

ASSET MANAGEMENT PLAN

2023-2033





CHIEF EXECUTIVE'S MESSAGE

The needs and expectations of our customers are changing. New technology and innovations are opening up new ways of powering the homes and businesses of our region. MainPower sees huge potential ahead. Our vision is to create a smarter future to deliver local value.

MainPower is continuing to build on our MPowered Future Strategic Plan. The MPowered Future framework includes four core functions: Networks, Services, Investment and Generation. It is designed to guide the people, homes and businesses on our network into the future while opening doors to make the adoption of new technology and life-changing innovations possible.

The energy industry is changing rapidly, with new technologies and innovations impacting the way consumers generate, buy and sell energy. In order to realise this potential, MainPower is partnering with our customers to understand their uptake and needs so that we can provide network services that fit their expectations.

As well as preparing our network for the changing needs of energy consumers, we're actively looking for ways to trial, test and report on our findings, including the feasibility of new innovations such as electric vehicles (EVs), distributed generation and smart technology.

MPowered Future is our plan to ensure we safeguard our current network assets and deliver value beyond them. The framework also sets out the way we tackle exciting new innovations and smart technology developments like solar generation, peer-to-peer trading and new-generation technology for the benefit of our business and the communities we operate in.

MainPower's Asset Management Plan outlines our commitment to providing a safe, secure, reliable and sustainable network that delivers electricity and energy services to homes and businesses in the North Canterbury region, from north of the Waimakariri River, through the Hurunui, to Kaikōura. This Asset Management Plan describes our network, our management practices and the assumptions that support our obligation as the responsible custodian of the MainPower electricity distribution network.

This plan details how MainPower will invest prudently in our electricity distribution network and related services for the next 10 years and how these services will enhance the delivery of safe, reliable and sustainable low-carbon energy – powering our communities while delivering value to our shareholders.

Andy Lester
Chief Executive

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1. SUMMARY

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. MainPower provides electricity distribution services to more than 43,000 residential and business connections.

We are responsible for providing 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.

We 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. The New Zealand electricity sector is facing significant transformation, driven by decarbonisation, decentralisation and digitisation (the “New Energy Future”).

Owing to changes in the sector, our role is also changing. 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.

Efforts over the last three years have focused 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 support 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.

Currently, our electricity distribution network performance (quality of supply) is unduly affected by defective equipment and planned works. This Asset Management Plan (AMP) describes the workstreams that will return the quality of supply to past historical levels and improve it into the future.





2. ASSET MANAGEMENT PLAN

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 43,000 North Canterbury homes and businesses.

Growth in the region, particularly with new subdivisions, has brought us close to 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.



Figure 2.1: MainPower's Electricity Distribution Network Region

We have lines and cables operating in three distinct voltage ranges:

- Sub-transmission – 33 kV and 66 kV;
- Distribution – mostly 11 kV and 22 kV, but also 6.6 kV; and
- Low voltage – 230 V single phase or 400 V three phase.

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 we own 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 Network Transformation and Evolution

The traditional production and use of “energy” is changing. Alternative affordable technologies, government policy, regulation and consumer behaviour has already created unpredictability in the energy sector. Some examples follow.

- The need to meet climate change objectives, which could be achieved by switching energy use to renewable electricity by 2035
- New consumer technology that is increasing the options for consumers to produce and store energy, thus impacting traditional energy use
- Consumers choosing to adopt new technology and options that reflect their needs as they meet climate change objectives (e.g. considering alternatives to hydrocarbon fuel for transport and heating)

2.2.1 Framework

MainPower’s Network Transformation Roadmap, which is based on the Electricity Networks Association Network Transformation Roadmap, is designed to provide an open platform, reliable connection and the efficient operation of the New Zealand electricity distribution industry for the long-term benefit of consumers. The roadmap contains a number workstreams to improve asset management maturity, designed to achieve an “Open Network Architecture” (see Figure 2.3).



Figure 2.3: Open Network Architecture

2.2.2 Climate Change Impact

As the North Canterbury community seeks to reduce its carbon footprint, the community’s electricity distribution network services will be a key enabler, providing a clean electricity energy source. The electricity distribution service is vital for the wellbeing of our community. This obliges MainPower to understand the impact of climate change on the community’s network, to achieve safe, reliable and resilient network services.

Climate change means our community will be exposed to extreme weather events. It also means our consumers’ consumption patterns will change because of changes in weather patterns impacting irrigation, heating and cooling, as well as the use of new technologies such as solar PV, electric vehicles (EVs). Based on the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD), MainPower now reports on the impact of climate change on our network assets for our consumers, including what we are doing about it, as outlined below.

2.2.2.1 Physical Impacts



	Risk Assessment	50 year Change	Impact	Treatment	Commitments	
Physical	Vegetation	High	Increasing	<p>Impacting continuity of supply, Network Performance, Event Resourcing</p> <p>The number of events are expected increase</p>	<p>Use of Coordinated Incident Management response (CIMs)</p> <p>Delivery of Vegetation Management as part of the annual work programme</p> <p>Employ public notifications and awareness</p>	<p>Improved Asset Management using Lidar technology for clearance management including tree identification and growth rates</p>
	Severe Weather	High	Increasing	<p>Damage to Overhead infrastructure from increased windspeed – beyond original design specification</p> <p>Damage to underground infrastructure from flooding</p>	<p>Review design criteria and designs standard</p> <p>Develop a digital twin model for the modelling of assets</p>	<p>Assess windspeed impacted to existing assets within digital twin model.</p> <p>Review replacement program based on assets impacted</p> <p>Partner with NIWA, Lifelines and Civil Defence for improved community sustainability modelling.</p>
	Wildfire	Medium	Increasing	<p>Dryer conditions leading to increased exposure and severity of fire, causing damage to assets</p> <p>Exposure to 3rd Party fire damage leading to reputational damage</p>	<p>Maintain clearances through vegetation management and fall zone reporting.</p> <p>Employ public notifications and awareness</p> <p>Review of areas susceptible to wildfires and assessed assets affected including loss of supply impact</p>	<p>Continued resource availability to support the management of fire risk to Network Assets.</p>
	Sea Level Rise Tsunami	Low	Gradual	<p>Impact to low lying areas of the Network, necessitating relocation of assets</p>	<p>Review of asset location when working in low lying and coastal areas</p>	<p>Review existing assets and their location as data around sea level rise changes</p> <p>Partner with Lifelines and Civil Defence enhancing community modelling</p>

Figure 2.4: Physical Impacts of Climate Change



2.2.2.2 Behavioural Impacts

		Risk Assessment	50-year Change	Impact	Treatment	Commitments
Behavioural	New Technology	Low	Increasing	<p>Increased demand on the network as consumers become more reliant on electricity</p> <p>Possible impacted to AMP forecasts and changes to work program as consumers become more reliant on electricity</p>	<p>Continued scenario based demand forecasting informing AMP expenditure programmes</p> <p>Continued consumer engagement and surveys to understand consumers future need for Network services</p>	Continued review and understanding of demand changes including engagement with other Electrical Distribution Boards (EDBs).
	Regulation	Low	Increasing	<p>Possible market changes impacting the way the Network is used</p> <p>Carbon pricing affecting consumer Low Carbon Technology (LCT) decision making</p>	Involvement in industry working groups to understand possible demand changes including the impact of change.	Continued review and understanding of demand changes including engagement with other Electrical Distribution Boards (EDBs).
	Pricing	Low	Increasing	Pricing signals to consumers leading to consumption behaviour changes that negatively impacts reliable power supply	<p>Continued implement of pricing Roadmap.</p> <p>Awareness to other market participants about the impact of pricing signals (Hour of Free Power)</p>	<p>Continued review and understanding of demand changes including engagement with other Electrical Distribution Boards (EDBs).</p> <p>Introduction of price signals that enhance market efficiency and value of consumer LCT choice</p>

Figure 2.5: Behavioural Impacts of Climate Change



2.2.2.3 Analysis and Management of Impacts



The National Institute of Water and Atmospheric Research (NIWA) climate projections describe greater variability in weather patterns, with more frequent and extreme weather events occurring as mean temperatures rise in the mid to long term. The upper South Island is expected to experience an increase in the number of hot days, a decrease in the number of cold nights, and an increase in temperature extremes on hot days. Extreme wind speeds are also predicted to increase throughout the South Island.

MainPower is developing a collaborative framework with external service providers to improve weather prediction and forecasting capability, and to overlay those predictions with network information to better manage the network in extreme situations and improve the resilience of the network. MainPower's ADMS real-time and historical information will be integrated with climate data to find network constraints in modelled scenarios. Additionally, ADMS data will be used to fine-tune resilience models for specific application in MainPower's region. With this data, 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.

2.2.3 Enhanced Asset Management – Condition-Based Risk Management Model

MainPower has identified the need to improve on its asset management investment decision making to enhance both price quality trade-off and overall asset portfolio risk. In 2022, MainPower embarked on introducing condition-based risk management (CBRM) models for overhead assets and distribution switchgear, taking into consideration both the cost of overhead asset replacement and the impact of defective switchgear equipment on network performance (see Figure 2.6.).

Leverage existing data to create actionable information

Embed expert knowledge within models

Monetise risk to enable economic analysis

Tailor modelling to the network and experience

Model the effect of your planned program of works

Compare results across asset classes

Align with industry best practice



Figure 2.6: CBRM Diagram

2.3 Asset Management

This AMP covers a 10-year planning period, from 1 April 2023 to 31 March 2033. It provides our stakeholders with insights and explanations as to how we provide electricity distribution network and energy services in a safe, secure, reliable and sustainable manner that meets their expectations.

The AMP is a planning document that provides information on asset management systems, processes and practices, with a specific focus on development, maintenance and replacement plans for our electricity distribution network assets while also balancing cost, risk and electricity distribution network performance in accordance with our stakeholders' requirements.

The information within the AMP also informs our annual business and financial planning. This ensures sufficient resources are directed to deliver identified asset management needs, consistent with MainPower's overall corporate objectives. The AMP demonstrates our alignment with best-practice asset management processes. The content and structure serve to achieve the information disclosure requirements set out in the Electricity Distribution Information Disclosure Determination 2012.

2.3.1 MainPower's Asset Management Objectives

As the community transitions to a low-carbon economy, the services the electricity distribution network provides will need to change. The services will need to enable widespread use of local generation sources connected to the network at multiple points, with associated two-way power flows. The services will also need to ensure open-access arrangements for consumers to allow them to transact over the network and connect any device they wish within acceptable safety and reliability limits. This means:

- the distribution network will rely on physical assets to convey electricity to consumers, as well as from consumer to consumer, or consumers to bulk supply points;
- consumers will be actively involved in the management of their energy acquisition, generation and consumption;
- the distribution network will provide network connections for multiple sources of distributed generation devices and other consumer-side devices;
- the distribution utility may not become involved in the transactions between consumers and other parties and may only be involved in balancing supply and demand on the network; and
- network stability will be managed by the EDB for a range of operating scenarios.

2.3.2 MainPower's Asset Management System Purpose

The purpose of asset management at MainPower is to:

- specify the requirements for establishing, implementing, maintaining and improving MainPower's Asset Management System;
- cultivate 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; and
- ensure the Asset Management System aligns with MainPower's requirements, other business management systems, company objectives and policies.



Figure 2.7: Asset Management Standards

2.3.3 MainPower's Asset Management Policy



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, as shown in Figure 2.9.

- DO WHAT'S RIGHT**
 - Compliance and regulatory excellency ensuring we comply with laws, regulation, standards and industry codes of practice
 - Ensure consumer engagement effectively informs asset management
 - Provide resources that ensure asset management objectives can be delivered
- MAKE IT BETTER**
 - Apply quality management systems and strive for continuous improvement and innovation
 - Apply industry best practice, systems and processes
 - Apply performance monitoring and benchmarking against industry
 - Apply risk-based approach to managing our assets balancing cost performance and risk
 - Ensure network growth delivers consumer requirements while facilitating regional development
- WORK TOGETHER**
 - Effective business systems, processes, roles and responsibilities
 - Enable collaboration driving strategic change within the industry delivering real value to our customers and market efficiency through transparency
- MAKE IT HAPPEN**
 - Manage competency and training
 - Effectively plan our activities
 - Optimise operational activities and do it right first time

Figure 2.8: MainPower's Asset Management Policy

2.3.4 MainPower's Asset Management System

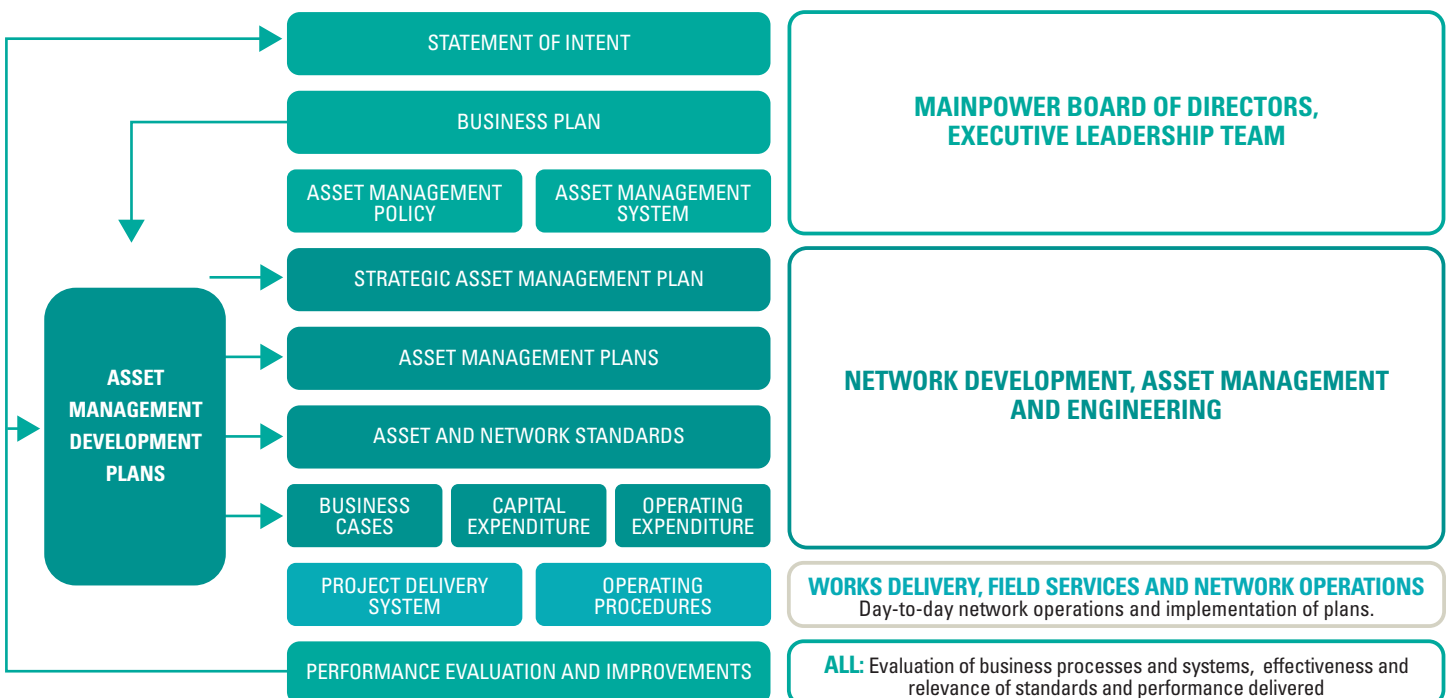


Figure 2.9: MainPower's Asset Management Framework

System Components	DESCRIPTION
Statement of Corporate Intent	Presents the strategic direction and operational environment of the organisation.
Business Plan	Articulates the business goals and objectives that are aligned with the strategic intent of the organisation 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 plan 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 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 2.1: MainPower's Asset Management System Components

2.3.5 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 2.14).



Figure 2.10: Asset Lifecycle Planning

The steps of the process are as follows:

- **Develop a need or idea:** The need or idea can come from anywhere within the business. It typically details a high-level view of the intent or requirement of a given project. Each idea is formulated by the project's sponsor, using a "sponsor's brief" document. Once the brief is written, a project is initiated and a project manager is assigned.
- **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. The project manager is responsible for the project plan and delivering the project against the plan. The project sponsor approves the plan and provides oversight throughout the project.
- **Design phase:** A completed design is a design that is informed by the requirements of the project, design criteria and standard design. We must complete the design; only then is the design fit for achieving the outcomes of the project. The asset manager must approve the asset before the design process introduces it. All assets on the MainPower electricity distribution network are approved by the asset manager.
- **Construct the asset:** The Service Delivery Team is responsible for project delivery, as detailed within the MainPower Project Delivery System. Later, the final step of "Practical Completion" can be issued only if the asset has a Fleet Management Plan, is entered into the computerised maintenance management system (CMMS) and has a maintenance schedule against the asset, and all asset data are reflected in our geographic information system (GIS).



- **Operate, maintain and monitor:** Asset criticality defines the level of maintenance. The treatment of the asset – in terms of maintenance activities (restoration or prevention) and/or critical spares – is defined in line with the criticality flowchart. Asset data, complete with template work orders entered into the CMMS and informed by rate cards, are used to develop annual resource planning (budgets, people, plant and equipment, and materials).
- **Modify and upgrade:** Assets are assessed against service levels. Sometimes this assessment highlights the need to modify or upgrade an asset. It is noted that assets can be upgraded due to changes in legislation, safe working procedures, etc. Instances also arise where existing assets are relocated based on changes of service levels.
- **Renewal, decommission or dispose:** Both an asset's condition (recorded in the Asset Health Indicator (AHI)) and its level of criticality inform the need for asset renewal, which is assessed against the cost and risk to the business.

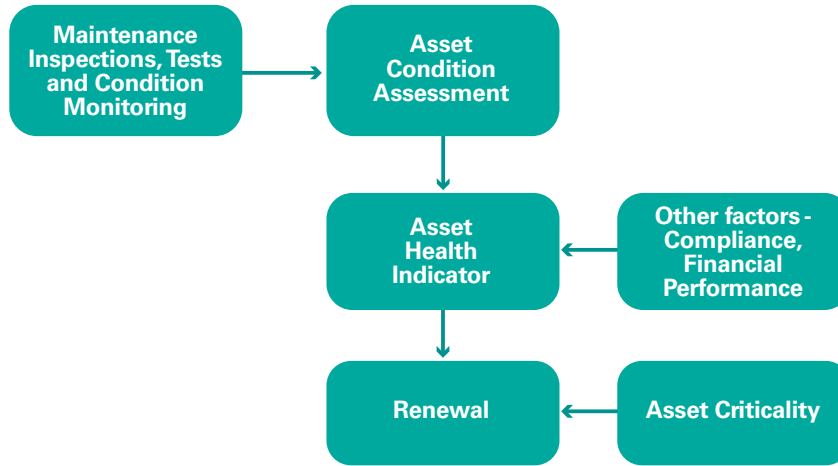


Figure 2.11: Maintenance Process for Asset Renewal

2.4 Planning Period

The AMP documents the likely development, maintenance and replacement requirements of the network and non-network assets over the next 10 years, from 1 April 2023 to 31 March 2033, with a focus on specific projects that have been identified for the next five years.

There is inherent uncertainty in AMP forecasts. Several factors contribute to this uncertainty, including pandemics and weather events. Our AMP forecasts are reasonably certain for five years. Except for potential large customer developments, including distributed generation, our plan has some certainty for the remainder of the planning period.

2.5 Date Approved by Directors

This AMP was completed for asset management purposes in 2022 and was approved by the MainPower Board of Directors at their December 2022 meeting.

2.6 Stakeholder Interests

Defining and understanding the needs and desires of our stakeholder groups allows us to structure our strategic objectives and define service levels in a way that is meaningful and relevant. Figure 2.12 shows our stakeholder groups.



Figure 2.12: MainPower's Stakeholder Groups

2.6.1 MainPower 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 purpose of this AMP, MainPower also refers to our customers as "consumers".

2.6.2 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 2.2.

Stakeholder	How We Identify the Expectations and Requirements of Stakeholders
All stakeholders	<ul style="list-style-type: none"> • Consultation and correspondence
Connected consumers	<ul style="list-style-type: none"> • Consumer account managers • Consumer discussion groups • Consumer research (quantitative and qualitative methods) • Direct current feedback/interactions • Events (including the Annual Meeting) • Informal contact/discussions • Open days • Public meetings and information sessions • Submissions on discussion papers
Community, representative groups	<ul style="list-style-type: none"> • Direct current feedback/interactions • Forums and working groups • One-on-one meetings • Open days • Submissions on discussion papers
MainPower Trust (ordinary shareholders)	<ul style="list-style-type: none"> • Direct current feedback/interactions • Events (including the Annual Meeting) • Operational interface • Other engagement activities
Government	<ul style="list-style-type: none"> • Disclosure requirements • Submissions on discussion papers
Regulators	<ul style="list-style-type: none"> • Adherence to corporate policies • Disclosure requirements • Operational interface
District and regional councils	<ul style="list-style-type: none"> • Disclosure requirements

Stakeholder	How We Identify the Expectations and Requirements of Stakeholders
Contractors and suppliers	<ul style="list-style-type: none"> • Direct current feedback/interactions • One-on-one meetings
Media	<ul style="list-style-type: none"> • Briefing sessions • Forums and working groups • Media monitoring and editorial opportunities • Open days • Public meetings and information sessions • Sponsorship involvement
Transpower	<ul style="list-style-type: none"> • Operational interface • Submissions on discussion papers
Electricity retailers	<ul style="list-style-type: none"> • Direct current feedback/interactions • Industry collaboration • Informal contact/discussions • One-on-one meetings
Electricity industry	<ul style="list-style-type: none"> • 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 2.2: How We Identify the Expectations and Requirements of Our Stakeholders

2.6.3 Summarising the Interests of Our Stakeholders

The expectations of our stakeholders are summarised in Table 2.3.

Stakeholder	Expectations
Connected consumers	<ul style="list-style-type: none"> • 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 length of time when power is off • Transparent communication (including outage information)
Community, representative groups	<ul style="list-style-type: none"> • Community focus • Corporate social responsibility • Engagement and consultation • Public safety around electricity
Other Stakeholders	
MainPower Trust (ordinary shareholder)	<ul style="list-style-type: none"> • 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

Stakeholder	Expectations
Government	<ul style="list-style-type: none"> • Appropriate investment in infrastructure • Delivery of a secure and reliable power supply • Future innovation • Health, safety and the environment • Industry collaboration
Regulators	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • Appropriate investment in infrastructure • Collaboration on shared service upgrades • Contribute 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	<ul style="list-style-type: none"> • Effective contractor management • Health, safety and the environment
Media	<ul style="list-style-type: none"> • Effective relationship management • Timely access to information
Partners	
Transpower	<ul style="list-style-type: none"> • Appropriate investment in infrastructure • Collaboration and effective relationship management • Engagement and consultation • Health, safety and the environment • Transparent communication (including outage information)
Electricity retailers	<ul style="list-style-type: none"> • Continuity and security of supply • Effective systems and processes • Health, safety and the environment • Transparent communication (including outage information)
Electricity industry	<ul style="list-style-type: none"> • Collaboration • Future innovation • Health, safety and the environment • Industry participation • Information and knowledge sharing
Bankers and insurers	<ul style="list-style-type: none"> • Accurate and timely performance information • Confidence in Board and leadership • Good governance • Prudent risk management • Sufficient revenue to maintain asset efficiency and reliability

Table 2.3: What Our Stakeholders Expect from Us

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

2.6.4 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; and
5. Efficiency and effectiveness.

2.7 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 are outlined in Figure 2.13.

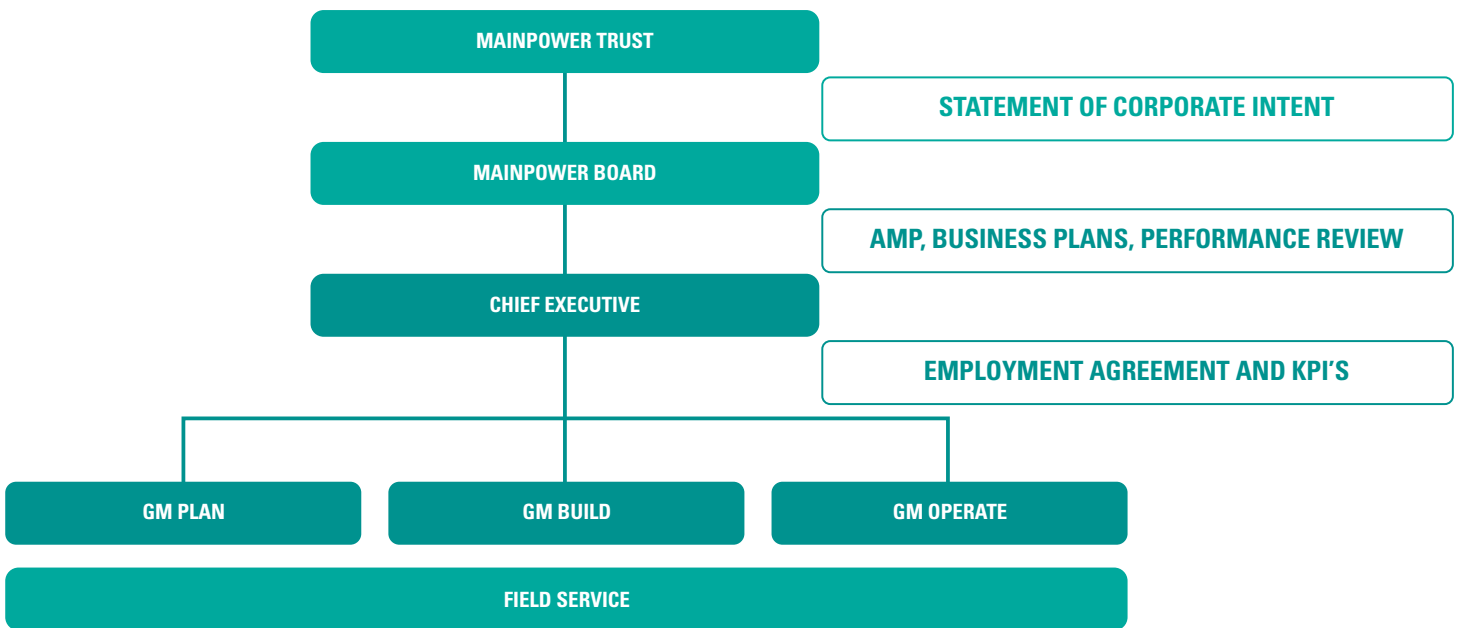


Figure 2.13: Organisational Management Structure

2.7.1 Ownership

We are 100% shareholder owned by the MainPower Trust, which holds shares in the Company on behalf of preferential 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 EDBs in terms of profits, price, expenditure and electricity distribution network reliability.

2.7.2 Governance and Executive Leadership

MainPower currently has six non-executive Directors who collectively make up the Board of Directors. The Board is accountable to the Trust.

The Board of Directors is responsible for the corporate governance of MainPower. The Board delegates the day-to-day responsibility for the operation and administration of MainPower to the Chief Executive. The Board also approves the AMP, business plan and budget. Financial approvals that exceed the delegated authority of the Chief Executive, such as large investment proposals, require Board approval.

The Chief Executive of MainPower is accountable to the Board through an employment agreement that includes performance criteria.

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

As part of our Network Transformation Roadmap we have also set up a Strategic Asset Management steering group. The purpose of the steering group is to oversee the strategic direction of asset management and enhance the link between the Board and asset management at MainPower.

2.7.3 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.

2.8 Overall AMP Assumptions

2.8.1 Significant Assumptions Made

The following assumptions have been made in the preparation of the AMP:

- Residential subdivision activity will continue or plateau (and possibly reduce) during the planning period.
- Major industrial plants will maintain similar kW and kWh demand for the next five years.
- While a significant renewable energy project (Mt Cass Wind Farm) may obtain approval to proceed within the next reporting cycle, the requirement to connect Mt Cass to the grid is not documented in this AMP.
- Small grid-connected distributed generation will increase throughout the planning period, impacting financial growth but not causing significant electricity distribution network constraints.
- Existing external regulatory and legislative requirements are assumed to remain unchanged throughout the planning period.
- All projections of expenditure are presented in constant terms, as at 1 April 2022, without inflation.
- 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.
- MainPower's existing corporate vision and strategic objectives will continue for the planning period.
- Neither MainPower's electricity distribution network nor the local transmission grid will be exposed to a major natural disaster during the planning period.
- During the planning period, our electricity distribution network will be exposed only to climatic (temperature, wind, snow and rain) variation that is consistent with our experience since the year 2000.
- Seasonal load profiles will remain consistent with recent historical trends.
- Zoning for land use purposes will remain unchanged during the planning period.
- EV-charging loads will not significantly affect electricity distribution network constraints within the planning period.
- All financial budgets when compared with actual project costs will vary due to uncertainty in the supply chain, exchange rate fluctuations and inflation.

2.8.2 Sources of Information

The principal sources of information relevant to this AMP are as follows:

- 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 Statistics New Zealand and the Waimakariri, Hurunui and Kaikōura District Councils; and
- Interaction with consumers and the community in relation to possible future developments within the electricity distribution network region.

2.8.3 Forecasting Certainty

MainPower considers the following factors could lead to material differences in actual outcomes versus planned outcomes. However, 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.

Changes in demand factors can affect future development plans the most significantly. Growth that is higher than forecast brings forward the need for investment in additional capacity, security, reliability or increased load management, while growth that is lower than expected can sometimes allow development plans to be deferred.

Uncertainties within our demand assumptions include the following:

- The rate of growth in demand could significantly accelerate or decelerate within the planning period.
- Dry/wet years could affect irrigation demand.
- Significant land-zoning changes may be implemented within the region.
- Significant new loads may require supply.
- Large existing loads may reduce or cease demand.
- Consumers could change their requirements for reliability and/or their willingness to pay for higher/lower levels of service.

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. Changes may include the following:

- 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.
- Regulatory requirements could change, requiring MainPower to achieve different service standards, health and safety standards, or design or security standards.

We have assessed the level of certainty of forecasts relevant to different consumer groups within this AMP's planning period as shown in Table 2.4.

Timeframe	Location	Constraint	Proposed Remedy
Year 1	Reasonable certainty	Reasonable certainty	Reasonable certainty
Year 2–3	Some certainty	Reasonable certainty	Reasonable certainty
Year 4–6	Some certainty	Little if any certainty	Some certainty
Year 7–10	Some certainty	Little if any certainty	None

Table 2.4: Planning Certainty

2.8.4 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), the NZD 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 given in Table 2.5.

Year	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Index	1.07	1.11	1.14	1.16	1.19	1.21	1.23	1.26	1.28	1.31

Table 2.5: Escalation Index Based on Westpac Economics Forecast Summary Spreadsheet 28 November 2022

2.9 Sources of Uncertainty

The following factors could lead to material differences in actual outcomes versus planned. However, as this AMP is updated annually, it is expected that any material differences would be anticipated in advance.

2.9.1 Demand Factors

Changes in demand factors most significantly impact future development plans. Growth that is higher than forecast can bring forward the need for investment in additional capacity, security or reliability, while growth that is lower than expected can sometimes allow development plans to be deferred. Uncertainties within our demand assumptions include the following:

- Within each region, load patterns could change, resulting in a movement from summer to winter peaks or vice versa.
- Significant land-zoning changes may be implemented within the region.
- Dry/wet years could affect irrigation demand.
- Significant new loads may require supply.
- Large existing loads may reduce or cease demand.
- Customers could change their requirements for reliability and/or their willingness to pay for higher/lower levels of service.
- Significant distributed generation, greater than 10% of its connected substation capacity, may be commissioned within the network supply area.

2.9.2 Operational Factors

Changes in operational factors may require us to reprioritise or reallocate our planned maintenance in the short term and increase or decrease maintenance or renewals allowances in the medium term. Changes may include the following:

- The network could experience major natural disasters such as an earthquake, flood, tsunami or extreme storm.
- Significant storm events could divert resources from scheduled maintenance.
- Regulatory requirements could change, requiring MainPower to achieve different service standards, health and safety standards, or design or security standards.
- Unforeseen equipment failure could require significant repair and possibly replacement expenditure.
- Asset management planning that is more detailed, undertaken over the next 3–5 years, could generate development and maintenance requirements that significantly differ from those currently provided for.

2.10 Systems and Information Management



The core of all MainPower's Asset Management is our CMMS. The CMMS adopted by MainPower is referred to as the "OneAsset" system. OneAsset is an enterprise resource planning (ERP) tool primarily designed to support financial reporting and operating assets management, through to works and human resources management.

2.10.1 Asset Lifecycle Management – Maintenance and Replacement

Preventative maintenance programmes are detailed in MainPower's Maintenance Standards. These are developed for all MainPower asset fleets. The 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) are collected when carrying out maintenance activities and inform asset health and replacement strategies. See Figure 2.14.

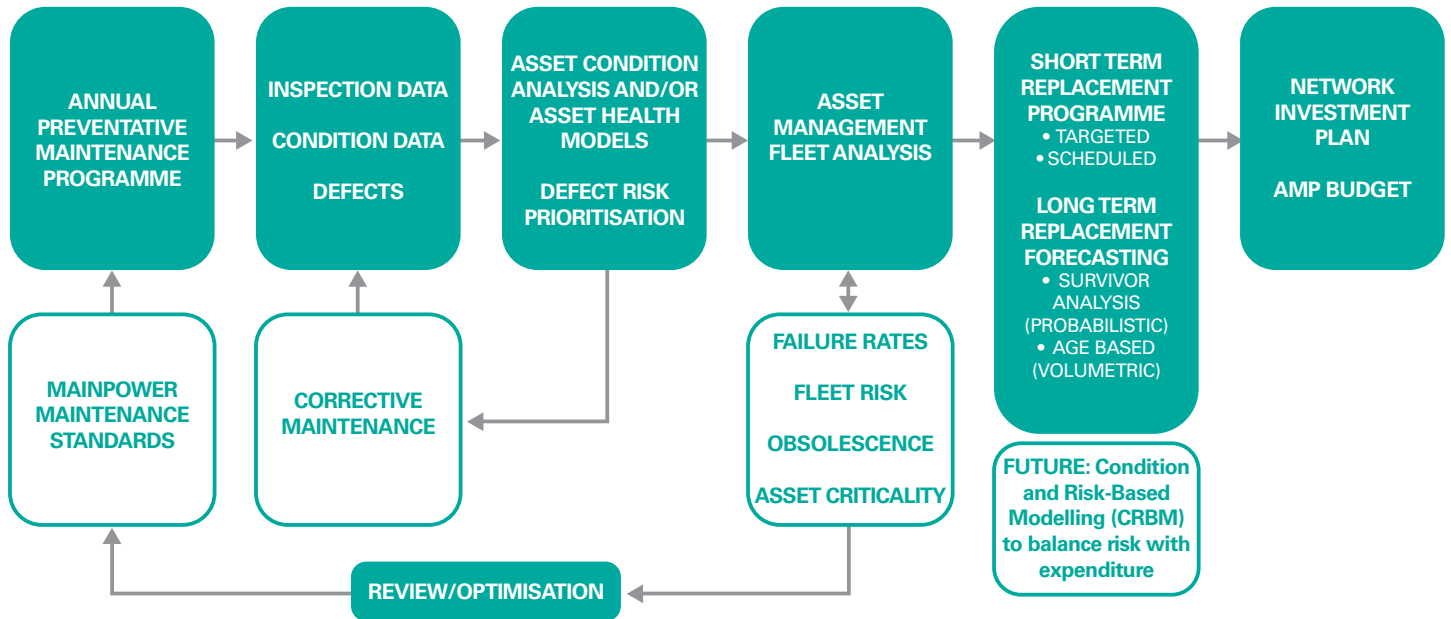


Figure 2.14: Asset Lifecycle Management

The asset data are 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.

