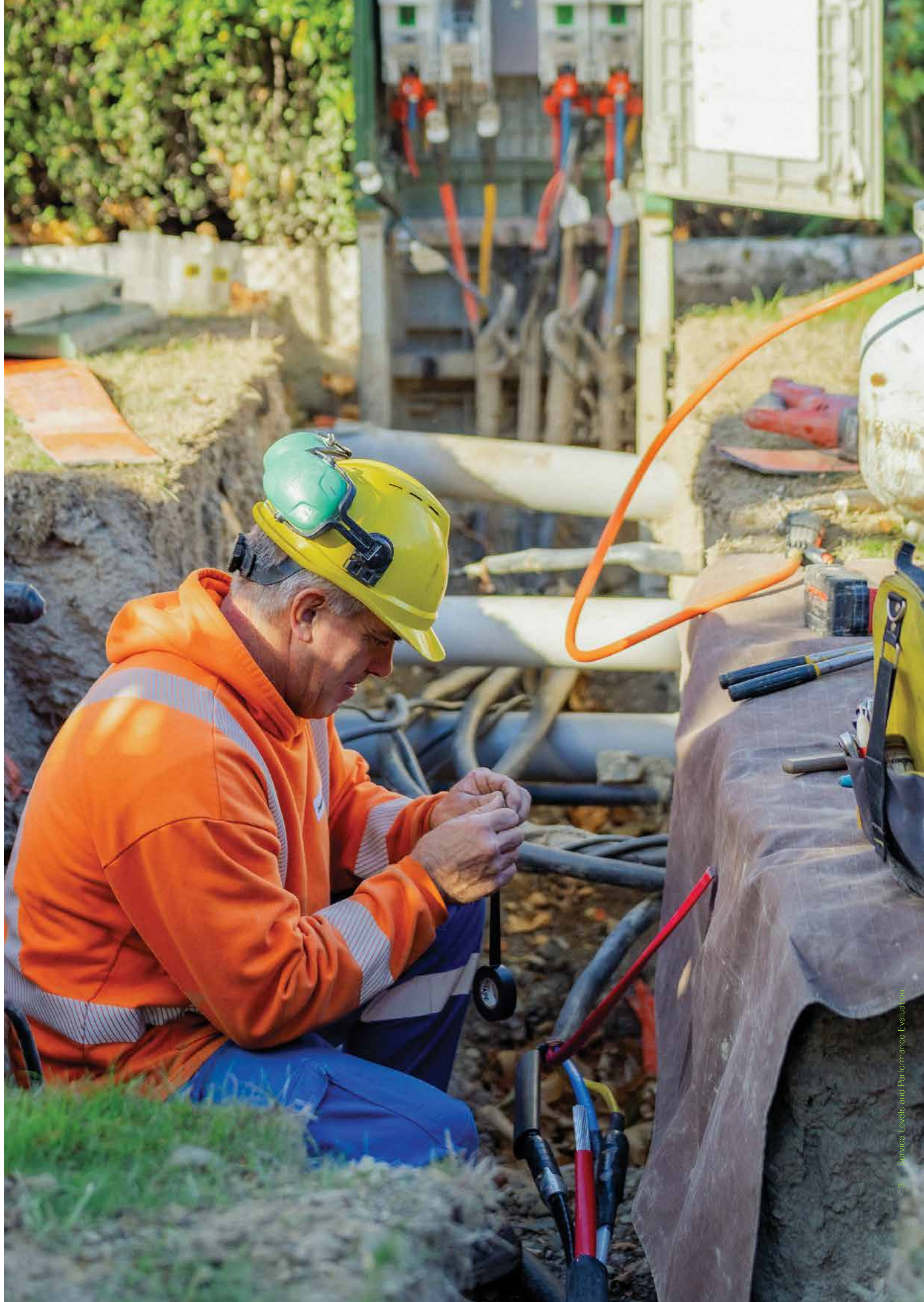
New offtake connections typically take a minimum of 15 working days' notice to process from beginning to completion, across all parties.

DG connection applications are processed in accordance with the timeframes required by Part 6 of the Electricity Industry Participation Code. Typically, it depends on the size and complexity of the application, some take considerably longer. The time the DG installer requires to complete their aspects of the work varies, including providing the necessary compliance paperwork, which may arrive up to 20 days after the work is completed.

3.5.5 APPROACH TO SHARING INFORMATION ON CURRENT AND FORECAST CONSTRAINTS WITH POTENTIAL CONSUMERS

MainPower provides information about current utilisation of assets, remaining capacity and forecast growth for zone substation transformers within the AMP. We share more specific information with potential customers when we receive applications or expressions of interest and work directly with those customers to explore options to connect to the network.

We have also been developing our network-wide modelling capabilities, including a high voltage network load-flow model and seeking access to smart meter data to enable us to model and better understand the low-voltage network capability to provide information to consumers.



3.6 NOTICE OF PLANNED AND UNPLANNED INTERRUPTIONS

MainPower notifies planned service interruptions by sending an electronic file using the Electricity Information Exchange Protocol 5A (EIEP5A) format to energy retailers of planned service interruptions with at least 11 days' notice, who in turn advise the affected consumers. We also advise consumers who have an active New Zealand mobile phone number using short messaging service (SMS) text communications. These are sent at the time the EIEP5A communication is sent, again 24 hours before the planned service interruption is scheduled to begin, and once the planned outage has ended. In situations where these normal processes are not viable, such as short notice outages, we usually email customers directly using their registered contact email and telephone any who do not provide any email address through their energy retailer. We do this at least 48 hours before the outage, in accordance with our Connection Agreement.

MainPower provides notice of unplanned service interruptions, via SMS text message when the unplanned outage is verified. A further SMS is sent when power is restored. All outages, planned and unplanned are available to view on a detailed map on our website. In special cases or for consumers with greater reliance on electricity, we occasionally communicate directly using email or phone calls to the affected consumers.

In unique cases, such as a national energy or power shortage, we also use social media channels and radio for rapid message distribution. If we have adequate advance warning of the unplanned service interruption, which is not common, we may also follow the short notice outage process outlined in the paragraph above.

3.7 PERFORMANCE INDICATORS

3.7.1 RELIABILITY

MainPower's network reliability is measured by the frequency and duration of interruptions to consumers' electricity supply. Our reliability targets guide our investment decisions, with the aim of meeting our consumers' expectations.

MainPower's key network reliability measures are applied as determined by the Commerce Commission's Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024, and include:

- SAIDI, which measures the average minutes that a consumer is without power during the year
- SAIFI, which measures the average number of supply interruptions for each consumer during the year
- customer impact ratio, which measures the number of unplanned customer interruptions by feeder – this is a newly defined measure that has come into force in January 2025 and will be reported in August 2025.

These measures include planned and unplanned interruptions with a duration longer than one minute on MainPower's sub-transmission and high-voltage networks. MainPower's consumers view network reliability as a top priority, and the surveys show that they are generally satisfied with the current level of reliability.

3.7.2 VOLTAGE QUALITY AND CONSTRAINTS

3.7.2.1 MONITORING VOLTAGE QUALITY ON THE LOW-VOLTAGE NETWORK

MainPower currently utilises a few methods to monitor voltage quality on the low-voltage network. Transformer monitors are used across the network to monitor low-voltage bus voltages and end-of-line voltages. We are further exploring low-voltage analytics tools based on smart meter data to better understand and monitor the capability of the low-voltage network. Product and data acquisition trials have been running over the past year and continue into FY26 to inform MainPower's longer-term low-voltage network strategy. We have a robust customer complaints process that begins further investigation where issues are identified.

MainPower is in talks with the meter providers to obtain smart meter data. The ability to access and use this data will be cost dependent.

3.7.2.2 WORK ON THE LOW-VOLTAGE NETWORK TO ADDRESS KNOWN NON-COMPLIANCE

MainPower deals with known non-compliance on the low-voltage network through our ongoing network operations and our maintenance and replacement programme. Reports of low-voltage supply and other network non-compliance are managed through a power quality analysis and management process, which includes keeping the customer involved. When upgrades are necessary, the upgrades are delivered under the maintenance and replacement programme.

3.7.2.3 RESPONDING TO REPORTS ON VOLTAGE QUALITY ISSUES

MainPower actively monitors customer complaints. When an issue is reported, a power quality analysis procedure is started. A Field Operator will visit the location to assess the network assets in the area and perform spot measurements and tests. If this is inconclusive, MainPower will install a logger at the ICP in question and observe the power quality data for any signs of issue that relate to the reported problem. Additionally, the smart meter data will be interrogated where available. From this data, MainPower can determine what is occurring and provide advice to the customer or a solution where appropriate. All complaints are logged in MACK so they can be referred to for any future queries or ongoing issues.

3.7.2.4 COMMUNICATING WITH AFFECTED CONSUMERS REGARDING VOLTAGE QUALITY ISSUES

MainPower engages with any impacted customers as they raise concerns and communicates whenever work is required to mitigate an issue. This can include notification of a required outage, consultation around design solutions, and ongoing communication about identifying any issues and underlying causes as an investigation proceeds.

3.7.2.5 PLANS FOR IMPROVEMENT

MainPower is actively seeking access to power data from ICP smart meters. This will allow better visibility of the low-voltage network to identify problem areas and allow MainPower to focus reinforcement spending on rectifying these issues. Additionally, accurate load information from ICPs will better inform planning and design practices to ensure issues are found early and fixed. This requires access to smart meter data from meter providers at a reasonable cost.

3.7.2.6 MONITORING LOAD AND INJECTION CONSTRAINTS

Availability of data

MainPower has managed to secure voltage, current and phase angle data at 5-minute intervals from one of the smart meter providers in our region; however, this is only for 3,500 meters (approx. 8% of our total network ICPs). More than 80% of the ICPs in our region have not been configured to record this data, and attempts are being made to have the meters re-configured to record the data required for network analysis.

Data cost

Whilst MainPower has secured access to some smart meter data (8%), across 45,000 ICPs this would be a significant operating expenditure cost on our consumers, which is currently a barrier to gaining access. We are exploring an option to gain access to consumption data and voltage event only; however, the benefit vs. cost is less attractive than full access to low-voltage data to understand and model current and upcoming constraints.

Analysis and modelling

MainPower has a high-voltage load flow model that currently uses assumptions for load distribution downstream of our high-voltage supervisory control and data acquisition (SCADA) points. We are intending to incorporate the collected smart meter data to refine this model and allow more accurate modelling of network capability and constraints, and the effectiveness of both traditional and non-network/flexibility solutions.

MainPower is currently finalising the low-voltage strategy, which includes our own internal data analysis as well as considering third-party analytics platforms to understand and proactively manage voltage compliance issues, consumer "energy use" trends, and to inform more accurate, bottom-up, network energy forecasting and constraint identification as consumer energy resources increase (electric vehicles, photovoltaics, batteries, etc.). We are currently using data we have secured for 8% of our network ICPs to develop general trends; however, this ultimately leads to assumptions due to the low coverage of the network.

MainPower intends to use smart meter data to help identify where supplementary network installed transformer monitors are needed to gain additional information to improve and validate our modelling. We intend to use smart meter data to analyse and inform changes to existing distribution transformer tap settings as a low-cost option to optimise existing assets to support consumer requirements, before implementing upgrades or other more costly solutions.

MainPower intends to continue working with all smart meter providers in our region to reconfigure meters to collect voltage, current and phase angle data, and obtain access to the smart meter data at a fair and reasonable price for our consumers.

3.7.3 NETWORK RESTORATION

When an unplanned network interruption occurs, MainPower targets a time for the power to be restored, which varies depending on the location of the interruption, and the cause. We typically consider our response in terms of residential areas, rural areas, and remote areas, where each has a distinct target. We have staff available around the clock to respond to unplanned interruptions, with depots in Rangiora, Culverden and Kaikōura holding a variety of resources to reduce response and repair times.

3.7.4 RESILIENCE

Resilience involves the ability of MainPower and our network to anticipate, absorb and recover from disruptive and extreme events such as snowstorms and earthquakes. A resilient network minimises the number of consumers impacted by significant events. We recognise the need to balance the cost of installing backup and redundant systems with providing a reasonable level of service that has the capacity to recover rapidly from extreme events. We are exploring ways to better manage MainPower's network and business resilience in line with industry guidelines.

MainPower has invested in an advanced distribution management system (ADMS) to help provide better visibility and control of our network. We also see an opportunity to improve both network restoration and resilience performance further through improved network architecture aligned with our Security of Supply Standard (see Section 6.2 of this document) and enhanced remote sensing and switching capability throughout the network.

3.7.5 HEALTH, SAFETY AND THE ENVIRONMENT

Our teams are committed to providing a safe network and healthy working environment across all our assets. MainPower promotes public safety around electricity throughout our region to help make sure our community is aware of our assets and activities. We take all reasonably practicable steps to minimise risk and harm to the public, our people and our service providers, and we measure this in terms of the:

- safety of employees and service providers
- safety of the public.

Our objectives are to:

- identify, manage and communicate risks associated with the workplace, the electricity distribution network and our business activities
- ensure compliance with legislative requirements and industry standards
- ensure that employees and field service providers have an appropriate level of training, skill and knowledge to carry out their work safely
- provide safe equipment, plant and systems to ensure public and worker safety.

We regularly monitor, review and report on our legal compliance obligations and risks. The main focus of this monitoring and reporting is to understand the compliance risks. Additionally, as part of the requirements for certification to ISO 9001, ISO 14001 and ISO 45001, we must be able to demonstrate how we manage our legal requirements.

We design, construct, commission, operate and maintain the electricity distribution network and other company assets to ensure that they are safe, fit for purpose and do not pose a risk to health. We also participate in industry-related benchmarking of safety incidents to provide a basis for measuring our performance.

MainPower is committed to protecting and improving our environment, and we recognise our responsibility to strive for environmental sustainability. In addition to our business environmental sustainability drivers, our current network environment measures include the following.

- **Sulphur hexafluoride (SF_6) gas:** This gas is used as an interruption medium in switchgear, and the Ministry for the Environment has set a compliance level of less than 1% annual loss, based on the total volume of gas on the network. MainPower is committed to minimising SF_6 emissions, and we monitor and report on losses.
- **Oil spills:** Some assets on our network use oil as an insulating medium. We use a range of containment and mitigation solutions to prevent, or minimise the impact of, spills. Our annual target is zero uncontained oil spills across our network.

3.7.6 DELIVERY PERFORMANCE

It is important that MainPower continually assesses our asset management maturity against the requirements of the business and whether we are tracking to achieve the required maturity level. We also review overall organisational financial indicators and how we have performed in delivering the work programme. In addition, MainPower assesses performance against industry peers to ensure we are aligned with the industry using industry benchmarking.

All this is achieved through our processes for:

- maintenance programme delivery
- capital programme delivery
- asset management maturity (using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT))
- financial performance
- industry benchmarking.

3.8 PERFORMANCE INDICATORS AND TARGETS

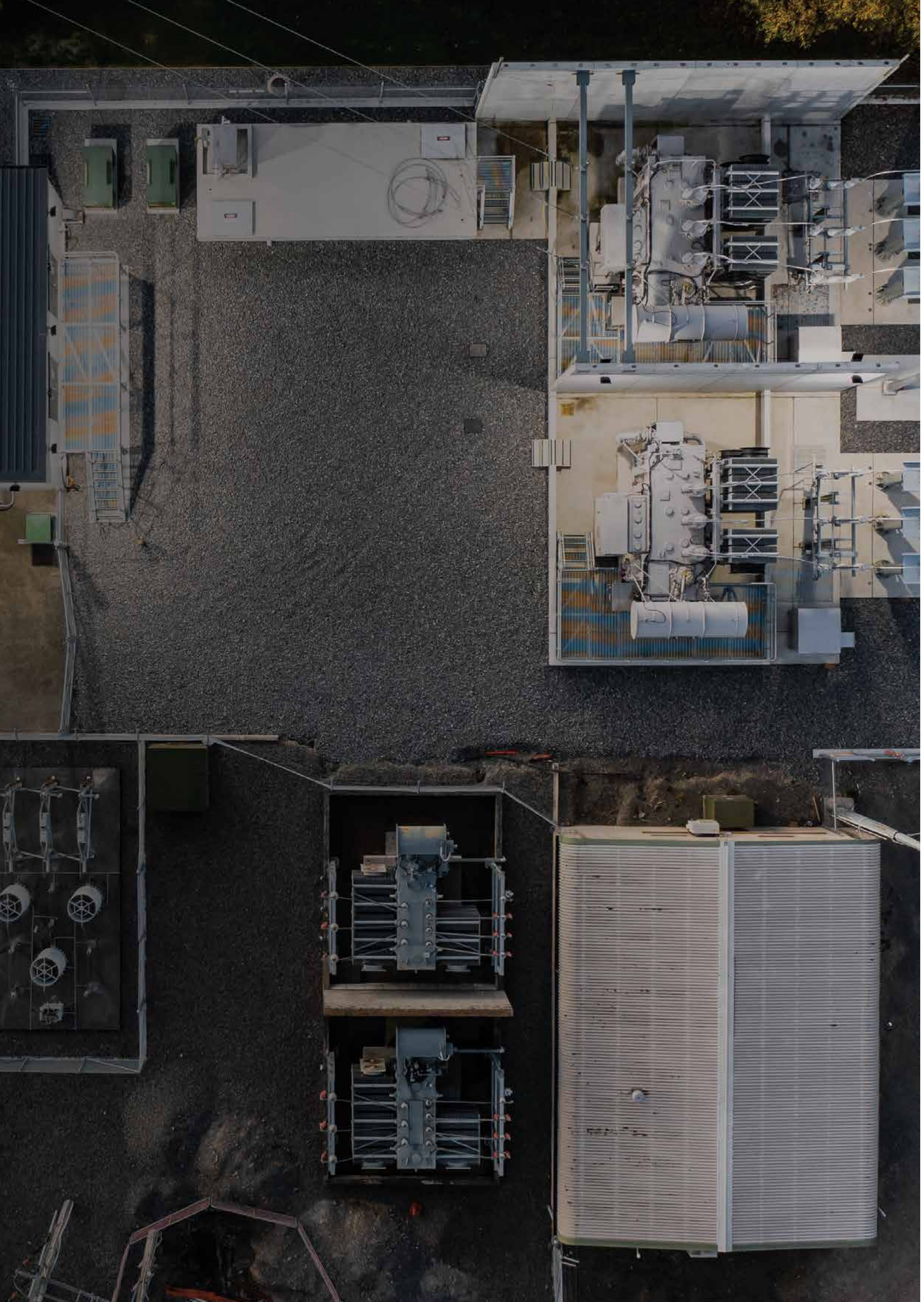
Performance targets for the 10-year planning period are shown in Table 3.4.

Service Class	Performance Indicator	Performance Measure	Past Performance Targets		Future Performance Targets									
			FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Reliability	SAIDI – System Average Interruption Duration Index*	Average minutes of supply lost per customer per year	272.0	265.1	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8
	SAIFI – System Average Interruption Frequency Index*	Average number of times a customer's supply is interrupted per annum	1.98	2.01	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
	Feeder reliability	None – forward indicator only												
	Unplanned interruptions restored within 3 hours	% of unplanned interruptions where the last customer was restored in less than 3 hours	No targets set (new)	80%	80%									
Health, safety, environment and quality	Safety of workers	No safety critical injuries	None		None									
	Safety of public	No injuries to members of the public	None		None									
	SF_6 gas lost	Gas lost as % of total gas volume	< 1%		< 1%									
	Oil spills	Uncontained oil spills	None		None									
Consumer oriented	Engagement effort	Customer Pulse Survey Score, from 1 (very dissatisfied) to 5 (very satisfied)	> 7		> 7									
	Staff friendliness		> 7		> 7									
	Quality of work		> 7		> 7									
	Timeliness of service		> 7		> 7									
	Communication		> 7		> 7									
	Website application		> 5		> 7									
	Final price**		> 5		> 3									
Delivery	Maintenance delivery	Maintenance programme delivery by budget	> 90%		> 90%									
	Capital delivery	Capital programme delivered by budget	> 90%		> 90%									
	Asset Management Maturity Assessment Tool (AMMAT)	Complete workstreams noted in AMMAT	> 90%		> 90%									
	Industry benchmarking	Assess ourselves against: • operating expenditure per ICP • capital expenditure per ICP • quality of supply (SAIDI and SAIFI) • non-network operating expenditure per ICP	< 75th percentile		< 75th percentile									

* "Future performance targets" for SAIDI and SAIFI reflect a change in the measurement of quality standards to align with the default price-quality path for electricity distribution businesses.

** This metric is considering being removed.

Table 3.4 MainPower's performance indicators and targets



3.9 PERFORMANCE EVALUATION

3.9.1 NETWORK RELIABILITY

Our network reliability is measured using the standard industry performance SAIDI and SAIFI indices, calculated in accordance with the Commerce Commission information disclosure requirements. These indices provide us with performance metrics for outage duration and the number of outages for the average customer experiences. We analyse our network's reliability by cause and asset category using both normalised data, which excludes major external events such as severe windstorms, and raw data, which includes all interruptions and outages. We also analyse feeder reliability by category and cause to understand where parts of our network might be experiencing interruption frequency or duration that is higher than average. Figure 3.6 shows MainPower's normalised network reliability performance over the 5-year period to March 2024.

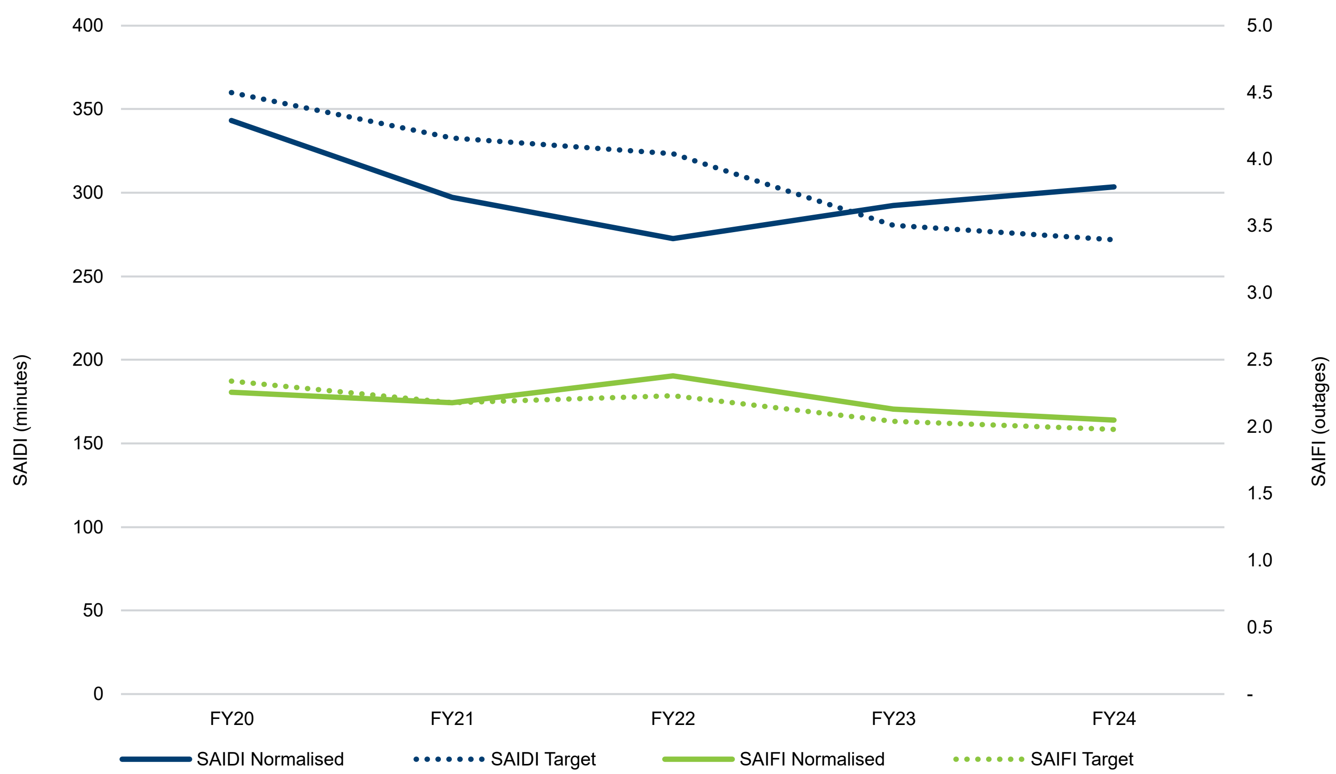


Figure 3.6 MainPower's network reliability SAIDI and SAIFI over 5 years (FY20–FY24) – normalised

MainPower's consumers view network reliability as a top priority and are generally satisfied with their current level of reliability. Examination of network performance over a five-year period indicates a downward trend in MainPower's normalised outage frequency and duration, but FY24 performance was severely impacted by a severe weather event that resulted in a substantial number of outages, and longer duration outages, than might have been expected from historical performance. To understand this trend, it is helpful to break down reliability into planned and unplanned events, using raw data that includes outages caused by extreme weather events (see Figure 3.7 and Figure 3.8).

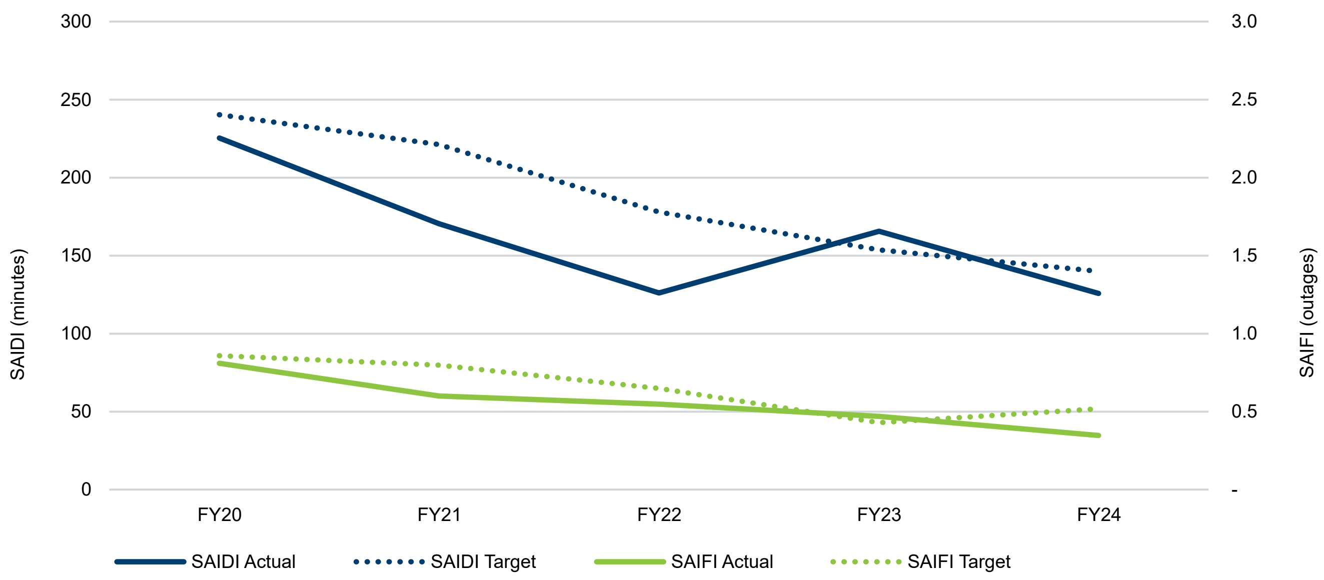


Figure 3.7 Network reliability – planned (FY20–FY24)

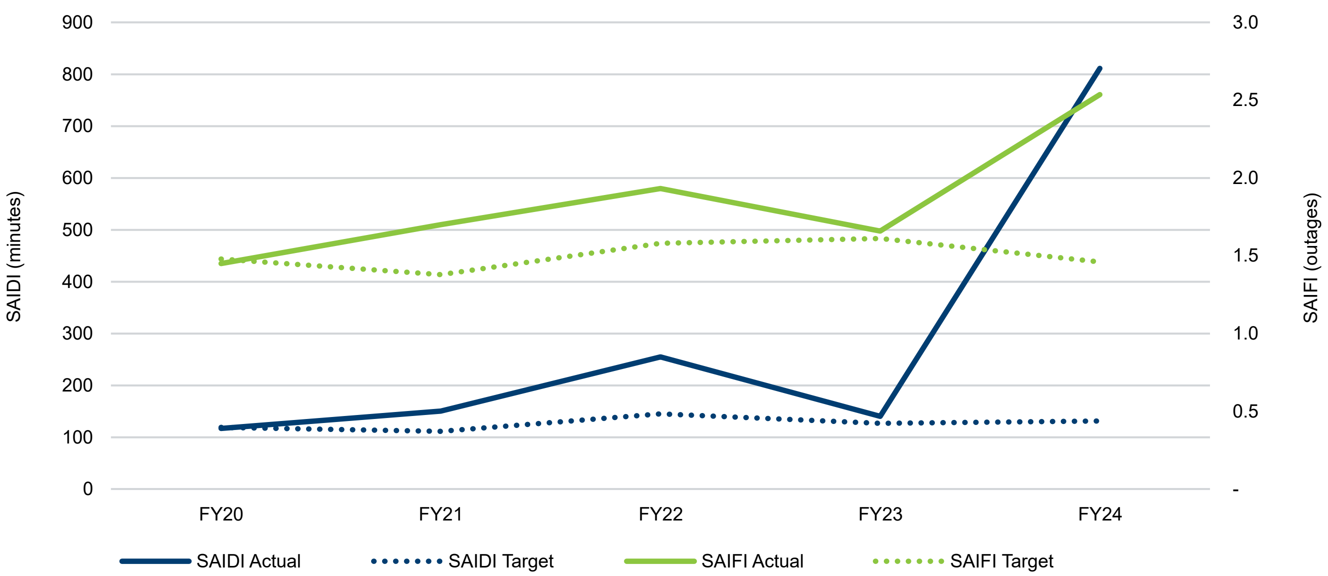


Figure 3.8 Network reliability – unplanned (FY20–FY24)

Figure 3.7 and Figure 3.8 show a reducing trend in planned outages in the last five years, and, even when excluding the impact of the severe weather event of FY24, an increasing trend in unplanned outages. The shift in planned performance was brought about by improving work practices in line with the long-term asset management objectives. Actual outage duration and frequency for planned work was better than forecast in four of the five years, and in line with plan in the remaining year. Forty-two percent of MainPower's FY24 normalised SAIDI was attributable to planned works, reflecting our risk-targeted renewals programme and network architecture. Our network architecture is based on a rural, radial configuration with limited ability to supply consumers via alternative sources, which increases the impacts of unplanned outages.

The most significant drivers of unplanned reliability performance in FY24 were related to adverse weather events, wildlife events, and equipment failure. Unanticipated equipment or system failure events are fed into MainPower's asset management programme and analysed for improvements to long-term asset management strategies. To better understand what contributes to unplanned electricity distribution network reliability, we analyse all outage data by cause, using outage statistics over time to reveal any underlying trends. We use a five-year rolling average across all outage categories (see Figure 3.9). MainPower expects adverse weather events to increase in the future because of climate change. This is likely to also have an impact on "cause unknown" events, where high winds or debris can impact our predominantly rural network without leaving behind any obvious signs of interference.

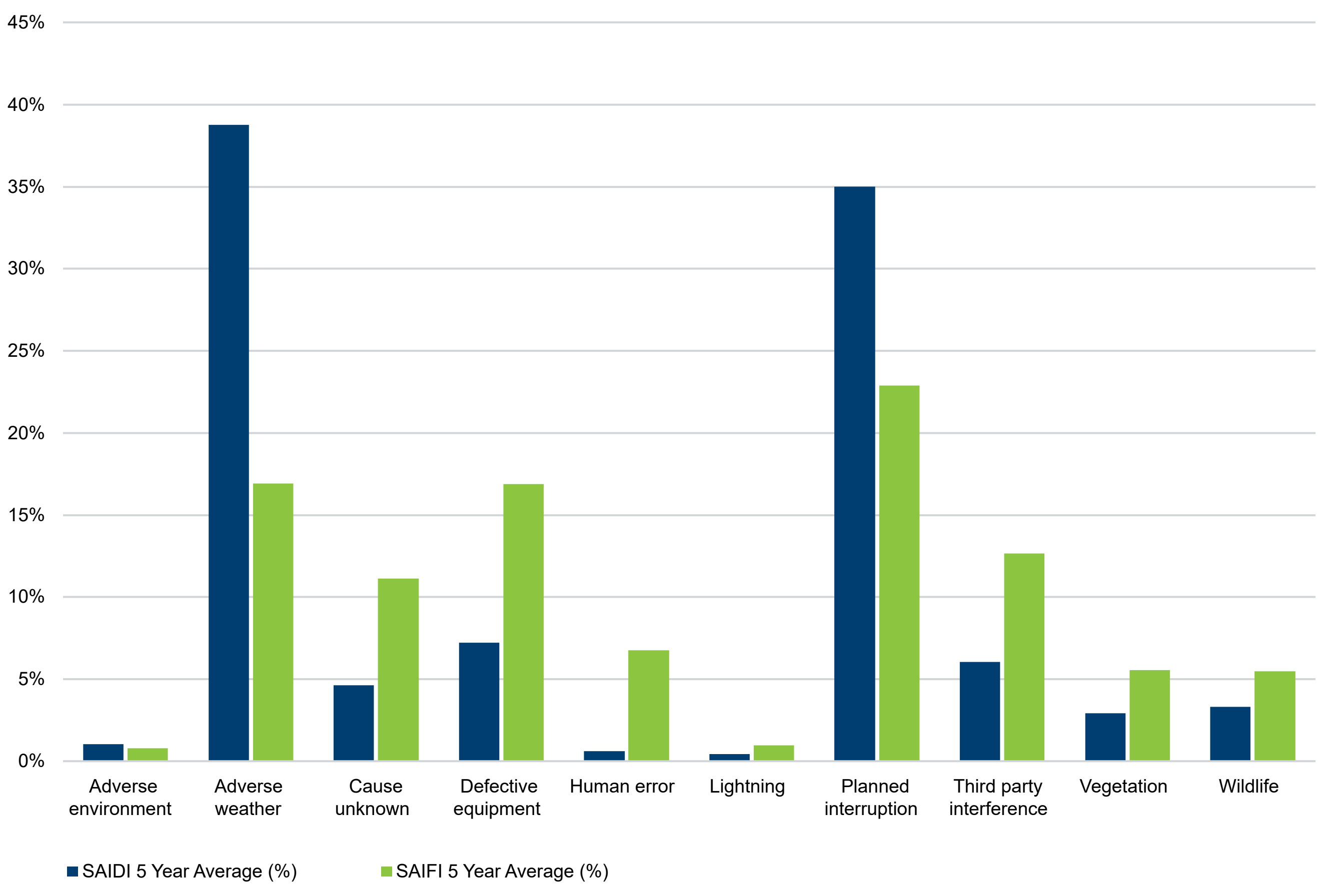


Figure 3.9 Network reliability, by cause (5-year rolling average, FY20–FY24)

While this analysis provides useful data on the overall contributors to deteriorating network performance, we know that trends can be affected by single events. Therefore, MainPower reviews the outages, by cause, over time. The results of this for FY20 to FY24 are shown in Figure 3.10 and Figure 3.11.

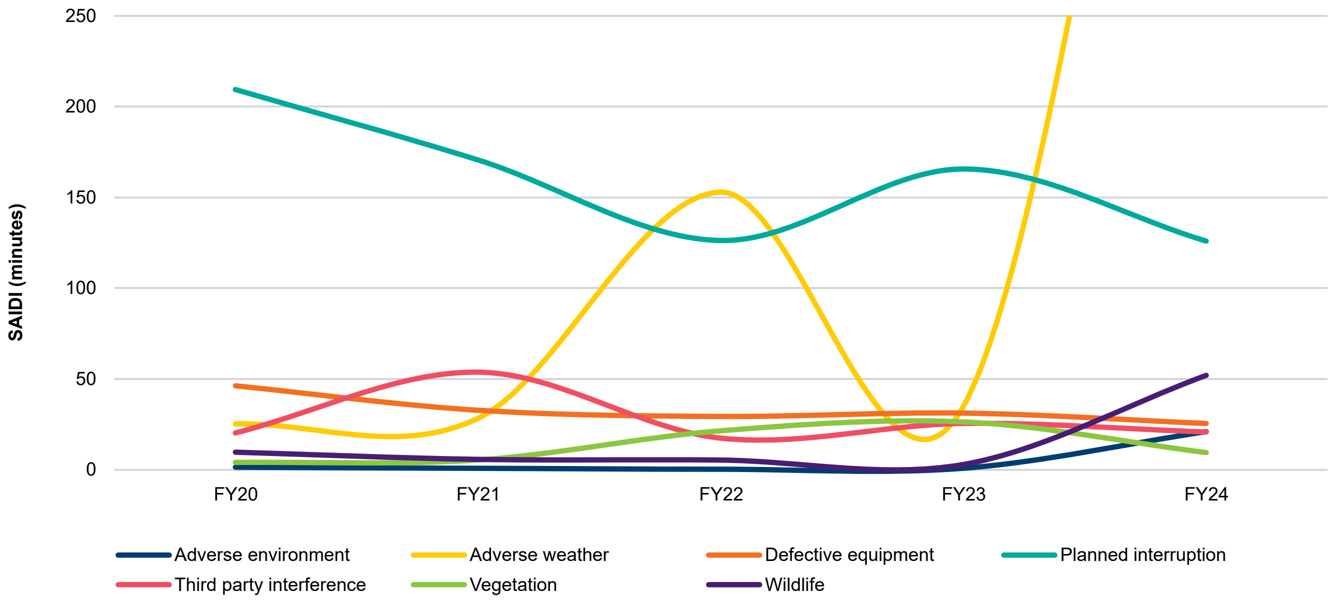


Figure 3.10 Network SAIDI, by cause (FY20–FY24)

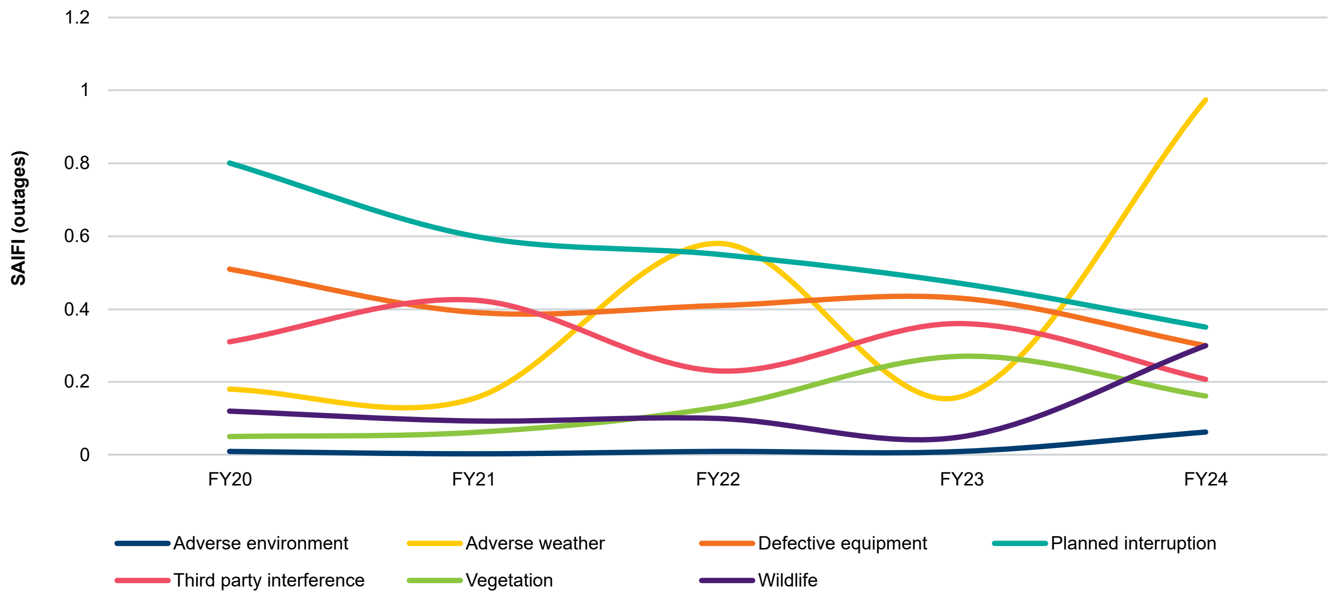


Figure 3.11 Network SAIFI, by cause (FY20–FY24)

The "adverse weather" category was impacted by significant events in September 2021 and October 2023.

It is important to include the real impact of outages on our network in the analysis to ensure root causes can be discovered and solutions implemented. Table 3.5 identifies the top contributors to outage duration (SAIDI) and outage frequency (SAIFI) over the 5-year period FY20 to FY24, in order of contribution.

Outage duration (SAIDI)	Outage frequency (SAIFI)
Adverse weather	Adverse weather
Defective equipment	Defective equipment
Third-party interference	Third-party interference
Wildlife	Human error
Vegetation	Vegetation
Adverse environment	Wildlife
Human error	Lightning
Lightning	Adverse environment

Table 3.5 A high-level analysis of the outages over the period FY20–FY24, by cause

Table 3.6 summarises the initiatives to improve network reliability.

Category	Analysis	Initiatives	Update	Target date
Planned Works	MainPower has augmented its planned works programme to target fleet renewal and to improve network resilience. Additional outages are required to implement these improvements because of the radial nature of the network.	Implement a company-wide discussion and working group to identify continued areas of improvement for the approach to planned work.	Previous initiatives during the last three years have been effective at limiting the impact on the reliability of MainPower's total work programme. New initiatives are expected to improve on this foundation.	FY26–FY35
Defective Equipment	Reviewing defective equipment by asset class indicates that reliability is adversely affected by: • switchgear • ring main units (RMUs) • cable faults • insulators.	Work programme: 1. Upgrade programme for the Amberley, Hanmer Springs and Hawarden zone substations within AMP period. 2. RMU replacement programme 3. Insulator and crossarm inspection programme 4. LiDAR* aerial inspection pole maintenance programme 5. Line-tightening programme	• RMU replacement programme progressing. • Insulator and crossarm inspection programme underway. • Aerial inspection programme complete with forward annual programme underway. • CBRM models partially in use and under further development across other assets fleets.	FY27–FY30
Adverse Weather	Adverse weather events are increasing in frequency and rural radial feeders are exposed to windblown interference during storms.	LiDAR aerial survey to assist in identifying potential risks from vegetation, line clashes and latent pole-top failures to proactively inform the overhead distribution line maintenance programme.	Taking advantage of the ADMS roll-out for early identification of location and potential cause of outages, and for better management of repair activities during weather events.	FY26–FY27
Third-Party Interference	MainPower has a public advertising campaign to communicate the need to watch out for overhead lines. We also issue "High Load" and "Close" approach permits, including action plans where evidence suggests the terms and conditions under which the permit is issued can be ignored. Additionally, customers have 24-hour access to underground cable locations information via the online "beforeUdig" service.	Active watch: MainPower intends to monitor third-party interference and determine whether additional steps need to be implemented.	Third-party interference impacts have begun to decline. MainPower will continue the awareness campaign to ensure the trend continues in this direction.	FY26–FY27

* LiDAR (light detection and ranging) is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances).

Table 3.6 Network reliability improvement summary

3.9.2 FEEDER RELIABILITY

In addition to system-wide interruption cause analysis, we review our network reliability trends over five years at a distribution-feeder level. This helps us understand where parts of our network might be experiencing interruption frequency or duration that is higher than average, as shown in Figure 3.12 and Figure 3.13. Initiatives to improve network reliability are summarised in Table 3.7.

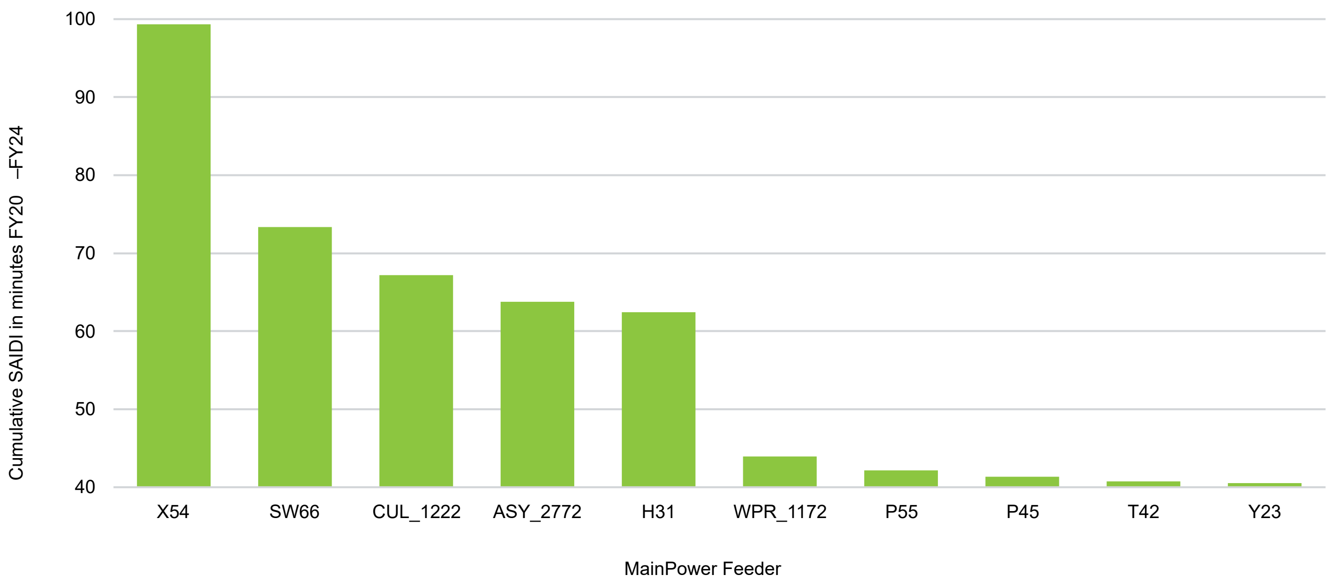


Figure 3.12 Top 10 feeders with the most minutes of unplanned outage (FY20–FY24 SAIDI average)

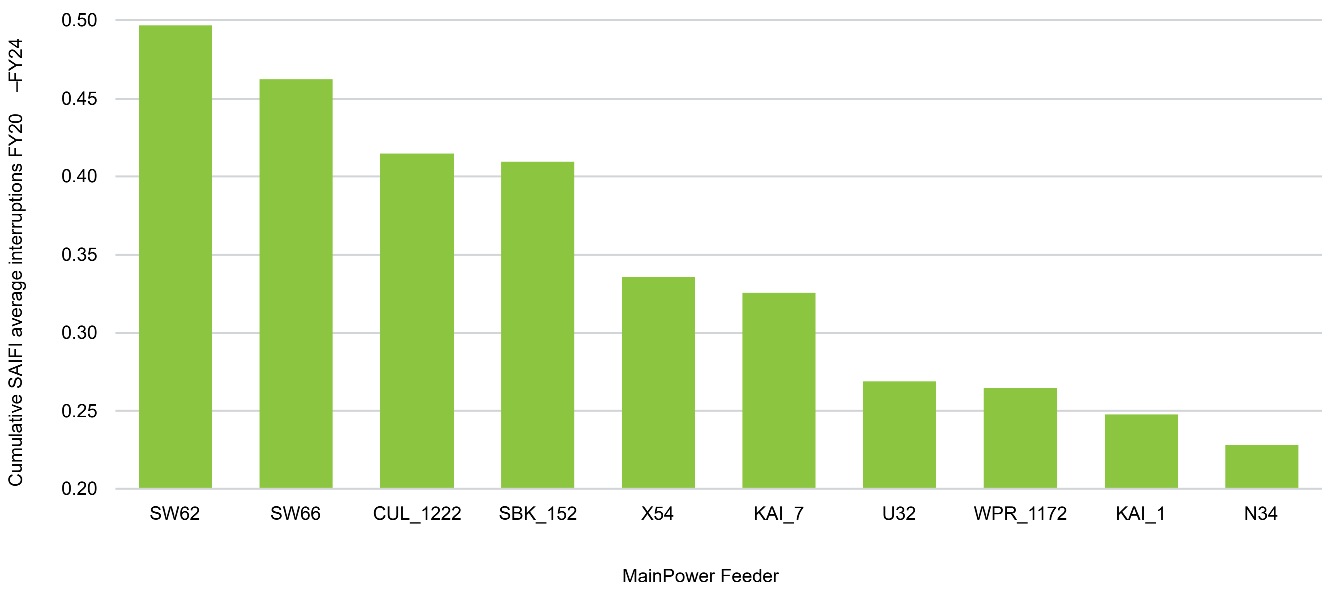


Figure 3.13 Top 10 feeders with the highest number of unplanned outage (FY20–FY24 SAIFI average)

Feeder	Analysis	Initiatives	Target date
X54	This feeder supplies the Oxford township and a large amount of the surrounding rural area. This feeder is predominantly 11 kV rural overhead network.	Several projects in the 10-year plan will help with alternative supplies for this feeder. They include feeder ties to other feeders supplied out of Swannanoa zone substation and Ashley grid exit point (GXP). It is expected these will minimise the impact of severe weather events on this part of the rural network. In the short term MainPower has reconfigured the downstream network, which is expected to improve feeder reliability.	FY29–FY34
SW66	This feeder supplies the West Eyreton region from our Swannanoa zone substation. This feeder is also a large rural overhead feeder that has experienced a high number of vegetation- and weather-related interruptions over the past five years. Although it is a rural feeder, this region is more densely populated than a typical rural feeder, and therefore interruptions have a higher impact, owing to the larger number of connections.	Several reinforcement projects have recently been completed on this feeder to minimise the number of customers affected by outages. We also aim to improve and target our vegetation management programme to prevent vegetation-related interruptions. Ongoing reliability of this feeder will be monitored to assess the effectiveness of these reinforcements.	FY29–FY30
SW62	This is the main feeder supplying the rural area west of Rangiora. It is predominantly 11 kV rural overhead construction. Investigations into the feeder have revealed several outages with unidentified causes – the disproportionate number of vegetation- and lightning-related outages may be related to some of these unidentified causes.	Comprehensive assessments of the feeder revealed opportunities for enhancing equipment compatibility. We've implemented targeted improvements, which are anticipated to substantially boost the feeder's reliability.	FY25
Cul_1222	This is the 33kV sub-transmission line supplying the Hanmer Springs region.	A major project to upgrade the Hanmer Springs sub-transmission line will improve the resilience and reliability of the existing line with stronger conductor and structures. The line route and structure footings will also be reviewed to mitigate the impact of potential natural hazards where possible.	FY29–FY30
ASY_2772	This feeder supplies the Loburn and Okuku area. This feeder is predominantly 11 kV rural overhead network.	Future projects are planned to provide an alternative supply to this feeder from the Burnt Hill zone substation. This is expected to significantly improve feeder resilience.	FY33–FY34
H31	This feeder supplies the Hawarden township and the large rural area west of the township. The feeder is entirely rural overhead in construction.	As the inclusion of this feeder in the high-impact list was largely related to a weather event that had a large impact on the entire network, the feeder will be monitored for ongoing contributions to SAIDI and SAIFI during weather events and action taken if the trend continues.	N/A

Table 3.7 Network feeder reliability improvement summary

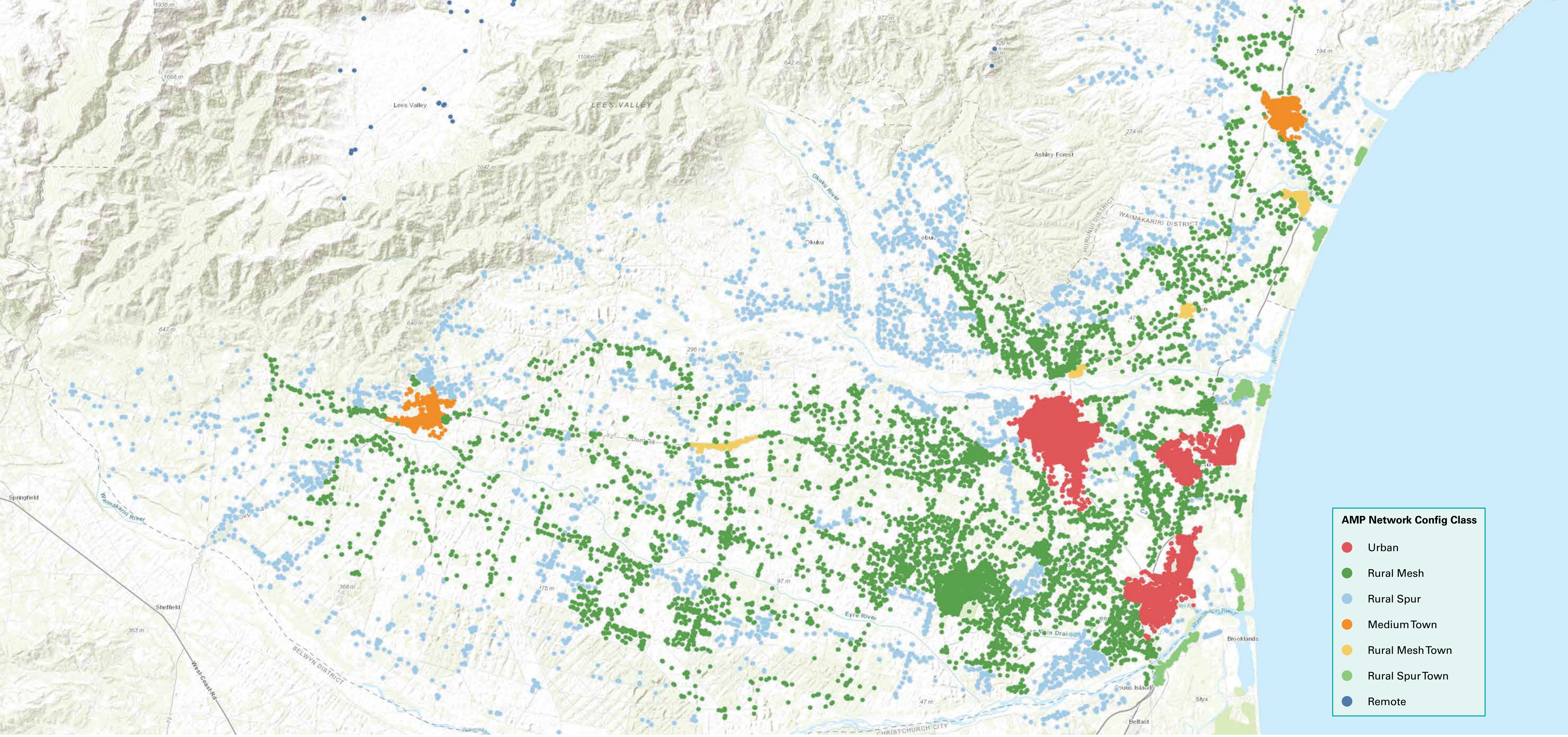


Figure 3.14 MainPower's reliability analysis model

3.9.3 RELIABILITY ANALYSIS MODEL

MainPower has been building a reliability analysis model to support the development of a more comprehensive understanding of our network reliability (see Figure 3.14). This tool allows analysis at an ICP level for both low-voltage and high-voltage outages, using data from our ADMS system.

