mainpower

Asset Management Plan 2021–2031

Chief Executive’s Message

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.

These are exciting times, as New Zealand transitions to a low-carbon economy. The services that MainPower provides will become increasingly important, with the company acting as the backbone for decarbonisation and the sustainable future of our communities.

A highlight of this reporting year is the delivery of our work programme, which includes a technology upgrade to the systems and process MainPower uses to manage its electricity distribution network. The recent completion of our Advanced Distribution Management System is one of a number of major system improvements that we have completed over the past few years and represents a key milestone in our journey to enabling carbon-free energy services in the North Canterbury community.

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 40,000 residential and business connections and delivers electricity to a population base of around 65,000 people.

We are responsible for providing a 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 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. We believe we have been successful in this and we have moved the business to a healthier position. We have adopted and refined systems and processes to ensure we can continue to manage an effective network business. A key achievement in 2020 was the rethinking of MainPower’s strategic intent. 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.

This year, MainPower also went live with its new Advanced Distribution Management System (ADMS) for the smart operational management of its network. This is a key milestone in ensuring our network is ready for a New Energy Future.

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 two workstreams that will return the quality of supply to past historical trends and improve it into the future.

Changing consumer behaviours, the advent of new technologies and the national transition to a low-carbon economy will all influence the way our electricity distribution network will be used in the future and the services that consumers require. Electricity distribution network development policies and procedures take account of this new trajectory and recognise the need to move from the traditional distribution network approach of demand-based planning to a scenario-based planning approach. This remains a key focus of MainPower’s work for the planning period ahead and it now forms part of the Master Plan or Strategic Asset Management Plan.

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 deliver electricity to more than 40,000 North Canterbury homes and businesses.

Growth in the region, particularly with new subdivisions, has brought us more than 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.

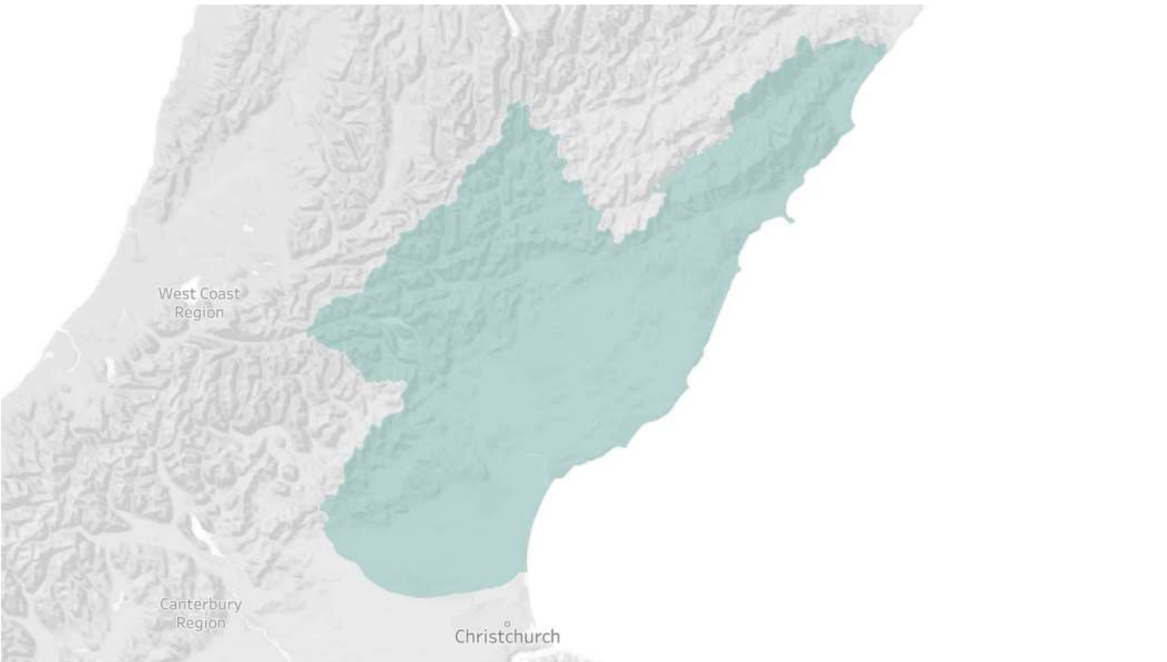

Figure 2.1: MainPower's Electricity Distribution Network Region

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 (LV) – 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 Asset Management

This AMP covers a 10-year planning period, from 1 April 2021 to 31 March 2031. It provides our stakeholders with insight and explanation as to how we provide electricity distribution network and energy services in a safe, secure, reliable and sustainable manner that meets the expectations of our stakeholders.

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.

2.2.1 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. It 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, as well as from consumer to consumer, or consumer to bulk supply point.
- 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.
- Network stability will be managed by the EDB for a range of operating scenarios.

2.2.2 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.

MPNZ BOARD-APPROVED POLICIES	RISK	ENVIRONMENT	ASSET MANAGEMENT
INTERNATIONALLY ACCEPTED STANDARDS	ISO 31000	ISO 14001	MPNZ BOARD-APPROVED POLICIES
	PROCESSES, PROCEDURES, WORK INSTRUCTIONS, GUIDES, INTERNAL STANDARDS		

Figure 2.3: Asset Management Standards

2.2.3 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 2.4.

- 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

- 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 grow delivers consumer requirements while facilitating regional development

- Effective business systems and processes roles and responsibilities
- Enable collaboration driving strategic change within the industry delivering real value to our consumers and market efficiency through transparency

- Manage competency and training
- Effectively plan our activities
- Optimise operational activities and do it right first time

Figure 2.4: Asset Management Policy

2.2.4 Asset Management System

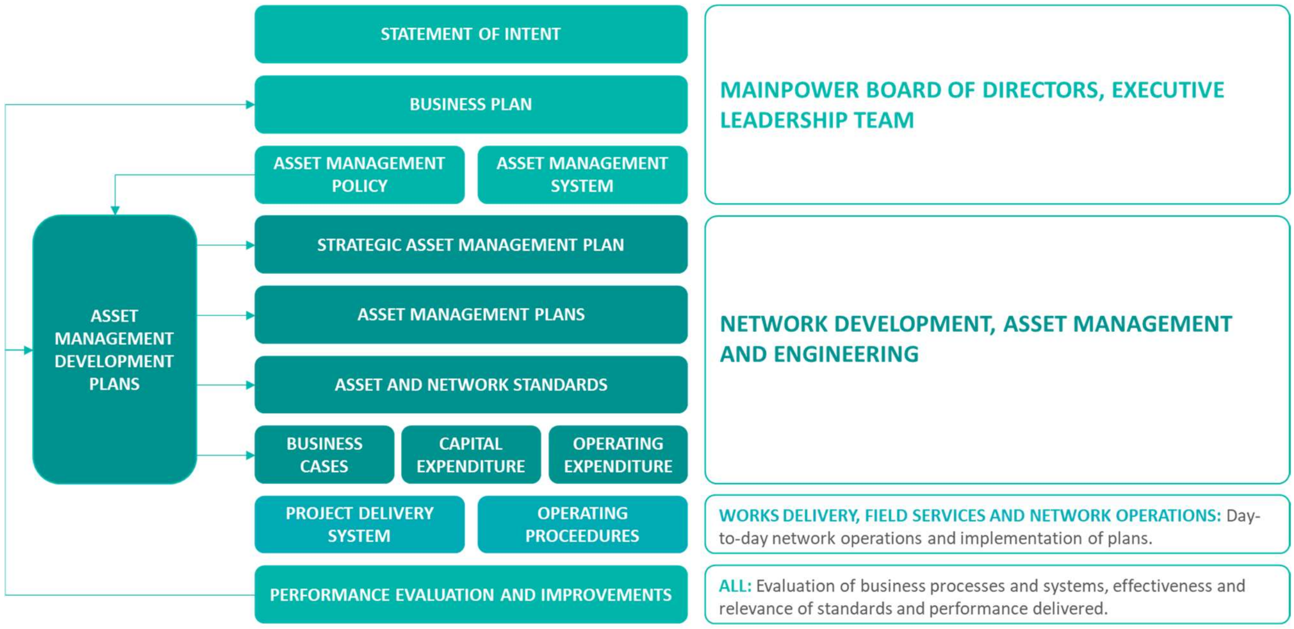

Figure 2.5: Asset Management Framework

Asset Management	
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 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	(Not this document) 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: Asset Management System Components

2.2.5 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 2.6).

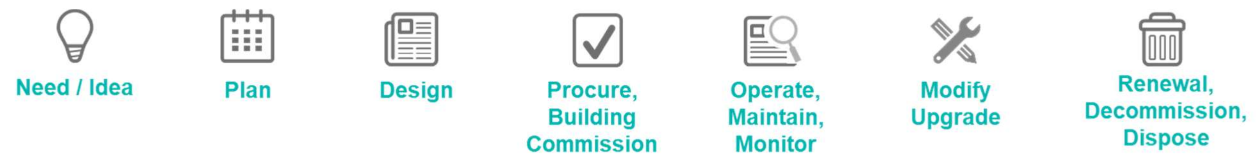

Figure 2.6: Asset Lifecycle Planning

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 out4 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 is reflected in our GIS.
- **Operate and maintain:** 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, 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.
- **Refurbish, Renew 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.

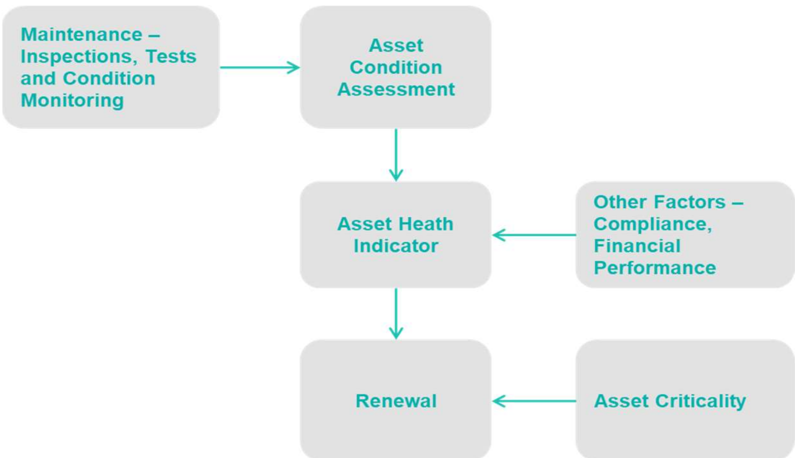

Figure 2.7: Maintenance Process for Asset Renewal

2.3 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 2021 to 31 March 2031, with a focus on specific projects that have been identified for the next five years.

There is inherent uncertainty in the AMP forecasts. Several factors contribute to this uncertainty, including pandemics and weather events. Our AMP forecasts are reasonably certain for 5 years. Except for potential large customer developments including distributed generation, our plan has some certainty for the remainder of the planning period.

2.4 Date Approved by Directors

This Asset Management Plan was completed for asset management purposes in 2020 and was approved by the MainPower Board of Directors at the February 2021 meeting.

2.5 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 2.8 shows our stakeholder groups.

Figure 2.8: Our Stakeholder Groups

2.5.1 MainPower Consumers and Customers

Primarily, the link between MainPower's consumers and our customers is through our Use of System Agreement. Under Part 12A of the Electricity Authority Code, the Use of System Agreement with our retailer customers and MainPower-connected consumers is based on conveyance. Under the Use of System Agreement, MainPower's consumers are our customers. For the purposes of this AMP, MainPower also refers to our customers as "consumers".

2.5.2 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	• Consultation and correspondence
Connected consumers	• 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	• Direct current feedback/interactions • Forums and working groups • One-on-one meetings • Open days • Submissions on discussion papers
MainPower Trust (Ordinary Shareholders)	• Direct current feedback/interactions • Events (including the Annual Meeting) • Operational interface • Other engagement activities
Government	• Disclosure requirements • Submissions on discussion papers
Regulators	• Adherence to corporate policies • Disclosure requirements • Operational interface
District and Regional Councils	• Disclosure requirements
Contractors and suppliers	• Direct current feedback/interactions • One-on-one meetings
Media	• Briefing sessions • Forums and working groups • Media monitoring and editorial opportunities • Open days • Public meetings and information sessions • Sponsorship involvement
Transpower	• Operational interface • Submissions on discussion papers
Electricity retailers	• Direct current feedback/interactions • Industry collaboration • Informal contact/discussions • One-on-one meetings
Electricity industry	• Forums and working groups • Informal contact/discussions • One-on-one meetings • Open days • Participation in industry (including membership) • Public meetings and information sessions • Submissions on discussion papers

Table 2-2: How We Identify the Expectations of Our Stakeholders

2.5.3 Summarising the Interests of Our Stakeholders

The expectations of our stakeholders are summarised in Table 2-3.

Stakeholder	Expectations
Connected consumers	• Accessibility – easy to contact provider when necessary • Consistency of service delivery (including response time) • Continuity of supply – keeping the power on • Future innovation • Health, safety and 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	• Community focus • Corporate social responsibility • Engagement and consultation • Public safety around electricity
Other Stakeholders	
MainPower Trust (Ordinary Shareholder)	• Delivery of a secure and reliable power supply • Effective and efficient incident response • Future innovation • Health, safety and environment • Maintaining shareholder value • Prudent risk management • Statutory/regulatory compliance
Government	• Appropriate investment in infrastructure • Delivery of a secure and reliable power supply • Future innovation • Health, safety and environment • Industry collaboration
Regulators	• Contribution via industry consultations/submissions • Cost-reflective pricing methodology • Delivery of a secure and reliable power supply • Health, safety and environment • Future innovation • Statutory/regulatory compliance
District and Regional Councils	• 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 environment • Future innovation
Contractors and suppliers	• Effective contractor management • Health, safety and environment
Media	• Effective relationship management • Timely access to information

Stakeholder	Expectations
Partners	
Transpower	• Appropriate investment in infrastructure • Collaboration and effective relationship management • Engagement and consultation • Health, safety and environment • Transparent communication (including outage information)
Electricity retailers	• Continuity and security of supply • Effective systems and processes • Health, safety and environment • Transparent communication (including outage information)
Electricity industry	• Collaboration • Future innovation • Health, safety and environment • Industry participation • Information and knowledge sharing
Bankers and insurers	• Accurate and timely performance information • Confidence in Board and leadership • Good governance • Prudent risk management • Sufficient revenue to maintain asset efficiency and reliability

Table 2-3: What our Stakeholders Expect from Us

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

2.5.4 Managing Stakeholder Interests when they Conflict

Where stakeholder conflicts arise, the priorities for managing the conflicts are ranked in the following order:

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

2.6 Accountabilities and Responsibilities

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

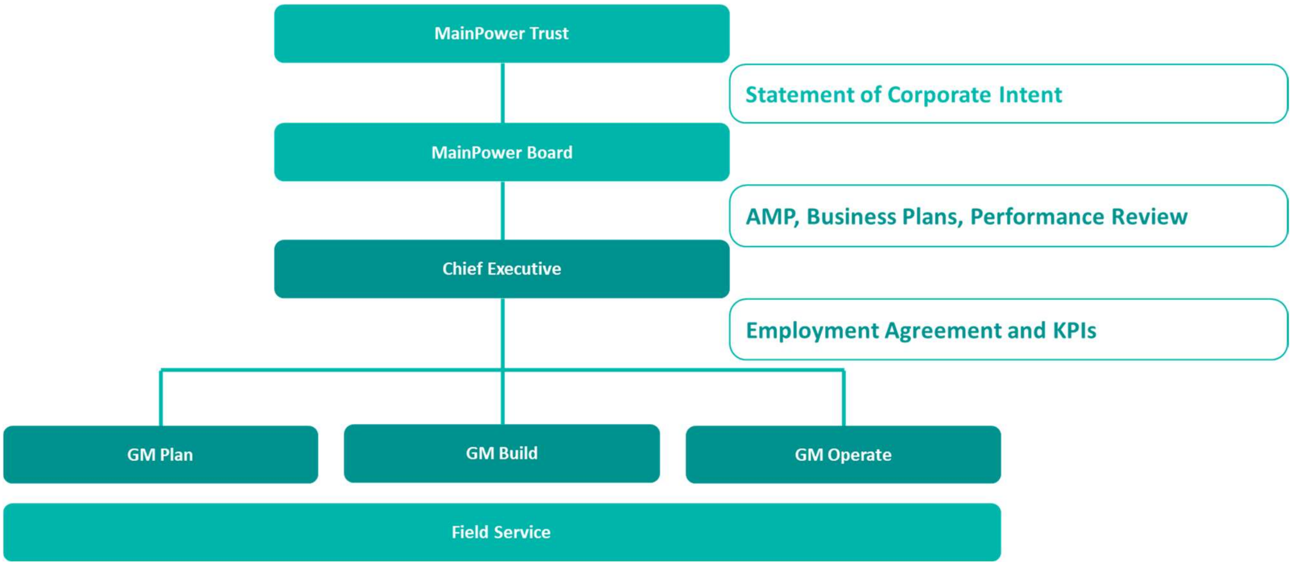

Figure 2.9: Organisational Management Structure

2.6.1 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.

2.6.2 Governance and Executive Leadership

MainPower currently has six non-executive Directors who collectively comprise 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 (CE). The Board also approve the AMP, business plan and budget. Financial approvals that exceed the delegated authority of the CE, such as large investment proposals, require Board approval.

The CE 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's approach to asset management. Corporate objectives, expenditure, electricity distribution network and asset management performance are reported to the Board monthly.

As MainPower transforms its electricity distribution network for a New Energy Future, it has 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.

2.6.3 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 (RFP) 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.

2.7 Assumptions Made

2.7.1 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 2021, 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.
- Our electricity distribution network will only be exposed to climatic (temperature, wind, snow and rain) variation during the planning period that is consistent with our experience since 2000.
- Seasonal load profiles will remain consistent with recent historical trends.
- Zoning for land use purposes will remain unchanged during the planning period.
- Electric vehicle-charging loads will not significantly affect electricity distribution network constraints within the planning period.

2.7.2 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.

2.7.3 Forecasting Certainty

MainPower considers the following factors could lead to material differences in actual versus planned. 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 most significantly affect future development plans. 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 that impact 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 (Opex) in the short term and increase or decrease Opex 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

2.7.4 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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Index	1	1.01	1.03	1.05	1.07	1.09	1.12	1.15	1.18	1.21

Table 2-5: Escalation Index Based on Westpac Inflation Index

2.8 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.

2.8.1 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.

2.8.2 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.

2.9 Systems and Information Management

The core of all MainPower's Asset Management is our Computerised Maintenance Management System (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.

2.9.1 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.

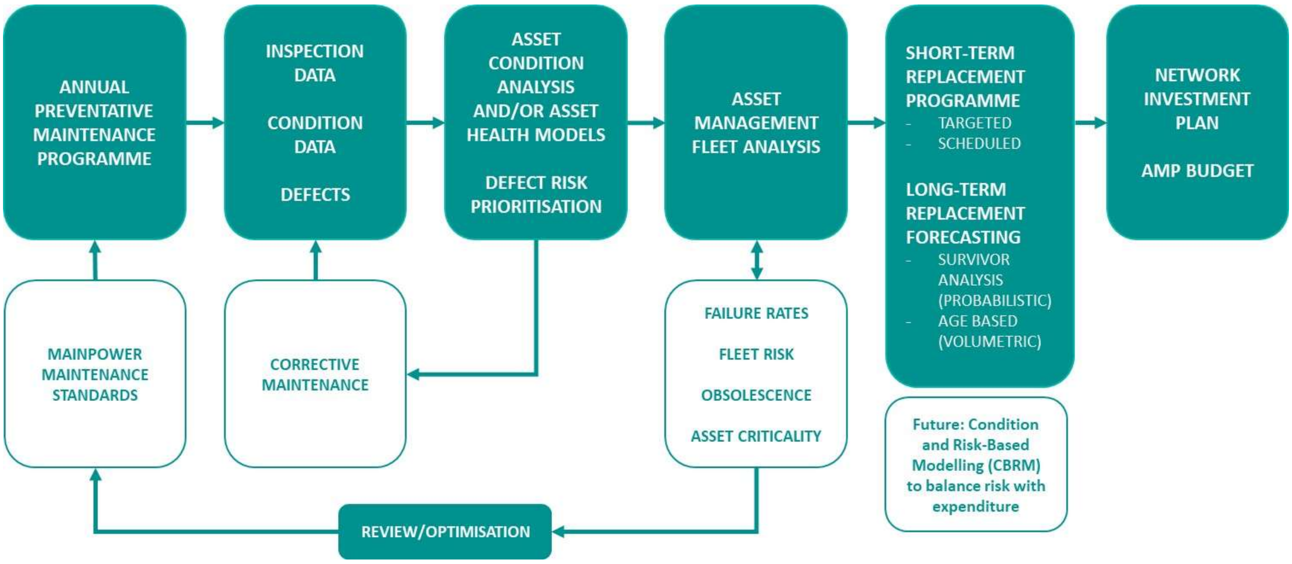

Figure 2.10: Asset Lifecycle Management

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.