2.10.2 Limitation of Asset Data and Improvements

MainPower holds good information on our assets. The focus in the future is to centralise all asset data, including vegetation, 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 will look to improve the quality and consistency of our data.

2.10.3 Electricity Distribution Network Planning

The planning for electricity distribution network growth is informed by load, connection growth, connection of new technologies and customer projects. This change in capacity requirement is assessed against existing capacity, security of supply standards and reliability. At this point a decision may be made to implement a tactical solution for increased capacity, such as reconductoring or voltage regulator deployment. Alternatively, a decision may be made to upgrade a GXP or zone substation, which is more expensive. The tactical upgrades are primarily used to defer capital expenditure that is more expensive. All capacity upgrades are referred to a capital-sanctioning process.

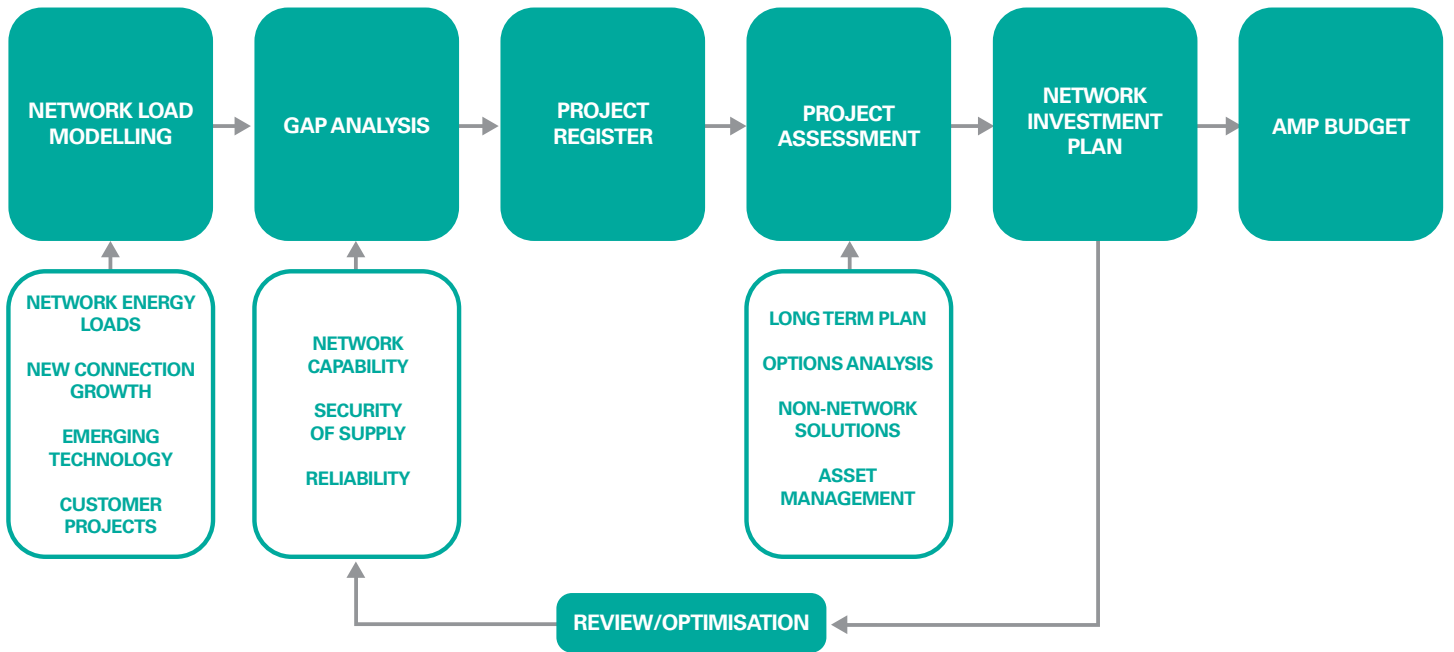
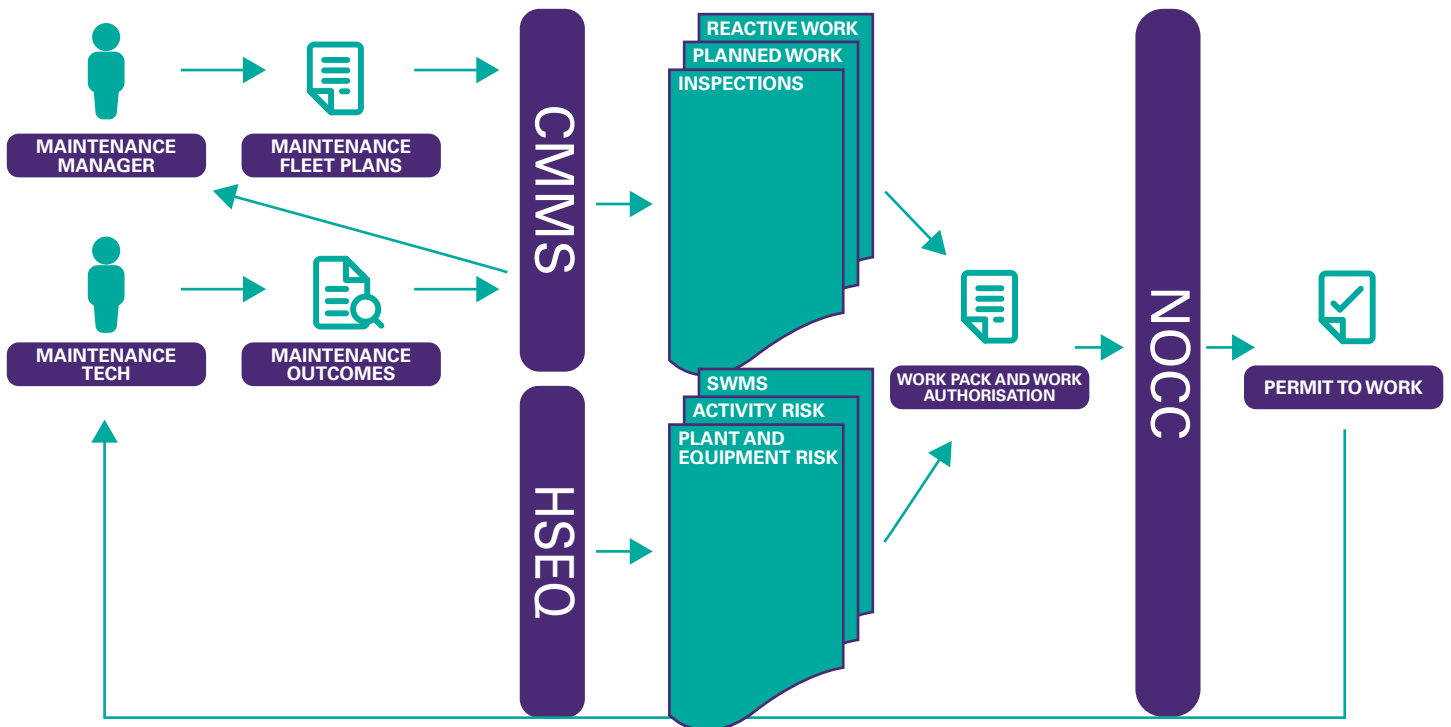


Figure 2.15: Electricity Distribution Network Development

2.10.4 Maintenance Processes

The requirement to deliver maintenance on our assets is defined in MainPower’s Asset Maintenance Standards. The standards are then implemented within MainPower’s CMMS ERP system. A summary of the maintenance workflow is detailed in Figure 2.16, including the need to work within a controlled working environment, the issuing of authorisation, and the receiving of asset condition data that are used to manage defects, inform renewals and so on.



Note. CMMS = computerised maintenance management system; HSEQ = health, safety, environment and quality; NOCC = Network Operations & Control Centre; SWMS = safe work method statement

Figure 2.16: Asset Management Workflow Process

2.10.5 Measuring Electricity Distribution Network Performance



MainPower maintains an ISO 90001-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 90001 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 CMMS against the applicable asset. Costs associated with the maintenance are linked back to the asset via the work order.

2.11 Communication and Participation

MainPower communicates its asset management strategy, objectives and outcomes to stakeholders as outlined in Table 2.6.

Reporting From/To	Reporting Type
MainPower Trust to consumers and the wider community	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • 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
General Manager Network Planning & Strategy to Chief Executive and MainPower Board	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • Weekly direct reporting from team meetings • One-on-one discussion with direct managers • Daily updates during brief meetings, including health and safety updates • Monthly management accounting reports
Field Services Supervisors	<ul style="list-style-type: none"> • Weekly progress reports • Monthly meetings on progress to budget
External contractor to General Manager Field Services	<ul style="list-style-type: none"> • Weekly progress reports • Monthly meetings on progress

Table 2.6: Reporting Asset Management Plans and Outcomes

3. SERVICE LEVELS AND PERFORMANCE EVALUATION

MainPower’s electricity distribution network and business service levels are an integral part of the decision-making processes throughout the organisation. We are committed to listening to our consumers and stakeholders and better understanding their needs. This allows us to monitor and improve the services we provide continuously, throughout our region, now and into the future. We use a range of engagement methods to find out what consumers 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 consumers, 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 40,000 homes and businesses across the Waimakariri, Hurunui and Kaikōura regions in the South Island of New Zealand. Types of consumers include residential, small to medium businesses, large and industrial businesses, rural (farming and irrigators) and individually managed consumers (see Table 3.1). Partners include retailers as well as distributed generation owners and operators.

Understanding consumer expectations, monitoring and improving the service MainPower provides are all vital if we are to establish and maintain trust and goodwill with our consumers and stakeholders throughout the region. We do this by actively consulting with our consumers. 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	34,950	81.03%	294	47%
Commercial	6,364	14.76%	127	20%
Large commercial or industrial	45	0.10%	57	9%
Irrigators	1,451	3.36%	69	11%
Council pumps	207	0.48%	13	2%
Streetlights	113	0.26%	3	1%
Individually managed consumer	1	0.0%	60	10%
Total	43,131	100.0%	623	100%

Note. ICPs = installation control points; GWh = gigawatt-hours

Table 3.1: Electricity Consumption and Consumers, by Consumer Category

3.1.1 Customer Engagement Programme

Every second year we hold workshops with consumers across our three main regions. Groups of around 20 consumers explore the price/quality trade-off topics inherent in our network investment decision-making framework, such as reliability, resilience and the future of energy and our electricity network. These workshops aim to enhance engagement with our consumers in relation to asset management. This engagement has provided considerable insights into how MainPower can balance the cost, risk and performance of its electricity distribution network. Given the challenges posed by COVID-19, we expect to complete the next round of engagement sessions in 2022.

3.1.2 Online Consumer Surveys

MainPower gathers feedback from a number of online surveys, including the annual Customer Pulse survey. This is designed to give us an understanding of how we are performing over time in a broad range of areas.

3.1.3 Customer Engagement Programme



MainPower Customer Engagement Programme		
Engagement Type	Frequency	Purpose
Service Monitoring Survey	Monthly	To gather feedback from customers who have interacted with MainPower in the previous month. Allows the opportunity to follow up customer feedback sooner and mitigate potential complaints.
Asset Management Plan Service Experience Survey	Annual	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. The areas measured are as follows. <ul style="list-style-type: none"> 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	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.
Asset Management Plan Customer Engagement Sessions – World Café style	Every two years (alternates with AMP Future Networks Survey)	To gather qualitative feedback from residential, rural and commercial/business customers in each main region (Waimakariri, Hurunui and Kaikōura). Covers reliability, future technology, resilience and safety, with the opportunity to include other topical subjects e.g. pricing, sustainability.
Asset Management Plan Engagement Survey	Every two years (alternates with AMP Future Networks Survey)	To gather quantitative feedback from residential, rural and commercial/business customers in each main region (Waimakariri, Hurunui and Kaikōura). Covers reliability, future technology, resilience and safety, with the opportunity to include other topical subjects e.g. pricing.
Asset Management Plan Future Networks Survey	Every two years (alternates with AMP Engagement Survey)	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 Consumers Have Told Us

According to the feedback from the FY22 surveys, MainPower customers have high satisfaction levels overall, in line with the results of previous years.

- More than 50% consistently rated MainPower’s performance and services at 9 or 10 (out of 10).
- More than 90% consistently rated their electricity supply as “reliable” or “very reliable”.

As 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 stable nature of MainPower’s high scores is a sign of success.

3.2.1 Consumers – Performance and Service

While our consumers have remained highly satisfied with MainPower’s performance and service, with no statistically significant changes in satisfaction levels since 2017 (see Figure 3.1), in the Customer Pulse Survey FY22, the “net positive score” dipped below 40 for the first time, probably reflecting the nationwide trend noted above.

MAINPOWER’S PERFORMANCE AND SERVICE

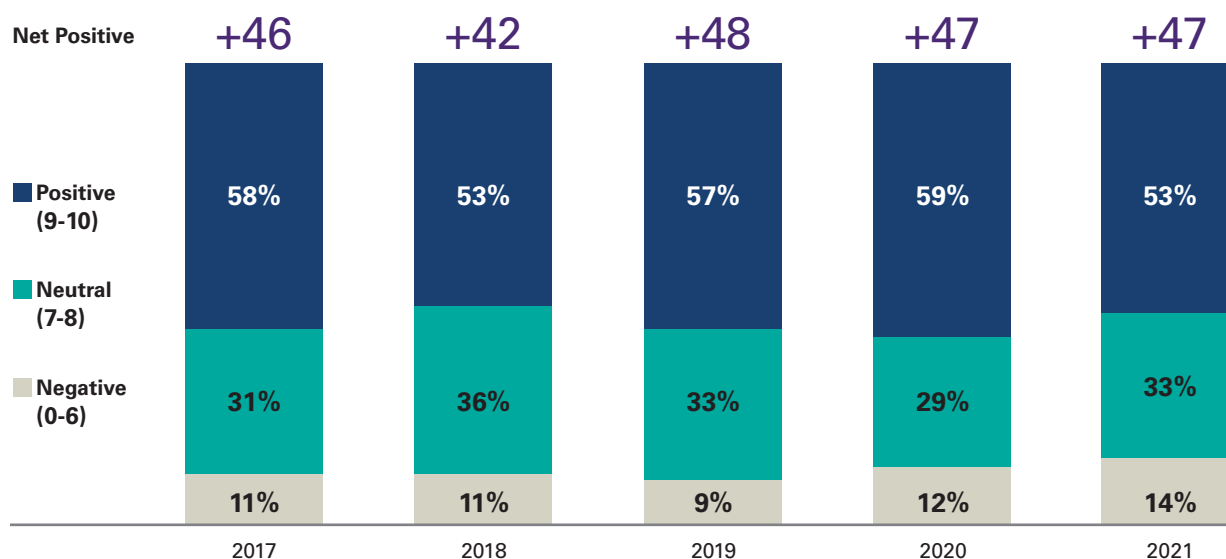


Figure 3.1: MainPower Consumers’ Perceptions of Our Performance and Service (Source: MainPower’s Customer Pulse Surveys FY18–FY22)

3.2.2 Consumers – Reliability

Reliability is usually an important factor in customers’ satisfaction levels. While our customers’ perceptions of reliability have remained stable and high over time, these scores seem to be trending downwards (see Figure 3.2).

In the Customer Pulse Survey FY22, the ratings of reliability tended to differ between area and customer type. For example:

- customers in Waimakariri are significantly more likely to think their power is “very reliable”
- residential customers are significantly more likely to think their power is “very reliable”, while rural customers are more likely to suggest their power is only “reliable”.



PERCEIVED RELIABILITY

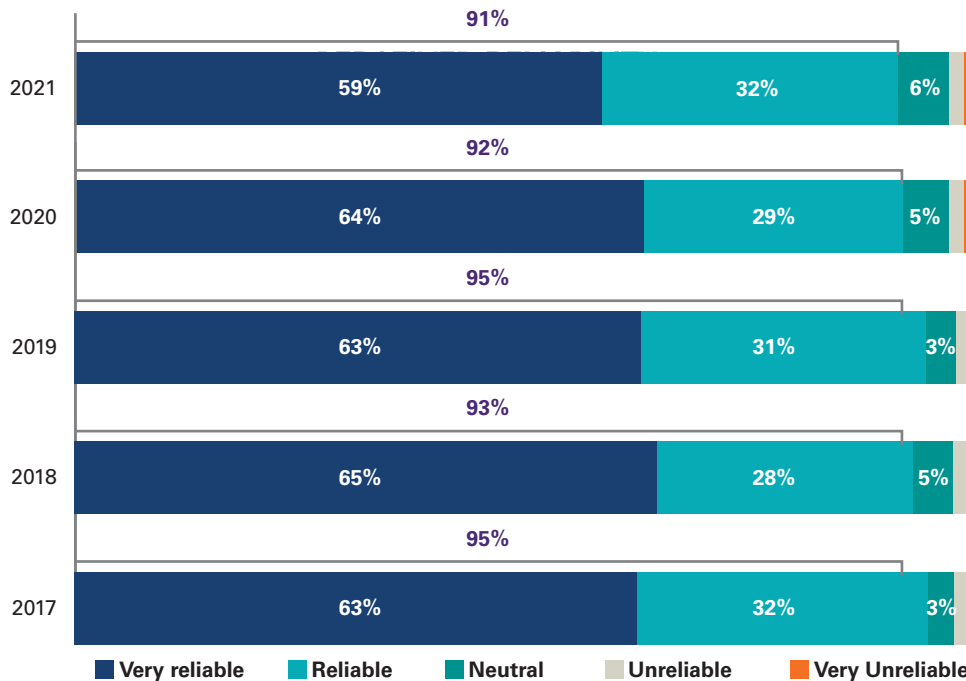


Figure 3.2: MainPower Customers' Scores for Our Reliability (Source: Customer Pulse Survey FY22)

3.2.3 Consumers – Supply Continuity, Quality, Restoration and Price

The Customer Pulse Survey FY22 showed that MainPower was delivering strongly in all important service areas except for price (see Figure 3.3).

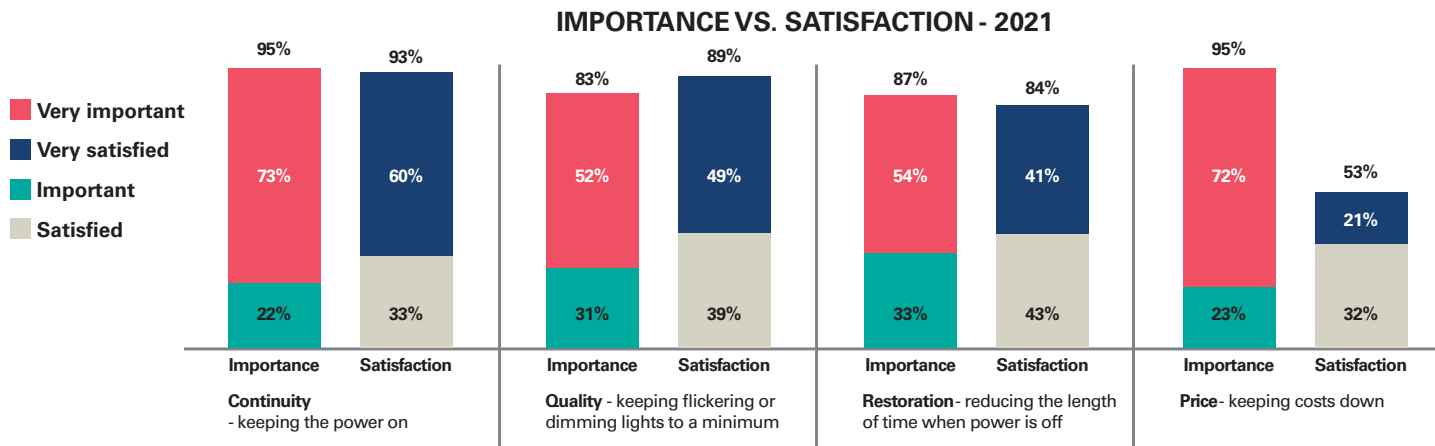


Figure 3.3: MainPower Customers' Scores Regarding Importance and Satisfaction across Service Areas (Source: Customer Pulse Survey FY22)

3.2.4 Consumers – Safety Messaging Recall

Customers' recall of safety messages remained high in the Customer Pulse Survey FY22 (see Figure 3.4), with some differences according to customer type.

- Rural customers were significantly more likely than residential and commercial customers to recall safety messages about keeping trees well clear of power lines (91%).
- Commercial customers were significantly more likely to recall seeing messaging about "No power? Call us first" (42%).

Clearly, MainPower has continued to meet its responsibility to provide relevant safety messages through a range of traditional and digital channels.

MESSAGING RECALL

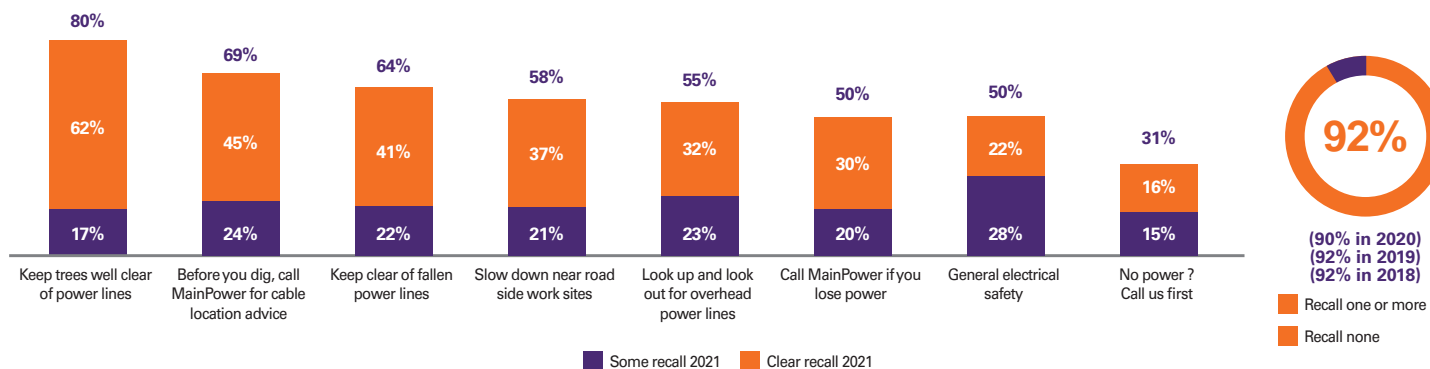


Figure 3.4: MainPower Customers' Recollection of Safety Messaging (Source: Customer Pulse Survey FY22)

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

3.3.1 Inputs

These are based on:

- the customer expectations revealed in the customer engagement surveys (discussed earlier in Section 3.2)
- analysis and industry benchmarking across our peer group (to be discussed in Section 3.6.7).



3.3.2 Planning

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

- Security of Supply Standard;
- Asset Portfolio Strategies, including asset health (CBRM) models;
- Project and Works Delivery Planning and Processes;
- Network Operating Standards;
- Network Architecture Standards; and
- Network Reliability Strategy.

3.3.3 Works Programme

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

- Asset replacement/renewals;
- Reliability and security of supply-focused network reinforcement and major capital projects;
- Refined and targeted network maintenance programme; and
- 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, 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 Performance Indicators

3.4.1 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 both our consumers' expectations and the regulatory requirements.

MainPower's key network reliability measures are applied as determined by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, and include the following:

- **SAIFI**, which measures the average number of supply interruptions for each consumer during the year; and
- **SAIDI**, which measures the average minutes that a consumer is without power during the year.

The above SAIDI and SAIFI measures include planned and unplanned interruptions on MainPower's sub-transmission and high-voltage networks with a duration longer than one minute. MainPower's consumers view network reliability as a top priority and are generally satisfied with their current level of reliability.

3.4.2 Network Restoration

When an unplanned network interruption occurs, we target commencing the restoration of supply within three hours, deploying our Network Operations and Field Services teams, who are available around the clock. Our Network Field Operators are based throughout the region, and we hold spares of strategic parts in our depots to reduce repair times.

3.4.3 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 recently invested in an 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 6.3 of this document) and enhanced remote sensing and switching capability throughout the network.

3.4.4 Health, Safety and the Environment

Our teams are committed to providing a safe network and healthy working environment across 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 practical steps to minimise risk and harm to the public, our people and our service providers, and we measure this using:

- Safety of employees and service providers; and
- Safety of the public.

Our objectives are to:

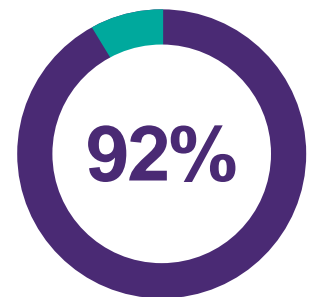
- Identify, manage and communicate risks associated with the workplace, the electricity distribution network and our business activities;
- To ensure compliance with legislative requirements and industry standards;
- To ensure that employees and field service providers have an appropriate level of training, skill and knowledge to carry out their work safely; and
- 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 focus of monitoring and reporting is to understand compliance risks. Additionally, as part of the requirements for certification to ISO 9001, ISO 14001 and AS/NZS 4801, 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 (SF6) 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 SF6 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.



**AWARENESS OF
SAFETY MESSAGING**

(90% in 2020)

(92% in 2019)

(92% in 2018)

3.4.5 Physical and Financial



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 AMMAT);
- Financial performance; and
- Industry benchmarking.



Service Measures and Targets														
Service Class	Performance Indicator	Performance Measure	Past Performance Targets		Future Performance Targets									
			FY21	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Reliability	SAIDI – System Average Interruption Duration Index	Average minutes of supply lost per customer per year	323	280	272	263	255	248	241	235	229	224	220	216
	SAIFI – System Average Interruption Frequency Index	Average number of times a customer's supply is interrupted per annum	2.23	2.04	1.98	1.91	1.86	1.81	1.76	1.71	1.67	1.63	1.60	1.57
	Feed 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%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Health, Safety, Environment and Quality	Safety of workers	No injuries related to a safety critical risk	None											
	Safety of public	No injuries to members of the public	None											
	SF6 gas lost	Gas lost as % of total gas volume	< 1%											
	Oil spills	Uncontained oil spills	None											
Consumer Oriented	Engagement effort	Customer Pulse Survey Score, from 1 (very dissatisfied)–5 (very satisfied)	> 2.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	
	Staff friendliness		> 4	> 4	> 4	> 4	> 4	> 4	> 4	> 4	> 4	> 4	> 4	
	Quality of work		> 4	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	
	Timeliness of service		> 3.5	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	
	Communication		> 3.5	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	
	Staff reliability		> 4	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	> 3.8	
	Final price		> 4	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	> 3.5	
Service Measures and Targets														
Service Class	Performance Indicator	Performance Measure	Past Performance Targets		Future Performance Targets									
			FY21	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Physical and Financial	Maintenance delivery	Maintenance programme delivery by budget	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	
	Capital delivery	Capital programme delivered by budget	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	
	AMMAT	Complete workstreams noted in AMMAT	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	> 90%	
	Industry benchmarking	Assess ourselves against: <ul style="list-style-type: none"> operating expenditure per ICP capital expenditure per ICP quality of supply (SAIDI and SAIFI) non-network operating 	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	< 75th percentile	

Table 3.3: MainPower's Performance Indicators and Targets

3.6 Performance Evaluation



3.6.1 Network Reliability

Our network reliability is measured using SAIDI and SAIFI indices averaged across the entire network (see Figure 3.6). This provides us with the outage duration (time) and the number of outages that the “average” customer experiences. We analyse our network’s quality of supply by causes, asset categories and feeder reliability, which helps to inform forward network-related projects and internal workstream improvements.

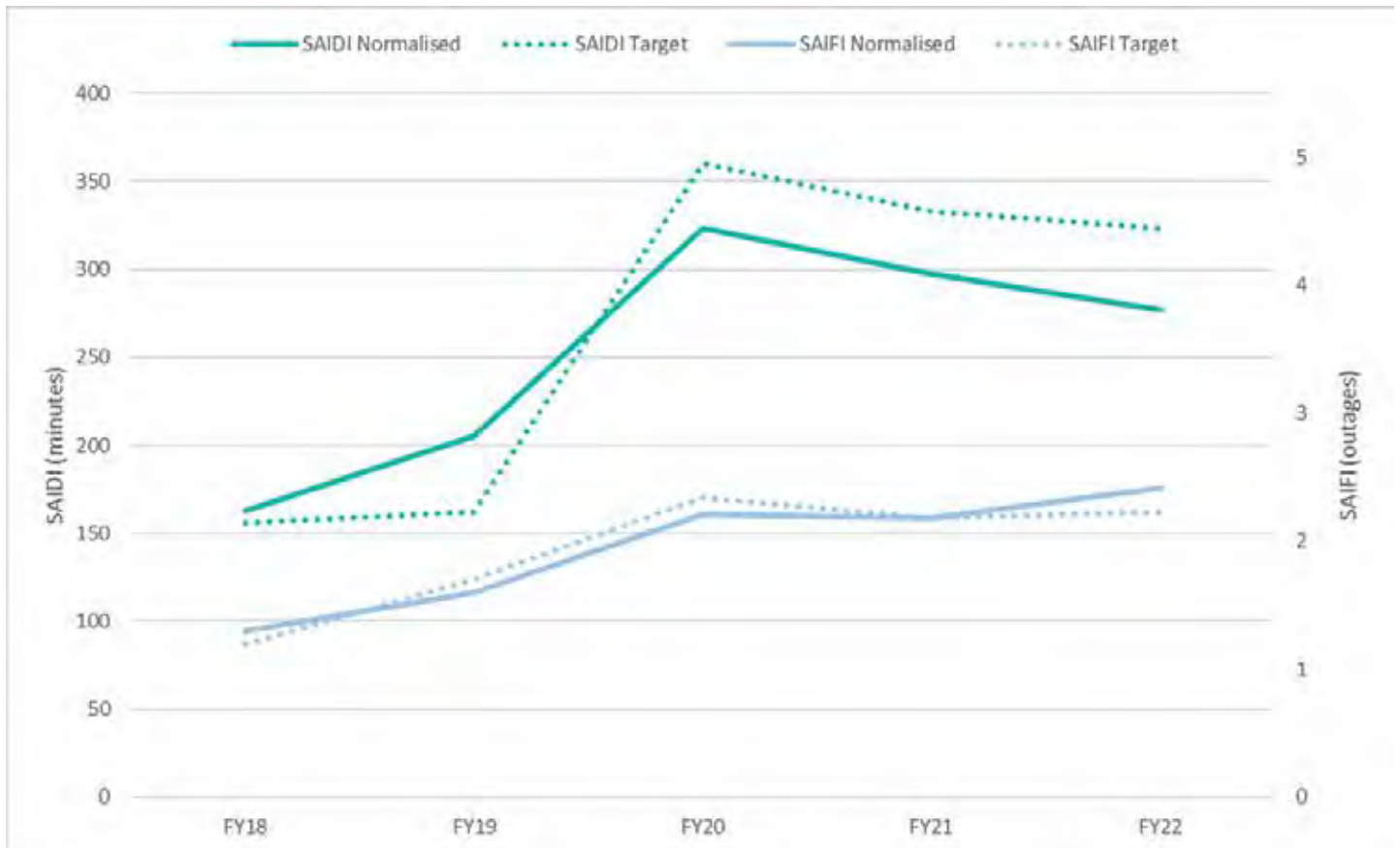


Figure 3.6: MainPower’s Network Reliability SAIDI and SAIFI over 5 years (FY18 – FY22)

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 step change in MainPower’s network performance that has resulted in the occurrence of more outages, and with longer duration, than might have been expected from historical performance. To understand this trend, it is helpful to break down reliability into planned and unplanned events (see Figure 3.7 and Figure 3.8).

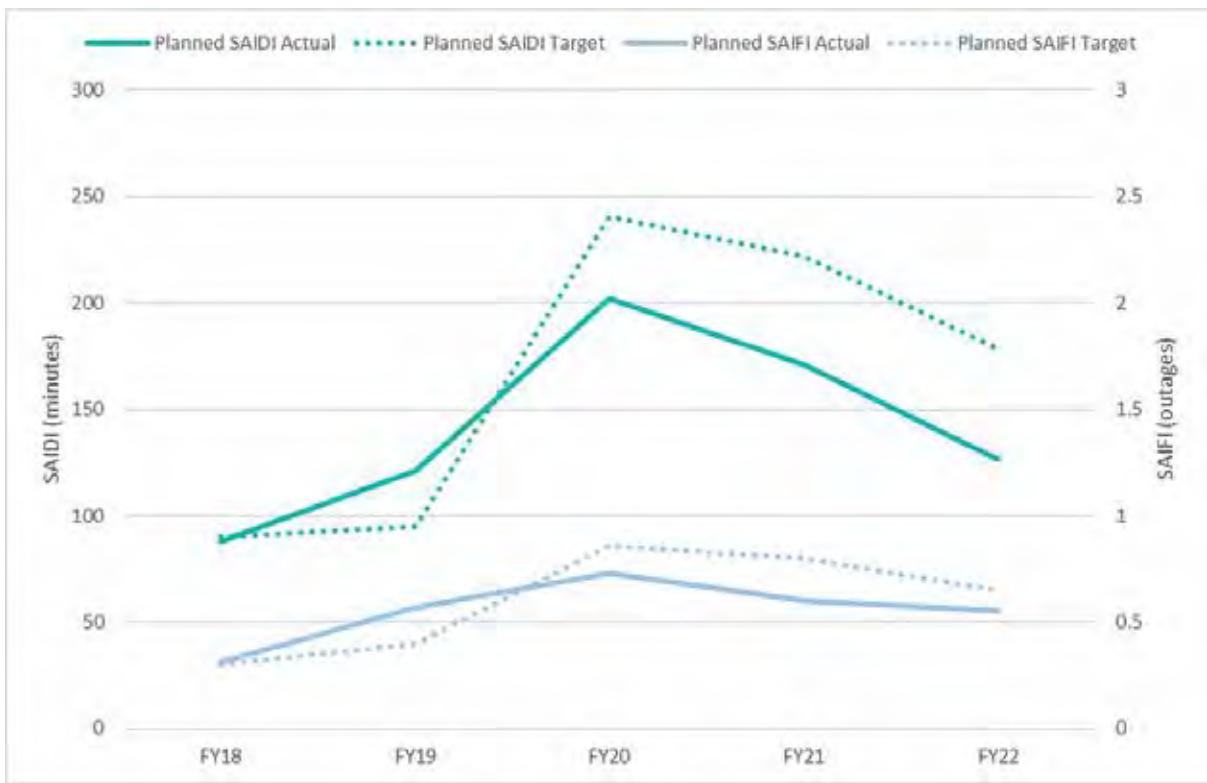


Figure 3.7: Network Reliability – Planned (FY18–FY22)

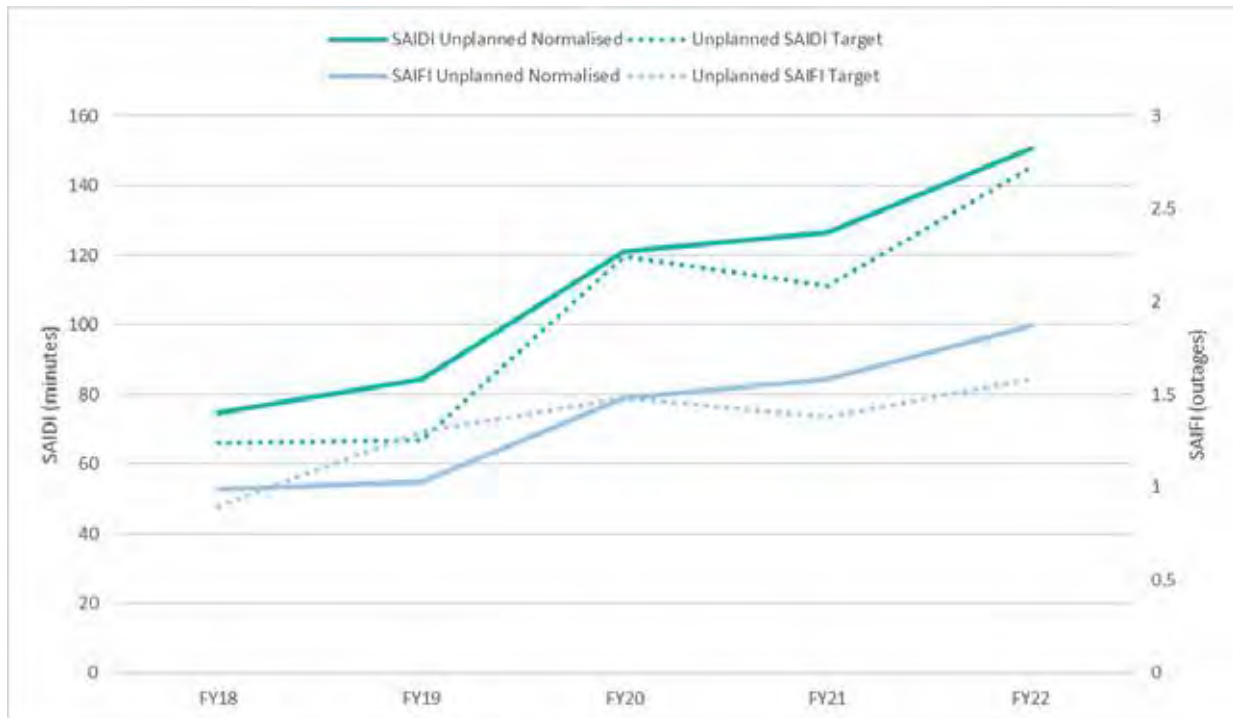


Figure 3.8: Network Reliability – Unplanned (FY18–FY22)

Figure 3.7 and Figure 3.8 show that in the last three years, planned outages had a declining influence on network performance compared to unplanned outages, particularly in relation to the duration of outages. This shift in 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 during the last three years. Forty-seven percent of MainPower’s 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 FY22 were related to adverse weather events, followed by equipment failure and “cause unknown” events. Unanticipated equipment or system failure events are fed into MainPower’s asset management programme and analysed for improvement(s) 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.