In Figure 3.14, we have categorised ICPs using the customer classification shown in Figure 3.15 and geographical attributes to better understand and measure our network against expected levels of reliability. We see this as being a more customer-centric approach to reliability analysis, extending beyond aggregated feeder reliability levels. We intend to continue to develop this tool and use it to inform a more targeted approach to our investment in network reliability, alongside direct customer consultations.

This customer-centric approach to reliability should provide greater detail on the success of MainPower's operations through the eyes of our consumers. By stepping away from measurements based on system-wide averages and focusing on the impact to specific consumer groups and specific ICP locations, MainPower will be able to better understand if the expectations of our community and owners are being met.

It is well known that geographical area plays a significant role in the ability to supply power. Until now, the impact of this aspect on the reliability of power supplies in different geographical locations has largely been ignored through the SAIDI and SAIFI reporting as a system average. MainPower has now split consumers into groups based on their location in the network, which roughly translates to distance from a main supply. Figure 3.15 shows the approximate number of consumers in each group.

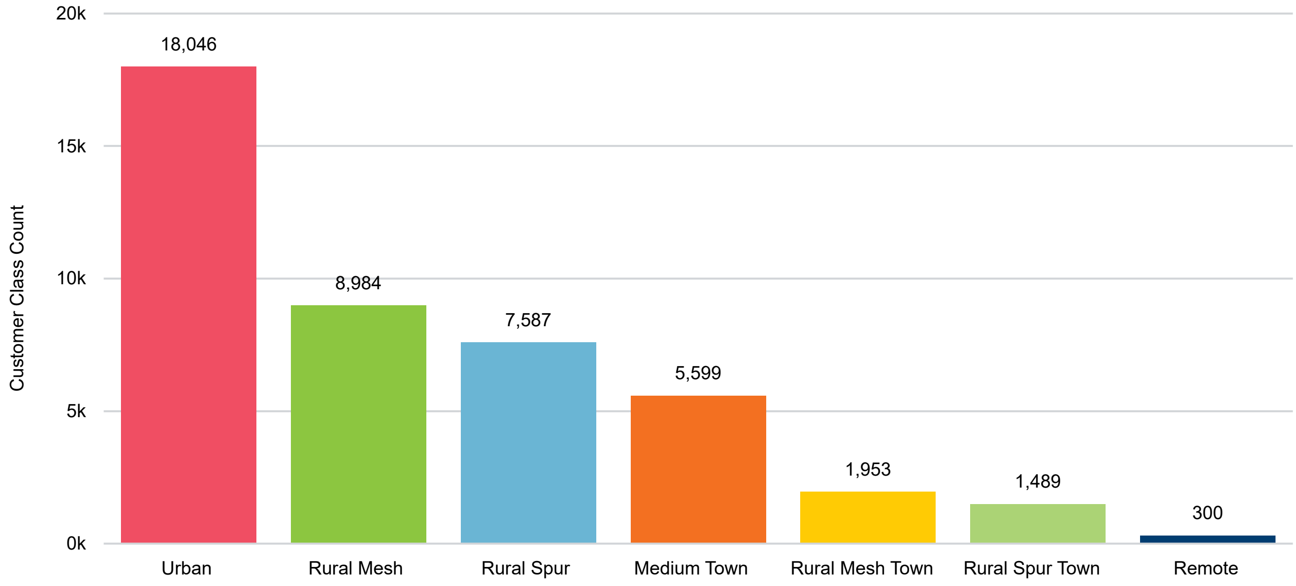


Figure 3.15 Number of connected consumers, by classification group, FY24

One area of particular interest is the high number of connected ICPs at our urban centres such as Kaiapoi and Rangiora, and the low number of consumers connected in remote areas of the network. This breakdown of consumer groups can be used to show where the largest impact of network reinforcement and capital expenditure is likely to occur. The impact of outages on the MainPower network to each of these consumer groups is shown in Figure 3.16. It should be noted that these figures are non-normalised and heavily impacted by large events, especially the figures for remote consumers. With so few consumers in this group, a high result for a small number of consumers significantly lifts the average value.

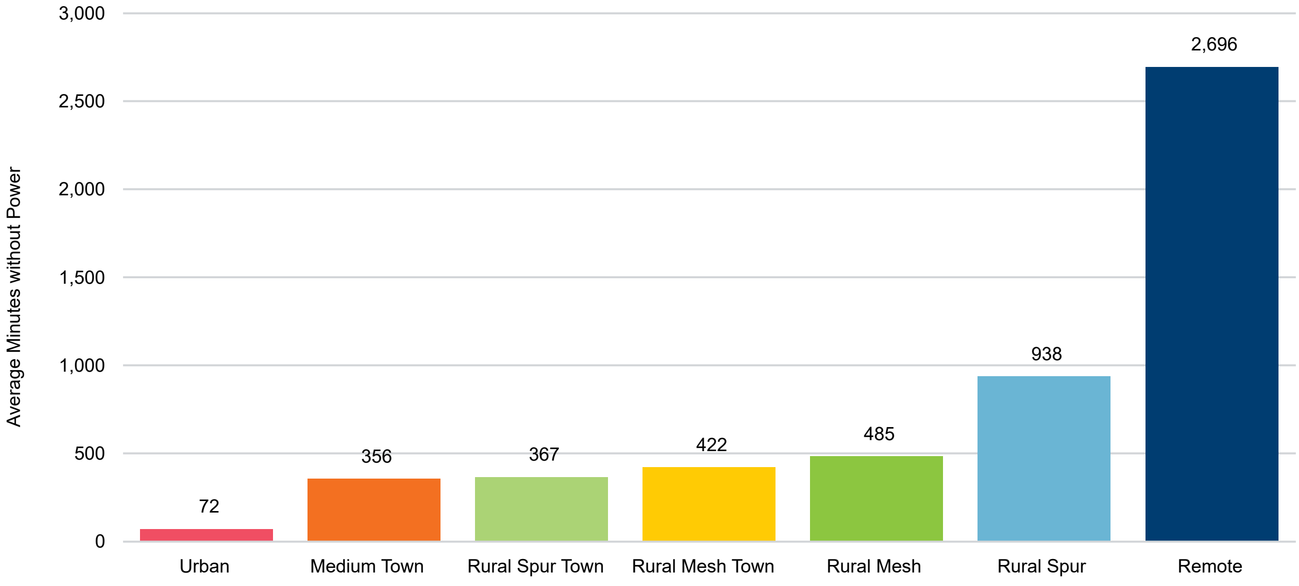


Figure 3.16 Average time spent without power, by classification group, FY24

The appearance of the graph in Figure 3.16 is an approximate inverse of the graph in Figure 3.15. This is due to the increased number of alternate supplies in denser areas, where the network naturally becomes meshed, and the increased number of consumers connected to these supplies that would be impacted by outages. This provides insight into where improvements can be found for both SAIDI and SAIFI, and where consumer engagement can be more targeted and relevant for the different consumer segments.

MainPower can assess both the network performance for specific groups against customer expectations and the network performance against the weighted average expectation. These comparisons can directly inform the long-term strategic goals and capital expenditure for reliability at MainPower.

The reliability dashboard also provides advantages to network planning and visibility, through the ability to view the network as individual ICPs geographically. This enables the planning team to examine outages in more depth than the previous "worst-performing feeder" analysis allowed.

3.9.4 HEALTH, SAFETY AND THE ENVIRONMENT

We report all employee injury and public safety events through our Vault safety information management system (see Table 3.8). In addition to employee and public safety monitoring, we have been process mapping our critical processes and identifying critical controls. MainPower also places significant emphasis on being an environmentally responsible company and complying with our responsibilities.

Personal safety	FY24 target	FY24 actual
No safety critical injuries	0	0
No injuries to members of the public	0	0
SF_6 loss (% to total gas volume)	< 1%	< 1%
Uncontained oil spills	0	0

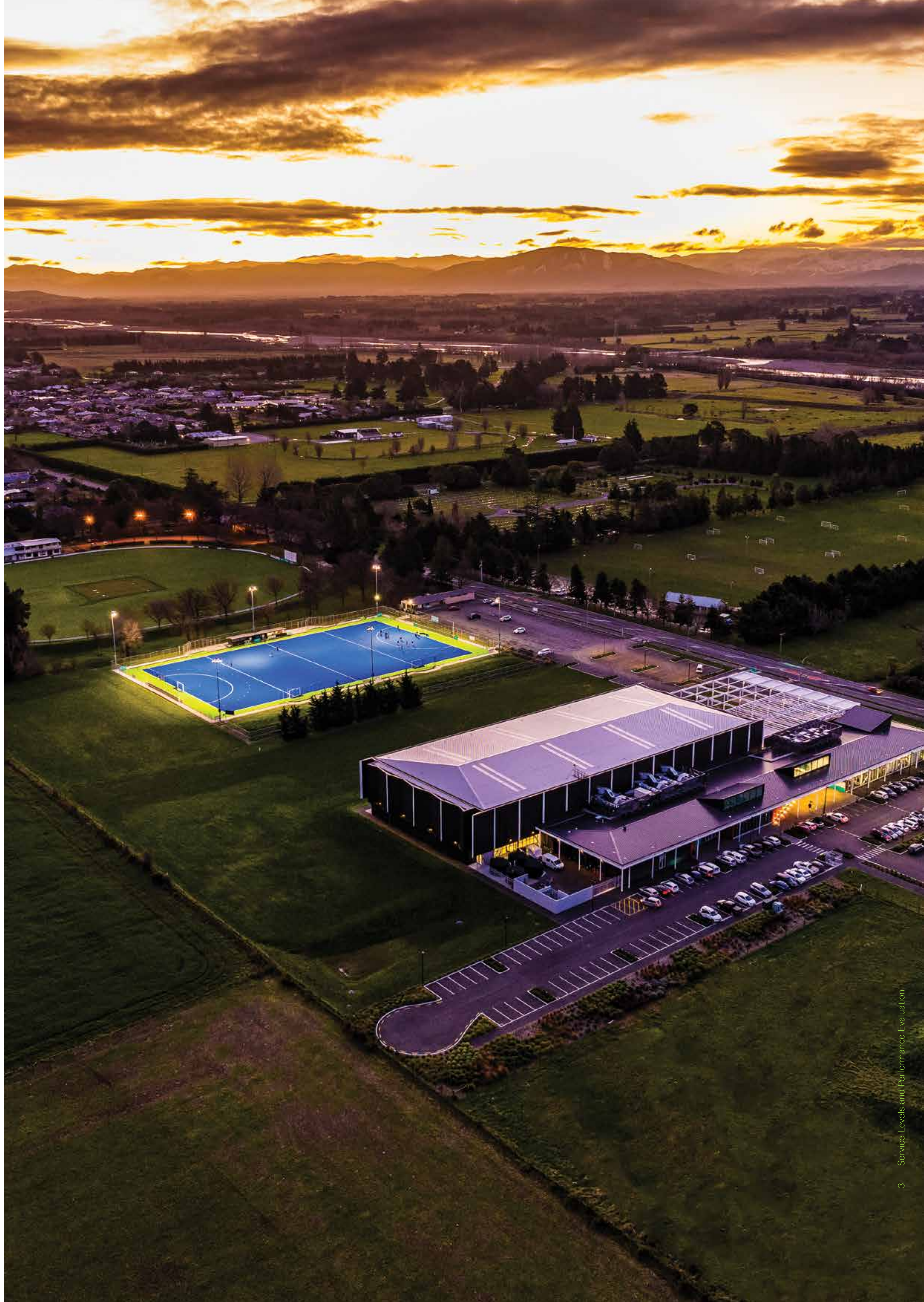
Table 3.8 Health, safety, environment and quality evaluation

3.9.5 CONSUMER ORIENTED

Monitoring and improving service delivery is vital if we are to establish trust and goodwill with consumers and maintain our reputation with our stakeholders. While our customer satisfaction scores have continued to improve over time, we recognise that additional improvement is required in some areas. New baseline targets have been established in FY22 after redeveloping the survey to better align with our "Plan–Build–Operate" model (see Table 3.3).

Category	Analysis	Initiatives	Target date
Engagement Effort	MainPower is aware that consumers interact with MainPower for different reasons and that the systems that support individual interactions are at varying stages of integration and maturity.	MainPower uses a "Plan–Build–Operate" model. In recent years, high demand for services has put pressure on existing resources in our Service Delivery Team. Recently a number of process and resourcing improvements have been implemented. As the Service Delivery Team settles into their new structures and processes, we expect to see further improvement in engagement effort scores.	FY26
Timeliness of Service	Respondents were those who engaged with MainPower regarding customer-initiated work. The results confirm the challenge faced when balancing work required to deliver the AMP alongside fluctuating customer-initiated works.	The demand for MainPower services (in particular, our Service Delivery function) is high, which has an impact on timeframes. Recent changes to resource and processes within this department are improving delivery times. However, we remain committed to continuously finding new opportunities to improve.	FY26
Communication	Communication in this instance refers to communication regarding customer-initiated work. We recognise that with MainPower's high workload this year, there have been communication challenges.	The following initiatives are currently addressing this issue. • Process mapping of all existing processes and procedures related to customer-initiated work, and finding opportunities for improvement, is underway. • The Service Delivery Team is completing a MACK system development to align the system with their processes. • The Service Delivery Team has introduced service-level agreements to define appropriate timeframes for response to customers.	FY26
Final Price	MainPower recognises there is value in providing more consistent pricing to customers in relation to customer-initiated work. There is always a challenge when pricing customer-initiated work, as it is a payment that is not often associated with instant gratification, given the nature of our business. External factor have caused significant supply constraints and the cost of materials has increased. This has been reflected in MainPower's pricing rate cards.	MainPower reviews the pricing rate card regularly to ensure alignment with the current market. MainPower is also undertaking a review of our Network Extension, Upgrades and Capital Contributions Policy to ensure it is fair, sustainable and able to be consistently implemented.	FY26

Table 3.9 Customer feedback of our performance measures and initiatives to improve them



3.9.6 DELIVERY

3.9.6.1 MAINTENANCE

MainPower has delivered on its safety critical maintenance throughout FY24. The works also included asset data collection, which enabled MainPower to assess overall asset portfolio health, as detailed in Section 7. Expenditure was within the performance target for the year. All maintenance was completed, as shown in Table 3.10.

Class	Description	Status
Maintenance	Overhead inspections	Complete
	Zone substations	Complete
	Kiosks	Complete
	Transformers	Complete
	Switchgear	Complete
	Secondary systems	Complete
	Underground assets	Complete
	Network property	Complete
	Reactive	Complete

Table 3.10 Maintenance programme summary

3.9.6.2 CAPITAL PROGRAMME DELIVERY

Capital expenditure on network assets finished above target for FY24 as MainPower has continued to deliver on the asset expenditure programme, which is informed by asset condition, criticality and the relevant Security of Supply Standard (see Table 3.11). This work programme refinement will be reflected in elevated levels of capital expenditure in upcoming years.

Class	Description	Status	Comment
Major Projects	Cheviot to Kaikōura sub-transmission line upgrade	In progress	FY26–FY27
	Hanmer Springs sub-transmission upgrade	In progress	FY29–FY30
	Amberley zone substation 33 kV upgrade	In progress	FY26–FY27
	Coldstream zone substation	In progress	FY26–FY31
Reinforcement Projects	Amberley Reserve Road link	In progress	FY25
	Reinforce Swannanoa SW63 and SW66 – Stage 2	In progress	FY27
	Fernside reconfiguration	Deferred	FY27–FY28
	Mandeville area voltage improvements	Deferred	FY29
	Kaiapoi K7 feeder split	Complete	FY25
	Island Road feeder extension – Stage 1	Complete	FY25
Renewals	Overhead assets, replace 710 units	Complete	100% complete
	RMUs, replace 10 units	In Progress	10% complete
	Distribution transformers, replace 29 units	In Progress	100% complete
	Low-voltage link boxes, replace 23 units	In Progress	100% complete
	Low-voltage switchgear units, replace 10 units	In Progress	50% complete
	Service boxes, replace 50 units	In Progress	84% complete

Table 3.11 Capital programme summary (FY24)

3.9.6.3 FINANCIAL PERFORMANCE

Table 3.12 compares actual revenue and expenditure to the previous forecasts that were made for the FY24 disclosure year.

Expenditure on assets	Forecast ($000)	Actual ($000)	% variance
Consumer connection	6,404	11,279	76%
System growth	7,978	1,442	(82%)
Asset replacement and renewal	9,145	13,932	52%
Asset relocations	–	–	–
Reliability, safety and environment			
Quality of supply	1,696	651	(62%)
Legislative and regulatory	–	458	–
Other reliability, safety and environment	1,666	2,300	38%
Total reliability, safety and environment	**3,362**	**3,410**	**1%**
Expenditure on network assets	**26,888**	**30,063**	**12%**
Expenditure on non-network assets	694	7,204	938%
Expenditure on assets	**27,582**	**37,267**	**35%**
Operating expenditure			
Service interruptions and emergencies	1,067	1,265	19%
Vegetation management	1,217	1,155	(5%)
Routine and corrective maintenance and inspection	5,810	5,366	(8%)
Asset replacement and renewal	–	19	–
Network operating expenditure	**8,094**	**7,805**	**(4%)**
System operations and network support	11,388	12,603	11%
Business support	5,262	4,339	(18%)
Non-network operating expenditure	**16,650**	**16,942**	**2%**
Operating expenditure	**24,743**	**24,747**	**0%**

Table 3.12 FY24 financial performance compared with FY23 nominal dollar expenditure forecast

Performance analysis for the FY24 disclosure year is summarised in Table 3.13 below.

Category	Analysis
Consumer connection	Contestable in nature and above target, due to greater than expected demand for new connections.
System growth	Below forecast due to early works and design phase of the zone substation projects taking longer than expected, resulting in delays in the commencement of construction.
Asset replacement and renewal	Higher asset replacement and renewal expenditure.
Network and non-network assets	Greater than the FY23 forecast due to the factors described above plus some strategic decisions to acquire non-network assets.
Network operating expenditure	In accordance with forecast expenditure, but expenditure on service interruptions and emergencies was above plan due to weather-related faults.

Table 3.13 FY24 financial performance analysis

3.9.7 INDUSTRY BENCHMARKING

The objective of benchmarking is to observe and understand how MainPower is performing as an organisation when compared with other EDBs. MainPower benchmarks itself against seven other network businesses (listed in Table 3.14) based on ICP density (± 2.0).

Organisation	ICP/km	ICPs
Alpine Energy	7.7	33,539
EA Networks	6.5	20,538
Firstlight Network	3.3	25,872
Horizon Energy	9.6	25,179
MainPower NZ	8.5	44,109
Marlborough Lines	7.6	26,830
Network Tasman	11.4	42,224
Top Energy	8.0	33,740
Median	**7.8**	**30,184**

Table 3.14 Benchmark organisations (from the Commerce Commission electricity distributers dataset, FY23)

3.9.7.1 NETWORK OPERATING EXPENDITURE

MainPower's network operating expenditure, which includes planned and unplanned network maintenance and fault response, was lower than the peer group average during FY23 (see Figure 3.17). This reflected MainPower reviewing the asset management practices that were detailed in the last AMP. Expenditure is expected to increase to around the peer group average as MainPower implements its revised asset management practices.

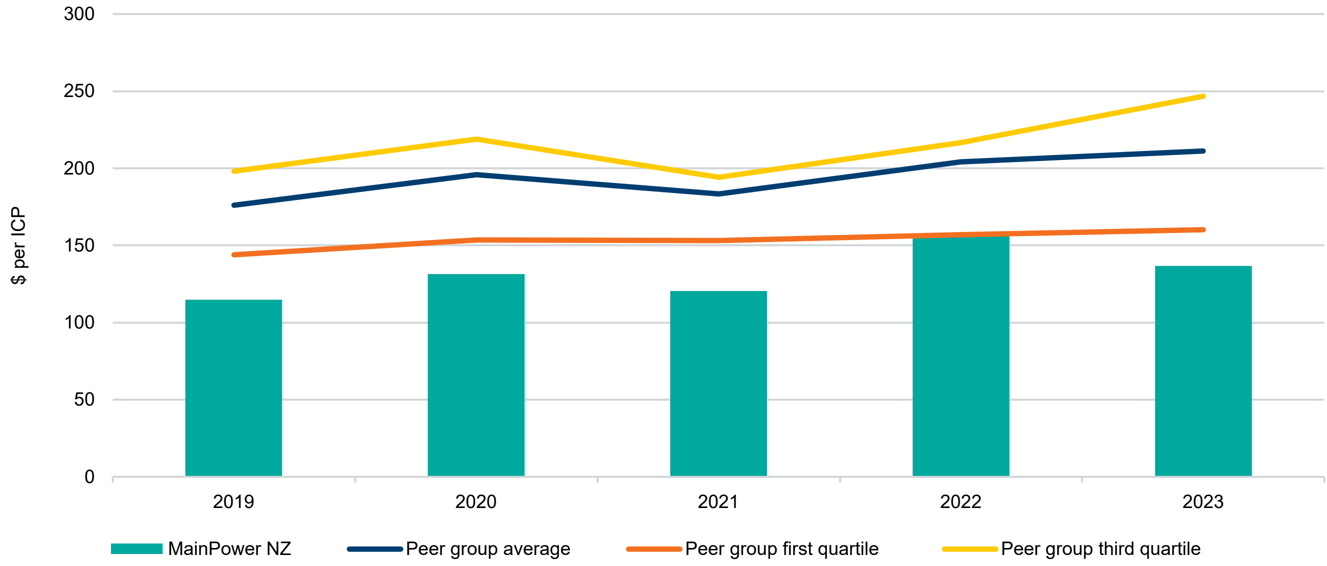


Figure 3.17 Benchmarking – network operating expenditure per ICP (FY19–FY23)

3.9.7.2 NON-NETWORK OPERATING EXPENDITURE

Non-network operating expenditure, which includes corporate, business support, asset management planning and network operation, is similar to the peer group average (see Figure 3.18). This reflects MainPower's focus on improving asset management maturity and the development of robust and effective business processes.

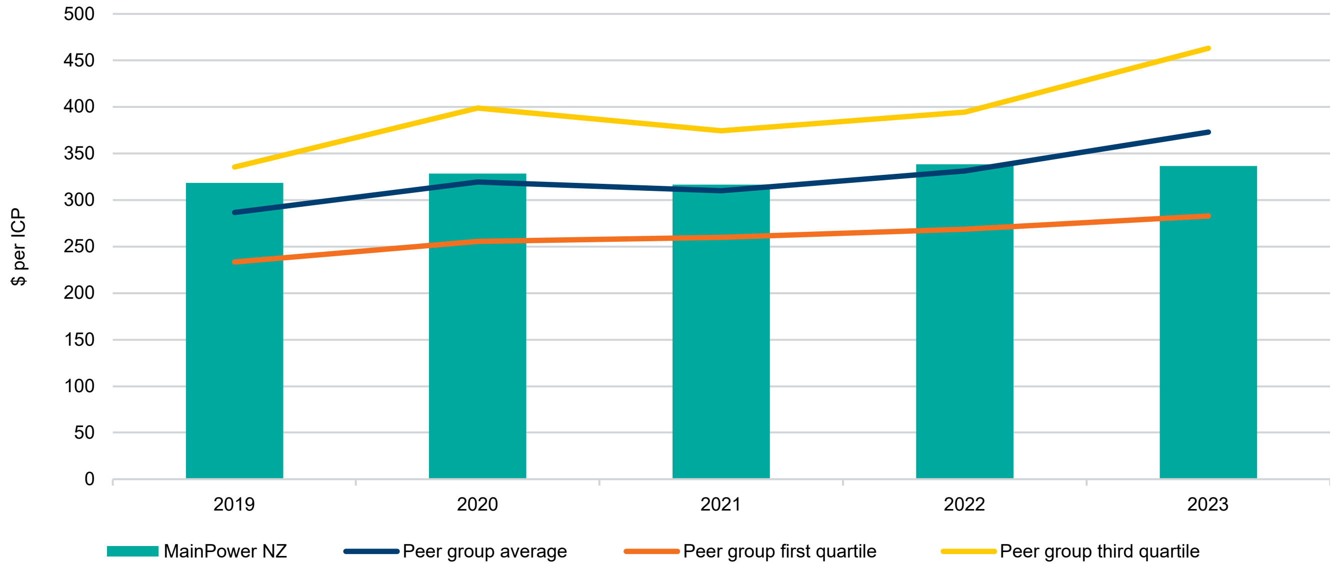


Figure 3.18 Benchmarking – non-network operating expenditure per ICP (FY19–FY23)

3.9.7.3 CAPITAL EXPENDITURE ON NETWORK ASSETS

Capital expenditure is the cumulative expenditure required to deliver network requirements, including:

- capacity
- security of supply
- asset replacement and renewals.

MainPower's capital expenditure on network assets is influenced by both network reinforcement and new zone substation projects, and an increase in the number of consumer connection requests. This has resulted in capital expenditure per ICP performance between the peer group third quartile and the peer group average (see Figure 3.19). Going forward, this is expected to remain at sustained levels owing to works required to deliver security of supply, network reliability, an increase in consumer connection requests and an increase in MainPower's replacement and renewals programme.

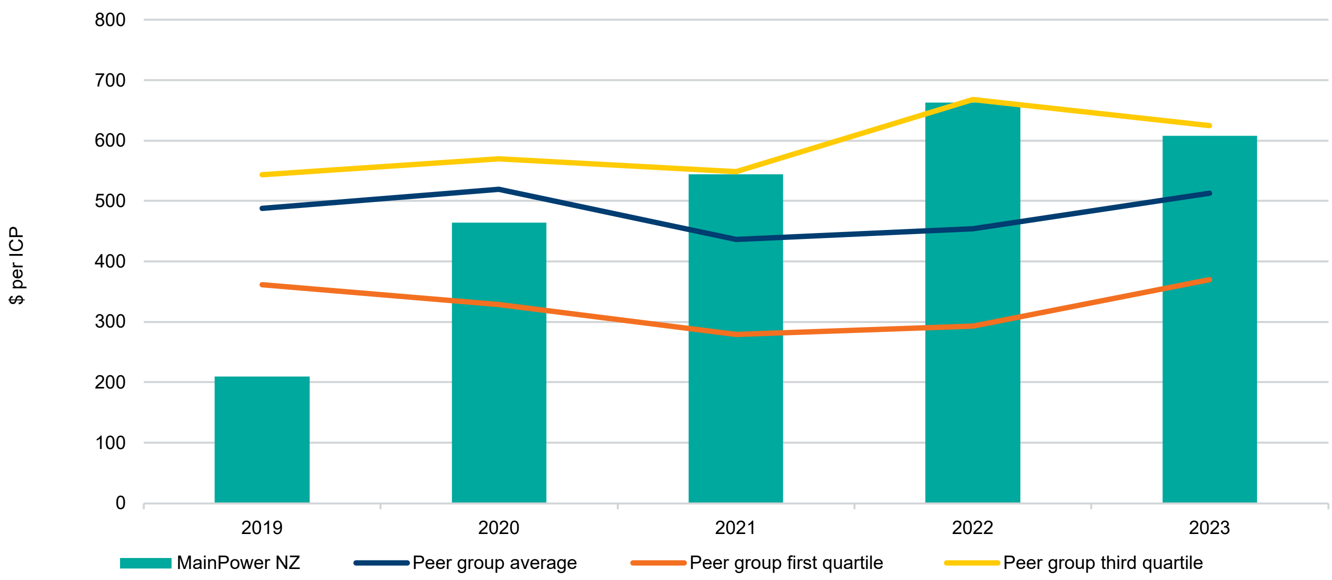


Figure 3.19 Benchmarking – network capital expenditure per ICP (FY19–FY23)

3.9.7.4 RELIABILITY

MainPower's network reliability remains within the industry peer group average. However, forecast SAIDI and SAIFI is trending lower, with both SAIDI and SAIFI at or near the peer group average over the longer term (Figure 3.20 and Figure 3.21). Reliability initiatives have been identified to address quality of supply for MainPower in the future and return it to historical norms.

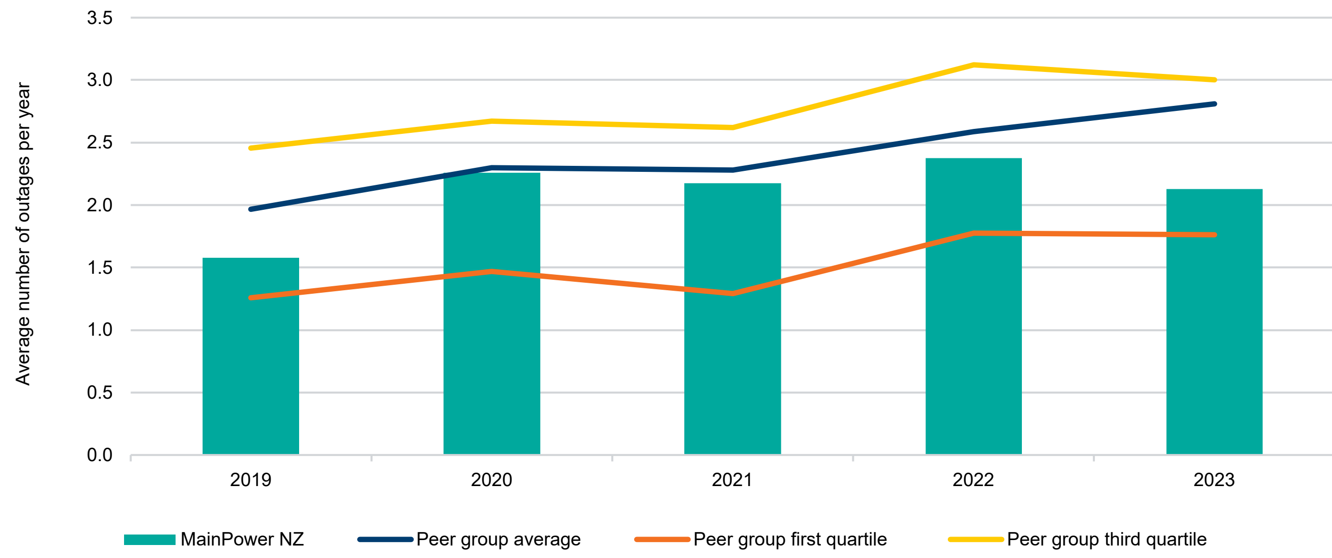


Figure 3.20 Normalised SAIDI benchmarking (FY19–FY23)

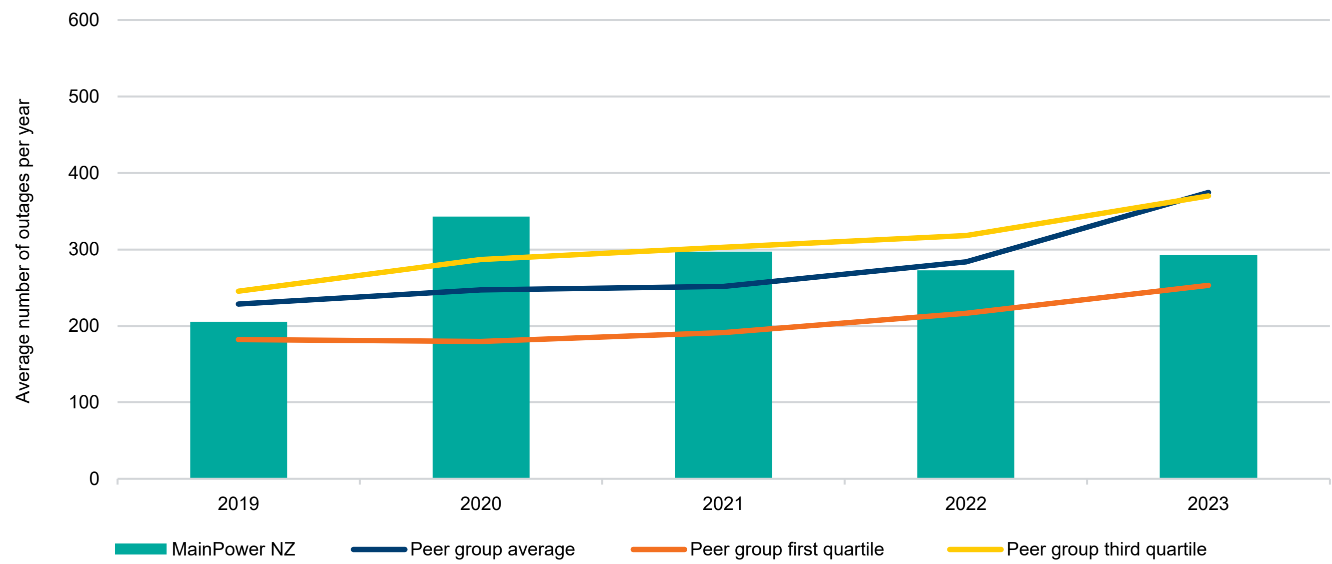


Figure 3.21 Normalised SAIFI benchmarking (FY19–FY23)

3.10 CHANGES IN FORECAST EXPENDITURE

A change in forecast expenditure that may materially affect performance definitions is not expected within the reporting year.

Any instances where expenditure may affect network performance in the future will be reported and the internal response will be defined and implemented.

4
RISK AND THE ENVIRONMENT

Asset risks are identified from asset management studies, risk registers, industry forums, incident analysis, audits, inspections, field observations, and site-specific safety plans and safety observations, and are captured in an online platform that is used to manage and report on risks, criticality levels and control measures.

"Bow tie" diagrams are developed to visualise the risks and provide a means to qualify and communicate the control measures that manage each risk. Bow tie diagrams are also used to support investigating incidents, critical tasks and managing safety and business critical risks (see the next section).

A customised risk matrix is used to assess and quantify the likelihood and consequence of individual risks and define the auditing requirements and effectiveness of each of the control measures.

Compliance is assured through measured compliance reporting of critical control observations, carried out by all staff and captured in MainPower's online platform.

The Chief Executive has ultimate responsibility and accountability for ensuring that risk is managed across MainPower. The Chief Executive and Executive Team provide leadership, agree the strategic direction and risk appetite, and promote a health and safety oriented culture to ensure the best outcome for MainPower, our people and the community.

The MainPower Board actively considers risks during strategic and tactical decision-making processes (as do all levels of management), as well as determining the level of residual risk appetite.

A key priority of MainPower's Strategic Plan is to strengthen the links between critical risks, critical processes and incidents, focusing on prevention and reduction. Essential to this process is having a clear understanding of what our safety and business critical risks are, and providing assurance that controls are effective.

4.1 OUR APPROACH TO RISK

Protecting the public, our team, our service providers, and the environment from the inherent risks posed by our electricity distribution network sits behind everything we do. Our Asset Risk Management programme is structured to incorporate these elements of public, personnel and environmental protection into a programme that ensures continuity of electricity supply, efficient protection of network assets, and protection of shareholder and commercial interests while ensuring that MainPower continues to meet its service-level targets.

MainPower recognises that risk management is an integral part of good governance and best management practice and has adopted the principles of risk management as detailed in ISO 31000:2018 *Risk Management – Guidelines* (see Figure 4.1).

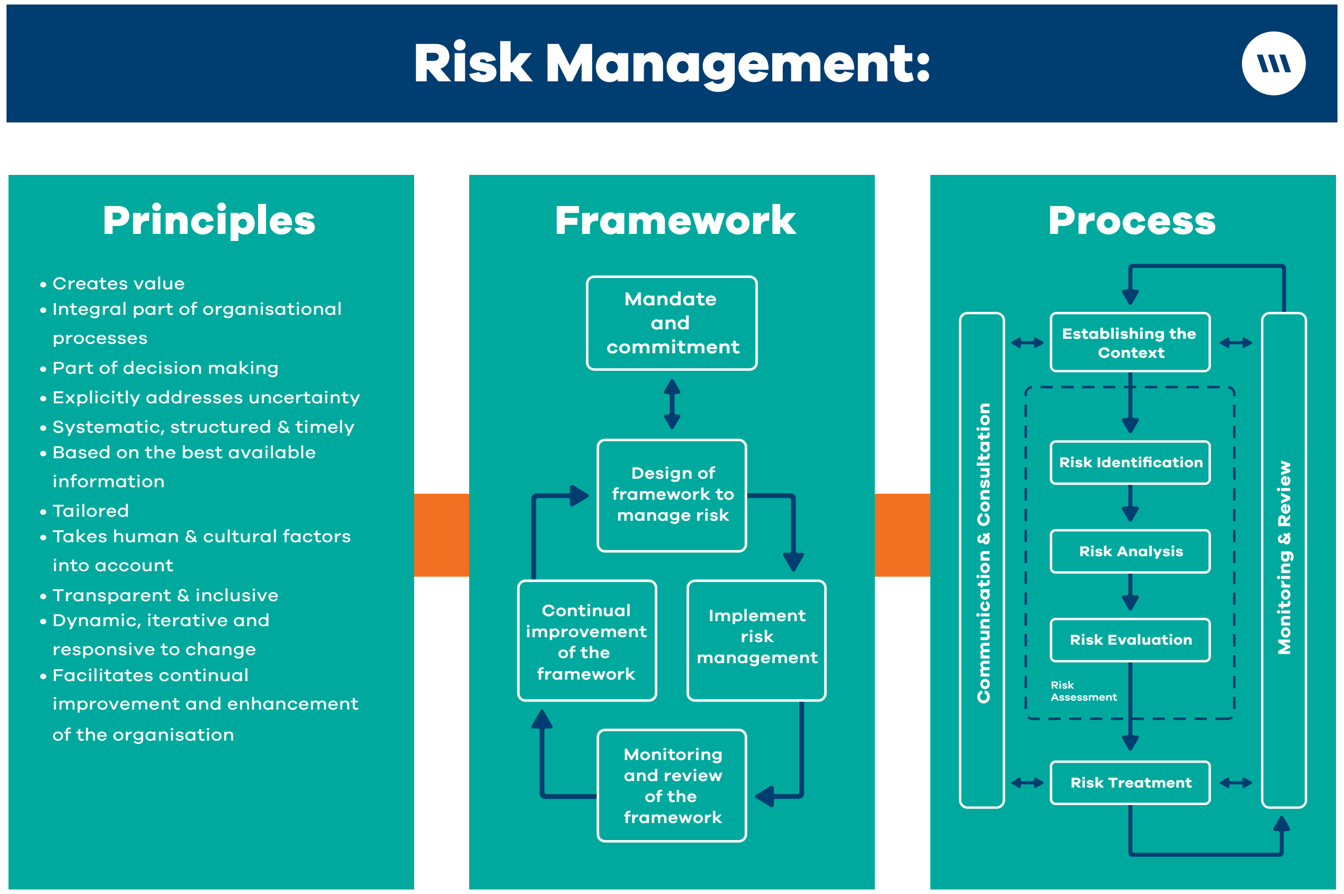


Figure 4.1 MainPower's Risk Management Framework (drawn from ISO 31000:2018)

4.1.1 CRITICAL RISKS

Critical risks are defined as anything that has the actual or potential to cause:

- death to employees, contractors or members of the public
- significant property damage, or
- MainPower to be severely impacted as a business.

MainPower has identified 10 safety critical risks and five business critical risks relevant to our business via a collaborative approach (see Figure 4.2). Each risk has a risk control plan (bow tie) in place that is owned by a member of the Executive Team and is reviewed at least annually.

The bow tie methodology that MainPower uses for risk management offers an excellent visual tool for illustrating risk, providing a direct link between controls and management systems, highlighting areas where controls are weak, assisting with incident investigation and ensuring critical controls do not "fall through the cracks".

Figure 4.2 MainPower's critical risks

4.2 ENVIRONMENT AND SUSTAINABILITY

MainPower takes an integrated approach to managing, delivering, and continually improving the environmental aspects of our business activities, services and products.

Using the United Nations Sustainable Development Goals as a foundation, we have identified three key areas where we believe we can make the most difference: prosperity, people and planet (refer to Figure 4.3). These strategic areas form the basis of our Sustainability Management Plan.

MainPower is committed to:

- reducing waste
- using reusable and refillable products
- rethinking how we do things (changing to more sustainable products)
- using a greener supply chain (through prequalification)
- enabling electrification (low-voltage monitoring)
- supporting renewable energy (hydro, wind and solar)
- prioritising energy efficiency (e.g. LEDs)
- engaging with our community
- supporting inclusion, diversity and equity
- reducing carbon emissions
- repurposing materials (e.g. cable drums and power poles).

Our sustainability strategy considers the energy trilemma of finding balance between energy reliability, affordability and sustainability and its impact on everyday lives. We plan to achieve this by:

- reviewing the implications for the speed and direction of energy transition
- enabling low-carbon energy to drive innovation, economic recovery, and positive image
- accelerating digitalisation opportunities in energy and the new challenges of resilience.

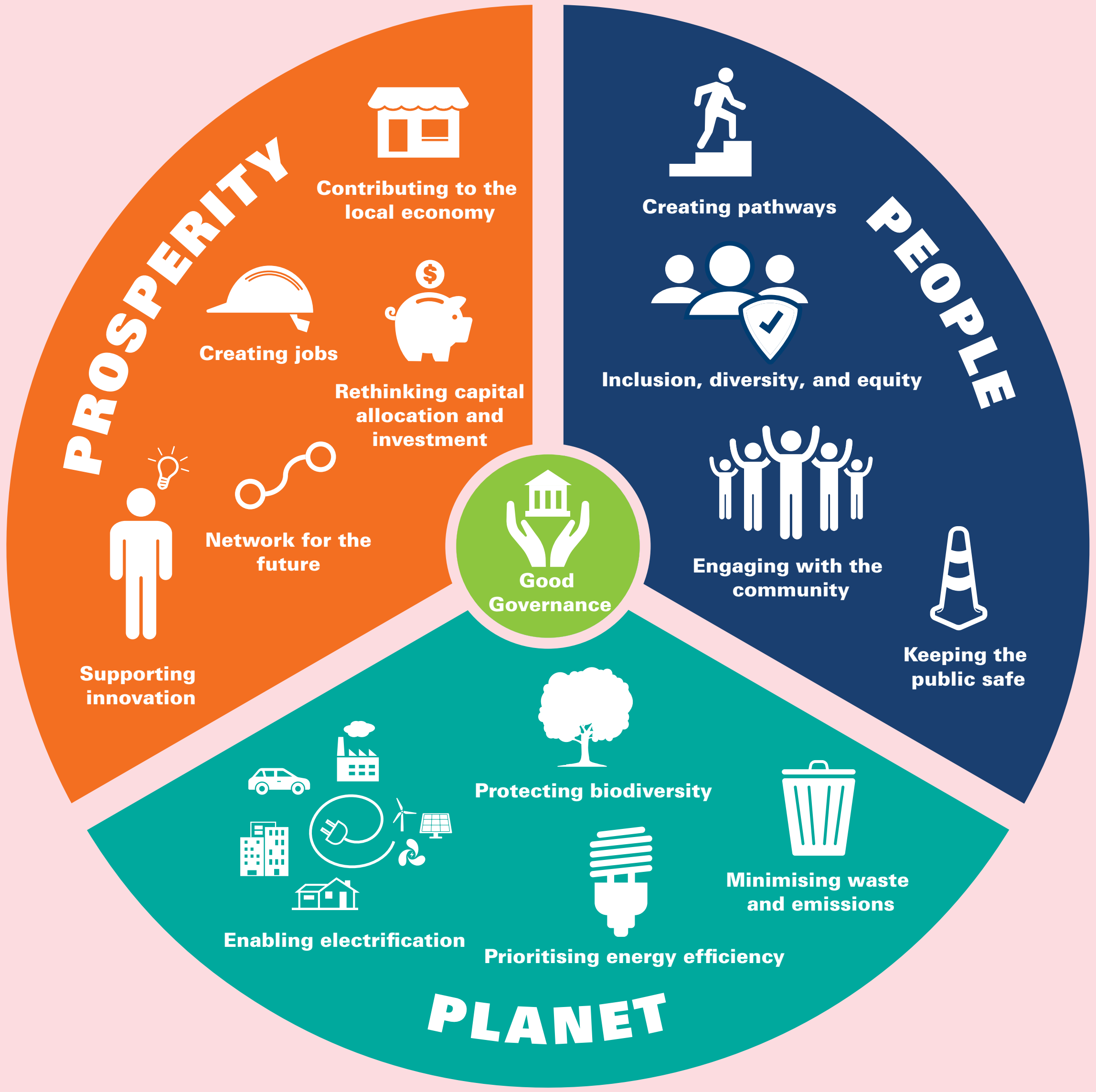


Figure 4.3 MainPower's sustainability priorities

4.3 NETWORK RESILIENCE

MainPower considers network risk within its Asset Management and Network Planning Framework, including:

- high-impact low-probability (HILP) events
- physical risk to grid exit points (GXPs), zone substations, and transmission and distribution systems
- meteorological hazards – storms, floods, snow, wind, lightning, and resulting wildfires
- national grid emergencies
- cybersecurity and terrorism
- pandemics.

MainPower has an ongoing initiative to assess the impact of HILP events and network resilience in coordination with local authorities across North Canterbury and Civil Defence Emergency Management (CDEM) agencies.

4.3.1 PLANNING FOR MAJOR EVENTS

MainPower uses the bow tie risk methodology to analyse and demonstrate causal relationships in high-risk scenarios, and to identify the assets at threat from HILP events. Key assets that are identified in these studies include 66 kV and 33 kV sub-transmission systems, and zone substations.

While the frequency of meteorological events such as wind, flood and snowstorms far exceed that of earthquakes, it is the consequences of earthquakes that most threaten our assets. MainPower has examined the risk of earthquake in its bow tie studies and identified escalation measures and response plans to manage these situations.

The effects of climate change are being considered, and summary findings are detailed in Section 4.5. Sea level rise along the east coast is not expected to cause major disruption to the electricity network in the Asset Management Plan (AMP) planning period. Table 4.1 presents a high-level assessment of the risks posed by natural hazard events.

Asset	Flood	Windstorm	Electrical storm	Snowstorm	Wildfire	Earthquake	Landslip	Tsunami
66 kV & 33 kV sub-transmission system								
Zone substation								

Note: = low impact
= medium impact
= high impact

Table 4.1 Assessment of risk by natural hazard events

4.3.1.1 SUB-TRANSMISSION SYSTEMS

MainPower is in the process of developing models in conjunction with CDEM agencies to assess the threat to sub-transmission and distribution networks from HILP events.