2.9.2 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 (EAM). This 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 support MainPower’s AMP and work programme, we will look to improve the quality and consistency of our data.

2.9.3 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.

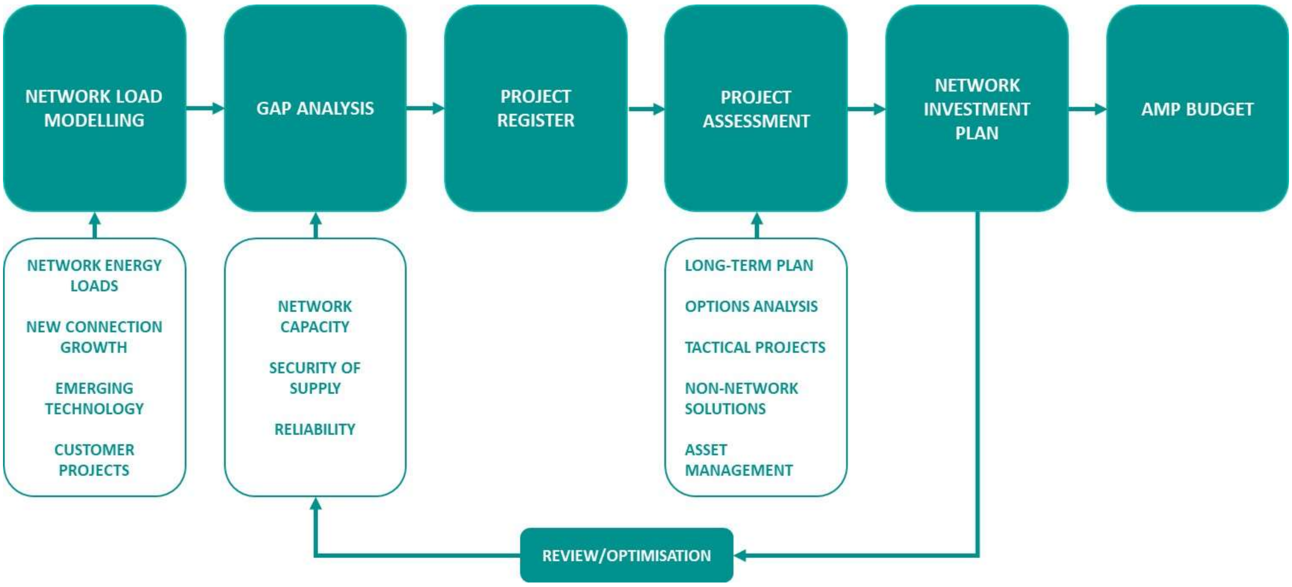

Figure 2.11: Electricity Distribution Network Development

2.9.4 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 2.12, including the need to work within a controlled working environment, the issuing of authorisation and receiving of asset condition data that is used to manage defects, inform renewals and so on.

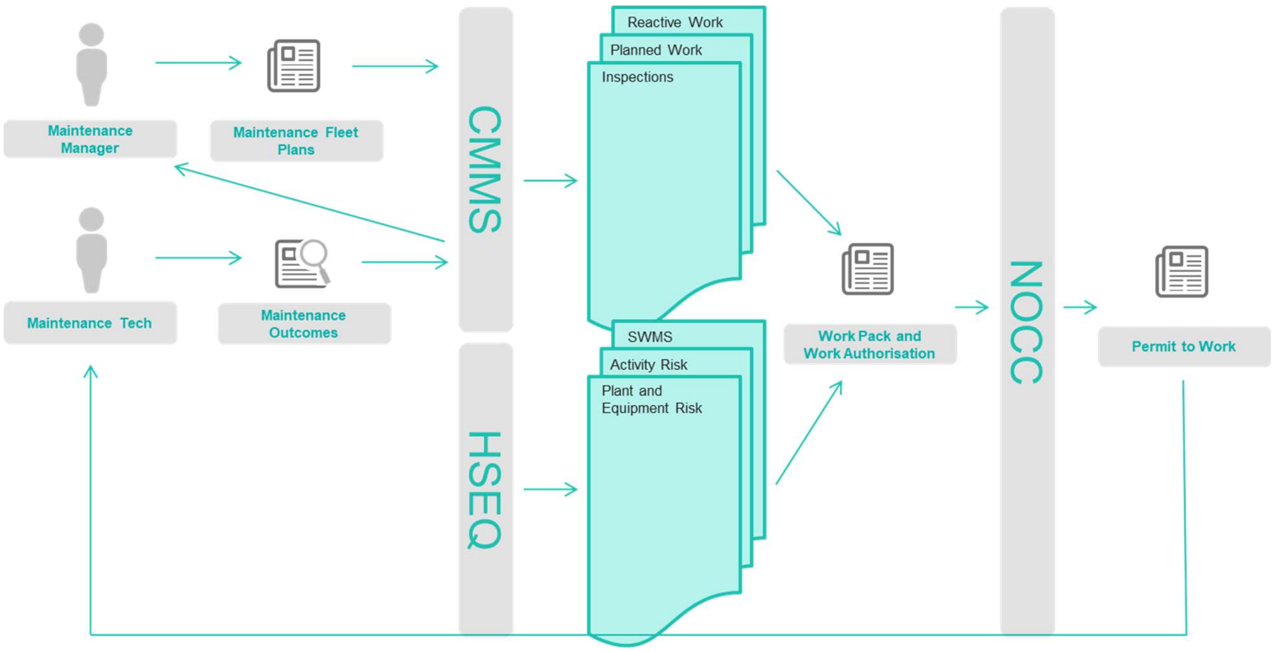

Figure 2.12: Asset Management Workflow Process

2.9.5 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.

2.10 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	• Consultation on the Trust's Letter of Expectation to the MainPower Board • MainPower Trust's Annual Report and audited accounts
MainPower Board to MainPower Trust	• Statement of Corporate Intent • Company Annual Report, including Chair and Chief Executive's statements and audited accounts • Annual information disclosure • Twice-yearly presentation, including financial and operational performance
Chief Executive to MainPower Board	• Chief Executive's statement in 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 to Chief Executive and MainPower Board	• Annual report on budget and major projects • Monthly report, including year-to-date performance and progress against budget • Individual reports on major projects • Daily updates on areas of concern, including health and safety
Managers	• Weekly direct reporting from team meetings • One-on-one discussion with direct managers • Daily updates during brief meetings, including health and safety updates • Monthly management accounting reports
Field Services Supervisors	• Weekly progress reports • Monthly meetings on progress to budget
External contractor to General Manager Field Services	• 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 Consumer Engagement

We supply electricity to more than 40,000 homes and businesses across the Waimakariri, Hurunui and Kaikōura regions in the South Island of New Zealand. 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[1]	% of ICPs	Units Delivered (GWh[2])	% of Units Delivered
Residential	33,052	81.6%	276	44%
Commercial	5,748	14.2%	125	20%
Large commercial or industrial	48	0.1%	60	9%
Irrigators	1,354	3.3%	95	15%
Council pumps	200	0.5%	12	2%
Streetlights	112	0.3%	3	0%
Individually managed consumer	1	0.0%	61	10%
Total	**40,515**	**100.0%**	**632**	**100%**

Table 3-1: Consumption and Consumers by Category

Notes:
1. Installation Control Point
2. Gigawatt-hours

3.1.1 Consumer Engagement Workshops

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, resiliency and the future of energy and our electricity network. These workshops aim to enhance MainPower engagement with its 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.

3.1.2 Online Consumer Surveys

During 2019, MainPower commissioned an independent organisation to conduct an online survey with more than 1,200 respondents, to validate and quantify the information collected during the consumer engagement workshop discussions. The online survey expanded on consumers' interest in different future technologies, willingness to pay for improvements in reliability and resilience, and preferred communication methods.

We also conducted a service experience survey of consumers who had contacted MainPower over the past year regarding services such as faults, new connections, network extensions or asset relocations. This information has helped us to provide a better consumer experience and ensure that we continually improve and meet consumers' expectations.

3.2 What Consumers Have Told Us

Our engagement workshops and surveys have provided valuable insights into what is important to our consumers and where they would like us to direct our attention and investments. The online engagement survey covered wider representation across our consumer groups and the feedback was closely aligned with the insights gained from the consumer workshops, supporting our focus on the key components of our asset management strategy (see Figure 3.1). The questions were as follows:

- **Reliability:** How satisfied are you with the reliability of your electricity supply?
- **Resilience:** How much of your lines charges should MainPower invest to get power restored after a major event?
- **Future networks:** How would you like MainPower to prepare for future technologies?
- **Safety:** Should MainPower go beyond the existing industry and company safety standards? (These discussions were incorporated within other workshop categories).

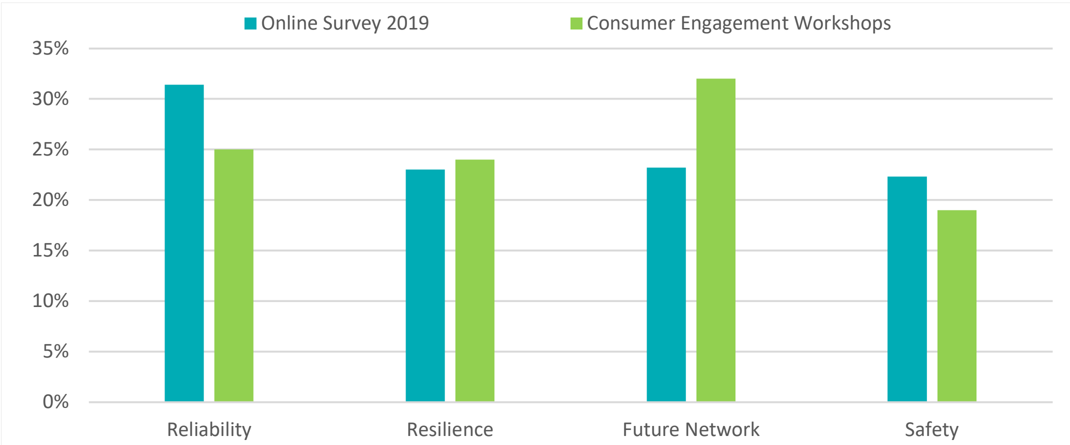

Figure 3.1: Overall Importance of Asset Management Focus Areas (Note: as this was focused on network investment, pricing was excluded)

3.2.1 Consumers – Reliability

Overall, consumers viewed network reliability as the top priority. As an electricity distribution business (EDB), a reliable network is a fundamental part of the service we provide. Consumers indicated through both the engagement workshops and the online survey that they were satisfied with their current levels of reliability. The online survey results (see Figure 3.2) showed that more than 90% of the consumers surveyed perceived their network reliability as either reliable or very reliable. Consumers expected a focus on incrementally reducing the overall number and/or the duration of outages and expected MainPower would continue to invest in maintaining, or cost-effectively improving, current levels of reliability.

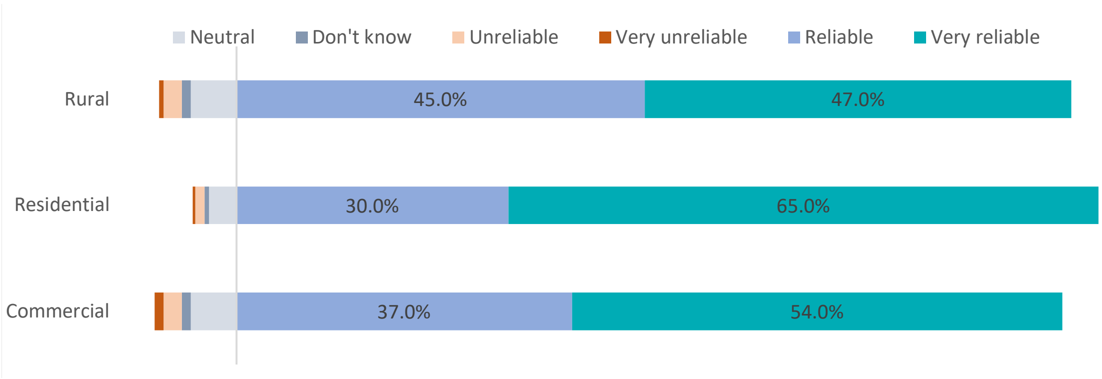

Figure 3.2: MainPower Consumers' Perception of Network Reliability (Source: Online Survey 2019)

In addition to reliability, feedback from the consumer engagement workshops highlighted that improving the quantity, quality and timeliness of information provided to consumers during both planned and unplanned outages is of high importance. Communication such as reminders of upcoming outages, changes to planned outage periods and proactive notifications during unplanned outages were viewed as valuable, but they often occurred in timeframes that did not allow retailers to contact their consumers. As shown in Figure 3.3, more than 60% of consumers expected information about an unplanned outage within less than an hour from the outage, indicating what caused the outage and when supply would likely be restored. This indicated that consumers expected MainPower to be proactive and timely with its communication.

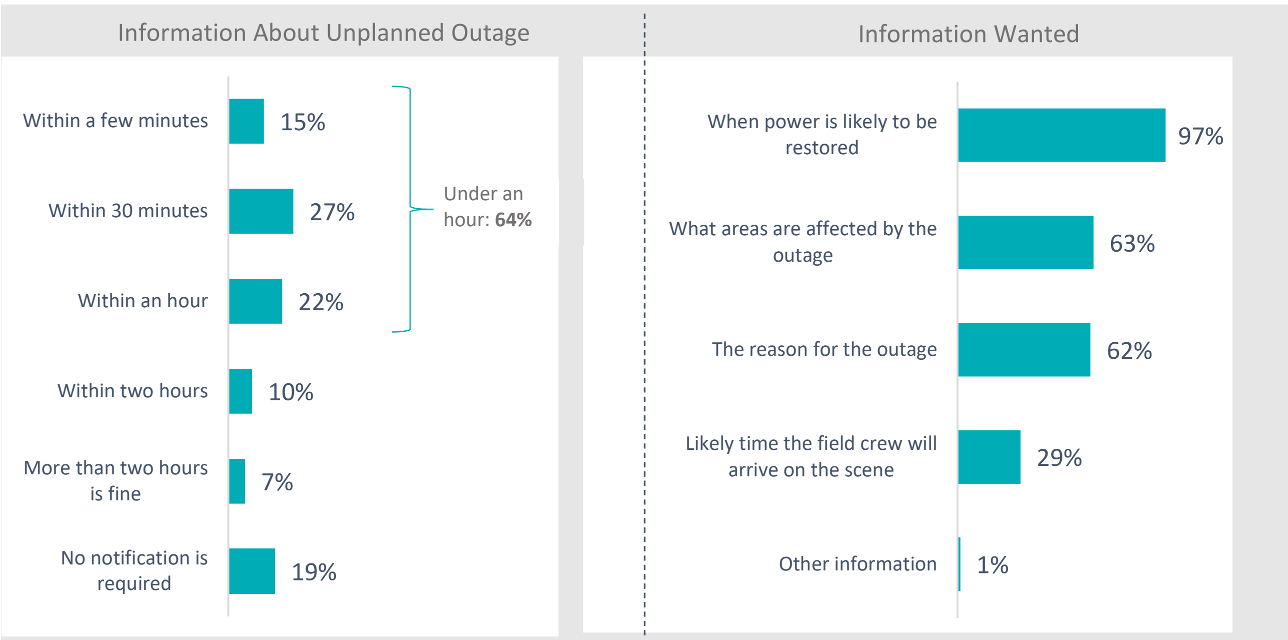

Figure 3.3: MainPower Consumers' Expectations for Unplanned Outage Notifications (Source: Online Survey 2019)

3.2.2 Consumers – Resilience

Our customers told us our level of resilience was meeting their expectations and MainPower's balanced investment in resilience was worthwhile. Nearly three-quarters of consumers surveyed indicated that a reasonable restoration time following a significant rare event, such as an earthquake or snowstorm, was between 12 and 48 hours, rather than weeks (see Figure 3.4). Throughout the engagement workshops, rural consumer groups tended to be slightly more self-sufficient as regards longer periods without power than the commercial consumers, who felt they would need power restored quickly.

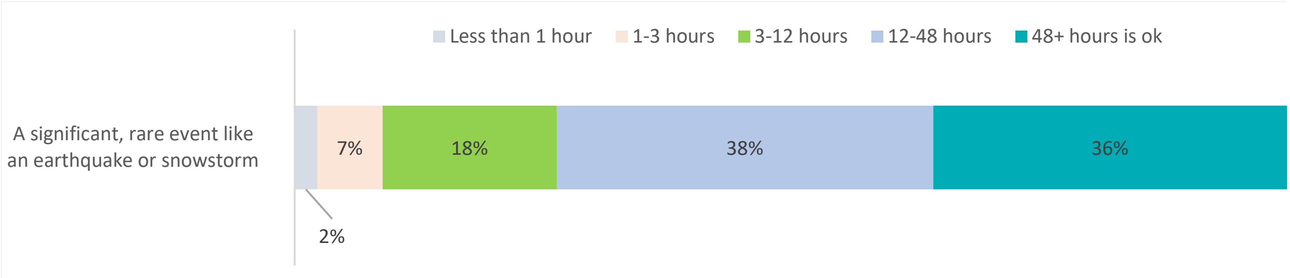

Figure 3.4: MainPower Consumers' Expected Restoration Time Following a Significant Event (Source: Online Survey 2019)

3.2.3 Consumers – New Technology

Creating a network for the future that meets consumers' expectations requires us to develop and maintain an understanding of how technology and consumer choices may affect the network and service MainPower provides. We need to enable consumer choice and remain relevant to our consumers and local community.

"MainPower should be innovative and take a leadership role in investing and preparing for future technology."

Our consumers showed good awareness of, and interest in, emerging technologies and were eager to improve New Zealand's carbon footprint through increased adoption of new technologies.

In our consumer engagement workshops, we asked consumers how proactive MainPower should be in preparing for future technologies, finding a high degree of support for MainPower taking a leadership role. This was reinforced in our online survey, where more than 60% of respondents were willing to pay to ensure our network was ready for consumers to take advantage of future technologies. The respondents showed high levels of interest in solar technology and electric vehicles but lower levels of knowledge of complementary technologies such as energy management systems and peer-to-peer energy trading.

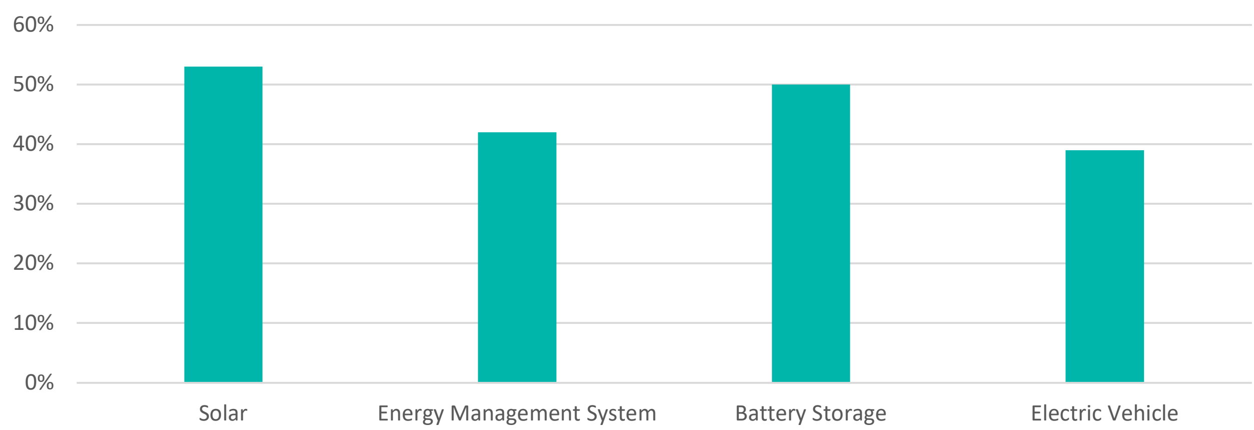

Figure 3.5: MainPower Consumers Who Currently Own (or Are Considering Owning) the Respective Technologies within the Next 10 Years (Source: Online Survey 2019)

As shown in Figure 3.5, nearly 40% of our consumers were considering ownership of new technologies within the next 10 years, particularly solar power, followed closely by battery storage and electric vehicles. They identified cost as the main barrier prohibiting their uptake.

3.2.4 Consumers – Safety

We did not have a specific workshop discussion area for safety, but rather, incorporated it within discussions about the other topic areas. Our consumers expected safety to be a top priority and that we should be aligned with industry safety standards, requirements and best practices.

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 3.6.

Figure 3.6: MainPower's Performance Indicator Continuous Improvement Process

3.3.1 Inputs

These are based on:

- Consumer expectations from consumer engagement surveys and workshops (as discussed already in Section 3.2); and
- Analysis and industry benchmarking across our peer group (to be discussed in Section 3.6).