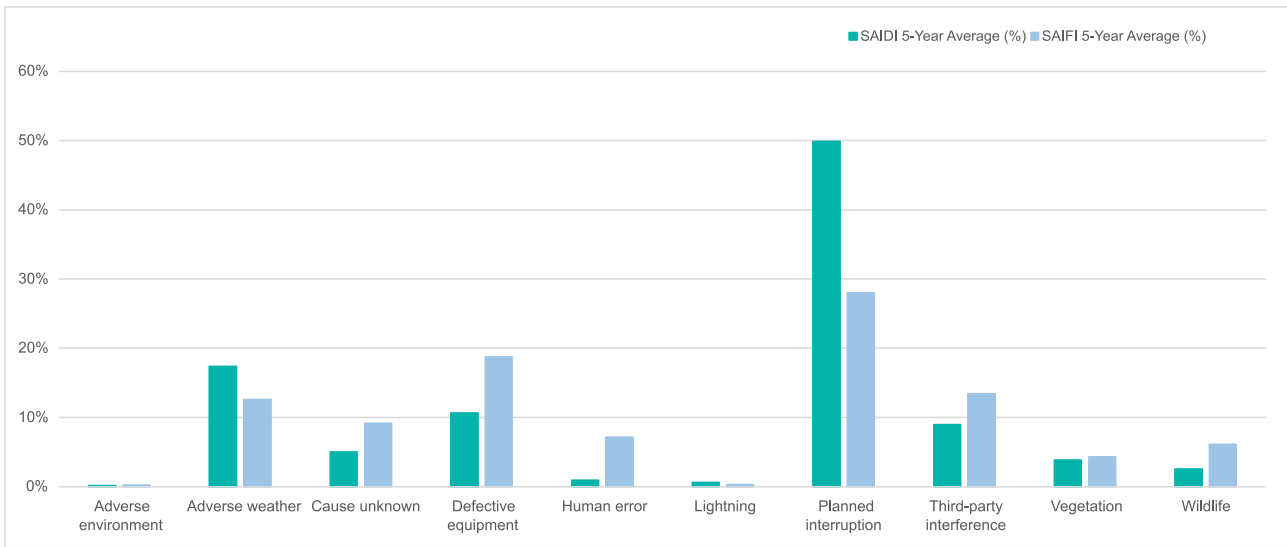


Figure 3.9: Network Reliability, by Cause (5-Year Rolling Average, FY18–FY22)

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 FY18 to FY22 are shown in Figure 3.10 and Figure 3.11.

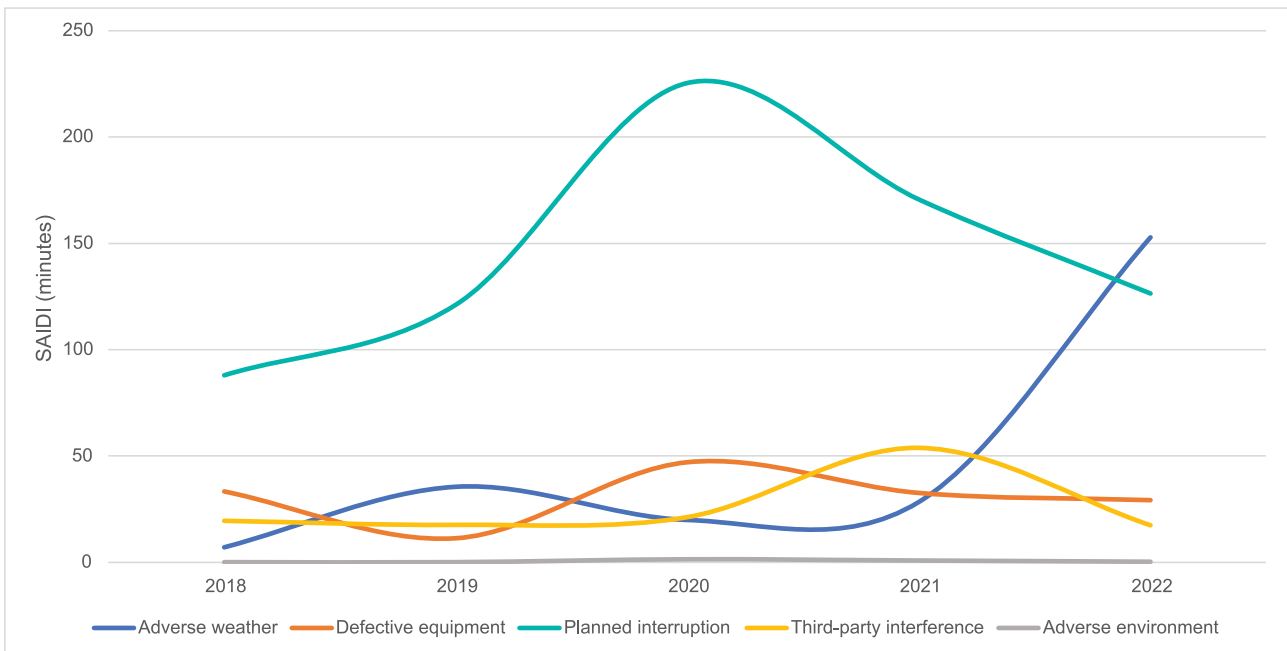


Figure 3.10: Network SAIDI, by Cause (FY18–FY22)

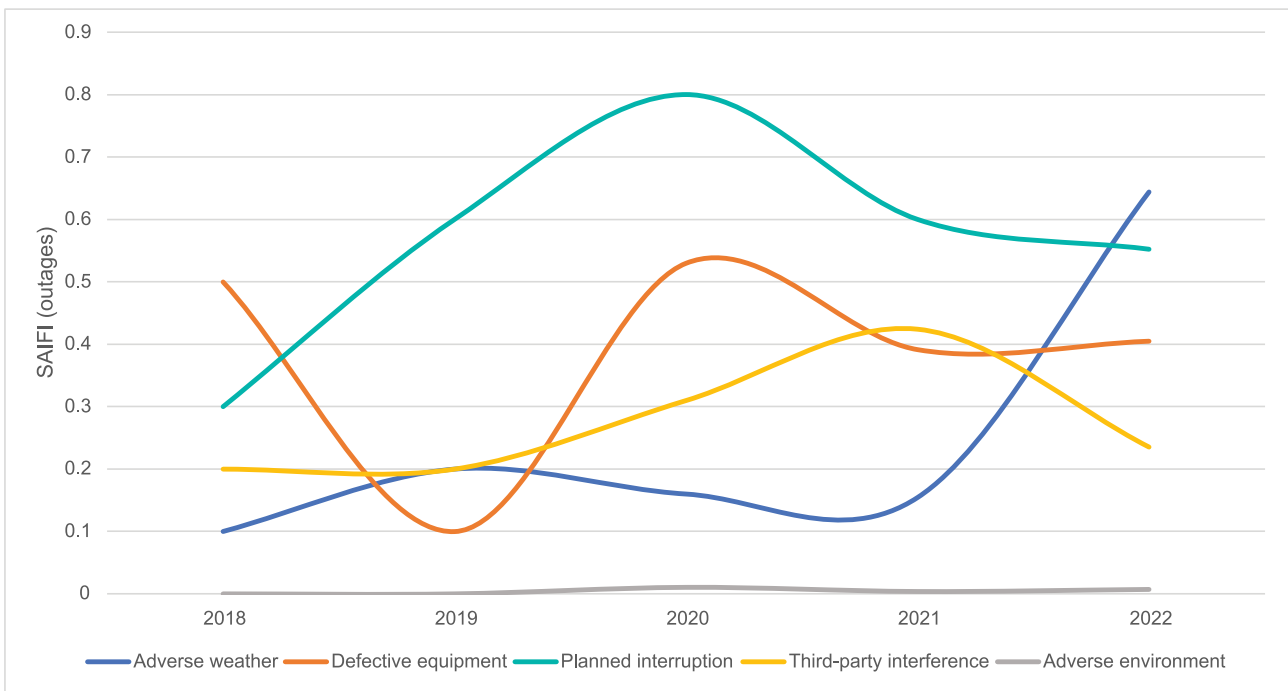


Figure 3.11: Network SAIFI, by Cause (FY18–FY22)

The “adverse weather” category was impacted by a single significant event in September 2022.

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. The below table identifies the top contributors to outage duration (SAIDI) and outage frequency (SAIFI) over the 5-year period FY18 to FY22, in order of contribution.

Outage Duration (SAIDI)	Outage Frequency (SAIFI)
Adverse weather	Defective equipment
Defective equipment	Third-party interference
Third-party interference	Adverse weather
Cause unknown	Human error
Vegetation	Cause unknown
Wildlife	Wildlife
Human error	Vegetation
Lightning	Lightning

Table 3.4: A High-Level Analysis of the Outages, by Cause

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.	Embedding and improving upon the functionality of the new ADMS system, improved service delivery through business realignment.	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.	FY24
Defective Equipment	Reviewing defective equipment by asset class yields that reliability is adversely affected by: <ol style="list-style-type: none"> 1. Switchgear; 2. Ring main units (RMUs); 3. Cable faults; and 4. Insulators. 	Work programme: <ol style="list-style-type: none"> 1. Completion of the Southbrook Zone Substation. 2. Upgrade programme for the Amberley, Hanmer and Hawarden zone substations. 3. RMU replacement programme. 4. Insulator and crossarm inspection programme. 5. LiDAR¹ aerial inspection pole maintenance programme 6. Line tightening programme. 	<ul style="list-style-type: none"> • Southbrook Zone Substation complete. • RMU replacement programme proceeding well and over 50% complete. • Insulator and crossarm inspection programme budgeted in FY23–FY24. • Aerial inspection programme budgeted for commencement in FY23. • CBRM models to be introduced FY23–FY24 	FY24–FY25
Adverse Weather	Adverse weather events are relatively infrequent, but 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.	FY23–FY25
Third-Party Interference	MainPower has a public advertising campaign to communicate the need to watch out for overhead lines. We also issue “High LoadTable 3.5: Network Reliability Improvement Summary” 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”	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.	FY24

¹ 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 3.5: Network Reliability Improvement Summary

3.6.2 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. The graphs in Figure 3.12 and Figure 3.13 show that in the years FY18–FY22, the impact on reliability from the top five-worst-performing feeders had started to decrease (see details in Table 3.6).

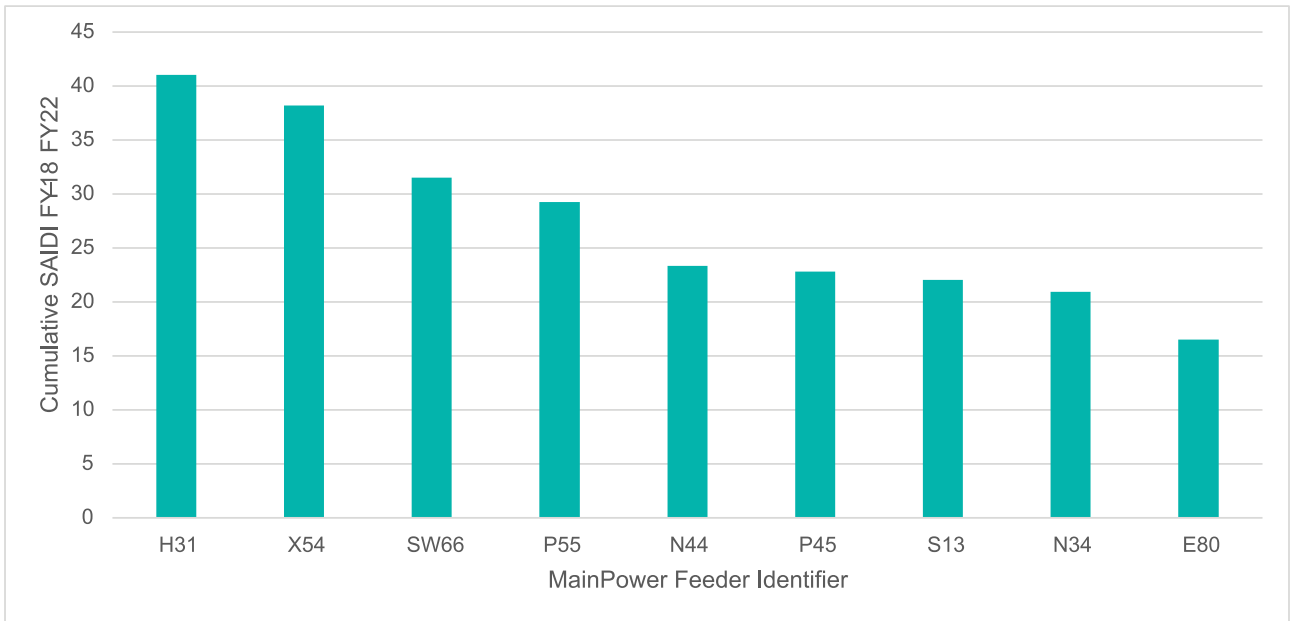


Figure 3.12: Top 10 Feeders with Highest Cumulative Unplanned SAIDI (FY18–FY22 Average)



Figure 3.13: Top 10 Feeders with Highest Cumulative Unplanned SAIFI (FY18–FY22 Average)

Feeder	Analysis	Initiatives	Target Date
S13 West	This feeder supplies southern Rangiora and Waikuku township from our Southbrook Zone Substation. Investigation into the feeder found it has urban and commercial loads that are being affected by interruptions mainly caused on the large overhead rural sections of the feeder. These interruptions mainly consist of third-party interference (vehicle contact with assets) and defective equipment, resulting in a large outage area because of the size of the feeder with minimal downstream protection and isolation.	The undergrounding of part of this feeder, performing switching alterations to the feeder configuration to minimise single-interruption impact, and replacing the feeder protection equipment as part of our Southbrook Zone Substation rebuild. This was completed under the Southbrook 66 kV Substation Upgrade Major Project. Increasing the number of feeders out of this substation, and the areas they supply, will have a positive impact on reliability through lower affected customer numbers for any given fault.	FY23
H31	This feeder supplies the Hawarden township and the large rural area west of the township. The feeder is entirely rural overhead in construction. Investigations into the large SAIDI contribution found a large proportion of outages related to a windstorm in September 2022. The impact of this event was considerable across the network, especially in rural areas.	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
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. The September windstorm heavily impacted this feeder, along with a few incidents at the start of the feeder (including flooding and vehicle accidents) that impacted many customers.	Several projects in the 10-year plan will assist with alternative supplies for this feeder. They include feeder ties to other feeders supplied out of Swannanoa Zone Substation and Ashley GXP. It is expected these will minimise the impact of severe weather events on this part of the rural network.	FY26
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.	A project is underway to install an intermediate circuit breaker and reconfigure the 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 the new configuration.	FY23 – Complete
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.	Projects are currently in place to limit the number of customers impacted by events on the feeder. The separation of the feeder into smaller outage areas will also assist with identifying areas of concern and gathering information to identify root causes. As noted above, we aim to improve and better target our vegetation management programme to prevent vegetation-related interruptions.	FY23

Table 3.6: Network Feeder Reliability Improvement Summary

3.6.3 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.

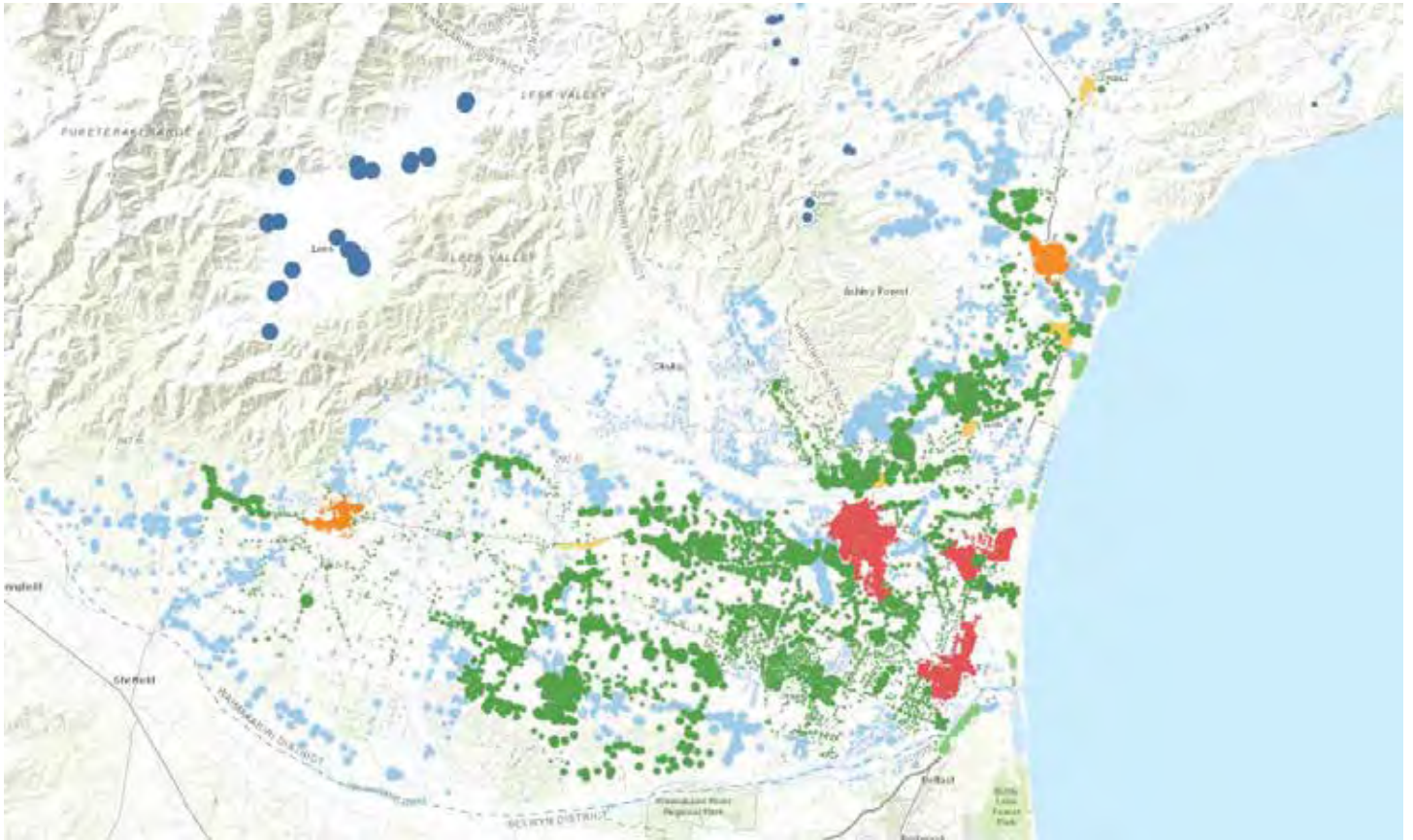


Figure 3.14: MainPower's Reliability Analysis Model

In Figure 3.14 above, 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.

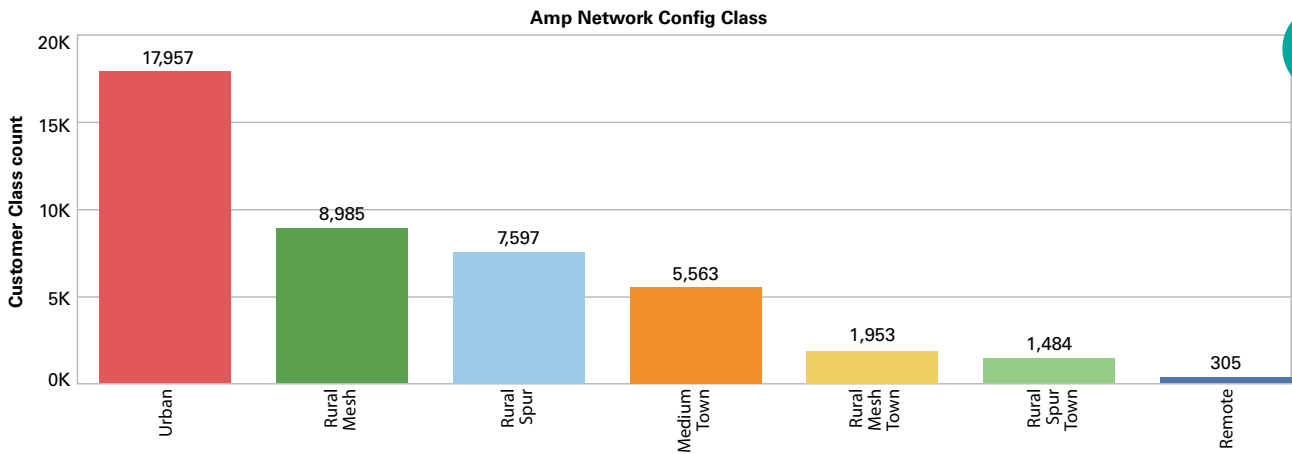


Figure 3.15: MainPower's Connected Consumers by Classification Group

One 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 consumers 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 consumers groups is shown Figure 3.16. It should be noted that these figures are non-normalised and heavily impacted by large events, especially the remote consumers. With so few consumers in this group, a high result for a small number of consumers significantly lifts the average value.

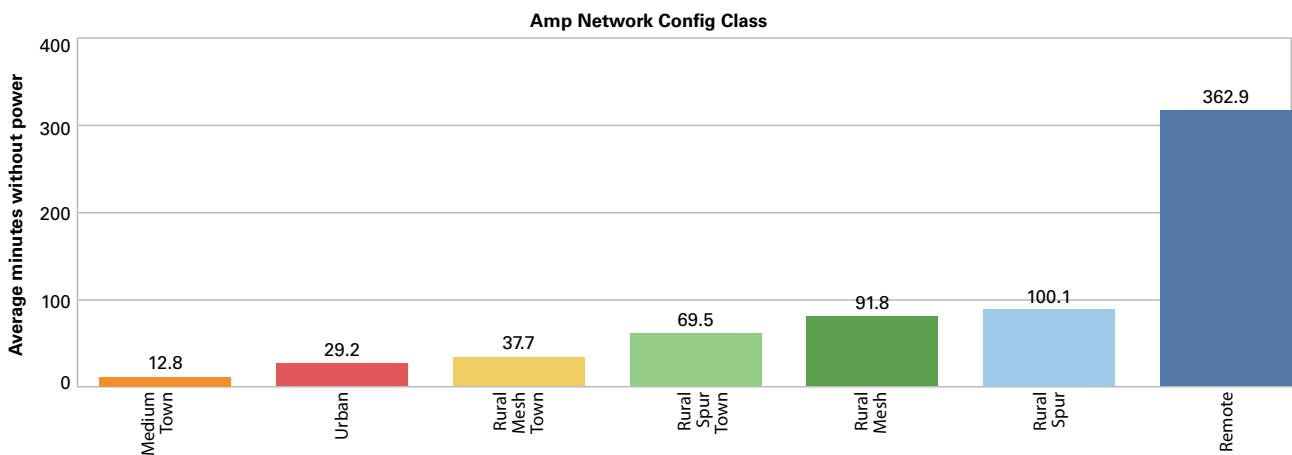


Figure 3.16: Average Time Spent Without Power for Each Classification Group

The appearance of this graph is an approximate inverse of the previous connected consumers graph. 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. Figure 3.17 shows an example of the information display and the process.

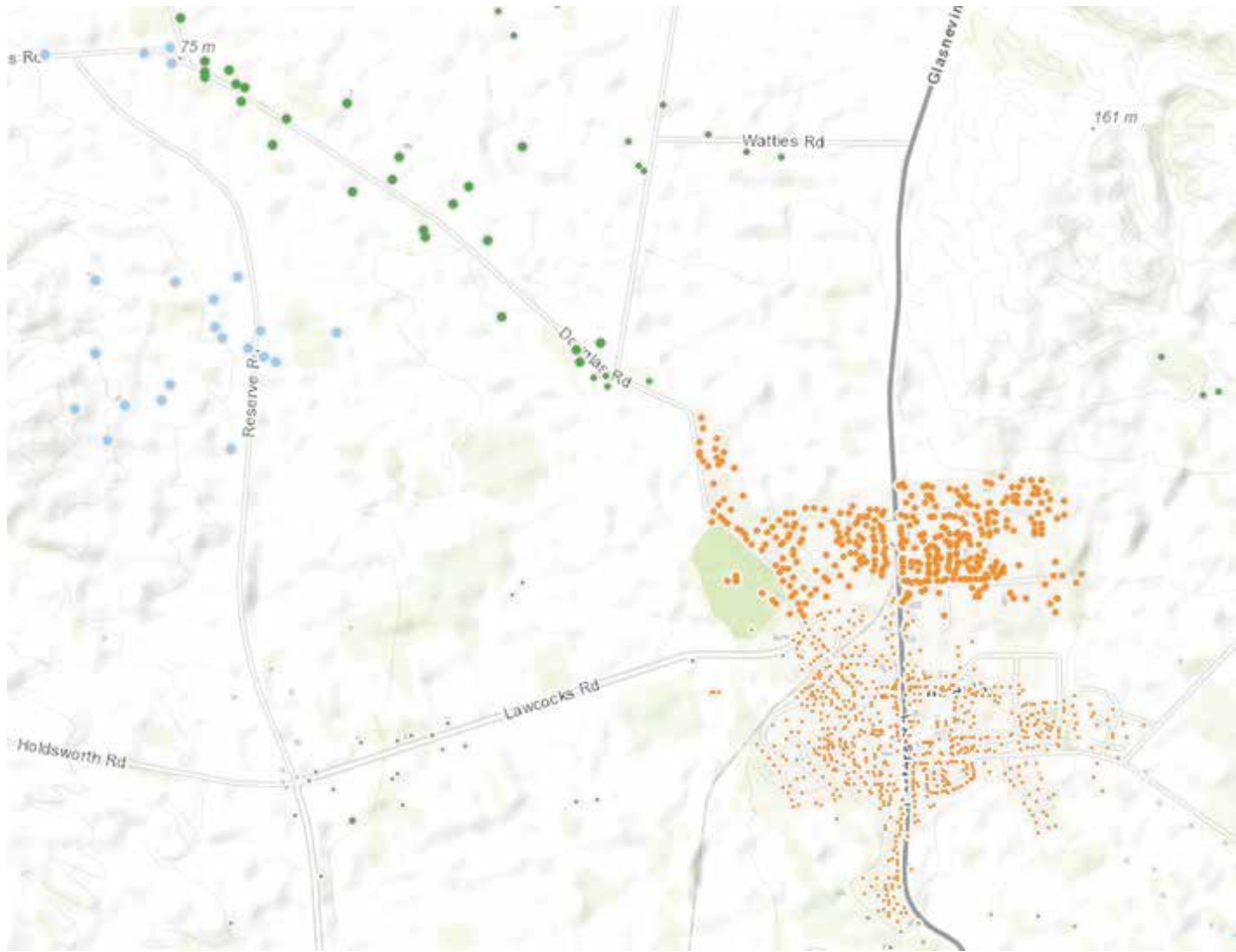


Figure 3.17: Example of ICPs Coloured by Classification Group and Sized by the Total Length of Outages Experienced

The various colours in Figure 3.17 show the different classifications of each ICP. In this case, the Amberley township is orange, representing the “medium town” category, and the areas outside Amberley are blue or green, representing “rural spur” and “rural mesh”, respectively. The difference in performance between the northern part of Amberley and the southern part is obvious. This highlights an area of improvement for MainPower and indicates the importance of an alternative supply being made available to this part of the network. Additionally, the similar size of the dots in the rural areas and the town ICPs indicates that there may be some interaction whereby faults in rural parts of the network are resulting in outages for customers who are more urban. Again, this highlights an area that will benefit from further investigation and reinforcement. These issues have been resolved in this AMP work programme with identified projects resulting from these visualisations and analysis.

As shown above, taking a view of reliability that starts at the ICP and builds upwards to a system level, instead of looking back down from the system level, has significant benefits for the individual consumers and for MainPower’s business through more targeted capital expenditure and better reliability outcomes.

3.6.4 Health, Safety and the Environment

We report all employee injury and public safety events through our Vault safety information management system (see Table 3.7). 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	FY21 Target	FY21 Actual
No injuries related to a safety critical risk	0	0
No injuries to members of the public	0	0
SF6 loss (% to total gas volume)	< 1%	< 1%
Uncontained oil spills	0	0

3.6.5 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 the business' "Plan-Build-Operate" model (see Table 3.8 and Table 3.9).

Customer Satisfaction	FY22 Target	FY22 Actual
Engagement Effort	> 3.5	3.54
Staff Friendliness	> 4	4.3
Quality of Work	> 3.8	3.71
Timeliness of Service	> 3.8	3.81
Communication	> 3.8	3.68
Staff Reliability	> 3.8	3.92
Final Price	> 3.5	3.08

Table 3.8: AMP Customer Service Experience Survey (FY22)

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.	In 2021 MainPower moved to a "Plan-Build-Operate" model. This resulted in a number of changes to the teams delivering customer-initiated work. As these teams bed down their new structures and processes, we expect to see further improvement in engagement effort scores.	FY23
Timeliness of Service	The respondents of this survey are only those who have engaged with MainPower related to customer-initiated work. The results confirm the challenge faced when balancing work required to deliver the AMP alongside fluctuating customer-initiated works.	A business realignment was undertaken in FY21-FY22 to improve efficiency and communication internally between functions, to allow for improved responsiveness to customers. As these teams bed down their new structures and processes, we expect to see further improvement in timeliness and communication, particularly in relation to customer-initiated work.	FY22 – Complete
Communication	Communication in this instance is related to communication surrounding customer-initiated work. We recognise with the recent business realignment there have been communication challenges.	There are several initiatives to address this issue: <ul style="list-style-type: none"> • Process mapping all existing processes and procedures related to customer-initiated work and finding opportunities for improvement. • The Service Delivery Team is completing customer relationship management development to align the system to their new processes. • The Service Delivery Team has recently introduced service level agreements in regard to responding to customers. 	FY23

Category	Analysis	Initiatives	Target Date
Staff Reliability	Customers indicate that MainPower staff are responding to their needs more consistently compared to FY21.	We believe that setting expectations early with customers (e.g. SLAs introduced with the Service Delivery Team for customer-initiated work) and keeping them informed about progress relating to their jobs on a timely basis will further support perceptions of reliability.	FY23
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. The COVID-19 pandemic and other external factors, including the war between Russia and Ukraine, 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.	FY23

Table 3.9: Customer Rating of Our Performance Measures and Initiatives to Improve Them

3.6.6 Physical and Financial

3.6.6.1 Maintenance

MainPower has delivered on its safety critical maintenance throughout FY22. 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 (see Table 3.10).

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

Table 3.10: Maintenance Programme Summary

3.6.6.2 Capital Programme Delivery



Capital expenditure finished above target for FY22 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	Update
Major Projects	Ludstone Switchgear Replacement Project	Closed	N/A
	Hanmer Line Upgrade Project	Complete	FY26
	Cheviot to Oaro Sub-transmission Line Upgrade	In progress	FY23
	Southbrook Substation Capacity Upgrade	In progress	Southbrook substation complete. Phase II scheduled for completion in FY23.
	Amberley Zone Substation 33 kV Upgrade	In progress	Project in progress, with delivery across FY23–FY25.
Reinforcement Projects	Cheviot North Voltage Regulator and Capacitor Installation	In progress	N/A
	Cheviot South Voltage Regulator Installation	Complete	N/A
	Ashley Regulator and Capacity Installation	Complete	N/A
	Rangiora Northbrook Road Link	Complete	N/A
	WDC Blake Street	Complete	N/A
	X53–X56 Link Burnt Hill	Complete	N/A
	Rangiora East Belt North	Complete	N/A
	Amberley South de-loading	Complete	N/A
Renewals	Overhead, replaced 654 units	Complete	N/A
	RMU, replaced 17	Complete	N/A
	Low-voltage link box, replaced 80	Complete	N/A
	Low-voltage switchgear units, replaced 10	Complete	N/A

Table 3.11: Capital Programme Summary (FY22)

3.6.6.3 Financial Performance

Expenditure on Assets	Forecast (\$000)	Actual (\$000)	% variance
Consumer connection	5,000	9,257	85%
System growth	6,564	8,646	32%
Asset replacement and renewal	11,629	9,883	(15)%
Asset relocations	-	-	-
Reliability, safety and environment:			
Quality of supply	474	544	15%
Legislative and regulatory	-	67	-
Other reliability, safety and environment	250	207	(17)%
Total reliability, safety and environment	724	817	13%
Expenditure on network assets	23,917	28,603	20%
Expenditure on non-network assets	2,941	1,412	(52)%
Expenditure on assets	26,858	30,014	12%
Operational Expenditure			
Service interruptions and emergencies	1,100	1,479	34%
Vegetation management	1,000	752	(25)%
Routine and corrective maintenance and inspection	4,575	4,545	(1)%
Asset replacement and renewal	103	6	(94)%
Network opex	6,779	6,781	0%
System operations and network support	6,304	10,169	61%
Business support	7,354	4,430	(40)%
Non-network opex	13,658	14,599	7%
Operational expenditure	20,436	21,380	5%

Table 3.12: Financial Performance FY22

Category	Analysis
Customer	Contestable in nature and above target, due to greater than expected demand for new connections
Expenditure on Assets	Aligned with planned budget and planned units of replacement – system growth actual exceeded target following the delayed completion of the Southbrook substation upgrade. Asset replacement and renewal expenditure was below budget, impacted by works to support strong consumer growth
Operational Expenditure	Maintenance, both planned and reactive, was completed in the reporting year

Table 3.13: Financial Performance Analysis

3.6.7 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 the seven network businesses listed in Table 3.14 based on a ICP density (± 2.0).