Natural hazards such as flood, windstorm, electrical storm, snowstorm, wildfire, earthquake, landslip, and tsunami are considered in Table 4.2. The information was sourced from external publications such as the Canterbury Regional Council Natural Hazards in Canterbury report, which has been reviewed against network design criteria.

Hazard	Observations	Likelihood	Consequences
Flood	• The risk to overhead lines from flood hazard is limited, even in a 100-year flood event. • Damage is isolated, resulting from landslips and/or subsidence or damage to individual poles sited within the normal course of a river. • A 500-year flood event would result in extensive flooding of some urban areas and subsequent damage to ground-mounted distribution equipment.	Possible	Major
Windstorm	• Damage to overhead lines is routinely caused by high winds. • Historically, this has resulted in minor and isolated damage. • Our design criteria meet or exceed the requirements for a 50-year return period event, as set out in AS/NZS 7000:2016. • The most severe winds are winds from the northwest (these occurred in 1945, 1964, 1975, 1988 and 2013). • The peak wind speed of 193 km/h recorded in August 1975 exceeded the 100-year recurrence interval. • Average recorded wind speeds in Christchurch approach 45% of design speed on 54 days a year and 66% on 3 days a year. • Canterbury has recorded four significant tornado events in the last 25 years, none of them located in our distribution area.	Possible	Catastrophic
Electrical storm	• Most parts of Canterbury have few electrical storms. • Over the plains, fewer than five thunder days, on average, occur each year, with the highest frequencies occurring between September and March. • Near the Southern Alps, 20 thunder days, on average, occur each year, with the highest frequencies during April and May. • Zone substations, transformers and communications equipment are protected with lightning arrestors.	Unlikely	Moderate
Snowstorm	• Canterbury occasionally experiences weather events that deposit heavy, wet snow on overhead lines. • Higher inland areas can be subject to ice build-up with coincident wind loading, which places high loads on overhead infrastructure. • Isolated sections of overhead lines may be exposed to a risk of avalanche.	Unlikely	Major
Wildfire	• This can cause damage and destruction to the overhead network infrastructure. • Can cause particulate accumulation on power lines and insulators.	Rare	Catastrophic
Earthquake	• Liquefaction can cause equipment foundations to fail. • Power line foundations can fail, causing loss of supply. • Underground conductor failures can cause loss of supply. • Repairs can be hampered by access restrictions. • Stock resupply limitations can occur because of transport issues.	Unlikely	Catastrophic
Landslip	• Remote sections of sub-transmission networks may be exposed to landslip, causing loss of supply.	Unlikely	Major
Tsunami	• While the occurrence of a tsunami is uncertain, this hazard is a realistic possibility for Canterbury, particularly at the mouth of the Waimakariri and Ashley rivers, at Leithfield Beach, Motunau, and at Kaikōura where the narrow continental shelf and presence of submarine canyons makes this area particularly susceptible, especially Goose Bay and Oaro. • Most overhead lines are not generally exposed to this hazard.	Rare	Moderate

Table 4.2 Hazard identification for sub-transmission and distribution systems

4.3.1.2 ZONE SUBSTATIONS

We have developed natural hazard exposure limits for our zone substation assets, using a weighting factor for the strategic importance of individual sites. This weighting is based on asset value, peak load and the capability to switch load away from the substation. The two measures used to define risk factors and risk priorities are:

1. **risk factor = probability (years recurrence) × consequence (% damage)**
2. **natural hazard exposure = risk factor × weighted strategic importance.**

This assessment has identified earthquake hazards as the greatest risk to zone substations.

Flood hazards for zone substations are not rated as significant, owing to the location and/or the resilience of design of a substation in a 1-in-500-year flood event (i.e. the likelihood that a 500-year flood event will occur in any given year). Other meteorological hazards have comparatively high probabilities, but the consequences for these assets are generally moderate.

4.3.2 RESILIENCE OF THE NETWORK

MainPower is taking part in a regional programme to model network vulnerability to hazard events and climate change using nationally accepted impact assessment modelling tools. The outputs from this vulnerability assessment will inform MainPower's resilience planning and the Network Regional Plans.

Network resilience is supported by the following documents and plans.

Asset Management Policy:

This describes our commitment to:

- asset management, setting out our commitment to complying with regulatory requirements and industry standards
- our consumers
- ensuring we are resourced to deliver on our asset management objectives.

Risk Management Plans

We have developed risk bow ties for our critical risks and defined the escalation control measures to manage critical events and reduce their consequences.

Incident Response Plans

These are aligned with New Zealand's Coordinated Incident Management System (CIMS), which is a key resource for our response to major incidents or events.

Participant Rolling Outage Plan

This sets out the actions that MainPower will take to reduce consumption in the event of an emergency being declared by the System Operator.

Security of Supply Standard

This defines the level of service that is required of the network to meet normal demand under contingency events, such as equipment failure or serious incident.

4.4 RISK MITIGATION, PRACTICES AND PLANS

4.4.1 RISK MITIGATION MEASURES

Maintaining our network is a key priority and includes a scheduled programme of planned works, as well as a defect management programme.

MainPower is moving to a Condition-Based Risk Management (CBRM) approach, based on the Electricity Engineers' Association (EEA) *Asset Health Indicator Guide* and *Asset Criticality Guide*, in combination with CBRM principles from the United Kingdom. This allows us to use condition data, attribute data and probability of failure to develop asset health ratings for our assets which, when combined with asset criticality, allows us to optimise asset portfolio investment and target our highest-risk assets.

4.4.2 ACTIVITY, PLANT AND EQUIPMENT RISK

All critical activities required to operate and maintain the network – including plant and equipment – are risk assessed using bow tie methodology. These are living documents and are reviewed after events, where new risks have arisen or controls have been added or removed.

At MainPower, critical controls are deemed effective when they are:

- implemented (i.e. there is a process in place and people are trained)
- applicable to the hazard and independent (i.e. not reliant on other controls)
- reliable (i.e. function consistently)
- monitored and audited.

Risk controls are monitored through inspection programmes and "critical control observations", with key performance indicators set for people leaders and executive leaders across the business.

All critical risks are formally reviewed on an annual basis, in addition to ongoing incident and risk reviews.

4.4.3 BUSINESS CONTINUITY PLAN

Our Business Continuity Plan is incorporated into our Incident Management Plan (see the next section), which is designed to minimise disruption after a critical event. We have identified our critical business activities and processes, and the types of events that can interrupt them.

The plan has assessed critical risks arising from:

- disruption of electricity supply during a natural disaster
- disruption of electricity supply from a major supplier (e.g. Transpower)
- climate change impacts (e.g. rising sea level, extreme flooding, extreme change in temperature, significant weather events, wildfire)
- disrupted systems and shortage of staff during a pandemic
- legislative non-compliance
- risk of fire to our assets or work undertaken within the network area.

4.4.4 USING AN INCIDENT MANAGEMENT PLAN TO RESPOND TO DISRUPTIVE INCIDENTS

The Incident Management Plan guides our response to any disruptive incident that has a serious impact on our people, operations, services and reputation. The plan outlines how we will strategically and operationally manage our response so that we can prevent or reduce the impact and can continue to deliver those functions and services that are critical to our business.

Part of our response has been to adopt an Incident Management Framework, which outlines how we respond to, and operate in, any disruptive incident. The framework is based on New Zealand's CIMS and covers the 5 R's – Reduction, Readiness, Response, Recovery, Review (see Figure 4.4).

Simulations are practised at least twice per year, with additional training exercises facilitated across the Incident Management Team to increase competency.

Figure 4.4 New Zealand's Coordinated Incident Management System: Five R's

4.4.5 LIAISING WITH CIVIL DEFENCE EMERGENCY MANAGEMENT AGENCIES

As a "Lifeline Utility", we are obliged under the law (including the Civil Defence Emergency Management Act 2002) to ensure we can continue to function, even potentially at a reduced level, during and after an emergency, and that we have plans available to ensure continued operation. We are also obliged to participate in developing the CDEM Strategy and CDEM Plans, and to provide technical advice to the Director and CDEM Groups as required.

As noted earlier, some of our recovery plans will activate once predetermined triggers are met.

4.4.6 USING INSURANCE PRACTICES TO MINIMISE THE IMPACT FROM LOSS OF, OR DAMAGE TO, OUR ASSETS

We maintain an insurance programme with an objective to cost-effectively minimise the impact to MainPower from any loss of, or damage to, our assets. We currently operate three insurances that are relevant to risks in our network operation, for:

- public liability
- materials damage on stations, including zone substations, load plants and contained structures
- ground-mounted transformers.

It is not cost effective to insure the remaining sub-transmission and distribution systems with external providers. MainPower maintains a self-insurance fund to cover those network assets that cannot be insured cost effectively. The amount of insurance is reviewed regularly and held in a self-insurance fund.

4.5 CLIMATE CHANGE

Our electricity assets are vulnerable to changes in climate and extreme weather events. The impacts of climate change are already being observed in the frequency and severity of storms in recent years resulting in extensive damage to MainPower's network and significant disruption to our customers. Table 4.3 summarises the physical and behavioural risk to assets due to climate change.

Threat	Risk	Risk treatment
Severe weather, wind speed and storms	• Asset damage caused by increased wind speeds and vegetation.	• Vegetation management, including an increase in tree scoping from 5 yearly to 2 yearly. • Use light detection and ranging (LiDAR) technology for the management clearances. • Use Digital Twin technology for the modelling of increased windspeeds. • Increase community awareness of risks through our website, radio and community pages.
Wildfire	• Asset failure due to asset location in wildfire zones.	• Review loss of supply impact to consumers because of asset failure due to wildfire.
Rising sea levels/ Extreme flooding	• Asset failure due to flooding in low-lying areas or susceptible to new flood zones. • Stranded assets due to shifts in the population.	• Conduct a review of asset locations in low-lying and coastal areas.
Changing supply/demand (behavioural) trends	• Change in electricity consumption due to climate change, influenced by temperatures, consumers' use of low-carbon technology, carbon prices.	• Develop and implement network transformation road map that supports consumer engagement. • Use pricing signals to manage network constraints.

Table 4.3 Risks related to climate change and their treatment

5
MAINPOWER'S NETWORK

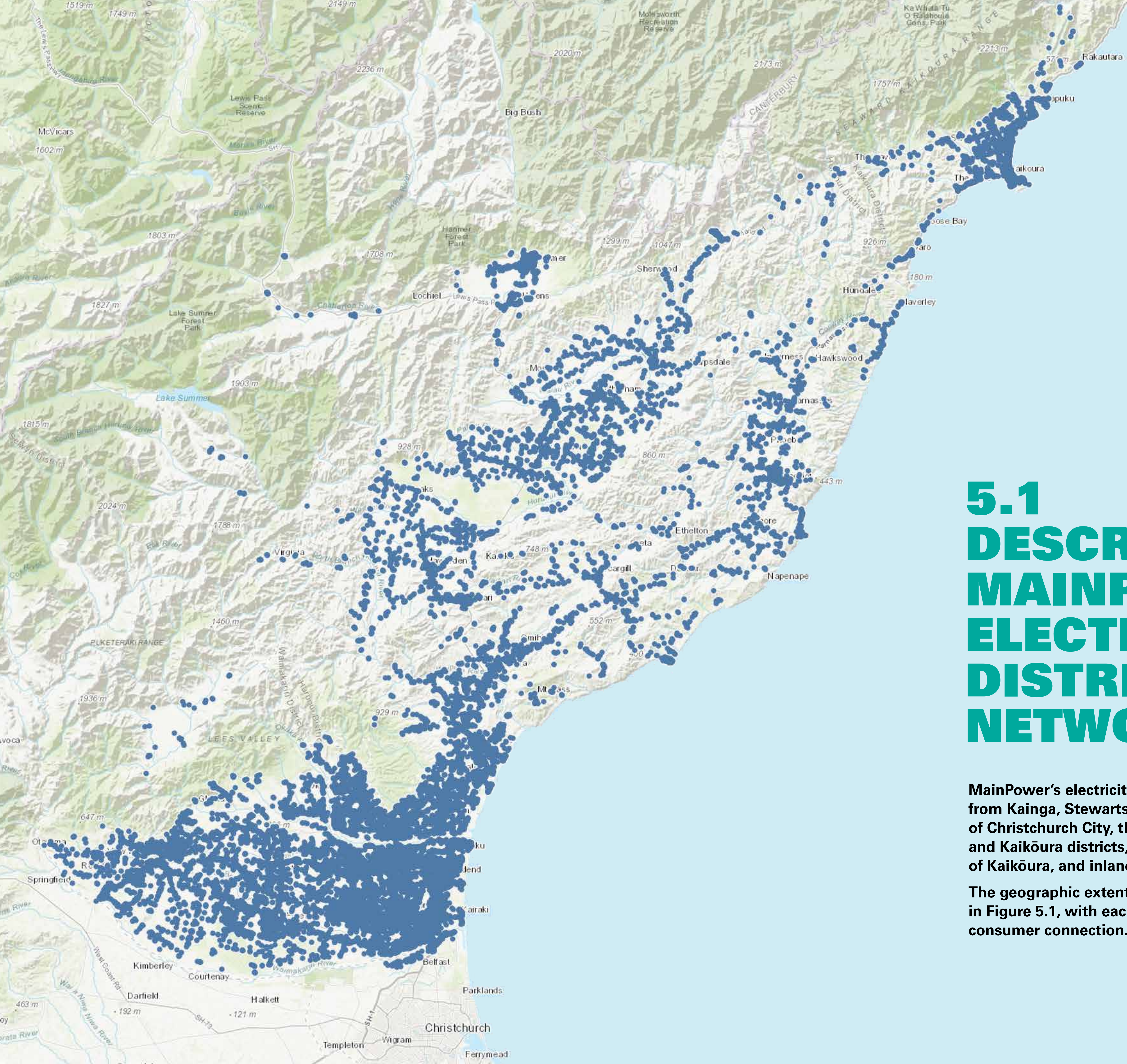


Figure 5.1 MainPower's electricity network consumer geographic distribution

5.1 DESCRIPTION OF MAINPOWER'S ELECTRICITY DISTRIBUTION NETWORK

MainPower's electricity distribution network extends from Kainga, Stewarts Gully and Coutts Island north of Christchurch City, through the Waimakariri, Hurunui and Kaikōura districts, up to the Puhi Puhi Valley north of Kaikōura, and inland to Lewis Pass.

The geographic extent of the network is represented in Figure 5.1, with each blue dot representing a consumer connection.

5.1.1 LARGE CONSUMERS

Our large consumers are:

Daiken New Zealand medium-density fibreboard mill at Ashley

The Daiken mill is supplied from the Ashley grid exit point (GXP) via four 11 kV feeders, which provide reasonable levels of security. The Daiken controllers can disconnect power supply during emergencies, and maintenance is scheduled to coincide with Daiken maintenance programmes or times of low production.

Hellers meat-processing plant at Kaiapoi

The site has undergone rapid growth, and the total load can be switched between two 11 kV feeders. Hellers has also installed a backup generator for critical supply during emergencies.

Sutton Tools NZ Limited tool-manufacturing plant at Southbrook

This plant was formerly located in Kaiapoi. Due to a total loss caused by fire, it is being rebuilt from the ground up in the Southbrook industrial park. Currently, it does not consume a significant amount of electricity.

McAlpines sawmill at Southbrook

The sawmill has been transferred onto a new high-security dual-feeder-supplied switchboard, which has reduced the risk of power interruptions to the site.

Mitre 10 Megastore at Southbrook

This site has an alternative 11 kV feeder.

Belfast Timber Kilns at Coutts Island

This plant is connected near the end of a rural 11 kV spur line. No alternative supply is available at the site. Line maintenance is scheduled to coincide with plant maintenance programmes.

We also have several large supermarkets and other commercial businesses located in Rangiora, Kaiapoi, and Kaikōura. The transformers for each of these sites are part of ringed feeders with ring main units (RMUs), allowing alternative switching of supply in the event of a fault on one feeder.

5.1.2 LOAD CHARACTERISTICS

Table 5.1 shows the peak demand and timing of zone substation loads for FY22–FY24.

Substation	FY22 (MVA)	FY23 (MVA)	FY24 (MVA)	Peak
Ashley GXP	20.9	19.9	17.6	Winter
Culverden GXP 0331	17.9	17.6	18.3	Summer
Culverden GXP 0661	9.6	8.8	7.4	Winter
Kaiapoi GXP	34.8	30.2	30.2	Winter
Southbrook GXP 0331	34.7	0.0	0.0	Summer
Southbrook GXP 0661	39.1	52.1	53.3	Summer
Waipara GXP 0331	8.5	8.3	8.2	Winter
Waipara GXP 0661	9.1	7.2	9.5	Winter
Southbrook	31.7	37.8	38.3	Winter
Swannanoa	15.0	15.7	17.7	Summer
Burnt Hill	14.1	14.8	14.6	Summer
Amberley	6.0	6.8	5.9	Winter
Mackenzies Road	2.3	2.0	2.8	Winter
Greta	1.4	1.5	1.6	Summer
Cheviot	3.4	3.4	3.8	Summer
Leader	1.5	1.4	1.6	Summer
Ludstone Road	5.8	6.2	5.8	Winter
Mouse Point	15.6	15.7	18.3	Summer
Hanmer Springs	4.8	4.8	4.9	Winter
Lochiel	0.1	0.1	0.1	Winter
Hawarden	3.6	3.6	4.0	Summer

Table 5.1 MainPower network load characteristics (FY22–FY24)

5.1.3 PEAK DEMAND AND TOTAL ENERGY DELIVERED

Table 5.2 shows key system measures of the network for FY22–FY24.

System measure	FY22	FY23	FY24
Peak load	123.5 MW	122.4 MW	115.7 MW
Energy entering the system	662 GWh	656 GWh	653 GWh
Energy delivered	624 GWh	620 GWh	640 GWh
Loss ratio	5.8%	5.4%	5.6%
Load factor	61%	61%	66%
Average number of installation control points (ICPs)	43,130	44,108	44,918
Zone substation capacity (base ratings)	143 MVA	136 MVA	145 MVA
Distribution transformer capacity	588 MVA	599 MVA	672 MVA
Circuit line length	5,170 km	5,198 km	5,234 km

Table 5.2 System measures (FY22–FY24)

Table 5.3 provides a three-year trend of the connected installation control points (ICPs) by consumer group.

Consumer group ICPs	Average number of ICPs		
	FY22	FY23	FY24
Residential	35,451	35,868	37,177
Commercial	5,868	6,414	5,918
Large commercial or industrial	42	42	41
Irrigators	1,452	1,466	1,462
Council pumps	206	207	209
Streetlights	110	111	110
Individually managed consumer	1	1	1
Total	**43,130**	**44,109**	**44,918**

Table 5.3 Connected ICPs, by consumer group (FY22–FY24)

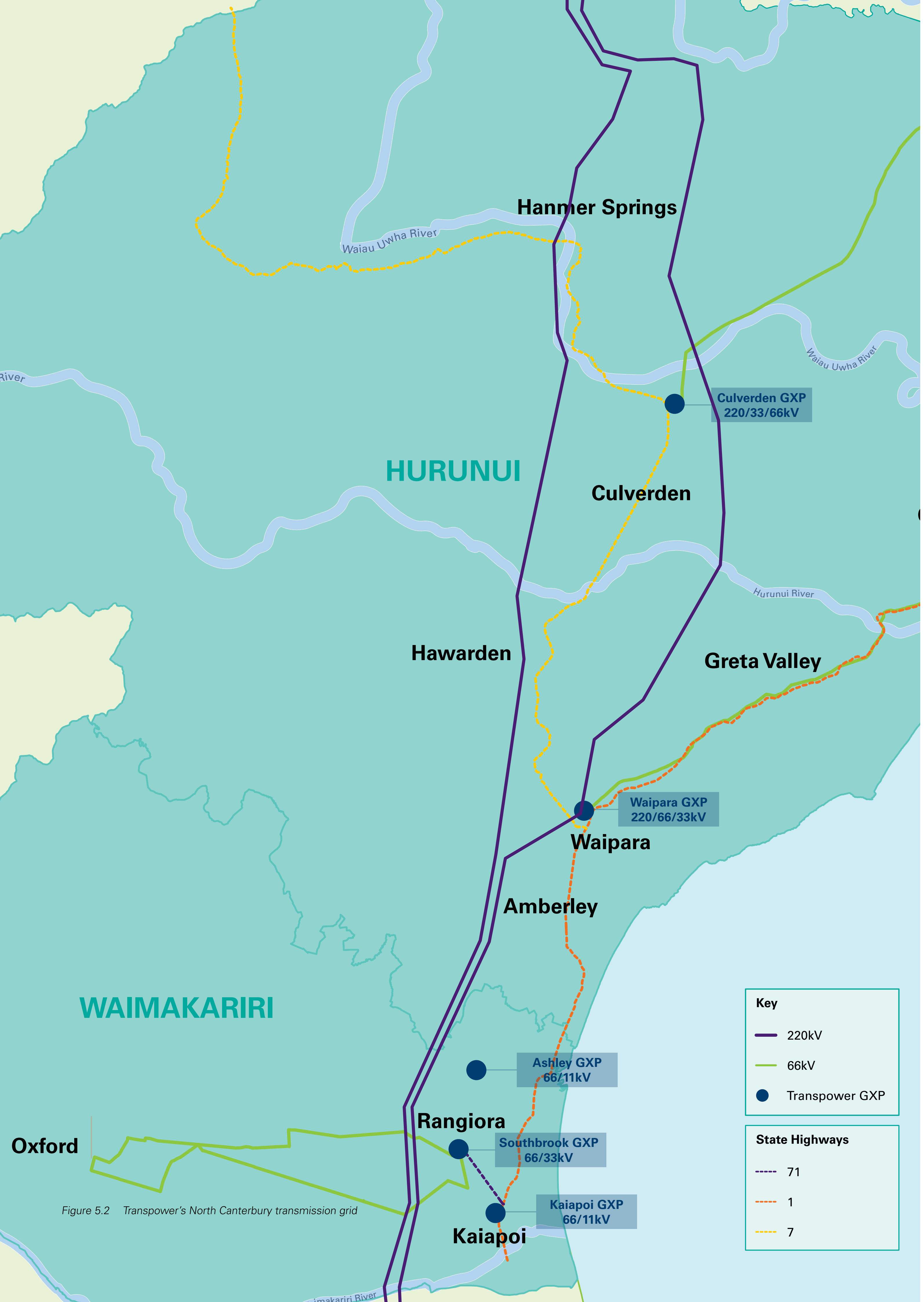


Figure 5.2 Transpower's North Canterbury transmission grid

5.2 NETWORK CONFIGURATION

5.2.1 TRANSMISSION NETWORK CONFIGURATION

The 220 kV South Island transmission network is owned and managed by Transpower New Zealand Limited. Four 220 kV circuits supply Transpower's Islington substation from the Waitaki Basin, with double-circuit and single-circuit tower lines from Tekapo, Ōhau and Benmore following different routes to Islington. A single-circuit tower line also connects Livingston and Islington.

MainPower's distribution network is supplied via five Transpower GXPs from the 220 kV and 66 kV transmission circuits out of Islington (see Figure 5.2). Table 5.4 provides a summary of the GXP substations in the North Canterbury region.

GXP	Description	
Kaiapoi	Transformer capacity	76 MVA
	Firm capacity	38 MVA
	Peak load	29.5 MW
	Configuration	Two 38 MVA 66/11 kV three-phase transformers
	Supply to MainPower	Eight 11 kV circuit breakers
Southbrook 66 kV	Supply to MainPower	Four 66 kV circuit breakers (Swannanoa, Burnt Hill, Southbrook × 2)
Ashley ASY011	Transformer capacity	80 MVA
	Firm capacity	40 MVA
	Peak load	13.9 MVA
	Configuration	Two dual-rated 40 MVA 66/11 kV three-phase transformers
	Supply to MainPower	One transformer normally feeding five 11 kV circuit breakers supplying the rural area. One transformer normally feeding four 11 kV circuit breakers for the Daiken plant (which produces medium-density fibreboard).
Waipara WPR0331 and 0661	Transformer capacity	160 MVA
	Firm capacity	80 MVA to the 66 kV bus
	Peak load	14.0 MW total at 66 kV, 7.9 MW at 33 kV
	Configuration	Two 80 MVA 220/66 kV transformers directly connected to the Islington–Kikiwa 220 kV circuits – the 66 kV supply from these transformers feeds a single 66/33 kV dual-rated 10/16 MVA three-phase transformer
	Supply to MainPower	Two 33 kV and one 66 kV feeder circuit breakers and one 66 kV load plant circuit breaker
Culverden CUL0331 and 0661	Transformer capacity	60 MVA
	Firm capacity	30 MVA to the 33 kV bus
	Peak load	21.9 MW
	Configuration	Two 30 MVA 220/33 kV transformers directly connected to the Islington–Kikiwa 220 kV circuits – a 10/20 MVA 33/66 kV transformer rated at 13.09 MVA with no fans has been installed to supply 66 kV to Kaikōura
	Supply to MainPower	33 kV via two feeder circuit breakers and cables, 66 kV feeder circuit breaker

Table 5.4 Description of each GXP

5.2.2 SUB-TRANSMISSION CONFIGURATION

The locations of Transpower's GXPs supplying our network, along with MainPower's zone substations and 66 kV and 33 kV sub-transmission circuits, are shown in Figure 5.3.

5.2.3 DISTRIBUTION CONFIGURATION

MainPower's distribution system is largely rural, with many long radial spurs. The 11 kV and 22 kV distribution is approximately 90% overhead-line network. The only areas of significant underground reticulation are Rangiora and Kaiapoi, where 11 kV reticulation is approximately 90% underground.

5.2.4 LOW-VOLTAGE DISTRIBUTION CONFIGURATION

Approximately 70% of our low-voltage network is underground, mostly in the larger urban areas. Cables are typically terminated in plastic service boxes above ground, with larger link boxes used to create tie-points between substations, where practicable, increasing security of supply.

Overhead low-voltage systems are common in smaller townships and rural areas. These legacy designs provided cost-effective supply to many consumers from one transformer. Most overhead low-voltage conductors are bare conductor.

Almost all new low-voltage reticulation since 1990 has been underground. Conversion to underground reticulation is the preferred replacement strategy for old low-voltage lines, where this can be justified economically.

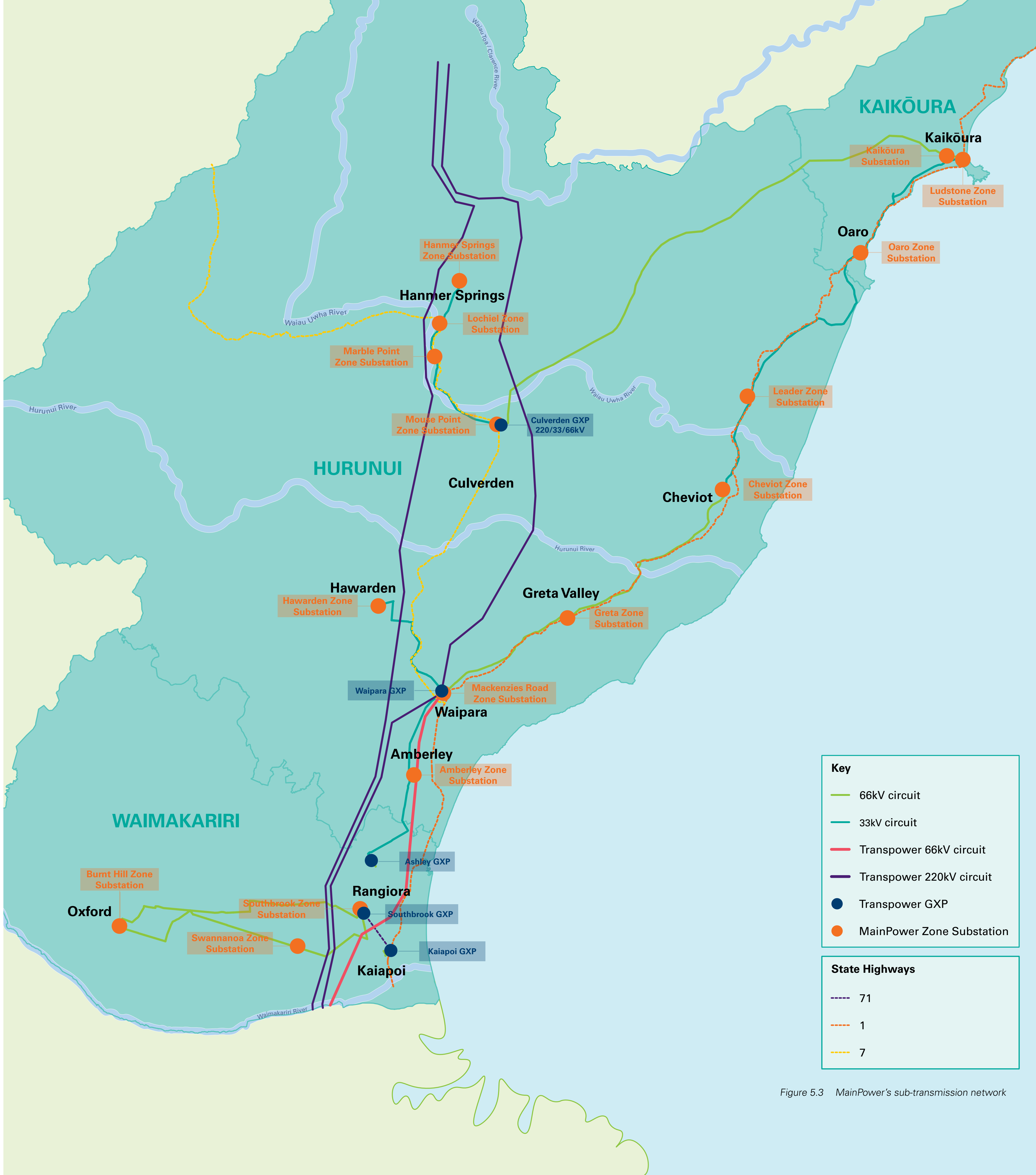


Figure 5.3 MainPower's sub-transmission network

5.3 OVERVIEW OF ASSETS, BY CATEGORY

5.3.1 SUB-TRANSMISSION

The sub-transmission system is a mixture of 33 kV and 66 kV circuits on concrete and hardwood poles, with a few short-cabled sections.

5.3.2 ZONE SUBSTATIONS

Zone substations are buildings or outdoor yards that house power transformers, circuit breakers, disconnectors, and projection systems, among other assets.

Zone substation power transformers above 1 MVA capacity have On Load Tap Changers to regulate the bus voltages.

5.3.3 OVERHEAD DISTRIBUTION

Historically, large numbers of hardwood poles were used on the overhead network. Larch poles impregnated with creosote were used in the late 1950s through to the 1960s, in combination with hardwoods. Treated Corsican pine poles were used from 1973, and concrete poles were also purchased from the mid-1970s. The main pole types used today are H5-treated radiata pine and pre-stressed concrete.

Since the year 2000, many lines have been converted from 11 kV to 22 kV. This is mostly in rural areas experiencing high demand growth, usually from irrigation demand and dairy conversions.

5.3.4 UNDERGROUND DISTRIBUTION

Most of the high-voltage underground cables are either 95 mm^2 or 185 mm^2 aluminium cables, although more recently, 300 mm^2 aluminium cables have been used for major urban feeders or to supply distribution switching stations. Smaller sizes are being used for rural customer spurs.

5.3.5 DISTRIBUTION SUBSTATIONS

As our high-voltage distribution network is predominantly overhead, most distribution substations are pole mounted. MainPower has more than 7,500 distribution transformers. Large quantities of transformers were purchased between 1967 and 1973 because of the growth in the distribution network at this time.

Most customers are supplied from distribution substations at voltages of 11 kV or 22 kV. A small number of customers are supplied from single-wire earth return (SWER) systems operating at 6.6 kV or 11 kV, typically in remote areas.

In rural areas, distribution substations are typically pole mounted for transformers up to 200 kVA and ground mounted above 200 kVA, although many irrigation consumers require their high-voltage spurs to be underground, with ground-mounted distribution substations. Pole-mounted transformers are protected with expulsion drop-out fuses and low-voltage high rupturing capacity (HRC) fuses where practicable.

Our urban areas have largely underground distribution with ground-mounted substations. Most substations located in residential or rural areas are located on private property within easements, or on land purchased by MainPower. Our distribution substations consist of a range of construction types and designs, as outlined below.

Building substations

These are large buildings or rooms of poured concrete, with stucco exteriors. They were generally built with exposed overhead 11 kV bus-work, but most have been changed to more modern ground-mounted RMUs.

Kiosks

These are smaller, predominantly front-access steel kiosks, which can house a transformer and/or switchgear at high or low voltage. RMUs are used with an 11 kV HRC fuse protecting the transformer. The box design allows for a maximum transformer size of 500 kVA. Low-voltage panels were typically bare exposed HRC fuses, and many of these have been replaced with Deutsches Institut für Normung (DIN) standard switchgear.

Mini-sub

These are mini-substation packages. Some have RMUs, and the remainder have fuses.

Outdoor transformers

More recently, outdoor transformers with cable boxes and separate front-access outdoor cabinets have been used to allow for the use of low-voltage panels. This design affords more flexibility for a wider range of switchgear, changes in transformer size, and better accessibility, and it allows the full rating of the transformer to be used.

5.3.6 DISTRIBUTION SWITCHGEAR

There are several different types of circuit breakers and reclosers on the system, including bulk oil, sulphur hexafluoride (SF_6) and vacuum types. All circuit breakers purchased since 1995 are remote controllable.

Most of the air break switches installed between 1950 and 1980 were Canterbury Engineering types 955, DA2, DA27, NL7 and NG10. More recently, Schneider's integrated spar-mounted air break switches and Electropar EPS2 switches have been used. Sealed switches are replacing critical air break switches and almost all are remote controlled.

During the 1970s and 1980s, ABB's SD range of oil RMUs were used, followed in the 1990s by increased use of air-insulated Holec MD series (Magnefix) switchgear. The Holec Xiria sealed air-insulated range has also been used since year 2000.

5.3.7 LOAD CONTROL

We use ripple injection plant for load control and tariff switching, which is located at zone substations that are co-sited with Transpower GXPs, or co-sited at the GXPs themselves. The ripple injection plants inject signals at a frequency of 283 Hz through the electricity distribution network, allowing us to control connected devices within our network and customer installations. These connected devices are equipped with receiver relays, either owned by MainPower or by a metering equipment provider (MEP). The devices controlled are typically streetlighting, hot water cylinders, and irrigation systems, with the latter only being controlled in emergency situations.

5.3.8 STREETLIGHTS

Most streetlights are controlled by ripple receiver relays located at local low-voltage distribution substations, where the relays receive a signal by ripple injection initiated from a light-level sensor. Dedicated street light supply cables loop around several lights from each control point. Increasingly, new streetlights are controlled by local photocell sensors. Streetlight relays are modern and reliable, with extremely low reported failure rates.

5.3.9 SUPERVISORY CONTROL AND DATA ACQUISITION

Our supervisory control and data acquisition (SCADA) system uses modern DNP3 remote terminal units or is slaved to modern remote terminal units on site. All remote sites communicate via the DNP3 protocol. Work is proceeding on new field devices with remote communication facilities, to increase network automation. We are committed to using the latest distribution automation technologies to improve system performance and fault response times.

5.3.10 COMMUNICATIONS

Our voice and data radio equipment was migrated to new systems since 2016. This provides reliable communications throughout most of our network. Tait voice radios and Mimomax data radios are currently our preferred technology.

5.3.11 PROTECTION AND METERING SYSTEMS

Our zone substations span many decades of analogue and digital technology improvements. All modern zone substations use Areva, SEL or Siemens digital electronic protection systems. Older substations have GEC electromechanical relays, which are still reliable but have limited setting ranges and functionality. These older systems are being progressively phased out. We also own high-voltage metering systems for several large users, including the Daiken medium-density fibreboard plant and the McAlpines timber-processing plant.

5.3.12 POWER FACTOR CORRECTION PLANT

While MainPower has no system power factor correction installations of its own, the Daiken medium-density fibreboard plant at Ashley has two 11 kV capacitor banks. Transpower has also installed power factor correction for voltage support on the 66 kV bus at Southbrook.

5.3.13 PROPERTY AND BUILDINGS

MainPower owns substation buildings, offices, remote depots, administration buildings, operational buildings, property for outdoor distribution assets in the communities, and bare land parcels.

5.3.14 MAINPOWER ASSETS WITHIN TRANSPOWER GXPS

MainPower owns metering and communications equipment at the Transpower GXPs that supply our network. These monitor load for load management and revenue metering. All have ion-type meters, installed after year 2000. MainPower's ripple injection plants are within Transpower GXPs at Waipara, Ashley and Kaiapoi. We also have SCADA and local service equipment associated with load control at these sites.

5.3.15 MOBILE GENERATORS

We have invested in mobile diesel generation plant to assist with reducing the number of planned interruptions. Our generators are used during planned work to maintain the supply to customers and have enough capacity to supply the average load of an urban transformer kiosk.

6
NETWORK DEVELOPMENT PLANNING

Network development planning is a key area of focus for MainPower within our Asset Management Framework and processes. Given the changes already identified and the ways MainPower's network is predicted to be used in future, the current traditional distribution network approach of demand-based, deterministic development planning will no longer meet the future needs of our consumers – both current and new market participants.

The underlying elements and influences of these changes from the perspective of an electricity distribution business (EDB) are:

- significantly greater integration between distributed generation (DG), transmission, and energy storage on the network, together with increased interaction with more active consumers
- new technologies producing variable power sources, two-way power flows and new demands that are already creating serious challenges on networks internationally
- the impact of new commercial parties, models, and business platforms, working through the distribution network and changing the ways that our network is used
- a growing focus on energy communities, peer-to-peer trading, and local markets
- the impact of non-linear loads, such as rapid electric vehicle (EV) chargers, on standard network infrastructure and the ability to manage the significant demand peaks and power-quality issues these introduce at the low-voltage distribution level
- the potential for use of separated distribution micro grids where these are the most economical solution when considering renewals or new supplies
- the national transition to a low-carbon economy.

The above can be summarised as highlighting the need to move from the traditional passive distribution network to an active network that has more dimensions.

In response to this, MainPower is continuing to re-evaluate and evolve its network development-planning methodology. In simplistic terms, we see the need to move from the traditional distribution network approach of demand-based, deterministic planning to scenario-based planning. To achieve this, new skills and systems will be required. We are actively engaged in identifying how these requirements will be met through learning from the experiences of others (both locally and internationally) and by participating in industry working groups such as the Electricity Networks Association and the Electricity Engineers' Association. This evolution of our network development approach will help us better understand the range of capacity and energy service requirements the network will need to provide.

We also recognise that this new future for distribution networks offers increased opportunities for non-traditional/flexibility solutions (where economically viable) and for existing and new market participants to provide energy solutions. MainPower recognises the need to identify these opportunities in a timely manner to facilitate the market response and potentially seek providers of non-traditional solutions.

Although we are evolving our network development planning processes to accommodate the above changes, our network development plans are primarily driven by safety, security of supply, resiliency, reliability and compliance requirements – these will evolve to include the future requirements for the North Canterbury region.

The following section identifies our current planning process, with some innovation-based thinking about the future and early movements to a new model of network development planning.

6.1 PROJECT PRIORITISATION

Prioritising network capital expenditure projects is a multi-faceted process, balancing numerous internal and external factors for MainPower. Consideration is given to our customer expectations, managing risk, coordinating with other projects and organisations, and delivering the company's strategic goals. This structured approach ensures that resources are allocated to projects that support short-term constraints and operational needs and align with long-term strategic outcomes. Project prioritisation factors are set out in Table 6.1 below.

Prioritisation factors	Primary driver(s) for the project
	Impact on consumers if the project does not proceed or is deferred
	Cost and funding implications
	Alternative non-traditional solutions
	Planning uncertainties
	Consumer-driven projects for new connections or upgrades
	Future network and company strategic alignment
	Local authority and NZ Transport Agency Waka Kotahi (NZTA) projects
	Consumer expectations
	Compliance, health, safety and the environment
	Meeting service levels such as the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), and security of supply
	Cost–benefit analysis

Table 6.1 Capital expenditure project prioritisation factors

6.2 SECURITY OF SUPPLY CLASSIFICATION

The following sections describe how we define security of supply classifications for zone substations and distributed connected loads.

6.2.1 ZONE SUBSTATION SECURITY

Zone substations are classified for security according to Table 6.2.

Substation class	Substation load type	Targeted duration for first transformer, line or cable fault	Targeted duration for bus or switchgear fault
AAA	Urban or industrial load > 10 MW peak or 30 GWh annual consumption	No interruption	No interruption for 50% and restore the rest within 2 hours
AA	Urban load > 2 MW peak or 6 GWh annual consumption	45 minutes	Restore 75% within 2 hours
A1	Predominantly rural and semi-rural loads totalling > 1 MW	Isolation time	Repair time
A2	Predominantly rural and semi-rural loads totalling < 1 MW	Repair time	Repair time

Note:

Zone substation classification descriptions:

AAA Supply is uninterrupted in the event of the outage of one major element of the sub-transmission network.
Load can be transferred to other substations without interruption by switching on the network, if necessary, to avoid exceeding ratings.

AA Supply may be lost in the event of the outage of one major element of the sub-transmission network.
Supply can be restored within 45 minutes by switching at the sub-transmission or distribution level.

A1 Supply may be lost in the event of the outage of one major element of the sub-transmission network.
Supply can be restored by switching after the faulted element is isolated.

A2 Supply may be lost in the event of the outage of one major element of the sub-transmission network.
Supply cannot be restored until the faulty element is repaired or replaced.

Table 6.2 Security of supply zone substation restoration times

6.2.2 DISTRIBUTED LOAD CLASSIFICATIONS

Distribution loads are classified according to Table 6.3.

Classification	Description
L1	Large industrial (> 5 MW/15 GWh of industrial load)
L2	Commercial/Central business district (> 5 MW/15 GWh of commercial load)
L3	Metropolitan (> 2 MW/6 GWh of urban mixed load)
L4	Rural (predominantly rural and semi-rural areas)
L5	Remote rural

Table 6.3 Security of supply load types

6.2.3 SECURITY LEVEL

Network configuration is arranged so that the security criteria shown in Table 6.4 can be met, subject to technical and economic feasibility.

Load type	Security level
L1	After a fault is located, supply can be restored to all but the isolated section in 1 hour. The isolated section shall be limited to 500 kVA, unless it is a single consumer with a load in excess of this.
L2	After a fault is located, supply can be restored to all but the isolated section in 2 hours. Restoration of supply via low-voltage connection is acceptable here. The isolated section shall be limited to 750 kVA, unless it is a single consumer with a load that is in excess of this.
L3	After a fault is located, supply can be restored to all but the isolated section in 3 hours. The isolated section shall be limited to 1.5 MVA or 4.8 GWh.
L4	After a fault is located, supply can be restored to any section of the feeder with a load exceeding 1.5 MVA or 4.8 GWh in 4 hours.
L5	After a fault, supply may remain interrupted until repairs are completed.

Table 6.4 Distribution load security level

6.3 USE OF STANDARD DESIGNS

Standard designs are used to achieve, and are aligned with, MainPower's asset management objectives. Standard designs exist for all MainPower overhead structures. Work is currently being undertaken to further standardise our engineering solutions. Standard designs are identified through:

- total cost of ownership
- economies of scale
- compliance
- service levels
- security of supply
- safety.

6.4 STRATEGIES FOR ENERGY EFFICIENCY

MainPower has a focus on improving the energy efficiency of our network through reducing losses (where reasonably practical), placing a high value on efficiency parameters when purchasing new equipment, and on education programmes to improve demand-side management.

All conversions from 11 kV to 22 kV will cause a replacement transformer to be installed that meets the new Minimum Energy Performance Standards. Additionally, we consider loss capitalisation when purchasing transformers. As a company, MainPower actively promotes energy efficiency in the community through consumer education and our community sponsorship programme (insulation and energy efficiency solutions). We are actively engaging with our consumers and assessing demand-side management concepts regarding emerging technologies and consumer behaviour.

6.5 NETWORK PLANNING

6.5.1 OVERVIEW

We use the terms "growth" and "security" to describe capital investments that increase the capacity, functionality or size of our network. These include the following four main types of investments.

Major projects

Involving sub-transmission, zone substation or grid exit points (GXP) works.

Network reinforcement

Focused on the distribution network such as feeder capacity and voltage upgrades, security (N-1) reinforcements, distribution substation and transformer upgrades, and low-voltage reinforcement.

Future network

Investments to support the transition towards an open-access network, including network monitoring, communications, power-quality management and flexibility services.

Reliability and automation

Includes network automation projects to help manage and improve the reliability performance of our network; currently integrated within our major projects and network reinforcement investment categories.

6.5.2 REGIONAL GROWTH TRENDS

Our network demand-forecasting process forecasts demand at Transpower's North Canterbury GXPs and MainPower's zone substations over the next 10 years.

When developing demand forecasts, several key inputs are applied, including:

- population and household projections obtained from Stats NZ
- local district schemes and community plans
- notified changes in land use designations
- known commercial, residential and industrial developments
- historical electrical demands
- non-network solutions (such as demand management and flexibility services)
- historical extreme movements in temperature and rainfall where this affects peak demand
- expected commercial developments
- emerging technology adoption, such as EVs.

Our network continues to undergo steady growth, as shown by installation control point (ICP) growth in Figure 6.1.

The consistent growth shown in the network is mainly due to:

- steady residential subdivision activity in Amberley, Kaiapoi, Pegasus/Ravenswood, and Rangiora
- commercial development in Rangiora and Ravenswood.

Growth in each area of our network varies because of changes in demographics and regional characteristics. The map in Figure 6.1 indicates annual ICP growth rates, by planning area, for MainPower's network region. Figure 6.2 shows the annual growth in the average number of ICPs.

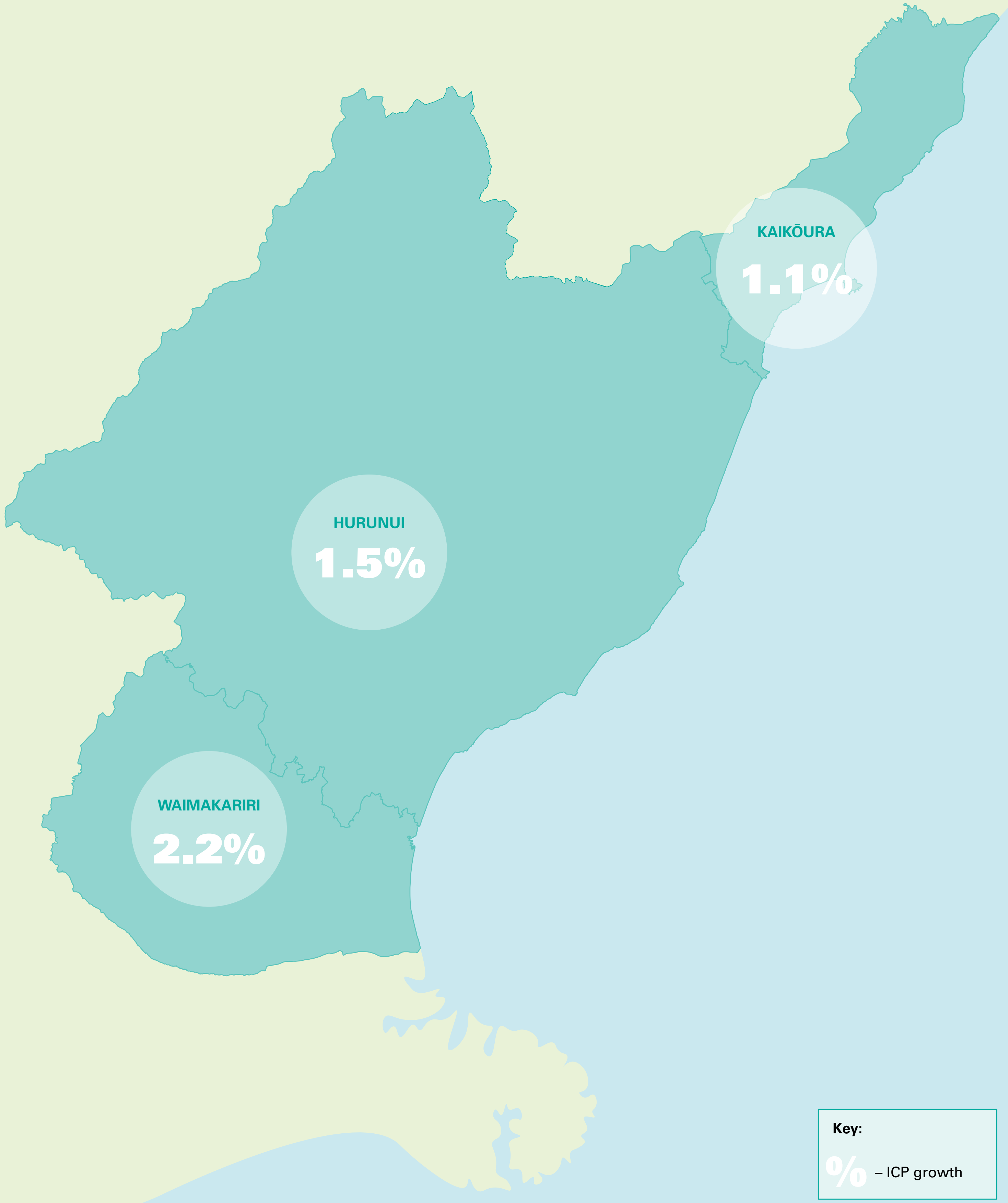


Figure 6.1 Annual ICP growth by planning area

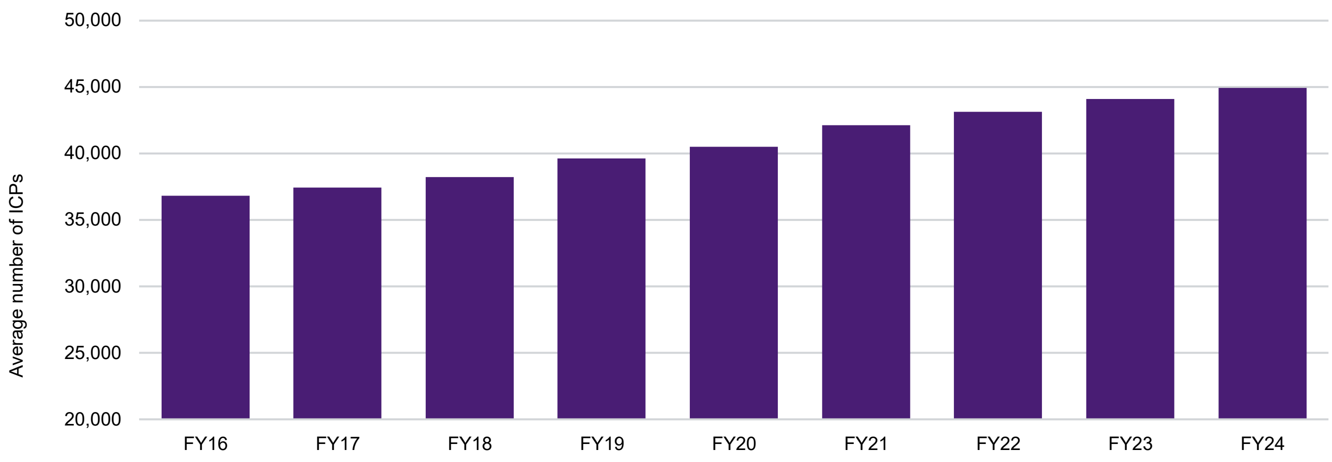


Figure 6.2 Annual average number of ICPs (FY16–FY24)

6.5.3 RELIABILITY

The number and duration of service interruptions are of primary interest from the consumers' point of view, as specified in Section 3 of this document. MainPower uses reliability statistics and targets to identify if and where system improvement is needed. We select development options based on the lowest whole-of-life cost to provide target reliability outcomes.