3.3.2 Planning

Using these inputs, MainPower has refined its Network Development and Asset Management guidelines to include:

- Security of Supply Standard;
- Asset Portfolio Strategies, including Asset Health (condition-based risk management – CBRM) models;
- Project and Works Delivery Planning and Processes;
- Network Operating Standards;
- Network Architecture Standards; and
- Network Reliability Strategy.

3.3.3 Works Programme

Asset Management guidelines are used to inform a targeted Asset Management Plan work programme and budgeting/resource planning, including:

- 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

This involves:

- Internal data analytics of historical service levels, including feeder reliability, root cause and common mode failure analysis, and applying predictive modelling; and
- Network service-level performance being 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 conducted into major outage causes.

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, and combines with other inputs to better understand, inform and refine future service levels.

3.4 Performance Indicators

3.4.1 Reliability

Network reliability is measured by the frequency and duration of interruptions to consumers' electricity supply. Our reliability targets guide our investment decisions and aim to meet both our consumers' expectations and 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** (System Average Interruption Frequency Index), which measures the average supply interruptions for each consumer during the year; and
- **SAIDI** (System Average Interruption Duration Index), 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 does occur, we challenge ourselves to restore supply to consumers within three hours. Our network operations and field services teams have people available around the clock to respond when unplanned interruptions occur. Our Network Field Operators are based throughout our region and we hold strategic spares in our depots to reduce response and repair times.

3.4.3 Resilience

Resilience is the ability of MainPower's network and people to respond to, and recover from, infrequent and significant events such as snowstorms and earthquakes. A more resilient network will minimise the number of consumers impacted by significant events. We recognise we need to balance costs with providing a reasonable level of service and we are exploring ways to better measure MainPower's network and business resilience and response capability.

We have invested in an Advanced Distribution Management System (ADMS) to help provide better visibility and control of our network. We also see an opportunity to improve both network restoration and resilience performance further through improved network architecture aligned with our Security of Supply Standard (see Section 6 of this document) and enhancing our 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.

Figure 3.7: Customer Pulse Survey 2019

Our objectives are to:

- Identify, manage and communicate risks associated with the workplace, the electricity distribution network and our business activities;
- Ensure compliance with legislative requirements and industry standards;
- Ensure that employees and field service providers have an appropriate level of training, skill and knowledge to carry out their work safely; 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 (SF_6) Gas:** This gas is used as an interruption medium in switchgear and the Ministry for the Environment has set a compliance level of less than 1% annual loss, based on the total volume of gas on the network. MainPower is committed to minimising SF_6 emissions and we monitor and report on losses.
- **Oil Spills:** Some assets on our network use oil as an insulating medium. We use a range of containment and mitigation solutions to prevent, or minimise the impact of, spills. Our annual target is zero uncontained oil spills across our network.

3.4.5 Customer Oriented

Customer engagement is increasing in significance as the electricity industry evolves and industry participants place more value on being relevant. Creating a strong, lasting relationship with customers today means we will ensure we stay relevant tomorrow.

By listening to our customers and community, we can develop a clear understanding of the measures of performance that are most important to them and how MainPower is currently performing against those measures. Currently, MainPower assesses our performance regarding engaging with consumers through our pulse survey, in which we monitor:

- 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; and
- Price – to ensure our pricing is fair.

3.4.6 Physical and Financial

It is important that MainPower continually assesses its 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 its performance against our 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 Maturity Assessment Tool);
- Financial Performance; and
- Industry Benchmarking.

3.5 Performance Indicators and Targets

Service Measures and Targets														
Service Class	**Performance Indicator**	**Performance Measure**	**Past Performance Targets**		**Future Performance Targets**									
			FY20	**FY21**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
Reliability	SAIDI – System Average Duration Index	Average minutes lost per customer per year	340	332	323	314	299	296	293	284	276	268	260	252
	SAIFI – System Average Frequency Index	Average number of times a customer's supply is interrupted per annum	1.71	2.18	2.23	2.08	1.93	1.92	1.91	1.87	1.82	1.78	1.74	1.70
	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%	
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											
	SF_6 gas lost	Gas lost as % to total gas volume	< 1%											
	Oil spills	Uncontained oil spills	None											
Consumer Oriented	Engagement effort	Customer Pulse Survey: 1 – very dissatisfied 5 – very satisfied	2.5	> 2.5	> 3		> 3		> 3.5		> 4		> 4	
	Staff friendliness		4.5	> 4	> 4		> 4		> 4		> 4		> 4	
	Quality of work		4.5	> 4	> 4		> 4		> 4		> 4		> 4	
	Timeliness of service		4.5	> 3.5	> 4		> 4		> 4		> 4		> 4	
	Communication		4.5	> 3.5	> 4		> 4		> 4		> 4		> 4	
	Staff reliability		4.5	> 4	> 4		> 4		> 4		> 4		> 4	
	Final price		4	> 3.75	> 3.75		> 3.75		> 3.75		> 3.75		> 3.75	
Physical and Financial	Maintenance delivery	Maintenance programme delivery by budget	> 90%	> 90%	> 90%		> 90%		> 90%		> 90%		> 90%	
	Capital delivery	Capital programme delivered by budget	> 90%	> 90%	> 90%		> 90%		> 90%		> 90%		> 90%	
	AMMAT	Complete workstreams noted in AMMAT	> 90%	> 90%	> 90%		> 90%		> 90%		> 90%		> 90%	
	Industry benchmarking	Assess ourselves against: • Operating Expenditure per ICP; • Capital Expenditure per ICP; • Quality of Supply (SAIDI and SAIFI); and Non-Network Operating Expenditure per ICP.	< 75^{th} percentile	< 75^{th} percentile	< 75^{th} percentile		< 75^{th} percentile		< 75^{th} percentile		< 75^{th} percentile		< 75^{th} percentile	

Table 3-2: 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 3.8). 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.

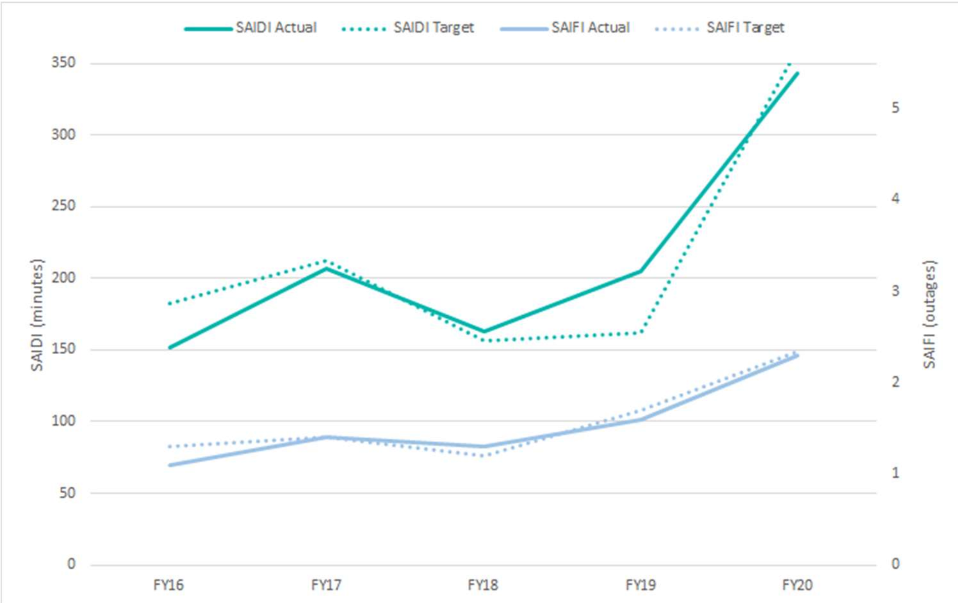

Figure 3.8: MainPower’s Network Reliability SAIDI and SAIFI over 5 years (FY16–FY20)

MainPower’s consumers view network reliability as a top priority and are generally satisfied with their current level of reliability. Considering reliability over a 5-year period, at times MainPower’s network performance has been below the target performance, and overall reliability is deteriorating. To understand the cause of this trend, it is helpful to break down reliability into both planned and unplanned events (see Figure 3.9 and Figure 3.10).

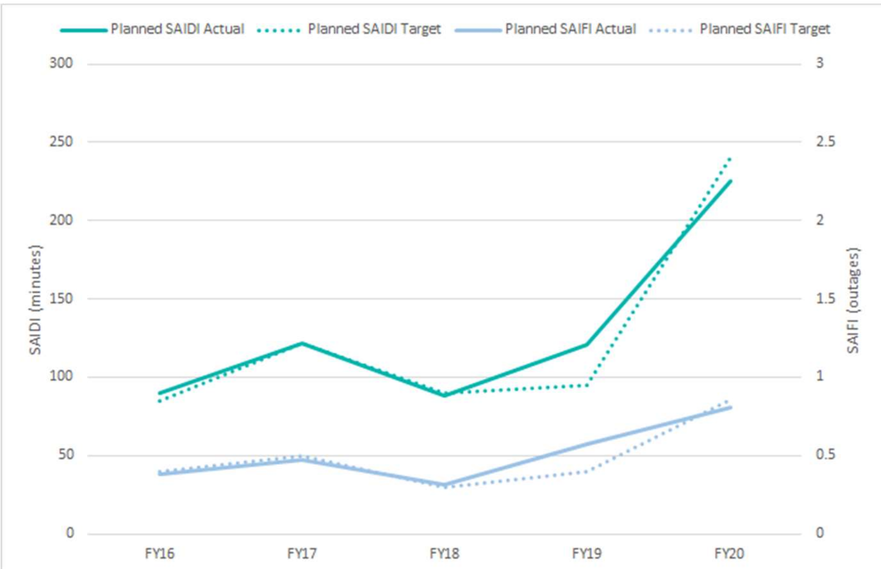

Figure 3.9: Network Reliability – Planned (FY16–FY20)

It can be seen that it was not the number of times that planned outages occurred that affected overall planned outages, it was the duration of the outages. This indicates that when planning outages for works, MainPower is either underestimating their durations or the outages are extending beyond the initial expected and planned period.

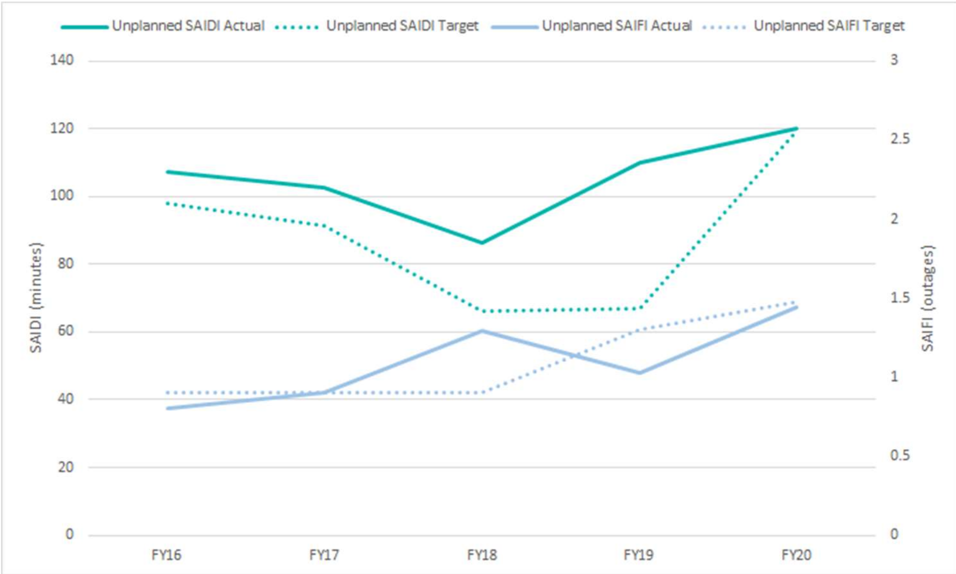

Figure 3.10: Network Reliability – Unplanned (FY16–FY20)

Conversely, when analysing unplanned outages, it was the frequency of unplanned outages that affected overall unplanned outage performance. We need to further analyse unplanned outages to understand whether there is an underlying trend causing the number of unplanned outages.

In summary, MainPower did not exceed its reliability targets for FY20. For that year, 65% of our SAIDI was due 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. These factors negatively affect the frequency and duration of outages.

To highlight and better understand what contributes to unplanned electricity distribution network reliability, we analysed all outage data by cause, using outage statistics over time to illustrate any underlying trends. We used a 5-year rolling average across all outage categories (see Figure 3.11).

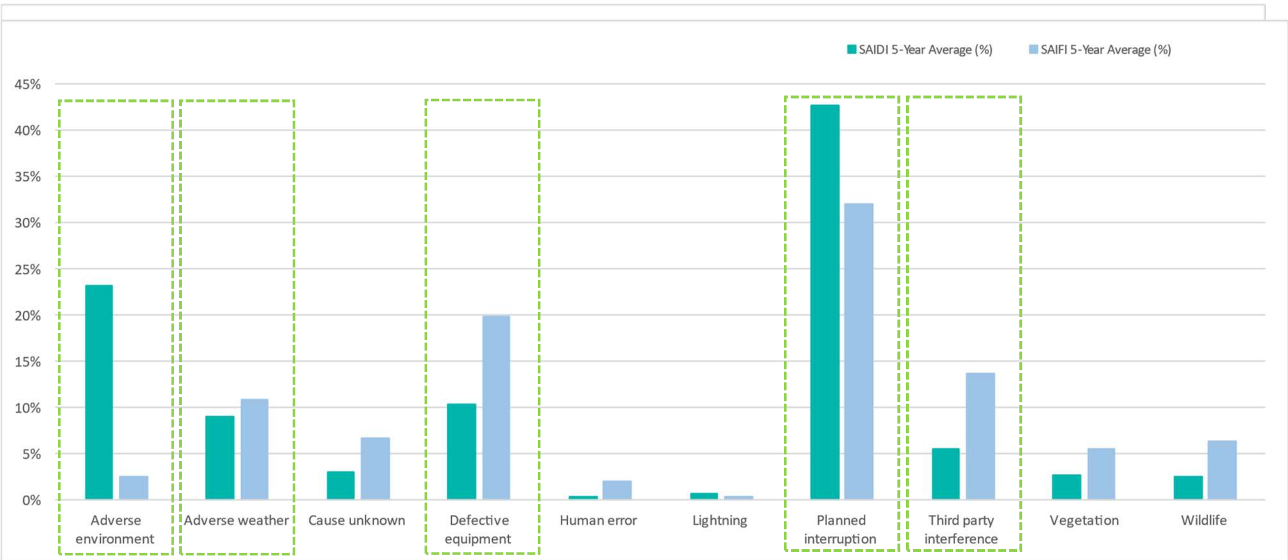

Figure 3.11: Network Reliability by Cause (5-Year Rolling Average, FY16–FY20)

While the analysis provided useful data about the overall contributors to deteriorating network performance, we know that trends can be affected by single events. Therefore, MainPower reviewed the outages, by cause, over time. The results are shown in Figure 3.12 and Figure 3.13.

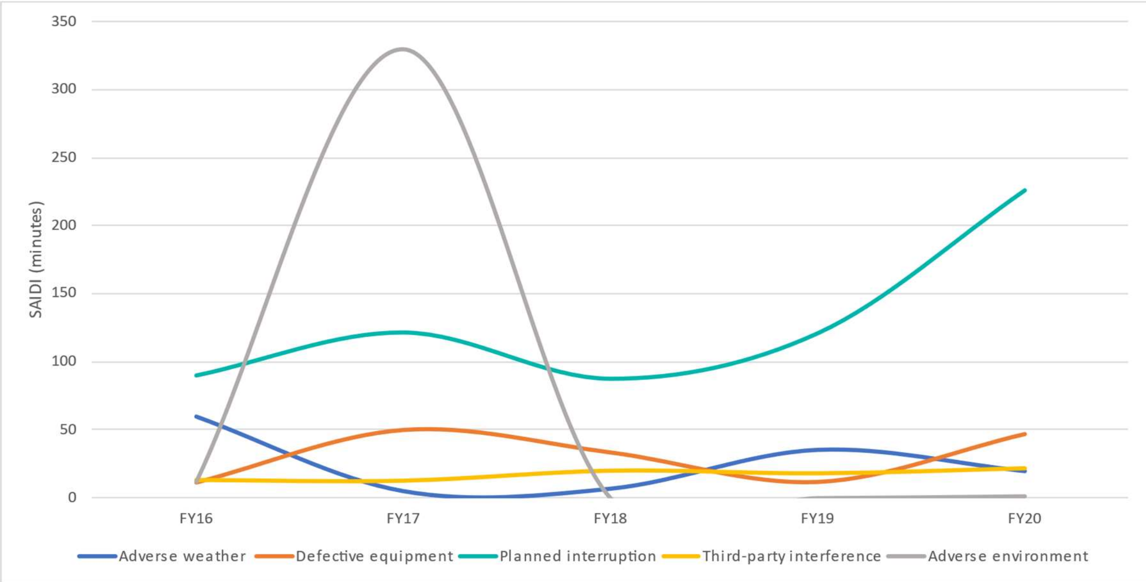

Figure 3.12: Network Reliability by Cause Trend – SAIDI (FY16–FY20)

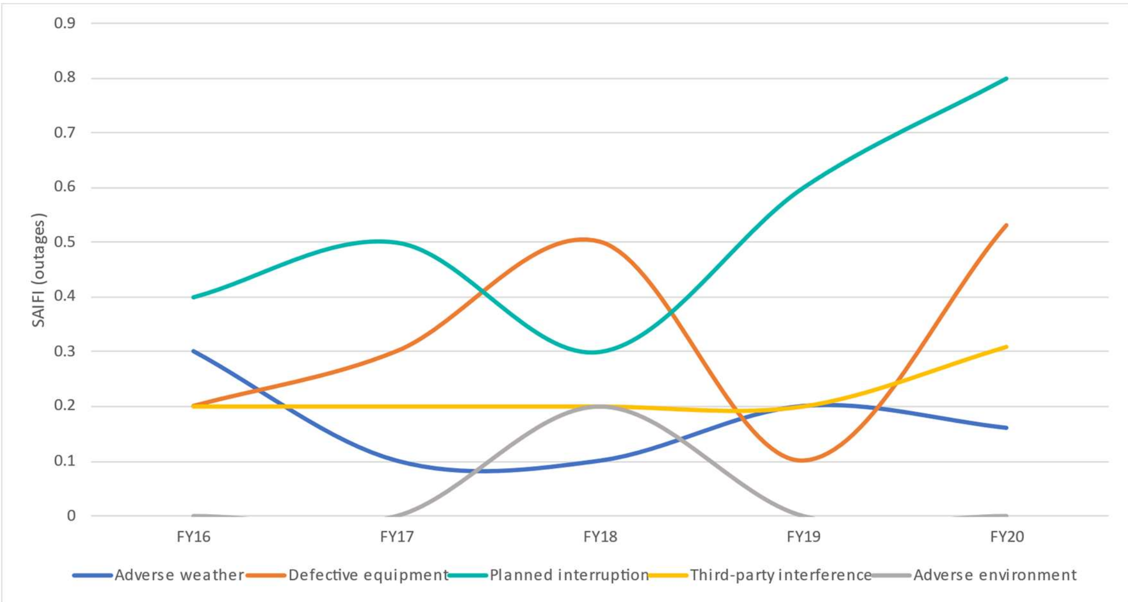

Figure 3.13: Network Reliability by Cause Trend – SAIFI (FY16–FY20)

The peaking of "adverse environment" in FY17 was due to the Waiau Earthquake. As this was a single event, "adverse environment" was not considered a significant contributor to overall network performance. The top contributors to adverse reliability over the 5-year period (FY16–FY20) were:

- Planned works;
- Defective equipment;
- Adverse weather; and
- Third-party interference.

These are explained in detail in Table 3-3.

Category	Analysis	Initiatives	Update	Target Date
Planned Works	Currently, MainPower plans works across its network using multiple systems, which can lead to suboptimal planning. MainPower planned to "go live" with its Advanced Distribution Management System in FY20 which should enhance planning in the future.	Go live and embed the ADMS project into the organisation. Review works planning post going live, monitor and make improvements as required.	ADMS has gone live and a new planning team has been embedded into the Network Operation Function. Work remains to optimise the work programme in FY21–FY22.	FY22
Defective Equipment	Reviewing defective equipment by asset class yields that reliability is adversely affected by: 1. Switchgear; 2. Ring Main Units; 3. Cable Faults; and 4. Insulators.	Work Programme: 1. Switchgear replacement – Ludstone Zone Substation and Southbrook Zone Substation. 2. Ring Main Unit replacement – network wide. 3. Insulator and Crossarm Inspection Programme – budget allocated to implement a maintenance programme for early detection of faulty insulators or crossarms on the network before failure in service.	Ludstone Substation Complete, Southbrook remains work in progress. RMU replacement programme still being delivered. Crossarm and insulator programme budgeted in FY21–FY22. Technology recommendation has been made for FY21.	FY22
Adverse Weather	Adverse weather reporting appears to be inconsistently used, as MainPower has not experienced many major weather events.	Review of internal process for the allocation of reliability categories, enabling consistent, detailed reporting.	Taking advantage of the ADMS roll out, "adverse weather" issues are no longer being reported as "vegetation". A deteriorating trend in such reporting is now evident in 2020.	Complete
Third-Party Interference	MainPower already has a public advertising campaign in place communicating the need to watch out for overhead lines. We also issue "High Load" and "Close" approach permits, including action plans where evidence suggests the terms and conditions under which the permit is issued can be ignored.	Active watch: MainPower intends to monitor third-party interference and determine whether additional steps need to be implemented.	Third-party interference is still trending in the wrong direction. Funds are available in the FY21–FY22 period to increase public awareness of this issue.	FY22

Table 3-3: 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 normal. The graphs in Figure 3.14 and Figure 3.15 show that the reliability impact started to increase from the top five-worst-performing feeders in the years FY16–FY20 (see details in Table 3-4).