Organisation	ICP/km	ICPs
Eastland Network	6.5	25,783
Network Waitaki	7.0	13,097
Buller Electricity	7.3	4,709
Marlborough Lines	7.7	33,700
Alpine Energy	7.8	26,426
Top Energy	8.0	32,877
MainPower NZ	8.2	42,117
Horizon Energy	9.8	25,416
Median	7.8	26,104

Table 3.14: Benchmark Organisations (Data from the Commerce Commission Electricity Distributors Information Disclosure Data)

3.6.7.1 Network Operating Expenditure

MainPower’s network operating expenditure, which includes planned and unplanned network maintenance and fault response, was lower than peer group average during the 2021 financial year (see Figure 3.18). This reflected MainPower reviewing the asset management practices that were detailed in the last AMP. Expenditure is expected to increase to above the peer group average as MainPower implements its revised asset management practices.

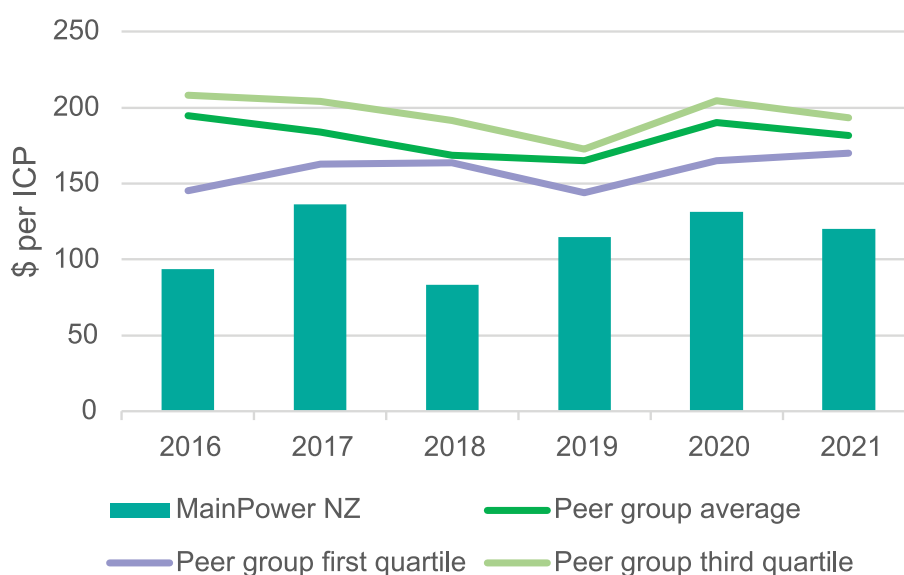


Figure 3.18: Benchmarking – Network Operating Expenditure Per ICP

3.6.7.2 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 3.19). This reflects MainPower's focus on improving asset management maturity and the development of robust and effective business processes.

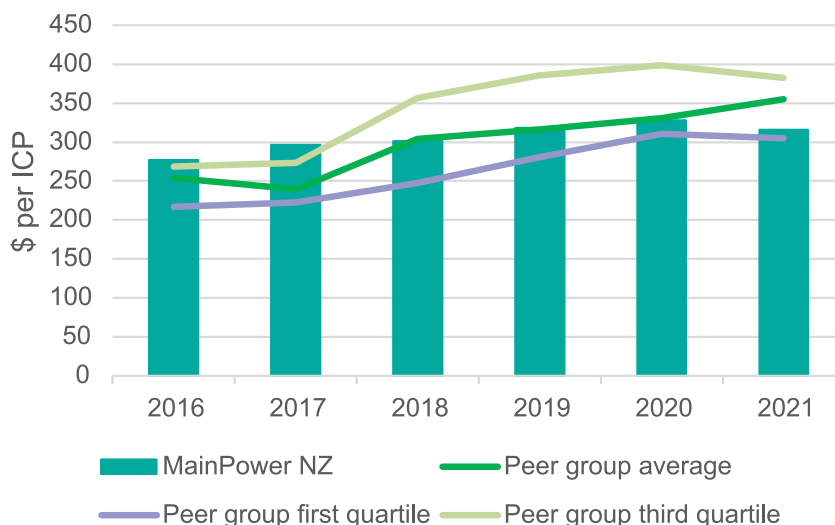


Figure 3.19: Benchmarking Non-Network Operating Expenditure Per ICP

3.6.7.3 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 for the period 2018 to 2019 was below its peer group first quartile and group average (see Figure 3.20) and has increased to match the peer group average. Going forward, this is expected to remain at sustained levels owing to works required to deliver security of supply, network reliability and an increase in MainPower's replacement and renewals programme.

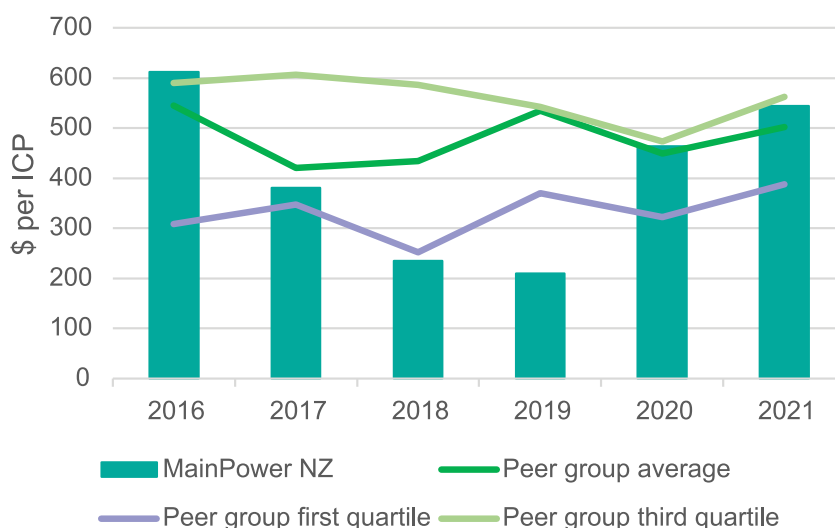


Figure 3.20: Benchmarking Network Capital Expenditure Per ICP

3.6.74 Reliability



Reliability for MainPower remains within the figures for our industry peers. However, forecast SAIDI and SAIFI means that we are trending towards the 75th percentile (see Figure 3.21 and Figure 3.22). Initiatives have been identified to address quality of supply for MainPower in the future and return it to within historical norms.

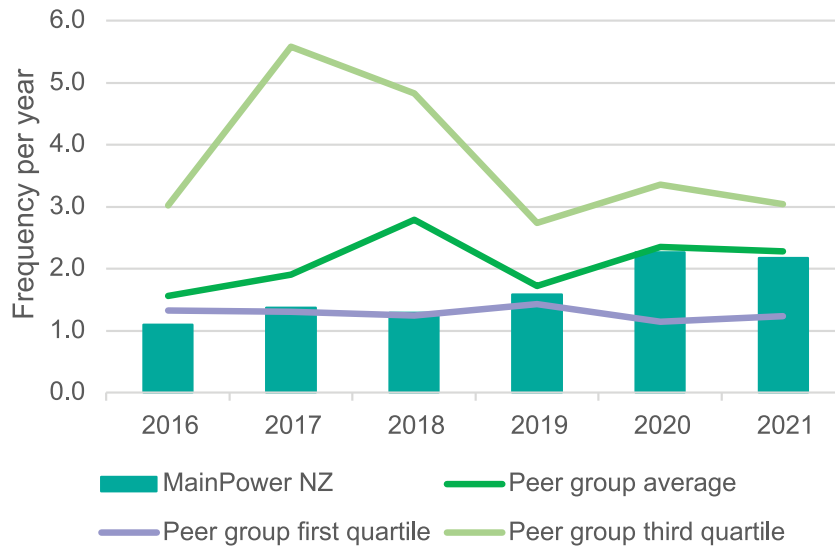


Figure 3.21: Normalised SAIFI Benchmarking

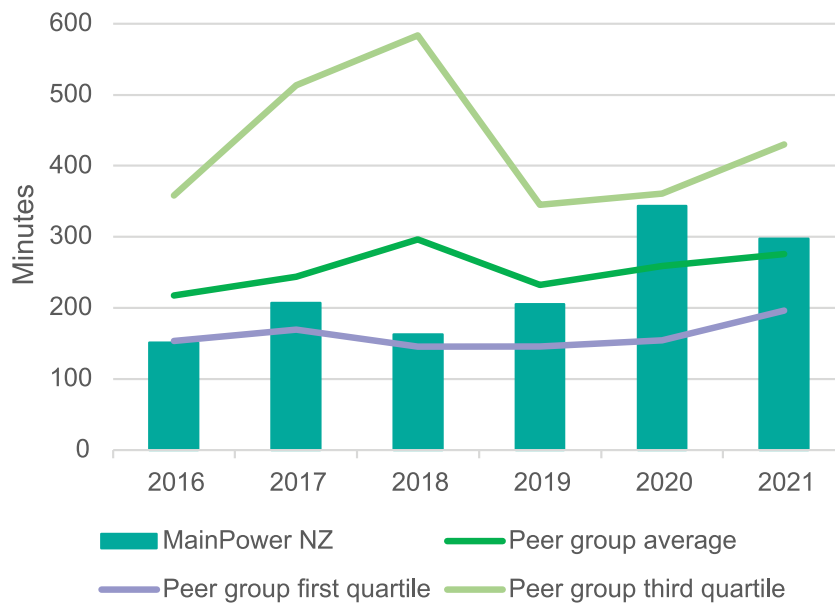


Figure 3.22: Normalised SAIDI Benchmarking

3.7 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

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 AS/NZS ISO 31000:2009 Risk Management – Principles and Guidelines (see Figure 4.1).

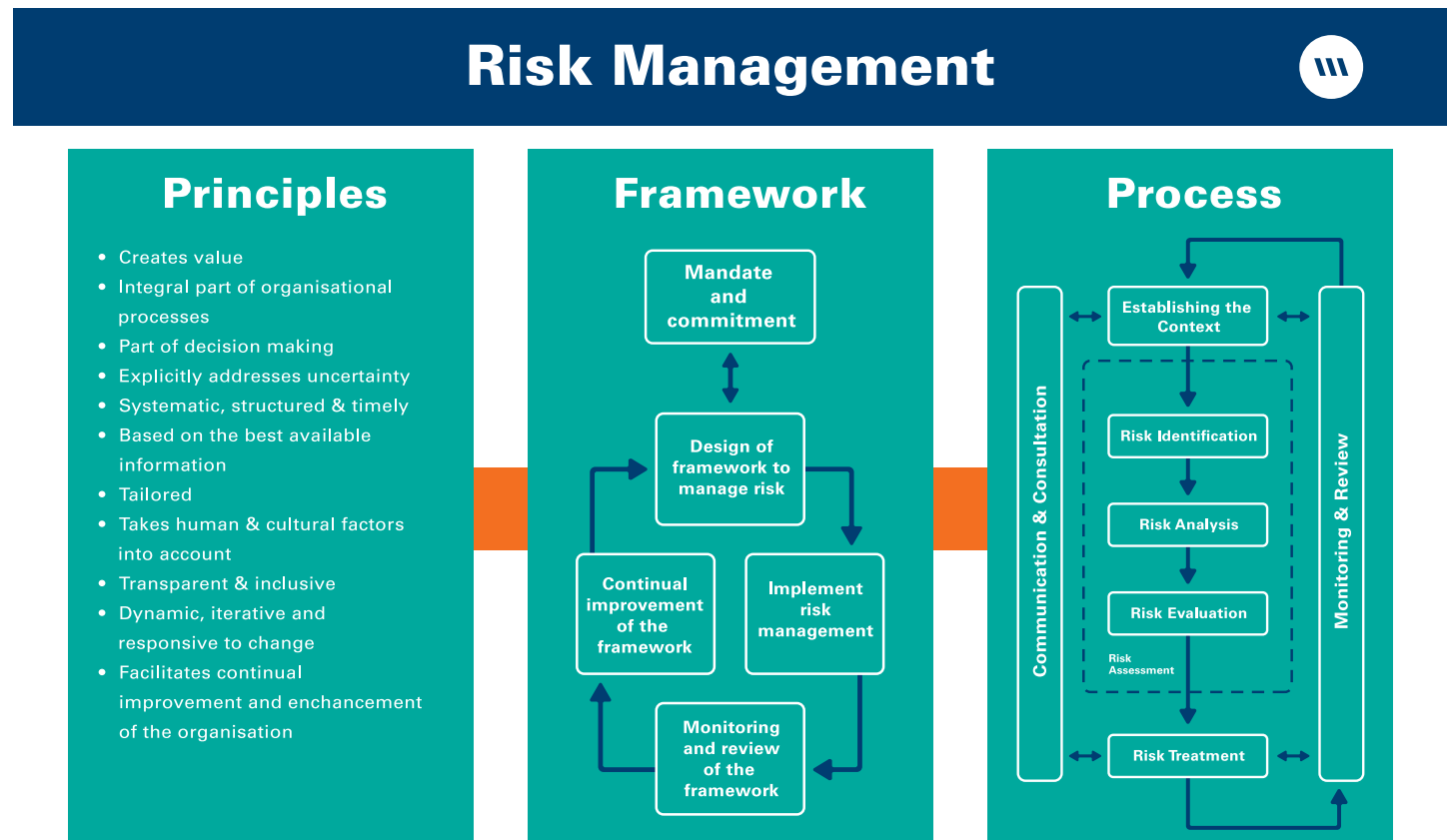


Figure 4.1: Risk Management Framework (drawn from ISO 31000:2018)

Asset risks are identified from asset management studies, risk registers, industry forums, incident analysis, audits, inspections, field observations, 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 they are willing to accept.

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.

4.1.1 Critical Risks



Critical risks are defined as anything that has the actual or potential ability to cause death to employees, contractors or members of the public; cause significant property damage; or cause MainPower to be severely affected as a business. MainPower has identified 10 safety critical risks and five business critical risks relevant to our business via a collaborative approach. 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

4.1.2 High-Impact, Low-Probability Events

MainPower has adopted several methods to ensure the risks to the network are managed effectively. MainPower uses the bow-tie risk methodology to analyse and demonstrate causal relationships in high-risk scenarios. In addition, assessments have been undertaken to identify those assets at threat from high-consequence events (high impact/low probability). High-impact, low-probability events are discussed in the following sections, namely:

- Natural disasters, where the extent of damage and the likelihood of occurrence can be estimated; and
- Climate change, the impact of which can be assessed, and which will manifest in the future.

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 Goals as a foundation, we have identified three key areas where we believe we can make the most difference. They are; prosperity, people, and planet. These strategic areas form the basis of our Sustainability Management Plan.

A selection of the sustainable initiatives MainPower is committed to:

- reducing waste
- reusable and refillable products
- rethinking how we do things (changing to more sustainable products)
- greener supply chain (through prequalification)
- enabling electrification (LV monitoring)
- supporting renewable energy (hydro, wind and solar)
- prioritising energy efficiency (installing 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;
- low carbon energy enabler to drive innovation, economic recovery, and positive image; and
- accelerating digitalisation opportunities in energy and the new challenges of resilience.



Figure 4.3: Environment and Sustainability

4.3 Network Risk Assessment



MainPower considers network risk within its asset management and network planning framework, including:

- High-Impact Low-Probability (HILP) events
- physical risk to GXPs, zone substations, transmission and distribution systems
- meteorological hazards – storms, floods, snow, wind, and 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 and Emergency Management (CDEM) agencies.

4.3.1 High-Impact Low-Probability (HILP) Risks

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, namely:

- 66 kV and 33 kV sub-transmission systems
- 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 4.6. Sea level rise along the east coast is not expected to cause major disruption to the electricity network in the AMP planning period. Table 4.1 presents a high-level assessment of HILP events on the network.

Asset	Risk																
	Hurricane/Windstorm	Snow	Lightning	Flooding	Storm surge (coastal)	Tsunami	Drought	Heatwave	Wildfire	Earthquake	Landslide	Volcanic Eruption	Geomagnetic storm	National grid failure	Terrorism	Cyber incident	Pandemic
66kV & 33 kV Sub-Transmission System	M	H	L	M	L	L	L	I	H	H	H	L	I	M	H	H	L
Zone Substation	L	L	M	L	L	L	L	I	M	M	L	L	I	M	H	H	L

Note: L = low impact, M = medium impact, H = high impact, I = assessment in progress.

Table 4.1: Assessment of HILP Risks

4.3.1.1 Sub-Transmission Systems

MainPower is reassessing the sub-transmission and distribution network for HILP events. This work is being undertaken in conjunction with CDEM agencies.

Natural hazards of flood, windstorm, electrical storm, snowstorm and tsunami to the sub-transmission and distribution system 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/Consequence
Flood	<ul style="list-style-type: none"> 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. 	<p>Likelihood: Possible Consequences: Moderate</p>
Windstorm	<ul style="list-style-type: none"> 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 north-west (these occurred in 1945, 1964, 1975, 1988 and 2013). The peak wind speed of 193 km/hr 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 4 significant tornado events in the last 25 years, none of them located in our distribution area. 	<p>Likelihood: Possible Consequences: Major</p>
Electrical storm	<ul style="list-style-type: none"> Most parts of Canterbury have few electrical storms. Over the plains, fewer than 5 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. 	<p>Likelihood: Unlikely Consequences: Moderate</p>
Snowstorm	<ul style="list-style-type: none"> 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. 	<p>Likelihood: Unlikely Consequences: Major</p>
Wildfire	<ul style="list-style-type: none"> This can cause damage and destruction to the overhead network infrastructure. Particulate accumulation on power lines and insulators. 	<p>Likelihood: Rare Consequences: Catastrophic</p>
Earthquake	<ul style="list-style-type: none"> 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. 	<p>Likelihood: Unlikely Consequences: Catastrophic</p>
Landslip	<ul style="list-style-type: none"> Remote sections of sub-transmission networks may be exposed to landslip, causing loss of supply. 	<p>Likelihood: Unlikely Consequences: Major</p>
Tsunami	<ul style="list-style-type: none"> 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. 	<p>Likelihood: Rare Consequences: Minor</p>

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:

- risk factor = probability (years recurrence) × consequence (% damage)
- 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.

4.4 Resilience of the Network

MainPower is taking part in a pilot 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; to our consumers; and to 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 CIMS, which are key resources 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.



4.5 Risk Mitigation, Practices and Plans

4.5.1 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 CBRM approach, based on the Electrical Engineers' Association (EEA) Asset Health 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.

4.5.2 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 post 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 inspections 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.

4.5.3 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.

4.5.4 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 Rs – 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.



The 5 “R’s”



Figure 4.4: New Zealand’s Coordinated Incident Management System: Five Rs

4.5.5 Liaising with Civil Defence and Emergency Management

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 National Civil Defence Emergency Management (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.

4.5.6 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.

4.6 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 climate change.

Threat	Risk	Risk Treatment
Severe weather, wind speed and storms	<ul style="list-style-type: none"> • Asset damage caused by increased wind speeds and vegetation. 	<ul style="list-style-type: none"> • Vegetation management, including an increase in tree scoping from 5 yearly to 2 yearly. • Use LiDAR technology for the management clearances. • Digital Twin technology for the modelling of increased windspeeds. • Increase community awareness of risks through our website, radio and community pages.
Wildfire	<ul style="list-style-type: none"> • Asset failure due to asset location in wildfire zones. 	<ul style="list-style-type: none"> • Review loss of supply impact to consumers because of asset failure due to wildfire.
Rising sea levels/extreme flooding	<ul style="list-style-type: none"> • Assets failure due to flooding in low lying areas or susceptible to new flood zones. • Stranded assets due to shifts in the population. 	<ul style="list-style-type: none"> • Conduct a review of asset locations in low-lying and coastal areas.
Changing supply/demand (Behavioural) trends	<ul style="list-style-type: none"> • Change in electricity consumption due to climate change, influenced by temperatures, consumes use of low carbon technology, carbon prices. 	<ul style="list-style-type: none"> • Develop and implement network transformation road map that supports consumer engagement, use of pricing signals to manage network constraints.

Table 4.3: Risks Related to Climate Change and their Treatment

5. MAINPOWER'S NETWORK



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 Puhī Puhī 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.

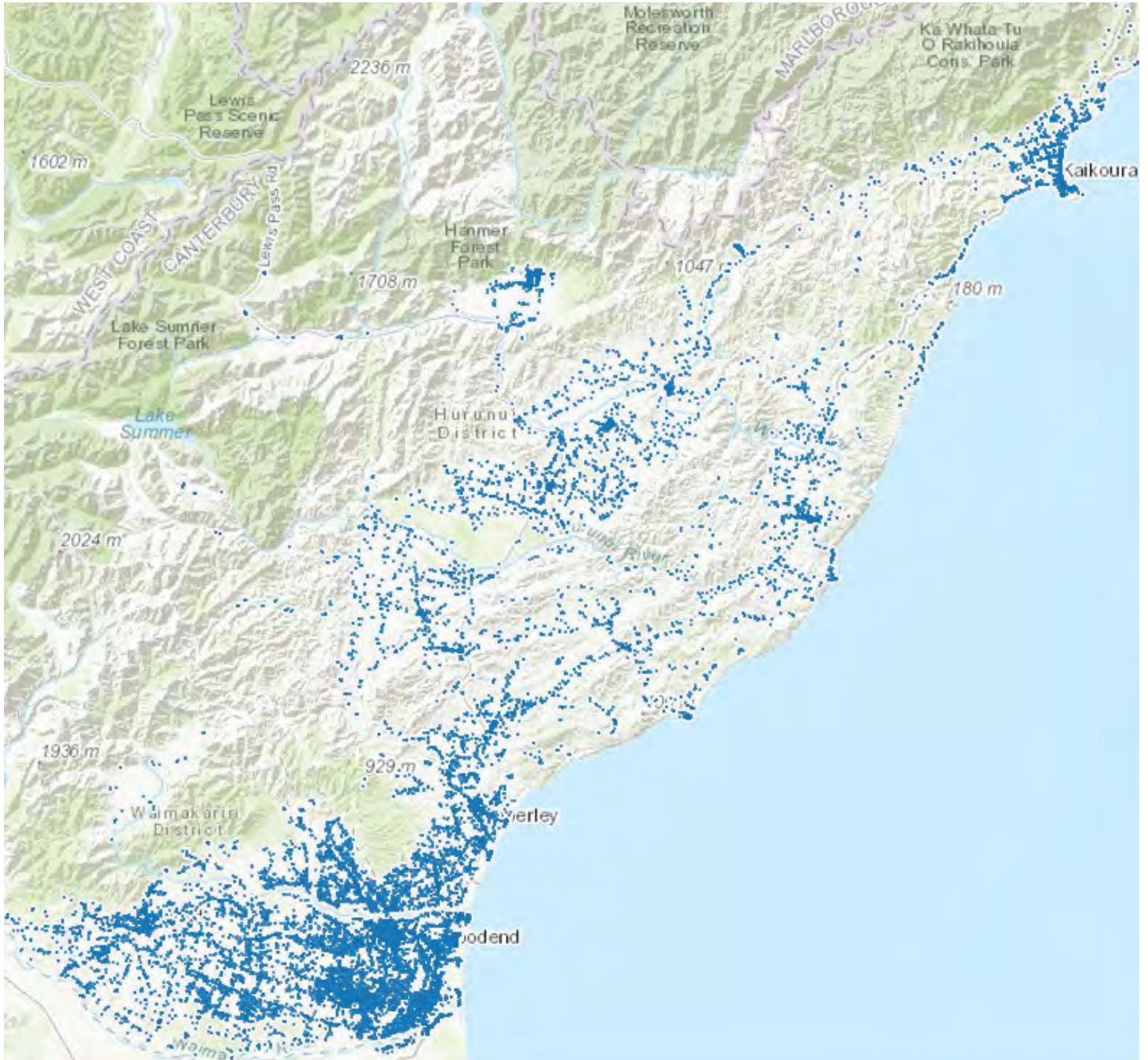


Figure 5.1: MainPower's Electricity Network Consumer Geographic Distribution

5.1.1 Large Consumers

Our large consumers are:

- **Daiken NZ medium-density fibreboard mill at Ashley:** The Daiken mill is supplied from the Ashley 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 in Kaiapoi:** This plant can be supplied from either of two 11 kV supplies from the Kaiapoi switching station, and one of these can also be swapped to an independent backup feeder.
- **McAlpines sawmill at Southbrook:** Recently, this mill has been transferred onto a new high-security dual-feeder-supplied switchboard, which has reduced the risk of power interruptions to the site.
- **McAlpines Mitre 10 Mega 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 RMUs, allowing alternative switching of supply in the event of a fault on one feeder.

5.1.2 Load Characteristics

Substation	FY19 (MVA)	FY20 (MVA)	FY21 (MVA)	FY22 (MVA)	Peak
Southbrook	22.8	24.9	27.4	31.7	Winter
Swannanoa	15.2	15.5	15.1	15.0	Summer
Burnt Hill	15.0	15.3	15.5	14.1	Summer
Amberley	6.0	5.4	5.4	6.0	Winter
Mackenzies Road	1.6	3.3	1.8	2.3	Summer
Greta	1.3	1.3	1.4	1.4	Summer
Cheviot	3.2	3.4	3.5	3.4	Summer
Leader	1.5	1.5	1.5	1.5	Summer
Ludstone Road	5.9	5.3	5.7	5.8	Winter
Mouse Point	15.6	15.2	14.5	15.6	Summer
Hanmer	4.8	4.3	4.2	4.8	Winter
Lochiel	0.1	0.1	0.1	0.1	Summer
Hawarden	3.7	3.6	3.8	3.6	Summer
Kaiapoi GXP	29.0	29.5	31.6	32.2	Winter

Table 5.1: MainPower Network Load Characteristics

5.1.3 Peak Demand and Total Energy Delivered



System Measure	2021	2022
Peak load	127.6 MW	123.5 MW
Energy entering the system	666 GWh	662 GWh
Energy delivered	626 GWh	624 GWh
Loss ratio	5.9%	5.8%
Load factor	60%	61%
Average number of ICPs	42,117	43,130
Zone substation capacity (base ratings)	132 MVA	150 MVA
Distribution transformer capacity	580 MVA	588 MVA
Distribution transformer capacity utilisation	22%	21%
Circuit length lines	5,165 km	5,170 km

Table 5.2: System Measures

Consumer Group ICPs	Average Number of ICPs	
	2021	2022
Residential	34,087	34,950
Commercial	6,241	6,364
Large commercial or industrial	44	45
Irrigators	1,427	1,451
Council pumps	203	207
Streetlights	114	113
Individually managed consumer	1	1

Table 5.3: Key MainPower Network Statistics

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.



Figure 5.2: Transpower's North Canterbury Transmission Grid

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 x 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).

GXP	Description	
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 location 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.



Figure 5.3: MainPower’s Sub-Transmission Network

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 the townships of Rangiora and Kaiapoi, where 11 kV reticulation in Rangiora and Kaiapoi is approximately 90% underground.

5.2.4 Distribution Substations

As our high-voltage distribution network is predominantly overhead, most distribution substations are pole mounted. 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.

The main 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:** Large buildings or rooms of poured concrete and stucco exteriors. These were generally built with exposed overhead 11 kV bus-work, but most have been changed to more modern ground-mounted RMUs. They are ideal locations for automated switchgear.
- **Kiosks:** Smaller, predominantly front-access steel kiosks housing the transformers and switchgear. RMUs are used with an 11 kV HRC fuse protecting the transformer. The box design allows for a maximum transformer size of 500 kVA; however, these have to be de-rated because of reduced cooling. Low-voltage panels are typically the open-style Lucy HRC fuses, but many of these have been replaced with DIN standard switchgear.
- **Mini-sub:** Mini-substation packages with RMUs in every second substation and air-mounted fuses in the remainder.
- **Outdoor transformers:** More recently, outdoor transformers with cable boxes and separate front-access outdoor cabinets have been used for including using low-voltage panels. This design allows more flexibility for a wider range of switchgear for changing transformer sizes, for accessibility and allowing the full rating of the transformer to be used.

5.2.5 Low-Voltage Distribution Configuration

Approximately 70% of our low-voltage network is underground, typically located 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 located in smaller townships and rural areas to enable cost-effective supply to a number of consumers from one transformer. Most overhead low-voltage conductors are bare conductor or covered copper.

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.

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 hardwood poles, with newer lines predominantly constructed using concrete poles, with a few short-cabled sections.

5.3.2 Zone Substations



Network assets are housed within zone substation buildings or on zone substation sites, including power transformers, circuit breakers, disconnectors and projection systems.

Zone substation transformers above 1 MVA capacity have on-load tap-changers to regulate the bus voltages, with loads typically kept below the manufacturer's ratings. These transformers have been subject to normal and typical urban and commercial load curves and cyclic loading.

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.

During the past 11 years, many lines have been converted from 11 kV to 22 kV by changing the insulators. This has largely been undertaken in rural areas experiencing high growth in irrigation demand and dairy conversions.

5.3.4 Underground Distribution

Most of the high-voltage underground cables are either 95 mm² or 185 mm² aluminium, although more recently, 300 mm² 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

Most customers are supplied from primary distribution substations at voltages of 11 kV or 22 kV. A small number of customers are supplied from single-wire earth return systems operating at 6.6 kV or 11 kV, and a very small number of remote customers from distribution transformers on the 33 kV sub-transmission system. However, as this arrangement constrains the operation of the sub-transmission system, they are progressively being removed.

Substations are either ground mounted outdoors or within an enclosure, or pole mounted. As our distribution area is mainly rural, most substations are pole mounted. Most recent designs have used mini-subs, micro-subs or the Pegasus Modular configuration, using a stand-alone transformer with high-voltage and low-voltage cable boxes and a separate shell for the high-voltage and low-voltage switchgear.

MainPower has more than 7,500 distribution transformers, which come from a variety of manufacturers, including Tyree, ABB, Astec, Tolley and Wilsons. Large quantities of transformers were purchased between 1967 and 1973 because of the growth in the distribution network at this time. Many of these were in the 10 kVA to 30 kVA range.

5.3.6 Distribution Switchgear

There are several different types of circuit breakers and reclosers on the system, including bulk oil, SF₆ 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 employ Landis+Gyr SFU-G and 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 of the receiver relays are in new smart meters or are Zellweger/Enermet RM3, installed between 1993 and 1997. The remainder are the later Landis+Gyr RC5000 series, while more-recent purchases are RO3-type relays.

5.3.8 Streetlights

Most street lights are controlled by ripple 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. A small number of lights are controlled from local photocell sensors. Street light relays are modern and reliable, with extremely low reported failure rates

5.3.9 Supervisory Control and Data Acquisition

In the 2020 MainPower reporting year, implementation and deployment of the Open Systems International Monarch ADMS progressed.

MainPower's first Supervisory Control and Data Acquisition (SCADA) system used remote terminal units communicating with Conitel protocol, and these have now either been completely changed to more modern DNP3 remote terminal units or slaved to more modern remote terminal units on site. All remote sites now communicate via the DNP3 protocol. Work is proceeding on new field devices with remote communication facilities. 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 has migrated to new systems during the past eight years and operates reliably. Tait voice radios and Mimomax data radios are currently employed. During 2016, "lone worker" and "worker down" functions were added to the voice radio platform via the use of portable radios working through the base vehicle radio.

5.3.11 Protection and Metering Systems

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. Several individual relays in these substations have been replaced in conjunction with circuit-breaker replacements. We also own high-voltage metering systems for several large users, including the Daiken medium-density fibreboard plant and 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, administration buildings and operational buildings. All our buildings are well maintained. MainPower relocated to a new, purpose-built head office and works facility in June 2014.

5.3.14 Assets Owned at Transpower Grid Exit Points

MainPower owns metering and communications equipment at Transpower GXP's that connect to 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 located in Transpower GXP's at Waipara, Ashley and Kaiapoi. We also have SCADA and local service equipment associated with load control at these sites.

5.3.15 Mobile Substations and Generators

We have invested in a mobile diesel generation plant to assist with reducing the number of planned interruptions. The plant is rated at 275 kVA. The 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, and it has enough capacity to supply the average load of an urban transformer kiosk. Alternatively, it can be connected to overhead lines at 11 kV or 22 kV, supplying up to 100 customers. We also have a smaller 88 kVA generator for use with low-voltage customers. This is often large enough to supply small subdivisions during maintenance.

5.4 Network of the Future



A network of the future enables the widespread use of local generation sources connected to the network at multiple points, with associated two-way power flows. It also ensures open-access arrangements for consumers to allow them to transact over the network and to connect any device they wish within acceptable safety and reliability limits. In addition:

- It relies on physical assets to convey electricity, as well as from consumer to consumer, or consumer to bulk supply point.
- Consumers are actively involved in their energy acquisition, generation and consumption management.
- It provides network connections for multiple sources of distributed generation devices and other consumer-side devices.
- The distribution utility may not become involved in the transactions between consumers and other parties, nor in the balance between supply and demand.
- Network stability is managed by the EDB for a range of operating scenarios.



5.4.1 Network Transformation Plan

More work is required to achieve distribution system integrator status. This work is summarised in Table 5.5, including how we are tracking to complete these workstreams.

Objectives	Description	Description	Status
Consumer Insights	Understand consumer motivations and behaviours to determine: <ol style="list-style-type: none"> 1. The impact on distributed energy resource deployment and consumption patterns 2. New load requirements. 	<ul style="list-style-type: none"> • Low-voltage monitoring strategy. • Understand distributed energy resource deployment through scenario planning. • Understand new loads. • Understand new distributed generation. 	<ul style="list-style-type: none"> • Trial low-voltage monitoring deployed. • ADMS reports on ICP outage basis. • MPowered Future complete for scenario planning. • Distributed generation support for Kate Valley and Mt Cass Windfarm's distributed generation.
Managing Uncertainty	Stay abreast of technology developments and update the EDB industry. Update this roadmap to remain relevant.	<ul style="list-style-type: none"> • Continuous monitoring. 	<ul style="list-style-type: none"> • Ongoing.
Open Network Framework	Access to the electricity distribution network by existing and new consumers and traders to connect and operate any equipment they desire (specifically distributed energy resources and new loads) with appropriate consideration of: <ul style="list-style-type: none"> • cost of access; • network operation and system security; • standard equipment; and • standard access arrangements. 	<ul style="list-style-type: none"> • Enable distributed energy resource trading. • Trial distributed energy resource and demand response for network support. • Demand response framework. 	Currently review how distributed energy resource and distributed generation can be contracted differently, taking advantage of an intermediary as opposed to a pricing tariff, which is the existing method.
Standardise Technical Arrangements	Provide consistent method of connection of any equipment (distributed energy resources or appliances) across all EDB areas. Ensure equipment complies with approved standards to minimise its impact on the electrical power system.	<ul style="list-style-type: none"> • Standard distributed energy resource connection standards. • Equipment standards. • Network engineering. • Cyber security and autonomous distributed energy resource. 	Already engage with other EDBs to support consistent agreements, equipment standards and asset management practices.
Network Operation, Monitoring and Stability	Ensure the stability of the open network through deeper monitoring of the network and improved planning techniques.	<ul style="list-style-type: none"> • Low-voltage monitoring and visibility. • Understand impact on network stability of multiple distributed energy resources. 	Low-voltage monitoring remains a work in progress. Roadmaps are developed to deliver: <ul style="list-style-type: none"> • Power flow management; • State estimator; • Volt-Var, and compensation; • Fault location isolation and service restoration.
Build EDB Capability	Understand networks in greater depth, their ability to host distributed energy resources, congestion, and contracting for network support. Ensure working understanding of regulations and obligations.	<ul style="list-style-type: none"> • Procurement and contract for services management. • Asset management maturity. 	Contestable asset management, customer connections and network access for third parties are developed and implemented. Maturity improvements include upgrades to MainPower ERP and the implementation of CBRM models.