6.5.4 SYSTEM GROWTH (CAPACITY)

We must ensure there is sufficient capacity available to meet network system growth. This is provided in conjunction with our existing demand-side management capability and use of flexibility services.

We follow a process of monitoring existing loads on the network, forecasting network energy requirements and assessing this against our network capability and Security of Supply Standard to establish the areas where we may experience a shortfall in capacity at a defined security level.

We plan to implement and monitor more extensive security performance indicators to show the capacity available across the network at each security level.

6.5.5 POWER-QUALITY COMPLIANCE

One of the key criteria for distribution development planning is power-quality compliance, such as voltage. Voltage performance is monitored by our supervisory control and data acquisition (SCADA) system using field voltage measurements, load flow analysis, manual voltage checks (under normal and abnormal configurations) and investigations into consumer complaints about power quality.

Voltage regulators are used at 11 kV and 22 kV to assist in maintaining the voltage within the statutory voltage limits. Zone substation voltage regulators are generally set to control in the 100–102% band of nominal voltage at sites with 1.25% control steps. With line drop compensation, voltage regulation is set to control within the 11,000 V to 11,300 V band. Line drop compensation is rarely used because of the large consumer spread along the distribution lines.

Field voltage regulators generally have 0.625% control steps and are set to operate in the range 10,900 V to 11,000 V.

Systems are generally designed to have less than 10% total voltage drop to the network connection point to allow for additional voltage drop when the system is being supplied in an abnormal configuration (e.g. during an equipment outage). In normal operating configurations, this also allows for the bus voltage to be reduced by 1% to facilitate a higher penetration of DG.

6.5.6 SECURITY OF SUPPLY

Security of supply is the ability of the network to meet normal demand under contingency events, such as equipment failure. The more secure the network, the greater the ability to continue to provide supply during a contingency or to perform restoration from a fault or series of faults.

Note that security of supply differs from reliability. Reliability is a measure of how the network performs and is measured through indices such as the number of times supply to consumers is interrupted.

6.5.7 FORECAST IMPACT OF DISTRIBUTED GENERATION AND DEMAND-SIDE MANAGEMENT

All demand forecasts take into consideration the impact of existing DG connections and proposed DG sites known to MainPower through engagement with our consumers. This includes energy-efficiency initiatives, with the major contributor being irrigation schemes converting to piped irrigation. Our load-forecasting process considers the impact of the Demand-Side Management scheme that MainPower already employs.

Figure 6.3 and Figure 6.4 show the growth of small DG sites (< 1,000 kW capacity) distributed within the network. The connection rate is increasing slowly. On average, approximately 476 kWh of generation is exported per kW of capacity.

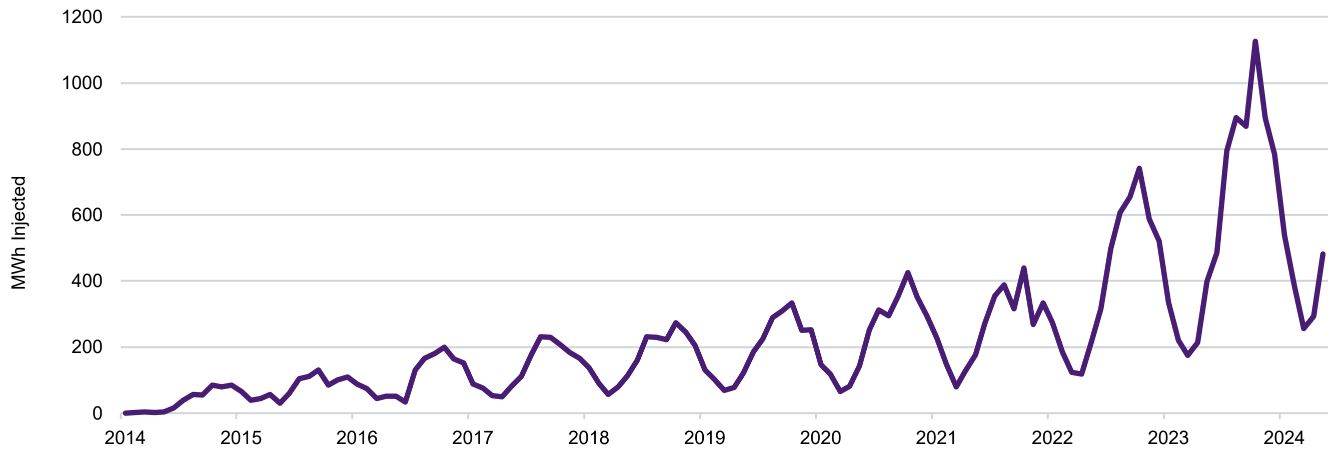


Figure 6.3 Power supplied by distributed generation sites with capacity less than 1,000 kW, 2014–2024

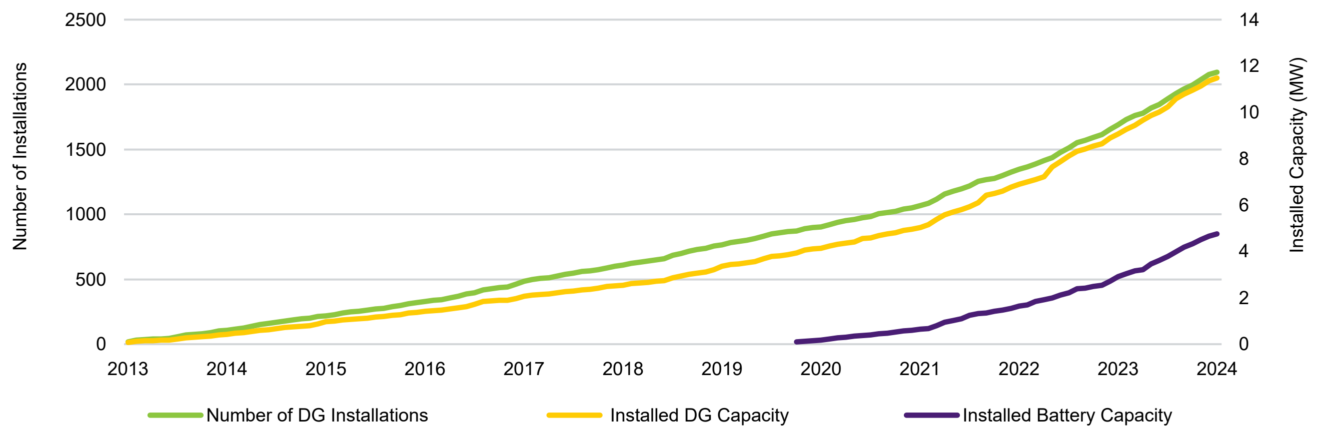


Figure 6.4 Distributed generation installations on MainPower's network (individual size less than 1,000 kW, 2013–2024

6.5.8 IMPACT OF NEW CONNECTIONS ON NETWORK OPERATIONS OR ASSET MANAGEMENT PRIORITIES

6.5.8.1 ASSESSING THE IMPACT OF NEW DEMAND, GENERATION OR STORAGE

Measuring the scale and impact of new demand

MainPower observes substation peak measurements to quantify total network load and generation. These coincident peaks are used to forecast energy needs in our community and to reinforce the network as and where appropriate. Measurement of specific point loads can be done with installed low-voltage monitoring equipment. This is typically reserved for areas of the network that MainPower is aware are becoming heavily loaded and where distribution transformers may need to be upgraded.

Growth forecasting is completed using a range of information, from historical demand figures to council-estimated population growth and new technology (e.g. EV) uptake rates. These factors are brought together to give an indication of the expected network growth.

MainPower currently does not forecast or assess the impact of generation or energy storage. As load forecasting gets more mature, it is expected that both factors will be taken into consideration.

Taking account of the timing and uncertainty of new demand, generation and storage capacity

MainPower uses scenario planning to estimate the impact of variable uptake rates of EVs and population growth. The underlying model assumes correct council predictions for population growth and EV uptake targets to assess the required network growth rates. From there MainPower builds scenarios around this base case to define faster or slower growth.

MainPower currently does not plan for unknown future large point loads or utility-scale generation connections due to the uncertainty inherent with this process.

Taking account of other factors (e.g. network location of new demand, generation and storage capacity)

MainPower uses regional population figures to determine the expected population growth in the three council regions within our network area. This provides a baseline expected growth that needs to be accounted for. Beyond this, MainPower relies on applications for connection and council planning/consenting information to determine likely areas of significant future growth. For large point loads and utility-scale generation, MainPower will begin planning after the application has been received as these types of connections are typically applicant funded.

6.5.8.2 ASSESSING AND MANAGING THE RISK TO THE NETWORK POSED BY UNCERTAINTY REGARDING NEW DEMAND, GENERATION AND STORAGE CAPACITY

MainPower uses load forecasting tools with scenario planning to minimise the likelihood of unexpected demand increases. This forecasting is used to assess the timing of significant network upgrades to ensure they are completed before issues arise. The suitability of load forecasts is regularly monitored to ensure any significant load or generation changes in the network are captured.

MainPower does not currently forecast or attempt to anticipate new generation or storage on the network as this is likely to result in increased costs to our customers.

6.5.9 INNOVATION PRACTICES

6.5.9.1 INNOVATION PRACTICES PLANNED OR UNDERTAKEN SINCE THE LAST ASSET MANAGEMENT PLAN

As MainPower is an exempt EDB under the Commerce Act 1986, we do not identify innovation projects as defined by the Commerce Commission. We do, however, undertake the following innovative projects to ensure our customers are getting the best outcomes.

Low-Voltage Network Visibility

MainPower has gained access to a small amount of low-voltage smart meter data to improve our understanding of our low-voltage network. We have completed a trial of third-party analytics software and are currently building internal data analytics tools to extract insight from the smart-meter data. This will allow MainPower to better prepare the low-voltage network for increased distributed energy resource penetration and enable us to identify and rectify any power quality issues much faster. We are working with other smart meter providers in our region to get meters reconfigured to collect the data we need and to gain access.

NIWA Collaboration and Resilience Explorer

MainPower is working with NIWA on workstreams to better understand how our region's climatology is changing and the impacts this will have on our network. We're also participating in local Civil Defence/Canterbury Lifelines initiatives to improve coordination of disaster preparation and response across infrastructure providers in our region. We've partnered with a local organisation to access a Resilience Explorer platform that can assess the vulnerability of our network to major weather and disaster events.

6.5.9.2 DESIRED OUTCOMES OF ANY INNOVATION PRACTICES, AND HOW THEY MAY IMPROVE OUTCOMES FOR CONSUMERS

All innovation projects undertaken by MainPower strive to increase network visibility to minimise long-term capital expenditure. This improves outcomes for consumers through lower energy costs and potentially increased rebates. Additionally, the network visibility will enhance MainPower's ability to target weaker network areas with reinforcement spending resulting in easier facilitation of customer energy choices, whether it be EVs, DG or any other new technology.

6.5.9.3 MEASURING THE SUCCESS AND MAKING DECISIONS REGARDING INNOVATION PRACTICES

For a new project to be successful it must provide more economic benefit to our customers than it costs them to implement. MainPower will start a project when it makes operating, controlling or observing the network simpler, easier or safer. A scope will be written with specific deliverables and expected outcomes or improvements from each project, and a trial will be undertaken. If this trial fails to meet the expectations laid out in the scope, MainPower will discontinue the project. If the scope is met, MainPower will move forward with the project.

6.5.9.4 HOW THE DECISION-MAKING AND INNOVATION PRACTICES DEPEND ON THE WORK OF OTHER COMPANIES

MainPower relies on both internal resources and third parties to provide innovative solutions to identified problems. When looking at network reinforcement projects, MainPower will consider non-network solutions and, where appropriate, will go out to market for these.

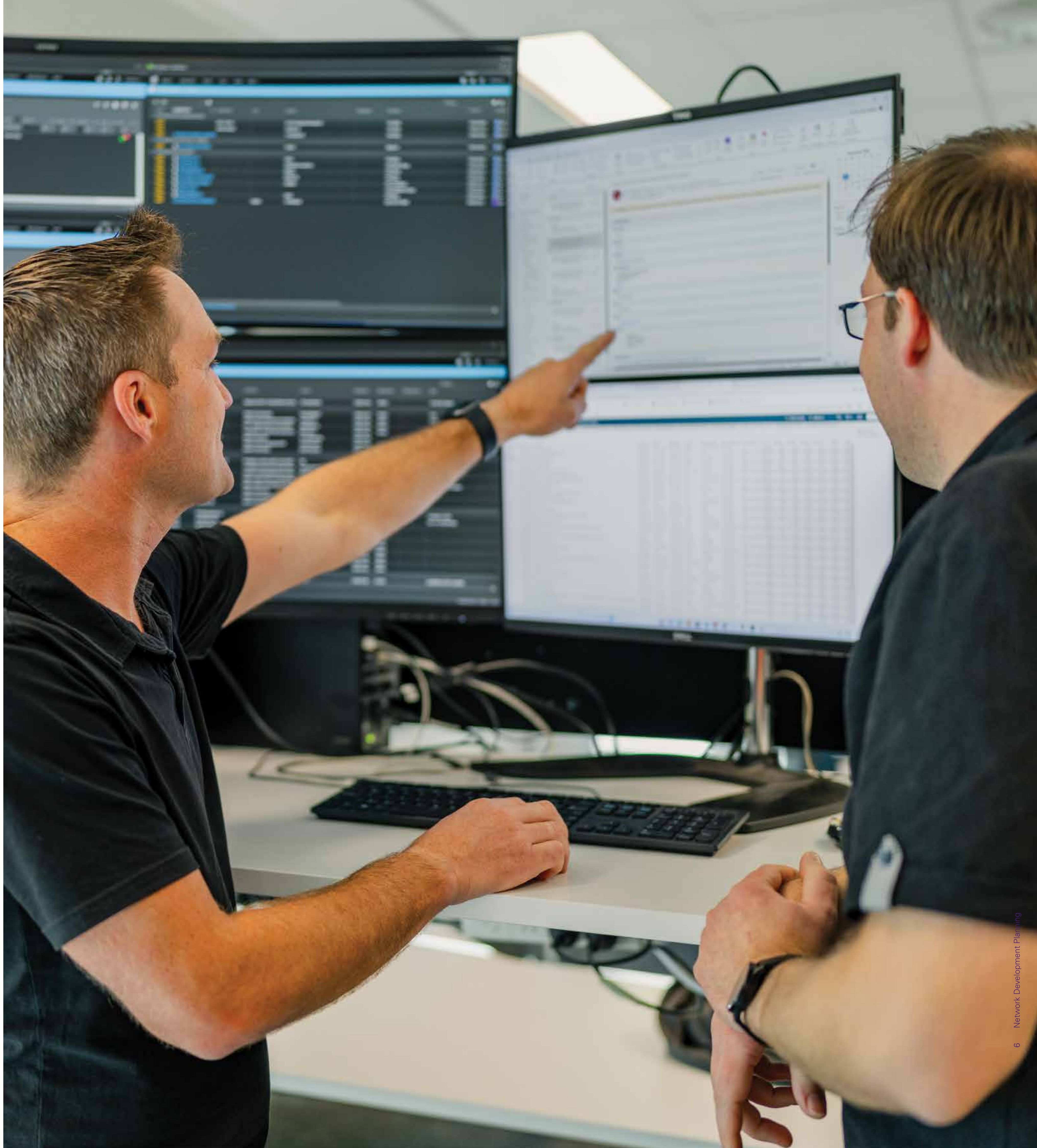
In relation to the identified innovation projects above, MainPower has utilised internal resources where available to determine the best outcomes. Following this, third parties are engaged to offer solutions to the identified problems. MainPower relies on these third-party companies to provide data and software to be used internally for better network visibility and decision making.

6.5.9.5 THE TYPES OF INFORMATION USED TO INFORM OR ENABLE ANY INNOVATION PRACTICES, AND THE APPROACH TO SEEKING THAT INFORMATION

MainPower is actively seeking ICP smart meter data to improve network visibility and investment decision making. The current approach to seeking this data is to talk directly to the smart meter owners and attempt to enter commercial agreements for access to this data.

MainPower is also seeking weather data from NIWA to better plan resource allocations around storm events and to find trends in weather and outages. This will inform network reinforcement work to improve customer reliability.

Data is a key asset to MainPower and will continue to grow in importance. As a result, MainPower invests in data capture, storage and management where appropriate and justified to get the best returns for our customers.



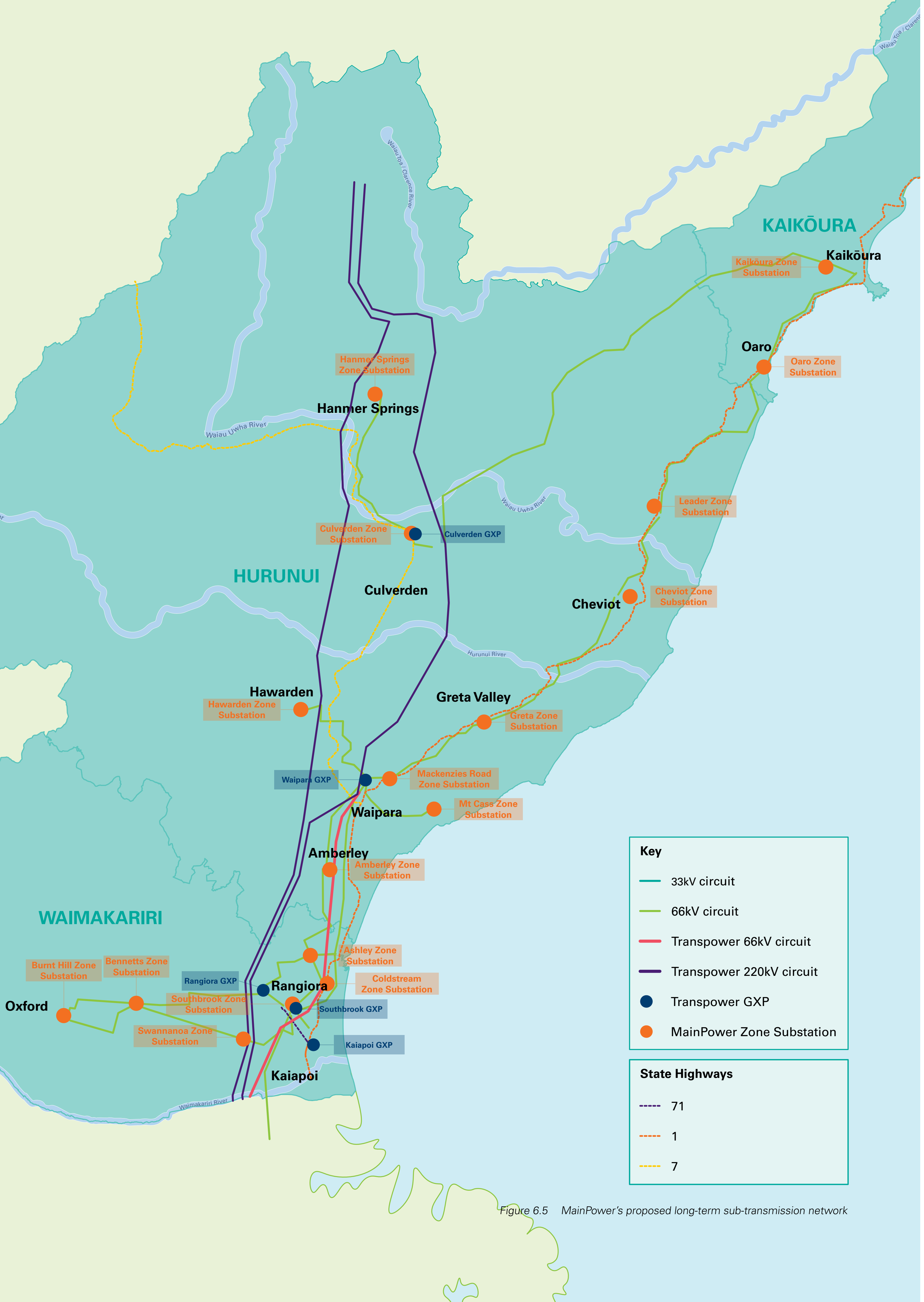


Figure 6.5 MainPower's proposed long-term sub-transmission network

6.6 LONG-TERM SUB-TRANSMISSION NETWORK STRATEGY

MainPower has developed a long-term sub-transmission strategy to help inform and align future investment (see Figure 6.5). This long-term strategy targets the following key objectives.

- **Enable and support regional growth.**
- **Provide an appropriate security of supply.**
- **Facilitate continuous improvement in network reliability.**
- **Standardise sub-transmission and distribution assets.**
- **Facilitate consumer-driven technology adoption.**

The Network Regional Plans identified in the following sections have been developed to align with and facilitate MainPower's long-term sub-transmission network strategy.

6.7 NETWORK REGIONAL PLANS

MainPower's network spans three main regions across North Canterbury: Waimakariri, Hurunui and Kaikōura. We have divided the network into these planning areas to better understand and focus our investment planning to local needs. These area plans are summarised below.

6.7.1 WAIMAKARIRI REGIONAL OVERVIEW

The Waimakariri area plan covers the region from the Waimakariri River to Balcairn, and between the South Island's east coast and the Main Divide. The main towns include Kaiapoi, Oxford, Pegasus, Rangiora and Woodend.

The region's proximity to Christchurch has contributed to its substantial residential growth, further supported by NZTA projects to further develop the Christchurch Northern Motorway.

The region is characterised by flat, open plains used for a range of farming activities, combined with an increasing number of small to medium-sized lifestyle blocks. Seasonal weather extremes, including snow and strong winds, can affect the region's quality of supply. In addition, peak electricity demand in Burnt Hill and Swannanoa occurs during summer when the thermal ratings of overhead lines are limited by the higher ambient temperatures.

MainPower's sub-transmission network in the Waimakariri area is supplied from Transpower's Southbrook GXP, as shown in Figure 6.6.

The sub-transmission network is dominated by a large overhead 66 kV ring circuit, serving Burnt Hill and Swannanoa, with a double-circuit 66 kV tower line, which is owned by Transpower, feeding Kaiapoi. The 66 kV Burnt Hill and Swannanoa ring currently operates in an open state and is supplied from Southbrook. Our sub-transmission and distribution networks in the Waimakariri area are predominantly overhead, reflecting the rural nature of the area.

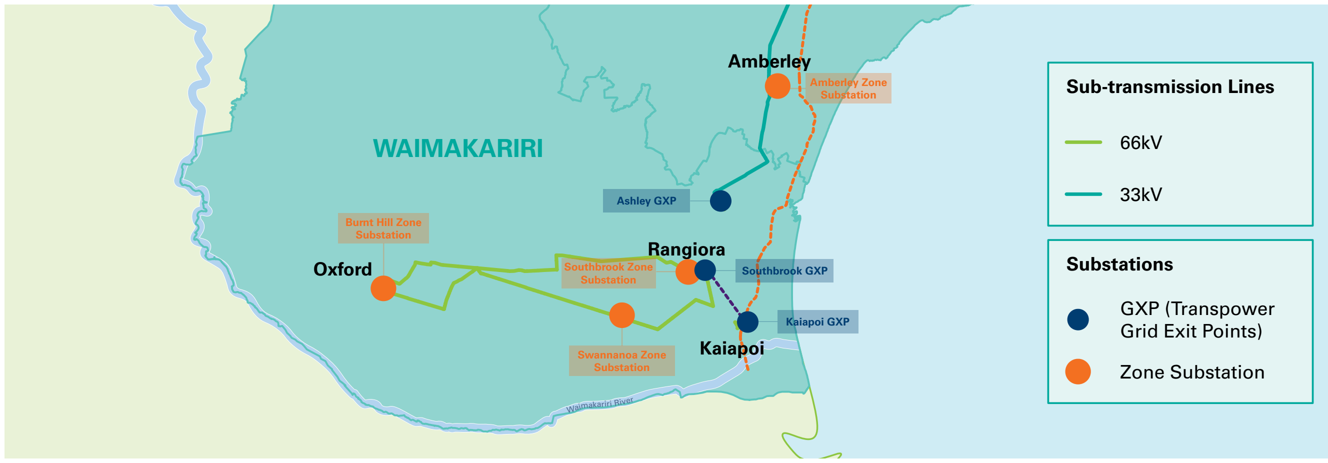


Figure 6.6 Waimakariri region sub-transmission network (existing)

6.7.1.1 DEMAND FORECASTS

Table 6.5 shows the demand forecasts for the Waimakariri zone substations.

Substation	Security class	Class capacity (MVA)	Demand forecast (MVA)									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Ashley 11 kV	A1	40.0	19.3	19.5	19.7	19.9	20.0	20.2	20.5	20.7	21.0	21.3
Burnt Hill	A1	23.0	15.1	15.3	15.6	15.9	16.1	16.4	16.7	17.1	17.4	17.7
Kaiapoi 11 kV	AAA	38.0	31.1	32.4	33.7	35.1	36.6	38.1	39.6	41.2	43.0	44.7
Southbrook	AAA	40.0	39.7	41.4	42.9	44.6	46.4	48.0	49.5	51.2	53.0	54.8
Swannanoa	A1	23.0	18.2	18.4	18.7	19.0	19.3	19.6	19.9	20.3	20.6	21.0

Note: Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

Table 6.5 Waimakariri area network demand forecast (FY26–FY35)

6.7.1.2 NETWORK CONSTRAINTS

Table 6.6 describes the major network constraints affecting the Waimakariri area.

Load affected	Major issues	Growth and security projects
Ashley GXP	The Ashley GXP has a "Grid Direct" single major consumer and cannot be restored within 15 seconds.	• We recognise this as a gap in the Security of Supply Standard and have discussed and agreed this configuration with the single consumer supplied via this site.
Southbrook, Burnt Hill, Swannanoa and Kaiapoi	Limited ability to achieve Transpower's load requirements during a half-bus outage.	• Coldstream 66/11 kV zone substation programme. • Develop long-term 66 kV interconnection capacity between Waipara, Southbrook, and the future Coldstream zone substation.
Southbrook and Kaiapoi 11 kV	Forecast to exceed security-of-supply capacity in FY26.	• Construction of Coldstream zone substation planned for FY26–FY29, along with tactical reinforcement projects to allow load transfer to Ashley and Swannanoa.

Table 6.6 Waimakariri area network constraints

6.7.1.3 MAJOR PROJECTS

One major growth and security project is planned for the Waimakariri area:

- Coldstream 66/11 kV zone substation upgrade (see Table 6.7).

Residential and commercial growth in the Rangiora, Woodend, Ravenswood and Pegasus areas is driving the need for a new zone substation east of Rangiora. The Coldstream 66/11 kV zone substation upgrade incorporates a series of sub-projects to construct a 66 kV sub-transmission network and a new Coldstream 66 kV zone substation.The overall project includes the following stages.

Project description	Expected project timing	Strategic drivers
Coldstream 66/11 kV zone substation upgrade	FY26–FY31	System growth, quality of supply, resilience

Table 6.7 Coldstream 66/11 kV zone substation upgrade

Coldstream 66 kV sub-transmission line design

Line route detailed design, including easements and consents for a 66 kV overhead line connecting from Ashley GXP to the new Coldstream 66 kV zone substation, and from the Coldstream zone substation to the Southbrook GXP. The design stage will allow construction from Ashley to the Rangiora Woodend Road area and will be timed to provide support at 11 kV to assist with growing loads in Ravenswood and to reduce load on Southbrook zone substation. Completion of the second 66 kV circuit from Coldstream to Southbrook GXP will follow construction work on the substation.

Ashley GXP to Coldstream 66 kV sub-transmission line build

These stages construct the Ashley to Coldstream 66 kV sub-transmission line, which will initially operate at 11 kV, providing additional capacity into the Coldstream region until the Coldstream zone substation is completed.

Coldstream zone substation design and construction

This will extend on initial concept studies to deliver a full detailed design, construct the new Coldstream 66 kV zone substation and terminate the 66 kV sub-transmission line from Ashley to commission the new zone substation.

Southbrook GXP to Coldstream 66 kV sub-transmission line build

This stage completes the Coldstream zone substation project by constructing the Southbrook to Coldstream 66 kV sub-transmission circuit, providing full N-1 supply to the new Coldstream zone substation.

6.7.1.4 REINFORCEMENT PROJECTS

MainPower invests in tactical network reinforcement projects to improve network reliability and security of supply, as well as to help defer higher-capital projects. Table 6.8 summarises the reinforcement projects in the Waimakariri area.

Financial year	Project title	Description
FY26	Ashley–Ravenswood feeders 1 & 2	Undertake multiple network upgrades (cable, ring main unit (RMU) and air break switch installations) to allow the (future) 66 kV line from Ashley GXP substation to be used as a temporary 11 kV supply to Ravenswood.
FY26	Woodend network upgrade	Install new cable, RMUs and replacement of a regulator to allow additional capacity for Pegasus and Ravenswood.
FY26	Island Road feeder extension	Extend an 11 kV feeder on Island Road to address capacity constraints and meet increasing demand requirements in southeast Kaiapoi.
FY26	Rangiora North feeder bypass	Install a new cable to alleviate a capacity limitation on the corner of East Belt and Coldstream Road.
FY26	Loburn regulator installation	Install a new voltage regulator within the Loburn area.
FY27	Fernside reconfiguration, Swannanoa to Southbrook	Undertake multiple small overhead network upgrades to allow reconfiguration of the Fernside network to enable it to be transferred onto a more reliable supply from Southbrook zone substation.
FY27	Rangiora West overhead feeder	Construct an overhead link down Lehmans Road to strengthen the supply to north-western Rangiora to support further load growth.
FY27	Automate existing RMUs	Install automation within existing RMUs across MainPower’s network to improve remote switching capability.
FY29	Lineside Road feeder creation	Extend an existing 11 kV feeder to support the growing load at Kaiapoi GXP substation.
FY29	Burnt Hill and Swannanoa phasing reconfiguration	Reconfigure the 11/22 kV network to remove phase shifts within the network – reducing switching risk and improving network load transfer options.
FY29	Connect X52, X53 and X55 spurs	Install new overhead lines and circuit breakers to allow connection of three spur lines close to the Waimakariri River, increasing security of supply.
FY29	Mandeville area voltage improvement stage 1	Install a regulator and reconductor sections of the line between Kaiapoi and Mandeville to improve the voltages in that area of the network.
FY29	Automate existing RMUs	Install automation to existing RMUs across MainPower’s network to improve remote switching capability.
FY30	Belgrove feeder installation	Install a high-capacity feeder cable within the Bellgrove subdivision to provide a high-capacity supply path into North Rangiora.
FY30	Burnt Hill X53–X56 link	22kV network upgrades are to be undertaken around Harmans George Road, Inland Scenic Route 72 and Thongcaster Road, improving network resilience and reliability.
FY30	Ashley–Leithfield 11kV link	Install a cable and reconductor line along Rangiora Leithfield Road to allow additional supply into the Leithfield region, improving security of supply.
FY30	Automate existing RMUs	Install automation within existing RMUs across MainPower’s network to improve remote switching capability.
FY31	Kaiapoi 8376 to S11 link	Create an interconnection between 11 kV feeders in Kaiapoi to increase alternative supply options.
FY31	High Street cable installation	Install a new cable between High Street and East Belt to connect spur lines, improving resilience and security of supply.
FY31	Mandeville area voltage improvement stage 2	Reconductor existing overhead conductor along Giles Road.
FY32	Blackett Street cable installation	Install a new high-capacity feeder cable along Blackett Street to allow a high-capacity backup supply from the (future) Coldstream zone substation into central Rangiora.
FY32	Mandeville area voltage improvement stage 3	Reconductor a section of line between Kaiapoi and Mandeville to improve the voltages in that area of the network.
FY33	Barkers Road links	Install a new 11kV overhead line and a switching device along Barkers Road to allow for security of supply.
FY33	Birch Hill link stage 1	Install a new line and reconductor an existing line along Birch Hill Road to link two spur lines supplied from Burnt Hill and Swannanoa zone substations, improving security of supply.
FY34	Oxford to German Road link	Link the Ashley Gorge feeder to X57 on German Road to improve security of supply and reliability.
FY34	Birch Hill link stage 2	Reconductor existing overhead line to allow additional customers to be supplied via the new connection during outages on the adjacent feeder.
FY35	West Belt undergrounding	Underground the south end of West Belt to remove ageing overhead assets and improve network connectivity.
FY35	Kaiapoi Stone Street undergrounding	Underground the existing 11kV overhead conductor to improve security of supply and reduce risk.

Table 6.8 Waimakariri area reinforcement projects

6.7.2 HURUNUI REGIONAL OVERVIEW

The Hurunui area plan covers the region north of Balcairn to the Conway River, and between the South Island's east coast and the Main Divide. The main towns are Amberley, Cheviot, Hawarden, Culverden, Rotherham, Waiau and Hanmer Springs.

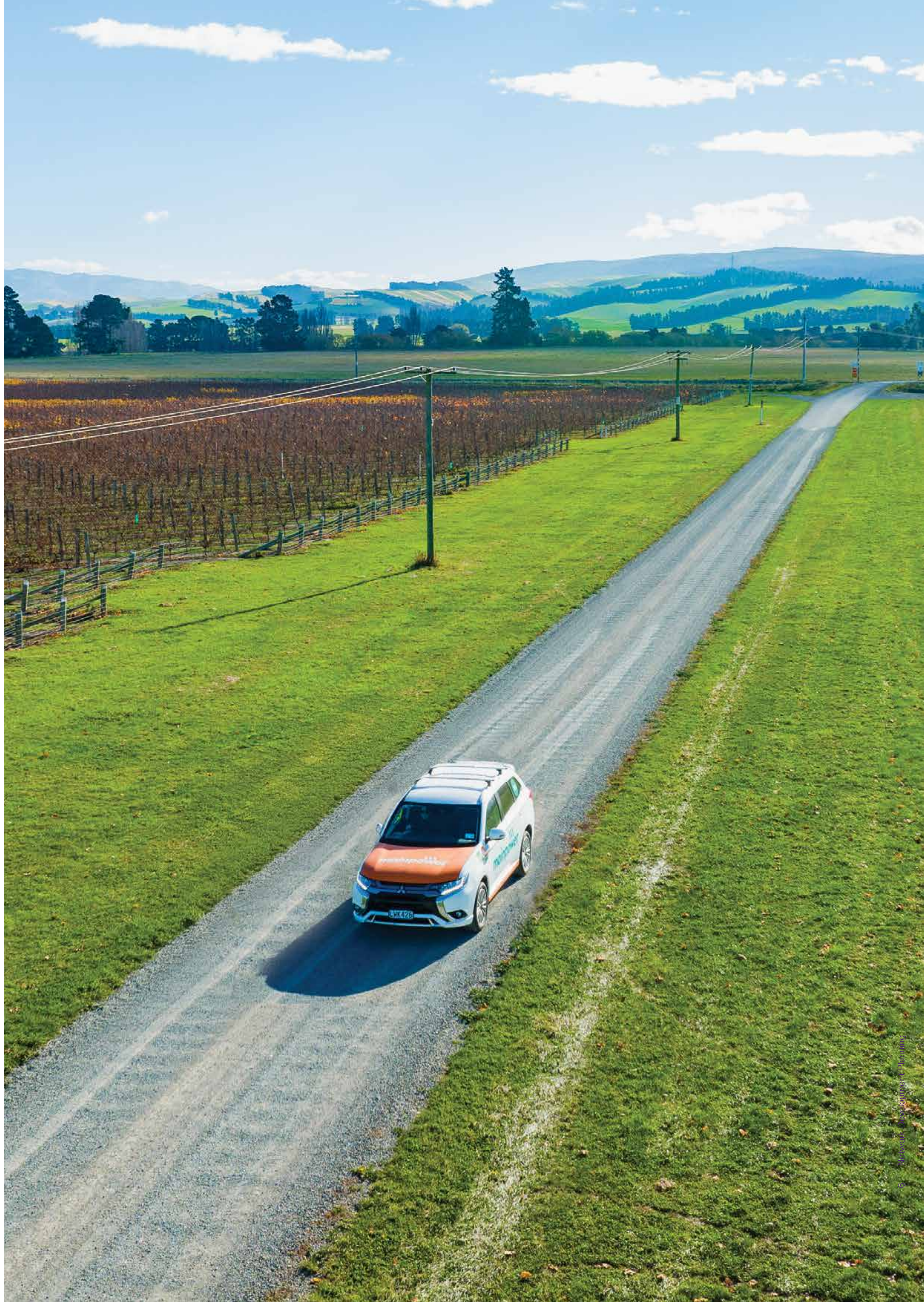
Amberley's location on SH1 and its relative proximity to Christchurch have contributed to its recent residential and commercial growth. The Culverden Basin and Cheviot area have seen rapid irrigation and dairy development during the last 20 years, with relatively low residential and general commercial growth. The Waipara area has also had significant vineyard developments established. In the north, Hanmer Springs is a medium-sized tourist destination with steady growth anchored largely around the Hanmer Springs Thermal Pools and Spa complex. Hanmer Springs's network load is dominated by tourist and holiday home activities.

The region is characterised by a mixture of flat, open plains, rolling hills and rugged hill country. South of Amberley, land is used for a range of farming activities, with an increasing number of small to medium-sized lifestyle blocks. Seasonal weather extremes, including snow and strong winds, can affect the region's quality of supply. In addition, electricity demand in the central Culverden Basin, Waipara, Cheviot and Parnassus area are summer peaking when the thermal ratings of overhead lines are limited by the higher ambient temperatures. The northern and southern areas are winter peaking.

MainPower's sub-transmission network in the Hurunui area is supplied from Transpower's Waipara and Culverden GXPs, as shown in Figure 6.7. The area uses a combination of 66 kV and 33 kV sub-transmission voltages, with our long-term plan to phase out 33 kV. The sub-transmission network consists of a long 66 kV and 33 kV interconnection between Waipara and Culverden GXPs, which supplies the Mackenzies Road, Greta, Cheviot and Parnassus substations in the Hurunui area, as well as the Oaro and Kaikōura/Ludstone Road substations in the Kaikōura area. Hanmer Springs is on a 33 kV spur from the Culverden GXP, while Amberley is tee-connected on a 33 kV circuit from the Waipara GXP to Ashley GXP.

The Kate Valley Landfill site is generating a significant and growing amount of electricity from its landfill gas (currently up to 4 MW). In addition, the neighbouring Mt Cass is forecast to become the site of a large wind farm. Both of these would feed back to the Waipara GXP.

Figure 6.7 Hurunui sub-transmission network (existing)



6.7.2.1 DEMAND FORECASTS

Table 6.9 shows the demand forecasts for the Hurunui zone substations.

Substation	Security class	Class capacity (MVA)	Demand forecast (MVA)									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Amberley	AA	4	6.3	6.6	6.9	7.2	7.5	7.8	8.2	8.5	8.9	9.2
Mackenzies Road	A1	4	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.1
Greta	A1	4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9
Cheviot	A1	4	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9	4.0	4.0
Leader	A1	4	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9
Hawarden	A1	4	3.9	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.2
Mouse Point	AA	13	19.5	19.7	20.0	20.1	20.4	20.5	20.7	20.8	21.0	21.1
Marble Point	A2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lochiel	A2	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Hanmer Springs	AA	2.5	5.0	5.2	5.3	5.5	5.7	5.9	6.1	6.3	6.5	6.8

Note: Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

Table 6.9 Hurunui area network demand forecasts (FY26–FY35)

6.7.2.2 NETWORK CONSTRAINTS

Table 6.10 describes the major network constraints affecting the Hurunui area.

Load affected	Major issues	Growth and security projects
Amberley	Load exceeds security-of-supply class rating (N-1). Peak load cannot be supplied in the event of a transformer or sub-transmission outage.	• Planned load transfer to Mackenzies Road zone substation to minimise the capacity shortfall. • Upgrade of Amberley zone substation FY24–FY27.
Greta	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	• Planned tactical distribution-level reinforcement projects will link the Greta area to the Cheviot zone substation to provide switchable backup at 22/11 kV.
Cheviot	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	• The Cheviot–Kaikōura 66 kV sub-transmission line upgrade in FY24–FY26 will increase the capacity of the Leader zone substation to supply into the northern Cheviot area during peak summer loads. • The Cheviot area will be linked to the Greta zone substation to provide switchable backup at 22/11 kV.
Leader	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	• The Cheviot–Kaikōura 66 kV sub-transmission line upgrade will increase the capacity of the Leader zone substation in FY24–FY26. • There are currently no plans to provide full switchable backup within the planning period.
Hawarden	This is an N security substation and peak load cannot be supplied in the event of a transformer outage. The substation is also supplied from a single 33 kV spur line.	• The Hawarden zone substation is planned to be rebuilt as a dual transformer substation in FY31–FY33. • Tactical reinforcement projects will increase load-transfer capacity from Mouse Point, enabling backup for growth and non-irrigation load. Peak load for Hawarden is primarily driven by irrigation load, and we are exploring non-network load management/flexibility options in this area.
Mouse Point	The peak load is above the security-of-supply capacity (N-1). Switching of the 33 kV supply following a 33 kV cable fault is local and would require more than 45 minutes.	• MainPower has installed emergency control on irrigation loads in this region to allow all but irrigation loads to be restored on a single 13 MVA transformer. A spare 8 MVA transformer is held as a backup. We are exploring non-network load management/flexibility options in this area. • Summer cyclic ratings will be explored to maximise the contingency rating of the transformers. • The Mouse Point zone substation will be rebuilt in a full N-1 configuration, in FY29–FY31.
Hanmer Springs	The peak load is above the security-of-supply capacity (N-1) of the installed spare transformer. This zone substation is also supplied from a 33 kV radial spur.	• A project is planned to replace the Hanmer Springs zone substation with full N-1 configuration, in FY27–FY29. • We are exploring non-network and flexibility options to help manage peak loads and improve security of supply and resilience for the Hanmer Springs region. • The 33 kV line is being upgraded over the period FY20–FY27 to improve its resilience and minimise the risk of prolonged outages during extreme weather events.

Table 6.10 Hurunui area network constraints

6.7.2.3 MAJOR PROJECTS

Four major growth and security projects are planned for the Hurunui area:

- Amberley zone substation upgrade (see Table 6.11)
- Mouse Point zone substation upgrade (see Table 6.12)
- Hanmer Springs zone substation upgrade (see Table 6.13)
- Hawarden zone substation upgrade (see Table 6.14)

Amberley zone substation upgrade

Project description	Expected project timing	Strategic drivers
Amberley zone substation upgrade	FY24–FY27	System growth, quality of supply, asset replacement and renewal

Table 6.11 Amberley zone substation upgrade

This project involves replacement of the Amberley 33 kV zone substation, rebuilding it for future 66/11 kV operation on a new site and eliminating the existing sub-transmission line spur connection. It will be configured as an N-1 substation, will remove capacity and security constraints, and will replace the end-of-life assets. The long-term plan is to convert the 33 kV sub-transmission line to 66 kV from FY35 to FY37. The zone substation project will be staged as follows.

Consenting and detailed design

The first stage of this project is the detailed design for the zone substation site, including sub-transmission line terminations provisioned for future 66 kV. Any consenting requirements are also included in this stage.

Amberley zone substation build

This stage constructs the zone substation and commissions it to operate at 33 kV until the 66 kV sub-transmission line upgrade project is completed.

Waipara-Amberley-Ashley sub-transmission line upgrade

This stage completes the Amberley 66/11 kV zone substation upgrade project by upgrading the existing 33 kV sub-transmission line to 66 kV, allowing the zone substation to operate at 66/11 kV (future project expected to occur from FY35 to FY37).

Hanmer Springs zone substation upgrade

Project description	Expected project timing	Strategic drivers
Hanmer Springs zone substation upgrade	FY28–FY31	System growth, security of supply, resilience, asset replacement and renewal

Table 6.12 Hanmer Springs zone substation upgrade

The Hanmer Springs zone substation does not currently meet MainPower's Security of Supply Standard of restoration within 45 minutes following a single sub-transmission failure. The existing overhead-line structures are approaching end of life and need replacement. The cost to replace and maintain the existing sub-transmission line and build a second sub-transmission circuit to achieve the full security of supply is very high; therefore, this project is targeted at the following.

Hanmer Springs sub-transmission line upgrade

Improve the resilience and reliability of the existing line with stronger conductor and structures. The line route and structure footings will also be reviewed to mitigate the impact of potential natural hazards where possible.

Hanmer Springs zone substation replacement

Hanmer Springs zone substation currently operates on N security of supply, with limited alternative (back-up supply). Consented developments will continue to exacerbate this issue. Hanmer Springs zone substation assets are also approaching end of life and are scheduled for replacement. This project rebuilds the Hanmer Springs zone substation to increase capacity into the Hanmer Springs region, provide substation N-1 security of supply, and replace end-of-life assets.

Potential subdivision growth in the Hanmer Springs region may affect the scope and timing of this project.

Mouse Point zone substation upgrade

Project description	Expected project timing	Strategic drivers
Mouse Point zone substation upgrade	FY32–FY34	System growth, security of supply, asset replacement and renewal

Table 6.13 Mouse Point zone substation upgrade

The peak load of the Mouse Point zone substation exceeds the continuous rating of its firm (N-1) capacity and is approaching the cyclic rating of the transformers. The zone substation assets are also approaching end of life. MainPower is currently investigating relocation of the Mouse Point zone substation to the Transpower Culverden GXP site. This upgrade project is to rebuild the zone substation either on or near the Culverden GXP site. The substation will be constructed at 66/22 kV, although initially operated at 33/22 kV. It is forecast that Transpower will replace the 220/33 kV transformers at the GXP with 220/66 kV transformers in the late 2030s. The timing of works will depend on load growth and whether other technologies, such as DG, effectively reduce the region's summer peaks.

MainPower is interested in non-network flexibility solutions that may be able to manage peak load of the Mouse Point zone substation and help defer any capacity upgrades.

Hawarden zone substation upgrade

Project description	Expected project timing	Strategic drivers
Hawarden zone substation upgrade	FY31–FY33	System growth, security of supply, asset replacement and renewal

Table 6.14 Hawarden zone substation upgrade

We are exploring non-network solutions to reduce the peak load of Hawarden zone substation and manage within capacity of the site. This project will also look to tactically upgrade the existing zone substation site to support future growth in the Hawarden region.

6.7.2.4 REINFORCEMENT PROJECTS

Table 6.15 summarises the reinforcement projects in the Hurunui area.

Financial year	Project title	Description
FY26	Mouse Point – Hawarden link upgrade	A new section of 11 kV line is to be installed along SH7 north of the Hurunui River to enable increased remote load-transfer capacity between Hawarden zone substation and Mouse Point zone substation.
FY27	Cheviot–Greta 22 kV link (stage 1 and stage 2)	An existing section of overhead 11 kV line is to be reconductored and uprated to 22 kV and a 22/11 kV transformer installed to allow a backup supply for Greta zone substation and a partial backup supply for Cheviot zone substation.
FY29	Greta–Hawarden link upgrade	An existing section of overhead 11 kV line is to be reconductored and uprated to 22 kV. A 22/11 kV transformer will also be installed to allow a backup supply for Greta zone substation and a partial backup supply for Cheviot zone substation.
FY32	Cheviot–Leader upgrade	The 11 kV conductor between Parnassus and Waiau East Road and Waiau West Road is to be upgraded, improving the security of supply for Cheviot and Leader zone substations.
FY33	Reinforce P35 to H41 along SH7	Installation of 3.6 km of new 11 kV overhead line along SH7 north of the Hurunui River to improve load transfer capacity and security of supply.
FY33	Underground double circuit line along Lawcocks Road	The existing double circuit 11 kV line that extends along Lawcocks Road is to be undergrounded to improve capacity and reduce security of supply risks to Amberley from a single pole fault.
FY34	Reinforce P25 south and across the Hurunui River	A new section of overhead line is to be installed between McKays Road and Bishells Road across the Hurunui River, increasing security of supply between spur circuits.
FY35	Mouse Point feeder security	A new feeder from Mouse Point zone substation to the Culverden township will be installed to provide security of supply for the existing Culverden township loads (P25 and P35 feeders) and increase transfer capacity to Hawarden to meet the Security of Supply Standard.
FY36	Amberley Beach alternative supply	Installation of a new 11 kV line along Hursley Terrace Road and Crosses Road to improve security of supply between spur lines.

Table 6.15 Hurunui area reinforcement projects

6.7.3 KAIKŌURA REGIONAL OVERVIEW

The Kaikōura area plan covers the region north of the Conway River to the Puhi Puhi Valley north of Kaikōura, and between the South Island's east coast and the Main Divide. The area extends northwards up the coast to Half Moon Bay. Kaikōura is the main township in the region.

Kaikōura is a significant tourist destination, and a key stop-off point on SH1 for people travelling between Blenheim and Christchurch. Like Hanmer Springs, the town is also a popular holiday location, particularly for Canterbury residents. Growth is dependent on the strength of the tourism industry. The area was severely affected by damage in the 2016 Waiau earthquake and the associated access constraints. Future growth is uncertain. Kaikōura's isolated location on SH1 may make it a key charging location for EVs in the future.

The region is characterised by narrow, rocky coastal margins, flat open plains, steep bushy valleys and rugged hill country. The flats are used for a range of farming activities, including dairying, without the intensive irrigation of other areas. Seasonal weather extremes, including snow, strong winds and rain, can affect the region's quality of supply and access for repairs. Electricity demand is reasonably flat, with high winter loads balanced by increased visitor numbers in summer. Demand typically peaks on cold holiday weekends.

The Kaikōura area is normally supplied from the Culverden GXP at 66 kV, transitioning to 33 kV at Kaikōura, as shown in Figure 6.8. The small coastal communities south of Peketā are supplied from the 33 kV and 66 kV interconnection between Kaikōura and the Waipara GXP.