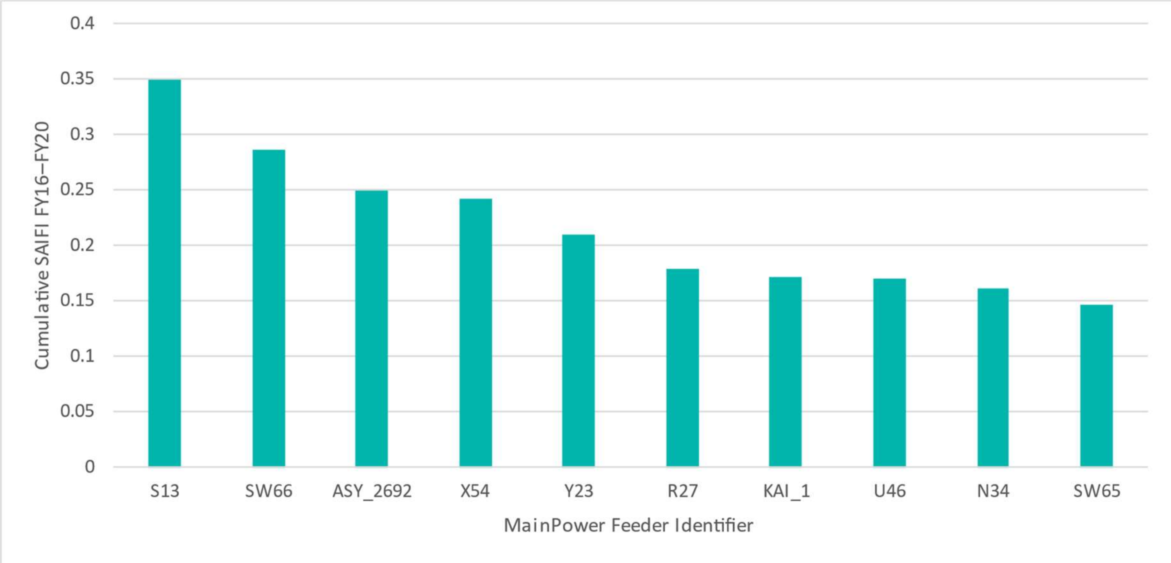

Figure 3.14: Top 10 Feeders with Highest Cumulative Unplanned SAIFI (FY16–FY20 Average)

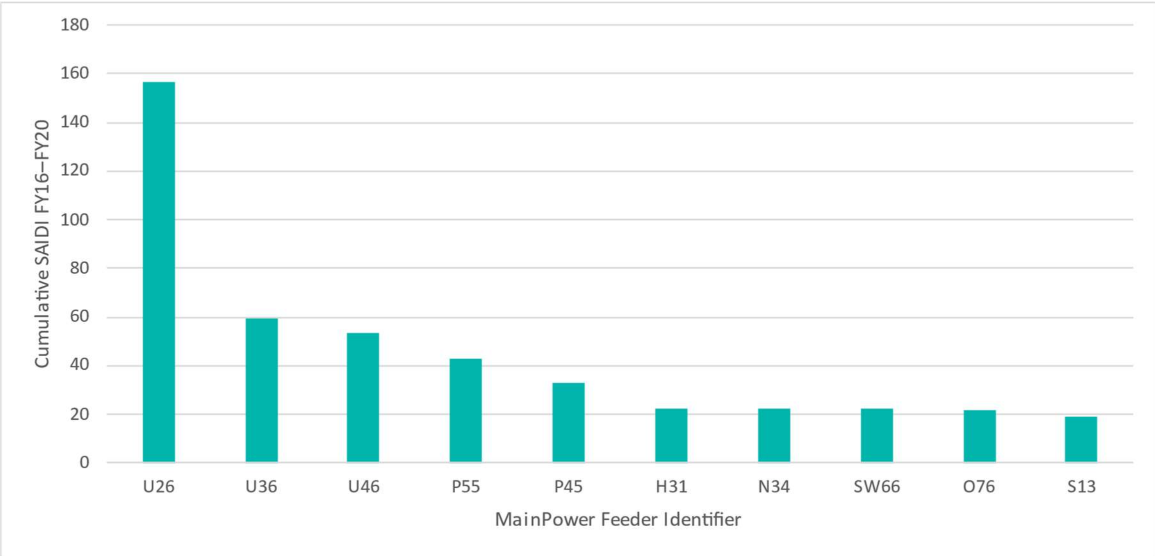

Figure 3.15: Top 10 Feeders with Highest Cumulative Unplanned SAIDI (FY16–FY20 Average)

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 will be completed under the Southbrook 66kV 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.	FY21

Feeder	Analysis	Initiatives	Target Date
U26, U36 and U46	These 11 kV feeders supply the Kaikōura region from our Ludstone Zone Substation. These feeders experienced significant interruptions due to damage caused by the 2017 Waiau Earthquake, as well as 11 kV switchgear failure at the Ludstone Zone Substation. These interruptions had a range of causes, mainly cable faults and asset failures.	As the Waiau Earthquake was a single event, we currently do not have any direct initiatives in response to this analysis. We are assessing our general network resilience and network design standards.	N/A
Y23 and Y33	These two feeders supply the Amberley, Leithfield Beach and Balcairn areas from our Amberley Zone Substation. They are both long, rural overhead feeders and analysis of interruptions over the past 5 years indicates they are prone to unplanned outages caused by vegetation and weather events.	Reconfigure the network in this region to limit the impact of single events and improve and target our vegetation-management programme to prevent vegetation-related outages. As part of the ASY_2692 feeder split project there will be wider network reconfigurations to reduce the impact of these rural faults on the network. This will be completed in FY22.	FY21
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 5 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.	Planning 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. A circuit breaker has been installed on this feeder. On-going reliability gains are inspected and the impact of this will be monitored to ensure MainPower is getting the expected improvements.	FY21
ASY_2692	This is a very large rural feeder supplying the Loburn and Okuku areas from the Ashley GXP. We currently have limited line-circuit breakers installed along this feeder and minimal capability to separate or isolate parts of this feeder during interruptions. Analysis of interruptions over the past 5 years indicates a trend of vegetation, weather and wildlife causes, reflective of the environment the feeder passes through in the foothills of North Canterbury.	An identified network reinforcement project will separate this large feeder into two smaller feeders. This will minimise the overall consumer impact of single outages. As mentioned above, we aim to improve and better target our vegetation-management programme, to prevent vegetation-related interruptions. The feeder split project has been mostly completed. This will be finished in FY22.	FY21

Table 3-4: Network Feeder Reliability Improvement Summary

3.6.3 Health, Safety and Environment

We report all employee injury and public safety events through our Vault safety information management system (see Table 3-5). 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	FY20 Target	FY20 Actual
No injuries related to a Safety Critical Risk	None	1 (contractor)
No injuries to members of the public	None	None
SF_6 loss (% to total gas volume)	< 1%	< 1%
Uncontained oils spills	None	None

Table 3-5: Health, Safety, Environment and Quality Evaluation (FY20)

3.6.4 Consumer Oriented

Monitoring and improving service delivery is vital if we are to establish trust and goodwill with consumers and maintain our reputation amongst our stakeholders. While our customer satisfaction scores have continued to improve over time, we are not meeting our targets in some areas (see Table 3-6 and Table 3-7).

Customer Satisfaction	FY19 Target	FY2019 Actual
Engagement Effort	2.5	2.43
Staff Friendliness	4	4.39
Quality of Work	4	4.44
Timeliness of Service	4	3.19
Communication	4	3.14
Staff Reliability	4	3.82
Final Price	3.5	3.92

Table 3-6: Consumer Satisfaction and Service Delivery (FY19)

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.	An update to the MainPower website was completed in 2019, including integrating several consumer interactions into our Customer Relationship Management (CRM) package. We will continue to monitor this target and identify new workstreams throughout 2020.	FY20
Timeliness of Service	We are aware that the way MainPower is currently responding to consumer requires further work. These workstreams also link to "Engagement Effort" and "Communication".	Review of timeliness aspects associated with consumer interactions, with front line staff to understand possible issues in systems and processes. Develop an improvement and implementation plan. A business realignment has also been undertaken to improve efficiency and communication internally between functions, to allow for improved responsiveness to customers.	FY21
Communication	In both the consumer-oriented and engagement sessions, communication has presented as an issue when engaging with consumers and as it relates to outages.	There are several initiatives to address this issue: 1. New website – complete; 2. Workstream development for consumer interactions within CRM (vegetation is the first workstream); and 3. Integration of the ADMS system and automation of outage notification to the	FY21

		website – Phase 1 complete; Phase 2 to be completed 2021.	
Staff Reliability	Customers indicate that MainPower staff are not responding to their needs consistently.	We believe this relates more to communication (as above) and setting expectations early. We are currently working on initiatives to improve this in FY20. We expect the business realignment to have a positive impact on this, based on process improvements and flow of communication between functions.	FY20

Table 3-7: Customer Performance Measures

3.6.5 Physical and Financial

3.6.5.1 Maintenance

MainPower has delivered on its safety-critical maintenance throughout FY21. The works also included asset data collection, which enabled MainPower to assess overall asset portfolio health, as detailed in the "Assets" section of this document. Expenditure was within the performance target for the year (see Table 3-8).

Class	Description	Status	Update
Maintenance	Overhead inspections	Complete	N/A
	Zone substation	Complete	N/A
	Kiosk substations	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 3-8: Maintenance Programme Summary

3.6.5.2 Capital Programme Delivery

Capital expenditure finished below target for the FY20 year as MainPower has continued to ensure that asset renewal was informed by asset condition, criticality and the relevant security of supply standard (refer Figure 3.16). This work programme refinement will be reflected in elevated levels of capital expenditure in upcoming years.

Class	Description	Status	Update
GXP	Kaiapoi GXP Project	Complete	Not economically efficient – closed this project
	Culverden GXP Purchase	In progress	Funding approved, awaiting detailed design and final project costs
Major Projects	Renewal of Ludstone switchgear restoring N-1* supply, as determined by MainPower design and security of supply criteria	Complete	N/A
	Kaikōura Zone Substation Fan Upgrade	Complete	N/A
	Cheviot–Oaro Upgrade – purchase land for substation	Complete	N/A

Class	Description	Status	Update
	Southbrook Substation Capacity Upgrade	In progress	Project approved and delivery in progress FY21–FY22
	Amberley Zone Substation 33 kV Upgrade	In progress	Project in progress, with delivery across FY21–FY22
Reinforcement Projects	Cheviot North Voltage Regulator and Capacitor Installation	Complete	N/A
	Cheviot South Voltage Regulator Installation	Complete	N/A
	Ashley Regulator and Capacity Installation	Complete	N/A
	Rangiora Northbrook Rd Link	Complete	N/A
	WDC Blake St	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, target 1,000 poles, replaced 1,085	Complete	N/A
	RMU, target 25 units, replaced 28	Complete	N/A
	Low-voltage link box, targeted 107 units, replaced 70	Complete	N/A
	Pines Beach Upgrade (poles, overhead and low-voltage assets)	Complete	N/A

**N-1 is an indication of power supply security that specifically means that when one circuit fails, another will be available to maintain an uninterrupted power supply.*

Table 3-9: Capital Programme Summary (FY20)

3.6.5.3 Financial Performance

Expenditure on Assets	Forecast ($000)	Actual ($000)	% variance
Consumer connection	$ 6,800	$ 4,257	-37%
System growth	$ 1,584	$ 741	-53%
Asset replacement and renewal	$ 8,863	$ 10,571	19%
Asset relocations	$ -	$ 40	0%
Reliability, safety and environment:			
Quality of supply	$ -	$ 1,481	0%
Legislative and regulatory	$ 917	$ -	-100%
Other reliability, safety and environment	$ 1,340	$ 1,723	29%
Total reliability, safety and environment	$ 2,257	$ 3,204	42%
Expenditure on network assets	$ 19,504	$ 18,813	-4%
Expenditure on non-network assets	$ 4,069	$ 7,073	74%
Expenditure on assets	**$ 23,573**	**$ 25,886**	**10%**
Operational Expenditure			
Service interruptions and emergencies	$ 1,131	$ 1,274	13%
Vegetation management	$ 675	$ 515	-24%
Routine and corrective maintenance and inspection	$ 1,131	$ 2,964	162%
Asset replacement and renewal	$ 2,263	$ 573	-75%
Network opex	$ 5,200	$ 5,326	2%
System operations and network support	$ 3,910	$ 6,463	65%
Business support	$ 9,122	$ 6,838	-25%
Non-network opex	$ 13,032	$ 13,302	2%
Operational expenditure	**$ 18,232**	**$ 18,628**	**2%**

Figure 3.16: Financial Performance FY20

Category	Analysis	Initiatives	Target Date
Revenue	No target.	Complete	N/A
Customer	Contestable in nature and slightly below target, mainly due to subdivision works being completed in other years and the ability to connect to the network with limited resources.	Complete	N/A
Expenditure on Assets	Aligned with planned budget and planed units of replacement. Budget overall exceeded target because of changes in accounting standards relating to the recognition of long-term leases at the full Net Present Value.	Complete	N/A
Operational Expenditure	All maintenance, both planned and reactive, was completed into the reporting year.	Complete	N/A

Table 3-10: Financial Performance Analysis and Initiatives

3.6.5.4 Asset Management Maturity

Owning the right assets, managing them well, funding them sustainably and managing the risks are all critical to the ongoing provision of the high-quality and cost-effective services that MainPower provides to its consumers. This means MainPower is committed to ensuring investment management and asset performance practices remain fit for purpose.

Using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT), MainPower reassesses its asset management system and processes, and develops improvement plans. Progress is summarised in the following tables.

Defining the Requirements	Improvement	Actual	Target Date
Levels of Service and Performance Management	MainPower has introduced the Voice of the Customer Programme, which has enabled MainPower to translate consumer requirements into network performance.	Customer engagement completed – work remains on translating what our customers are telling us into actual service levels.	FY22
Demand Forecasting	This remains a key focus for MainPower, taking into consideration consumer segments, location and the network impact of emerging technology and a low-carbon economy.	To be completed.	FY22
Asset Register Data	Major advancements have been made in ensuring asset data (including condition data) are logged against the asset in the Computerised Maintenance Management System (CMMS).	Completed – went live with a new CMMS, poles loaded, remainder of the assets in FY22.	FY20–FY22
Asset Condition Assessment	A condition assessment programme is in place for poles, which is MainPower's largest asset class by quantity. All pole renewals are now informed by condition data, compliance and criticality.	Expand to all asset portfolios by FY21.	FY22
Risk Management	Risk has been integrated into the network, including division/team, plant, equipment and activity risk, as well as documentation of controls. High risks are introduced in the Corporate Risk Register.	Completed.	FY19

Table 3-11: Asset Management Maturity Requirements

Lifecycle Decision Making	Improvement	Actual	Target Date
Decision Making	Decision making for major capital is assessed against a capitalisation process that is informed by a security of supply standard and reliability classification. MainPower is introducing risk-based decision making across its business.	Completed. MainPower introduces its Security of Supply Standard – projects link to this Standard.	FY22
Asset Class [Renewal] Strategies (ACRS)	A Condition and Criticality Framework has been introduced and largely remains to be implemented.	In progress. This has been introduced within this AMP for three asset classes.	FY22
Operational Planning and Reporting	Business emergency response plans and escalation are developed and implemented. Asset planning is informed by demand (e.g. quantity of consumer connections).	Completed. We have implemented Coordinated Incident Management System (CIMS) training for our staff for event management.	FY21
Maintenance Planning	Maintenance activities are prescribed for all asset classes. These remain to be implemented in the CMMS for all assets.	Completed. MainPower has asset maintenance standards for all its assets, which were introduced into the CMMS in Q1 2019.	FY20
Capital Investment Strategies	Capital expenditure is prescribed, linking cost, risk and network performance.	To be completed.	FY22
Financial and Funding Strategies	Funding for capital expenditure is on a 10-year cycle, informed by asset performance, reliability and supporting assumptions.	To be completed.	FY22

Table 3-12: Lifecycle Decision-Making Improvements

Asset Management Enablers	Improvement	Actual	Target Date
Asset Management Teams	The Network Strategy and Planning team has been created within MainPower. Staff understand their roles and asset management best practice is supported by the Executive Leadership Team.	Completed.	FY19
Asset Management Plan (AMP)	MainPower's AMP describes service levels and assets, and includes a 10-year forecast of expenditure. Asset management improvement plan created.	Completed annually.	FY22
Information Systems	A comprehensive asset register exists. Systems have been introduced to track consumer requests and defects. Works management remains to be automated using schedules linked to assets, creating work orders automatically.	Completed. MainPower CMMS is now the single source of the truth for all our assets.	FY19
Service Delivery Models	Service-Level Agreements are currently being implemented, defining minimum levels of service required from internal crews, and formal contracts exist where external providers are required.	To be completed.	FY22
Quality Management	MainPower is accredited to ISO 9001 and all asset management processes are documented.	Completed.	FY19
Improvement Planning	Improvement planning is currently in place and includes efficiency and productivity within the business, and an upgrade to the CMMS. The projects are approved, funding in place and progress against the plan is reported to the Executive and Board.	Underway.	FY22

Table 3-13: Asset Management Enablers Improvements

Maintaining Our Assets	2019 Actual	Target 2020–2021
Asset Maintenance Standards	MainPower has maintenance standards for all our assets.	Implement standards with scheduled maintenance in TechnologyOne for all asset classes.
Asset Portfolio Strategies	To be started.	MainPower to have Asset Portfolio Strategies for all assets.
Asset Health Indicator (AHI)	AHIs are implemented for three asset classes.	Establish and monitor asset health for all asset classes.
Asset Maintenance and Replacement	AHI models will inform condition and risk-based approach to asset management.	Apply condition- and risk-based maintenance and replacement programmes.
Regional Planning	AMP contains a regional approach to network development planning.	Extend network planning to provide region-specific master plans.
Engineering Design	Standard designs aligned with regional EDBs are in progress.	Develop standard engineering designs across main asset classes.
New Energy Future	Active watch.	Monitor emerging technologies and conduct network development scenario planning.

Table 3-14: Areas of Focus for Asset Management Indicators

3.6.6 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 3-15. This list will be reviewed in FY22 to ensure ongoing benchmarking with similar EDBs.

Organisation	ICP/km	ICPs
Alpine Energy	7.7	33,212
EA Networks	6.3	19,441
Eastland Network	6.7	25,597
Horizon Energy Distribution	9.7	25,114
MainPower NZ	**7.9**	**39,624**
Marlborough Lines	7.6	25,629
Network Tasman	11.1	39,967
Top Energy	7.9	31,901
Median	**7.8**	**28,765**

Table 3-15: Benchmark Organisations (2019 data from PWC ID Compendium)

3.6.6.1 Network Operating Expenditure

MainPower's Network Operating Expenditure, which includes planned and unplanned network maintenance and fault response, was low during the 2019 financial year (see Figure 3.17). This reflected MainPower reviewing its asset management practices detailed in the last AMP. Expenditure is expected to increase to above the peer group average as MainPower implements its revised asset management practices.

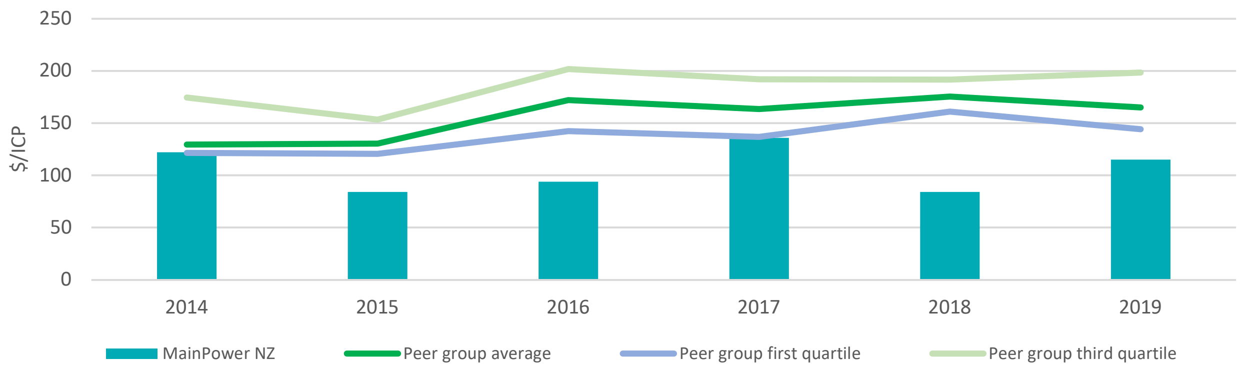

Figure 3.17: Benchmarking – Network Operating Expenditure Per ICP

3.6.6.2 Non-Network Operating Expenditure

Non-Network Operating Expenditure, which includes corporate, business support, asset management planning and network operation, has increased by 50% since 2014 and is now similar to the peer group average (refer Figure 3.18). This reflects MainPower's focus on improving asset management maturity and the development of robust and effective business processes.