Table 5.5: Network Transformation Plan

6. NETWORK DEVELOPMENT PLANNING

Network development planning is a significant 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 EDB are:

- significantly greater integration between distributed generation, transmission and energy storage on the network, together with increased interaction with active traditional 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 both the distribution network and the "internet of things" but impacting on the use of the network
- a growing focus on energy communities, peer-to-peer trading and local markets
- the impact of non-linear loads, such as rapid 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 currently re-evaluating 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 the results, learnings and tools being made available from industry working groups such as GREEN Grid, Electricity Networks Association and EEA forums. This evolution of our network development approach will help us better understand the range of capacity and service requirements the network will need to deliver.

We also recognise that this new future for distribution networks offers increased opportunities for non-network 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-network solutions.

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

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

6.1 Network Development Planning Criteria

Our network development is informed by our defined levels of service and performance, planning criteria and standard design implementations, which are a function of:

- Capacity;
- Power-quality compliance;
- Security, and
- Reliability.

We use options analysis to consider alternative development and engineering solutions. When selecting a solution, we consider cost and sustainability.

6.1.1 Capacity

We must ensure there is sufficient capacity available to meet network peak load. This is provided through network capacity in conjunction with our demand-side management capability.

We follow a process of forecasting network demand and assessing this demand against our 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 security performance indicators to show the capacity we provide at each security level.

6.1.2 Power-Quality Compliance

One of the key criteria for distribution development planning is power-quality compliance, such as voltage. Voltage performance is monitored by SCADA 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 11,000–11,300 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 10,900–11,000 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 distributed generation.

6.1.3 Security

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 actually performs and is measured through indices such as the number of times supply to consumers is interrupted.

6.2 Project Prioritisation

A risk-based approach is applied to establish project prioritisation, in combination with other factors such as:

- compliance and safety
- meeting service obligations and targets as defined by our consumers
- cost-benefit analysis
- options analysis.

In general terms, development projects are prioritised as follows.

- Addressing compliance, health, safety and environmental issues
- Consumer-driven projects for new connections or upgrades
- Providing for load growth
- Meeting consumer service levels

Prior to the commencement of each planning period, potential projects for the following 10 years are identified. Inputs to the prioritisation process include:

- determining the primary driver for the project
- impact on consumers if the project does not proceed, or if it is deferred
- seasonal requirements
- cost and funding implications
- alternative non-network solutions
- planning uncertainties.

6.3 Security of Supply Classification



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

6.3.1 Zone Substation Security

Zone substations are classified for security according to Table 6.1.

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

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 6.1: Security of Supply Zone Substation Restoration Times

6.3.2 Distributed Load Classifications

Distribution loads are classified according to Table 6.2.

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 6.2: Security of Supply Load Types

6.3.3 Security Level

Network configuration is arranged so that the security criteria shown in Table 6.3 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 6.3: Distribution Load Security Level

6.4 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; and
- Safety.

6.5 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.

6.6 Network Planning



6.6.1 Overview

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

- **Major projects** – more than \$1 million, generally involving sub-transmission, zone substation or GXP works.
- **Reinforcement projects** – typically below \$1 million, including distribution-feeder capacity and voltage upgrades, security (N-1) reinforcements, distribution substation and transformer upgrades, and low-voltage reinforcement.
- **Open-access network investments** – investments to support the transition towards an open-access network, including network monitoring, communications and power-quality management.
- **Reliability and automation** – include network automation projects to help manage the reliability performance of our network; currently integrated within our major projects and reinforcement projects.

6.6.2 Demand 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 Statistics New Zealand;
- Local District Scheme 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);
- Historical extreme movements in temperature and rainfall where this affects peak demand;
- Expected economic developments; and
- Emerging technology adoption, such as EVs.

Our network continues to undergo steady growth, as shown by both ICP and population growth in Figure 6.1. The consistent growth shown in the network is mainly due to:

- Steady residential subdivision activity in Kaiapoi and Rangiora;
- Commercial development in Rangiora; and
- Irrigation developments and other agricultural loads.

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 and population growth rates, by planning area, for MainPower’s network region.

Key:
 % – Population growth
 % – ICP growth

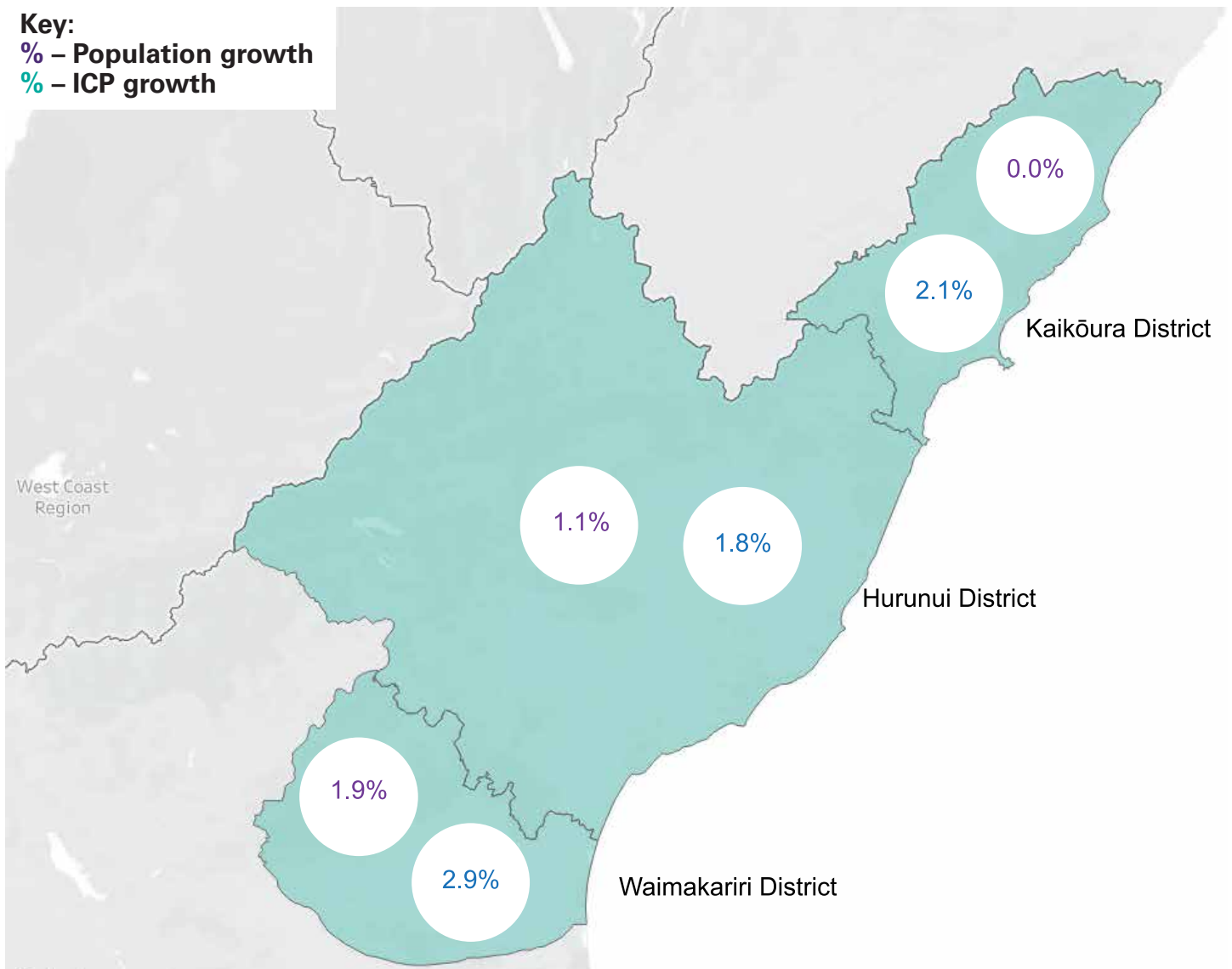


Figure 6.1: Annual ICP and Population Growth Rates by Planning Area

6.6.3 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.

6.6.4 Forecast Impact of Distributed Generation and Demand-Side Management

All demand forecasts take into consideration the impact of existing and proposed distributed generation 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 6.2 and Figure 6.3 show the growth of small-scale (< 1000 kW capacity) distributed generation within the network. The connection rate is increasing slowly. On average, approximately 476 kWh of generation is exported per kW of capacity. The average connected distributed generation per consumer across the three planning regions are Waimakariri (5.43 kW, 1,269 consumers or 4.2% of total consumers), Hurunui (5.98 kW, 298 consumers or 3.0% of total consumers) and Kaikōura (5.50 kW, 37 consumers or 1.3% of total consumers).

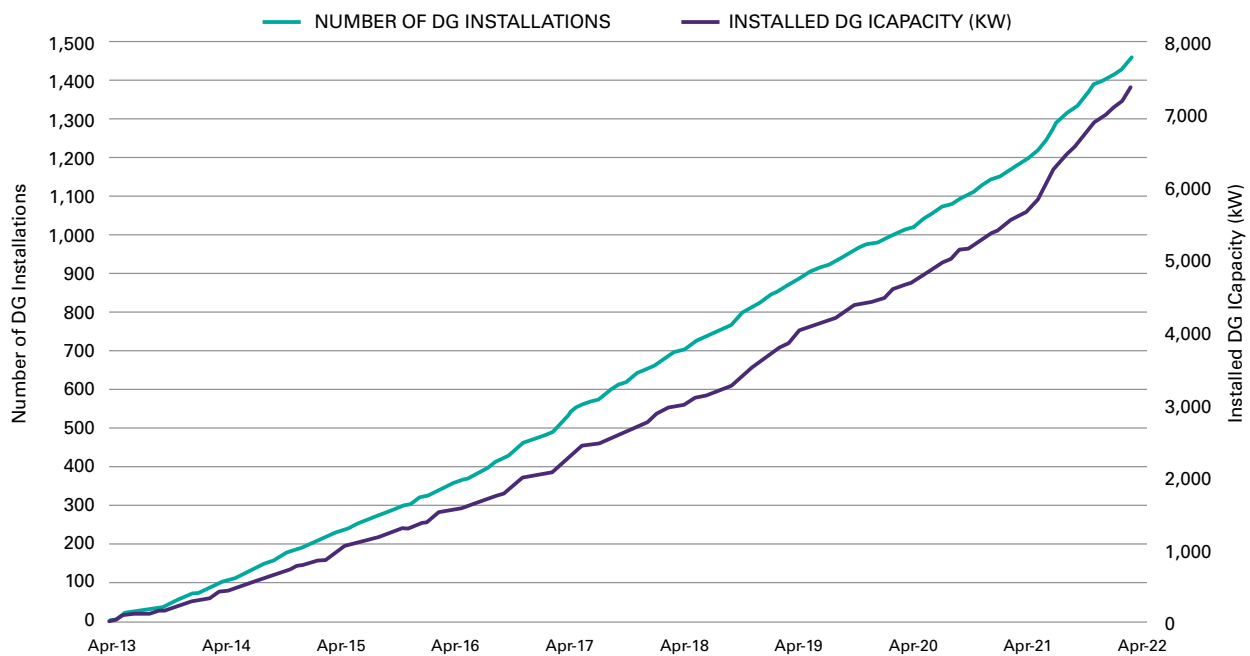


Figure 6.2: Number of Distributed Generation Installations on MainPower’s Network (Individual Size Less than 1 MW)

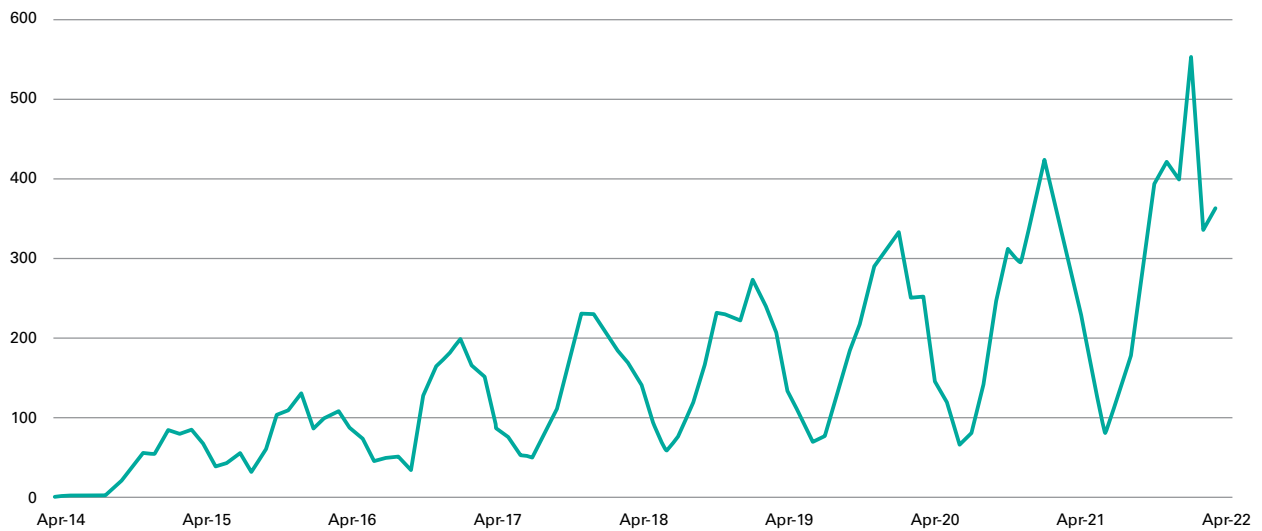


Figure 6.3: Distributed Generation Export Volume (MWh)

6.6.5 Distribution Innovation

MainPower’s future focus in network development planning is summarised in regional plans that detail projected demand growth and network projects in defined North Canterbury areas.

The purpose of the regional Master Plans is to:

- improve stakeholder engagement involving local councils, suppliers of technology, community and energy users;
- provide a consultative platform to accept new technology or behavioural changes to assist with deferring network expenditure and reducing supply-related costs;
- detail our approach to network augmentation and the service levels delivered – where no feasible market-driven alternative solution exists, MainPower may then apply a traditional network development-planning approach;
- provide regional documents to all stakeholders, market participants and energy consumers; and
- facilitate a market response by encouraging the use of non-network or non-lines-network solutions – these do not necessarily need to be delivered by MainPower; they can be supplied, maintained and operated by others.

6.7 Long-Term Sub-Transmission Network Strategy

MainPower has developed a long-term sub-transmission strategy to help inform and align future investment (Figure 6.4). 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.

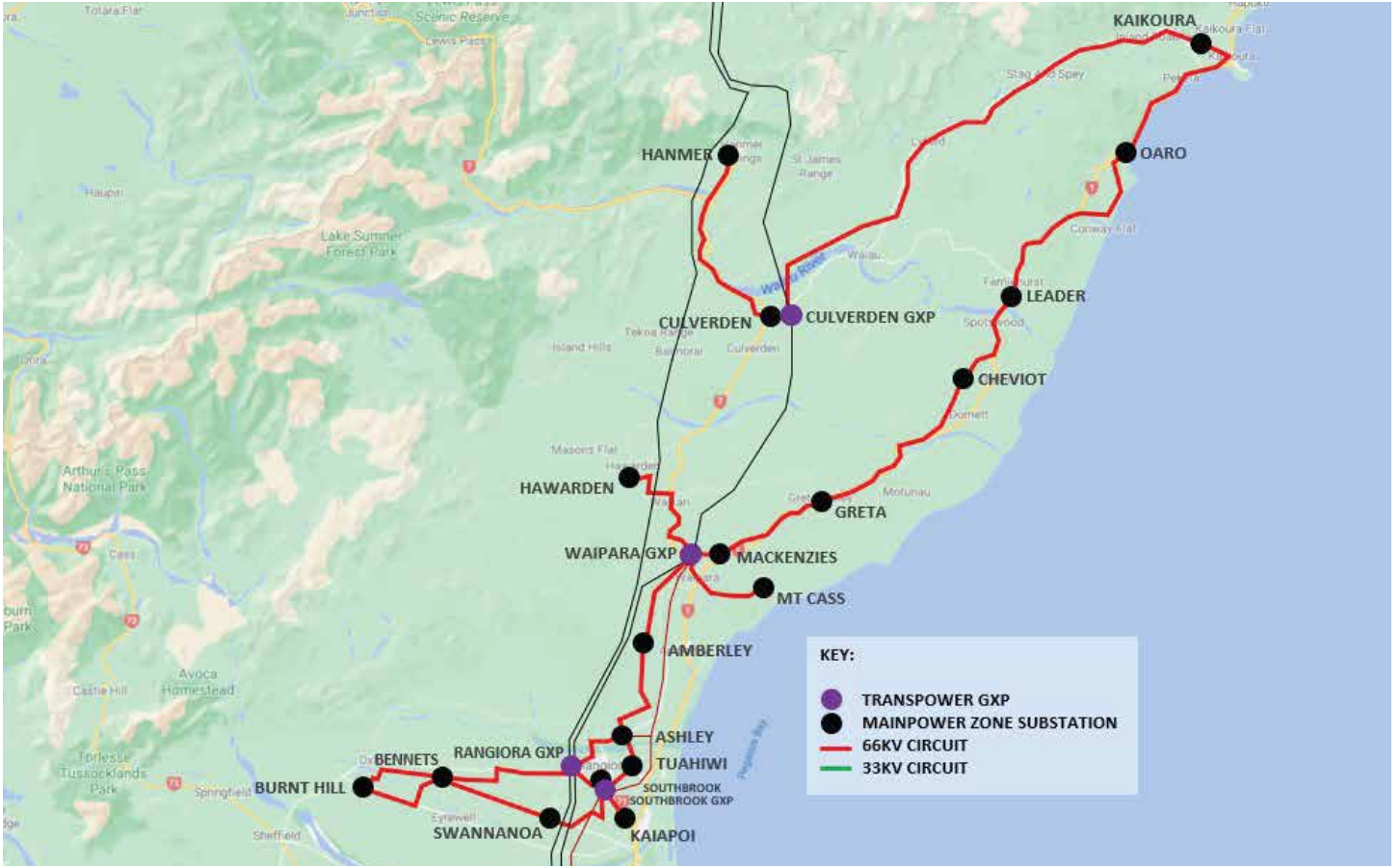


Figure 6.4: MainPower's Long-Term Sub-Transmission Network Strategy

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

6.8 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.

6.8.1 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 Waka Kotahi NZTransport Agency 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.

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.

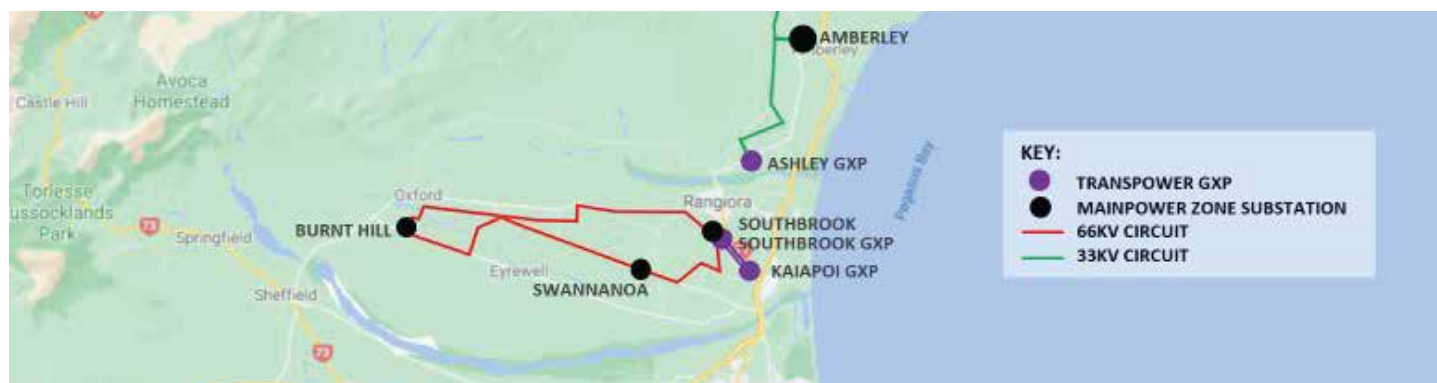


Figure 6.5: Waimakariri Region Sub-Transmission Network (Existing)

6.8.1.1 Demand Forecasts

Demand forecasts for the Waimakariri Zone Substations are shown in Table 6.4.

Substation	Security Class	Class Capacity (MVA)	Demand Forecast (MVA)										10 Year high EV growth
			FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	
Ashley 11 kV	A1	40.0	18.6	18.8	19.1	19.4	19.7	20.0	20.3	20.6	21.9	22.3	27.6
Burnt Hill	A1	23.0	16.9	16.3	17.8	18.3	18.7	19.2	19.7	20.1	20.7	21.2	25.2
Kaiapoi 11 kV	AAA	38.0	31.6	32.7	33.9	35.1	36.2	37.4	38.6	39.8	41.2	42.6	48.7
Southbrook	AAA	40.0	34.3	35.8	37.5	39.1	40.7	42.4	44.0	45.6	47.5	49.4	56.6
Swannanoa	A1	23.0	15.8	16.2	16.6	17.0	17.4	17.8	18.3	18.7	19.1	19.7	24.7

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

Table 6.4: Waimakariri Area Network Demand Forecast

6.8.1.2 Network Constraints

Major constraints affecting the Waimakariri area are shown in Table 6.5.

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.	Tuahiwi Zone Substation programme. Develop long-term 66 kV interconnection capacity between Waipara, Southbrook, and the future Tuahiwi Zone Substation.
Southbrook and Kaiapoi 11 kV	Forecast to exceed security-of-supply capacity between FY28 and FY30.	Construction of Tuahiwi Zone Substation planned for FY26–FY29, along with tactical reinforcement projects to allow load transfer to Ashley and Swannanoa.

Table 6.5: Waimakariri Area Network Constraints

6.8.1.3 Major Projects

Table 6.6 provides individual summaries of the major growth and security projects planned for the Waimakariri area.

Tuahiwi 66/11 kV Zone Substation	
Expected Project Timing	FY24, FY26–FY29
Strategic Drivers	System Growth, Quality of Supply – Resilience
Business Case Required?	Yes

Table 6.6: Tuahiwi 66/11 kV Zone Substation

Residential and commercial growth in the Rangiora, Woodend, Ravenswood and Pegasus areas will drive the need for a new zone substation east of Rangiora. The Tuahiwi Zone Substation programme incorporates a series of sub-projects to construct a 66 kV sub-transmission network and a new Tuahiwi 66 kV Zone Substation. The overall programme is staged as follows.

- **Stage 1 – Tuahiwi 66 kV Sub-transmission Line Design:** The first stage of this programme is the line route detailed design, including easements and consents for a 66 kV overhead line connecting Ashley GXP, Tuahiwi 66 kV Zone Substation site, and from Tuahiwi Zone Substation to the Southbrook GXP (FY24). The design stage will allow construction from Ashley to the Rangiora Woodend Road area and will be timed to provide support at 11 kV for the eastern rural area to assist with reducing load on Southbrook Zone Substation. Completion of the circuit from Tuahiwi to Southbrook in FY29 will follow construction work on the substation.
- **Stages 2 and 3 – Ashley to Tuahiwi 66 kV Sub-transmission Line Build:** These stages construct the Ashley to Tuahiwi 66 kV sub-transmission line, which will initially operate at 11 kV, providing additional capacity into the Tuahiwi region until the Tuahiwi Zone Substation is completed.
- **Stages 4, 5 and 6 – Tuahiwi Zone Substation Design and Construction:** These stages will extend on initial concept studies to deliver a full detailed design, construct the new Tuahiwi 66 kV Zone Substation and terminate the 66 kV sub-transmission line from Ashley to commission the new zone substation.
- **Stage 7 – Southbrook to Tuahiwi 66 kV Sub-transmission Line Build:** This stage completes the Tuahiwi Zone Substation programme by constructing the Southbrook to Tuahiwi 66 kV sub-transmission circuit, providing full N-1 supply to the new Tuahiwi Zone Substation.

6.8.1.4 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 6.7 summarises the reinforcement projects in the Waimakariri area.

FY	Project Title	Description
FY24	Reinforce SW63 and SW66 Swannanoa	These are large, highly loaded feeders with limited switching capability. This project improves safety and reliability by installing three remote-controlled switches.
FY24	Fernside Reconfiguration	Reconfigure supply to the Fernside area to improve security of supply and reliability after the Southbrook Zone Substation upgrade.
FY24	Mandeville Area Voltage Improvements	Install a regulator and reconductor sections of the line between Kaiapoi and Mandeville to improve voltage.
FY24	Kaiapoi K7 Feeder Split	Improve the reliability and capacity of the large Wetheral feeder (KAI_7) by extending and livening a second 300 mm ² cable from the Kaiapoi GXP.
FY24	Reinforce X52 Burnt Hill	Increase the security of supply of feeder X52 by upgrading 660 m of conductor in North Eyre Road.
FY25	Marsh Road Feeder	Install a new cable from Southbrook Zone Substation to Marsh Road to improve the capacity and reliability to Pegasus/Ravenswood.
FY25	East Belt to Railway Link	Improves security of supply to central Rangiora by linking capacity from the eastern feeders and removing commercial load from a spur connection.
FY25	Loburn Barkers Road Links	Create a mesh network with links along Barkers Road to improve security of supply for the area.
FY25–FY27	Automate RMUs	Install automation to existing RMUs across MainPower's network to improve remote switching capability.
FY25–FY27	Birch Hill Link Stages 1 and 2	Link the Okuku and Ashley Gorge feeders to the Summerhill feeder in the Birch Hill area to improve reliability and security of supply for the region.
FY26	Loburn Feeder	Create a new Loburn feeder to separate the supply to Loburn and Marshmans Road, Sefton, to improve the security and reliability of both areas. Uses an existing spare Ashley circuit breaker.
FY26	Kaiapoi–Island Road Upgrade	Installation of an additional 11 kV cable section between a previously installed cable section and Neeve Street to improve network resiliency.
FY27	Burnt Hill X53–X56 Link	Link 22 kV from Thongcastor Road to Harmans Gorge Road via the end of Depot Gorge Road. This requires the conversion of part of Depot Gorge Road to 22 kV and will improve reliability and security of supply.
FY27	Kaiapoi 8376 to S11 Link	Create an interconnection between 11 kV feeders in Kaiapoi to increase alternative supply options.
FY28–FY29	Tuahiwi to Rangiora Feeders	Install 300 mm ² AL XLPE feeder cables between the new Tuahiwi 66 kV Zone Substation and the eastern side of Rangiora to improve security of supply.
FY29	Stone Street Underground	Remove the last of the overhead network on Stone Street in Kaiapoi utilising existing cables and ducts.
FY29	Rangiora Western Overhead Feeder	Build an overhead link down Lehman's Road to strengthen the supply to north-western Rangiora where considerable load growth due to residential subdivisions is expected.
FY30	West Belt Underground	Underground the south end of West Belt to remove ageing overhead assets and improve network connectivity.
FY31	Oxford to German Road Link and Switch Install	Link the Ashley Gorge feeder to X57 on German Road to improve security of supply and reliability.
FY32	Burnt Hill X53 to X55 Link	Create a mesh network between these two feeders to provide alternative supply options for high-use ICPs.

Table 6.7: Waimakariri Area Reinforcement Projects

6.8.2 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.

Amberley's location on SH1 and its relative proximity to Christchurch has 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 is a medium-sized tourist destination with steady growth anchored largely around the Hanmer Springs Thermal Pools and Spa complex. Hanmer'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 GXP. 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 GXP, 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 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 6.6: Hurunui Sub-Transmission Network (Existing)

6.8.2.1 Demand Forecasts

Demand forecasts for the Hurunui Zone Substations are shown in Table 6.9.

Substation	Security Class	Class Capacity (MVA)	Demand Forecast (MVA)										10 Year high EV growth
			FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	
Amberley	AA	4	6.6	7.1	7.6	7.9	8.2	8.6	8.9	9.2	9.6	10.0	11.7
Mackenzies Rd	A1	4	2.6	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.6	3.8	4.0
Greta	A1	4	1.4	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.8
Cheviot	A1	4	3.5	3.5	3.6	3.7	3.7	3.8	3.8	3.9	4.0	4.1	4.3
Leader	A1	4	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7
Hawarden	A1	4	3.7	3.8	3.8	3.9	4.1	4.2	4.3	4.4	4.6	4.8	6.1
Mouse Point	AA	13	16.3	16.6	16.9	17.3	17.6	17.9	18.3	18.6	19.0	19.4	22.1
Marble Point	A2	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Lochiel	A2	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Hanmer	AA	2.5	5.4	5.6	5.9	6.1	6.3	6.5	6.7	6.9	7.1	7.4	8.8

Note. Grey shading indicates peak demand exceeds current security-class capacity.

Table 6.8: Hurunui Area Network Demand Forecasts

6.8.2.2 Network Constraints

Major constraints affecting the Hurunui area are shown in Table 6.9.

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.	<ul style="list-style-type: none"> Planned load transfer to Mackenzies Road Zone Substation, to minimise the capacity shortfall. Upgrade of Amberley Zone Substation FY23–FY25.
Greta	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	<ul style="list-style-type: none"> 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.	<ul style="list-style-type: none"> The Cheviot–Kaikōura 66 kV Sub-transmission Upgrade in FY24–FY25 will increase the capacity of the Leader 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 Substation capacity will be increased in FY22.
Leader	This is an N Security substation and peak load cannot be supplied in the event of a transformer outage.	<ul style="list-style-type: none"> The Cheviot–Kaikōura 66 kV Sub-transmission Upgrade will increase the capacity of the Leader Zone Substation from 2 MVA to 4 MVA in FY24–FY25. 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.	<ul style="list-style-type: none"> The Hawarden Zone Substation is planned to be rebuilt as a dual transformer substation in FY35–FY38. Tactical reinforcement projects will increase load-transfer capacity from Mouse Point in FY25, 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 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.	<ul style="list-style-type: none"> 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. Summer cyclic ratings will be established to maximise the contingency rating of the transformers. The Mouse Point Zone Substation will be rebuilt as 66/22 kV, in a full N-1 configuration, in FY29–FY31.
Hanmer	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.	<ul style="list-style-type: none"> A project is planned to upgrade the second transformer and replace the 11 kV switchboard in FY24–FY25, which will provide backup capacity during peak loads. The 33 kV line is also being upgraded over FY20–FY25 to improve its resilience and minimise the risk of prolonged outages during extreme weather events.

Table 6.9: Hurunui Area Network Constraints

6.8.2.3 Major Projects

The following tables (Table 6.10–Table 6.13) summarise the major projects (growth and security) planned for the Hurunui area.

Amberley Zone Substation Upgrade	
Project Timing	FY23–FY25
Strategic Drivers	System Growth, Quality of Supply, Asset Replacement and Renewal
Business Case Required?	Yes

Table 6.10: 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 FY33 to FY35. The project will be staged as follows.

- **Stage 1 – Consenting and Detailed Design:** The first stage of this programme 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.
- **Stages 2 and 3 – Amberley Zone Substation Build:** These stages construct the Zone Substation site and commission it to operate at 33 kV until the 66 kV sub-transmission line upgrade project is completed.
- **Stage 4 – Waipara-Amberley-Ashley Sub-transmission Line Upgrade:** This stage completes the Amberley 66/11 kV Zone Substation upgrade programme by upgrading the existing 33 kV sub-transmission line to 66 kV, allowing the zone substation to operate at 66/11 kV.

Mouse Point Substation Upgrade	
Expected Project Timing	FY29–FY31
Strategic Drivers	System Growth, Security of supply, Asset Replacement and Renewal
Business Case Required?	Yes

Table 6.11: Mouse Point Substation Upgrade

The peak load of the Mouse Point Zone Substation exceeds the continuous rating of its firm 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 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 kV/33 kV transformers at the GXP with 220/66 kV transformers around FY39. The timing of works will be dependent on load growth and whether other technologies, such as distributed generation, effectively reduce the region's summer peaks. MainPower is interested in non-network solutions that may be able to manage peak load of the Mouse Point Zone Substation and help defer any capacity upgrades.

Hanmer Sub-Transmission Network Upgrade	
Expected Project Timing	FY23–FY26
Strategic Drivers	System Growth, Security of Supply, Asset Replacement and Renewal
Business Case Required?	Yes

Table 6.14: Hanmer Sub-Transmission Network Upgrade

The Hanmer 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 programme is targeted at the following.

- **Hanmer 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 Zone Substation concept study and upgrade:** The Hanmer Zone Substation peak load currently exceeds the peak rating of the second transformer, leaving part of the Hanmer region load at risk of prolonged outages following a fault. This project is to review the existing zone substation configuration, investigate options to improve security of supply for the Hanmer region and replace the 11 kV oil-filled switchgear that is reaching end of life.

Potential subdivision growth in the Hanmer region may impact on the scope and timing of this project.

6.8.2.4 Reinforcement Projects



FY	Project Title	Description
FY24	Amberley Reserve Road Link	Construct a new line to supply the rural area north of Amberley independent of the urban supply to improve reliability and capacity for the Amberley urban area.
FY24–FY26	Greta–Cheviot 22 kV Link	Improve security of supply to the Cheviot and Greta Zone Substations by extending the Cheviot South feeder 1,500 m to link to Greta feeder G31 to allow transfer of load between the two substations.
FY25	Amberley Beach Alternative Supply	Install 800 m of new line in Hursley Terrace Road to provide an alternative supply to Amberley Beach.
FY26	Cheviot–Leader Upgrade	Improve security of supply for Cheviot and Leader by upgrading the 11 kV conductor between Parnassus and the Waiau East/West Roads.
FY26	Hawarden–Mouse Point Link Upgrade	Install a voltage regulator and switches to enable increased remote load-transfer capacity between Hawarden and Culverden (Mouse Point Zone Substation).
FY27	22 kV Upgrades	This project provides for upgrading parts of the rural network to 22 kV to improve voltage as loads grow.
FY28	Leithfield Beach–Mays Road Link	Installation of overhead conductor and underground cable with a switch to allow Leithfield Beach to be supplied independently of Leithfield town.
FY28	Greta–Hawarden Link Upgrade	Install a voltage regulator and upgrade conductor in the Scargill Valley to increase transfer capacity between Greta and Waikari (Hawarden Zone Substation).
FY29–FY31	Mouse Point Feeder	Create a Mouse Point feeder to the Culverden township 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.
FY31	Amberley Douglas Road Cable	Install a new cable down Douglas Road to improve security of supply for both Amberley and Amberley Beach.
FY32	Culverden Constitution Road Link	Construct 3.2 km of new line to provide a mesh supply to the Mount Palm area, which requires significant capacity due to dairy in the area and currently has no alternative supply.