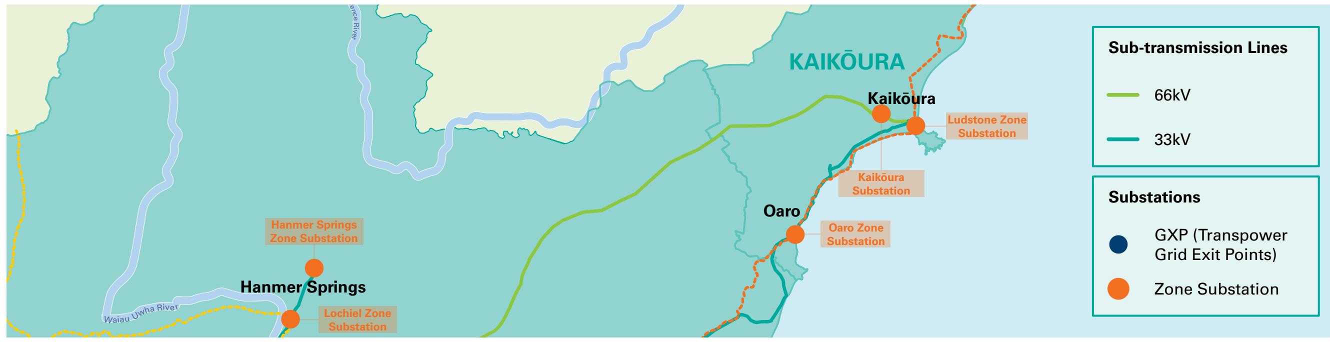


Figure 6.8 Kaikōura region sub-transmission network

6.7.3.1 DEMAND FORECASTS

Table 6.16 shows the demand forecasts for the Kaikōura zone substations.

Substation	Security class	Class capacity (MVA)	Demand forecast (MVA) FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Ludstone*	AA	6.0	5.0	5.2	5.3	5.5	5.7	5.9	6.1	6.3	6.5	6.8
Oaro	A1	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Note: Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

*We are exploring the use of non-network load management/flexibility options in the Kaikōura area as well as investigating re-rating the transformers using cyclic ratings.

Table 6.16 Kaikōura area network demand forecasts (FY26–FY35)

6.7.3.2 NETWORK CONSTRAINTS

Table 6.17 describes the major network constraints affecting the Kaikōura area.

Load affected	Major issues	Growth and security projects
Kaikōura township and areas down the Kaikōura Coast to Waipara	Peak load on Ludstone zone substation, which supplies the greater Kaikōura region, exceeds the nameplate continuous rating of a single power transformer under N operation.	MainPower is intending to utilise cyclic transformer ratings and load management to manage peak load until a project to rebuild the Ludstone zone substation on the Kaikōura 66/33 kV substation site begins in FY29. A new transformer modelling tool to allow this has been developed and will be applied to Ludstone transformers from FY26 onwards.
	The required 45-minute security-of-supply switching time for a sub-transmission fault cannot be achieved. In addition, the backup N-1 capacity from Waipara GXP has reached full capacity.	The Cheviot–Kaikōura 66 kV sub-transmission line upgrade project (FY24–FY27) will upgrade the existing 33 kV sub-transmission system from Cheviot to Kaikōura to 66 kV.

Table 6.17 Kaikōura area network constraints

6.7.3.3 MAJOR PROJECTS

Two major growth and security projects are planned for the Kaikōura area:

- Cheviot to Kaikōura sub-transmission line upgrade (see Table 6.18)
- Kaikōura 66 kV zone substation upgrade (see Table 6.19).

MainPower's sub-transmission line between Oaro and Kaikōura, along the Kaikōura coast, was affected by the 2016 Kaikōura earthquake. Short-term repairs were performed on the line section that crosses over the Raramai Tunnel; however, these require review and replacement to provide a long-term resilient solution for this section of the sub-transmission network.

Cheviot to Kaikōura sub-transmission line upgrade

Project description	Expected project timing	Strategic drivers
Cheviot to Kaikōura 66 kV sub-transmission line upgrade	FY24–FY27	Security of supply, system growth, asset replacement and renewal

Table 6.18 Cheviot to Kaikōura sub-transmission line upgrade

The line between Cheviot and Kaikōura is constructed at 66 kV but is currently operating at 33 kV. This project removes the 66/33 kV transition point and completes the sub-transmission line upgrade to operate the full Waipara to Kaikōura line at 66 kV. Land has been purchased for the relocation and rebuild of the end-of-life 33 kV Oaro zone substation to a new site. A new 66 kV bay will be constructed at Kaikōura substation to allow two 66 kV circuits into Kaikōura and provide full N-1 sub-transmission line security of supply.

This project also includes the replacement of the sub-transmission line structures that cross the Raramai Tunnel to provide a more resilient solution.

Kaikōura 66 kV zone substation upgrade

Project description	Expected project timing	Strategic drivers
Kaikōura 66 kV zone substation upgrade	FY29–FY32	Security of supply, system growth, asset replacement and renewal

Table 6.19 Kaikōura 66 kV zone substation upgrade

This project involves replacement of Ludstone 33 kV zone substation, relocating the zone substation to MainPower's existing Kaikōura substation site and decommissioning the old Ludstone site. Existing 66 kV infrastructure at the Kaikōura substation site will be used, with two new 66/11 kV transformers installed and an 11 kV switch room constructed. The zone substation project will be staged as follows.

Consenting and detailed design

The first stage of this project is the detailed design for the zone substation site, including sub-transmission line terminations and integration into the 11 kV distribution network. Any consenting requirements are also included in this stage.

Kaikōura zone substation build

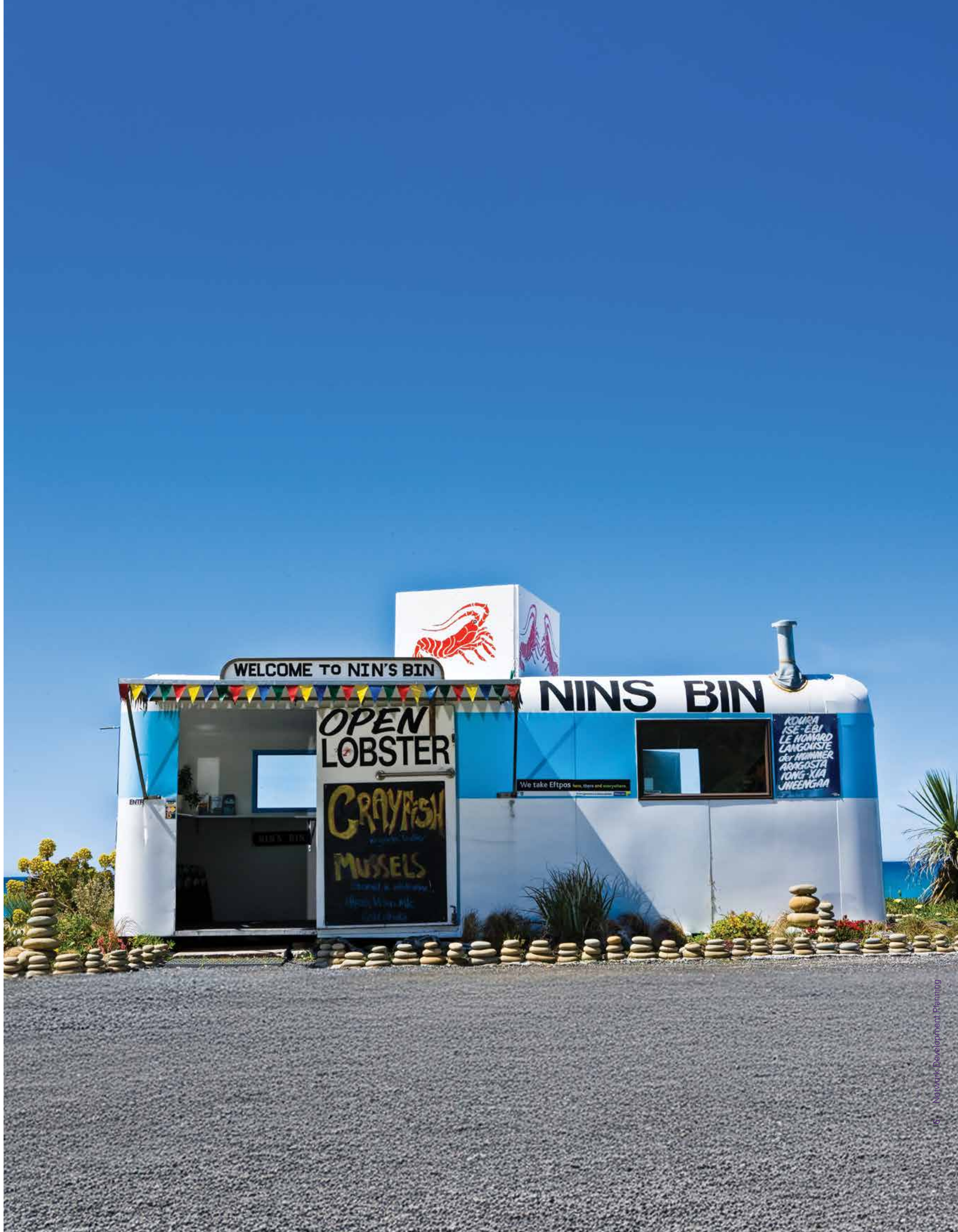
This stage constructs and commissions the zone substation at 66/11 kV.

6.7.3.4 REINFORCEMENT PROJECTS

Table 6.20 summarises the reinforcement projects in the Kaikōura area.

Financial year	Project title	Description
FY26	Beach Road cable installation	An existing section of 11 kV cable is to be replaced along Beach Road in Kaikōura to ensure capacity for future demand requirements for customers north of Ludstone Road.
FY30	Ocean Ridge feeder upgrade	A new cable is to be installed extending south from the future Kaikōura zone substations along Mt Fyffe Road towards SH1, allowing connection with an existing feeder, improving capacity and security of supply to the Ocean Ridge subdivision.
FY31	North Kaikōura feeder cable	A new 11 kV overhead line is to be constructed along Rorrisons Road, and the existing overhead line along Hawthorne Road is to be reconductored to provide additional capacity for the existing 11 kV line on SH1 north of Kaikōura.
FY32	Seaview feeder extension	A new 11 kV cable is to be installed extending south along Mt Fyffe Road and into the Seaview subdivision to provide additional capacity and security of supply.

Table 6.20 Kaikōura region reinforcement projects



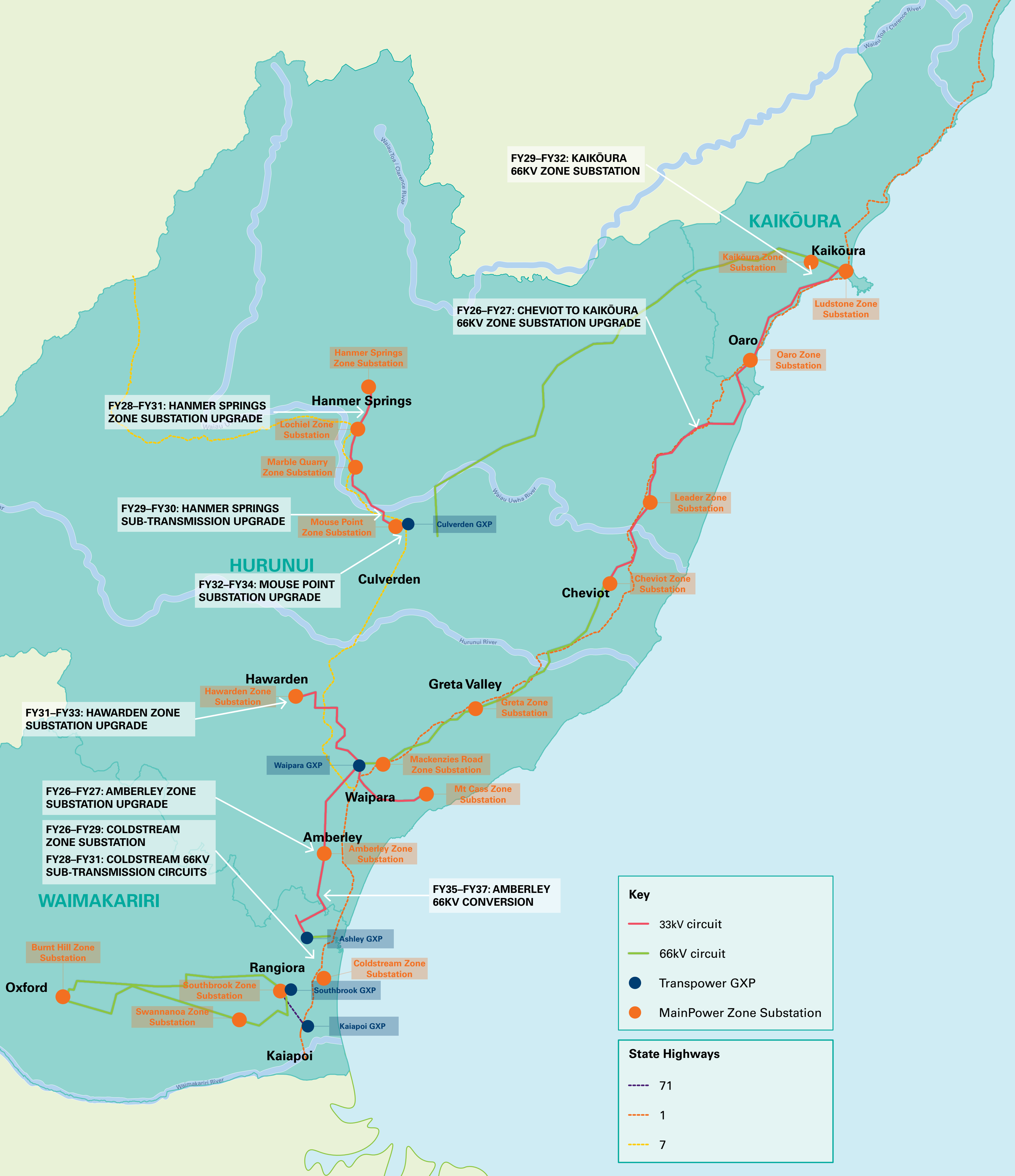


Figure 6.9 10-year AMP projects

6.8 NETWORK DEVELOPMENT PROJECT SUMMARY

An overall summary of the major and reinforcement projects for the 10-year planning period across all planning regions is presented in Figure 6.9, and in Tables 6.21 and 6.22. Several large projects create a "lumpy" major project expenditure, balanced by activity in minor works.

Major Projects	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Cheviot to Kaikōura 66kV sub-transmission circuit										
Kaikōura zone substation upgrade										
Amberley zone substation upgrade										
Amberley 66kV conversion										
Coldstream zone substation										
Coldstream 66kv sub-transmission circuits										
Hanmer Springs zone substation upgrade										
Hanmer Springs sub-transmission circuit upgrade										
Hawarden zone substation upgrade										
Mouse Point zone substation upgrade										
South Waimakariri zone substation study										
Early works investigations and concept designs										
Major Projects Expenditure ($000)	**13,167**	**13,900**	**11,450**	**9,630**	**12,041**	**7,830**	**5,850**	**9,000**	**6,000**	**5,050**

Table 6.21 Major projects summary

Reinforcement Projects	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Ashley–Ravenswood feeders 1 & 2										
Woodend network upgrade										
Island Road feeder extension										
Rangiora North feeder bypass										
Mouse Point – Hawarden link upgrade										
Beach Road cable installation										
Loburn regulator installation										
Fernside reconfiguration, Swannanoa to Southbrook										
Cheviot–Greta 22 kV link (stage 1 and stage 2)										
Rangiora West overhead feeder										
Automate existing RMUs										
Lineside Road feeder creation										
Burnt Hill and Swannanoa phasing reconfiguration										
Connect X52, X53, and X55 spurs										
Greta–Hawarden link upgrade										
Mandeville Area voltage improvement stage 1										
Automate existing RMUs										
Bellgrove feeder installation										
Burnt Hill X53–X56 link										
Ashley–Leithfield 11 kV link										
Ocean Ridge feeder upgrade										
Automate existing RMUs										
Kaiapoi 8376 to S11 link										
High Street cable installation										
Mandeville Area voltage improvement stage 2										
North Kaikōura feeder cable										
Cheviot–Leader upgrade										
Seaview feeder extension										
Blackett Street cable installation										
Mandeville Area voltage improvement stage 3										
Reinforce P35 to H41 along SH7										
Barkers Road links										
Underground double circuit line along Lawcocks Road										
Birch Hill link stage 1										
Oxford to German Road link										
Reinforce P25 south across the Hurunui River										
Birch Hill link stage 2										
Mouse Point feeder security										
West Belt undergrounding										
Kaiapoi Stone Street undergrounding										
Amberley Beach alternative supply										
Early works budget										
Low-voltage network reinforcement										
Network intelligence and flexibility										
Unscheduled reinforcement										
Reinforcement expenditure ($000)	**3,521**	**3,111**	**3,130**	**4,056**	**2,913**	**2,251**	**2,467**	**2,320**	**1,854**	**4,137**

Table 6.22 Reinforcement projects budget summary

6.9 DISTRIBUTED GENERATION POLICIES

Our policies on DG are located on our website (mainpower.co.nz/get-connected). These set out the requirements for connecting DG (of less than 10 kW and greater than 10 kW) and general safety requirements. We also comply with Part 6 of the Electricity Industry Participation Code in this respect.

6.10 UNECONOMIC LINES

The remote nature of parts of our network results in network assets that test the bounds of economic investment. As part of our network development planning processes, we identify remote uneconomic supplies and explore, through a consultation process with consumers and market participants, alternative solutions for supplying these locations when the present assets are due for replacement.

In this reporting period, MainPower intends to identify sub-economic lines and facilitate a market response through a Request for Proposal process to identify non-network solutions that are more sustainable, with the intent to decommission sub-economic lines.

6.11 NON-NETWORK SOLUTIONS

6.11.1 LOAD CONTROL

We use ripple control to manage peak demand, alleviate network constraints, defer capital investment and reduce transmission charges. Irrigation load can also be controlled during contingencies or at times of system constraints. Other initiatives under consideration are tariff restructuring to encourage night load.

The introduction of the Upper South Island Load Control system has resulted in a flat load profile for the upper South Island transmission system. Additional controls are being used to ensure that individual GXP and zone substation peaks are managed. In particular, the Amberley and Ludstone zone substation loads are actively managed through winter peak periods to maintain security levels (to achieve N-1 loading whenever possible). The Kaikōura load is also controlled during maintenance outages on the Culverden–Kaikōura 66 kV line. At these times, our 66/33 kV coastal backup line is unable to transmit the normal daily peaks.

6.11.2 FLEXIBILITY SERVICES

Under MainPower's Network Transformation Plan, there is a workstream to develop a Demand-Side Management strategy that will describe:

- MainPower's network role in flexibility
- how market responses may be contracted in the future to provide for demand-side management beyond 300 Hz ripple control
- how to best promote competition in, reliable supply by, and the efficient operation of the New Zealand electricity industry for the long-term benefit of consumers.

6.11.3 DISTRIBUTED ENERGY RESOURCES

Aligned with MainPower's Demand-Side Management scheme, non-network solutions such as distributed energy resources (solar energy, energy storage, energy efficiency and demand response) can help to offset or delay network growth expenditure.

The Amuri area has already been identified as having demand exceeding MainPower's Security of Supply Standard, and the deployment of renewable resources could offset this constraint.

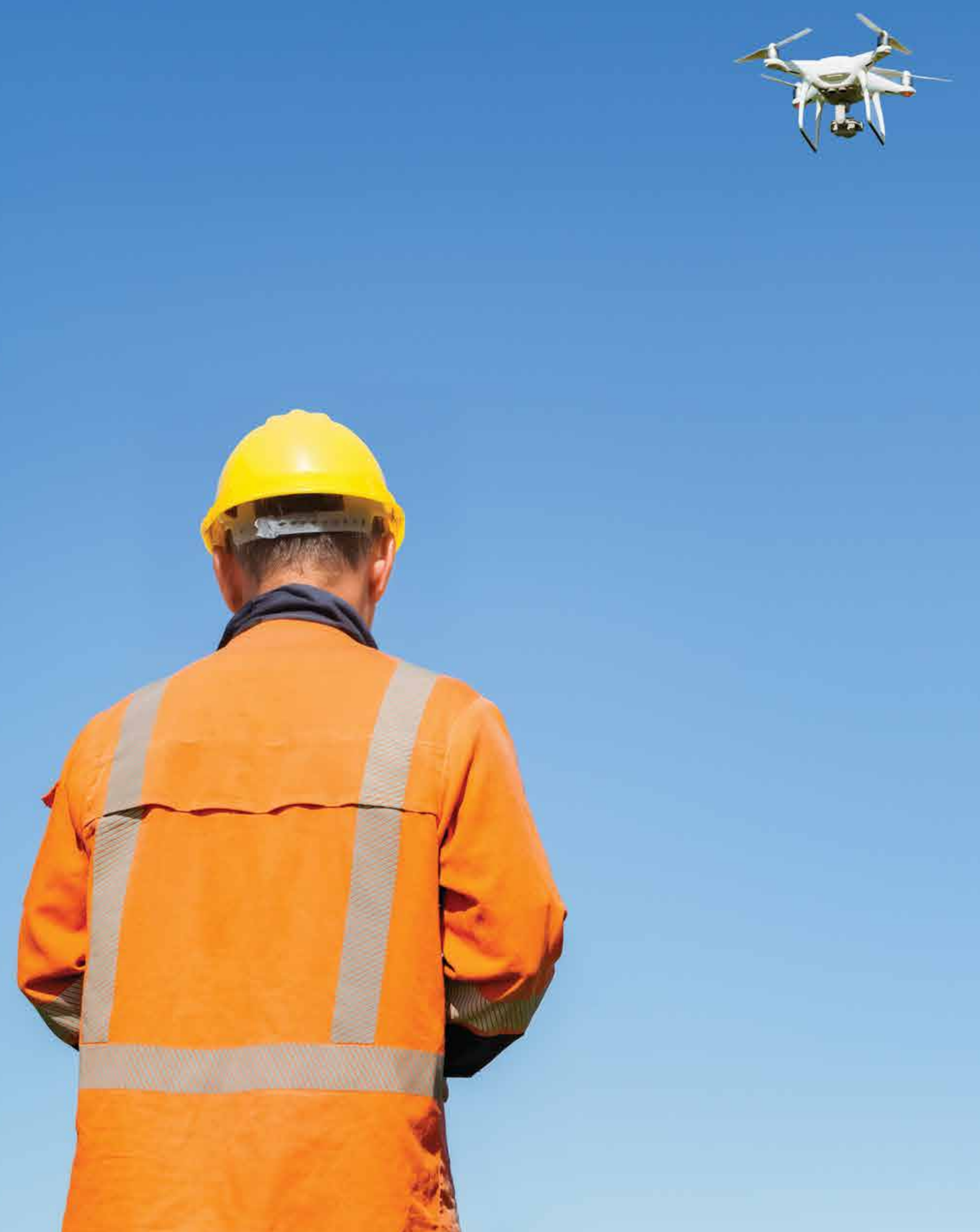
In this reporting period, MainPower intends to facilitate a market response through a Request for Proposal process to identify non-network solutions that are more sustainable, with the intent to alleviate security-of-supply risk in the Amuri area.

6.12 ALTERNATIVES AND DEFERRED INVESTMENT

Projects presented within the AMP are subjected to internal approval through MainPower's business case approval process. Part of the approval process includes evaluating the projects against non-network alternatives, demand-side management and deferral.

We are actively exploring use of non-network solutions, such as flexibility services, during our project evaluation and options analysis stage to understand all viable cost-effective solutions to network constraints to ensure we are investing in the lowest-cost viable option for consumers.

7
MAINPOWER'S ASSETS



This section provides an overview of MainPower's lifecycle asset management approach for our asset portfolio. Our whole-of-life approach is governed by the Asset Management Policy outlined in Section 2.3.1.

We recognise the need to migrate from traditional, age-based replacement and reactive renewals of assets to a holistic approach to portfolio management. For selected fleets, we have implemented a forecasting method of asset replacement that is more prescribed through the adoption of the Electricity Engineers' Association (EEA) *Asset Health Indicator Guide* to quantify and inform our replacements. The Asset Health models utilise condition data collected from inspections and maintenance programmes, engineering expertise, and asset information to optimise replacement. We consider this planned approach more sustainable for managing work programmes, as well as more effective in reducing outages and optimising our asset portfolios. In 2021 we started the journey to further improve our asset modelling capabilities by beginning to implement Condition-Based Risk Management (CBRM) models and adopting the EEA *Asset Criticality Guide.*

Our asset management drivers are informed by several reviews and consumer consultations. This includes the service-level requirements determined through consumer engagement, environmental initiatives, compliance requirements and health and safety considerations.

MainPower's network assets (discussed in the next section and shown in Table 7.1) are grouped into portfolios to reflect the way we manage these assets.

7.1 ASSET PORTFOLIO

Asset portfolio management is an integral part of MainPower's Asset Management System. It defines the maintenance and replacement programmes for each of the asset fleets to help achieve our asset management objectives.

For each asset portfolio, we outline the key information that informs our asset management decisions. The key points covered are:

- fleet objectives
- fleet statistics, including asset quantities and age profiles
- fleet health, condition, failure modes and risks
- preventative maintenance and inspection tasks
- replacement strategies.

Asset portfolio	Asset fleet
Overhead Lines	Poles and pole structures
	Crossarms and insulators
	Conductors
Switchgear	Circuit breakers
	Reclosers, sectionalisers and load break switches
	Ring main units (RMUs)
	Air break switches
	Low-voltage switchgear
Transformers	Power transformers
	Distribution transformers (ground mounted and pole mounted)
	Voltage regulators
Substations	Zone substations
	Switching stations
Underground Assets	High-voltage underground cables
	Low-voltage underground cables
	Low-voltage distribution boxes
	Low-voltage link boxes
Secondary Systems	Direct current (DC) systems
	Protection
	Communications and supervisory control and data acquisition (SCADA)
	Load control and ripple plant
Property	Zone substation buildings
	Distribution substation buildings
	Distribution kiosks
	Non-electricity distribution network buildings

Table 7.1 Portfolio and asset fleet mapping

7.2 OVERHEAD LINES

MainPower's overhead electricity distribution network has approximately 57,000 poles in service, carrying over 4,000 km of high- and low-voltage overhead conductor. Figure 7.1 shows the MainPower distribution network, giving an overall geographic view.

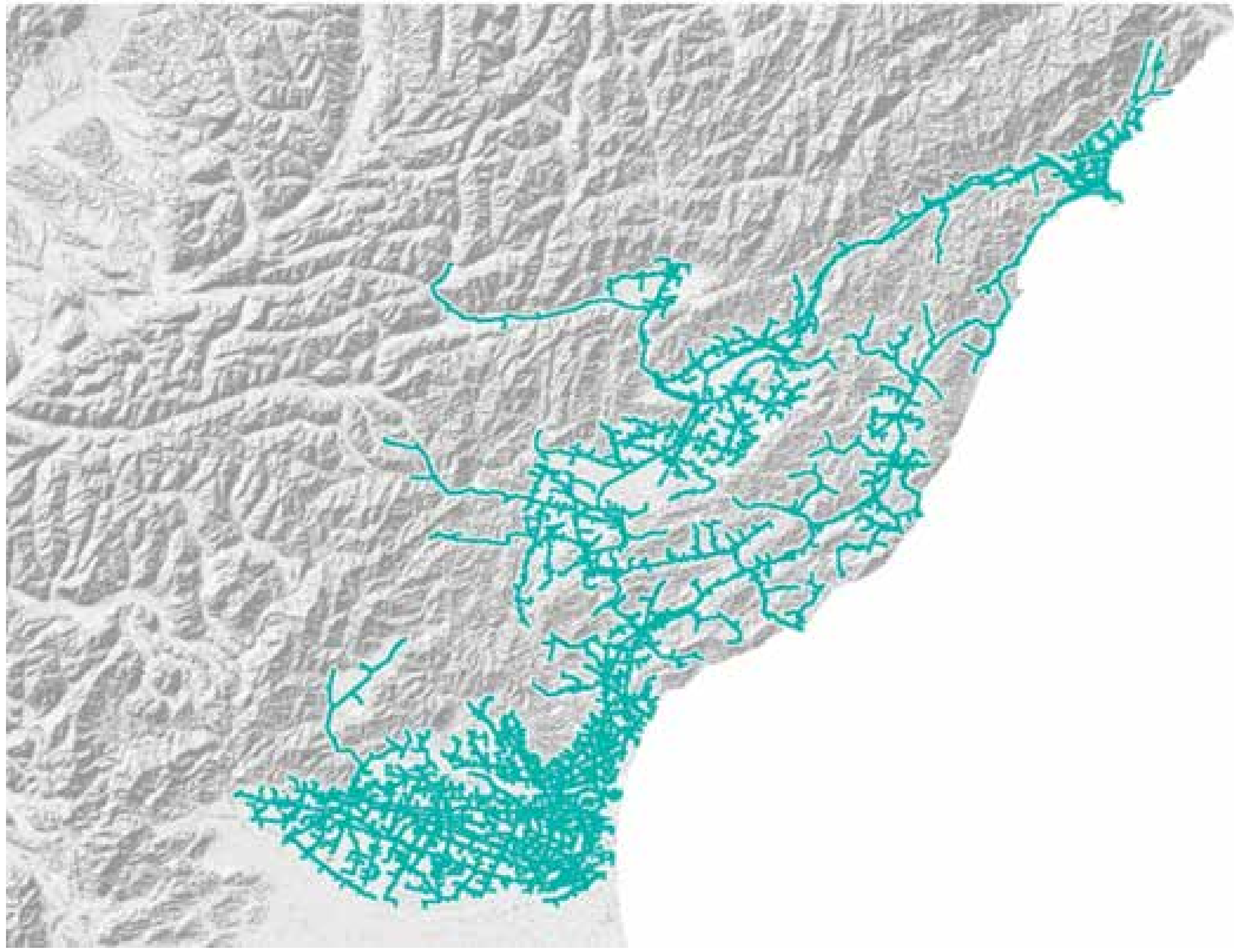


Figure 7.1 MainPower's electricity distribution network's geographical distribution

MainPower's pole inspection and renewal programme aims to proactively minimise the risks from pole failures while balancing cost. As most of our overhead electricity distribution network is accessible to the public, managing our overhead structure assets is a key priority to help ensure public safety.

7.2.1 POLES AND POLE STRUCTURES

MainPower has a large range of pole types, including:

- hardwood (pre-mid-1970s)
- larch poles impregnated with creosote (late 1950s to 1960s)
- treated pine (post-mid-1970s)
- concrete (post-1960s).

Figure 7.2 shows the current age profile of poles on the MainPower network.

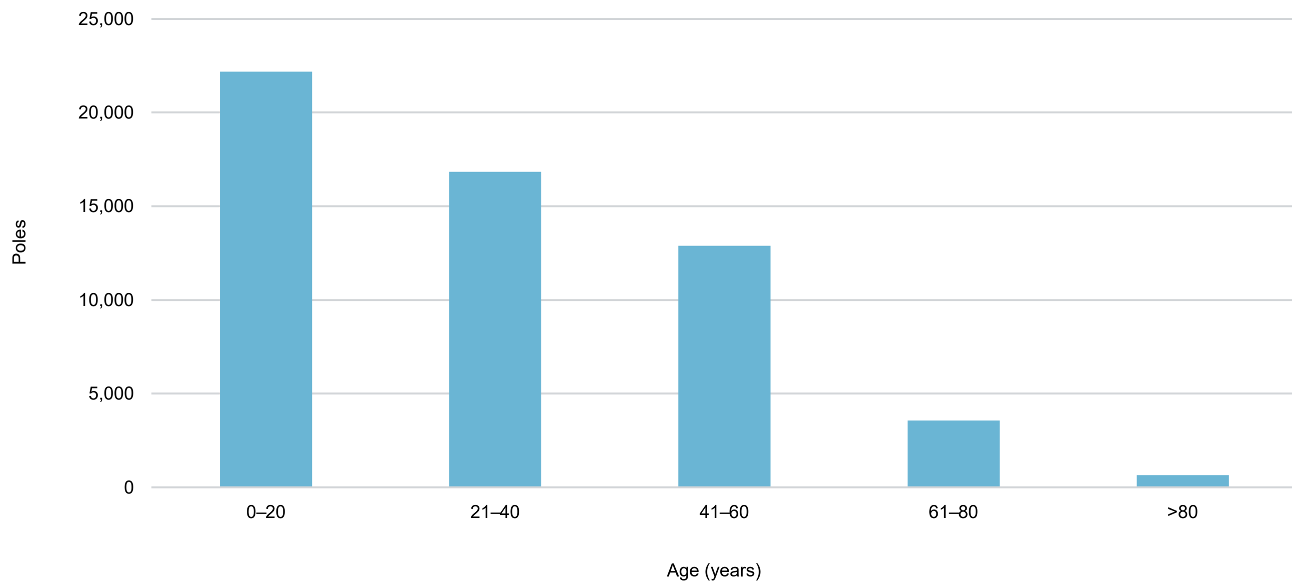


Figure 7.2 Pole age profile (FY24)

The main pole types used today are H5-treated radiata pine and pre-stressed concrete.

There are approximately 10,060 concrete poles in use on the network today, including reinforced and pre-stressed concrete. Most new poles installed today are pre-stressed and are designed and manufactured to meet stringent structural standards, with a design life of 80 years. Reinforced concrete poles contain reinforcing steel bars covered by concrete; these were used regularly from the 1960s to 1980s and are being progressively replaced, in accordance with our CBRM modelling outputs.

7.2.1.1 POLES CBRM MODEL

In 2023, we partnered with EA Technology Limited to develop a robust CBRM model for our pole fleet. This model leverages asset data, engineering expertise, and industry best practices to optimise asset renewal strategies. By calculating the health index and probability of failure for each pole, the model effectively assesses risk and informs decisions regarding replacement programmes. This approach ensures a balanced allocation of capital expenditure and operating expenditure while managing the risk of unexpected failures.

7.2.1.2 MAINTENANCE

Maintenance is based on condition assessment carried out on a five-year rotation. The inspections are governed by MainPower's *Overhead Inspection and Maintenance Standard* (MPNZ 393S049). The inspections cover pole condition and pole attachments such as crossarms, insulators and conductors. The introduction of CBRM has motivated us to review further our pole-testing and data collection methodology to ensure it aligns with CBRM and is in line with industry standards. Consistent with this, we are moving to a combination of an aerial pole-top inspection programme using aircraft and the latest camera technology, combined with our light detection and ranging (LiDAR) data to guide the inspections. This is supported by ground-based inspections to capture condition information about the poles and foundations. These inspections capture a wide range of condition information and identify defects.

MainPower has invested in a LiDAR capture of our entire overhead network. This is being maintained year-by-year, with progressive surveys. We use modelling software with a 3D dynamic virtual network representation that allows us to manage network clearances, identify defects, design our network in 3D, and to model environmental scenarios to gauge network resilience.

MainPower has a significant overhead maintenance programme, which includes repairing defects based on the inspection data. Defects are managed based on risk. Higher-risk defects are dealt with more quickly, and lower-risk defects are monitored or addressed depending on our assessment of the risk.

A summary of the overhead inspection and maintenance programme, including crossarms and conductors, is provided in Table 7.2.

7.2.1.3 REPLACEMENT AND DISPOSAL

With the introduction of CBRM, MainPower's pole replacement programme uses condition assessment data and a range of other information about poles to create a risk-based replacement priority list. Our strategy is maintaining the current level of pole fleet health and risk. This is shown in the CBRM pole health scenario options in Figure 7.4 of "Do Nothing" versus "Target" over the next 10 years. So, if we do nothing, we expect to see a substantial increase in the number of poles move into Asset Health Indicator (AHI) Band 1 (H1).

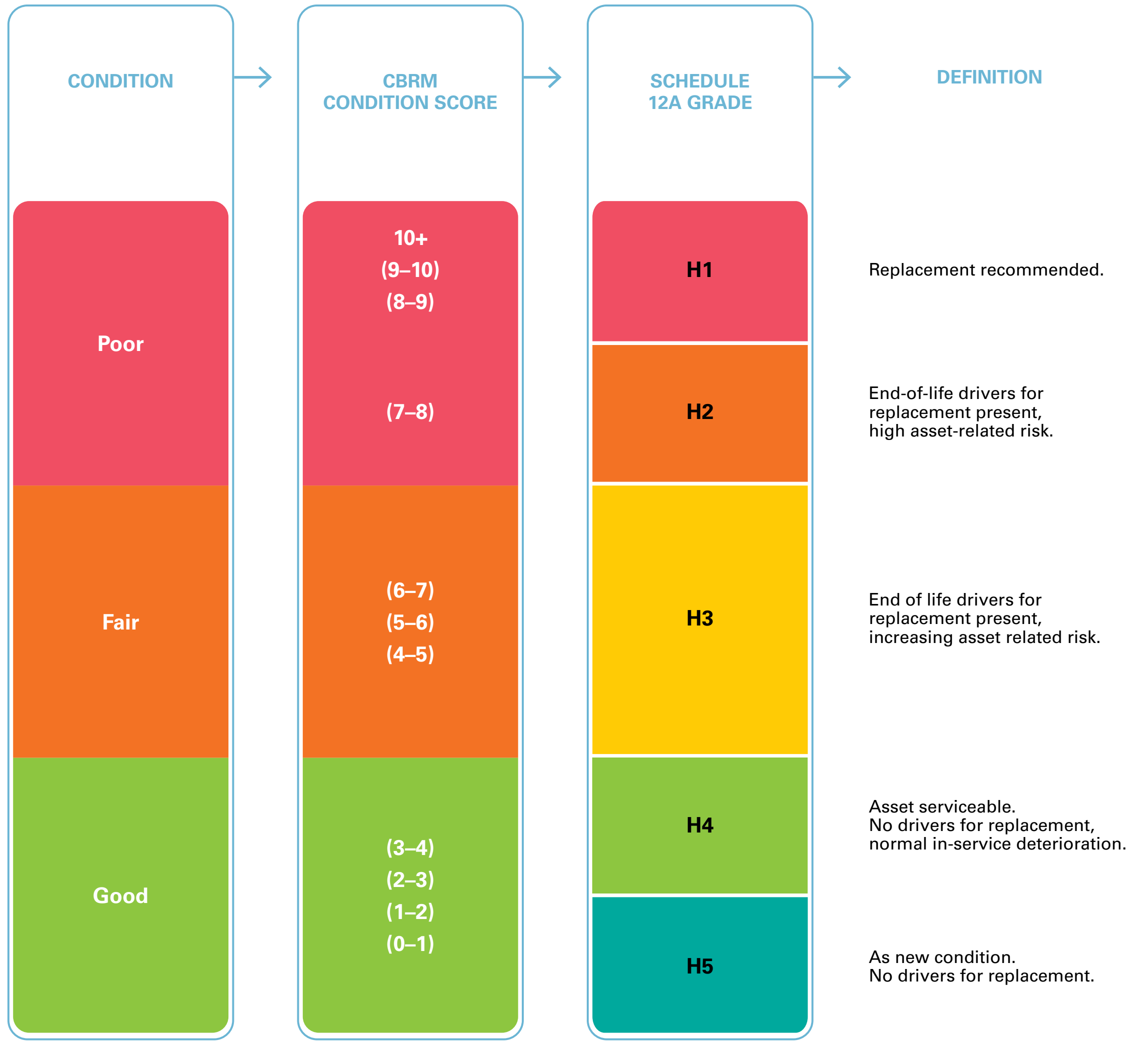


Figure 7.3 Asset Health Index

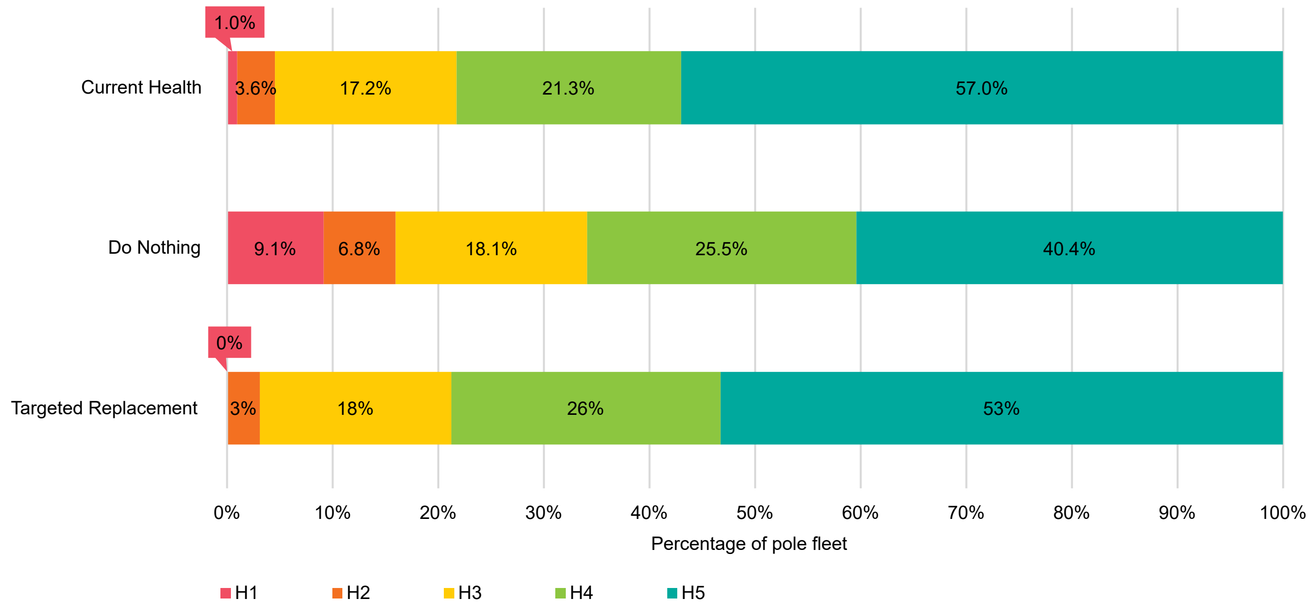


Figure 7.4 CBRM pole fleet health and risk scenarios

Pole replacements are also triggered by the need to upgrade conductors because of condition or capacity, or to improve the environmental resilience of the line structure. As part of conductor upgrade projects, we identify poles that are in poor condition and coordinate their replacement alongside the conductor upgrade to ensure efficient delivery.

7.2.2 CROSSARMS AND INSULATORS

Crossarms support the insulators that support the conductor on an overhead-line structure. A crossarm assembly is made of one or more crossarms and a range of subcomponents, such as insulators, high-voltage fuses, surge arrestors, armour rods, binders and jumpers, and arm straps. MainPower predominantly uses hardwood timber crossarms and a smaller number of galvanised-steel crossarms. These are fitted out with insulators of various types, including porcelain, glass and polymer.

7.2.2.1 MAINTENANCE

Inspection and maintenance of crossarms is included in MainPower's *Overhead Inspection and Maintenance Standard* (MPNZ 393S049) and summarised in Table 7.2. We have changed our approach to asset inspections, introducing aerial surveys to increase cost-efficiency and information capture. This will enhance our asset replacement decision making.

Based on ongoing monitoring, we have increased our overhead maintenance programme to address a growing number of defects on pole-top equipment.

To reduce the chances of new defects occurring on the pole-top equipment, line-tightening is performed selectively.

7.2.2.2 REPLACEMENT AND DISPOSAL

Crossarms are replaced based on condition, prior to a material risk developing. The pole-top equipment replacement programme addresses pole-top equipment individually and in conjunction with the pole replacement programme, through either coordinating works during outages, or replacing entire structures if required because of a combination of poor-condition elements.

7.2.3 CONDUCTORS

MainPower has a wide range of conductor types spread over three main categories:

- sub-transmission overhead conductors
- high-voltage distribution overhead conductors
- low-voltage overhead conductors.

The type of conductor used is influenced by economic, location, environmental and performance factors. Owing to the rural nature of our network, overhead conductors are a significant component, and we are working to better understand this asset fleet and its end-of-life condition indicators.

Many rural areas still have old bare or covered copper conductor in service. Covered copper conductor in some areas is starting to show signs of insulation peeling and fraying. There are also sections where the conductor has been re-joined over the years, using "sleeves", "Fargos" or "twist joints".

7.2.3.1 MAINTENANCE

Inspection and maintenance of conductors is included in MainPower's *Overhead Inspection and Maintenance Standard* (MPNZ 393S049) and summarised in Table 7.2.

7.2.3.2 REPLACEMENT AND DISPOSAL

MainPower has a limited replacement programme for conductors; our replacements are based on observed condition. We aim to understand fleet health and optimise our progression towards a larger conductor replacement programme. The potential introduction of a conductor model using CBRM would enable MainPower to develop and justify our conductor replacement planning expenditure technically and economically.

When conductor reaches end of useful life and is recovered from the network, it is disposed of by recycling as scrap metal.

MainPower's overhead inspection and maintenance is summarised in Table 7.2 for poles, conductors, crossarms and line hardware.

Component	Maintenance/Renewal category	Action
Poles	Asset inspection/condition assessment	5-yearly pole test and overhead inspection programme, a combination of aerial and ground-based inspections
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Condition-based, from data collected during the inspection programme
Conductors	Asset inspection/condition assessment	5-yearly overhead inspection for corrosion, binder fatigue and incorrect sag, as part of the overhead inspection programme Ad-hoc inspections using unmanned aerial vehicle (UAV) as required
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Replacement based on condition assessment data
Crossarms	Asset inspection/condition assessment	5-yearly inspection as part of the overhead inspection programme
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Replacement based on condition assessment data from the inspection programme
Line Hardware	Asset inspection/condition assessment	5-yearly inspection as part of the overhead inspection programme
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Replacement based on condition assessment data

Table 7.2 Overhead electricity distribution network inspection matrix

7.3 SWITCHGEAR

Switchgear is used for switching, isolating and protecting the electricity distribution network. This section covers the following types of switchgear.

- **Circuit breakers**
- **Reclosers, sectionalisers and load break switches**
- **RMUs**
- **Air break switches**
- **Low-voltage switchgear**

7.3.1 CIRCUIT BREAKERS

This section covers indoor and outdoor circuit breakers installed at zone substations and switching stations.

MainPower's older circuit breakers are predominantly oil-filled (either bulk or minimum oil). Newer circuit breakers, 25 years old or less, generally use gas or a vacuum as the interruption medium and insulation. A model based on the EEA *Asset Health Indicator Guide* has been developed for circuit breakers (excluding reclosers and sectionalisers). Figure 7.5 shows the current asset health profile of MainPower's circuit breakers.

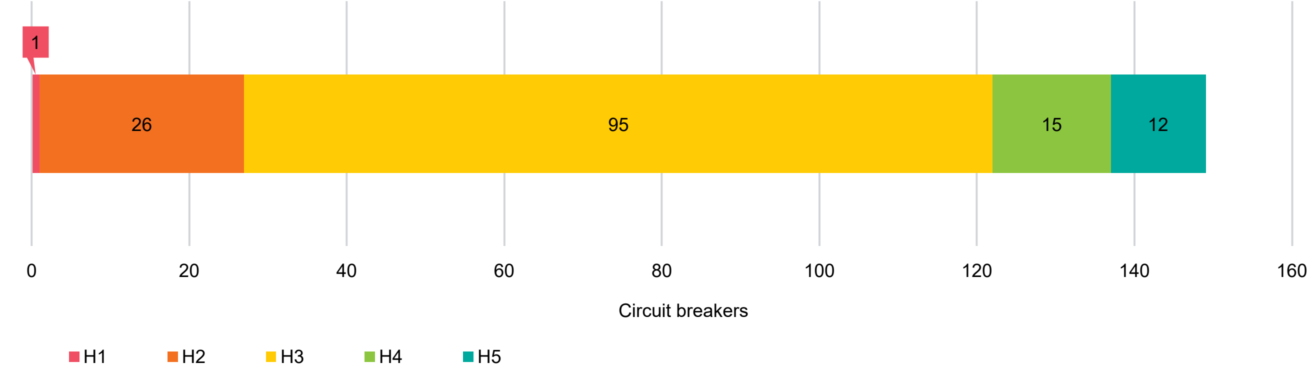


Figure 7.5 Circuit breaker asset health profile (FY24)

7.3.1.1 MAINTENANCE

Routine maintenance is important to ensure satisfactory operation of the switchgear throughout its intended serviceable life. Maintenance involves visual inspections to identify units in poor condition, partial discharge and infrared testing to locate units showing signs of deterioration, and full servicing to ensure satisfactory operation of the equipment. Table 7.3 summarises MainPower's circuit breaker maintenance programme.

Switchgear type	Frequency
Circuit breakers	3 monthly – Visual inspection 12 monthly – Partial discharge test + infrared test 5 yearly – Full service (including clean and oil change if required)

Table 7.3 Circuit breaker maintenance programme summary

7.3.1.2 REPLACEMENT AND DISPOSAL

Scheduled replacement is based on asset condition and health, informed by MainPower's AHI model. This is combined with an asset criticality score and ranks the switchgear in order of priority for replacement. As a result, MainPower's replacement programme for this asset fleet is focused on older oil-filled switchgear.

MainPower's key drivers for this replacement programme are minimising risk, improving network reliability, obsolescence, and operational control of the network. We expect unscheduled replacement works to reduce during the next five years as the maintenance and replacement programmes mature.

Oil-filled units are drained and then recycled by a scrap metal dealer along with vacuum units. Sulphur hexafluoride (SF_6) filled units have their gas recovered and are disposed of by a specialist contractor.

7.3.2 RECLOSERS, SECTIONALISERS AND LOAD BREAK SWITCHES

MainPower's reclosers, sectionalisers and load break switches (LBSs) provide protection and isolate faults, as well as allowing safe and efficient switching of the electricity network. These pole-mounted assets are installed in strategic positions along distribution feeders.

Figure 7.6 shows the current age profile of reclosers, sectionalisers and LBSs in service on the network.