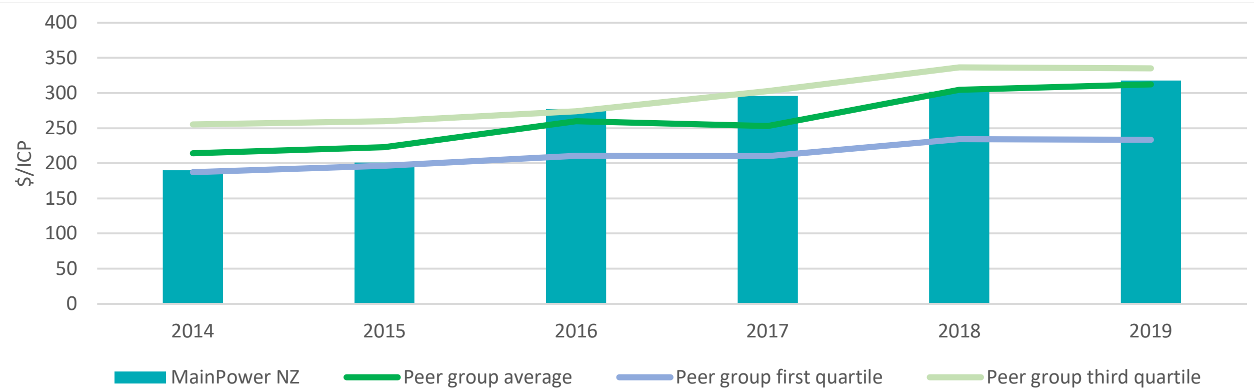

Figure 3.18: Benchmarking Non-Network Operating Expenditure Per ICP

3.6.6.3 Capital Expenditure on Network Assets

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

- Capacity;
- Security of supply; and
- Asset replacement and renewals.

MainPower's capital expenditure on network assets for the previous two years was below its peer group first quartile and group average (refer Figure 3.19). Going forward, this is expected to increase owing to works required to address security of supply, network reliability and an increase in MainPower's replacement and renewals programme.

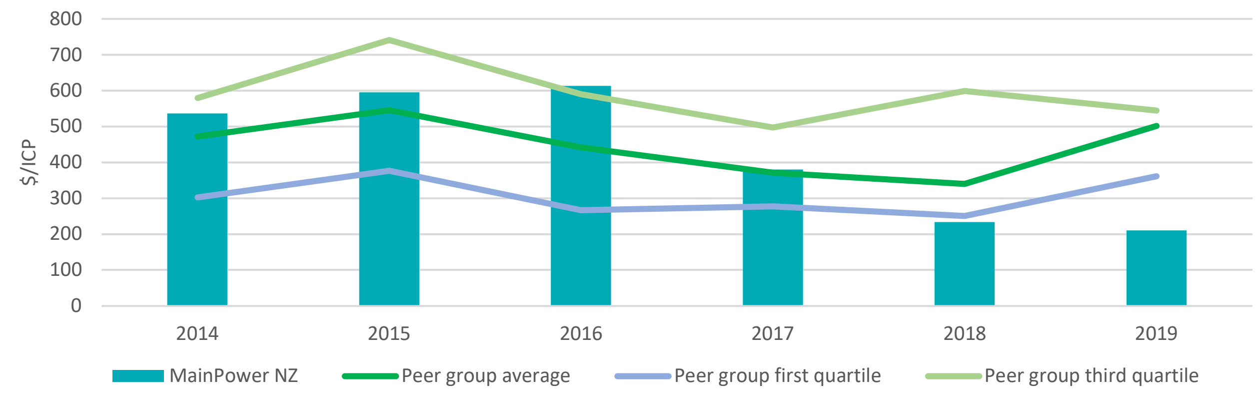

Figure 3.19: Benchmarking Network Capital Expenditure Per ICP

3.6.6.4 Reliability

Reliability for MainPower remains within the figures for our industry peers. However, forecast SAIDI and SAIFI means that we are trending towards to the 75th percentile (see Figure 3.20 and Figure 3.21). Initiatives have been identified to address quality of supply for MainPower in the future and return it to within historical norms.

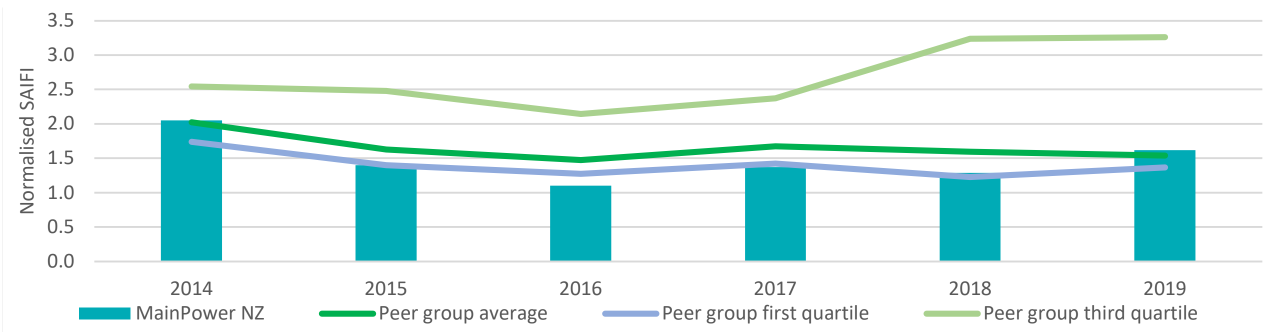

Figure 3.20: Normalised SAIFI Benchmarking

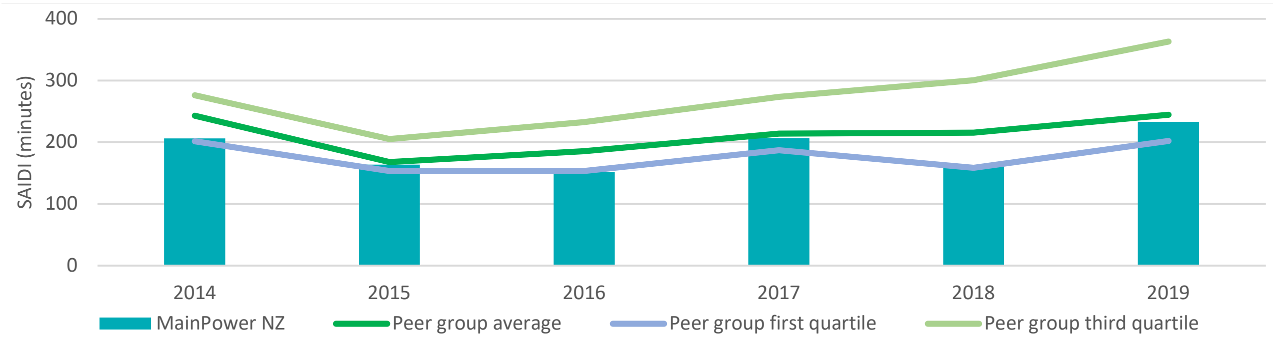

Figure 3.21: Normalised SAIDI Benchmarking

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 Management

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.

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.

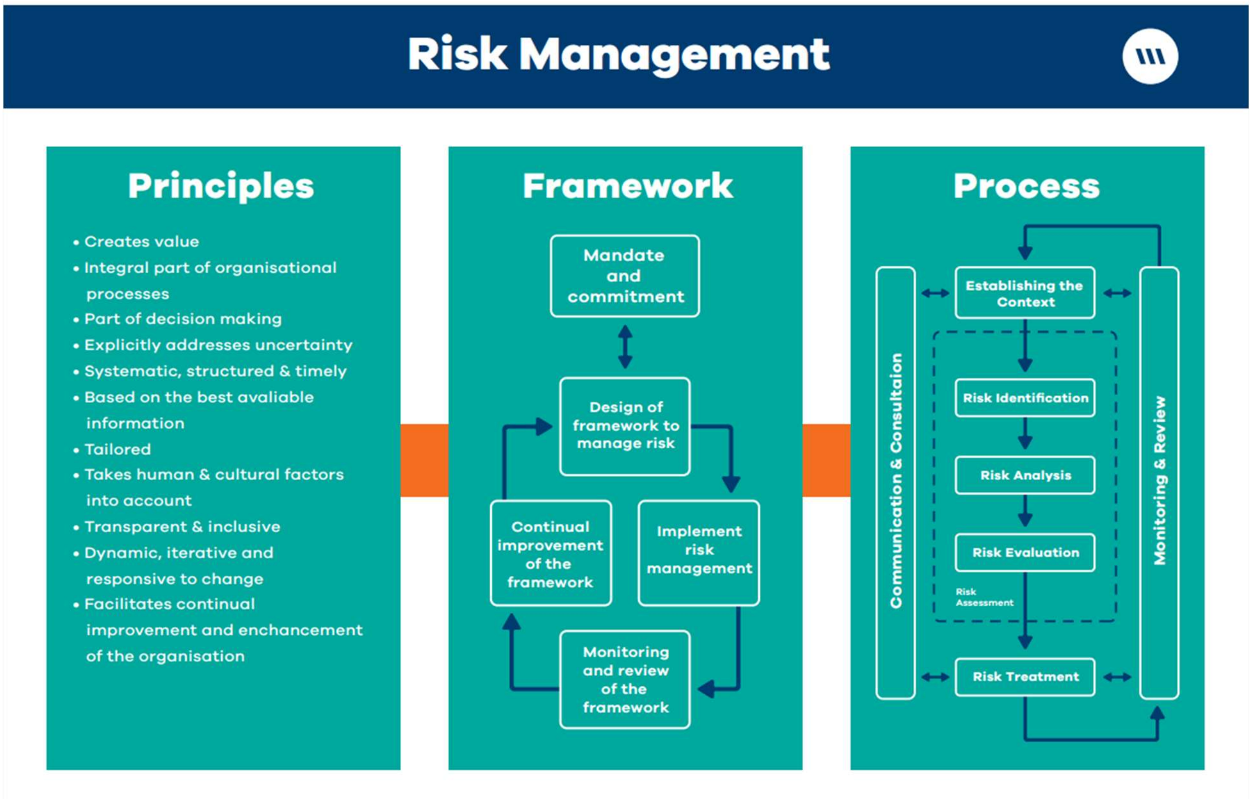

Figure 4.1: Risk Management Framework (drawn from ISO 31000:2018)

The principles in Figure 4.1 describe the essential attributes of good risk management; the framework provides a risk management structure, while the process prescribes a tailored approach to understanding, communicating and managing our risk in practice.

The Chief Executive has ultimate responsibility and accountability for ensuring that risk is managed across MainPower. The Chief Executive and Executive Leadership 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 risk, 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 uses a “bow tie” methodology for risk management. Bow tie models are 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”.

All critical risks are assigned risk owners, with “Welcome to risk” training made available to all MainPower people through workshops and e-learning.

4.1.2 MainPower Risk Matrix

MainPower has designed a Risk Matrix to assess and analyse risk. It includes four levels of risk – minor, moderate, major and catastrophic (see Table 4-1).

LIKELIHOOD / CONSEQUENCE	MINOR	MODERATE	MAJOR	CATASTROPHIC
Almost Certain Happens (or is expected to occur) daily or weekly within MainPower.	M8	M12	H18	H23
Likely Happens (or is expected to occur) monthly within MainPower.	L4	M8	H14	H19
Possible Will occur in some circumstances and has happened in MainPower before (every 1-5 years).	L3	L7	M13	H18
Unlikely Could occur in some circumstances (every 5-50 years) and is known in the industry).	L2	L6	M12	H17
Rare Could occur but only in exceptional circumstances, possible in the industry (50 years+).	L1	L5	M11	H16
	Low (Range 1–7)	Medium (Range 8–13)	High (Range 14–23)	

Table 4-1: Matrix Ranking Risk by Likelihood and Consequences

Assessing the likelihood and consequences of a risk provides an overall score. The risk appetite Table 4-2 provides guidance on the required risk treatments to reduce the risk as much as is reasonably practicable, as well as defining key responsibilities.

Risk Rating	Risk Treatment
Low (1–7)	Managed through risk assessments, risk register, incident analysis, internal audits and observations.
Medium (8–10)	Escalation to Executive Leadership Team to review appropriate risk mitigations. Action plan developed and implemented.
Medium (11–13)	Reduce risk, if not possible, manage through risk controls and audit control effectiveness. Must be approved by Executive Leadership Team.
High (14–17)	Reduce risk, if not possible, risk management plan must be in place, approved by Board and audited and monitored.
High (18–23)	Activity/task/process must be stopped until risk is reduced and mitigations are in place.

Table 4-2: Risk Appetite

4.2 Activity, Plant and Equipment Risk

All critical activities required to operate and maintain the network – including plant and equipment – are risk assessed using bow tie methodology. These are living documents and are reviewed post events, where new risks have arisen or where 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); and
- Monitored and audited.

Risk controls are monitored through "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.

4.2.1 Permit to Work Control

An outline of the permit to work control process is shown in Figure 4.2.

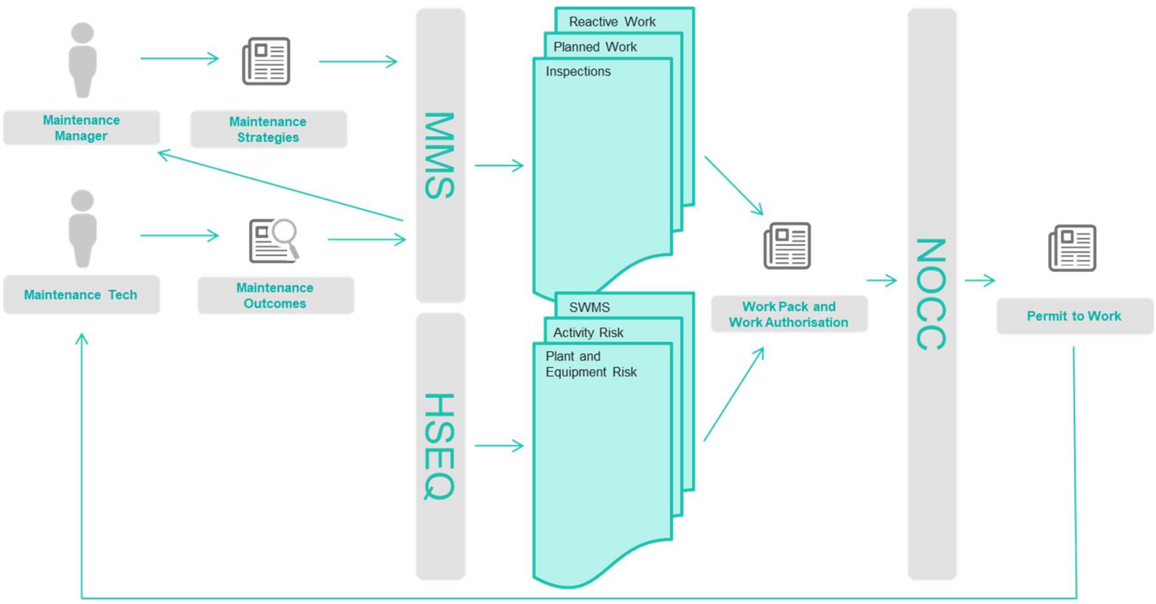

Figure 4.2: Permit to Work Control

Assurance of risk treatment for activity, plant and equipment risk is shown in Figure 4.3.

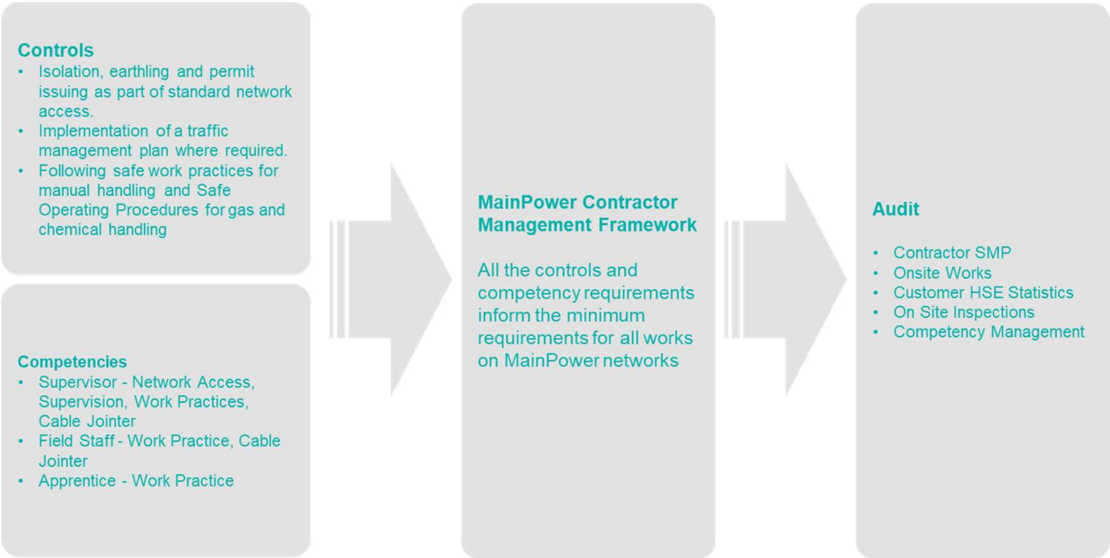

Figure 4.3: Assessment of Risk for Activity, Plant and Equipment

4.3 Project Risk

Critical projects are risk assessed using bow tie methodology, which includes safety in the design, procurement, planning, operational and environmental impact aspects. The Project Manager must update and maintain the project risks periodically, including the control effectiveness through monitoring.

4.4 Network Risk

MainPower has conducted the following risk assessment studies:

- High-Impact, Low-Probability (HILP) event assessment (to be updated in FY22);
- Physical risk to Grid Exit Points (GXPs), zone substations, transmission and distribution systems; and
- Compliance with the Resource Management Act.

The natural hazards considered include:

- Earthquakes, avalanches and landslides;
- Tsunami;
- Volcanic activity;
- Floods, snow, wind and lightning; and
- Extreme temperatures, drought and wildfires.

An update to the HILP event impact assessment is currently underway as part of MainPower's State of Infrastructure review, which will be completed within the next 12 months.

4.4.1 Measuring High-Impact, Low-Probability Risks

Natural hazards with the potential to damage major network assets that affect the most consumers are considered for risk mitigation. Those assets are:

- 66 kV and 33 kV sub-transmission systems;
- Zone substations; and
- Communications systems (see Table 4-3).

	Earthquake	Avalanche	Landslide	Tsunami	Volcanic Eruption	Flood	Snow	Wind	Lightning	Extreme Temperature	Drought	Wildfire	Climate Change
66 kV Sub-Transmission System	H	H	H	L	L	M	H	M	L	L	L	H	L
33 kV Sub-Transmission System	H	H	H	L	L	M	H	M	L	L	L	H	L
Zone Substation	M	L	L	L	L	L	L	L	M	L	L	M	L
Communications Systems	M	L	L	L	L	L	L	M	H	H	L	H	L

Table 4-3: Assessment of High-Impact, Low-Probability Risks

4.4.2 Mitigating Risk at Grid Exit Points

Grid Exit Point (GXP) stations are situated at Kaiapoi, Southbrook, Ashley, Waipara and Culverden. Transpower has completed an extensive programme of seismic damage mitigation, which included MainPower's GXPs. The assessment concluded that Transpower's assets could withstand earthquakes up to the magnitude experienced in the Kaiapoi region in 2010.

4.4.3 Studying Our Sub-Transmission and Distribution Systems

We have undertaken a qualitative study on the impact of natural disasters on our sub-transmission and distribution systems. That study identified earthquakes as being of greatest risk to our sub-transmission system. We considered three earthquake-intensity scenarios for the network. The average damage ratios shown in Table 4-4 represent the percentage of the full replacement value of the assets likely to be damaged for those three scenarios.

	1:500 years	1:200 years	1:100 years
Sub-Transmission Network	6.2%	3.2%	1.2%
Distribution Network	17.0%	9.8%	4.1%

Table 4-4: Summary of Average Damage Ratio on Our Sub-Transmission Network and Distribution Network

While some sections of each system were assessed at a ratio of more than 10% under certain earthquake scenarios, overall damage to the sub-transmission and distribution systems did not exceed 6.2% and 17%, respectively, under any of the three earthquake scenarios.