Table 6.13: Hurunui Area Reinforcement Projects



6.8.3 Kaikōura Regional Overview

The Kaikōura area plan covers the region north of the Conway River to the Puhī Puhī 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, 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 Waiāu 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 a mixture of 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 6.7. The small coastal communities south of Peketā are supplied from the 33 kV and 66 kV interconnection between Kaikōura and the Waipara GXP.

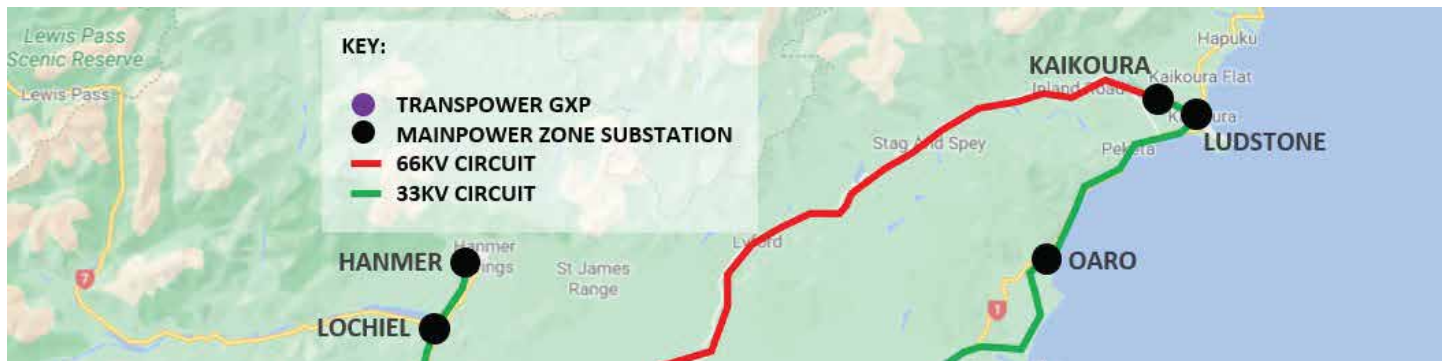


Figure 6.7: Kaikōura Region Sub-transmission Network

6.8.3.1 Demand Forecasts

Demand forecasts for the Kaikōura Zone Substations are shown in Table 6.16.

Substation	Security Class	Class Capacity (MVA)	Demand Forecast (MVA)										10-Year High EV Growth
			FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	
Ludstone	AA	7.2	5.7	6.0	6.2	6.5	6.8	7.0	7.3	7.6	7.9	8.2	10.4
Oaro	A1	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5

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

Table 6.14: Kaikōura Area Network Demand Forecasts

6.8.3.2 Network Constraints

Major constraints affecting the Kaikōura area are provided in Table 6.15.

Load Affected	Major Issues	Growth and Security Projects
Kaikōura township and areas down the Kaikōura Coast to Waipara	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. Growth is also likely to exceed the cyclic rating of the Ludstone transformers by FY29.	<ul style="list-style-type: none"> Cheviot–Kaikōura 66 kV Sub-transmission Upgrade Project – Upgrades the existing 33 kV sub-transmission system from Cheviot to Kaikōura to 66 kV, FY24–FY25. 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 FY31

Table 6.15: Kaikōura Area Network Constraints

6.8.3.3 Major Projects



Table 6.16 and Table 6.17 summarise the major growth and security projects planned for the Kaikōura area.

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 66 kV Sub-Transmission Upgrade	
Expected Project Timing	FY24–FY25
Strategic Drivers	Security of Supply, System Growth, Asset Replacement and Renewal
Business Case Required?	Yes

Table 6.16: Cheviot to Oaro Sub-Transmission Line Upgrade

The line between Cheviot and Oaro 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 of the end-of-life 33 kV Oaro Zone Substation to a new site.

This project also includes the realignment of the sub-transmission line away from the Raramai Tunnel to provide a more resilient solution.

6.8.3.4 Reinforcement Projects

FY	Project Title	Description
FY25 –FY26	Kaikōura Town Security Upgrades	Underground the existing overhead double circuit supplying the Kaikōura township with cables to provide security of supply and more efficient load transfer between feeders.

Table 6.17: Kaikōura Region Reinforcement Projects



6.9 Network Development Programme Summary

An overall summary of the major, reinforcement and GXP projects for the 10-year planning period across all planning regions is presented in Figure 6.8, Table 6.18 and Table 6.19. Several large projects create a “lumpy” major project expenditure, balanced by activity in minor works.

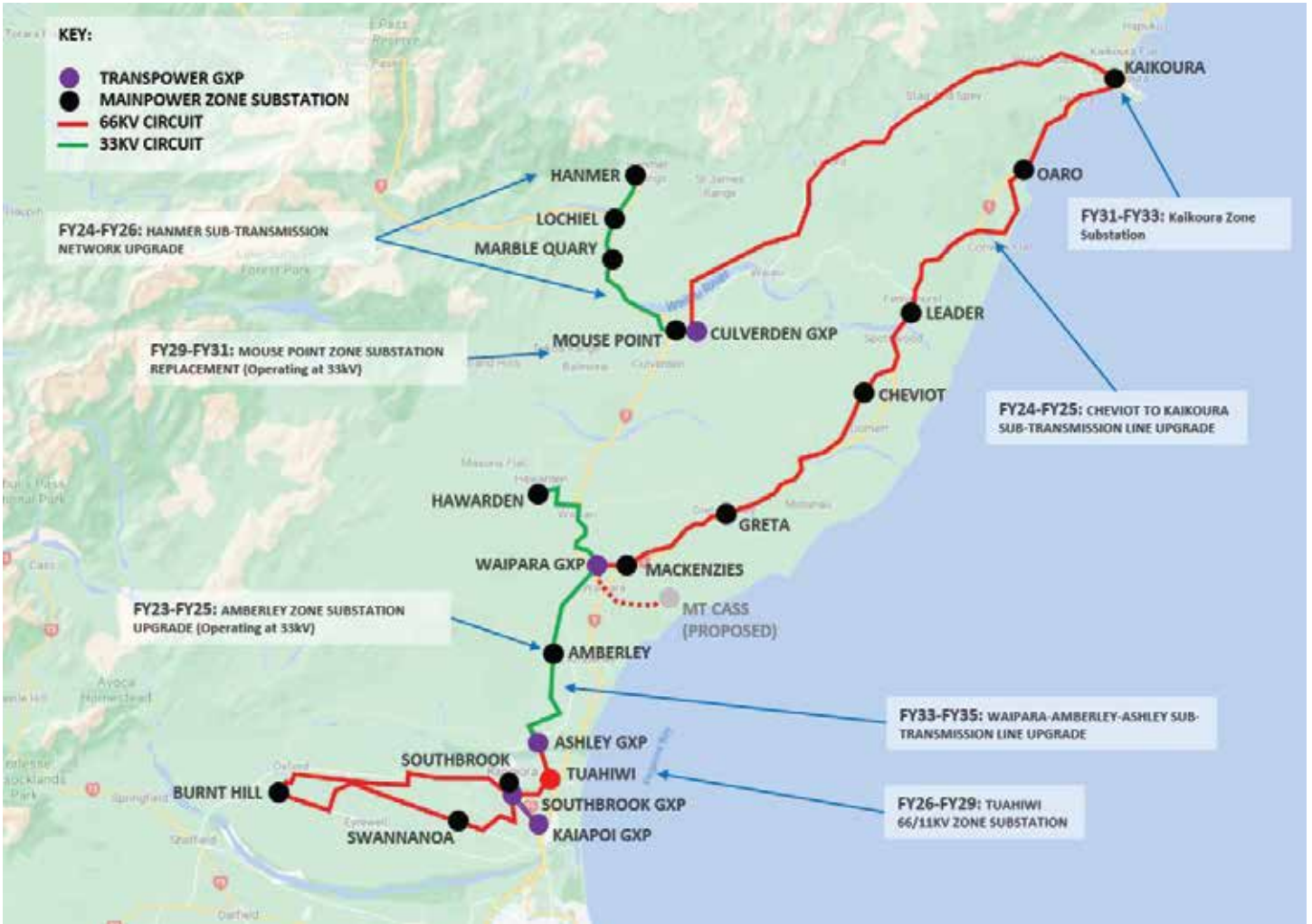


Figure 6.8: 10-year AMP Projects

6.9.1 Major Projects Summary



Project/Programme	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Cheviot to Kaikōura Sub-Transmission Upgrade										
Amberley Zone Substation Upgrade										
Hanmer Sub-Transmission Network Upgrade										
Tuahiwi Zone Substation										
Mouse Point Zone Substation Upgrade										
Kaikōura Zone Substation										
MAJOR PROJECT EXPENDITURE (\$000)	7,895	8,710	6,960	5,000	5,000	6,500	4,000	4,500	3,500	6,300

Table 6.18: Major Projects Programme Summary

6.9.2 Reinforcement Projects Summary

Project/Programme	Area	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Amberley Reserve Road Link	HUR										
Reinforce SW63 and SW66 Swannanoa	WAI										
Fernside Reconfiguration	WAI										
Mandeville Area Voltage Improvements	WAI										
Kaipoi K7 Feeder Split	WAI										
Reinforce X52 Burnt Hill	WAI										
Greta–Cheviot 22 kV Link	HUR										
Amberley Beach Alternate Supply	HUR										
Marsh Road Feeder	WAI										
Loburn Barkers Road Links	WAI										
Kaikōura Town Security Upgrades	KAI										
Automate RMUs	WAI										
East Belt to Railway Link	WAI										
Birch Hill Link Stages 1 and 2	WAI										
Loburn Feeder	WAI										
Cheviot–Leader Upgrade	HUR										
Hawarden–Mouse Point Link Upgrade	HUR										
Kaipoi–Island Road Upgrade	WAI										
Burnt Hill X53–X56 Link	WAI										
22 kV Upgrades	HUR										

Project/Programme	Area	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Leithfield Beach–Mays Road Link	HUR										
Greta–Hawarden Link Upgrade	HUR										
Kaipoi 8376 to S11 Link											
Tuahiwi to Rangiora Feeders											
Stone Street Underground											
Rangiora Western Overhead Feeder	WAI										
Mouse Point Feeder	HUR										
West Belt Underground	WAI										
Amberley Douglas Road Cable	HUR										
Oxford to German Road Link	WAI										
Culverden Constitution Road Link	HUR										
Burnt Hill X53 to X55 Link	WAI										
Network Automation											
Network Intelligence and Monitoring											
Early Works											
Unscheduled Reinforcement											
REINFORCEMENT EXPENDITURE (\$000)		2,730	3,653	3,237	2,728	2,748	2,748	2,751	2,751	2,750	2,742

Table 6.19: Reinforcement Projects Budget Summary

6.9.3 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 alternatives, demand-side management and deferral.

6.10 Distributed Generation Policies

Our policies on distributed generation are located on our website (mainpower.co.nz/get-connected). These set out the requirements for connecting distributed generation (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.

6.11 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 will 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 Price process to identify non-network solutions that are more sustainable, with the intent to decommission sub-economic lines.

6.12 Non-Network Solutions



6.12.1 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 Southbrook Zone Substation load is actively managed through winter peak loads 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 kV/33 kV coastal backup line is unable to transmit the normal daily peaks.

6.12.2 Demand-Side Management

Under MainPower’s MPowered Future programme, there is a workstream planned in 2024 to develop a Demand- Side Management strategy that will describe:

- MainPower’s Network Role in Demand-Side Management
- how market responses may be contracted in the future to provision 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.

6.12.3 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) 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 Price process to identify non-network solutions that are more sustainable, with the intent to alleviate security-of-supply risk in the Amuri area.



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 Two of this document.

We recognise the need to migrate from traditional, age-based replacement and reactive renewals of assets to a holistic approach to portfolio management. We have implemented a forecasting method of asset replacement that is more prescribed through the adoption of the EEA Asset Health Indicator (AHI) guide to quantify and inform our replacements. The 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 on this by initiating a project to implement CBRM models and adopting the EEA Asset Criticality Indicator 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 eight 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 renewal programmes for each of the asset fleets to help achieve our asset management objectives. Our goal is to deliver acceptable electricity distribution network service levels, ensure assets are safe and fit for purpose, and minimise the total cost of ownership.

Asset Portfolio	Asset Fleet
Overhead Lines	Poles and pole structures
	Conductors
Switchgear	Circuit breakers, reclosers and sectionalisers
	Ring main units (RMUs)
	Air break switches
	Low-voltage switchgear
Transformers	Zone transformer
	Ground-mounted distribution transformers
	Pole-mounted distribution transformers
	Regulators
Zone Substations	Zone substations
	Switching substations
Underground Assets	Low-voltage underground cables
	High-voltage underground cables
	Low-voltage service boxes
	Low-voltage link boxes
Vegetation Management	Vegetation



Asset Portfolio	Asset Fleet
Secondary Systems	DC systems
	Protection systems
	Earthing systems
	Communications/SCADA
	Load control/ripple plant
Property	Electricity distribution network buildings – distribution kiosks
	Non-electricity distribution network buildings

Table 7.1: Portfolio and Asset Fleet Mapping

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

- High-level objectives;
- Fleet statistics, including asset quantities and age profiles;
- Fleet health, condition, failure modes and risks;
- Preventative maintenance and inspection tasks; and
- Replacement (renewal) strategies.

7.2 Overhead Lines

MainPower has approximately 56,000 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).

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

There are approximately 9,000 concrete poles in use on the network today, including reinforced and pre-stressed concrete. Reinforced concrete poles contain reinforcing steel bars covered by concrete; these were used regularly from the 1960s to 1980s. Reinforced concrete poles were produced by many different manufacturers, resulting in differences in design, manufacturing standards and material quality. This has caused differing lifecycle performances, especially in our coastal areas. 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.

7.2.1.1 Maintenance

Maintenance is based on a condition-based 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. During the next 12 months, we are undertaking a review of our pole-testing methodology to ensure it remains fit for purpose and in line with industry standards.

This year, MainPower has invested in a LiDAR capture survey of its entire overhead network, which was completed in August 2022. This overhead network LiDAR survey will provide a dynamic virtual network representation that will allow us to leverage accurate, up-to-date data for assessment of network clearances, identification of defects, and to model environmental scenarios to gauge network resilience. The survey also enables MainPower so transition to Aerial Inspection of OH Asset and the use of Artificial Intelligence for lifecycle decision making and defect management.

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

7.2.1.2 Replacement and Disposal

MainPower employs a condition-based replacement programme resulting from data collected during the overhead five-yearly inspection programme. 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 and space 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 uses hardwood timber crossarms that have a nominal asset life of 35 years, and insulators including porcelain, glass and polymer types.

Based on ongoing monitoring, the number of defects of pole-top equipment is found to be increasing steadily, in part due to the increased number of ageing assets, resulting in equipment that is more susceptible to rot and electrical tracking.

7.2.2.1 Maintenance

Inspection and maintenance of crossarms is included in MainPower's Overhead Inspection and Maintenance Standard, MPNZ 393S049, summarised in Table 7.2. Thermal imaging and acoustic testing are currently being investigated, to consider incorporating them into the inspection. We are currently reviewing our asset inspections and considering the use of aerial surveys to optimise efficiencies in inspecting, enhance our asset replacement decision making in conjunction with the introduction of CBRM modelling of pole structures, crossarms and conductors.

To minimise the steady increase of the defects of pole-top equipment, a line-tightening programme is initiated to reduce any potential increase of defective failures.



7.2.2.2 Replacement and Disposal

A pole-top equipment replacement is initiated to address the potential fire risk due to failure. The programme is delivered to replace them 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 conductors 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, as shown in Table 7.2.

7.2.3.2 Replacement and Disposal

MainPower does not currently have a scheduled replacement programme in place for conductors; however, we are working to better understand the condition of this asset fleet during the next 12 months, which may result in a future scheduled replacement programme based on condition inspection.

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
	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
	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 and sectionalisers;
- RMUs;
- Pole-mounted switches; and
- Low-voltage switchgear.

7.3.1 Circuit Breakers, Reclosers and Sectionalisers

MainPower's circuit breakers, reclosers and sectionalisers provide protection and the isolation of faults and allow safe and efficient switching of the electricity network. Circuit breakers are generally located at zone substations. Reclosers and sectionalisers are located on overhead-line structures.

Figure 7.2 shows the number and age of circuit breakers, reclosers and sectionalisers (including spares).

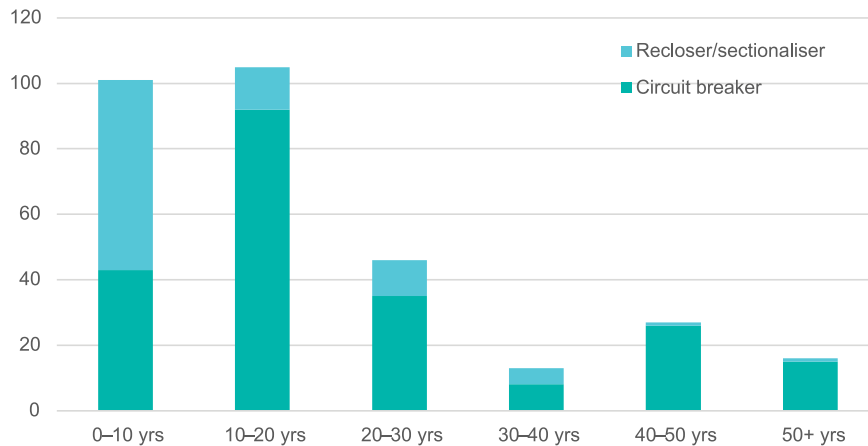


Figure 7.2: Switchgear Age Profile

MainPower's older circuit breakers are predominantly oil filled (bulk or minimum oil). Circuit breakers that are 25 years old and younger generally use gas or a vacuum as the interruption medium and insulation. A model based upon the EEA Asset Health Indicator Guide has been developed for all circuit breakers (excluding reclosers and sectionalises), shown in Figure 7.3.

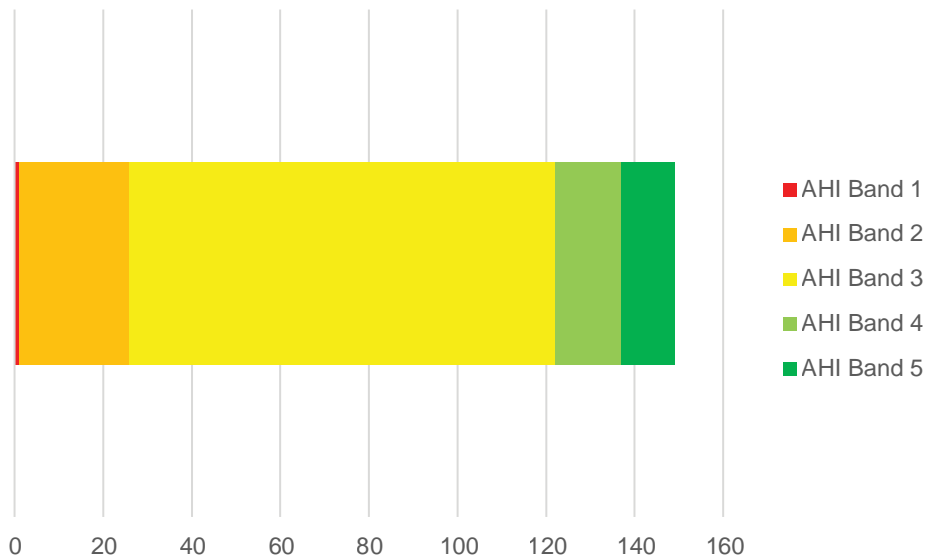


Figure 7.3: Circuit Breaker Current Asset Health Profile

The general guide is that:

- H1 is at end of serviceable life and immediate intervention is required
- H2 likely requires intervention as end-of-life drivers for replacement are present
- H3, H4 and H5 indicate good condition but still require regular inspection and maintenance.



Figure 7.4 shows the same information but includes the relevant criticality of each asset. This information gives a clearer picture of the overall risk and importance of the asset.

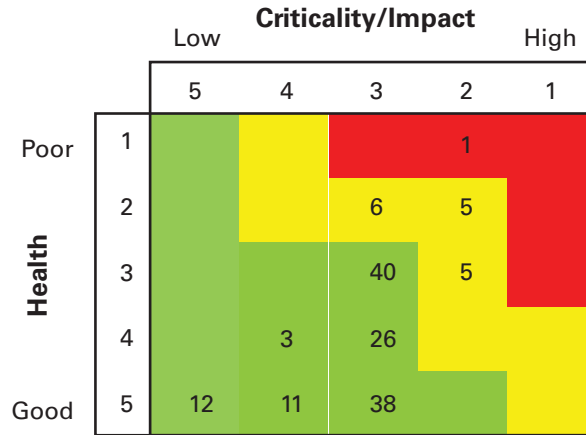


Figure 7.4: Circuit Breaker Criticality/Health Matrix

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 or structures 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.

Siemens Fusesaver sectionalisers are also interrogated, via a Bluetooth connection, for information that includes the state of the internal battery and operation count. Table 7.3 summarises the maintenance types and frequencies for the different types of switchgear.

Type	Frequency
Circuit breakers	<ul style="list-style-type: none"> • 3 monthly – Visual inspection • 12 monthly – Partial discharge test + infrared test • 3 yearly – Full service (including clean and oil change if required)
Reclosers and sectionalisers (sub-transmission and distribution)	<ul style="list-style-type: none"> • 12 monthly – Visual inspection • 2.5 yearly – Infrared scan • 10 yearly – Full service (including clean and oil change if required)

Table 7.3: Switchgear Maintenance Programme Summary

7.3.1.2 Replacement and Disposal

Scheduled replacement is based on asset condition and health, informed by MainPower’s asset health 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, including South Wales circuit breakers and McGraw Edison reclosers. The Nulec units installed on the network 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. We expect unscheduled replacement works to reduce during the next five years as the maintenance and replacement programme matures.

7.3.2 Ring Main Units

As shown in Figure 7.5, MainPower's RMUs are:

- cast resin (1960s through to early 2000s)
- oil filled (1960s through to early 2000s)
- vacuum or SF6 (post 2000).

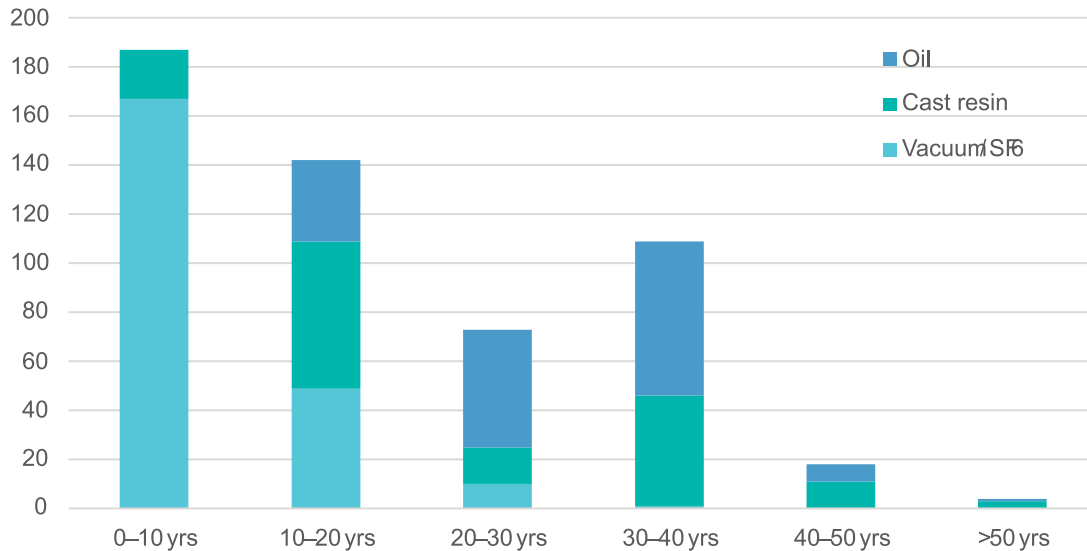


Figure 7.5: RMU Quantities and Age Profile

MainPower's older oil-filled RMUs currently have operational restrictions to reduce any inherent risk, and our replacement programme is targeting these assets to remove them from the network. A MainPower RMU asset health model has been developed to help optimise the replacement and maintenance programme for this asset fleet, as shown in Figure 7.6.

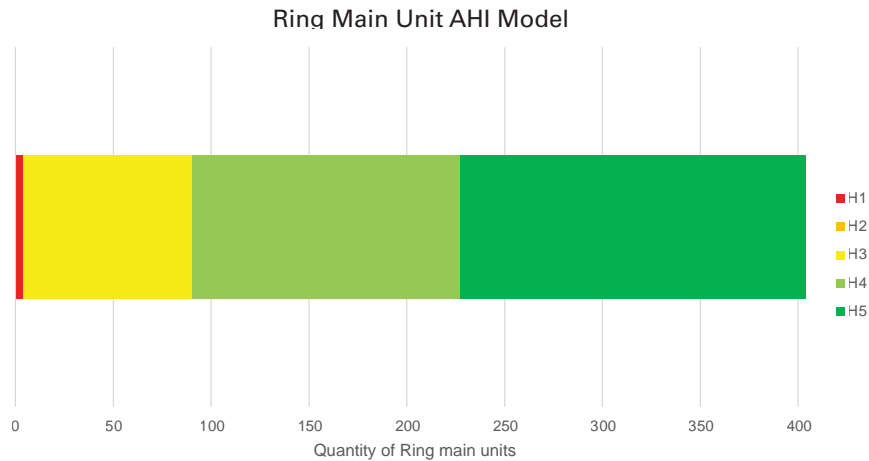


Figure 7.6: RMU Current Asset Health

7.3.2.1 Maintenance

Regular maintenance is important to ensure the safe and efficient operation of RMUs. Oil-filled and cast resin types are typically more expensive to maintain and service than the vacuum and SF6 types. SF6 units are checked regularly for gas levels to ensure there are no gas leaks.

Table 7.4 shows the maintenance types and frequencies for the different types of units.

Type	Frequency
Oil filled	<ul style="list-style-type: none"> • 12 monthly – Inspection + partial discharge test • 5 yearly – Service (including oil change) + infrared test
Cast resin	<ul style="list-style-type: none"> • 12 monthly – Inspection + partial discharge test + infrared test • 5 yearly – Service (including a full clean of contacts)
Vacuum/SF6	<ul style="list-style-type: none"> • 12 monthly – Inspection + partial discharge test • 5 yearly – Service + infrared test
All	<ul style="list-style-type: none"> • Real time – Indication including SF6 gas pressure alarm, operation count (where available)

Table 7.4: Switchgear Inspection and Maintenance Summary

7.3.2.2 Replacement and Disposal

MainPower’s RMU replacement programme is targeting the units with a low health score. In the medium to long term, it is expected that approximately 10 units will be replaced per year.

7.3.3 Pole-Mounted Switches

Pole-mounted 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); and
- Entec Fully Enclosed Vacuum Break (present).

Most historical pole-mounted switches are air break designs, with an increasing number of vacuum switches. The vacuum break switches have a good load-breaking ability, in addition to providing remote control and indication, helping to improve network visibility and providing opportunity for increased automation. Figure 7.7 gives the age profile of the pole-mounted switches.

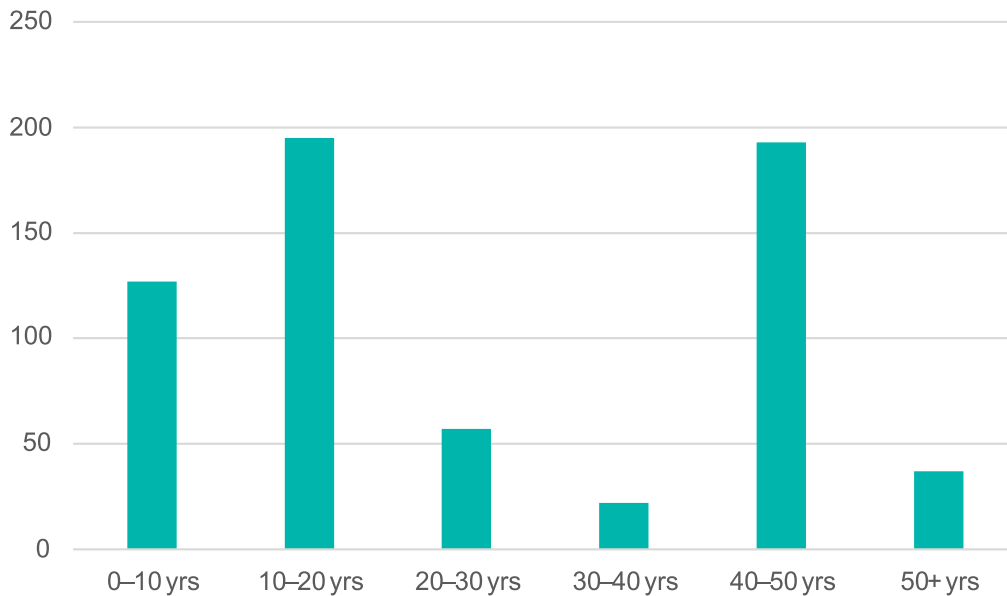


Figure 7.7: Pole-Mounted Switch Quantities and Age Profiles

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, as outlined below.

7.3.3.1 Maintenance

Pole-mounted switches are maintained every five years. This includes a condition assessment of the switch, which is combined with inspection and asset data to inform the replacement programme (see Table 7.5).

Type	Frequency
Pole-mounted switches	5 yearly – Visual inspection + full service + infrared test to identify hotspots

Table 7.5: Pole-Mounted Switchgear Inspection and Maintenance Summary

7.3.3.2 Replacement and Disposal

A replacement programme is in place to replace the older switches, prioritised through asset inspection data and observed asset reliability information. The implementation of the ADMS will enable more accurate collection of switch operation frequency and condition data from visual inspections, which will feed into an asset health replacement model to better prioritise the programme.

7.3.4 Low-Voltage Switchgear

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

- exposed (skeleton) panels
- D&S fused switches
- Terasaki circuit breakers
- ABB Fastline (SLK) fuse gear
- DIN-style fused switches (current type for new installations).

There is currently limited data in our asset database regarding quantities and types of low-voltage switchgear. MainPower has initiated an inspection programme to collect asset attribute and condition information. The known issues for the switchgear types outlined above are shown in Table 7.6.

Low-Voltage Switchgear Type	Known Issues/Defects
Exposed (skeleton) panels	<ul style="list-style-type: none">• Porcelain fuse handles, which can be the cause of localised heating• Exposed bus-work
D&S fused switches	<ul style="list-style-type: none">• Incomplete switching risk
Terasaki circuit breakers	<ul style="list-style-type: none">• Incomplete switching risk
ABB Fastline (SLK) fuse gear	<ul style="list-style-type: none">• Localised heating due to poor cable terminations
DIN-style fused switches	<ul style="list-style-type: none">• Localised heating due to poor cable or fuse terminations

Table 7.6: Low-Voltage Switchgear Common Defects

7.3.4.2 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 7.7). Any defects 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 7.7: Low-Voltage Switchgear Inspection Summary

7.3.4.2 Replacement and Disposal

The units most likely to be prioritised for replacement will be the exposed panels, D&S fused switches and Terasaki circuit breakers, owing to their issues. The replacements are often combined with RMU maintenance or replacement to reduce the number of outages.

7.4 Transformers



The sub-categories and quantities of MainPower’s transformers are summarised in Table 7.8.

Transformer Fleet	Quantity
Power transformers	26
Distribution transformers	8,499
Voltage regulators	24

Table 7.8: MainPower’s Transformers

7.4.1 Power Transformers

MainPower’s zone substation power transformers transform sub-transmission voltages of 66 kV or 33 kV down to distribution voltages of 11 kV, 22 kV or 400 V. Their power ratings range from 0.3 kVA for isolated rural supplies up to 40 MVA within the densely populated parts of the network. MainPower also has five 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. The age profile of the in-service transformers is shown in Figure 7.8. The power transformer fleet has a typical nominal life of 45 years; however, this can vary significantly, depending on the load and operating conditions. Southbrook zone substation was rebuilt and commissioned in FY23 with two new 40 MVA transformers included in the following transformer figures.

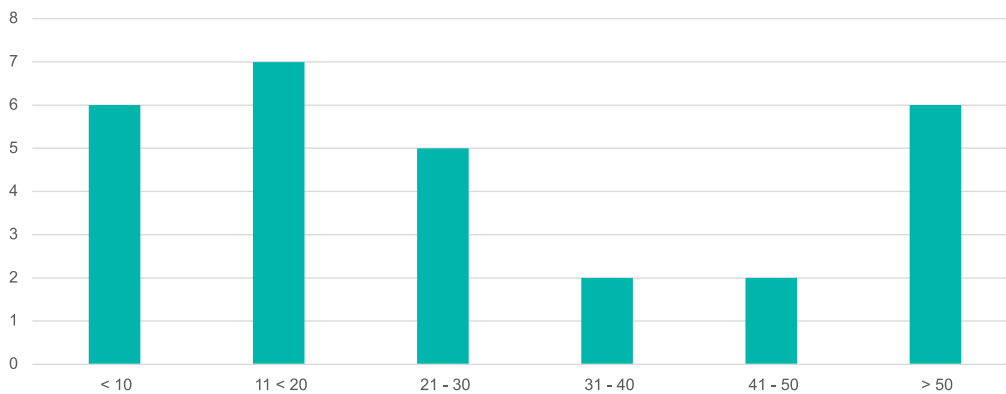


Figure 7.8: Power Transformer Age Profile

The power transformer fleet is managed using MainPower’s Power Transformer AHI Model. While the model was improved in 2019, resulting in a realignment of some transformers across categories, the overall asset fleet health numbers have remained largely unchanged relative to their condition (see Figure 7.9).

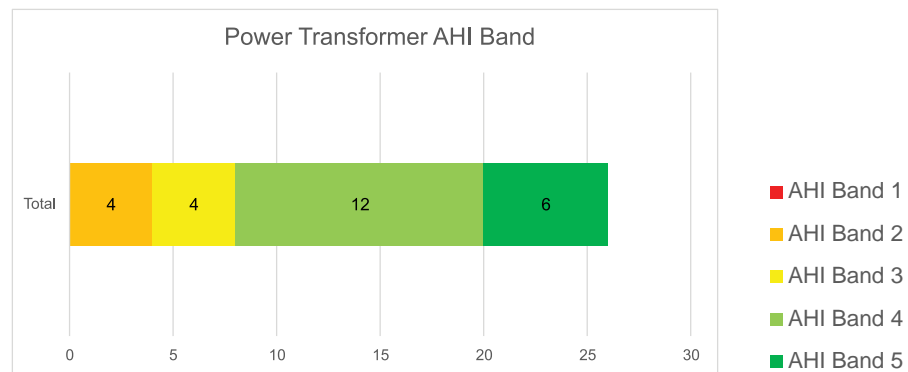


Figure 7.9: Power Transformer Current Asset Health

Four of the units with the lowest AHI scores are in the 51- to 60-year age bracket 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 in the 41- to 50-year age bracket. As the remaining units are showing no major defects and are ageing in accordance with their typical lifespans and loadings, much of the replacement will be undertaken as part of the major project.

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 7.9). 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.