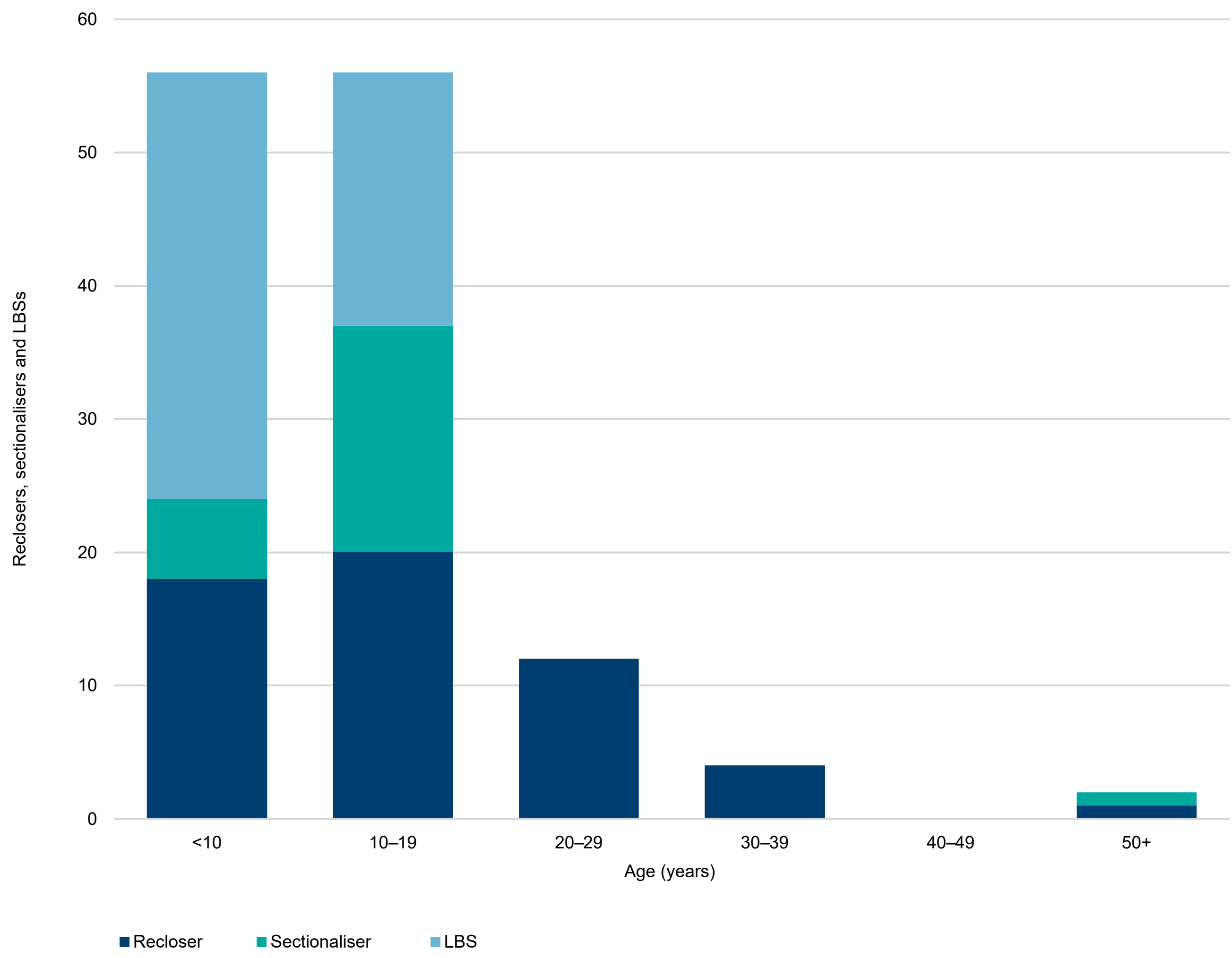


Figure 7.6 Recloser, sectionaliser and LBS age profile (FY24)

The majority of reclosers, sectionalisers and LBSs are vacuum or SF_6 insulated, although some older oil-insulated units remain on the network. Entec LBSs continue to be installed on the network allowing for flexibility in high-voltage overhead switching. A model based on the EEA *Asset Health Indicator Guide* has been developed for reclosers, sectionalisers and LBSs. Figure 7.7 shows the current asset health profile of MainPower's reclosers, sectionalisers and LBSs.

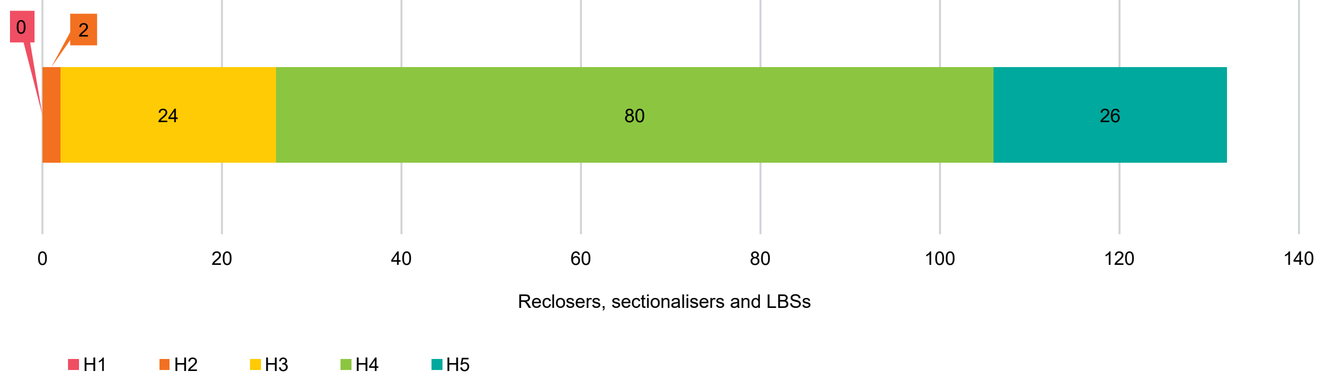


Figure 7.7 Recloser, sectionaliser and LBS asset health profile (FY24)

7.3.2.1 MAINTENANCE

Routine maintenance is important to ensure satisfactory operation of the switchgear throughout its intended serviceable life. Maintenance involves visual inspections to identify units in poor condition, partial discharge and infrared testing to locate units showing signs of deterioration, and full servicing to ensure satisfactory operation of the equipment.

Table 7.4 summarises MainPower's recloser, sectionaliser and LBS maintenance programme.

Switchgear type	Frequency
Reclosers, sectionalisers and LBSs	12 monthly – Visual inspection 2.5 yearly – Infrared scan 10 yearly – Full service (including clean and oil change if required)

Table 7.4 Recloser, sectionaliser and LBS maintenance programme summary

7.3.2.2 REPLACEMENT AND DISPOSAL

Scheduled replacement is based on asset condition and health, informed by MainPower's AHI model. This is combined with an asset criticality score and ranks the switchgear in order of priority for replacement. As a result, MainPower's replacement programme for this asset fleet is focused on older oil-filled switchgear. Selected models including Nulec and GVR units have also been prioritised for replacement due to their upcoming obsolescence.

MainPower's key drivers for this replacement programme are minimising risk, improving network reliability, obsolescence, and operational control of the network.

Oil-filled units are drained and then disposed of by recycling, through a scrap metal dealer, along with vacuum units. SF_6 filled units have their gas recovered and are disposed of by a specialist contractor.

7.3.3 RING MAIN UNITS

MainPower's RMUs are composed of various insulating mediums such as:

- cast resin (1960s through to early 2000s)
- oil (1960s through to early 2000s)
- vacuum or SF_6 (post-2000).

Figure 7.8 shows the current age profile of MainPower's RMUs.

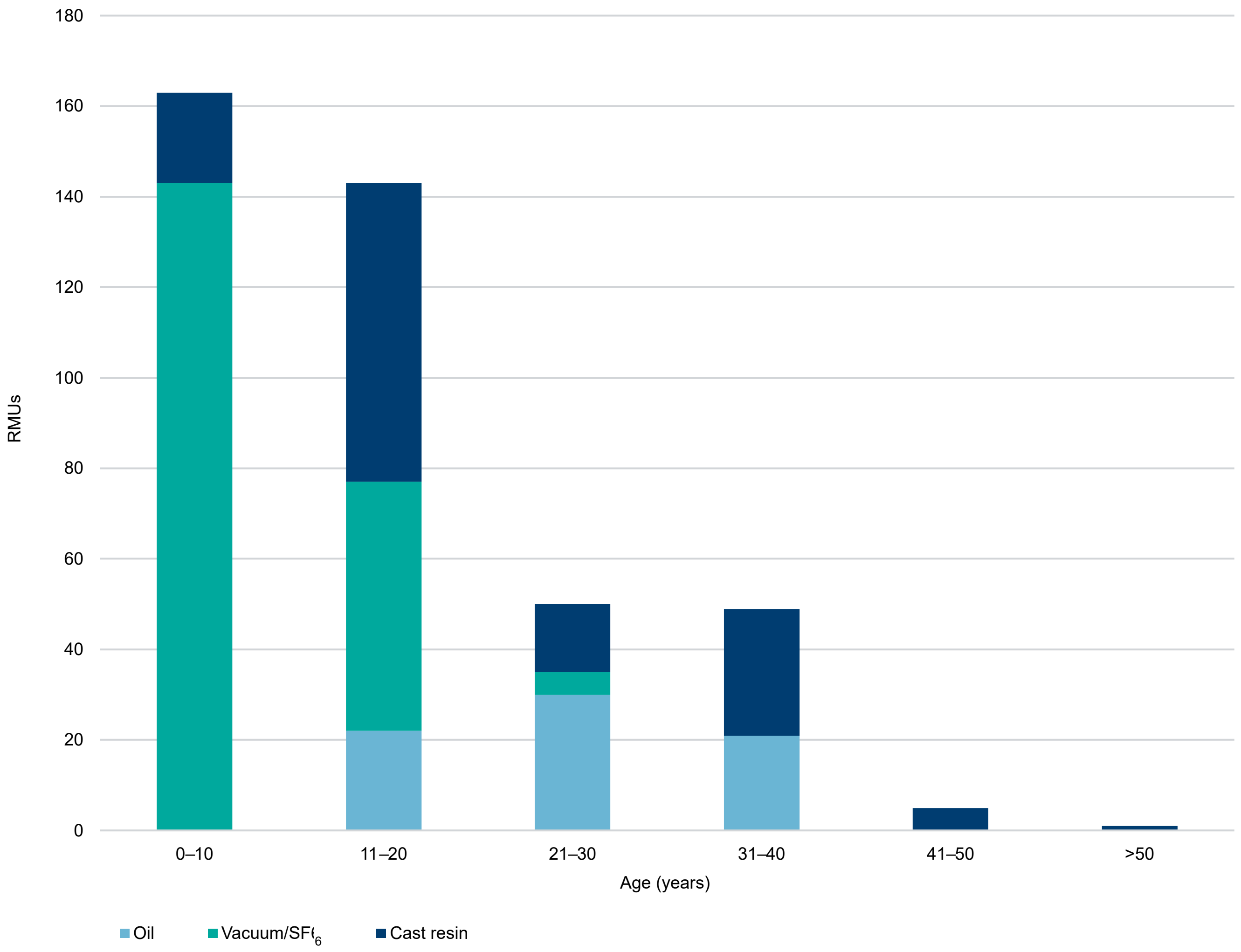


Figure 7.8 RMU age profile (FY24)

MainPower's older oil-filled RMUs have operational restrictions due to inherent failures, higher maintenance costs, risks from obsolescence, and spare parts shortages. These factors guide our replacement programme to remove them from the network. A MainPower RMU AHI model has been developed to help optimise the replacement and maintenance programme for this asset fleet. Figure 7.9 shows the current asset health profile of MainPower's RMUs.

Figure 7.9 RMU asset health profile (FY24)

7.3.3.1 MAINTENANCE

Regular maintenance is of paramount importance to ensure the safe and reliable operation of these RMUs. Oil-filled and cast resin types are typically more expensive to maintain than the vacuum and SF_6 types. SF_6 units are checked regularly for gas levels to ensure there are no gas leaks that could potentially harm the environment, affect operational performance, or pose a serious safety risk.

Table 7.5 shows the maintenance frequencies for the different RMU types of units by insulating medium.

Unit type	Frequency
Oil filled	12 monthly – Inspection + partial discharge test 5 yearly – Service (including oil change) + infrared test
Cast resin	12 monthly – Inspection + partial discharge test + infrared inspection 5 yearly – Service (including a full clean of contacts)
Vacuum/SF_6	12 monthly – Inspection + partial discharge test 5 yearly – Service + infrared test
All	Real time – Indication including SF_6 gas pressure alarm, operation count (where available)

Table 7.5 RMU inspection and maintenance summary

7.3.3.2 REPLACEMENT AND DISPOSAL

MainPower's RMU replacement programme is based on an AHI model. Asset health can be influenced by temporal factors such as type defects or obsolescence, and AHI scores are subject to change. Presently, given the small number of AHI H2-scored units, the replacement programme has been scaled back accordingly.

Planning, coordination, and engaging with disposal specialists are necessary to ensure minimal environmental footprint and maximum safety. Older oil-based units need to follow specific standards for disposal. Subsequently, we identify parts that can be retained or refurbished as spares for both new and old types.

7.3.4 AIR BREAK SWITCHES

Air break switches are high-voltage pole-mounted switches that allow for isolation and reconfiguration of the network. They are found in substations and on distribution feeders.

Air break switches are used from 11 kV up to 66 kV across the MainPower network, with an extensive range of makes and models, namely:

- Canterbury Engineering Type (1950s to 1980s)
- Dulmison, Electropar and ABB (1980s to present)
- Allied ABS (present).

Figure 7.10 shows the current age profile of MainPower's air break switches.

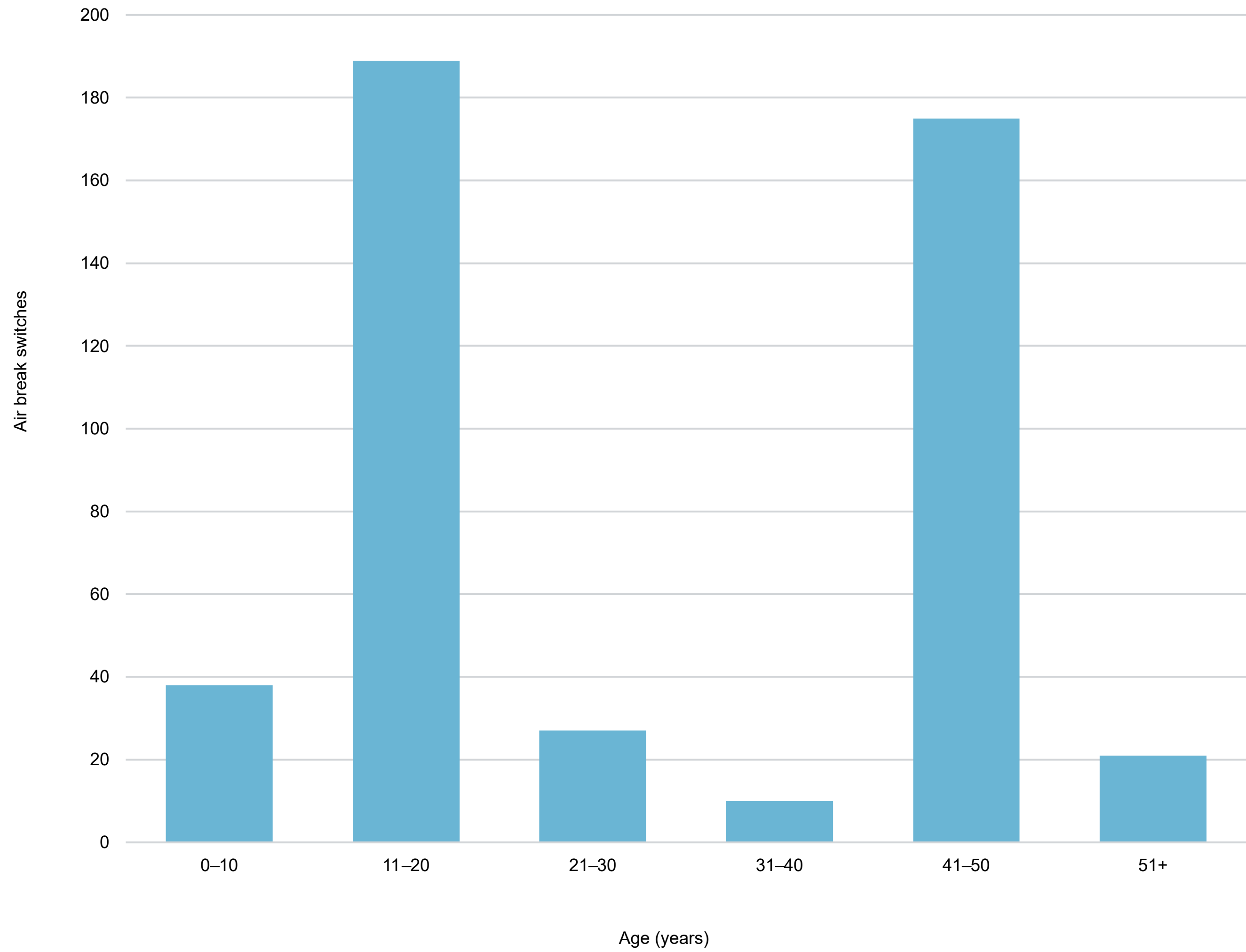


Figure 7.10 Air break switch age profile (FY24)

Inspection data is used to inform an AHI model. Figure 7.11 shows the current asset health profile of MainPower's air break switches.

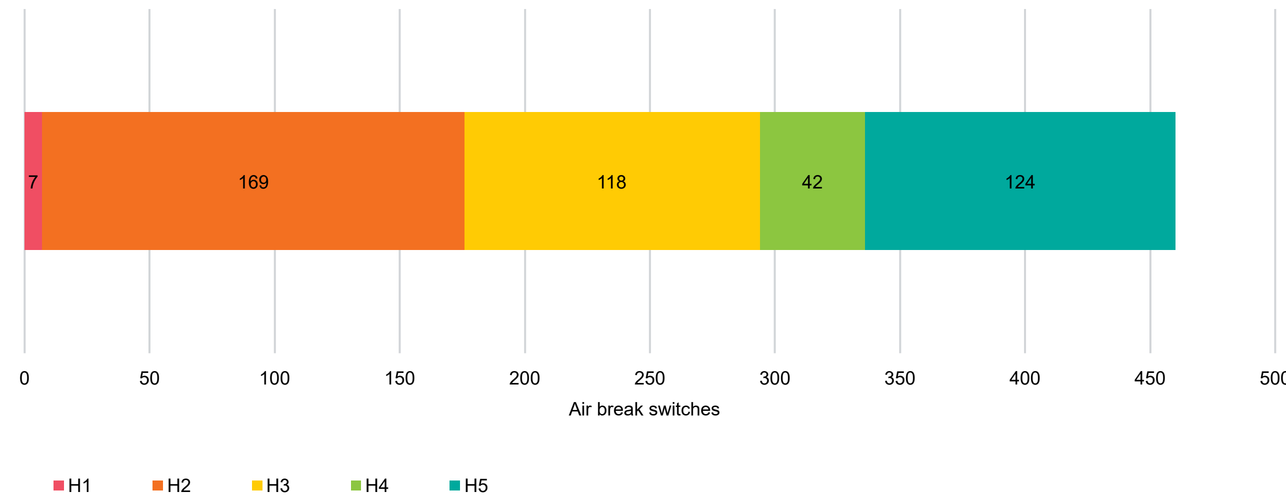


Figure 7.11 Air break switch asset health profile (FY24)

7.3.4.1 MAINTENANCE

The mechanisms on air break switches are prone to sticking or seizing if not operated or maintained for extended periods of time. This can cause unexpected delays during operation and further damage to the switch if it does not open or close correctly. This is addressed through a regular inspection and maintenance programme. Air break switches are maintained every five years. A thermal inspection is undertaken by a technician prior to visual inspection and servicing by the overhead crews to ensure heating defects are addressed during the service. The visual inspection includes a condition assessment of the switch, which is combined with inspection and asset data to inform the AHI model and replacement programme. Table 7.6 summarises MainPower's air break switch inspection and maintenance programme.

Type	Frequency
Air break switches	5 yearly – Visual inspection + full service + infrared inspection to identify hotspots

Table 7.6 Air break switch inspection and maintenance programme summary

7.3.4.2 REPLACEMENT AND DISPOSAL

MainPower's air break switch replacement programme is based on an AHI model. Asset health can be influenced by temporal factors such as type defects, and AHI scores are subject to change. The outputs from the model indicate that continued replacement initiatives are required to reduce the quantity of H1 switches on the network – in particular, older Canterbury Engineering switches, which are reaching end of life.

MainPower's network planning and engineering teams are consulted prior to replacement of an air break switch. Consideration is given to the network configuration and whether the air break switch should be replaced with an LBS or recloser to improve protection and switching performance of the network.

Before switches are disposed of they are checked and spare components are recovered to be used in future servicing tasks. The switches are then disposed of by recycling, through a scrap metal dealer.

7.3.5 LOW-VOLTAGE SWITCHGEAR

There are a range of different types of low-voltage switchgear on MainPower's network, the main types being:

- ABB Fastline (SLK) fuse gear
- DIN-style fused switches (our standard for new installations – including manufacturers like Jean Muller, Weber, and Efen, among others).

We have around 600 low-voltage switchgears in the network. These low-voltage switchgears are usually housed in kiosk sites co-located with a ground-mounted transformer and an RMU-switch asset. An asset on its own, it can have a combination of different fuse models or styles installed in each panel or enclosure. Each fuse model carries its own set of risks, where it provides some degree of complexity when prioritising for replacement. Table 7.7 lists the key issues for some of these switchgear types.

Low-voltage switchgear type	Known issues/defects
Exposed (skeleton) panels	• Porcelain fuse handles, which can be the cause of localised heating • Exposed bus-work
D&S fused switches	• Incomplete switching risk
Terasaki circuit breakers	• Incomplete switching risk
ABB Fastline (SLK) fuse gear	• Localised heating due to poor cable terminations
DIN-style fused switches	• Localised heating due to poor cable or fuse terminations

Table 7.7 Low-voltage switchgear common defects

7.3.5.1 MAINTENANCE

A visual inspection every 12 months is used to identify any hotspots and units in poor condition, as well as operational issues (see Table 7.8). This inspection is carried out in parallel with distribution substation (kiosk) inspections. Any defects raised are investigated, with the condition and criticality of the switchgear used to either prioritise corrective maintenance or schedule replacement.

Type	Frequency
Low-voltage switchgear	12 monthly – Visual inspection + infrared scan + condition assessment

Table 7.8 Low-voltage switchgear inspection summary

7.3.5.2 REPLACEMENT AND DISPOSAL

MainPower continues to replace low-voltage switchgear with identified safety and reliability risks, such as exposed panels, D&S fused switches, and Terasaki circuit breakers. These replacements are often done alongside RMU maintenance or transformer replacement to minimise outages. However, some low-voltage switchgears can be upgraded separately if newer equipment like RMUs or transformers is already on site.

7.4 TRANSFORMERS

The sub-categories and quantities of MainPower's transformers (including spares) are summarised in Table 7.9

Transformer fleet	Quantity
Power transformers	37
Distribution transformers	8,937
Voltage regulators	31

Table 7.9 MainPower's transformers

7.4.1 POWER TRANSFORMERS

MainPower's zone substation power transformers transform electricity from the sub-transmission network down to distribution voltages of 11 kV, 22 kV or 400 V. Their power ratings normally range from 4 to 40 MVA within the densely populated parts of the network. MainPower also has nine power transformers held as strategic spares. These are surplus units, typically made available from network upgrades, and are held to support network resilience and emergency responses.

MainPower uses transformer condition analysis and diagnostic tests to optimise management of its power transformer fleet. Figure 7.12 shows the current age profile of MainPower's in-service power transformers. The power transformer fleet has a typical nominal life of 45 years; however, this can vary significantly, depending on the load and operating conditions.

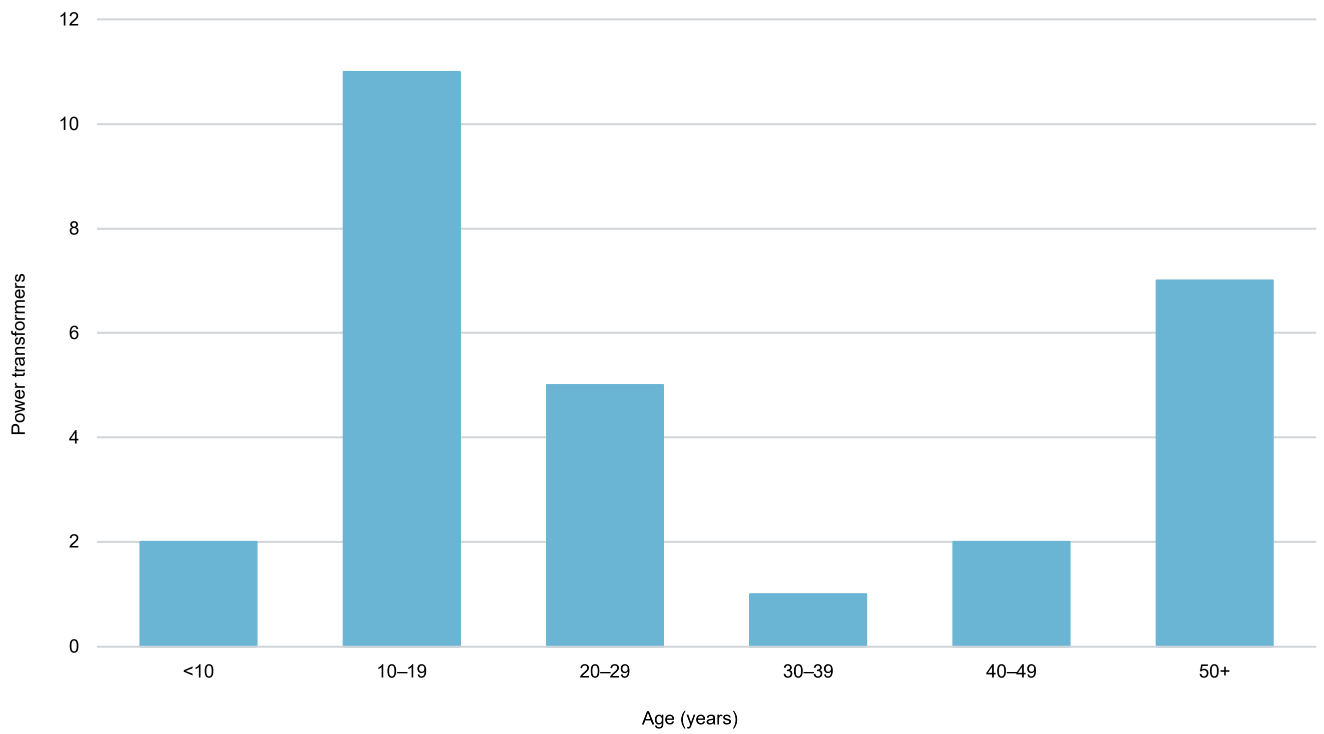


Figure 7.12 Power transformer age profile (FY24)

The power transformer fleet is managed using MainPower's Power Transformer AHI model. Figure 7.13 shows the current asset health profile of MainPower's power transformers.

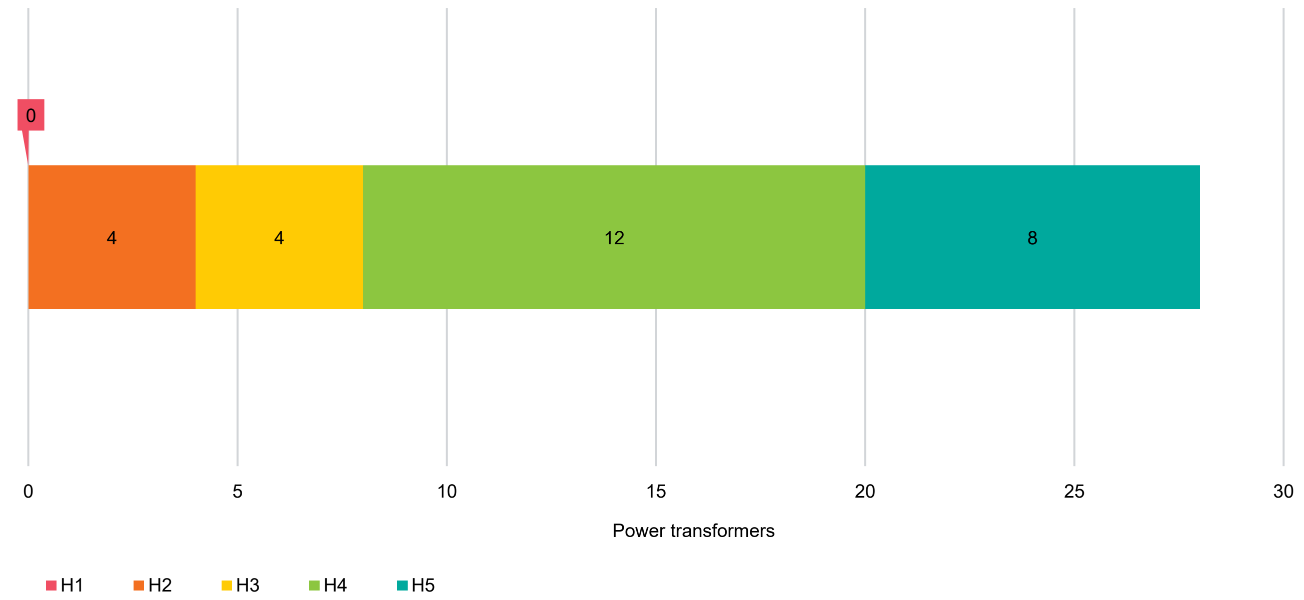


Figure 7.13 Power transformer asset health profile (FY24)

Four of the units with the lowest AHI scores are between 50 and 60 years old, and have end-of-life indicators showing they are likely to have less than 10 years of life remaining. The other low-scoring unit on the AHI model is between 40 and 50 years old. As the remaining units are showing no major defects and are ageing in accordance with their typical lifespans and loadings, many of the replacements will be undertaken as part of major projects.

7.4.1.1 MAINTENANCE

Power transformers are frequently inspected as part of MainPower's three-monthly zone substation inspections, in addition to specific diagnostic testing (see Table 7.10). Dissolved gas analysis is carried out annually, with the strategic spare transformers included in the annual dissolved gas analysis to check their ongoing suitability for service.

Equipment type	Frequency
Power transformers	3 monthly – Visual inspection as part of zone substation inspection schedule
	12 monthly – Dissolved gas analysis
	12 monthly – Thermographic and partial discharge tests
	5 yearly – Major service, including tap-changer service (some tap changers are on a 3-year cycle), electrical testing of transformer and accessories

Table 7.10 Power transformer inspection and maintenance summary

Oil treatment for moisture and acidity has been carried out historically, and this has been found to affect the chemical tracers for ageing. This was suspended in 2019 to enable dissolved gas analysis, which is more accurate.

7.4.1.2 REPLACEMENT AND DISPOSAL

No immediate replacements are planned for the current financial year. Close monitoring of the ageing trends and paper strength on the three units showing end-of-life indicators is continuing. The timing for replacement will be coordinated with planned 66 kV network upgrades to maximise the asset life and optimise investment.

When power transformers are at end of life, any usable parts are stripped, the units are drained of oil, and then they are recycled by a scrap metal dealer.

7.4.2 DISTRIBUTION TRANSFORMERS

MainPower has more than 8,300 distribution transformers in service. Approximately 85% are pole-mounted and the remaining units are in kiosks or as stand-alone units. These transformers supply customers with single-phase 230 V or three-phase 400 V electricity. Figure 7.14 shows the current age profile of MainPower's distribution transformers.

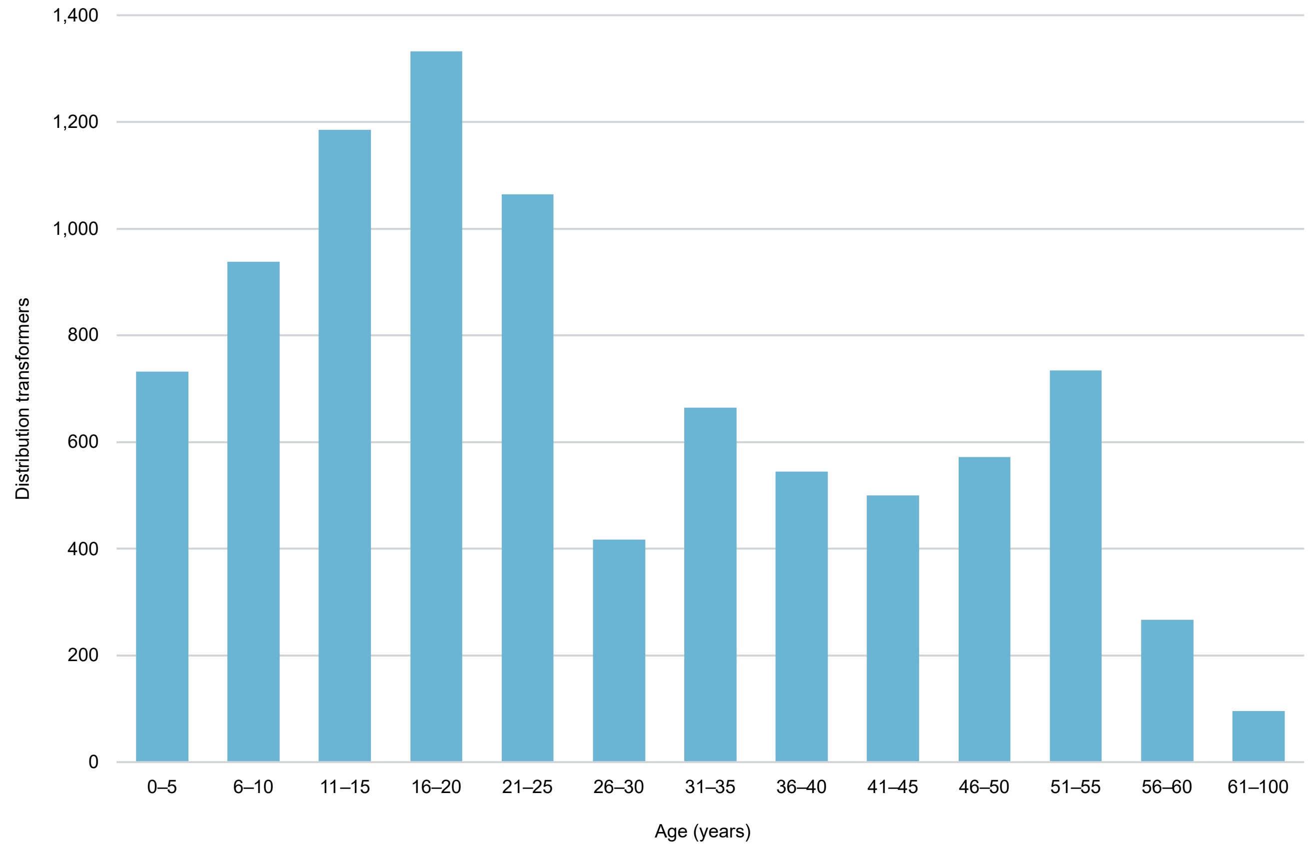


Figure 7.14 Distribution transformer age profile (FY24)

7.4.2.1 REPLACEMENT AND DISPOSAL

Typically, a distribution transformer is deemed to have failed when one of the following criteria is met.

- Diminishing oil containment
- Significant tank rusting
- Internal electrical failure

Transformers are replaced as they meet end-of-life criteria, informed by the inspection programme and reported defects. Scrap units are drained of oil and then sold to approved scrap dealers. Used oil is stockpiled until enough volumes are accumulated, and then it is disposed of using approved used-oil dealers.

7.4.2.2 GROUND-MOUNTED DISTRIBUTION TRANSFORMERS

MainPower operates approximately 800 ground-mounted distribution transformers. All units are mineral oil filled. Table 7.11 shows the ratings and quantities of these transformers, and Figure 7.15 shows their current age profile.

Rating	Number of transformers	% of total
< 15 kVA	1	0.1%
> 15 kVA and ≤ 30 kVA	17	2.2%
> 30 kVA and ≤ 100 kVA	131	16.7%
> 100 kVA and ≤ 500 kVA	537	68.4%
> 500 kVA	99	12.6%
Total	**785**	**100%**

Table 7.11 Ground-mounted distribution transformer ratings and quantities (FY24)

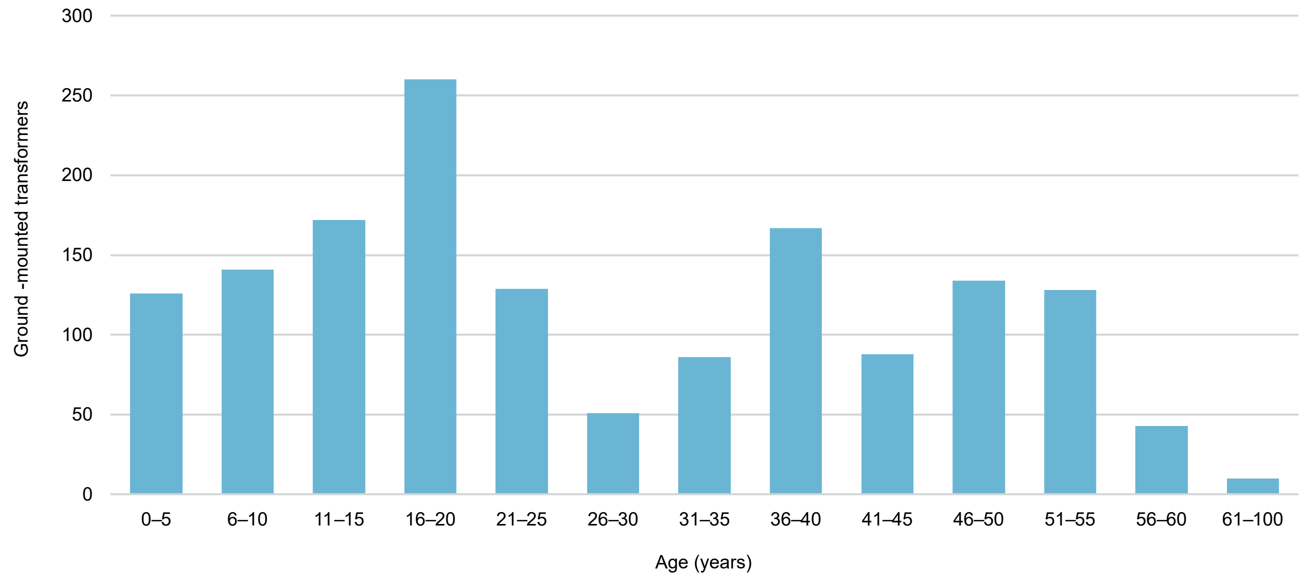


Figure 7.15 Ground-mounted distribution transformer age profile (FY24)

Maintenance

Ground-mounted distribution transformers are inspected on both an annual and a five-yearly cycle (see Table 7.12).

Type	Frequency
Ground-mounted transformers	12 monthly – General external condition assessment and labelling 5 yearly – Full visual check of all components and testing of the earthing systems

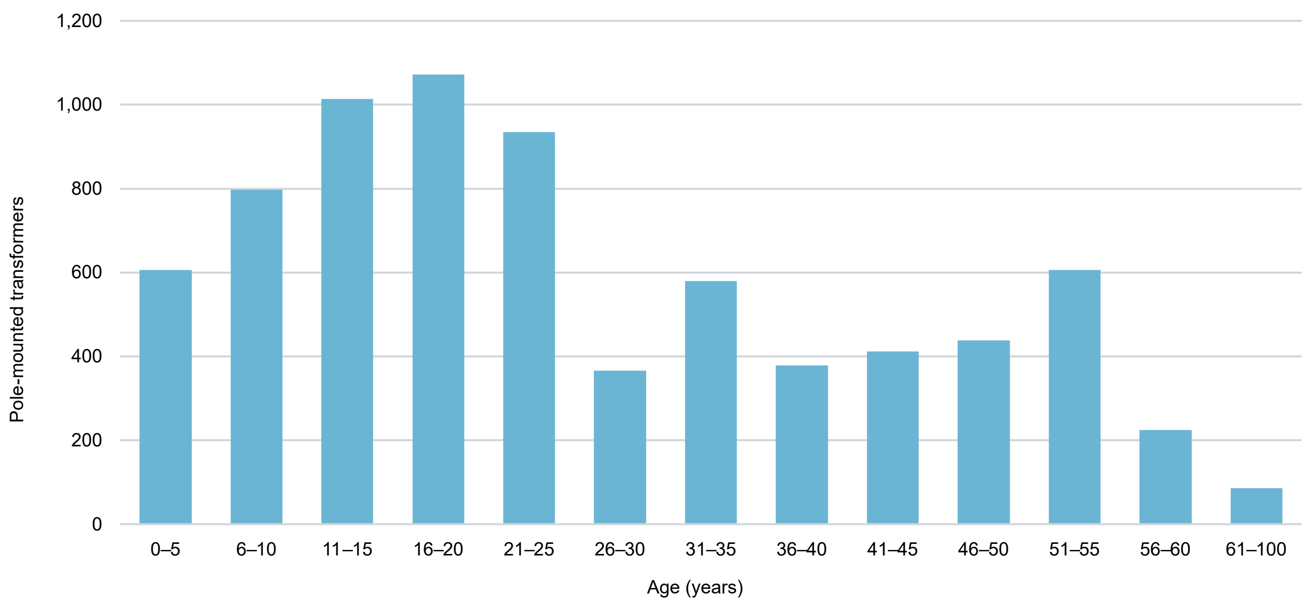
Table 7.12 Ground-mounted transformer inspection and maintenance summary

7.4.2.3 POLE-MOUNTED DISTRIBUTION TRANSFORMERS

MainPower operates approximately 7,000 pole-mounted distribution transformers. All units use mineral oil as the insulating medium. Table 7.13 shows the ratings and quantities of these transformers, and Figure 7.16 shows their current age profile.

Rating	Number of transformers	% of total
≤ 15 kVA	2,922	39%
> 15 kVA and ≤ 30 kVA	1,893	26%
> 30 kVA and ≤ 100 kVA	2,142	29%
> 100 kVA	468	6%
Total	**7,425**	**100%**

Table 7.13 Pole-mounted transformer ratings and quantities (FY24)



F igure 7.16 Pole-mounted distribution transformer age profile (FY24)

Maintenance

Pole-mounted distribution transformer inspections are carried out from the ground and include testing of the earthing system (see Table 7.14).

Type	Frequency
Pole-mounted distribution transformers	5 yearly – Full visual check of all components + testing of the earthing systems

Table 7.14 Pole-mounted distribution transformer inspection summary

7.4.3 VOLTAGE REGULATORS

MainPower operates 24 single-phase 11 kV voltage regulators, which are located across 12 sites, with multiple new sites commissioned since 2020 to support regional growth. Voltage regulators act to stabilise the voltage in the distribution network within prescribed limits for consumers.

The voltage regulators are mostly 220 kVA General Electric devices with automatic controllers. Their expected life is 45 years in normal service; it is anticipated that this could be extended through asset management practices. No issues have been identified with the existing voltage regulator assets.

7.4.3.1 MAINTENANCE

The voltage regulator maintenance programme is aligned with MainPower's asset inspections and maintenance programme for pole-mounted transformers (see Table 7.15).

Type	Frequency
Voltage regulators	5 yearly – Asset inspection, including oil sampling

Table 7.15 Voltage regulator inspection and maintenance summary

7.4.3.2 REPLACEMENT

No replacements are currently planned for this asset class. Disposal of these units will be in line with other oil-filled equipment such as distribution transformers.

Figure 7.17 Zone substation locations

7.5 SUBSTATIONS

7.5.1 ZONE SUBSTATIONS

MainPower's electricity distribution network is supplied via five grid exit points (GXPs) from the Transpower 220 kV and 66 kV transmission circuits passing through the region. There are 17 MainPower zone substations that operate at 66 kV and/or 33 kV. These supply the 11 kV and 22 kV distribution network. An image of the electricity distribution network is shown in Figure 7.17, followed by a summary of the zone substation capacity and feeders (Table 7.16).

Site	Voltage (kV)	Substation capacity (MVA)	Type
Amberley	33/11	8	Indoor
Burnt Hill	66/22	46	Indoor
Cheviot	66/11	4	Outdoor
Greta	66/22	4	Outdoor
Hanmer Springs	33/11	6	Indoor
Hawarden	33/11	4	Outdoor
Kaikōura	66/33	16	Outdoor
Leader	33/11	4	Outdoor
Lochiel	33/11	0.3	Outdoor
Ludstone Road	33/11	12	Indoor
Mackenzies Road	66/11	4	Outdoor
Marble Point	33/11	0.2	Outdoor
Mouse Point	33/22	26	Outdoor
Oaro	33/11	0.5	Outdoor
Southbrook	66/11	80	Indoor
Swannanoa	66/22	46	Indoor

Table 7.16 Zone substation statistics (FY24)

7.5.1.1 MAINTENANCE

Zone substations are maintained on three overlapping cycles, ranging from regular visual inspections through to a major zone substation service requiring substation shutdown (see Table 7.17).

Type	Frequency
Zone substations	3 monthly – Visual inspection/visual condition assessment
	12 monthly – Thermographic and partial discharge testing
	5 yearly – Major zone substation service with electrical testing on all equipment

Table 7.17 Zone substation inspection and maintenance summary

7.5.1.2 REPLACEMENT

Replacement of zone substations is typically driven by network growth and managed as a major capital expenditure project. Where possible, timing is optimised to coordinate replacement of end-of-life assets with additional sub-transmission development drivers, which include engineering, economic and security-of-supply analysis and optimisation.

7.5.2 SWITCHING SUBSTATIONS

In addition to zone substations, MainPower operates six switching stations that form part of the 11 kV electricity distribution network (see Table 7.18). These are strategic switching points that supply various feeder circuits throughout a localised area.

Site	Voltage	Type
Pegasus	11 kV	Indoor
Kaiapoi North	11 kV	Indoor
Rangiora West	11 kV	Indoor
Percival Street	11 kV	Indoor
Bennetts	22 kV	Indoor
Kaiapoi S1	11 kV	Indoor

Table 7.18 11/22 kV switching stations

7.5.2.1 MAINTENANCE

Switching substations are maintained on the same cycles as the zone substations mentioned above.

7.5.2.2 REPLACEMENT AND DISPOSAL

Switching station assets that reach their maximum practical life as assessed by AHIs are considered for replacement with modern, compact, ground-mounted kiosks where achievable.

7.6 UNDERGROUND ASSETS

The underground assets portfolio is made up of four asset fleets, as shown in Table 7.19.

Asset fleet	Length/Quantity
High-voltage underground cables	391 km
Low-voltage underground cables	1,314 km (including streetlight circuits)
Low-voltage service boxes	14,100
Low-voltage link boxes	735

Table 7.19 Underground asset quantities

7.6.1 HIGH-VOLTAGE UNDERGROUND CABLES

MainPower's high-voltage underground cables are primarily either 95 mm² or 185 mm² aluminium conductor. We now use 300 mm² aluminium conductor cables to supply major urban feeders or distribution switching stations. Smaller sizes, typically 35 mm² aluminium conductor, are used for rural consumer spurs.

Most high-voltage cable assets are within their nominal practical life. Known defects with this asset class are generally related to the cable terminations or joints.

Figure 7.18 shows the current age profile of MainPower's high-voltage cables.

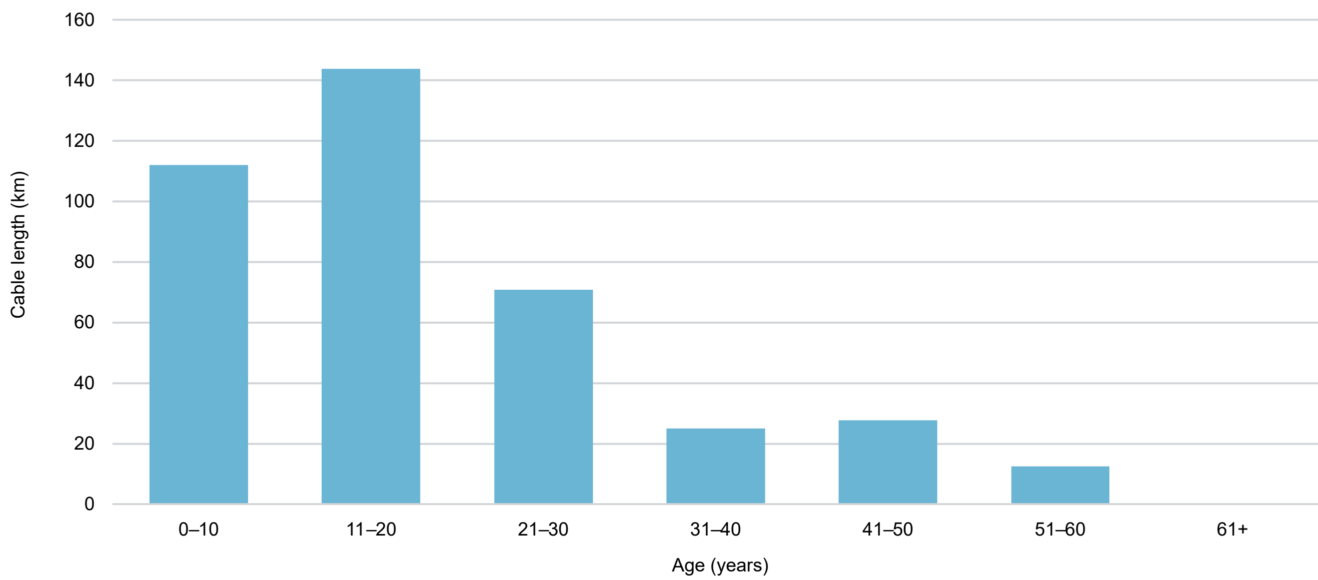


Figure 7.18 High-voltage cable age profile (FY24)

An age-based model based on the EEA *Asset Health Indicator Guide* has been developed for MainPower's cable assets. The model indicates that the high-voltage cable fleet is in generally good health, with a very small percentage of assets at or approaching their maximum practical life. It is important to note the limitations of this model, as it is based solely on asset age. Figure 7.19 shows the current asset health profile of MainPower's high-voltage cables.

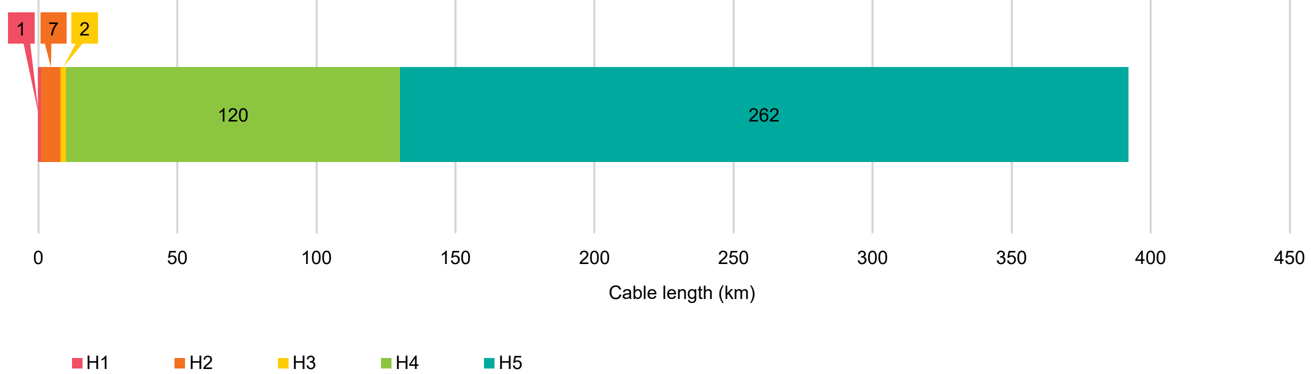


Figure 7.19 High-voltage cable asset health profile (FY24)

7.6.1.1 MAINTENANCE/INSPECTIONS

The inspection criteria for these assets fall within the maintenance and inspection programmes for other asset types – typically assets housing and supporting the cable termination, such as distribution buildings, distribution kiosks, overhead lines and zone substations. All end terminations are inspected by either thermographic or acoustic inspection, no less than five yearly, as part of these inspection programmes.