Natural hazards of flood, windstorm, electrical storm, snowstorms and tsunami to the sub-transmission and distribution system are considered in Table 4-5. 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	Probability/Consequence
Flood	The risk to overhead lines from flood hazard is limited, even in a 100-year flood event. Damage is isolated, resulting from landslips and/or subsidence or damage to individual poles sited within the normal course of a river. A 500-year flood event would result in extensive flooding of some urban areas and subsequent damage to ground mounted distribution equipment.	Probability: Low Consequences: Low
Windstorm	Damage to overhead lines is routinely caused by high winds. Historically, this has resulted in minor and isolated damage.	Probability: High Consequences: Low

Hazard	Observations	Probability/Consequence
	Our design criteria meet or exceed the requirements for a 50-year return period event, as set out in Australian/New Zealand Standard 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 three days a year. Canterbury has recorded four significant tornado events in the last 25 years; none were located in our distribution area.	
Electrical storms	Most parts of Canterbury have few electrical storms. Over the plains, fewer than five thunder days, on average, occur each year, with the highest frequencies occurring between September and March. Near the Southern Alps, 20 thunder days, on average, occur each year, with the highest frequencies during April and May. Zone substations, transformers and communications equipment are protected with lightning arrestors.	Probability: Moderate Consequences: Low
Snowstorm	Canterbury occasionally experiences weather events that deposit heavy, wet snow on overhead lines. Higher inland areas can be subject to ice build-up with coincident wind loading, which places high loads on overhead infrastructure. Isolated sections of overhead lines may also be exposed to a theoretical risk of avalanche.	Probability: Moderate/high Consequences: Low
Tsunami	While the occurrence of a tsunami is uncertain, this hazard is recognised as being a realistic possibility for Canterbury. There is a potential significant hazard at the mouth of both 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. The majority of overhead lines are not generally exposed to this hazard.	Probability: Remote Consequences: Insignificant

Table 4-5: Hazard Identification of Sub-Transmission and Distribution Systems

4.4.4 Developing Natural Hazard Exposure Limits for Our 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 measures used to define risk factors and risk priorities are:

- Risk Factor = Probability (years recurrence) x Consequence (% damage); and
- Natural Hazard Exposure = Risk Factor x Weighted Strategic Importance.

This assessment identifies 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 (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 insignificant or modest.

4.4.5 Ensuring Ongoing Communications and Robust Control Systems

MainPower's voice and data networks have radio sites located at Mt Grey, Mt Cass, Mt Thomas, Dead Man's Hill, Beltana, Wallace Peak and Ludstone. Mt Grey and Wallace Peak, in particular, are often exposed to heavy snow that can damage aerials and cause power to fail. The sites have battery back-up which, in the event of severe snow, can fail before we can access the sites.

The data network supports the Supervisory Control and Data Acquisition (SCADA) system and the load control system. Loss of data communication affects both these systems. The ability to control load may be especially important during cold weather, and we have enough local staff at or near remote sites to operate the load control system manually.

Our in-vehicle radio communication system can act as a back-up for the cellular network. A fleet of strategically located vehicles can relay information through each vehicle's radio system.

4.4.6 Identifying and Assessing Physical Risks to Our Sub-Transmission and Distribution Systems

MainPower has assessed the major physical risks for its sub-transmission and distribution systems. That assessment used the AS/NZS 4360:1999 methodology to identify the top 40 significant physical risks.

We assessed risks and hazards to the environment, including:

- Accidental excavation;
- Telemetry failure;
- Water ingress;
- Vehicle impact;
- Explosion; and
- Breaks in electrical connection.

We also assessed potential risk from wilful human behaviour and naturally occurring hazards (including rot, fire, and plant and animal activity) above and below ground.

The assessment assigned probability of occurrence and consequence scores that considered:

- Loss of supply;
- Personal injury;
- Damage to MainPower's property or the property of a third party;
- Impact on the environment; and
- Transpower power consumption peaks above allocation.

The assessment results show that:

- The highest risk score is for a vehicle impact on the 33 kV pole line feeding the Rangiora North Zone Substation; and
- The 40th score is vehicle pollution affecting the Oaro Zone Substation.

Of the top 40 risks identified, 17 had a risk score greater than 200. We have now reduced this number of risks, or mitigated the risks, so that currently, only eight have a risk score greater than 200, as shown in Table 4-6. These are not risks that MainPower can readily manage; however, we are working through projects to minimise or eliminate many of them.

More information on these projects is provided in Section 6 Network Development of this AMP.

Risk	Asset	Hazard	Risk Score
1	Rangiora North tee line (917)	Vehicle impact	308
2	Kaiapoi #3 (Hilton)	Accidental excavation	308
3	Kaiapoi #2 (Fuller)	Accidental excavation	308
4	Southbrook S17 (Flaxton)	Vehicle impact	272
5	Culverden GXP–Hanmer line (1222)	Gradual erosion of land	270
6	Culverden GXP–Hanmer line (1222)	Landslip	270
7	Ludstone–Oaro line	Plant or animal activity	210
8	Motunau–Omihi line	Vehicle impact	204

Table 4-6: Assets with a Risk Score Greater than 200

4.4.7 Identifying and Mitigating Risks to Our Zone Substations

The most likely types of asset failure in our zone substations are protection, tap-changer contacts, circuit breakers, bus-work and transformers, in that order. Table 4-7 notes each type of asset and explains how the impact of failure is mitigated.

Asset Failure	Issues that Contribute to Failure	Mitigation
Protection	Typically caused by complex under/over-voltage protection and transformer Buchholz, and inter-trip systems on older sites. Protection fails during paralleling of feeders. Battery failure.	A protection design review has been completed to standardise the types of systems used and their settings. Protection systems are simplified or removed when appropriate. The risk of damage occurring to a transformer or consumer equipment due to an under/over-voltage event is extremely low. Additional precautions and cross-checks are now made before undertaking any load-transfer switching. Battery voltage is inspected monthly.
Tap-Changer Contacts	Tap-changers have moving parts that suffer from wear.	Tap-changers are inspected regularly. Tap position and voltage is continually monitored via SCADA; if a tap-changer fault occurs we can quickly deploy staff to fix the problem. Spare contact parts are maintained in stock.
Circuit Breakers	Circuit breakers and reclosers approaching their end of life become increasingly unreliable.	A replacement programme is underway on old circuit breakers. Any zone substations with two or more 11 kV feeders can bypass one faulty circuit breaker, if necessary. If a circuit breaker fails at the remaining smaller rural sites, we can easily bypass the faulted circuit breaker as a temporary measure to restore power. The sophisticated adjustable protection systems on new circuit breakers mean that we can keep one spare circuit breaker for use at multiple sites.
Bus-Work	Bus-work can suffer from broken insulators, deterioration of the fault current and negative external influences.	Split bus systems and double-banked transformers help to provide some redundancy.
Transformers	A transformer bank can fail suddenly because of an internal explosion.	Spare emergency power transformers are kept in stock for transformer failures. Some larger sites (i.e. GXPs, Southbrook, Kaikōura and Culverden) have dual transformer banks to provide redundancy. Designs allow for transfer of load between zone substations to provide additional redundancy where possible.

Asset Failure	Issues that Contribute to Failure	Mitigation
		In a civil emergency, we can use additional initiatives, such as asking other lines companies to provide spare transformers. We can use diesel generation sets where appropriate. Planned upgrade projects will improve cover when a transformer fails in the future.

Table 4-7: Mitigation of the Effects of Zone Substation Assets Failing

An additional mitigating technique is load control. We will use load control as the first mitigation technique by using our Decabit injection system at zone substations during peak load. Table 4-8 shows the amount of load control available on each GXP station.

GXP	Load reduction available, assuming that water heating has been on all day	Load that must be restored, assuming that water heating has been off for 3 hours
Southbrook	5.3 MW	16.5 MW
Kaiapoi	2.6 MW	8.1 MW
Ashley	0.5 MW	1.0 MW
Waipara	1.3 MW	4 MW
Culverden	1.4 MW	4.5 MW

Table 4-8: Available Load Control, by Grid Exit Point

4.4.8 Enabling a Flexible 66 kV and 33 kV Sub-Transmission System

The sub-transmission systems between Southbrook and Waipara, and between Waipara and Kaikōura, can transfer load in either direction. This flexibility offers an alternative supply to major and minor zone substations located along this route. This now also applies to the two sub-transmission circuits supplying Swannanoa and Burnt Hill from Southbrook. For this reason, any asset failure on these line routes would only cause a short duration interruption, while power is switched from the other supply.

Spare parts are carried in sufficient quantity to cover the most likely cause of asset failure, including conductor, insulators, poles and hardware.

No 33 kV radial lines to other substations have an alternative supply. However, these substations typically have a smaller number of consumers and we can rectify any asset failure quickly because we have spares available.

A 22 kV supply from Mouse Point can back up the Waipara Hawarden 33 kV line for most of the year.

4.4.9 Ensuring Alternative Supply Routes for Our Distribution System

Major 22 kV and 11 kV feeders are backed up by alternative supply routes. Where more than two major feeders supply an area, each feeder is generally designed to carry a maximum of 75% of its rating. This allows some spare capacity for back-up. Where only two feeders are available, the designs are based on maximum loadings of 50% of their rating.

Major low-voltage networks are designed on a similar basis to the distribution system. In an emergency in an urban area, we can generally link low-voltage networks to ensure supply is maintained.

We hold minimum quantities of spares to cover faults and emergencies on the distribution network. These spares include larger critical items such as distribution transformers, switchgear and poles.

Likely causes of asset failure in underground systems are termination and joint problems, as well as excavation damage.

4.4.10 Ensuring Alternative Supply is Available for Main Towns on Our Network

Asset failure in the main urban areas of North Canterbury can affect many consumers. In these areas, we use alternative supplies to ensure consumers continue to receive electricity, as described in Table 4-9.

Location	Supply Options
Rangiora	The level of interconnection between all six feeders is high. Two feeders from Southbrook are capable of 9 MW each. The two feeders from Rangiora North are capable of 4 MW each. At peak times, the network is capable of meeting load requirements with one feeder out from each of the Southbrook and Rangiora Substations.
Kaiapoi	All four feeders at Kaiapoi have a high degree of interconnection and are capable of supplying 4 MW each. At peak times, the system is capable of meeting the load requirements with one feeder out of operation.
Amberley	Amberley is supplied from both the Broomfield and Balcairn feeders, using tie-points at Douglas Rd and Greys Rd. We can shift load to Mackenzies Rd to ensure back-up is available.
Cheviot	We can supply the entire town feeder from the north feeder by using a tie-switch outside the Cheviot Substation.
Culverden	Culverden has two main supply options using the 22 kV supply from two feeders out of Mouse Point Substation. Another 22 kV supply is available from Hawarden Substation to the south, if needed.
Hanmer	Hanmer is supplied from either the Argelins or Scarborough feeders, except in the most heavily loaded periods (typically, holiday weekends during winter). During these times, heavy load controlling is required to maintain supply to all consumers.
Kaikōura	The Ludstone Substation has four feeders that can supply into the Kaikōura township. The north and south feeders are lightly loaded and can back each other up. The Churchill St and town feeders are more heavily loaded and require a combination of feeders to take over supply, without overloading a remaining feeder during peak times. Each feeder has multiple paralleling points and enough capacity, with many combinations of circuits, to supply the town. Load control is unnecessary.
Oxford	Oxford is supplied from a single Burnt Hill Substation feeder. We can easily isolate a fault and quickly restore supply to consumers. Alternative feeders from the Burnt Hill Substation can take over the town supply if necessary.
Woodend and Pegasus	Supply to Woodend and Pegasus is normally split across three feeders from Kaiapoi. There is insufficient capacity to supply all urban customers from only two feeders at peak load times. During emergencies, the Southbrook Substation can provide an additional feeder, but this involves an operational phase shift between the Southbrook and Kaiapoi GXP Substations.

Table 4-9: Alternative Supply

4.4.11 Reviewing Our Asset Failure Recovery Systems

An independent expert has reviewed our asset failure recovery systems. Their assessment considered the eight biggest asset failure scenarios, based on impact on our consumers. Those scenarios included zone substation transformer failure, feeder cable failure, major circuit-breaker failure and major line failure.

Procedures to restore assets following failure are documented and robust. Even so, the expert's assessment made some recommendations from which we developed an action plan. Those recommendations and the plan are shown in Table 4-10.

Recommendations	Action Plan
Procure oil spill kits (if the risk is considered great enough) for any sites that do not yet have them.	Oil spill kits are in MainPower work vehicles.
Ensure that the spare 33/11 kV transformers and 1 of the 2 Kaikōura transformers are kept on standby for use. Consider moving the spare transformer to the substation most at risk of failing.	Spare transformers are kept in stock. A spare 2.5 MVA transformer is now located at Hanmer.
Consider building extra transformer pad and bus-work at remote single-transformer substations so they fit the dimensions of the spare transformer.	The portable generator truck provides a better back-up facility.
Ensure sufficient spare lengths of 66 kV and 33 kV single-core XLPE cable are stored at Rangiora – suggest a minimum of 3 lengths (each of 10 m), along with 2 complete sets of jointing kits, 2 complete termination kits, 6 jointing sleeves, 6 termination lugs and a compression tool.	Jumper cable sets are made up and stored in the yard.
Ensure sufficient spare lengths of 22 kV and 11 kV single-core XLPE cable are stored at Rangiora – suggest a minimum of 3 lengths (each of 10 m), along with 2 complete sets of jointing kits, 2 complete termination kits, 6 jointing sleeves, 6 termination lugs and a compression tool.	Jumper cable sets are made up and stored in the yard.
Ensure 3 spare 66/33 kV poles and arms are stored at each of Mouse Point or Culverden GXP, Swannanoa or Burnt Hill, and Cheviot.	Minimum quantities of spares are maintained at Rangiora, with some items stored at depots.
Ensure a spare 33 kV breaker and a reasonable array of spares for all makes are held at Rangiora.	Spare 11 kV, 22 kV and 33 kV circuit breakers are held at Rangiora.
Ensure access is secured to 4x4 line trucks with Palfinger hydraulic post-hole borer and elevated platform.	MainPower and its subsidiaries own or lease all the equipment.
Ensure the equipment to locate faults in cables is maintained in full working order and is always available.	The process to ensure equipment maintenance and availability started in 2019.
Prepare switching plans for restoring supply if a fault occurs on Cable S13–S421, or Fuller, Hilton, Waipara to Cheviot and Kaikōura to Waipara lines. Consider protection settings and any phase differences.	Already developed as refresher training programmes for controllers.
Secure access to an excavator to help dig up faulty cables – could be helpful to pre-arrange services with local contractors.	Secure access is now available.

Table 4-10: Recommended Measures and Action Plan to Reduce Risk

4.4.12 Improving Security of Supply Due to Transpower Upgrading Its Assets

Transpower’s risk management plans for all its GXP stations in North Canterbury are shown in Table 4-11. Recent upgrades mean that MainPower now has four 66 kV circuits supplying into the southern region. This has improved our security of supply into the largest load area.

Site	System No.	Installed Capacity	Cooling	Ratio (kV)	Contingency Plans
Ashley	T3/T5	2 x 40 MVA 3ph	ONAN[1] OFAF[2]	66/11	N-1[3] capacity (switched) Spare bank at Islington
Culverden	T1	2 x 30 MVA 3ph 1 x 10/20 MVA 3ph	ONAN ONAN	220/33 66/33	N-1 capacity Spare bank at Islington
Kaiapoi	T1/T2	2 x 38 MVA 3ph	ONAN OFAF	66/11	N-1 capacity Spare bank at Islington
Southbrook	T1/T2	2 x 30/40 MVA 3ph	ONAN OFAF	66/33	N-1 capacity Spare 20 MVA bank at Islington
Waipara	T3	1 x 10/16 MVA 3ph	ONAN OFAF	66/33	Spare 20 MVA bank at Islington Waipara load can be spread across other MainPower substations

Table 4-11: Transpower's Risk Management Plans for Their Grid Exit Points

Notes:

1. ONAN = oil natural air natural
2. OFAF = oil forced air forced
3. N-1 is an indication of power supply security that specifically means that when one circuit fails, another will be available to maintain an uninterrupted power supply.

4.5 Risk Mitigation

4.5.1 Asset Risk

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 conditioned based risk management (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 Using a Business Continuity Plan to Minimise Disruption to Our Business After a Critical Event

Our Business Continuity Plan is incorporated into our Incident Management Plan (see Section 4.5.3), 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 and significant weather events);
- Disrupted systems and lack of staff during a pandemic; and
- Legislative non-compliance.

4.5.3 Using an Incident Management Plan to Respond to Any Disruptive Incident

The Incident Management Plan guides our response to any disruptive incident that has a serious impact on our staff, operations, services and reputation. The plan outlines how we will strategically and operationally manage our response so that we 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 that outlines how we respond to, and operate in, any disruptive incident. The framework is based on New Zealand's Coordinated Incident Management System (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.

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

4.5.4 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 above, some of our recovery plans will activate once predetermined triggers are met.

4.5.5 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 our network operation:

- Public liability insurance;
- Materials damage on stations, including zone substations, load plants and contained structures; and
- 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.

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 Puhi Puhi Valley north of Kaikōura and inland to Lewis Pass.

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

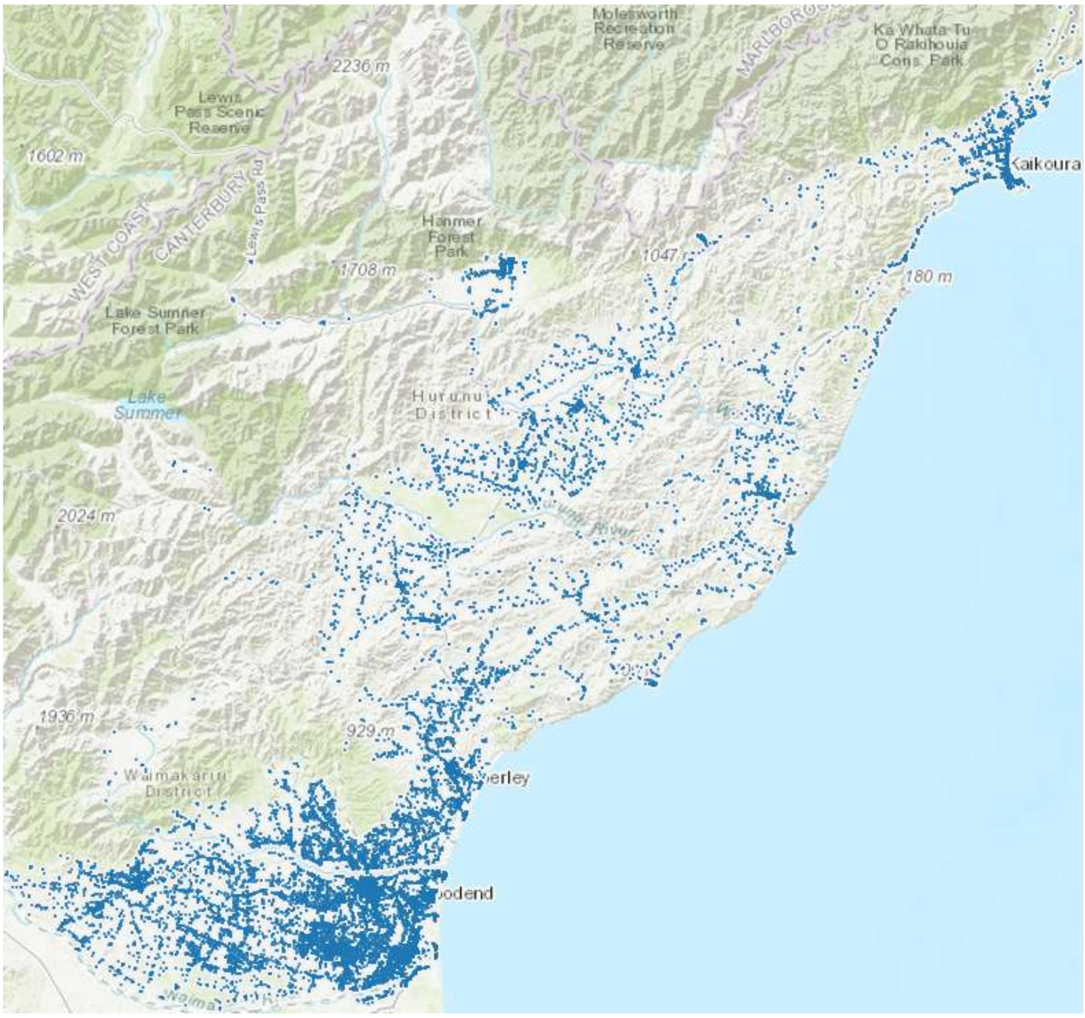

Figure 5.1: MainPower's Electricity Network Consumer Geographic Distribution

5.1.1 Large Consumers

Our large consumers are:

- **Daiken NZ medium-density fibreboard (MDF) 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 back-up 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 back-up 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.
- **Mitre 10 Megastore at Southbrook:** This site has an alternative 11 kV feeder.
- **Belfast Timber Kilns at Coutts Island:** This plant is connected near the end of a rural 11 kV spur line. No alternative supply is available at the site. Line maintenance is scheduled to coincide with plant maintenance programmes.