Type	Frequency
Power transformers	3 monthly – Visual inspection as part of zone substation inspection schedule
	12 monthly – Dissolved gas analysis
	12 monthly – Thermographic and acoustic partial discharge tests
	5 yearly – Major service, including tap-changer service, electrical testing of transformer and accessories

Table 7.9: Power Transformer Inspection and Maintenance Summary

Oil treatment for moisture and acidity have 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 results, which are 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.

7.4.2 Distribution Transformers

MainPower has more than 8,300 distribution transformers in service, with approximately 85% pole mounted and the remaining units ground mounted either in kiosks or as stand-alone units. These transformers supply end users with single-phase 230 V or three-phase 400 V. The age profile of these is shown in Figure 7.10.

Failure modes that drive distribution transformer replacement are:

- oil leaks;

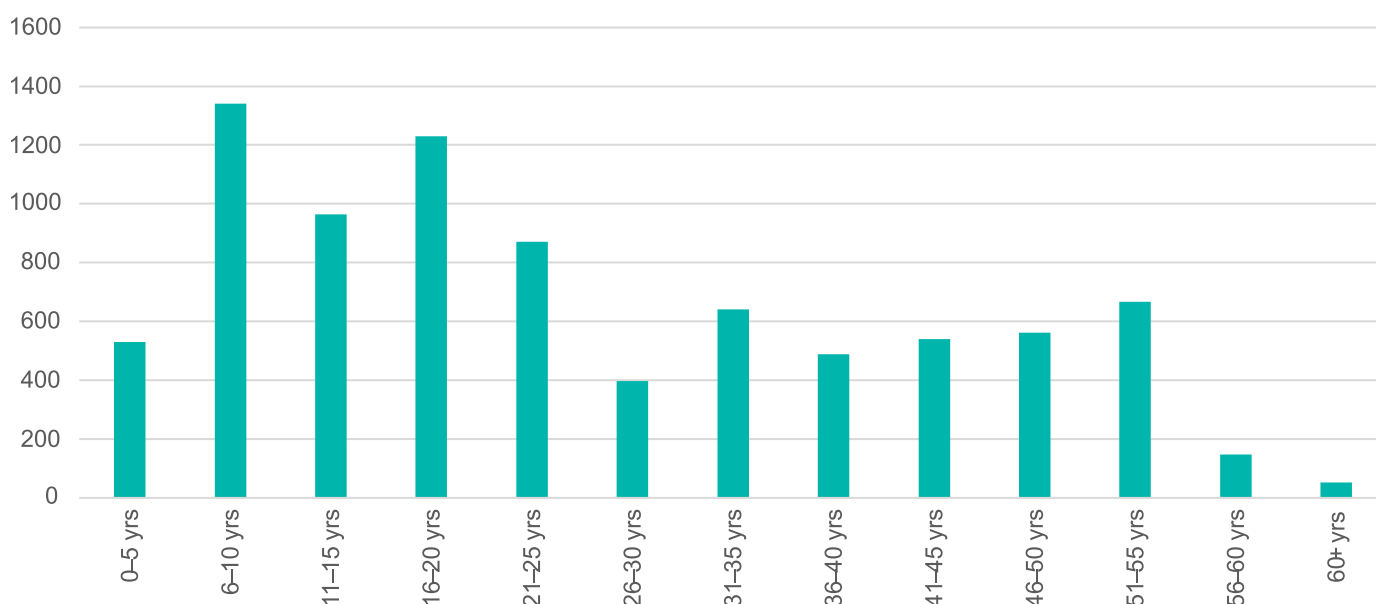


Figure 7.10: Distribution Transformer Age Profile

7.4.3 Ground-Mounted Distribution Transformers



MainPower operates approximately 800 ground-mounted distribution transformers. All units are mineral oil filled. The ratings, quantities and age profiles are summarised in Table 7.10 and Figure 7.11.

Rating	Number of Transformers	% of Total
> 15 and ≤ 30 kVA	20	1%
> 30 and ≤ 100 kVA	546	40%
> 100 and ≤ 500 kVA	696	51%
> 500 kVA	95	7%
Total	1,357	99%

Table 7.10: Ground-Mounted Distribution Transformers – Quantities

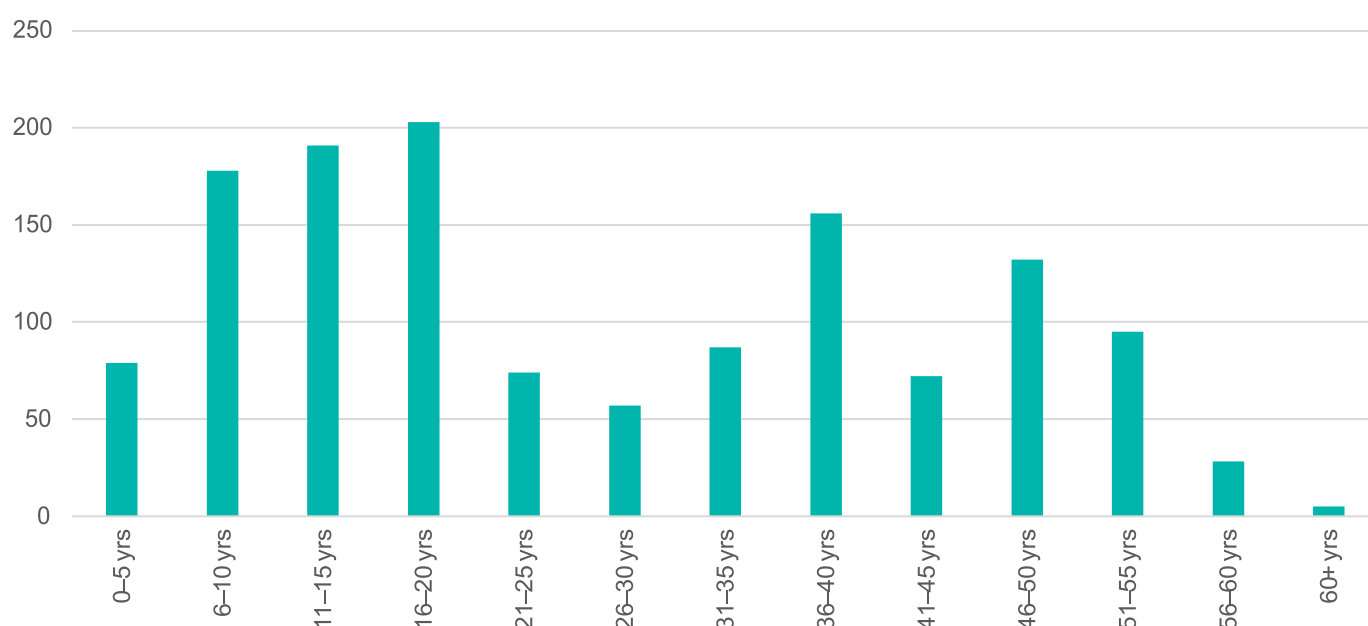


Figure 7.11: Ground-Mounted Distribution Transformers – Age Profiles

7.4.3.1 Maintenance

Ground-mounted distribution transformers are inspected on both an annual and a five-yearly cycle (see Table 7.11). Oil samples are taken for analysis on units over 500 kVA on a five-yearly basis owing to the size and criticality of these units.

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 7.11: Ground-Mounted Transformer Inspection and Maintenance Summary

7.4.3.2 Replacement and Disposal

Ground-mounted 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.

7.4.4 Pole-Mounted Distribution Transformers

MainPower operates approximately 7,000 pole-mounted distribution transformers. All units are mineral oil filled. Their ratings, quantities and age profiles are summarised in Table 7.12 and Figure 7.12.

Rating	Number of Transformers	% of Total
≤ 15 kVA	2,988	42%
> 15 and ≤ 30 kVA	1,943	27%
> 30 and ≤ 100 kVA	1,822	26%
> 100 kVA	321	5%
Total	7,074	100%

Table 7.12: Pole-Mounted Transformer Quantities

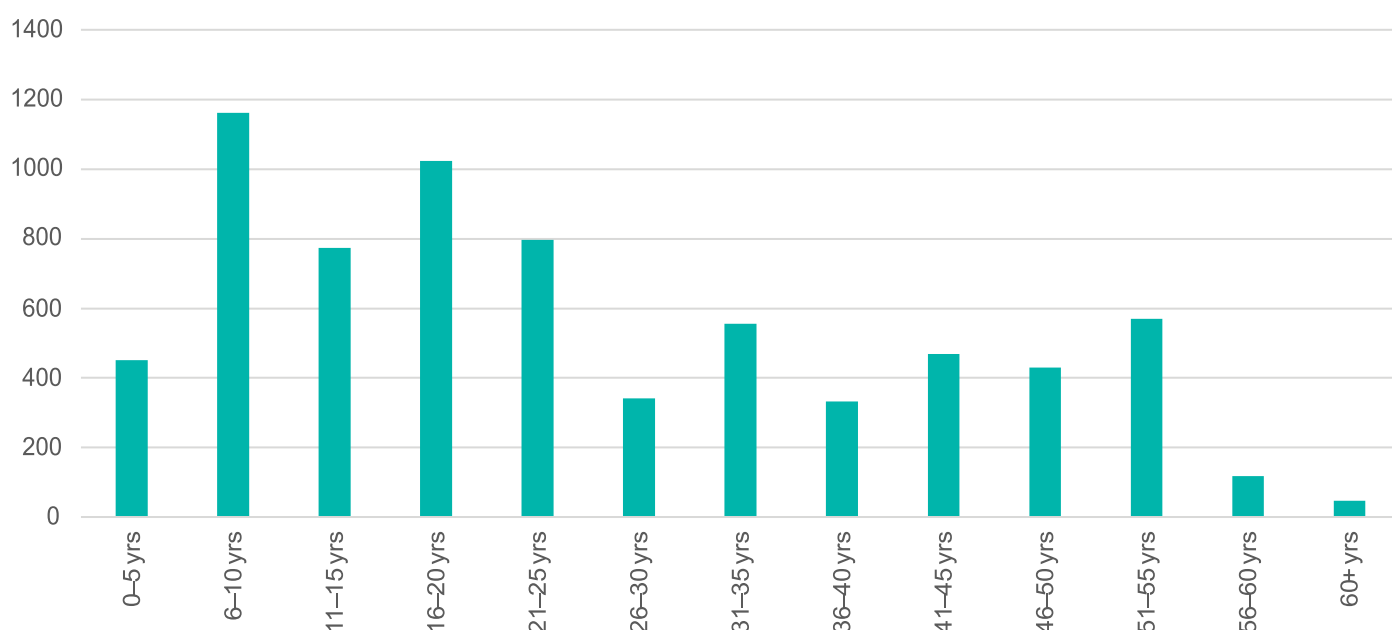


Figure 7.12: Pole-Mounted Distribution Transformer Age Profiles

7.4.4.1 Maintenance

Pole-mounted distribution transformer inspections are carried out from the ground and include testing of the earthing system (see Table 7.13).

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

Table 7.13: Pole-Mounted Distribution Transformer Inspection Summary

7.4.4.2 Replacement and Disposal

Ground-mounted 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.



7.4.5 Voltage Regulators

MainPower operates 21 single-phase 11 kV voltage regulators, which are located across 10 sites, with five new sites commissioned in March 2020. Voltage regulators act to stabilise the voltage in the distribution network within prescribed limits for consumers. This asset fleet will remain active, with the possibility of further installations if voltage issues are predicted because of load growth across the network.

The voltage regulators are mostly 220 kVA General Electric devices with automatic controllers. The age profile is between 1 and 20 years, with an expected life of 45 years in normal service. No issues have been identified with the existing regulator assets.

7.4.5.1 Maintenance

The regulator’s maintenance programme is aligned with MainPower’s asset inspections and maintenance programme for pole-mounted transformers (see Table 7.14).

Type	Frequency
Regulators	5 yearly – Asset inspection, including oil sampling

Table 7.14: Regulator Inspection and Maintenance Summary

7.4.5.2 Replacement and Disposal

No replacements are planned for this asset class. Disposal of these units will be in line with other oil-filled equipment at the end of their life, expected in around 30 years’ time.

7.4.6 Zone Substations

MainPower’s electricity distribution network is supplied via five 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 to supply the 11 kV and 22 kV distribution network. An image of the electricity distribution network is shown in Figure 7.13, followed by a summary of the zone substation capacity and feeders (Table 7.15).



Figure 7.13: Zone Substation Locations

Rating	Voltage (kV)	Substation Capacity (MVA)	Type
Southbrook	66/11	80	Indoor
Swannanoa	66/22	46	Indoor
Burnt Hill	66/22	46	Indoor
Amberley	33/11	8	Indoor
Mackenzies Rd	66/11	4	Outdoor
Greta	66/22	4	Outdoor
Cheviot	66/11	4	Outdoor
Leader	33/11	4	Outdoor
Oaro	33/11	0.5	Outdoor
Ludstone Rd	33/11	12	Indoor
Hawarden	33/11	4	Outdoor
Mouse Point	33/22	26	Outdoor
Marble Point	33/11	2	Outdoor
Lochiel	33/11	0.2	Outdoor
Hanmer	33/11	6	Indoor
Kaikōura	66/33	16	Outdoor

Table 7.15: Zone Substation Statistics

7.4.6.1 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 7.16).

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 7.16: Zone Substation Inspection and Maintenance Summary

7.4.6.2 Replacement and Disposal

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.

7.4.7 Switching Substation



In addition to zone substations, MainPower operates seven switching stations that form part of the 11 kV electricity distribution network (see Table 7.17). 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 St	11 kV	Indoor
Oxford	11 kV	Indoor
Bennetts	11 kV	Indoor
Kaiapoi S1	11 kV	Indoor

Table 7.17: 11 kV Switching Stations

7.4.7.1 Maintenance

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

7.4.7.2 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.

7.5 Underground Assets

The underground assets portfolio is made up of four asset fleets, shown in Table 7.18.

Asset Fleet	Length/Quantity
High-voltage underground cables	373 km
Low-voltage underground cables	1,250 km
Low-voltage service boxes	Approx. 10,000
Low-voltage link boxes	680

Table 7.18: Underground Asset Quantities

7.5.1 High-Voltage Underground Cables

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

Most of our conductor assets are within their nominal technical life. Known defects with this asset class are generally related to the cable terminations or joints. In particular, historical "pothead" - type terminations are replaced proactively because of known age-related failures.

7.5.1.1 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.

7.5.1.2 Replacement and Disposal

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

7.5.2 Low-Voltage Underground Cables

MainPower’s low-voltage underground cables are primarily 185 mm² aluminium cables, with some 120 mm² aluminium cables historically installed in smaller subdivisions, owing to their lower load requirements.

7.5.2.1 Maintenance/Inspections

The inspection criteria for these assets fall within the maintenance and inspection programmes for other assets, which typically are assets housing and supporting the cable termination, such as distribution buildings, kiosks and boxes, overhead low-voltage lines and zone substations. Most end terminations are inspected visually at five-year intervals, with a criticality-based approach employed to cable termination locations in higher-criticality areas such as business districts, parks, public amenity areas and schools (see Table 7.19).

Type	Frequency
Low-voltage underground cables	5 yearly – As part of general inspection and maintenance programme

Table 7.19: Low-Voltage Underground Cable Inspection Summary

7.5.2.2 Replacement and Disposal

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.

7.5.3 Low-Voltage Distribution Boxes



MainPower's low-voltage distribution boxes consist of:

- **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 service fuses 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).

MainPower recently initiated a new condition assessment programme to document the condition of these assets. This programme is underway and will collect condition data electronically on all link and service boxes over the five-year maintenance cycle.

Service boxes are undergoing a detailed inspection because of known overheating problems at service fuses. All service boxes on MainPower's network will have the quality of fuse terminations inspected over a five-year period, projected to be completed in 2023. Defects with service fuse terminations are repaired as found

7.5.3.1 Maintenance

Criticality-based maintenance is employed to determine the inspection priority of the low-voltage distribution boxes (see Table 7.20). For those located in higher-criticality areas, such as business districts, parks, public amenity areas and schools, these receive a more frequent inspection programme.

Type	Frequency
Low-voltage distribution boxes	Table 7.20: Low-Voltage Distribution Box Inspection Summary

Table 7.20: Low-Voltage Distribution Box Inspection Summary

7.5.3.2 Replacement and Disposal

MainPower currently has a programme to replace historical metal frame service boxes over the next 10 years, driven by asset condition. Other low-voltage distribution box replacements are primarily driven by defects identified by the inspection programme, or as a result of third-party damage.



7.6 Vegetation Management

The majority of MainPower’s overhead network is in rural areas. Vegetation is an ongoing concern and a common cause of outages, especially during high-wind events. MainPower communicates regularly with the public through different channels, including local newspapers and radio. 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.

7.6.1 Maintenance

In 2020, a review of our vegetation management programme was conducted with the aim of reducing unplanned outages and the risk of vegetation making contact with lines.

Prior to this review, MainPower split vegetation into three groups depending on the criticality of the overhead lines. The highest-criticality lines (sub-transmission) were inspected on an annual basis; the lowest-criticality lines (rural spurs with few connections) were on a three-yearly cycle; and all lines in between were on an 18-month cycle.

Starting with the 2020/2021 financial year, this programme was changed so that all lines are inspected annually. This is expected to reduce the number of unplanned outages by ensuring no vegetation enters a line’s growth limit zone. Lines in higher fire-risk areas are inspected in September each year so that notice letters can be sent and vegetation trimmed before the peak of summer, reducing the potential for contact with lines and for fires to start. The creation of the network Digital Twin as part of the LiDAR project initiated this year will help MainPower identify vegetation encroachments in the short term. This will eventually lead to better vegetation management plans to maintain corridors and clearances 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. These crews are supported by a Vegetation Inspector and Vegetation Control Supervisor, who work as required with tree owners and local authorities to support the maintenance programme.

7.7 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
- Communication/SCADA
- Load control/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.

7.7.1 DC Systems

MainPower’s DC systems are split into two 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 (see Table 7.21).

Asset	Nominal Life	Quantity
DC batteries	10 years	238
	5 years	239
	2 years	3
	Total	480

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 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. As with battery replacement, one local supplier has been chosen for all new chargers.

7.7.1.1 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

7.7.1.2 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.

7.7.2 Protection

The electricity distribution network has protection relays located in zone and switching substations, RMUs and reclosers. Figure 7.14 shows the number and age of the current protection relays.

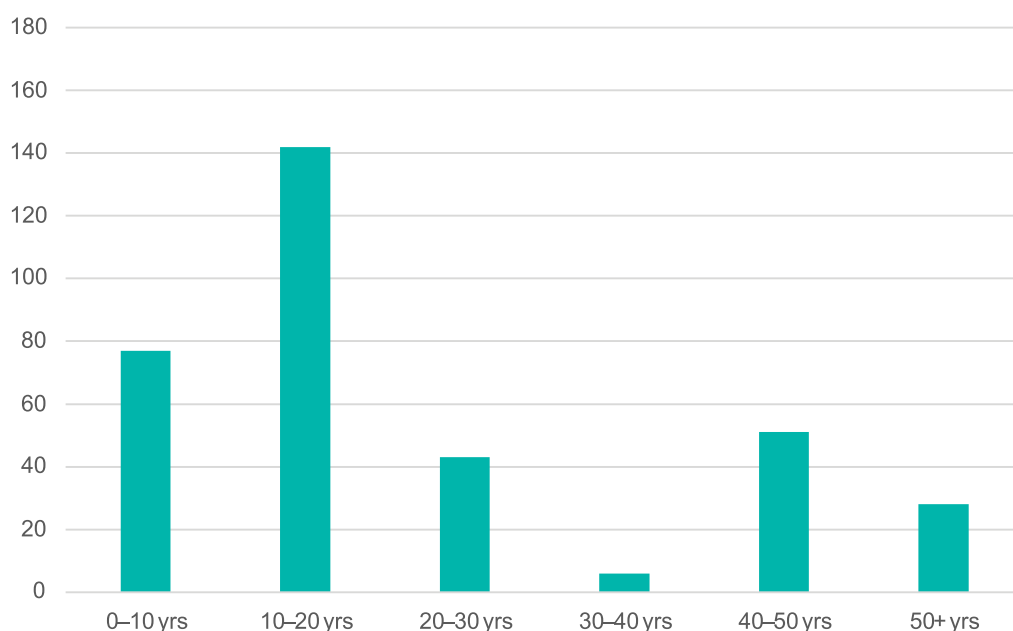


Figure 7.14: Protection Relay Age Profile

7.7.2.1 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	<ul style="list-style-type: none"> • 3 monthly – Visual inspection • 5 yearly – Full system test (digital)
Recloser	<ul style="list-style-type: none"> • 12 monthly – Visual inspection • 10 yearly – Full system test
RMU	<ul style="list-style-type: none"> • 12 monthly – Visual inspection • 5 yearly – Full system test
All sites	<ul style="list-style-type: none"> • Real time – Relay fail and other diagnostics (where available with digital relays)

Table 7.23: Protection Relay Inspection and Maintenance Summary

7.7.2.2 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.

7.7.3 Communications and SCADA

MainPower operates both a voice and 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, including 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, which currently use Tait voice radios and Mimomax data radios, is shown in Figure 7.15.

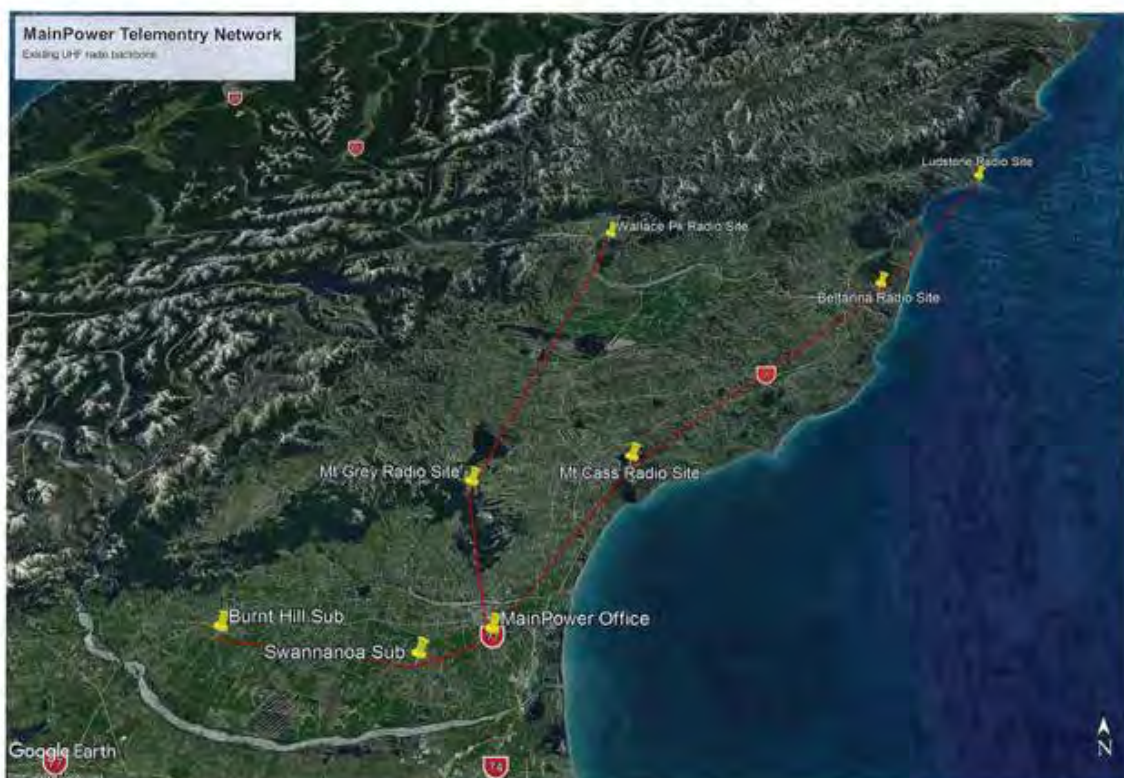


Figure 7.15: MainPower’s Voice and Data Communications Network

MainPower’s SCADA system is an Open Systems International 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 Racam RipEX technology. The maximum capacity of the newer systems currently deployed is 360 kbit/s and they are operating reliably.

7.7.3.1 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 a schedule: every six months for visual inspections and 12 months for diagnostic testing and servicing (see 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

7.7.3.2 Replacement and Disposal

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.

7.7.4 Load Control and Ripple Plant

MainPower uses Landis+Gyr SFU-G and 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 (see Table 7.25).

Rating	Age (years)	Operating Voltage (kV)
Kaiapoi GXP	18	11
Ludstone Rd	19	11
Mouse Point	18	33
Southbrook	1	11
Waipara GXP	17	66
Ashley GXP	8	11
Swannanoa	8	22
Burnt Hill	8	22

Table 7.25: Load Plant Location, Age and Operating Voltage

While the load control plants are generally in good condition, the SFU-G transmitter at Kaiapoi GXP is considered obsolete by Landis+Gyr and is no longer supported. MainPower has a complete spare unit on warm standby in case of failure.

7.7.4.1 Maintenance

Load plant control and 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.

7.7.4.2 Replacement and Disposal

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

7.8 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	4
Staff house	3
Storage building	6
Equipment and kiosk cover	781
Total	856

Table 7.26: MainPower's Property and Building Assets

7.8.1 Zone Substation 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	5	2
Concrete block	4	2
Concrete tilt slab	0	7
Container	0	2
Totals	9	13

Table 7.27: Zone Substation Building Types



7.8.1.1 Maintenance

Zone substation 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 buildings	3 monthly – Visual inspection

Table 7.28: Zone Substation Building Inspection Summary

All zone substation buildings had a detailed seismic assessment and building code compliance assessment carried out during the 2019 financial year. The outcomes of this assessment are being used to inform whether future strengthening work is required.

Asbestos surveys have been carried out on all zone substation 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.

7.8.1.2 Replacement and Disposal

The Rangiora North Zone Substation building will be removed following decommissioning of the zone substation in the 2022 financial year.

7.8.2 Distribution Substation Buildings

MainPower has 33 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 19 to 61 years, with most in the range of 50 to 60 years, as shown in Figure 7.16.

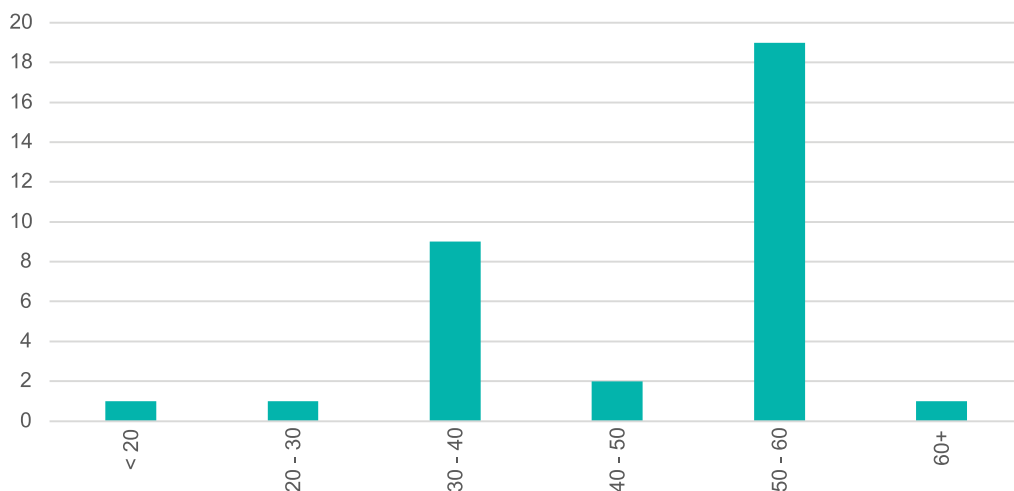


Figure 7.16: Age Profile of Distribution Substation Buildings

These buildings are in generally good condition, given their age. A detailed structural assessment in 2019 indicated they are fit for purpose, with some modifications required on a selection of buildings to increase their strength, typically in the roofing.

7.8.2.1 Maintenance

The solid concrete or masonry construction of these buildings requires little ongoing maintenance. Repairs and maintenance are carried out when issues are raised during routine inspections or in field defect reports.

7.8.2.2 Replacement and Disposal

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

7.8.3 Distribution Kiosks

Distribution kiosks are small ground-mounted covers that house electrical equipment. The covers are constructed from various materials, typically steel, fibreglass or plastic (see Figure 7.17).

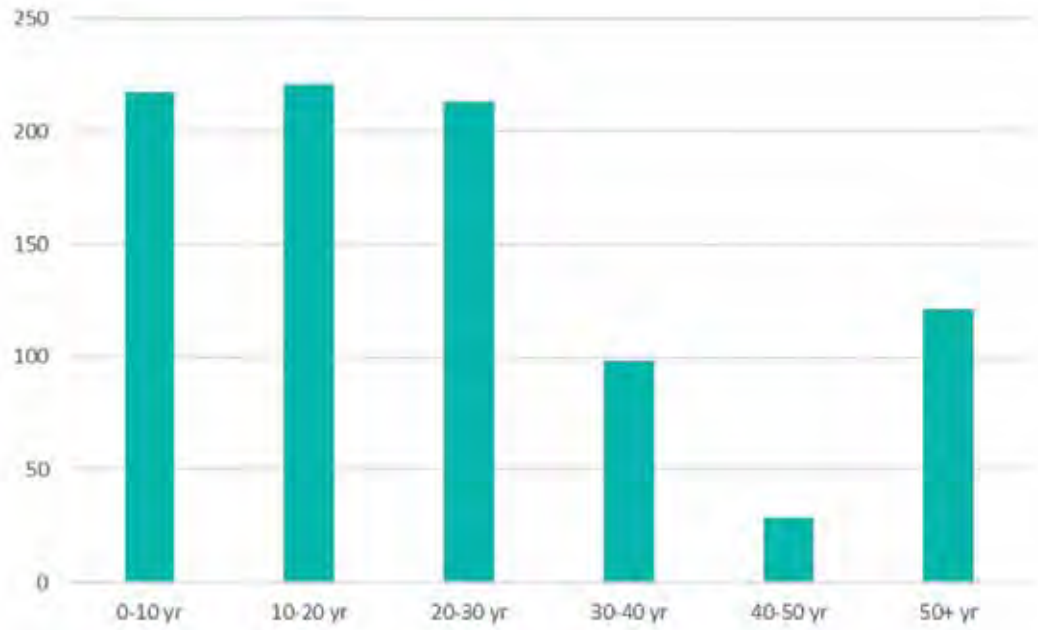


Figure 7.17: Age Profile of Kiosk Covers (Enclosures)

While the covers are generally in good condition, known issues include steel covers being prone to corrosion, especially in coastal areas, and fibreglass covers being susceptible to UV damage over time. These defects are monitored during the kiosk inspection programme, and repairs or replacements are made where necessary.

7.8.3.1 Maintenance

Kiosk covers are visually inspected on an annual basis as part of the electrical equipment inspections at the site.

7.8.3.2 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.

7.8.4 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	4
Staff Housing – #2	Culverden	3
Staff Housing – #3 (unoccupied, to sell)	Culverden	51
Office building	Culverden	42
Storage shed/workshop	Culverden	42
Holiday home	Hanmer Springs	42
Holiday home	Kaikōura	42
Corporate office and operational facilities	Rangiora	7

Table 7.29: MainPower's Non-Electricity Distribution Network Buildings

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

The buildings consist of:

- 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; and
- A 2,000 m² single-storey stores, 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 major 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 are received within 90 seconds of an earthquake and compare the site acceleration against building service levels, informing key staff of any possible damage to the building or its services.

7.8.4.1 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.

7.8.4.2 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.

7.9 Innovations

MainPower continues to innovate. In 2022, we:

- centralised all our assets into a single asset register, including other enhancements such as single crossarm assets, with an improved capitalisation process across all our assets
- completed our Digital Twin programme for the lifecycle design management of all our OH structures, including an environment to truly model the impact of climate change on our network assets
- embarked on the implementation of CBRM modelling for our overhead and switchgear fleet.

7.10 Non-Electricity Distribution Network Assets

7.10.1 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 ERP-integrated platform that is used for all asset management, works management and financial reporting
- GE Digital's Smallworld GIS, which is used as the primary geographical data repository for electricity distribution asset data
- customer relationship management from Salesforce for managing 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.

7.10.1.1 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.

7.10.1.2 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.

7.10.1.3 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.

7.10.1.4 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.

7.10.1.5 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.

7.10.2 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 lon-type meters, installed after year 2000. MainPower's ripple injection plants are located in Transpower GXPs at Waipara, Ashley and Kaiapoi. We also have SCADA and local service equipment associated with load control at these sites.



7.10.3 Mobile Generation Assets

MainPower has invested in a mobile diesel generation plant to assist with reducing the number of planned interruptions. The plant is rated at 275 kVA. The 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 smaller 88 kVA generator for use with low-voltage customers. This is often large enough to supply small subdivisions during maintenance.