The only exception is sub-transmission cables, which operate at higher than 22 kV; these cables have specific electrical tests conducted on a five-yearly basis to monitor and trend their condition. This is due to the higher impact of failure with these assets.

We are actively engaged in supporting and educating the local community and contractors about the risks of excavating near underground cable assets. We are a member of the "beforeUdig" online service and provide cable-locate and stand-over services to local contractors or individuals.

7.6.1.2 REPLACEMENT AND DISPOSAL

MainPower does not currently have a scheduled replacement programme for underground high-voltage cables. Replacement of cables is typically the result of inspection data or faults. Some sections of 33 kV cable have been identified for replacement within the 10-year period, due to condition.

Scrap cables are recycled by a scrap metal dealer.

7.6.2 LOW-VOLTAGE UNDERGROUND CABLES

Low-voltage underground distribution cables deliver energy to consumers at 400/230 V from distribution transformers. MainPower's low-voltage network primarily consists of 95 mm² or 185 mm² aluminium cables. Smaller aluminium and copper distribution cables are still in use, predominantly in Rangiora and Kaiapoi. For larger developments, 300mm² aluminium cables are now standard.

Figure 7.20 shows the current age profile of MainPower's low-voltage cables.

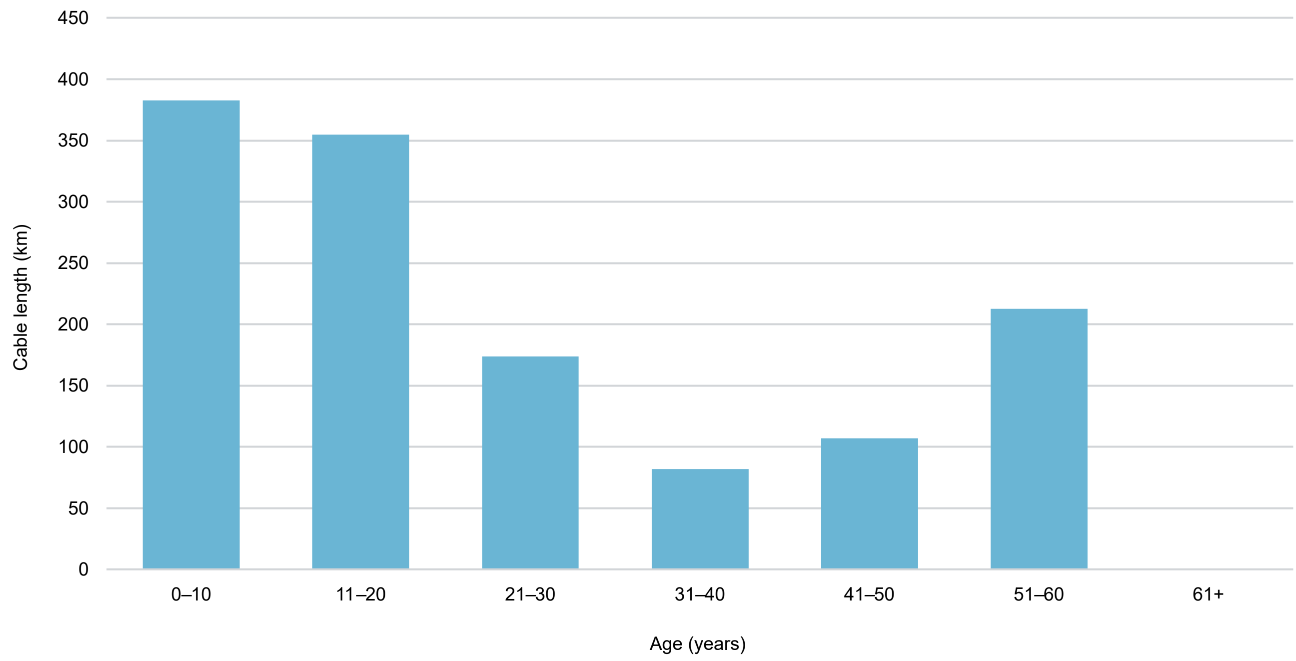


Figure 7.20 Low-voltage cable age profile (FY24)

An age-based model based on the EEA *Asset Health Indicator Guide* has been developed for MainPower's cable assets. The model indicates that the low-voltage cable fleet is in generally good health. It is important to note the limitations of this model, as it is based solely on asset age. Figure 7.21 shows the current asset health profile of MainPower's low-voltage cables.

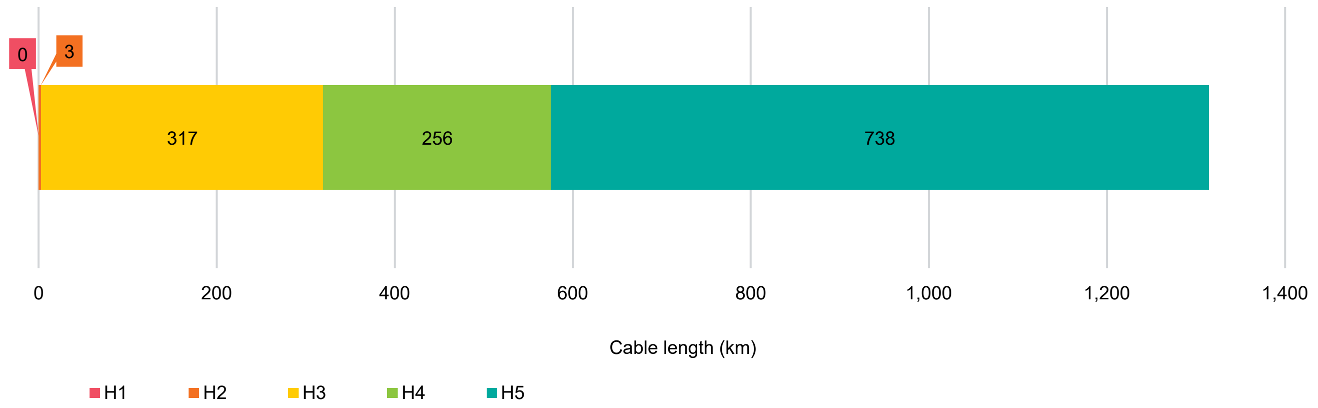


Figure 7.21 Low-voltage cable asset health profile (FY24)

7.6.2.1 MAINTENANCE/INSPECTIONS

The inspection criteria for these assets fall within the maintenance and inspection programmes for other assets, which are typically assets housing the cable termination, such as distribution substations, link boxes and service boxes. Through these programmes, the cable terminations are visually inspected at no less than five-yearly intervals. The service box inspection programme also includes a fault loop testing on distribution cables, which can indicate the presence of poor terminations or joints.

7.6.2.2 REPLACEMENT AND DISPOSAL

Some low-voltage underground circuits in Rangiora and Kaiapoi are to be replaced in the coming years. These circuits feature direct-connected service mains, often referred to as "tee-joints". These direct-buried joints are known to fail, causing extended outages. The cables are also undersized compared to the rest of the low-voltage network. Replacing these circuits will improve the risk profile, capacity and switching options of the network.

MainPower does not currently have a scheduled replacement programme for underground low-voltage cables. Replacement for cables is typically the result of inspection data or faults. A formal replacement strategy is yet to be developed.

Scrap cables are recycled by a scrap metal dealer.

7.6.3 LOW-VOLTAGE DISTRIBUTION BOXES

MainPower's low-voltage distribution boxes consist of the following.

Service boxes

These are small plastic boxes manufactured by either Gyro Plastics or TransNet, typically housing up to 12 standard domestic service fuses, which are used for single- or three-phase consumer connections. Some larger boxes, the same make as link boxes, are used for commercial connections where physically larger fuses are required. Some historical service box types that are constructed of metal frames with fibreglass lids exist on the network.

Link boxes

These are larger than service boxes, made of thermoplastic, and typically house 4 to 10 vertically mounted disconnectors for either domestic or commercial consumer connections. Link boxes provide an alternative supply point between distribution transformers and allow reconfiguration of the network. Some historical steel boxes exist on the network.

Low-voltage distribution boxes incorporate safety features into box design. Access is restricted and controlled via our Network Operations and Control Centre (NOCC).

Asset health models have been developed for service boxes and link boxes; inspection data is used to inform the models. The current asset health profiles are shown in Figure 7.22 and Figure 7.23.

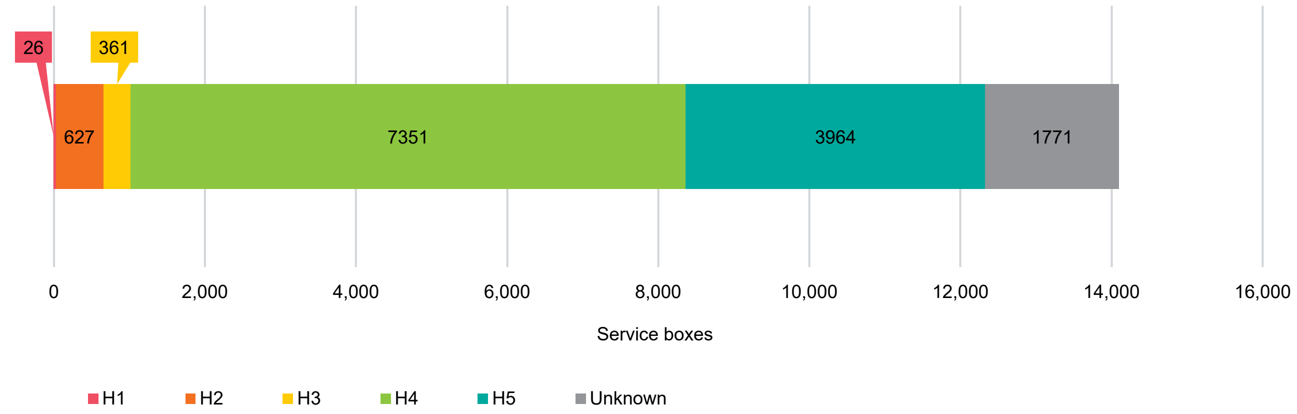


Figure 7.22 Service box asset health profile (FY24)

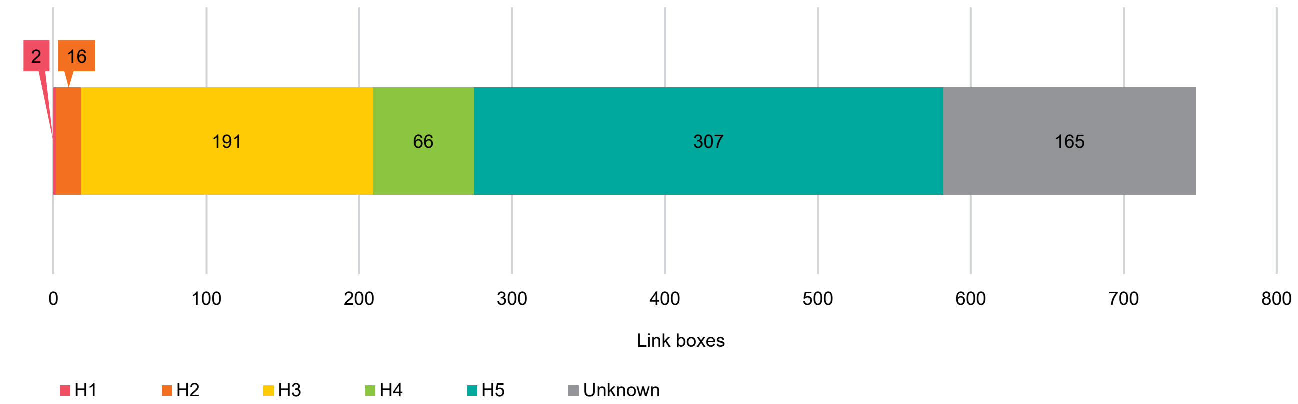


Figure 7.23 Link box asset health profile (FY24)

7.6.3.1 MAINTENANCE

Service boxes and link boxes are inspected every 5 years (see Table 7.20). Service boxes undergo a visual inspection and service, which includes torquing of terminal screws and fault loop testing. Link box inspections are similar, with the addition of a thermal scan to identify heating defects.

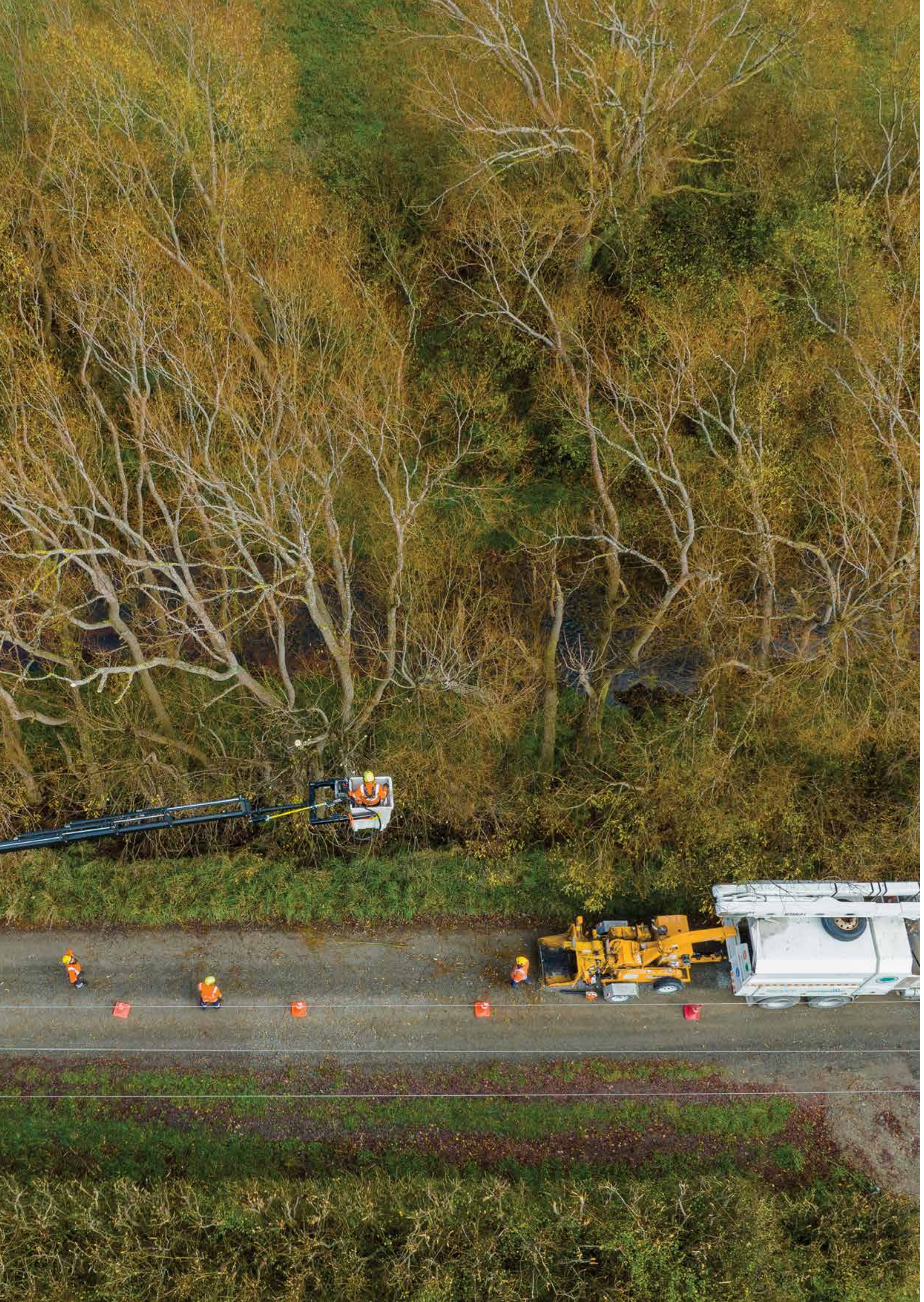
Type	Frequency
Service boxes	5 yearly – Inspection, including torquing of terminals and fault loop testing
Link boxes	5 yearly – Inspection, including thermal scan

Table 7.20 Service and link box inspection summary

7.6.3.2 REPLACEMENT AND DISPOSAL

MainPower's service box and link box replacement programmes are now driven by asset health outputs from AHI models. MainPower has an ongoing initiative to replace historical metal frame service boxes and link boxes in the Kaiapoi and Rangiora areas. The models are used to prioritise these replacements to ensure that the lowest health assets are replaced first. Unscheduled replacements are primarily driven by defects identified by our network field operators or because of third-party damage. Where possible, boxes scheduled for replacement are grouped by low-voltage circuit to minimise outages to customers.

Metal boxes are recycled by a scrap metal dealer, and fibreglass and plastic boxes are treated as refuse. Boxes containing asbestos backing plates are carefully recovered and disposed of by a licensed asbestos removal contractor.



7.7 VEGETATION MANAGEMENT

The majority of MainPower's overhead network traverses rural areas. Vegetation is an ongoing concern and a common cause of outages, especially during weather events. MainPower communicates regularly with the public through a variety of channels. MainPower's aim is to educate tree owners and the public about their responsibility for maintaining trees and the risks of trees falling on power lines.

MainPower has a dedicated team for managing vegetation, including a skilled team of arborists who undertake inspections and trimming around MainPower's network.

7.7.1 MAINTENANCE

MainPower's Vegetation Programme continues to evolve. Prioritising our high fire risk areas continues to be a focus area, particularly as we managed the drier El Niño weather patterns during 2024–2025 and looking ahead to 2026 and beyond.

We continue to explore new methods of vegetation programme delivery. This year we have refreshed our vegetation management strategy. Investigative steps continue into a range of different means to improve the programme, in accordance with our new strategic approach to the programme. This will eventually lead to better vegetation management outcomes in the future.

MainPower has two full-time arborist crews who carry out most of the vegetation maintenance within our region and provide supervision to third-party contractors working in the vicinity of our lines. We increasingly work with contractors to ensure that our vegetation management programme is successfully delivered.

7.8 SECONDARY SYSTEMS

Secondary systems provide protection and operational control to the electricity distribution network's primary assets. This section covers the following types of secondary systems.

- **DC systems**
- **Protection**
- **Communications and SCADA**
- **Load control and ripple plant**

The secondary system assets help MainPower deliver its reliability and safety-service levels. They are a vital asset fleet for ensuring the protection of the electricity distribution network assets, personnel and the general public. The systems are required to operate during loss of electricity supply to their respective sites and enable restoration.

7.8.1 DC SYSTEMS

MainPower's DC systems are split into two main parts.

- Batteries
- Battery chargers

A range of different battery models, by different manufacturers, are spread across the network, typically installed in zone and switching substations, pole-mounted recloser sites, and communication and repeater sites. Table 7.21 shows the quantities of MainPower's DC batteries by nominal life.

Asset	Nominal life	Quantity
DC batteries	10 years	253
	5 years	273
	1 year	3
	Total	**529**

Table 7.21 DC battery quantities based on nominal life (FY24)

MainPower has standardised with one battery supplier to provide efficiencies in procurement, installation and operation. Some known defects across the existing battery fleet include a shorter-than-expected asset life due to high ambient temperatures and historical issues caused by installing incorrect battery types for the intended purpose.

DC chargers include rectifiers, DC–DC converters, controllers and other associated hardware. MainPower has a range of types, from older in-house-built types through to modern SCADA-connected units.

7.8.1.1 MAINTENANCE

Batteries and DC chargers are frequently inspected and tested because of their importance for monitoring and controlling the network under contingency events (see Table 7.22).

Location	Frequency
Substation	3 monthly – Visual inspection + self-test (if available with charger model) 12 monthly – Electrical tests
Recloser	12 monthly – Visual inspection + electrical test
Communication site	6 monthly – Visual inspection + electrical test
All sites	Real time – Battery/charger diagnostics (if connected via SCADA)

Table 7.22 DC battery and charger inspection and maintenance summary

7.8.1.2 REPLACEMENT

Scheduled replacement of batteries is prioritised based on a combination of age relative to expended design life and inspection data. Batteries that prematurely fail are replaced immediately. DC charger replacement is primarily driven by end of life, obsolescence or lack of SCADA functionality.

7.8.2 PROTECTION

The electricity distribution network has protection relays located in zone and switching substations, RMUs and reclosers. Figure 7.24 shows the current age profile of MainPower's protection relays.

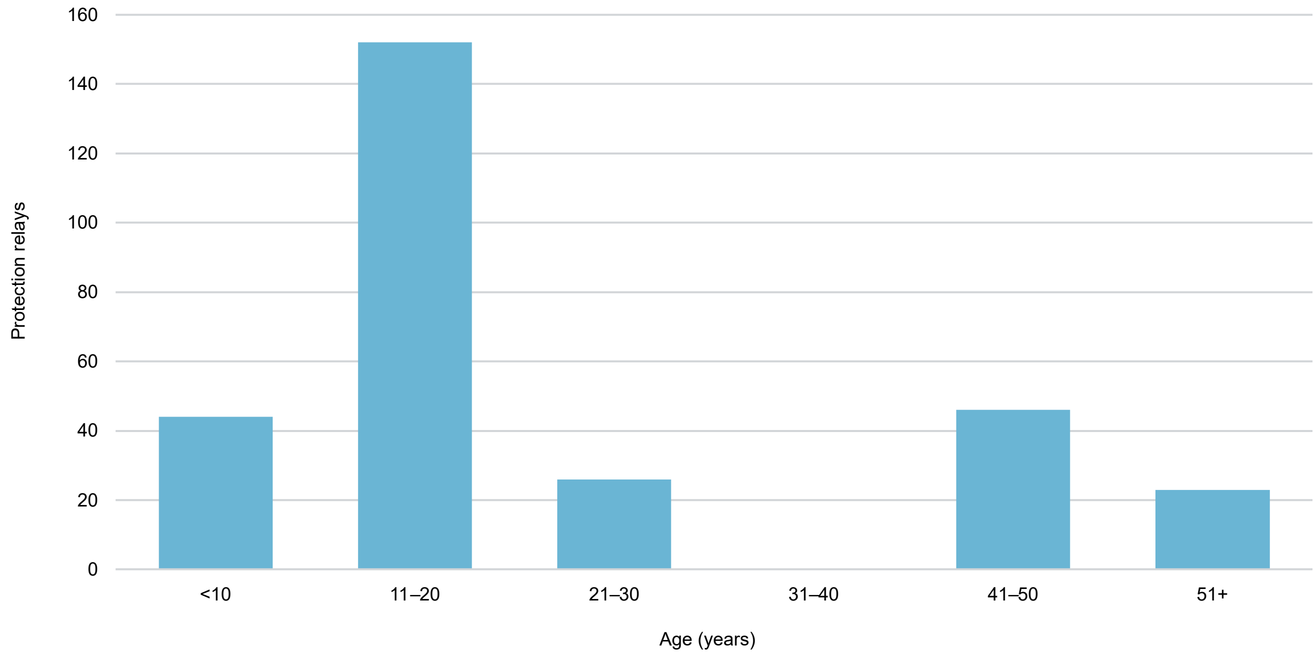


Figure 7.24 Protection relay age profile (FY24)

7.8.2.1 MAINTENANCE

Regular maintenance of the protection relays is critical in verifying operations and providing protection of the electricity distribution network primary assets (see Table 7.23).

Location	Frequency
Zone/switching substation	3 monthly – Visual inspection 5 yearly – Full system test
Recloser	12 monthly – Visual inspection 10 yearly – Full system test
RMU	12 monthly – Visual inspection 5 yearly – Full system test
All sites	Real time – Relay fail and other diagnostics (where available with digital relays)

Table 7.23 Protection relay inspection and maintenance summary

7.8.2.2 REPLACEMENT

Where possible, scheduled replacement of protection relays is combined with the replacement of the associated switchgear. MainPower also has a replacement programme to progressively replace older electromechanical relays with modern digital relays, providing additional protection functionality and control.

7.8.3 COMMUNICATIONS AND SCADA

MainPower operates both a voice and a data communications network via a combination of digital and analogue radio and fibre. The communications network is characterised by radial links out of the MainPower head office, located in Rangiora, to cover the densest part of the electricity distribution network in the Waimakariri region. A long-reach radio link extends up the east coast to service the Kaikōura region. Fibre links are limited to six sites within the Rangiora urban area: MainPower's head office, four substation sites, and the Waimakariri District Council offices.

Seven radio repeater sites are used to support the communications network, with three located in zone substations and four in stand-alone repeater sites. A visual representation of the radio communications network, which currently uses Tait voice radios and Mimomax data radios, is shown in Figure 7.25.

Figure 7.25 MainPower's voice and data communications network

MainPower operates an advanced distribution management system (ADMS). All remote SCADA sites use the DNP3 communication protocol. MainPower is also trialling new field devices with remote communication facilities for improved visibility and control of the network.

The data and voice networks run on Tait EE band equipment for the mobile repeaters and J band for the inter-site linking. MainPower has deployed several narrow-band digital radio systems of both point-to-point and point-to-multipoint. These provide communications for SCADA remote terminal units and remote engineering access at very low bandwidths, using a mixture of Mimomax, Dataradio and Racom RipEX technology. The maximum capacity of the newer systems currently deployed is 360 kbit/s, and they are operating reliably.

7.8.3.1 MAINTENANCE

Communication and SCADA systems are constantly monitored by the MainPower Engineering Team. Equipment at both zone substation and repeater sites are regularly inspected and serviced on the schedule shown in Table 7.24.

Asset fleet	Frequency
Communications and SCADA	6 monthly – Visual inspections
	12 monthly – Diagnostic testing and servicing

Table 7.24 Communications and SCADA system inspection and maintenance summary

7.8.3.2 REPLACEMENT

MainPower is planning progressive replacement of the analogue radio systems with a digital radio system at each of the repeater sites. The increase in capacity and functionality of the digital radio systems can support native lone- and remote-worker systems and increase bandwidth for improved digital services at substations.

7.8.4 LOAD CONTROL AND RIPPLE INJECTION PLANT

MainPower uses ripple injection plant to control load in our network. Our network uses Landis+Gyr SFU-K ripple injection plant, using Decabit code for load control and tariff switching. The plants operate at an injection frequency of 283 Hz, and all plants are GPS synchronised. Most load control receiver relays are in consumer smart meters or are Zellweger/Enermet RM3 installed between 1993 and 1997. The remainder are the later Landis+Gyr RC5000 series and, more recently, RO3-type relays. MainPower owns a diminishing amount of load control receivers, which are being systematically displaced by more modern receivers. Table 7.25 shows MainPower's ripple injection plant locations, age, and operating voltage.

Location	Age (years)	Operating voltage (kV)
Ashley GXP	9	11
Burnt Hill	9	22
Kaiapoi GXP	29	11
Ludstone Road	29	11
Mouse Point	29	33
Southbrook	2	11
Swannanoa	9	22
Waipara GXP	16	66

Table 7.25 Ripple injection plant location, age, and operating voltage

7.8.4.1 MAINTENANCE

Ripple injection plant and related specialist equipment maintenance is contracted out to Landis+Gyr under a service agreement. This covers annual inspections and testing, as well as carrying critical spares in their Auckland warehouse. MainPower has a 24-hour response arrangement with Landis+Gyr to attend to any faults that MainPower's technicians cannot repair.

MainPower staff carry out separate inspections and services of the high-voltage equipment on an annual and three-yearly cycle. Defects are reported and managed as per MainPower's defect management processes.

7.8.4.2 REPLACEMENT AND DISPOSAL

The 33 kV ripple injection plant at Southbrook was replaced with an 11 kV unit during the zone substation rebuild in 2021, making available an SFU-K transmitter that has been used to replace the obsolete Kaiapoi SFU-G unit. The remaining Southbrook components are being assessed for their suitability as spares for other sites.

7.9 PROPERTY

MainPower owns a range of buildings that serve both the electricity distribution network and non-network services. This covers corporate structures and properties, communication repeater sites, zone substation control buildings, and distribution substations, which are a mix of buildings and smaller housings for electrical equipment. The types and numbers are shown in Table 7.26.

Building type	Quantity
Zone substation control building	22
Distribution substation	34
Holiday home	2
Office	4
Repeater site	5
Staff house	2
Storage building	4
Equipment and kiosk cover	910
Total	**983**

Table 7.26 MainPower's property and building assets

7.9.1 ZONE SUBSTATION CONTROL BUILDINGS

There are 22 zone substation control buildings located across MainPower's network area. These buildings range from small portable sheds, housing up to five control panels, through to multiroom permanent constructions that include indoor switchgear and toilet facilities. A breakdown by construction and purpose is shown in Table 7.27.

Construction type	Control only	Control high-voltage switchgear
Timber framed	5	2
Concrete block	4	2
Concrete tilt slab	0	7
Container	0	2
Total	**9**	**13**

Table 7.27 Zone substation control building types

7.9.1.1 MAINTENANCE

Zone substation control buildings are inspected on a three-monthly regime as part of the zone substation routine inspection programme, as shown in Table 7.28.

Asset fleet	Frequency
Zone substation control buildings	3 monthly – Visual inspection

Table 7.28 Zone substation control building inspection summary

All zone substation control buildings had a detailed seismic assessment and building code compliance assessment carried out during FY19. The outcomes of this assessment have been used to inform whether future strengthening work is required.

Asbestos surveys have been carried out on all zone substation control buildings. Warning notices have been fitted where asbestos has been found (or assumed to be present) in the building materials or equipment in the buildings.

7.9.1.2 REPLACEMENT AND DISPOSAL

As the structural assessments of the zone substation control buildings did not indicate any serious faults with the buildings, no building replacements are planned in this 10-year planning period.

7.9.2 DISTRIBUTION SUBSTATION BUILDINGS

MainPower has 34 distribution substations that are housed in stand-alone buildings. These were generally built during the Municipal Electricity Department era and are of solid concrete or masonry construction. They typically contain high-voltage switches or circuit breakers, an 11 kV/400 V transformer and a low-voltage distribution panel. Their ages range from 20 to 62 years, with most in the range of 50 to 60 years, as shown in Figure 7.26.

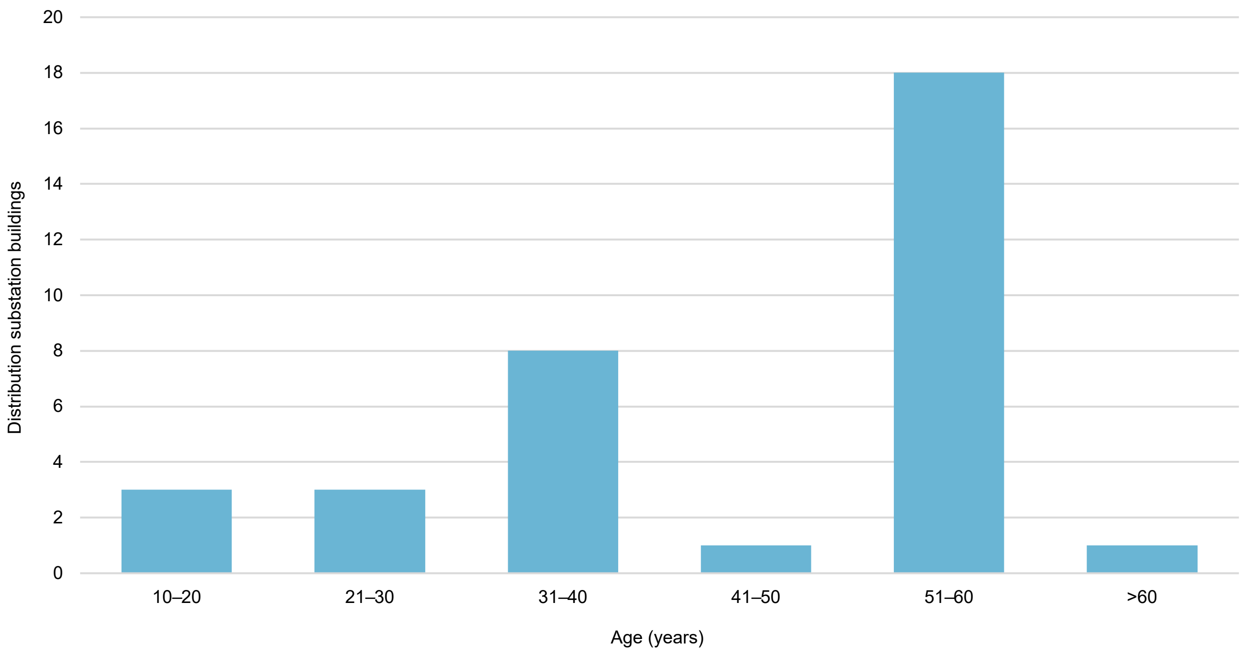


Figure 7.26 Age profile of distribution substation buildings (FY24)

These buildings are in generally good condition, given their age. A detailed structural assessment in FY19 indicated they are fit for purpose, with some modifications required on a selection of buildings to increase their strength, typically in the roofing.

7.9.2.1 MAINTENANCE

The solid concrete or masonry construction of these buildings requires little ongoing maintenance. General rubbish removal, repairs, and maintenance are carried out when issues are raised during yearly inspections or in field defect reports.

7.9.2.2 REPLACEMENT AND DISPOSAL

As the structural assessments of the distribution substation buildings did not indicate any serious faults with these buildings, no building replacements are planned in this 10-year planning period. Any buildings with identified asbestos will be disposed of in accordance with our asbestos management plan.

7.9.3 DISTRIBUTION KIOSKS

Distribution kiosks are small ground-mounted covers that house electrical equipment. These covers are constructed from various materials, typically steel, fibreglass or plastic. Figure 7.27 shows the current age profile of the distribution kiosks.

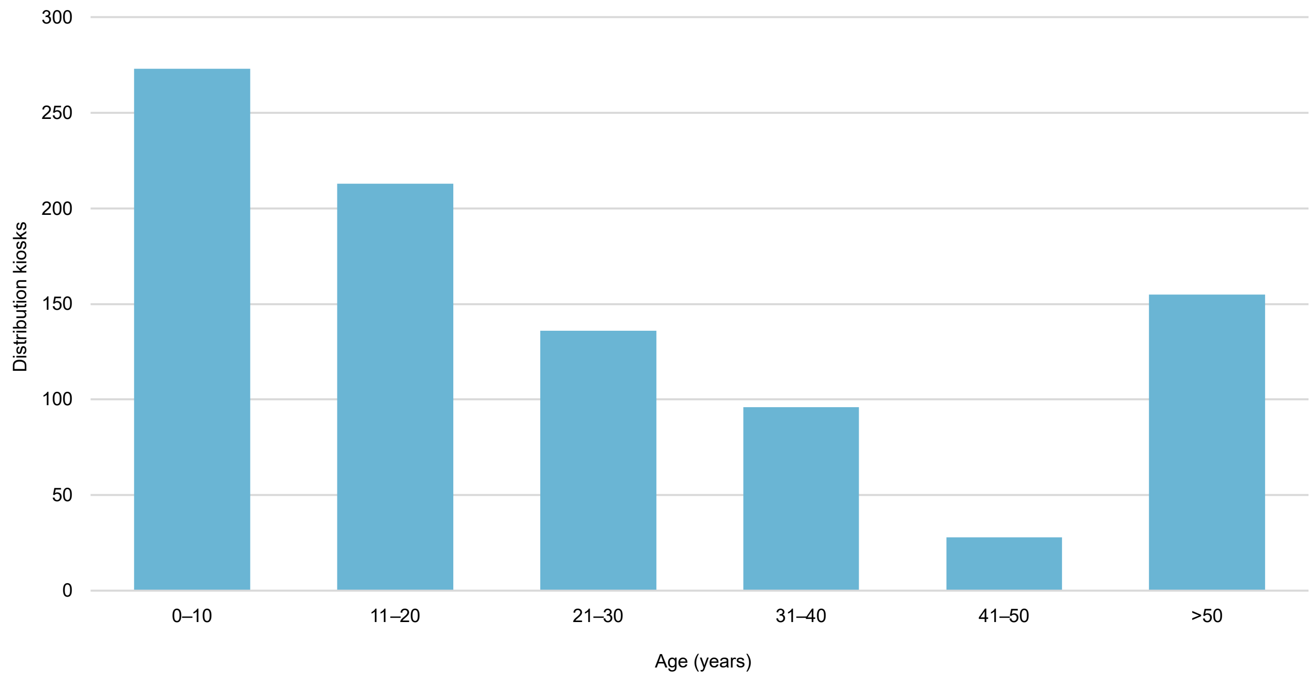


Figure 7.27 Age profile of kiosk covers (enclosures) – FY24

Steel covers can corrode, especially near coasts, and fibreglass covers can suffer ultraviolet radiation damage over time. These issues are checked during kiosk inspections, and repairs or replacements are done as needed. Disposal follows the company's standard process.

7.9.3.1 MAINTENANCE

Kiosk covers are inspected yearly as part of the site's electrical equipment checks. Steel enclosures near the corrosion zone are prioritised for review, with decisions made on whether to upgrade the enclosure material or simply repair them.

7.9.3.2 REPLACEMENT AND DISPOSAL

MainPower does not currently have a scheduled replacement programme for distribution kiosk enclosures. Defective enclosures identified during inspections are repaired where possible or replacement is coordinated with other works.

7.9.4 NON-ELECTRICITY DISTRIBUTION NETWORK BUILDINGS

MainPower owns offices, administration buildings, operational buildings, and staff and holiday housing throughout the North Canterbury region (see Table 7.29).

Description	Location	Age (years)
Staff housing – #1	Culverden	5
Staff housing – #2	Culverden	4
Office building	Culverden	43
Storage shed/workshop	Culverden	43
Holiday home	Hanmer Springs	43
Holiday home	Kaikōura	43
Corporate office and operational facilities	Rangiora	10

Table 7.29 MainPower's non-electricity distribution network buildings

MainPower's head office in Rangiora serves as the main location for corporate and operational management of the business and electricity distribution network.

The buildings there are:

- a two-storey 2,100 m² office building constructed to an Importance Level 4 standard
- a single-storey 320 m² café constructed to an Importance Level 3 standard
- a 2,000 m² single-storey store, garage and workshop building, with 660 m² of mezzanine storage area, constructed to an Importance Level 3 standard.

MainPower's electricity distribution NOCC and server room are both located in the head office building, with the ability to work remotely if required to ensure ongoing operational capability during a business continuity event. MainPower also provides the site as a backup Emergency Response Centre for local authorities in the event those authorities' main facilities are not occupiable.

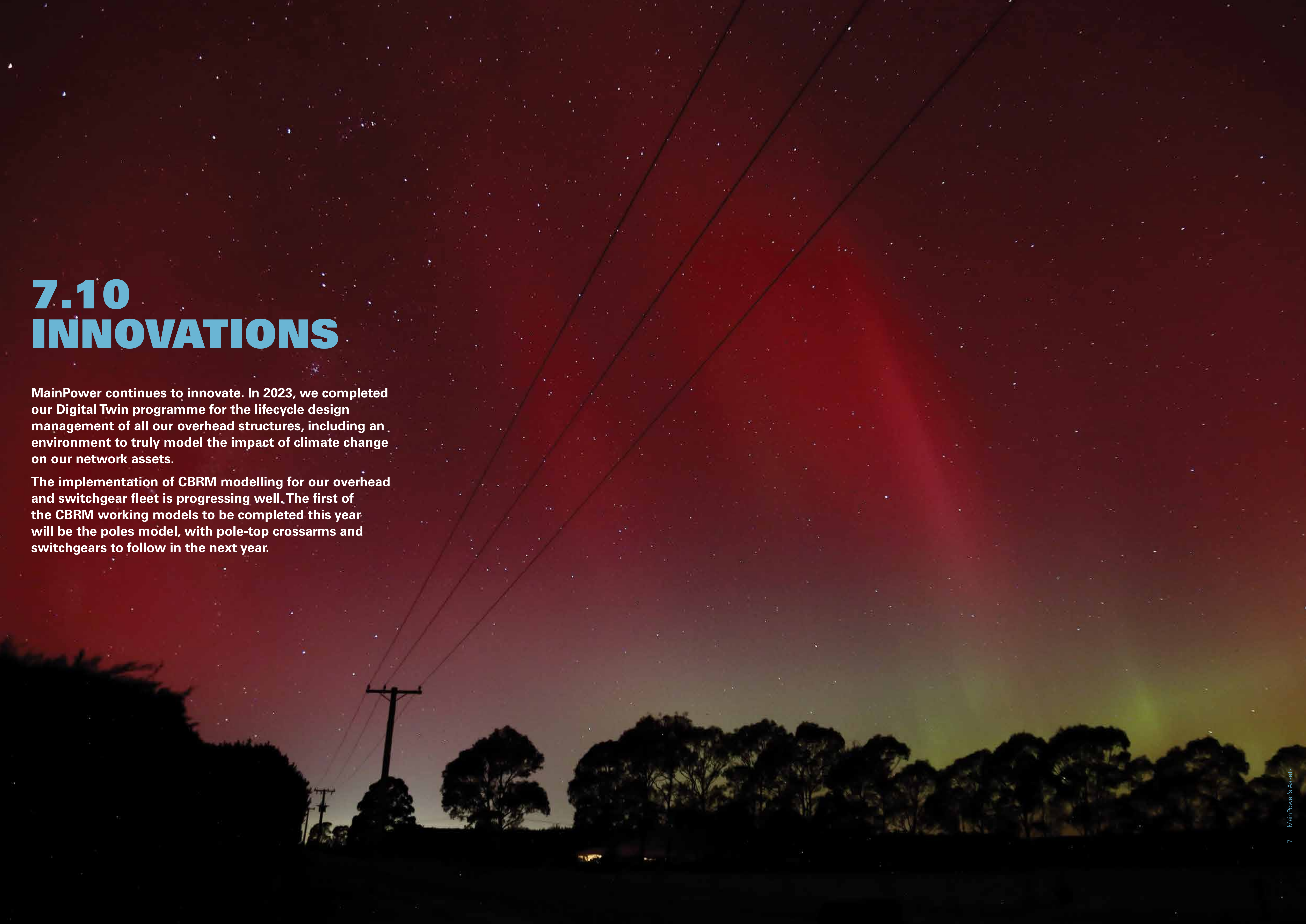
A peak ground acceleration monitor installed at the site supplies real-time data following earthquake events. The data is received within 90 seconds of an earthquake and the ground acceleration monitor compares the site acceleration against building service levels, informing key staff of any possible damage to the building or its services.

7.9.4.1 MAINTENANCE

Much of the facilities and equipment across MainPower's non-network property requires regular maintenance to ensure operational functionality. Ongoing contracts are managed with around 30 service providers to ensure the sites are maintained.

7.9.4.2 RENEWAL

We have a projected renewal programme out to FY50, with major replacement scheduled for FY25 and FY28, mainly consisting of renewing internal finishes such as carpet and paint, and external finishes such as wall cladding.



7.10 INNOVATIONS

MainPower continues to innovate. In 2023, we completed our Digital Twin programme for the lifecycle design management of all our overhead structures, including an environment to truly model the impact of climate change on our network assets.

The implementation of CBRM modelling for our overhead and switchgear fleet is progressing well. The first of the CBRM working models to be completed this year will be the poles model, with pole-top crossarms and switchgears to follow in the next year.

7.11 NON-ELECTRICITY DISTRIBUTION NETWORK ASSETS

7.11.1 INFORMATION TECHNOLOGY SYSTEMS

MainPower's information technology (IT) system consists of multiple software applications hosted internally on physical architecture within a data centre or operated as software as a service (SaaS). Disaster recovery is provided via replication of the internally hosted systems using a data centre in Christchurch.

Integral to the support of this architecture is an integration layer that facilitates the movement of data and synchronisation of master records to ensure integrity between applications.

The key components of MainPower's IT platform are:

- a TechnologyOne enterprise resource planning (ERP) integrated platform that is used for all asset management, works management and financial reporting
- GE Digital's Smallworld geographic information system (GIS), which is used as the primary geographical data repository for electricity distribution asset data
- MACK, which is MainPower's customer relationship management (CRM) system for managing installation control point (ICP) data, including registry obligations, billing history, and shareholder information on behalf of the Trust
- Open Systems International ADMS for controlling and operating MainPower's network.

7.11.1.1 ENTERPRISE RESOURCE PROCESS UPGRADE

The TechnologyOne platform will be migrated to a SaaS, with improvements to the ERP product's usability and the available functionality. The transition to SaaS over the next few years will provide access to new functionality, which will enable improvements to our asset management and operational practices.

7.11.1.2 TECHNOLOGY INTEGRATION

The Dell Boomi Integration platform has been implemented to replace the existing bespoke integrations, enabling rapid deployment of new integrations and proactive operational monitoring of the integration environment.

7.11.1.3 DATA WAREHOUSE AND DECISION SUPPORT EXPANSION

Further investment in data warehouse and analytics technology is planned to improve strategic and operational decision making, with a focus on opportunity identification and improved service delivery.

7.11.1.4 INTEGRATED MANAGEMENT SYSTEM AND CURRENT STATE MANAGEMENT

MainPower has implemented the Promapp and State3 technologies to create and maintain visibility of the organisation's current state from process, people, technology and consumer-experience perspectives.

7.11.1.5 DOCUMENT MANAGEMENT

A core component of our operational capability is controlling and accurately versioning documents and ensuring that the organisation can easily access these documents. The current document management system no longer meets the requirements of the business, and a new project aims to implement an integrated, modern and secure document management solution.

7.11.2 ASSETS OWNED AT TRANSPOWER GRID EXIT POINTS

MainPower owns metering and communications equipment at Transpower GXPs that connect to our network to monitor load for load management and for revenue metering. All have ion-type meters, installed after year 2000. MainPower's ripple injection plants are in Transpower GXPs at Waipara, Ashley, and Kaiapoi. We also have SCADA and local service equipment associated with the ripple injection plant at these sites.

7.11.3 MOBILE GENERATION ASSETS

MainPower has invested in mobile diesel generation plant to assist with reducing the number of planned interruptions. There are two units. One is rated at 275 kVA. This generator has been fitted on a tandem-axle truck along with the transformer, protection systems and connecting leads. The generator is used during planned work to maintain the supply to customers. It has enough capacity to supply the average load of an urban transformer kiosk, or it can be connected to overhead lines at 11 kV or 22 kV, supplying up to 100 customers. We also have a larger 500 kVA generator for use with low-voltage customers only. This is often large enough to supply small subdivisions during maintenance.

7.11.4 OTHER GENERATION

MainPower owns and operates a 1 MW generation asset that is located at Cleardale, near the Rakaia River Gorge, and is connected to the distribution network owned and operated by Electricity Ashburton. The Cleardale site is operated, managed and maintained in alignment with the MainPower network. This generation asset is identified as non-network and does not form part of MainPower regulatory reporting.

8
FINANCIAL EXPENDITURE

This section provides a summary of our expenditure forecasts during the 10-year Asset Management Plan (AMP) planning period. It is structured to align with the internal expenditure categories and forecasts provided in earlier sections.

8.1 TOTAL NETWORK EXPENDITURE FORECAST

Table 8.1 and Figure 8.1 show the forecast expenditure by category for the 10-year planning period.

	Expenditure ($000)									
Category	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**
Major projects	13,167	13,900	11,450	9,630	12,041	7,830	5,850	9,000	6,000	5,050
Network reinforcement	3,521	3,111	3,130	4,056	2,913	2,251	2,467	2,320	1,854	4,137
Replacement	13,085	14,037	14,048	14,135	14,243	14,341	14,110	14,104	14,217	14,217
Maintenance	8,492	8,381	8,104	8,260	8,404	8,607	8,608	8,487	8,705	8,825
Network operations	2,135	2,166	2,095	2,098	2,103	2,140	2,115	2,133	2,112	2,133
Non-network	4,621	4,800	2,983	2,958	3,996	3,094	2,874	3,304	4,304	2,904
Customer-initiated works	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Total	**51,021**	**52,395**	**47,810**	**47,137**	**49,700**	**44,263**	**42,024**	**45,348**	**43,192**	**43,266**

Table 8.1 Network total expenditure FY26–FY35

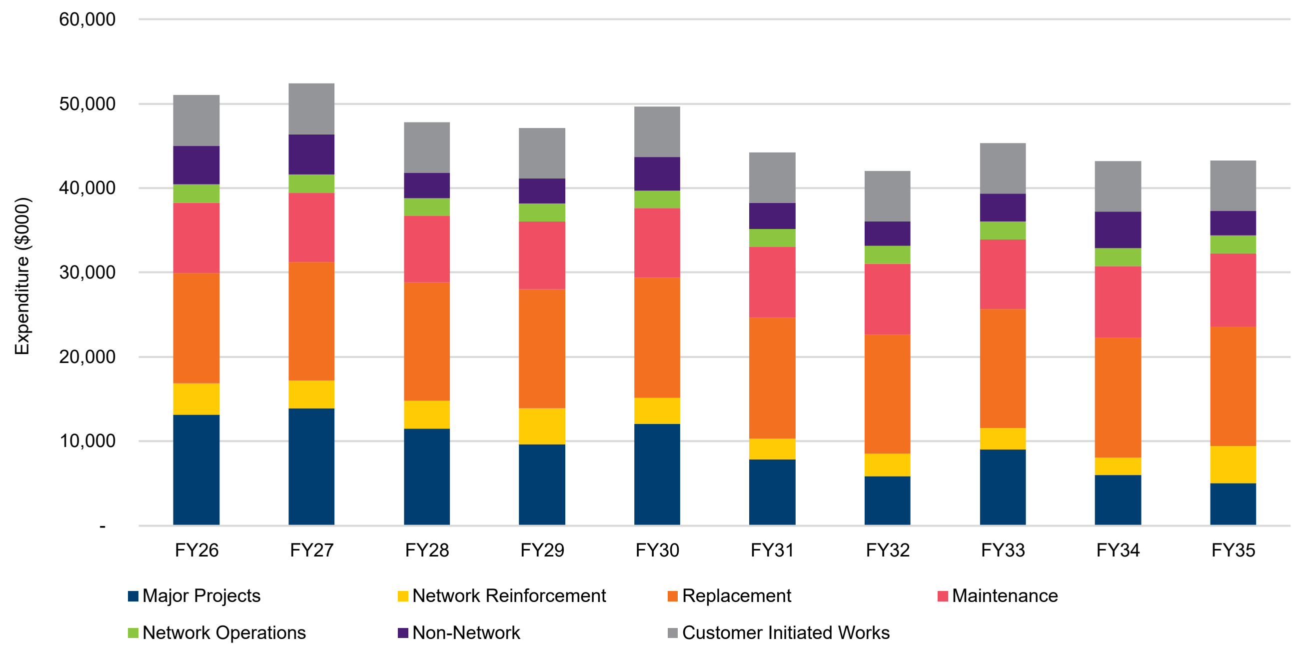


Figure 8.1 Network expenditure forecast FY26–FY35

8.2 NETWORK REPLACEMENT EXPENDITURE

A breakdown of network replacement expenditure for the 10-year planning period is provided in the Table 8.2.