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

5.1.2 Load Characteristics

Substation	FY17 MVA	FY18 MVA	FY19 MVA	FY20 MVA	Peak
Southbrook	22.5	23	22.8	24.9	Winter
Swannanoa	14.8	16	15.2	15.5	Summer
Burnt Hill	14.8	15	15.0	15.3	Summer
Rangiora North	5.2	6	5.6	5.3	Winter
Amberley	5.2	6	6.0	5.4	Winter
Mackenzies Rd	2.5	2	1.6	3.3	Summer
Greta	1.3	1	1.3	1.3	Summer
Cheviot	3.3	3	3.2	3.4	Summer
Leader	1.5	2	1.5	1.5	Summer
Ludstone Rd	6.0	6	5.9	5.3	Winter
Mouse Point	20.1	15	15.6	15.2	Summer
Hanmer	4.3	5	4.8	4.3	Winter
Lochiel	0.1	0	0.1	0.1	Summer
Hawarden	3.4	4	3.7	3.6	Summer
Kaiapoi S1[1]	9.0	9	8.9	8.4	Winter
Rangiora West[1]	8.1	9	8.3	8.2	Winter
Pegasus[1]	2.5	3	2.8	2.8	Winter
Kaiapoi North[1]	7.0	8	7.2	7.3	Winter

Table 5-1: MainPower Network Load Characteristics

[1] Switching Station

5.1.3 Peak Demand and Total Energy Delivered

System Measure	2019	2020
Peak load	117 MW	115.4 MW
Energy entering the system	633 GWh	671 GWh
Energy delivered	593 GWh	632 GWh
Loss ratio	6.4%	5.7%
Load factor	62%	66%
Average Number of ICP's	39,624	40,515
Zone substation capacity (base ratings)	135 MVA	132 MVA
Distribution transformer capacity	559 MVA	573MVA
Distribution transformer capacity utilisation	20.6%	20.4%
Circuit length lines (kms)	5021	5039

Table 5-2: System Measures

Consumer Group ICPs	Average Number of ICPs	
	2019	2020
Residential	32,205	33,052
Commercial	5,711	5,748
Large commercial or industrial	46	48
Irrigators	1,347	1,354
Council pumps	198	200
Streetlights	116	112
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, Ohau 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 Grid Exit Points (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.

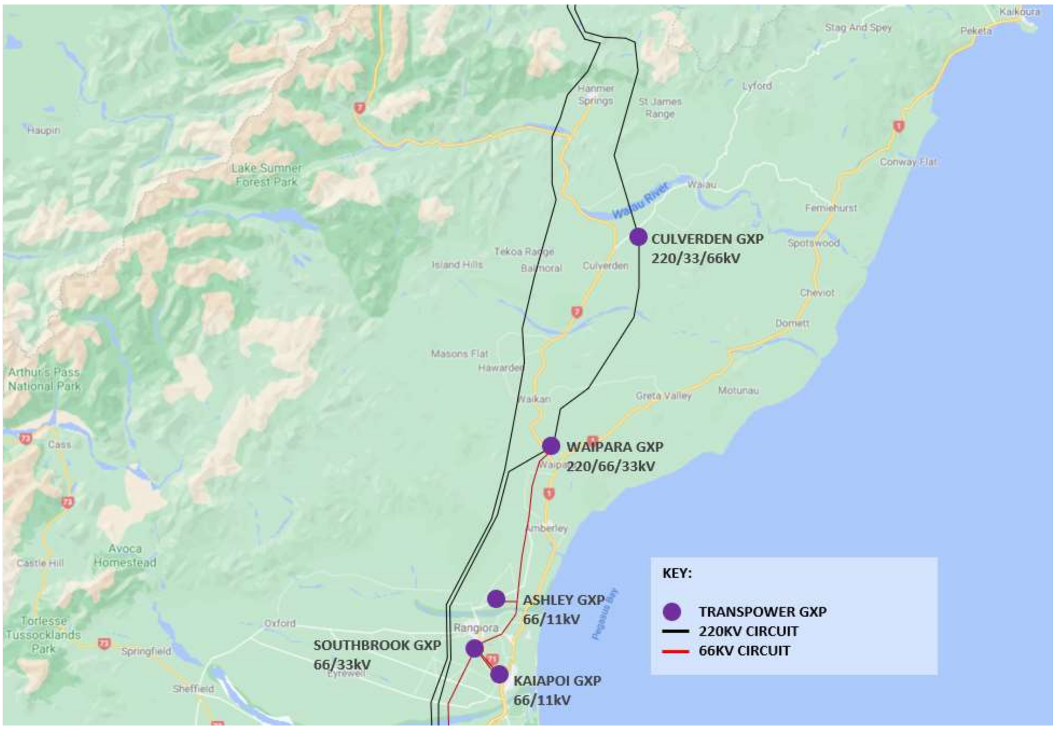

Figure 5.2: Transpower's North Canterbury Transmission Grid

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 **SBK0331 and 0661**	Transformer Capacity	80 MVA at 33 kV
	Firm Capacity	40 MVA at 33 kV
	Peak Load	27.6 MW at 33 kV
	Configuration	Two dual-rated 30/40 MVA 66/33 kV three-phase transformers.
	Supply to MainPower	Two 33 kV circuit breakers Two 66 kV circuit breakers
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.

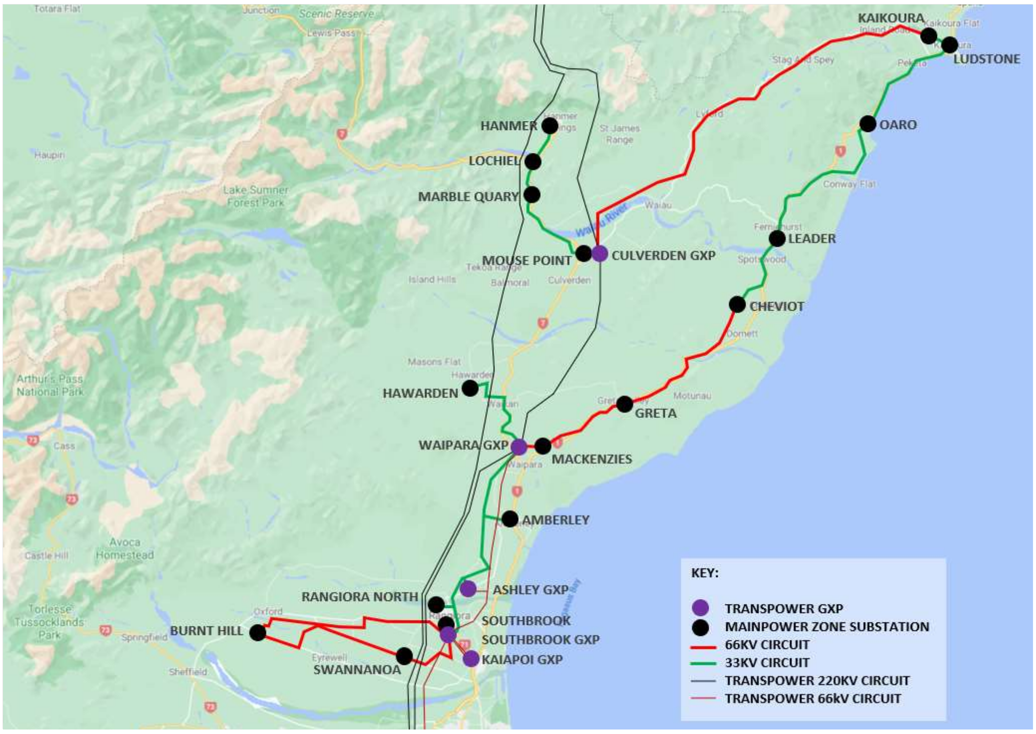

Figure 5.3: MainPower's Sub-transmission Network

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. Table 5-5 provides a summary of key information for each of MainPower's zone substations.

	General					Transformers					Switchgear	
Zone Substation	Peak Load (MVA)	Sub-transmission Security of Supply Level	Capacity (MVA)	Transformer capacity after a single fault	Capacity available after switching	Remote Control	Number of Feeders	Capacity (MVA)	Oil Containment	Seismic Restraint	Type	Feeder Circuit Breakers
Southbrook	24.9	2+	44	22	22.5	Yes	6	2 x 16/22	Yes	Yes	Indoor	6 Reyrolle vacuum
Swannanoa	15.5	2	46	23	26	Yes	5	2 x 11.5/23	Yes	Yes	Indoor	5 Tamco vacuum
Burnt Hill	15.3	2	46	23	26	Yes	6	2 x 11.5/23	Yes	Yes	Indoor	7 ABB UniGear ZS1
Rangiora North	5.3	2-	7	0	5.2	Yes	3	5/7	Yes	Yes	Outdoor	3 Nulec SF6
Amberley	5.4	2-	8	4	6	Yes	3	2 x 3/4	Yes	Yes	Indoor	3 Reyrolle oil
MacKenzies Rd	3.3	2	4	0	1.6	Yes	3	2/4	Yes	Yes	Outdoor	3 Nulec SF6
Greta	1.3	2-	4	0	0.5	Yes	3	2/4	Yes	Yes	Outdoor	3 Nulec SF6
Cheviot	3.4	2	4	0	0.5	Yes	3	2/4	Yes	Yes	Outdoor	3 Nulec SF6
Leader	1.5	2	2	0	0	Yes	3	1/2	Yes	Yes	Outdoor	3 Nulec SF6
Oaro	0.3	2	0.5	0	0	No	1	0.5	No	No	Outdoor	1 ME KFE vacuum
Ludstone	5.3	2	12	6	6	Yes	4	2 x 4/6	Yes	Yes	Indoor	4 South Wales oil
Hawarden	3.6	1	4	0	2.5	Yes	3	3/4	Yes	Yes	Outdoor	2 GPC oil, 1 Nulec SF6
Mouse Point	15.2	2	26	13	14	Yes	4	2 x 10/13	Yes	Yes	Outdoor	4 W&B SF6
Marble Quarry	0.2	1	0.2	0	0	No	1	0.2	No	No	Outdoor	Fuses
Lochiel	0.1	1	0.2	0	0	Yes	1	0.2	No	Yes	Outdoor	1 Nulec SF6
Hanmer	4.3	1	6	2.5	0	Yes	2	4/6 + 2.5	Yes	Yes	Indoor	2 South Wales SF6
Colour Key:	*Less than 75% of capacity utilised*				*75–100% of capacity utilised*			*Over 100% of capacity utilised*				

Table 5-5: Zone Substation Key Information

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:** More recently, outdoor transformers with cable boxes and separate front-access outdoor cabinets for the RMUs and low-voltage panels are being used. 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 mm^2 or 185 mm^2 aluminium, although more recently, 300 mm^2 aluminium cables have been used for major urban feeders or to supply distribution switching stations. Smaller sizes are being used for rural customer spurs.

5.3.5 Distribution Substations

Most customers are supplied from primary distribution substations at voltages of 11 kV or 22 kV. A small number of customers are supplied from SWER 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 standalone 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 10–30 kVA range.

5.3.6 Distribution Switchgear

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

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

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

In the 2020 MainPower reporting year, progressed implementation and deployment of the OSI Monarch Advanced Distribution Management System (ADMS) occurred.

MainPower's first SCADA system used remote terminal units (RTUs) communicating with Conitel protocol and these have now either been completely changed to more modern DNP3 RTUs or slaved to more modern RTUs 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 MDF 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 MDF 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 GXPs that connect to our network. These monitor load for load management and revenue metering. All have Ion-type meters, installed after 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.

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 of the Future Road Map

The services that MainPower and the electricity distribution network currently provide are aligned with the Distribution Network Provider (DNP). This needs to change and consider the following options:

- Two parts: differences between asset owner and asset operator;
- Progressing through the Smart Network phase (elements of which are already in place—ADMS);
- Open-access, bidirectional flow characteristics;
- Supporting distributed energy resource management systems; and
- Allowing participants to transact and connect any device (within limits).

The transformation road map (see Figure 5.4) will enable MainPower to transition from being a DNP to being a Distribution System Integrator (DSI). The introduction of the ADMS for the advanced management of our electricity distribution network is an example of our commitment to this need to change.

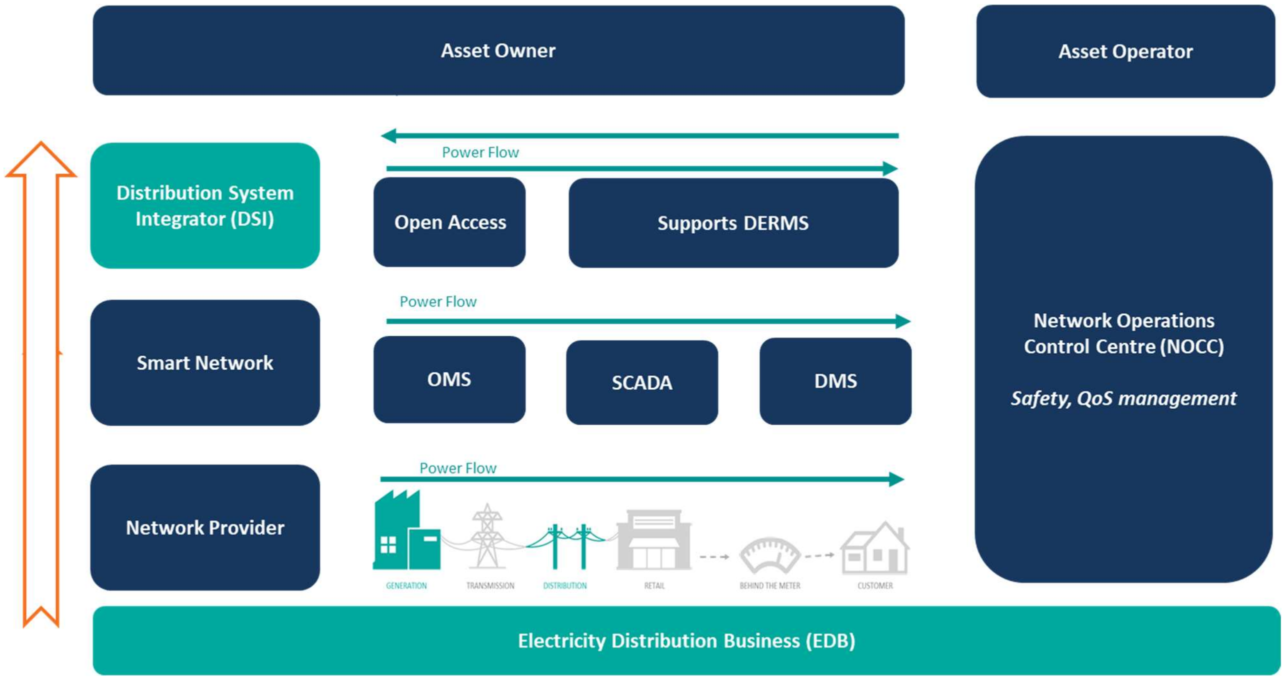

Figure 5.4: Transformation Road Map Programme

5.4.2 Electricity Distribution Business

In New Zealand, an electricity distribution business is the network company or lines company that owns and operates the regional network of overhead wires and underground cables suppling electrical energy to consumers. These days, an EDB is typically both a DNP and Distribution Network Operator (DNO) combined into a single entity.

5.4.3 Distribution Network Provider

A Distribution Network Provider (DNP) is the organisation that owns the electricity distribution network assets and provides the physical processes and systems that support the assets (i.e. asset management, system maintenance, security of supply, system resilience, etc.).

5.4.4 Distribution System Integrator

A Distribution System Integrator (DSI) allows for the widespread use of local generation sources connected to the network at multiple points, with associated multi-directional power flows. A DSI ensures open-access arrangements for consumers and other market participants, allowing parties to transact over the network and to connect any device they wish, within acceptable safety and reliability limits.

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 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 electric vehicle 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; and
- 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, ENA 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 10,900–11,000V.

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.

6.1.4 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 the functionality and meet target reliability outcomes.

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; and
- 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; and
- 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; and
- 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

Table 6-1: Security of Supply Zone Substation Restoration Times

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.

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/CBD (>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 (MEPS). 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 $0.5 m, generally involving sub-transmission, zone substation or GXP works;
- **Reinforcement projects** – below $0.5 m, 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; and
- **Reliability and automation** – includes 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 Grid Exit Points 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 electric vehicles.

Our network continues to undergo steady growth, as shown by historical data and our forecast of total system demand in Figure 6.1.

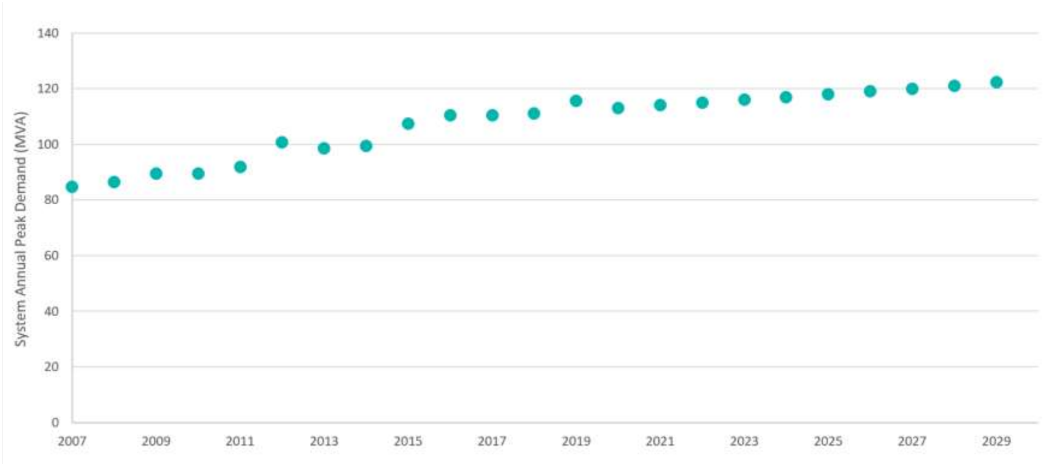

Figure 6.1: Historical and Forecast Total System Demand

The consistent growth shown in the figure 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 6.2 indicates annual forecast energy growth rates, by planning area, for MainPower's network region.

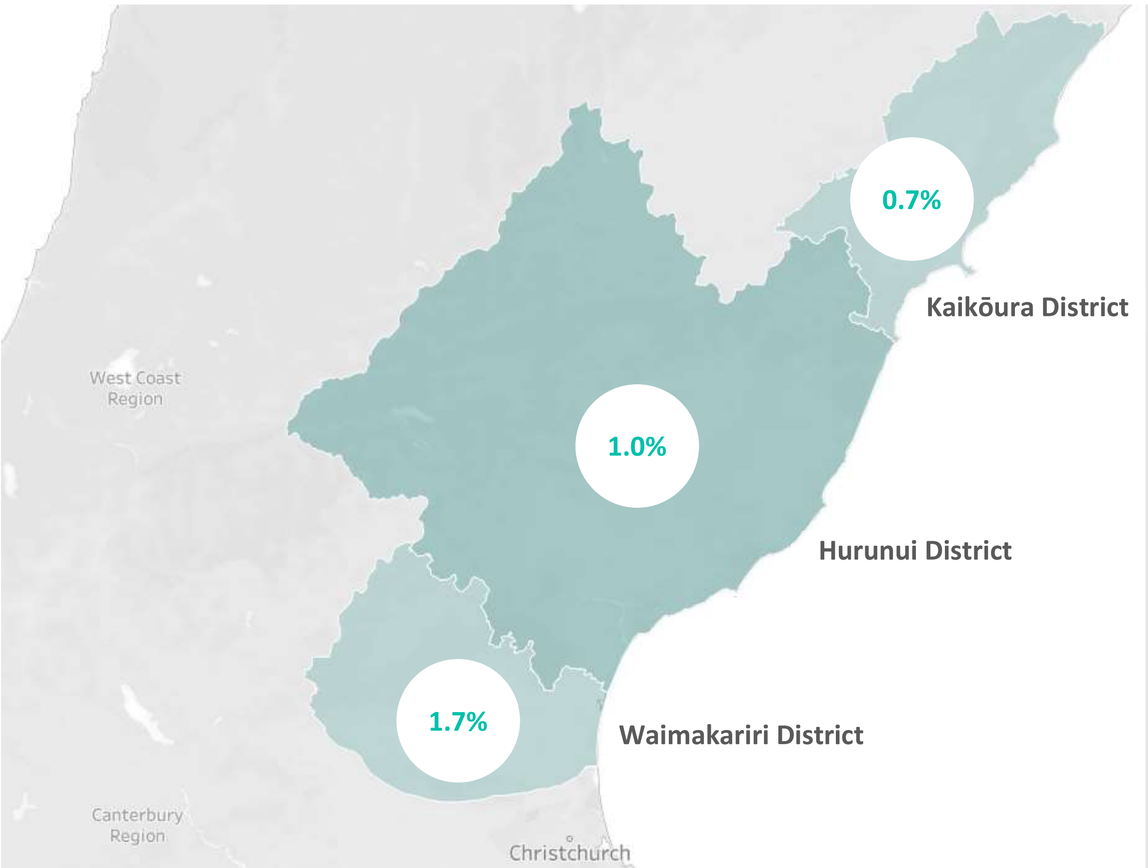

Figure 6.2: Annual Forecast Energy Growth Rates, by Planning Area

6.6.3 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 6.3 and Figure 6.4 show the growth of small-scale (< 100 kW capacity) distributed generation within the network. The connection rate is increasing very slowly. On average, approximately 500 kWh of generation is exported per kW of capacity. This corresponds to more than 40% of the energy produced from the connected distributed generation. The average connected distributed generation per consumer across the three planning regions are Waimakariri (0.12 kW, 784 consumers or 2.7%), Hurunui (0.08 kW, 166 consumers or 1.7%) and Kaikōura (0.02 kW, 16 consumers or 0.6%).