7.10.4 Other Generation

MainPower owns and operates a 1 MW generation asset that is located at Cleardale 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 AMP planning period. It is structured to align with the internal expenditure categories and forecasts provided in earlier sections

8.1 Total Network Expenditure Summary

8.1.1 Total Network Expenditure Forecast

Category	Expenditure (\$000)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Network Major Projects	7,895	8,710	6,960	5,000	5,000	6,500	4,000	4,500	3,500	6,300
Network Reinforcement Projects	2,730	3,652	3,236	2,728	2,747	2,748	2,751	2,751	2,749	2,741
Network Replacement	8,568	8,900	9,250	9,387	9,557	9,847	10,197	10,547	10,897	11,247
Network Maintenance	6,584	5,744	5,460	5,367	5,317	5,524	5,718	5,373	5,437	5,344
Network Operations	1,500	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455
Non-Network	2,179	2,417	2,092	1,842	2,292	1,842	1,842	1,842	2,292	1,842
Customer-Initiated Works	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
TOTAL	35,456	36,878	34,453	31,779	32,368	33,916	31,963	32,468	32,330	34,929

Table 8.1: Network Total Expenditure Summary FY24–FY33

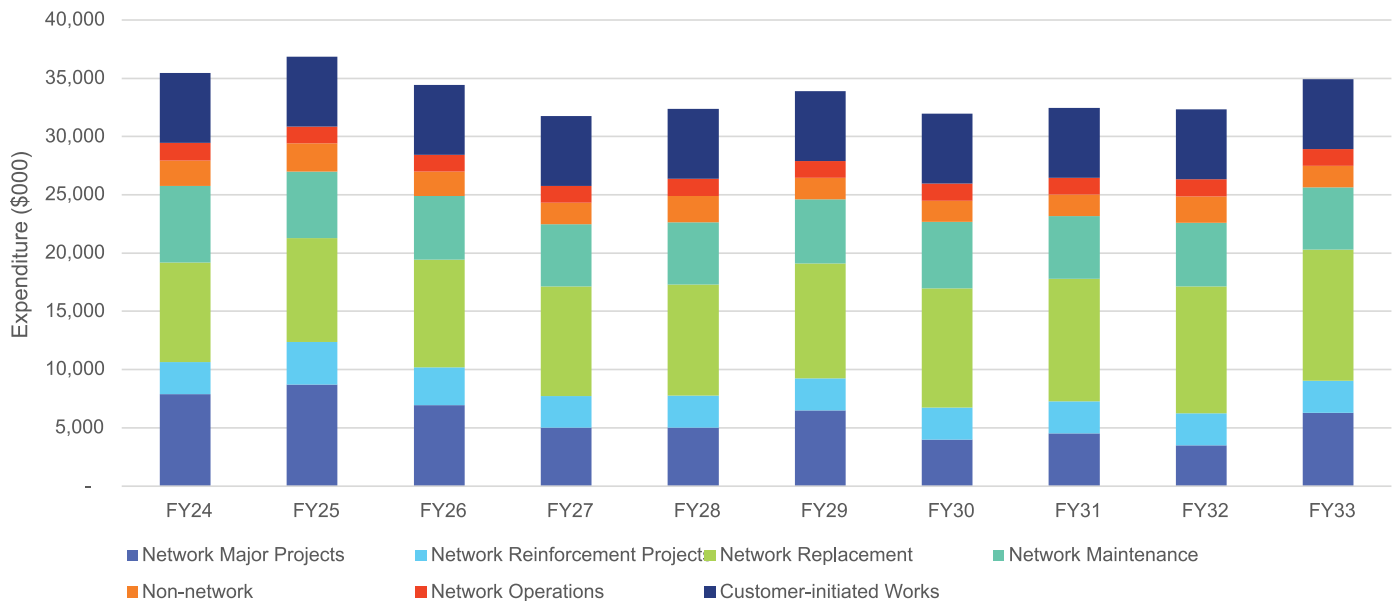


Figure 8.1: Network Expenditure Forecast FY24–FY33

8.2 Network Replacement



8.2.1 Network Replacement Expenditure

Asset Portfolio	Expenditure (\$000)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Overhead Network	5,185	5,535	5,885	6,235	6,585	6,935	7,285	7,635	7,985	8,335
Kiosks and Building Substations	768	728	728	728	548	548	548	548	548	548
Transformers	570	570	570	570	570	570	570	570	570	570
Switchgear	348	450	450	450	450	450	450	450	450	450
Secondary Systems	414	414	414	414	414	414	414	414	414	414
Underground Network	854	774	774	600	600	600	600	600	600	600
Network Property	139	139	139	100	100	45	45	45	45	45
Corrective Replacement	290	290	290	290	290	285	285	285	285	285
Network Replacement Subtotal	8,568	8,900	9,250	9,387	9,557	9,847	10,197	10,547	10,897	11,247

Table 8.2: Network Replacement Expenditure Summary

8.3 Network Maintenance

8.3.1 Network Maintenance Expenditure

Asset Portfolio	Expenditure (\$000)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Overhead Network	2,277	1,686	1,845	1,836	1,809	1,799	1,664	1,830	1,821	1,804
Zone Substations	829	1,042	694	629	540	657	1,043	598	681	542
Kiosks and Building Substations	669	619	531	518	582	681	620	551	539	601
Transformers	563	347	337	337	337	337	337	337	337	337
Switchgear	351	298	301	303	305	308	310	313	316	318
Secondary Systems	107	69	69	69	69	69	69	69	69	69
Underground Networks	545	460	460	460	460	460	460	460	460	460
Network Management	103	103	103	94	94	94	94	94	94	94
Vegetation	1,140	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Network Maintenance Subtotal	6,584	5,744	5,460	5,366	5,316	5,525	5,717	5,372	5,437	5,345

Table 8.3: Network Maintenance Expenditure Summary

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 that occur during the lifetime of the physical asset, as outlined in Figure 9.1.

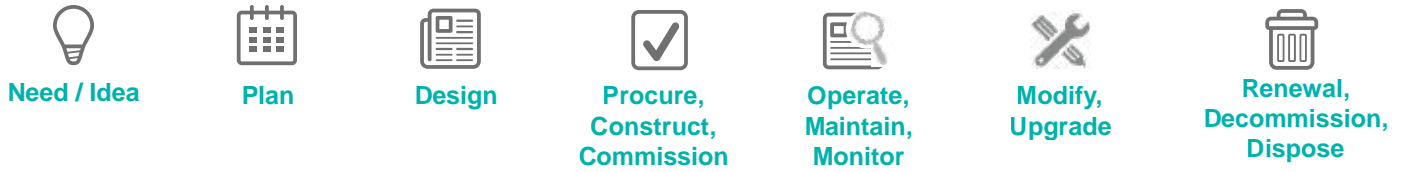


Figure 9.1: Asset Lifecycle Planning

The roles required throughout the asset lifecycle activities are detailed in Figure 9.2.

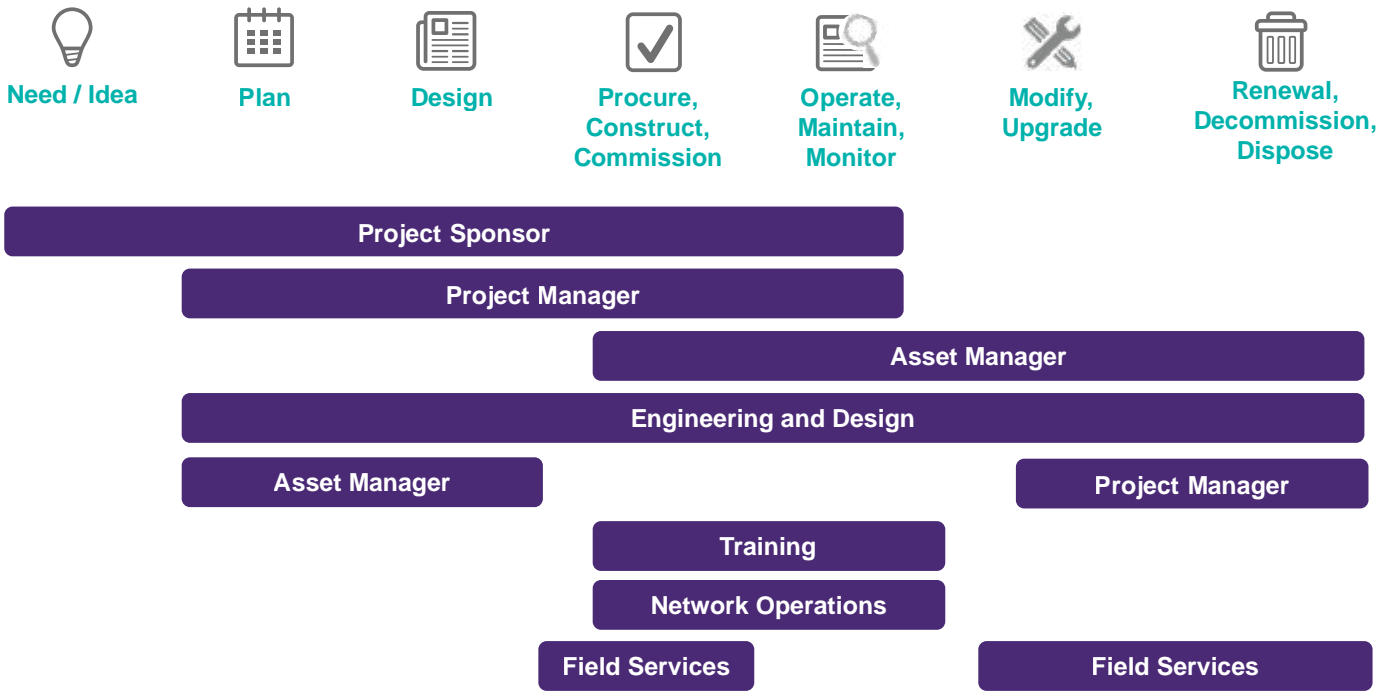


Figure 9.2: Alignment of Roles and Responsibilities against Lifecycle Activities

The responsibilities for each of these roles are outlined in clear position descriptions for them. If there is a gap between the role requirements and the competencies of the individual appointed to the role, a personal development programme is required to address the gap.

- **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:** 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.
- **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, GIS and Records Team.
- **Engineering and Design:** Involved in the development and approval of all designs, including safety by design.
- **NOCC:** MainPower control room resources for the safe operation and network release for working groups.

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.





Asset Management Plan 2023–2033

Appendices

This section provides additional information to support MainPower’s Asset Management Plan, 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
AMP	Asset Management Plan
AMMAT	Asset Management Maturity Assessment Tool
CBRM	condition-based risk management
CDEM	civil defence emergency management
CIMS	coordinated incident management system
CIS	customer information system
CMMS	computerised maintenance management system
Distribution Network	The power lines and underground cables that transport electricity from the national grid to homes and businesses
EDB	electricity distribution business
EEA	Electrical Engineers' Association
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
HRC	high rupturing capacity
ICP	installation control point
IT	information technology
kV	kilovolt
kVA	kilovolt-ampere
LCT	low-carbon technology
Master Plan	long-term network capacity development plan
MVA	mega-volt ampere
MW	megawatt (1 megawatt = 1,000 kilowatts = 1,000,000 watts)
MWh	megawatt-hours
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
NOCC	Network Operation & Control Centre
OMS	outage management system
Opex	operational expenditure
RMU	ring main unit
SaaS	software as a service

Term or Abbreviation	Definition
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SF6	sulphur hexafluoride
Statement of Corporate Intent	An annual document that outlines the overall intentions of the company and the objectives which 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
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 electric energy and connect between two or more feeders
XLPE	cross-linked polyethylene
Zone Substation	A substation that converts energy from transmission or sub-transmission voltages to distribution voltages



Appendix 2 – Description of Asset Management Systems



System	Definition
Accounting Systems	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> The asset management suite within the TechnologyOne platform is the principal source of data related to MainPower assets.
GIS	<ul style="list-style-type: none"> MainPower uses GE Digital's Smallworld platform (a geographic information system) for the management of spatial asset information. The TechnologyOne software platform has been integrated with the GIS system.
Infrastructure	<ul style="list-style-type: none"> MainPower's hardware and server software is continually updated, consistent with modern high-capacity hardware platforms. Information security management includes maintaining offsite backup facilities for stored information for protection from a security breach or disaster.
Works Management System	<ul style="list-style-type: none"> 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.
SCADA and Load Management Systems	<ul style="list-style-type: none"> Invensys Wonderware "Intouch" SCADA system: <ul style="list-style-type: none"> Displays voltage, current, and status information in real time from remote points on the network; Receives instantaneous information on faults; and Remotely operates equipment from the control centre. We operate Landis & Gyr ripple injection plants and On Demand load management software to control: <ul style="list-style-type: none"> Customer water heaters, to limit system peak loads and area loading constraints (mainly during winter months); Street lighting; and Electricity retailer tariffs.
AutoCAD	<ul style="list-style-type: none"> 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 GIS system.
Customer Information System (CIS)	<ul style="list-style-type: none"> 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.
Communication Systems	<ul style="list-style-type: none"> 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 communication.
Human Resource Systems	<ul style="list-style-type: none"> 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.
Inventory Systems	<ul style="list-style-type: none"> 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.
Outage Management System (OMS)	<ul style="list-style-type: none"> 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.
MACK CRM	<ul style="list-style-type: none"> Customer relationship management system to manage customer enquiries and jobs. Includes registry integration.

Appendix 3 – Directors' Certificate




MainPower New Zealand Limited
172 Ferris Road, RD 1, Saling 5017
PO Box 260, Rangiora 7600
T 044 8 35 6000 F 044 8 35 8000

CERTIFICATE FOR YEAR-BEGINNING 1 APRIL 2023 DISCLOSURE

Pursuant to Clause 2.9.1 of Section 2.9 of the Electricity Distribution Disclosure Determination 2012 (consolidated 9 December 2021)

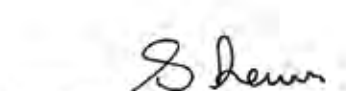
We, ANTHONY CHARLES KING and STEPHEN PAUL LEWIS, being Directors of MainPower New Zealand Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

- a) The following attached information of MainPower New Zealand Limited prepared for the purposes of clauses 2.6.1, 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; and
- 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
02/22/2023 15:20 NZDT

Date



Stephen Paul Lewis
Stephen Lewis
02/22/2023 10:34 NZDT

Date

www.mainpower.co.nz

Appendix 4 – Schedule 11a: Report on Forecast Capital Expenditure

11a(i): Expenditure on Assets Forecast

Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
\$000 (in nominal dollars)										
Consumer connection	6,414	6,670	6,853	6,968	7,112	7,252	7,398	7,547	7,699	7,853
System growth	3,246	3,012	2,824	2,653	2,497	2,357	2,232	2,121	2,023	1,936
Asset replacement and renewal	11,575	9,145	8,893	10,933	11,328	11,902	12,573	13,266	13,982	14,721
Asset relocations	--	--	--	--	--	--	--	--	--	--
Reliability, safety and environment:										
Quality of supply	1,152	1,696	2,181	2,446	2,794	2,800	2,997	3,064	2,739	1,245
Legislative and regulatory	--	--	--	--	--	--	--	--	--	--
Other reliability, safety and environment	1,584	1,666	1,432	1,918	462	1,121	395	396	789	2,343
Total reliability, safety and environment	2,735	3,362	3,613	4,222	3,177	3,321	3,392	3,460	3,528	3,588
Expenditure on network assets	25,556	26,888	30,305	26,921	27,624	30,332	28,295	29,933	29,699	34,409
Expenditure on non-network assets	3,359	694	917	657	379	393	401	409	994	425
Expenditure on assets	26,915	27,582	29,721	27,300	28,542	30,725	28,695	30,342	30,693	34,834
Cost of financing	--	--	--	--	--	--	--	--	--	--
less Value of capital contributions	3,500	3,735	3,891	4,076	4,149	4,230	4,316	4,402	4,493	4,583
plus Value of vested assets	--	--	--	--	--	--	--	--	--	--
Capital expenditure forecast	23,415	23,846	25,724	23,224	24,394	26,494	24,380	25,939	26,203	30,253
Assets commissioned	28,845	18,852	30,899	23,309	16,953	30,707	25,618	19,521	30,615	20,667
\$000 (in constant prices)										
Consumer connection	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
System growth	3,246	7,475	9,112	6,500	5,000	6,500	4,000	-4,500	3,500	6,300
Asset replacement and renewal	11,575	8,568	8,900	9,250	9,387	9,847	10,197	10,547	10,897	11,247
Asset relocations	--	--	--	--	--	--	--	--	--	--
Reliability, safety and environment:										
Quality of supply	1,152	1,589	1,962	2,017	2,357	1,820	2,431	1,435	2,134	953
Legislative and regulatory	--	--	--	--	--	--	--	--	--	--
Other reliability, safety and environment	1,584	1,561	1,288	1,680	390	928	320	315	615	1,790
Total reliability, safety and environment	2,735	3,150	3,250	3,696	2,747	2,748	2,751	2,751	2,749	2,741
Expenditure on network assets	23,556	25,193	27,262	23,115	23,304	25,095	22,948	23,798	23,146	26,288
Expenditure on non-network assets	3,359	650	825	575	325	325	325	325	775	325
Expenditure on assets	25,915	25,843	28,087	23,440	24,079	25,420	23,273	24,123	23,921	26,613

plus

less

plus

Subcomponents of expenditure on assets (where known)

*FDE: energy efficiency and demand side management, reduction of energy losses

Overhead to underground conversion

Research and development

Research and development

Cybersecurity (Commission only)

Difference between nominal and constant price forecasts

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Consumer connection	-	404	670	853	988	1,112	1,252	1,398	1,547	1,699	1,853
System growth	-	503	1,017	924	823	927	1,357	932	1,160	991	1,946
Asset replacement and renewal	-	576	993	1,315	1,546	1,771	2,095	2,376	2,719	3,085	3,474
Asset relocations	-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	107	219	287	346	437	380	566	628	604	294
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	105	144	239	103	72	194	75	81	174	553
Total reliability, safety and environment	-	212	363	526	449	509	573	641	709	778	847
Expenditure on network assets	-	1,695	3,043	3,618	3,806	4,319	5,237	5,347	6,135	6,553	8,120
Expenditure on non-network assets	-	44	92	82	54	144	68	76	84	219	100
Expenditure on assets	-	1,738	3,135	3,700	3,860	4,463	5,305	5,423	6,219	6,772	8,221

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

11a(iii): Consumer Connection

Consumer types defined by EDB*

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Residential	3,500	3,500	3,500	3,500	3,500	3,500
Irrigation	1,400	1,400	1,400	1,400	1,400	1,400
Large User	500	500	500	500	500	500
Streetsigns	150	150	150	150	150	150
Other	450	450	450	450	450	450

*Include additional rows if needed

Consumer connection expenditure	6,000	6,000	6,000	6,000	6,000	6,000
less Capital contributions funding consumer connection	3,500	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	200	3,400	1,650	5,000	-	-
Zone substations	2,800	4,075	6,700	1,500	5,000	5,000
Distribution and LV lines	276	-	762	-	-	-
Distribution and LV cables	-	-	-	-	-	-
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	3,246	7,475	9,112	6,500	5,000	5,000
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	3,246	7,475	9,112	6,500	5,000	5,000

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	250	-	-	-	-	-
Zone substations	200	-	-	-	-	-
Distribution and LV lines	7,800	5,185	5,535	5,885	6,235	6,585
Distribution and LV cables	715	855	774	774	600	600
Distribution substations and transformers	1,475	1,338	1,299	1,299	1,299	1,119
Distribution switchgear	320	348	450	450	450	450
Other network assets	815	843	843	843	804	804
Asset replacement and renewal expenditure	11,575	8,568	8,900	9,250	9,387	9,557
less: Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	11,575	8,568	8,900	9,250	9,387	9,557

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
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]						
*Include additional rows if needed						
All other projects or programmes - asset relocations						
Asset relocations expenditure						
less: Capital contributions funding asset relocations						
Asset relocations less capital contributions						

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
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]						
*Include additional rows if needed						
All other projects or programmes - quality of supply						
Quality of supply expenditure	1,152	1,589	1,962	2,017	2,100	2,357
less: Capital contributions funding quality of supply						
Quality of supply less capital contributions	1,152	1,589	1,962	2,017	2,100	2,357

Appendix 5 – Schedule 11b: Report on Forecast Operational Expenditure

	Current Year CY										
	31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28	CY+6 31 Mar 29	CY+7 31 Mar 30	CY+8 31 Mar 31	CY+9 31 Mar 32	CY+10 31 Mar 33
Operational Expenditure Forecast											
Service interruptions and emergencies	1,000	1,067	1,112	1,142	1,165	1,185	1,209	1,233	1,258	1,283	1,309
Vegetation management	1,000	1,217	1,245	1,279	1,304	1,328	1,354	1,381	1,409	1,437	1,466
Routine and corrective maintenance and inspection	4,361	5,810	5,140	4,957	4,946	4,975	5,323	5,669	5,349	5,539	5,529
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	6,361	8,094	7,456	7,378	7,415	7,488	7,886	8,283	8,015	8,259	8,304
System operations and network support	9,700	11,388	11,861	12,387	12,427	12,648	12,897	13,156	13,421	13,691	13,966
Business support	4,200	5,262	5,450	5,631	5,742	5,846	5,959	6,075	6,201	6,326	6,453
Non-network opex	13,900	16,649	17,341	17,818	18,169	18,491	18,856	19,235	19,622	20,016	20,419
Operational expenditure	20,261	24,743	24,838	25,196	25,584	25,979	26,742	27,518	27,637	28,275	28,723
Subcomponents of operational expenditure (where known)											
Service interruptions and emergencies	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Vegetation management	1,000	1,340	1,120	1,120	1,120	1,320	1,120	1,120	1,120	1,120	1,120
Routine and corrective maintenance and inspection	4,361	5,444	4,624	4,340	4,247	4,197	4,404	4,598	4,253	4,317	4,224
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	6,361	7,584	6,744	6,460	6,367	6,317	6,524	6,718	6,373	6,437	6,344
System operations and network support	9,700	10,670	10,670	10,670	10,670	10,670	10,670	10,670	10,670	10,670	10,670
Business support	4,200	4,930	4,930	4,930	4,930	4,930	4,930	4,930	4,930	4,930	4,930
Non-network opex	13,900	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600
Operational expenditure	20,261	23,184	22,344	22,060	21,967	21,917	22,124	22,318	21,973	22,037	21,944
Subcomponents of operational expenditure (where known)											
Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
Direct billing*	-	-	-	-	-	-	-	-	-	-	-
Research and Development	-	-	-	-	-	-	-	-	-	-	-
Insurance	783	860	860	860	860	860	860	860	860	860	860
Cybersecurity (Commission only)	-	-	-	-	-	-	-	-	-	-	-
Difference between nominal and real forecasts											
Service interruptions and emergencies	-	67	112	142	165	185	209	233	258	283	309
Vegetation management	-	77	125	159	184	208	234	261	289	317	346
Routine and corrective maintenance and inspection	-	366	516	617	699	778	919	1,071	1,096	1,222	1,305
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	-	510	753	919	1,048	1,171	1,362	1,565	1,643	1,822	1,960
System operations and network support	-	718	1,191	1,517	1,757	1,978	2,227	2,486	2,751	3,021	3,296
Business support	-	332	550	701	812	914	1,029	1,149	1,271	1,396	1,523
Non-network opex	-	1,049	1,741	2,218	2,569	2,891	3,256	3,635	4,022	4,416	4,819
Operational expenditure	-	1,560	2,494	3,137	3,617	4,062	4,617	5,200	5,665	6,238	6,779

*EDBC must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)

* Direct billing expenditure by suppliers that direct bill the majority of their consumers

Appendix 6 – Schedule 12a: Report on Asset Condition

Voltage	Asset category	Asset class	Asset condition at start of planning period (percentage of units by grade)										% of asset forecast to be replaced in next 5 years
			H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1-4)				
All	Overhead Line	Concrete poles / steel structure	0.6%	-	6.4%	27.4%	64.8%	0.8%	3	1%			
All	Overhead Line	Wood poles	0.8%	30.5%	43.0%	15.3%	10.2%	0.2%	3	7%			
All	Overhead Line	Other pole types	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	-	1.1%	9.0%	51.7%	38.2%	-	2	-			
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	-	0.1%	42.7%	4.7%	52.5%	-	3	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	-	-	-	-	-	-	N/A	-			
HV	Subtransmission Cable	Subtransmission submarine cable	-	-	-	-	-	-	N/A	-			
HV	Zone substation Buildings	Zone substations up to 66kV	-	-	60.0%	25.0%	15.0%	-	3	5%			
HV	Zone substation Buildings	Zone substations 110kV+	-	-	-	-	-	-	N/A	-			
HV	Zone substation switchgear	22/33kV CB (Indoor)	-	-	57.1%	-	42.9%	-	N/A	-			
HV	Zone substation switchgear	22/33kV CB (Outdoor)	7.7%	69.2%	7.7%	15.4%	-	-	2	6%			
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	-	-	-	-	-	-	N/A	-			
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	-	-	-	-	-	-	N/A	-			
HV	Zone substation switchgear	33kV RMU	1.2%	41.9%	2.3%	1.2%	53.5%	-	2	14%			
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	-	-	-	-	-	-	N/A	-			
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	-	-	-	-	-	-	N/A	-			
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	-	-	33.3%	66.7%	-	-	2	-			
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	-	33.3%	66.7%	-	-	-	2	-			
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	-	25.9%	70.4%	3.7%	-	-	2	4%			

Appendix 6 – Schedule 12a: Report on Asset Condition (cont.)

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
HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	15.4%	15.4%	46.2%	23.1%		3	8%
HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.1%	1.9%	13.4%	63.0%	20.5%	0.1%	2	2%
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A		-
HV	Distribution Line	SWER conductor	km	-	5.3%	29.0%	60.0%	5.7%		2	-
HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.7%	2.1%	6.9%	43.0%	47.2%		2	1%
HV	Distribution Cable	Distribution UG PILC	km	-	-	-	86.0%	14.0%		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.	0.9%	6.0%	22.2%	39.3%	31.6%		2	5%
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	6.3%	93.8%	-	-		2	3%
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.2%	1.5%	17.3%	39.4%	41.7%		2	2%
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%	-	21.4%	32.9%	45.0%		3	5%
HV	Distribution Transformer	Pole Mounted Transformer	No.	0.0%	19.2%	37.3%	29.2%	14.2%		2	5%
HV	Distribution Transformer	Ground Mounted Transformer	No.	-	21.2%	34.2%	30.4%	14.2%		2	5%
HV	Distribution Transformer	Voltage regulators	No.	-	4.2%	25.0%	20.8%	50.0%		3	-
HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.7%	15.7%	38.8%	26.0%	18.9%		2	3%
LV	LV Line	LV OH Conductor	km	0.5%	2.6%	54.1%	34.1%	6.6%	2.0%	2	2%
LV	LV Cable	LV UG Cable	km	-	-	13.1%	26.5%	60.3%	0.2%	2	1%
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.1%	0.3%	45.8%	9.8%	44.0%	-	2	1%
LV	Connections	OH/UG consumer-service connections	No.	-	0.0%	6.3%	21.7%	50.0%	21.9%	1	1%
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	21.1%	7.1%	31.0%	39.6%	1.2%	-	1	25%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1.8%	32.2%	23.8%	34.2%	7.2%	0.8%	2	20%
All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	N/A		-
All	Load Control	Centralised plant	Lot	-	25.0%	37.5%	25.0%	12.5%		2	20%
All	Load Control	Relays	No.	-	-	60.4%	24.8%	14.3%	0.5%	1	-
All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A		-

Appendix 7 – Schedule 12b: Report on Forecast Capacity

12b(i): System Growth – Zone Substations

Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity +5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
Southbrook	38	40	N-1	2	95%	40	102%	Transformer	To be resolved through load transfers and by construction of a new zone substation in Tushnet.
Bent Hill	36	23	N-1 switched	6	70%	23	81%	No constraint within +5 years	
Swantonline	15	23	N-1 switched	7	65%	23	76%	No constraint within +5 years	
Amherley	6	4	N-1 switched	2	151%	20	41%	No constraint within +5 years	
MacKinnon Rd	2	-	N	2	-	-	-	No constraint within +5 years	
Greta	1	-	N	4	-	-	-	No constraint within +5 years	
Chester	3	-	N	2	-	-	-	No constraint within +5 years	
Haywardin	4	-	N	-	-	-	-	No constraint within +5 years	
Ludstone	6	6	N-1 switched	-	97%	6	96%	No constraint within +5 years	
Leslie	2	-	N	-	-	-	-	No constraint within +5 years	
Ouro	0	-	N	-	-	-	-	No constraint within +5 years	
Mouse Point	16	13	N	-	120%	11	135%	Transformer	To be resolved through non-network load management/thermal solutions.
Hairner	5	-	N-1 switched	-	-	-	-	Transformer	
Lochei	0	-	N	-	-	-	-	No constraint within +5 years	
Murble Quarry	0	-	N	-	-	-	-	No constraint within +5 years	Plan to decommission this site within 5 years.
[Zone Substation 17]								[Select one]	
[Zone Substation 18]								[Select one]	
[Zone Substation 19]								[Select one]	
[Zone Substation 20]								[Select one]	

¹ Exempt forecast capacity table as necessary to disclose all capacity by each zone substation

Appendix 8 – Schedule 12c: Report on Forecast Network Demand

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
Residential	650	650	650	650	650	650
General	30	30	30	30	30	30
Irrigation	1	1	1	1	1	1
Council Pumping	2	2	2	2	2	2
[EDB consumer type]	120	120	120	120	120	120
Connections total	803	803	803	803	803	803

*include additional rows if needed

Distributed generation

Number of connections
Capacity of distributed generation installed in year (MVA)

	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	650	650	650	650	650	650
	30	30	30	30	30	30
	1	1	1	1	1	1
	2	2	2	2	2	2
	120	120	120	120	120	120
	803	803	803	803	803	803

	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	221	232	244	256	268	279
	1	1	1	1	1	1

12c(ii) System Demand

Maximum coincident system demand (MW)

GXP demand
plus Distributed generation output at HV and above
Maximum coincident system demand
less Net transfers to (from) other EDBs at HV and above
Demand on system for supply to consumers' connection points

	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	116	117	118	119	120	121
	6	6	6	6	6	6
	122	123	124	125	126	127
	122	123	124	125	126	127

Electricity volumes carried (GWh)

Electricity supplied from GXPs
less Electricity exports to GXPs
plus Electricity supplied from distributed generation
less Net electricity supplied to (from) other EDBs
Electricity entering system for supply to ICPs
less Total energy delivered to ICPs
Losses

	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	655	649	655	661	667	674
	43	29	31	33	35	37
	698	678	686	694	703	711
	657	640	648	657	665	674
	41	38	38	38	37	37

Load factor
Loss ratio

	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	65%	63%	63%	63%	64%	64%
	5.9%	5.6%	5.5%	5.4%	5.3%	5.2%

Appendix 9 – Schedule 12d: Report on Forecast Interruptions and Duration

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
SAIDI							
Class B (planned interruptions on the network)		153.7	140.0	137.0	132.7	128.7	124.7
Class C (unplanned interruptions on the network)		126.8	132.0	126.0	122.3	119.3	116.3
SAIFI							
Class B (planned interruptions on the network)		0.43	0.52	0.49	0.46	0.43	0.40
Class C (unplanned interruptions on the network)		1.61	1.46	1.42	1.40	1.38	1.36

Appendix 10 – Schedule 13: Report on Asset Management Maturity

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	MainPower has an asset management policy that is firmly part of MainPower's approach to asset management. Awareness of the policy is supported within the business through training and regular updates to staff on Asset Management.		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	As demonstrated in the Asset Management Policy there is clear link of sight between asset management policies and the statement of corporate intent, with asset management strategies and policies used to align other organisation documents and initiatives.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	The main focus of MainPower's approach to asset management is to cover full asset lifecycle including total cost of ownership from idea to Disposal.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Asset management plans and/or portfolio strategies exist or are currently being developed for all assets. Work remains to further link Asset Management Plans to policies and demonstrate full end-to-end asset life cycle.		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	The Asset Management Plans, work programmes and key milestones are presented to staff annually, from Board of Directors through to Field Staff. This is done via a variety of methods, from small steering group discussions, to larger general information sessions. The document is also provided and staff are encouraged to read it.		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 receiver's role in plan delivery. Evidence of communication.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	MainPower now has roles specifically designated for delivery of Asset Plan actions, with reporting on progress documented monthly.		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)	3	Asset Management and its importance is reported to all staff on a regular basis through company updates and staff engagement meetings. Delivery of asset management plan works is monitored and reported monthly, covering financial performance as well as work completion.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	Incident management processes are well documented and integrated within business activities. Emergency response is managed through the CMS framework with staff training provided and with mock incidents to further identify improvements. Work is currently underway on developing network contingency plans as well as documenting asset spares.		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	MainPower has adopted a Plan, Build, Operate model with key executive leadership team members responsible for ensuring MainPower meets its asset management strategies, objectives, and that the asset management plan is delivered.		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 fulfill their responsibilities. (This question, relates to the organisation's assets eg. para b), § 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), § 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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
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	Currently resources, systems and reporting is in place that demonstrates Maipower is completing asset management effectively on its core assets. This needs to be expanded to include more detail across financial performance vs work completed.		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 changehands 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	Asset Management and its importance is reported to all staff on a regular basis through general company updates / staff engagement meetings.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg. PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-arounds 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	Asset Management activities are well defined. Assurance in the form of work/project monitoring and data collection points are used to detail resulting outcomes. Work remains to audit the outcomes; this requirement is agnostic to outsourcing or insourcing. All work outsourced is still overseen by internal project/program managers.	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.
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	Training for the completion of asset management activities that deliver the required outcomes is in place for some assets. Some training is also provided on-the-job. Work remains detailing the training requirements, enabling the requirements on the team skills matrix and ensuring that competent people exist informed by the forward work program		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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
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 for the completion of asset management activities exist within the Asset Management and Operational plans. Activities are risk assessed and controls developed based on the risk appetite of the business. Work remains in developing a clear link between activities required, competency to complete the work and work authorisation.		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 plans(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, coordinated 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 organisation 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	All asset management activities are risk assessed and controls developed based on the risk appetite of the business. Work remains to be completed developing a clear link between activities required, competency to complete the work and work authorisation—see section on Risk within the AME.		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?	3	Pertinent asset management information is communicated to necessary parties to effectively deliver the asset management plan for most assets and workstreams. Work remains to be completed to extend this further, especially with contracted service providers.		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; news letters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Currently maintained, through process maps and an Asset Management System document, describes its approach and asset management framework including who is responsible and for what part of the process they are responsible.		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).

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	MainPower has committed to improving its asset register and information held in its ERP system. In addition, a new data warehouse has been established linking source data into a business improvement environment to help inform asset management activities. Other Asset Management Information systems are also being reviewed by the organisation so that the organisation can improve its approach to Asset Management.		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 alien 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?	3	This is achieved via a well defined, process mapped and documented as-built process which includes data quality assurance.		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	Information requirements are informed by the Asset Management Plan and financial and operational requirements. MainPower has committed to the Technology One ERP, an Asset Management system which supports improving it's maturity in a strategic:		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 organization's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Actively risk assessment for asset management activities have been assessed, documented and controls identified (through process mapping and risk bowties). Work remains to be completed detailing the operational risk of all assets (Plant and Equipment Risk Assessments).		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.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
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	Risk assessments are completed and controls identified that inform competency requirements and controls for works. Controls identified for the completion of works forms part of the contractor management framework and network access requirements. The end-to-end		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 organisation's risk management framework and training plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	Legal statutory risk forms part of the MainPower corporate risk management framework. MainPower also requires staff to complete a ComplyWith survey annually to re-assess compliance against requirements.		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 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 (eg. procedure(s) and process(es))	Top management. The organisation's 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 implementation 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	MainPower's asset management, engineering and operational process are well documented in ProMapp. Relevant documents and standards are linked to the ProMapp processes. This includes processes from Asset Creation, Maintenance and Replacement, Engineering and Design, Procurement, Operational activities and as-Building.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg. PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	Process and procedures are documented that detail how Asset Management plans are implemented. More work is needed to document and demonstrate that current activities fully align with asset management strategies and are implemented in a cost effective way.		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	Overall performance of the system is measured via SAIB, SAEI and other performance metrics documented in the regulatory AMP. This covers analysis of poor performing parts of the network and/or assets with specific projects or initiatives to improve performance. Condition assessments are carried out by field staff and office based experts using data collected from maintenance and inspection programs.		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 contractors 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).

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and 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	Asset failures are investigated depending on critically including operational incidents, roles and responsibilities are defined including the implementation of an organisational wide incident reporting, management and investigation system		Widely used AM standards require that the organisation establishes implements and maintains processes 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.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Main/owner engaged external support to help review and further develop its asset management system documentation in 2022.		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 investigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Incident investigations and corrective actions are undertaken in accordance with Main/owner's Incident Reporting and Management operating standard. Asset Management work programmes also include both preventative and corrective components, with the objective of preventative programs resulting in less corrective work. Corrective actions and work are reviewed annually to inform and improve preventative work.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a business 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 preventative actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Records changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Asset management activities are documented, risk assessed and coded in terms of time, materials, plant and equipment (Rate cards). Rate cards are benchmarked against perceived industry standards. All works are pre-costed using the rate card and maintenance activities are assessed against planned and actual costs.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
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	By way of industry forums, conferences and technology presentations, and collaboration with other EDSs.		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 organization 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 11 – Schedule 14a: Mandatory Explanatory Notes on Forecast Information

Company Name MainPower New Zealand Ltd
For Year Ended 31-March-2023

(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. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

In preparing the capital expenditure forecasts MainPower has used the Westpac Economics Forecast Summary sheet November 2022 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.

Year	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Index	1.07	1.11	1.14	1.16	1.19	1.21	1.23	1.26	1.28	1.31

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

In preparing the operational expenditure forecasts MainPower has used the Westpac Economics Forecast Summary sheet November 2022 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.

Year	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Index	1.07	1.11	1.14	1.16	1.19	1.21	1.23	1.26	1.28	1.31