	Expenditure ($000)									
Category	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**
Overhead network	8,326	9,105	9,324	9,444	9,723	9,819	9,819	9,819	9,819	9,819
Pole-mounted transformers	658	649	648	675	689	689	689	689	689	689
Pole-mounted switchgear	517	534	528	528	528	528	408	408	408	408
Substations and switchgear	968	912	794	794	720	749	687	681	794	794
Zone substations	140	240	190	190	80	80	80	80	80	80
Secondary systems	622	595	587	587	587	587	587	587	587	587
Underground network	793	907	907	907	907	880	831	831	831	831
Network property	100	135	110	50	50	50	50	50	50	50
Corrective replacements	360	360	360	360	360	360	360	360	360	360
Fault replacements	600	600	600	600	600	600	600	600	600	600
Network replacement subtotal	**13,085**	**14,037**	**14,048**	**14,135**	**14,244**	**14,342**	**14,111**	**14,105**	**14,218**	**14,218**

Table 8.2 Network replacement expenditure FY26–FY35

8.3 NETWORK MAINTENANCE EXPENDITURE

A breakdown of network maintenance expenditure for the 10-year planning period is provided in Table 8.3.

	Expenditure ($000)									
Category	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**
Overhead network	2,822	2,468	2,265	2,236	2,164	2,251	2,269	2,218	2,188	2,148
Pole-mounted transformers	313	385	378	361	349	313	385	378	361	349
Pole-mounted switchgear	303	288	267	268	294	293	308	297	286	294
Substations and switchgear	679	597	528	606	562	679	597	528	600	562
Zone substations	442	440	375	431	581	516	443	370	504	605
Secondary systems	33	33	33	33	33	33	33	33	33	33
Underground network	363	386	399	390	391	385	389	399	390	391
Network property	76	101	76	76	76	76	76	76	76	76
Vegetation management	1,800	1,910	2,020	2,120	2,220	2,320	2,410	2,500	2,590	2,690
Corrective maintenance	1,663	1,774	1,763	1,738	1,734	1,742	1,698	1,688	1,678	1,678
Total	**8,492**	**8,381**	**8,104**	**8,260**	**8,404**	**8,607**	**8,608**	**8,487**	**8,705**	**8,825**

Table 8.3 Network maintenance expenditure summary FY26–FY35

9
CAPACITY TO DELIVER

MainPower's lifecycle asset management process, which is structured on a total lifecycle cost of asset ownership, has as its foundation the activities and the roles required during lifecycle of the physical asset, as outlined in Figure 9.1.

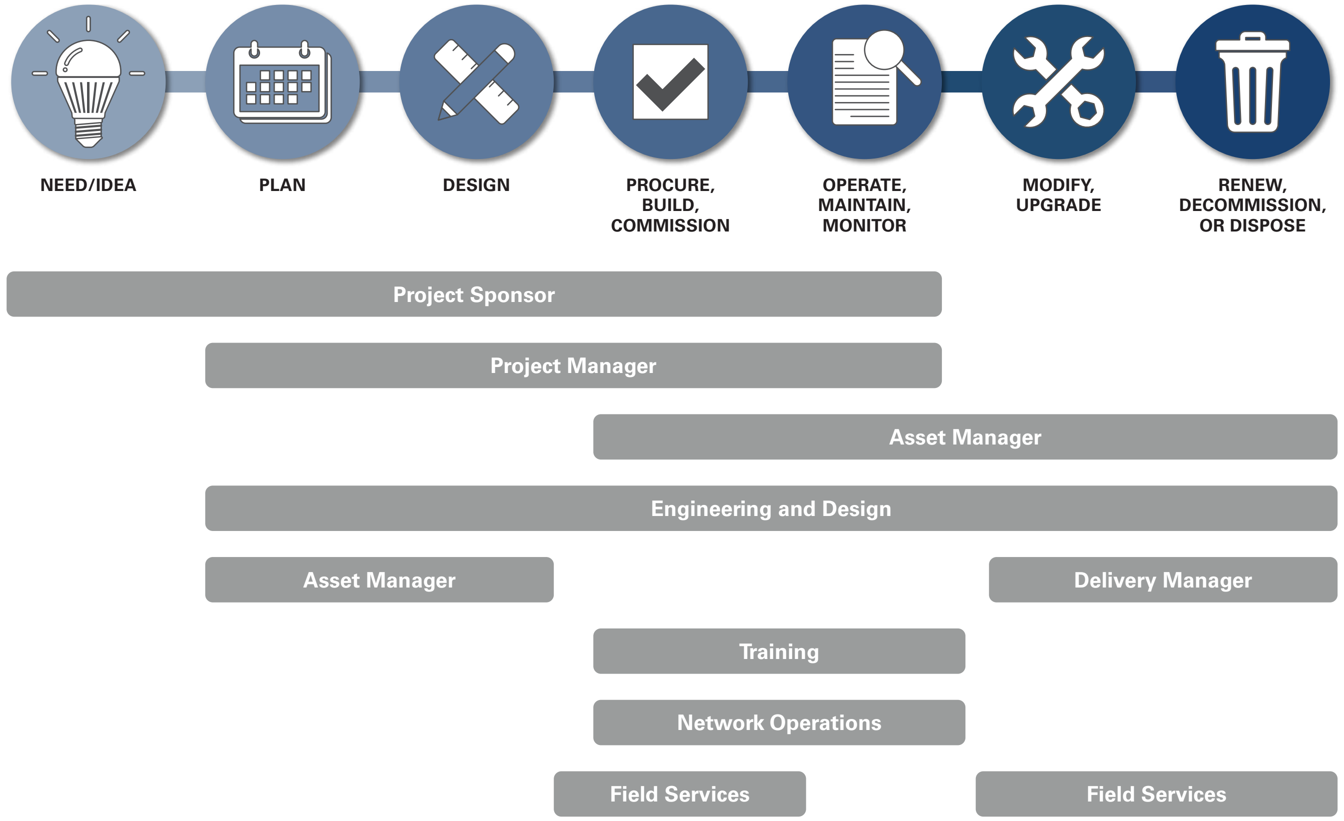


Figure 9.1 Alignment of roles and responsibilities against lifecycle activities

The responsibilities for the key roles are outlined below.

Project Sponsor

The person with a business need (e.g. renewal of asset, procurement of infrastructure) completes a sponsor's brief and steers the project to completion (i.e. practical completion, including handover).

Project Manager

The Project Manager delivers the project in accordance with the business project delivery framework or Project Delivery System. The project management resource pool also includes Works Planning and Scheduling Resources.

Delivery Managers

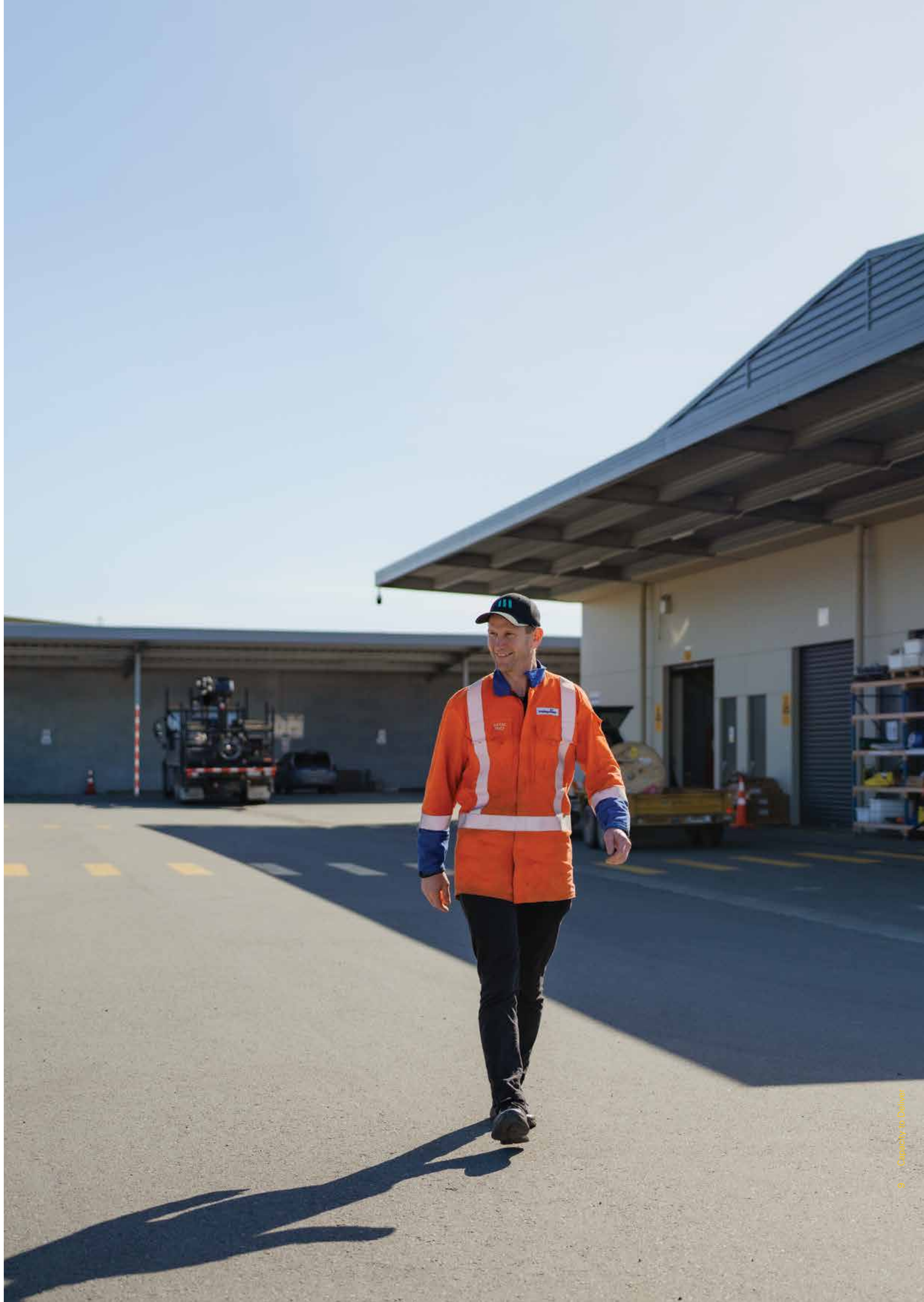
The Delivery Managers are responsible for delivering all the works associated with all asset renewals within the Asset Management Plan.

Asset Manager

The Asset Manager ensures all assets are maintained, using the minimum of resources, so they remain fit for purpose and enable the business to achieve its strategic intent. This resource pool also includes the Asset Data and Geographic Information System (GIS) team.

Field Services

Field Services is responsible for delivering all maintenance activities (inspection and defect works) for all assets as detailed in the Asset Management Plan.



9.1 RESOURCING REQUIREMENTS

Resourcing is defined for network development, maintenance and renewals, based on typical project resourcing models and rate card information that define labour, materials, plant and outsourcing across all workstreams over the reporting period.

Linking asset lifecycle management resources with the 10-year work programme indicates that MainPower's internal resourcing for the management and planning of works is currently adequate. Where there is a deficit, MainPower uses external resourcing to deliver the programme of works.

APPENDICES

The appendices provide additional information to support MainPower's Asset Management Plan (AMP), including our information disclosure schedules.

APPENDIX 1 – GLOSSARY OF TERMS AND ABBREVIATIONS

Term or abbreviation	Definition
ADMS	advanced distribution management system
AHI	Asset Health Indicator
AI	artificial intelligence
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
CBRM	Condition-Based Risk Management
CDEM	Civil Defence Emergency Management
CER	consumer energy resources
CIMS	Coordinated Incident Management System
CIS	customer information system
CMMS	computerised maintenance management system
CRM	customer relationship management
DC	direct current
DG	distributed generation
DIN	Deutsches Institut für Normung (German Institute of Standardisation)
Distribution network	The power lines and underground cables that transport electricity from the national grid to homes and businesses
DSO	distribution system operator
EDB	electricity distribution business
EEA	Electricity Engineers' Association
EIEP5A	Electricity Information Exchange Protocol 5A
ERP	enterprise resource planning
EV	electric vehicle
FY	fiscal year
GIS	geographic information system
GWh	gigawatt-hours
GXP	grid exit point – a point at which MainPower's network connects to Transpower's transmission network
HILP	high-impact low-probability
HRC	high rupturing capacity
HV	high voltage
ICP	installation control point
IT	information technology

Term or abbreviation	Definition
kV	kilovolt
kVA	kilovolt-ampere
LBS	load break switch
LiDAR	light detection and ranging
LV	low voltage
MACK	MainPower's customer relationship management system
MEP	metering equipment provider
MVA	mega-volt ampere
MW	megawatt (1 megawatt = 1,000 kilowatts = 1,000,000 watts)
N-1	An indication of power supply security that specifically means that when one circuit fails, another will be available to maintain an uninterrupted power supply
NIWA	National Institute of Water and Atmospheric Research
NOCC	Network Operations and Control Centre
NZTA	NZ Transport Agency Waka Kotahi
OMS	outage management system
RMU	ring main unit
SaaS	software as a service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SF6	sulphur hexafluoride
SMS	short messaging service
Statement of Corporate Intent	An annual document that outlines the overall intentions of the company and the objectives that the Directors and Trustees have agreed
Sub-transmission	An intermediate voltage used for connections between transmission connection points/bulk supply substations and zone substations – also used to connect between zone substations
SWER	single-wire earth return
Transmission	The high-voltage transmission network that connects areas of generation with towns and cities across New Zealand
Substation	A collection of equipment at one location, including any necessary housing, used to convert or transform electrical energy and connect between two or more feeders
UAV	unmanned aerial vehicle
Zone substation	A substation that converts electrical energy from transmission or sub-transmission voltages to distribution voltages

APPENDIX 2 –
DESCRIPTION OF ASSET MANAGEMENT SYSTEMS

System	Description
Accounting systems	The TechnologyOne software platform, an enterprise resource planning (ERP) system, is used to integrate financial, works and asset management information. Capital and maintenance expenditure is managed using a comprehensive financial system.
Asset register	The asset management suite within the TechnologyOne platform is the principal source of data related to MainPower assets.
AutoCAD	Detailed substation plans, standard construction drawings and many subdivision plans are prepared and stored in AutoCAD. Where applicable, these are linked to assets within TechnologyOne. Network details such as cable locations in trenches, boundary offsets and GPS location are stored in AutoCAD to be viewed without complicating the geographic information system (GIS).
Communication systems	• Voice radio system for communication to field staff • Digital radio network for communicating with zone substations and other field equipment • Sophisticated telephony system for general land-based and mobile phone communication
Customer information system (CIS)	This system is used to issue and maintain installation control points (ICPs) with retailers. It also manages customer information, lines tariff and consumption data. Outage information is imported from the outage management system (OMS) and stored against each customer. The CIS is linked to the GIS for customer location information. The CIS is maintained daily from event changes notified by retailers and new connections. The CIS is an important tool for MainPower's revenue protection.
Geographic information system (GIS)	MainPower uses GE Digital's Smallworld platform (a GIS) for the management of spatial asset information. The TechnologyOne software platform has been integrated with the GIS.
Human resource systems	MainPower's human resource information was transferred to the TechnologyOne platform using an iterative, incremental approach during 2016. It includes employment contracts, competency and skill set information, and safety and training records. A succession plan exists within each section.
Infrastructure	MainPower's hardware and server software is continually updated, consistent with modern high-capacity hardware platforms. Information security management includes maintaining off-site backup facilities for stored information for protection from a security breach or disaster.

System	Description
Inventory systems	All stock and supply chain details are managed through the TechnologyOne software platform as a single entity. MainPower maintains a separate storage facility for its own stock.
MACK CRM	MainPower's customer relationship management (CRM) system to manage customer enquiries and jobs. Includes registry integration.
Outage management system (OMS)	Traces across the GIS to identify all affected customers and switching points. For unplanned outages, all relevant fault information is entered into the GIS after the event. Reports are run from the GIS to generate outage statistics as required.
Supervisory control and data acquisition (SCADA) and load management systems	The Invensys Wonderware "Intouch" SCADA system: • displays voltage, current and status information in real time from remote points on the network • receives instantaneous information on faults • remotely operates equipment from the control centre. We operate Landis+Gyr ripple injection plants and On Demand load management software to control: • customer water heaters, to limit system peak loads and area loading constraints (mainly during winter months) • street lighting • electricity retailer tariffs.
Works management system	The works management system issues and tracks jobs through the TechnologyOne software platform. It also maintains cost and quality information. A comprehensive job-reporting system provides managers with detailed information about progress of the work plan, work hours and cost against budget.

APPENDIX 3 – DIRECTORS' CERTIFICATE

MainPower New Zealand Limited
172 Fernside Road, RD 1, Kaiapoi 7691
PO Box 346, Rangiora 7440
T. +64 3 311 8300 F. +64 3 311 8301

CERTIFICATE FOR YEAR-BEGINNING 1 APRIL 2025 DISCLOSURE

Pursuant to Clause 2.9.1 of Section 2.9 of the Electricity Distribution Disclosure Determination 2012 .

We, ANTHONY CHARLES KING and STEPHEN PAUL LEWIS, being Directors of MainPower New Zealand Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of MainPower New Zealand Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with MainPower New Zealand Limited's corporate vision and strategy and are documented in retained records.

Anthony Charles King

Tony King
2025-02-20 06:05 UTC

Date

Stephen Paul Lewis

Stephen Lewis
2025-02-18 23:59 UTC

Date

APPENDIX 4 – SCHEDULE 11A: REPORT ON FORECAST CAPITAL EXPENDITURE

		FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034	FY2035
11a(i)	Expenditure on Assets Forecast					$000 (in nominal dollars)						
	Consumer connection	7,875	6,000	6,118	6,244	6,384	6,532	6,690	6,850	7,013	7,181	7,352
	System growth	15,823	16,330	16,838	13,581	11,417	13,904	8,730	7,216	10,923	7,540	6,188
	Asset replacement and renewal	6,916	13,085	14,313	14,618	15,040	15,505	15,989	16,108	16,486	17,015	17,422
	Asset relocations	–	–	–	–	–	–	–	–	–	–	–
	Reliability, safety and environment:											
	Quality of supply	–	58	252	967	2,198	465	983	852	117	557	123
	Legislative and regulatory	–	–	–	–	–	–	–	–	–	–	–
	Other reliability, safety and environment	656	300	255	624	947	1,909	1,526	1,427	2,192	1,303	4,947
	Total reliability, safety and environment	**656**	**358**	**507**	**1,591**	**3,145**	**2,374**	**2,510**	**2,279**	**2,309**	**1,860**	**5,070**
	Expenditure on network assets	**31,270**	**35,772**	**37,777**	**36,034**	**35,986**	**38,315**	**33,919**	**32,452**	**36,730**	**33,595**	**36,032**
	Expenditure on non-network assets	614	1,705	1,555	208	372	1,361	288	–	468	1,676	–
	Expenditure on assets	**31,885**	**37,477**	**39,332**	**36,242**	**36,358**	**39,676**	**34,206**	**32,452**	**37,198**	**35,271**	**36,032**
plus	Cost of financing	–	–	–	–	–	–	–	–	–	–	–
less	Value of capital contributions	5,250	3,500	3,569	3,642	3,724	3,810	3,902	3,996	4,091	4,189	4,289
plus	Value of vested assets	–	–	–	–	–	–	–	–	–	–	–
	Capital expenditure forecast	**26,635**	**33,977**	**35,763**	**32,600**	**32,634**	**35,866**	**30,304**	**28,456**	**33,107**	**31,082**	**31,743**
	Assets commissioned	16,912	25,632	33,326	39,908	25,245	23,982	40,876	33,034	30,132	38,965	32,538

	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034	FY2035
					$000 (in constant prices)						
Consumer connection	7,500	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
System growth	15,070	16,330	16,513	13,051	10,730	12,773	7,830	6,321	9,345	6,300	5,050
Asset replacement and renewal	6,587	13,085	14,037	14,048	14,135	14,243	14,341	14,110	14,104	14,217	14,217
Asset relocations	–	–	–	–	–	–	–	–	–	–	–
Reliability, safety and environment:											
Quality of supply	–	58	248	929	2,066	427	882	746	100	465	100
Legislative and regulatory	–	–	–	–	–	–	–	–	–	–	–
Other reliability, safety and environment	625	300	250	600	890	1,754	1,369	1,250	1,875	1,089	4,037
Total reliability, safety and environment	**625**	**358**	**498**	**1,529**	**2,956**	**2,181**	**2,251**	**1,996**	**1,975**	**1,554**	**4,137**
Expenditure on network assets	**29,781**	**35,772**	**37,047**	**34,628**	**33,821**	**35,197**	**30,422**	**28,427**	**31,424**	**28,071**	**29,404**
Expenditure on non-network assets	585	1,705	1,525	200	350	1,250	258	–	400	1,400	–
Expenditure on assets	**30,366**	**37,477**	**38,572**	**34,828**	**34,171**	**36,447**	**30,680**	**28,427**	**31,824**	**29,471**	**29,404**
Subcomponents of expenditure on assets (where known)											
Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											

APPENDIX 4 – SCHEDULE 11A: REPORT ON FORECAST CAPITAL EXPENDITURE (CONTINUED)

11a(i)	Expenditure on Assets Forecast (continued)	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034	FY2035
	Difference between nominal and constant price forecasts						**$000**					
	Consumer connection	375	–	118	244	384	532	690	850	1,013	1,181	1,352
	System growth	753	–	325	530	687	1,132	900	895	1,578	1,240	1,138
	Asset replacement and renewal	329	–	277	570	905	1,262	1,648	1,998	2,382	2,798	3,205
	Asset relocations	–	–	–	–	–	–	–	–	–	–	–
	Reliability, safety and environment:											
	Quality of supply	–	–	5	38	132	38	101	106	17	92	23
	Legislative and regulatory	–	–	–	–	–	–	–	–	–	–	–
	Other reliability, safety and environment	31	–	5	24	57	155	157	177	317	214	910
	Total reliability, safety and environment	**31**	**–**	**10**	**62**	**189**	**193**	**259**	**283**	**334**	**306**	**933**
	Expenditure on network assets	**1,489**	**–**	**730**	**1,406**	**2,165**	**3,118**	**3,497**	**4,025**	**5,307**	**5,525**	**6,628**
	Expenditure on non-network assets	29	–	30	8	22	111	30	–	68	276	–
	Expenditure on assets	**1,518**	**–**	**760**	**1,414**	**2,188**	**3,229**	**3,526**	**4,025**	**5,374**	**5,800**	**6,628**

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15.

APPENDIX 4 – SCHEDULE 11A: REPORT ON FORECAST CAPITAL EXPENDITURE (CONTINUED)

11a(ii)	Consumer Connection	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	*Consumer types defined by EDB**			$000 (in constant prices)			
	Residential	4,500	3,600	3,600	3,600	3,600	3,600
	Irrigation	1,400	1,120	1,120	1,120	1,120	1,120
	Large User	1,000	800	800	800	800	800
	Streetlights	150	120	120	120	120	120
	Other	450	360	360	360	360	360
	Consumer connection expenditure	**7,500**	**6,000**	**6,000**	**6,000**	**6,000**	**6,000**
less	Capital contributions funding consumer connection	5,000	3,500	3,500	3,500	3,500	3,500
	Consumer connection less capital contributions	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**

11a(iii)	System Growth						
	Subtransmission	4,762	5,122	–	150	1,130	2,791
	Zone substations	7,700	8,045	13,900	9,800	7,000	9,250
	Distribution and LV lines	–	2,726	801	1,601	1,100	–
	Distribution and LV cables	2,608	437	1,812	1,500	1,500	732
	Distribution substations and transformers	–	–	–	–	–	–
	Distribution switchgear	–	–	–	–	–	–
	Other network assets	–	–	–	–	–	–
	System growth expenditure	**15,070**	**16,330**	**16,513**	**13,051**	**10,730**	**12,773**
less	Capital contributions funding system growth	–	–	–	–	–	–
	System growth less capital contributions	**15,070**	**16,330**	**16,513**	**13,051**	**10,730**	**12,773**

		FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
11a(iv)	Asset Replacement and Renewal			$000 (in constant prices)			
	Subtransmission	–	–	–	–	–	–
	Zone substations	80	140	240	190	190	80
	Distribution and LV lines	3,500	8,326	9,105	9,324	9,444	9,723
	Distribution and LV cables	818	793	907	907	907	907
	Distribution substations and transformers	1,000	1,626	1,561	1,442	1,469	1,409
	Distribution switchgear	280	517	534	528	528	528
	Other network assets	908	1,682	1,690	1,657	1,597	1,597
	Asset replacement and renewal expenditure	**6,587**	**13,085**	**14,037**	**14,048**	**14,135**	**14,243**
less	Capital contributions funding asset replacement and renewal	–	–	–	–	–	–
	Asset replacement and renewal less capital contributions	**6,587**	**13,085**	**14,037**	**14,048**	**14,135**	**14,243**

11a(v)	Asset Relocations	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	*Project or programme**			$000 (in constant prices)			
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other project or programmes – asset relocations	–	–	–	–	–	–
	Asset relocations expenditure	**–**	**–**	**–**	**–**	**–**	**–**
less	Capital contributions funding asset relocations	–	–	–	–	–	–
	Asset relocations less capital contributions	**–**	**–**	**–**	**–**	**–**	**–**

11a(vi)	Quality of Supply	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	*Project or programme**			$000 (in constant prices)			
	Network Reinforcement	–	58	248	929	2,066	427
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other project or programmes – quality of supply	–	–	–	–	–	–
	Quality of supply expenditure	**–**	**58**	**248**	**929**	**2,066**	**427**
less	Capital contributions funding quality of supply	–					
	Quality of supply less capital contributions	**–**	**58**	**248**	**929**	**2,066**	**427**

APPENDIX 4 – SCHEDULE 11A: REPORT ON FORECAST CAPITAL EXPENDITURE (CONTINUED)

11a(vii)	Legislative and Regulatory	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	*Project or programme**			$000 (in constant prices)			
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	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	**–**	**–**	**–**	**–**	**–**	**–**

11a(viii)	Other Reliability, Safety and Environment	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	*Project or programme**			$000 (in constant prices)			
	Network Reinforcement	625	300	250	600	890	1,754
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes- other reliability, safety and environment	–	–	–	–	–	–
	Other reliability, safety and environment expenditure	**625**	**300**	**250**	**600**	**890**	**1,754**
less	Capital contributions funding other reliability, safety and environment	–	–	–	–	–	–
	Other reliability, safety and environment less capital contributions	**625**	**300**	**250**	**600**	**890**	**1,754**

11a(xi)	Non-Network Assets	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	Routine expenditure			$000 (in constant prices)			
	*Project or programme**						
	Asset Management	360	435	1,325	150	50	50
	IT Systems	225	1,270	200	50	300	1,200
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes – routine expenditure	–	–	–	–	–	–
	Routine expenditure	**585**	**1,705**	**1,525**	**200**	**350**	**1,250**
	Atypical expenditure						
	*Project or programme**						
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes – atypical expenditure	–	–	–	–	–	–
	Atypical expenditure	**–**	**–**	**–**	**–**	**–**	**–**
	Expenditure on non-network assets	**585**	**1,705**	**1,525**	**200**	**350**	**1,250**

APPENDIX 5 – SCHEDULE 11B: REPORT ON FORECAST OPERATING EXPENDITURE

	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034	FY2035
Operating expenditure Forecast						**$000 (in nominal dollars)**					
Service interruptions and emergencies	1,260	1,200	1,224	1,249	1,277	1,306	1,338	1,370	1,403	1,436	1,470
Vegetation management	1,775	1,800	1,948	2,102	2,256	2,417	2,587	2,751	2,922	3,100	3,296
Routine and corrective maintenance and inspection	5,851	6,692	6,598	6,331	6,533	6,732	7,010	7,075	6,998	7,319	7,518
Asset replacement and renewal	–	–	–	–	–	–	–	–	–	–	–
Network operating expenditure	**8,886**	**9,692**	**9,769**	**9,682**	**10,065**	**10,455**	**10,934**	**11,196**	**11,323**	**11,855**	**12,285**
System operations and network support	14,280	15,181	15,862	15,781	15,952	16,476	16,961	17,375	17,824	18,224	18,685
Business support	6,291	8,183	8,258	8,248	8,434	8,629	8,894	9,112	9,354	9,577	9,806
Non-network solutions provided by a related party or third party	–	–	–	–	–	–	–	–	–	–	–
Non-network operating expenditure	**20,571**	**23,364**	**24,120**	**24,029**	**24,386**	**25,105**	**25,854**	**26,487**	**27,178**	**27,801**	**28,491**
Operating expenditure	**29,456**	**33,056**	**33,890**	**33,711**	**34,451**	**35,560**	**36,789**	**37,683**	**38,500**	**39,656**	**40,776**

	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034	FY2035
						$000 (in constant prices)					
Service interruptions and emergencies	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Vegetation management	1,690	1,800	1,910	2,020	2,120	2,220	2,320	2,410	2,500	2,590	2,690
Routine and corrective maintenance and inspection	5,572	6,692	6,471	6,084	6,140	6,184	6,287	6,198	5,987	6,115	6,135
Asset replacement and renewal	–	–	–	–	–	–	–	–	–	–	–
Network operating expenditure	**8,462**	**9,692**	**9,581**	**9,304**	**9,460**	**9,604**	**9,807**	**9,808**	**9,687**	**9,905**	**10,025**
System operations and network support	13,600	15,181	15,556	15,165	14,992	15,135	15,212	15,220	15,249	15,227	15,248
Business support	5,991	8,183	8,098	7,926	7,927	7,927	7,977	7,982	8,002	8,002	8,002
Non-network solutions provided by a related party or third party	–										
Non-network operating expenditure	**19,591**	**23,364**	**23,654**	**23,091**	**22,919**	**23,062**	**23,189**	**23,202**	**23,251**	**23,229**	**23,250**
Operating expenditure	**28,053**	**33,056**	**33,235**	**32,396**	**32,379**	**32,666**	**32,996**	**33,009**	**32,938**	**33,135**	**33,275**

Subcomponents of operating expenditure (where known)											
Energy efficiency and demand side management, reduction of energy losses	–	–	–	–	–	–	–	–	–	–	–
Direct billing*	–	–	–	–	–	–	–	–	–	–	–
Research and Development	–	–	–	–	–	–	–	–	–	–	–
Insurance	860	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

APPENDIX 5 – SCHEDULE 11B: REPORT ON FORECAST OPERATING EXPENDITURE (CONTINUED)

	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034	FY2035
Difference between nominal and real forecasts						**$000**					
Service interruptions and emergencies	60	–	24	49	77	106	138	170	203	236	270
Vegetation management	85	–	35	77	127	185	252	324	404	490	584
Routine and corrective maintenance and inspection	279	–	130	252	401	559	738	895	1,030	1,223	1,405
Asset replacement and renewal		–	–	–	–	–	–	–	–	–	–
Network operating expenditure	**423**	**–**	**189**	**378**	**606**	**851**	**1,127**	**1,389**	**1,636**	**1,949**	**2,260**
System operations and network support	680	–	306	616	960	1,341	1,749	2,155	2,575	2,997	3,437
Business support	300	–	160	322	507	702	917	1,130	1,351	1,575	1,804
Non-network solutions provided by a related party or third party (not required before DY2025)	–	–	–	–	–	–	–	–	–	–	–
Non-network operating expenditure	**980**	**–**	**466**	**938**	**1,467**	**2,043**	**2,665**	**3,285**	**3,926**	**4,572**	**5,241**
Operating expenditure	**1,403**	**–**	**655**	**1,315**	**2,073**	**2,894**	**3,793**	**4,674**	**5,562**	**6,521**	**7,501**

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operating expenditure for the current disclosure year and a 10 year planning period in Schedule 15.

APPENDIX 6 – SCHEDULE 12A: REPORT ON ASSET CONDITION

				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
All	Overhead Line	Concrete poles/steel structure	No.	0.2%	0.8%	9.0%	7.2%	80.5%	2.3%	2	1.5%
All	Overhead Line	Wood poles	No.	1.0%	4.1%	18.6%	24.2%	40.9%	–	2	6.5%
All	Overhead Line	Other pole types	km							N/A	
HV	Subtransmission Line	Subtransmission OH up to 66 kV conductor	km	–	1.2%	9.0%	51.6%	38.2%		2	–
HV	Subtransmission Line	Subtransmission OH 110 kV+ conductor	km							N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66 kV (XLPE)	km	0.2%	32.8%	–	9.4%	57.6%		3	0.2%
HV	Subtransmission Cable	Subtransmission UG up to 66 kV (Oil pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66 kV (Gas pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66 kV (PILC)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110 kV+ (XLPE)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110 kV+ (Oil pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110 kV+ (Gas Pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110 kV+ (PILC)	km							N/A	
HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
HV	Zone substation Buildings	Zone substations up to 66 kV	No.	–	–	60.0%	20.0%	20.0%		3	10.0%
HV	Zone substation Buildings	Zone substations 110 kV+	No.							N/A	
HV	Zone substation switchgear	22/33 kV CB (Indoor)	No.	–	–	61.3%	–	38.7%		2	–
HV	Zone substation switchgear	22/33 kV CB (Outdoor)	No.	3.1%	21.9%	68.7%	6.3%	–		2	9.0%
HV	Zone substation switchgear	33 kV Switch (Ground Mounted)	No.							N/A	
HV	Zone substation switchgear	33 kV Switch (Pole Mounted)	No.	1.2%	41.8%	2.3%	1.2%	53.5%		2	14.0%
HV	Zone substation switchgear	33 kV RMU	No.							N/A	
HV	Zone substation switchgear	50/66/110 kV CB (Indoor)	No.							N/A	
HV	Zone substation switchgear	50/66/110 kV CB (Outdoor)	No.	–	–	33.3%	66.7%	–		2	–
HV	Zone substation switchgear	3.3/6.6/11/22 kV CB (ground mounted)	No.	–	27.8%	72.2%	–	–		2	
HV	Zone substation switchgear	3.3/6.6/11/22 kV CB (pole mounted)	No.	–	12.5%	75.0%	12.5%	–		2	

APPENDIX 6 – SCHEDULE 12A: REPORT ON ASSET CONDITION (CONTINUED)

Voltage	Asset Category	Asset Class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	14.3%	14.3%	42.9%	28.6%		3	14.0%
HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.1%	2.0%	13.3%	63.7%	19.9%		2	2.0%
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
HV	Distribution Line	SWER conductor	km	–	5.3%	29.0%	61.3%	4.4%		2	–
HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.6%	1.5%	0.6%	24.8%	72.5%		2	1.0%
HV	Distribution Cable	Distribution UG PILC	km	–	–	1.5%	90.3%	8.2%		2	–
HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) – reclosers and sectionalisers	No.	–	3.1%	18.8%	68.8%	9.4%		2	4.0%
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	9.5%	90.5%	–	–		2	3.0%
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.2%	1.5%	16.8%	38.6%	43.0%		2	2.0%
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) – except RMU	No.							N/A	
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.7%	–	21.9%	31.3%	46.0%		3	4.0%
HV	Distribution Transformer	Pole-Mounted Transformer	No.	0.3%	26.7%	34.2%	25.4%	13.4%		3	5.0%
HV	Distribution Transformer	Ground-Mounted Transformer	No.	0.4%	18.9%	33.6%	30.2%	16.9%		2	5.0%
HV	Distribution Transformer	Voltage regulators	No.	–	4.2%	25.0%	20.8%	50.0%		3	–
HV	Distribution Substations	Ground-Mounted Substation Housing	No.	–	14.8%	37.3%	26.1%	21.8%		2	1.0%
LV	LV Line	LV OH Conductor	km	0.5%	2.6%	55.4%	35.1%	6.3%		2	2.0%
LV	LV Cable	LV UG Cable	km		0.8%	15.3%	28.3%	55.7%		2	1.0%
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	–	26.1%	14.2%	9.1%	50.6%		2	1.0%
LV	Connections	OH/UG consumer service connections	No.	–	0.0%	6.6%	22.3%	49.7%	21.5%	1	1.0%
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	22.1%	3.4%	33.3%	40.8%	0.3%		1	25.0%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1.0%	32.5%	26.3%	32.3%	7.8%		2	20.0%
All	Capacitor Banks	Capacitors including controls	No.							N/A	
All	Load Control	Centralised plant	Lot	–	28.6%	28.6%	28.6%	14.3%		2	10.0%
All	Load Control	Relays	No.	–	–	62.6%	26.2%	10.7%	0.5%	1	–
All	Civils	Cable Tunnels	km							N/A	

APPENDIX 7 – SCHEDULE 12B: REPORT ON FORECAST CAPACITY

12b(i) System Growth - Zone Substations

Exiting Zone Substation	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 +10 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 progress	Temporary constraint solution remaining lifespan	Explanation
Southbrook	Winter	40	N-1	No constraint	1.7	Winter	-6.4	N-1	Winter	-18.7	-10.8	N-1	Security	2	Zone substation transformer	Divert load to alternative substation	Implementation stage	Not applicable	MainPower is building a new Zone Substation (Coldstream) East of Rangiora which will pick up the rapid load growth from Southbrook.
Burnt Hill	Summer	23	N-1 switched	No constraint	7.7	Summer	6.9	N-1 switched	Summer	4.3	6.1	N-1 switched	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	No constraint.
Swannanoa	Summer	23	N-1 switched	No constraint	5.0	Summer	3.7	N-1 switched	Summer	0.9	2.8	N-1 switched	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	No constraint. Once Coldstream ZS is commissioned, Southbrook ZS can pick up some of the Swannanoa ZS load.
Amberley	Winter	4	N-1 switched	Security	-2.4	Winter	1.5	N-1 switched	Winter	-0.3	-0.1	N-1	Security	1	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Replacement ZS is being constructed due to capacity constraints and aging equipment. Backup subtransmission supply is limited to 6 MVA + 11kV offload capability.
MacKenzies Rd	Winter	4	N	Security	3.6	Spring	0.2	N	Spring	-0.3	1	N	Security	1	Subtransmission circuit	Distributed Generation	Planning stage	Not applicable	Backup subtransmission supply from Culverden GXP not always possible. Engaging with local generation to help address constraint.
Greta	Summer	4	N	No constraint	2.5	Summer	2.3	N	Summer	1.9	2.4	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint.
Cheviot	Summer	4	N	No constraint	0.3	Summer	0.2	N	Summer	-0.9	0.1	N	Capacity	9	Zone substation transformer	Demand response	Planning stage	Not applicable	Flexibility solutions have been explored via market engagement but were not cost effective. Localised demand response will be futher explored followed by Network reinforcements to shift load.
Hawarden	Summer	4	N	No constraint	0.04	Summer	0	N	Summer	-0.6	0	N	Capacity	5	Zone substation transformer	Demand response	Planning stage	> 3 years	Investigate load reduction options in conjunction with network reinforcement to allow load shift.
Ludstone	Winter	6	N-1 switched	Security	-0.2	Winter	-1.6	N-1	Winter	-3.9	-3.5	N-1	Security	1	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Ludstone ZS will be transferred to Kaikoura Subtation. Project deferred to maximise use remaining equipment life through dynamic ratings of assets. Flexibility options have been explored to improve security of supply however were not cost effective.
Leader	Summer	4	N	No constraint	2.3	Summer	2.1	N	Summer	2	2.2	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint.
Oaro	Winter	0.5	N	No constraint	0.3	Winter	0.25	N	Winter	0.15	0.25	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Will be replaced with a new 4 MVA Substation as the subtransmission supply is being upgraded from 33 kV to 66 kV.
Mouse Point	Summer	13	N-1	Security	-3.1	Summer	-7.4	N-1	Summer	-8.9	-7.3	N-1	Security	1	Zone substation transformer	Demand response	Planning stage	Not applicable	Working with customers to allow demand reduction during fault events at peak demand periods.
Hanmer	Winter	6	N	Security	1.1	Winter	-3.2	N	Winter	-0.9	-0.1	N-1	Security	1	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	A new Substation will be constructed due to equipment aging and capacity. New local backup generation to improve security of supply.
Lochiel	Winter	0.3	N	No constraint	0.1	Winter	0.1	N	Winter	0.05	0.1	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint
Marble Quarry	Summer	0.2	N	No constraint	0.1	Summer	0.1	N	Summer	0.05	0.1	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint

APPENDIX 8 – SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

		Number of connections					
12c(i)	Consumer Connections	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	Number of ICPs connected during year by consumer type						
	*Consumer types defined by EDB**						
	Residential	760	819	862	883	889	894
	Irrigation	30	32	34	35	35	35
	Large User	12	13	14	14	14	14
	Streetlights	1	1	1	1	1	1
	Other	–	–	–	–	–	–
	Connections total	**803**	**865**	**911**	**933**	**939**	**944**

	Distributed generation	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
	Number of connections made in year	243	299	342	392	431	489
	Capacity of distributed generation installed in year (MVA)	1	2	2	2	2	3

12c(ii)	System Demand						
	Maximum coincident system demand (MW)	**FY2025**	**FY2026**	**FY2027**	**FY2028**	**FY2029**	**FY2030**
	GXP demand	118	120	122	124	126	129
plus	Distributed generation output at HV and above	6	3	3	3	3	3
	Maximum coincident system demand	**124**	**122**	**125**	**127**	**129**	**131**
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	**124**	**122**	**125**	**127**	**129**	**131**
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	651	660	664	669	673	678
less	Electricity exports to GXPs	–	–	–	–	–	–
plus	Electricity supplied from distributed generation	29	29	31	35	37	40
less	Net electricity supplied to (from) other EDBs	–	–	–	–	–	–
	Electricity entering system for supply to ICPs	**680**	**689**	**695**	**704**	**710**	**718**
less	Total energy delivered to ICPs	645	645	651	657	662	668
	Losses	**35**	**44**	**44**	**47**	**48**	**50**
	Load factor	**63%**	**64%**	**64%**	**63%**	**63%**	**62%**
	Loss ratio	**5.1%**	**6.3%**	**6.3%**	**6.7%**	**6.7%**	**7.0%**

APPENDIX 9 – SCHEDULE 12D: REPORT ON FORECAST INTERRUPTIONS AND DURATION

	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
SAIDI						
Class B (planned interruptions on the network)	136.7	177.5	177.5	177.5	177.5	177.5
Class C (unplanned interruptions on the network)	128.3	204.3	204.3	204.3	204.3	204.3
SAIFI						
Class B (planned interruptions on the network)	0.57	0.64	0.64	0.64	0.64	0.64
Class C (unplanned interruptions on the network)	1.45	1.25	1.25	1.25	1.25	1.25

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	**3**	MainPower's Asset Management Policy is documented, authorised by the CEO and Board Chair, and communicated to staff in various ways including as part of MainPower's strategy, the MPowered Future, and the AMP.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	**3**	MainPower's Asset Management Strategy is aligned with its other policies and strategies, with an obvious downward cascade from Policy to Strategy. Stakeholder requirements are clearly understood and reflected in the Asset Management Strategy.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	**3**	MainPower's Asset Management Strategy reflects the recognised asset lifecycles of planning, design, construction, operation, maintenance, etc. The strategies include appropriate approaches for high-volume and low-volume asset fleets.		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**	The Asset Management Plans for each asset class are based on the asset lifecycle, and take a risk-based approach to optimise performance, costs and risks, which in turn defines interventions such as maintenance and renewals.		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).
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	**3**	MainPower communicates its plans through both documentation (the AMP) and through its induction procedures which includes MainPower's strategy, the MPowered Future.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	**3**	Various documents ranging from the Delegated Authority Policy through to job descriptions and reporting templates document what asset management outcomes people are responsible for.		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**	MainPower's AMP includes 10-year spend forecasts which are subject to an iterative process to smooth spending to within the revenue path and SCI ratios. Future staff resourcing has been considered.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

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."
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."

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
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**	MainPower has many leading plans that seek to avoid emergency situations (e.g. design standards, construction standards), and many lagging plans such as incident management procedures, business continuity plans, emergency recovery plans. These lagging plans are consistently linked to the Incident Management framework.		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.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	**3**	Chapter 2.7 of the 2024 AMP shows how MainPower has assigned responsibilities to various roles, cascading downwards from the Board's audit and risk committee and the Board's safety committee, down to Company staff whose responsibilities are described in the job descriptions.		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**	The AMP notes that internal staff numbers are considered adequate.		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**	MainPower communicates the importance of meeting asset management outcomes through both leading controls (which range from design standards to job descriptions) and lagging controls (which range from practice reviews to inspection of completed works).		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	**2**	MainPower has a range of leading controls (e.g. design standards, material specifications, contract terms etc.) to ensure compliant delivery of the Asset Management Strategy. These are complemented by a range of lagging controls that range from global (e.g. NZS7901 audits) to local (inspection of completed works).	The Construction Specifications and the Standard Construction Drawing Set have been examined (which form a key control mechanism).	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.

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities- including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	**2**	Job descriptions clearly define the asset management outcomes of roles, and show clear linkages to MainPower's values.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	**3**	Competency requirements (as reflected in job descriptions) are linked to asset management outcomes. There are comprehensive competency matrices in place for field staff.		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?	**3**	Field staff are subject to regular safety training and assessments. Engineering and asset management staff regularly attend training and up-skilling events (e.g. the EEA Conference).		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.
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**	MainPower communicates pertinent asset management information through a wide range of leading controls such as design standards, material specifications and work quality expectations. At a more macro level, MainPower's strategy, the MPowered Future sets the expectations for the direction of the business including the AMP and of values and behaviours.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	**2**	The AMP describes the main elements of MainPower's Asset Management System, and the linkages between those elements.		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.

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities- including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities- internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	**3**	Over time, the Asset Management Information System has been aligned to users information requirements, as evidenced by the quality of asset management decisions.		"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**	MainPower is in the process of consolidating IT platforms, including mobile data functionality. Data quality and consistency has been reviewed, and is considered sufficient to support future asset management.		"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.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	**3**	MainPower's many business management frameworks reflect good industry practice, and support users decision making requirements. A recent review confirms that data consistency is sufficient to support MainPower's decision making.		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**	The starting point for asset-related risks is MainPower's comprehensive Risk Management Plan. The detailed consideration of risk cascades from the Risk Management Plan, and takes inputs from a wide range of other planning processes including long-term issues such as climate resilience through to safety bow-ties.		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**	MainPower does allocate and reallocate resources in response to risk assessments and evaluations. The method of identifying options for risk mitigation, and quantifying the benefits and costs of those options is considered robust.		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.

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
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**	In addition to MainPower's wide range of staff being generally aware of various statutory and regulatory requirements (through such means as reading, receiving bulletins, attending conferences etc.), MainPower uses ComplyWith to compile a compliance calendar and minimise the risk of overlooking an obligation.		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
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	**3**	Leading controls such as design standards and material specifications reflect the expected performance, cost and risk parameters of assets, and include the accumulated experience of MainPower's staff and the wider industry to ensure that completed assets reflect those performance requirements.		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?	**3**	MainPower uses a wide range of leading controls (e.g. design standards, material specification) to minimise non-conformance, and complements this with a wide range of lagging controls (e.g. asset testing, AMMAT review, NZS7901 audits). These leading and lagging controls visibly link to the Asset Management Strategy.		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**	MainPower uses a wide range of leading controls (e.g. design standards, material specification) to set general asset performance and condition, and complements this with a wide range of audits and reviews (e.g. asset testing, AMMAT review, NZS7901 audits) to ensure that performance aligns with requirements.		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**	MainPower has systematic processes for assigning responsibility for investigating non-conformances, and taking remedial actions.		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.

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	At the peak level, MainPower has an Audit, Monitoring and Compliance Management Plan that sets out the strategy for minimising non-compliances. This plan references a wide range of detailed audits and reviews across many areas of the business including finance, safety, asset management and industry participation.		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?	3	MainPower uses a lot of leading controls (e.g. design standards, material specifications etc.) to minimise non-conformance before they occur. Processes are in place for ensuring that actions aligned with the Asset Management Strategy result from investigation of non-conformances.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	MainPower's current asset management activities include various strategies and plans that examine practice areas and asset fleets to identify how performance, costs and risks can be optimised.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	MainPower staff regularly attend industry events (e.g. the EEA Conference), receive vendor information, seek advice on equipment (e.g. the external consultants RMU evaluation report), and receive recommendations on practice improvements (e.g. the Telarc NZS 7901 audit report).		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.

APPENDIX 10 – SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (CONTINUED)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

APPENDIX 11 – SCHEDULE 14A: MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

Company Name: **MainPower New Zealand Ltd**
For Year Ended: **31 March 2025**

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. 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)

3. Box 1 explains 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

In preparing the capital expenditure forecasts, MainPower has used the Westpac Economics Forecast Summary sheet 25 October 2024 for the inflation (consumers price index (CPI)) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast and extrapolated at constant CPI for the final four periods of the AMP forecast.

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Index	1.00	1.02	1.04	1.06	1.09	1.11	1.14	1.17	1.20	1.23

Commentary on difference between nominal and constant price operating expenditure forecasts (Schedule 11b)

4. Box 2 explains the difference between nominal and constant price operating 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 operating expenditure forecasts

In preparing the operating expenditure forecasts MainPower has used the Westpac Economics Forecast Summary sheet 25 October 2024 for the inflation (CPI) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast and extrapolated at constant CPI for the final four periods of the AMP forecast.

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Index	1.00	1.02	1.04	1.06	1.09	1.11	1.14	1.17	1.20	1.23

Directors

Anthony Charles King	Chair
Graeme David Abbot	Director
Janice Evelyn Fredric	Director
Jan Fraser Jonker	Director
Stephen Paul Lewis	Director
Brian John Wood	Director

Executive Leadership Team

Andy Lester	Chief Executive
Sarah Barnes	General Manager Finance and Information Technology
Peter Cairney	General Manager Service Delivery
Penny Kibblewhite	General Manager Customer and Corporate Relations
Sandra O'Donohue	General Manager People and Culture
Todd Voice	General Manager Commercial
Damien Whiffen	Chief Assets and Operations Officer

Registered Office

172 Fernside Road
PO Box 346
Rangiora 7440

Principal Solicitor

Duncan Cotterill
Christchurch

Principal Banker

Westpac New Zealand Limited Rangiora

China Construction Bank (New Zealand) Limited

Auditor

Deloitte Limited Christchurch

MainPower New Zealand Limited
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