Figure 6.3: Distributed Generation Trends up to Dec 2019

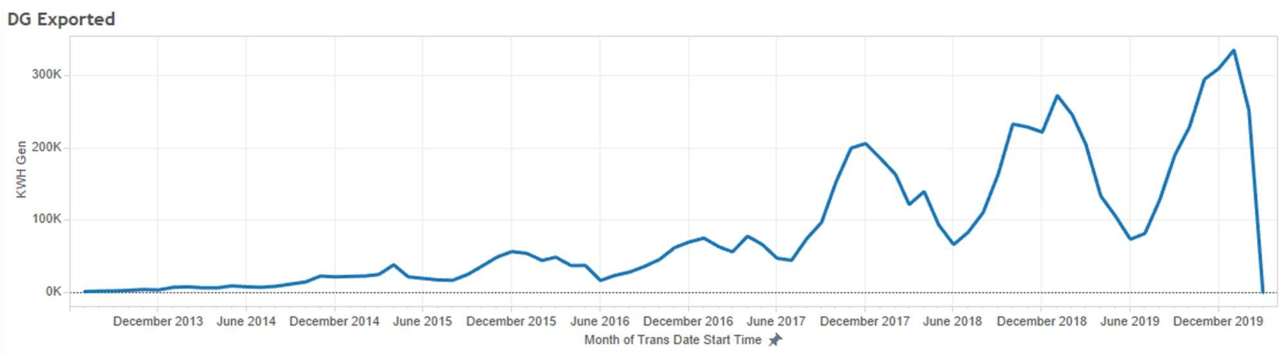

Figure 6.4: Distributed Generation Exported Volume

6.6.4 Distribution Innovation

MainPower's future focus in network development planning includes the development of regional Master Plans – documents that will detail projected demand growth, reliability statistics and network projects in defined North Canterbury areas.

The purpose of the 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 6.5). This long-term strategy targets the following key objectives:

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

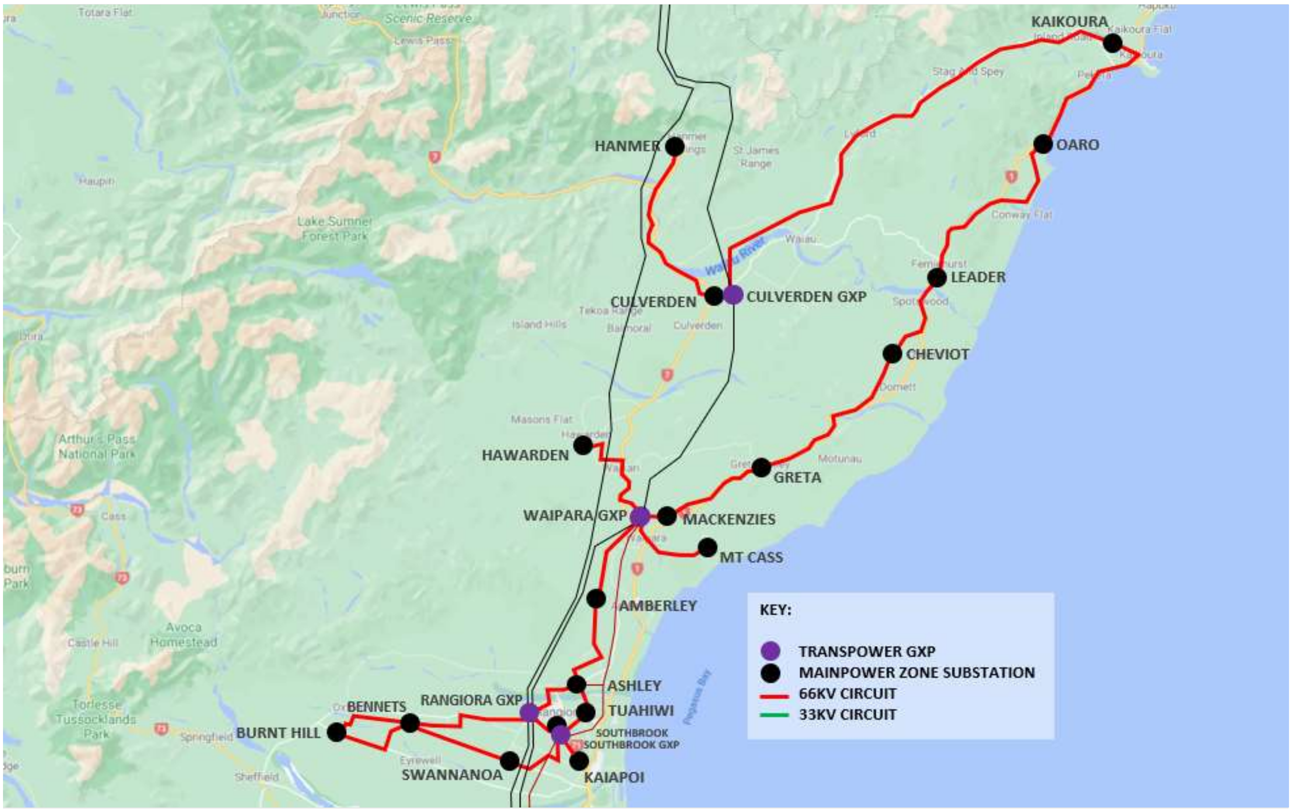

Figure 6.5: MainPower's Long-Term Sub-Transmission Network Strategy

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; grey shading in the demand forecast Table 6-4 and Table 6-7 indicates that peak demand exceeds current security-class capacity.

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 (NZ Transport 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 and is tied via 33 kV to Transpower's Waipara GXP in the Hurunui region. The area uses a combination of 66 kV and 33 kV sub-transmission voltages as shown in Figure 6.6. We are transitioning away from 33 kV.

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 feeding Kaiapoi. The 66 kV Burnt Hill and Swannanoa ring currently operates in an open state. Our sub-transmission and distribution networks in the Waimakariri area are predominantly overhead, reflecting the rural nature of the area.

Figure 6.6: Waimakariri Region Sub-Transmission Network (Existing)

6.8.1.1 Demand Forecasts

Demand forecasts for the Waimakariri Zone Substations are shown in Table 6-4.

Substation	Security Class	Class Capacity	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Ashley GD	AA+	0 MVA	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Ashley GN	A1	40 MVA	7.0	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.8
Burnt Hill	A1	23.0 MVA	15.5	15.6	15.7	15.8	15.9	16.0	16.1	16.2	16.3	16.4
Kaiapoi	AAA	40 MVA	31	27	26	26.4	26.8	27.2	27.6	28	28.4	28.8
Rangiora North	AA	7.0 MVA	6.0	0	0	0	0	0	0	0	0	0
Southbrook	AAA	22.0 MVA	23.2	33.2	33.8	34.4	35.0	35.6	36.2	36.8	37.4	38
Swannanoa	A1	23.0 MVA	15.5	15.6	15.7	15.8	15.9	16.0	16.1	16.2	16.3	16.4

Table 6-4: Waimakariri Area Network Demand Forecast

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

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 GD	The Ashley Grid Direct supplies one 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.
Rangiora North	Thermal limit at Rangiora North Substation exceeded when supplied via 33 kV from Waipara rather than Southbrook. Rangiora North does not meet its AA requirement as switching to alternative feeders would take more than 45min.	Upgrade of Southbrook Zone Substation (FY21 & FY22) combined with 11 kV reinforcement projects will allow Rangiora North to be decommissioned in FY23.
Southbrook, Burnt Hill, Swannanoa and Kaiapoi	Difficult to achieve Transpower's load requirements during a half-bus outage.	Transition Southbrook from 33/11 kV to 66/11 kV (FY22) and develop further 66 kV interconnections between Waipara, Southbrook and Kaiapoi.
Southbrook (Rangiora, Pegasus and Woodend)	The Southbrook Zone Substation exceeds its 22 MVA N-1 rating during peak winter periods.	A specific Southbrook bus-load control target has been implemented to minimise exposure to the N capacity rating. The Southbrook Zone Substation will be upgraded to 66/11 kV (completed FY22).

Table 6-5: Waimakariri Area Network Constraints

6.8.1.3 Major Projects

Below are individual summaries of the major growth and security projects planned for the Waimakariri area.

Southbrook 66 KV Substation Upgrade	
Estimated cost	\$10.9 m
Expected project timing	FY21–FY22
Project driver	Security of supply and asset condition replacement

This is a two-year project to rebuild MainPower's Southbrook 33/11 kV Zone Substation as a 66/11 kV zone substation. This will:

- Increase the N-1 capacity at 11 kV from 29 MVA to 45 MVA, to meet existing and future loads in this region;
- Remove the phase shift between the Southbrook 11 kV and the neighbouring Ashley and Kaiapoi Zone Substations, increasing MainPower's ability to transfer load and switch the network under contingency events;
- Replace end-of-life 33 kV switchgear;
- Improve network reliability and security of supply in the surrounding Southbrook and Rangiora regions; and
- Reduce the arc-flash risk of the Southbrook Zone Substation.

This project spans several years, with final completion due in FY22.

Southbrook 33 KV Substation Decommissioning	
Estimated cost (concept)	\$0.35 m
Expected project timing	FY23
Project driver	Asset end of life/redundancy

The project leads on from the Southbrook 66 kV Substation Upgrade project above and involves decommissioning and remediating the Southbrook Substation site following completion of the Southbrook Substation Upgrade.

Rangiora North Zone Substation Decommissioning	
Estimated cost (concept)	$0.12 m
Expected project timing	FY23
Project driver	Asset end of life/redundancy

The project leads on from the Southbrook 66 kV Substation Upgrade project above and involves decommissioning and remediating the Rangiora North 33 kV Zone Substation site following completion of the Southbrook Substation Upgrade.

Ashley to Tuahiwi 66 KV Sub-Transmission Line	
Estimated cost (concept)	$2.94 m
Expected project timing	FY22–FY29
Project driver	Growth and security of supply

Residential and commercial growth in the Rangiora, Woodend, Ravenswood and Pegasus areas will drive the need for a new N-1 zone substation east of Rangiora. This project initiates a series of sub-projects to construct the 66 kV sub-transmission network to support a new Tuahiwi 66 kV Zone Substation. The first stage of this is the route design, including easements and consents for a 66 kV overhead supply circuit from the Ashley GXP to the Tuahiwi 66 kV Zone Substation site in FY22–FY24. Construction from Ashley to the Rangiora Woodend Rd area will be timed to provide support at 11 kV for the eastern rural area. Completion of the circuit in approximately 2029 will coincide with construction work on the substation.

Southbrook to Tuahiwi 66 KV Sub-Transmission Line	
Estimated cost (concept)	$2.75 m
Expected project timing	FY31
Project driver	Growth and security of supply

Residential and commercial growth in the Rangiora, Woodend, Ravenswood and Pegasus areas will drive the need for a new N-1 zone substation east of Rangiora. This project is to construct a 66 kV overhead supply circuit from the Southbrook GXP to the new Tuahiwi 66 kV Zone Substation site. Construction will be timed to be completed in conjunction with the Tuahiwi Zone Substation.

Tuahiwi 66/11 KV Zone Substation	
Estimated cost (concept)	$11.1 m
Expected project timing	FY29–FY31
Project driver	Growth and security of supply

Residential and commercial growth in the Rangiora, Woodend, Ravenswood and Pegasus areas will drive the need for a new N-1 zone substation east of Rangiora. Timing of this zone substation also aligns as Southbrook reaches its firm capacity. Tactical distribution reinforcements will be completed in the preceding years to enable maximisation of Southbrook capacity, to help defer construction as well as strengthen feeders to better utilise capacity after the new Tuahiwi Substation is completed. Early consultation and consenting work will be completed in FY21–FY22.

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 6-6 summarises the reinforcement projects in the Waimakariri area.

FY	Project Title	Description	Cost ($,000)
FY22	Pegasus Feeders	Extend the 300 mm 11 kV cables for the Pegasus switching station from west of the SH1 roundabout to the vicinity of Okaihau Rd to deliver Southbrook Substation capacity directly to Pegasus.	950
FY22	Kippenberger Ave Circuit Breaker	Install a circuit breaker on the fringe of urban Rangiora to improve the reliability in eastern Rangiora.	72
FY22	Kippenberger Kiosk	Complete the underground connection of the north-east of Rangiora to Southbrook by installing a short length of cable and a new kiosk in Kippenberger Ave.	154
FY22–FY23	Townsend Rd Feeder	Install 300 mm² AL XLPE 11 kV cable to Pentecost Rd to create a new feeder route to south-western Rangiora, increasing capacity and security of supply.	505
FY23	Reinforce X52 Burnt Hill	Increase the security of supply of feeder X52 by upgrading 660 m of conductor in North Eyre Rd.	228
FY23	Kaiapoi KAI_7 Feeder split	Improve the reliability and capacity of the large Wetheral feeder (KAI_7) by extending and livening a second 300 mm cable from the Kaiapoi GXP.	232
FY24	Reinforce SW63 & SW66 Swannanoa	These are large, highly loaded feeders with limited switching capability. The project improves safety and reliability by installing three remote-controlled switches.	187
FY24	Loburn Feeder	Create a new Loburn feeder to separate the supply to Loburn and Marshmans Rd Sefton to improve the security and reliability of both areas. Uses an existing spare Ashley circuit breaker.	407
FY25	East Belt to Railway link	Improves security of supply to central Rangiora by linking capacity from the eastern feeders and removing 800 kVA of commercial load from a spur connection.	178
FY25	Marsh Rd Feeder creation	Install a new cable from Southbrook Substation to Marsh Rd to improve the capacity to Pegasus/Ravenswood by 2 MW and improve reliability.	450
FY25	Kaiapoi–Island Rd Upgrade	Install a 300 mm² AL XLPE 11 kV cable from the Kaiapoi GXP to beyond the urban area to increase capacity in the region.	500
FY27	Burnt Hill X53–X56 link	Link 22 kV from Thongcastor Rd to Harmans Gorge Rd via the end of Depot Gorge Rd. This requires the conversion of part of Depot Gorge Rd to 22 kV.	606
FY27	Loburn Links	Improve network mesh connections between long radial spurs.	190
FY28–FY30	Tuahiwi to Rangiora Feeders	Install 300 mm² AL XLPE feeder cables between the new Tuahiwi 66 kV Zone Substation and the eastern side of Rangiora to improve security of supply.	1,150

Table 6-6: 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 include 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 GXPs. The area uses a combination of 66 kV and 33 kV sub-transmission voltages and we are transitioning away from 33 kV. The sub-transmission network consists of a very long 66 kV and 33 kV interconnection between Waipara and Culverden GXPs, which supplies the Mackenzies Rd, Greta, Cheviot & Parnassus Substations in the Hurunui area, as well as the Oaro and Kaikōura/Ludstone Rd Substations in the Kaikōura area. Hanmer is on a 33 kV spur from the Culverden GXP, while Amberley is on a 33 kV spur from the Waipara GXP, which also ties through to the Southbrook 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 likely to become the site of a large wind farm. Both of these would feed back to the Waipara GXP.

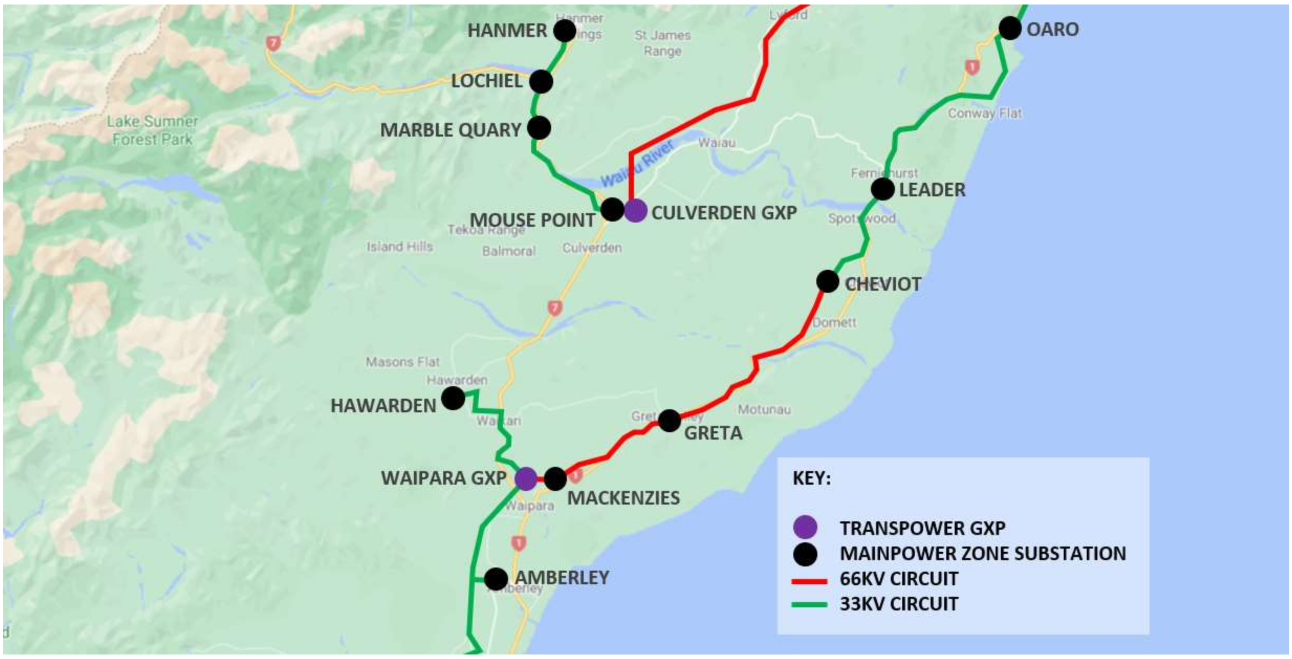

Figure 6.7: Hurunui Sub-Transmission Network (Existing)

6.8.2.1 Demand Forecasts

Demand forecasts for the Hurunui Zone Substations are shown in Table 6-7.`

Substation	Security Class	Class Capacity	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Amberley	A1	5 MVA	5.3	5.1	5.2	5.3	5.5	5.6	5.8	5.9	6.1	6.3
Mackenzies Rd	A1	4 MVA	3.5	3.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Greta	A1	4 MVA	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6
Cheviot	A1	4 MVA	3.4	3.4	3.5	3.5	3.6	3.6	3.7	3.7	3.8	3.9
Leader	A1	2 MVA	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9
Hawarden	A1	4.5 MVA	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.6	4.7	4.8
Mouse Point	AA	13 MVA	15.8	15.9	16.0	16.1	16.2	16.4	16.5	16.6	16.7	16.9
Marble Point	A2	0.3 MVA	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Lochiel	A2	0.5 MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Hanmer	AA	2.5 MVA	5.0	5.0	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7

Table 6-7: Hurunui Area Network Demand Forecasts

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

6.8.2.2 Network Constraints

Major constraints affecting the Hurunui area are shown in Table 6-8.

Load Affected	Major Issues	Growth and Security Projects
Amberley	The peak load cannot be supplied in the event of a transformer outage. The substation is supplied from a short 33 kV spur without a back-up. The 33 kV alternative supply to the spur from Southbrook will be removed by the Southbrook Upgrade.	Planned load transfer to Mackenzies Rd, to minimise the capacity shortfall. Replace the Southbrook alternative 33 kV supply with an approx. 6 MVA 33 kV supply from Ashley (FY21). The substation will be rebuilt for 66/11 kV, but operating at 33/11 kV, in a full N-1 configuration, in FY29–FY30.
Greta	The peak load cannot be supplied in the event of a transformer outage.	The Greta area will be linked to the Cheviot Substation to provide switchable back-up at 22/11 kV in FY23.
Cheviot	The peak load cannot be supplied in the event of a transformer outage.	The Cheviot–Oaro 66 kV Upgrade in FY21–FY22 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 Substation to provide switchable back-up at 22/11 kV in FY23. Capacity from the Leader Substation will be increased in FY24.
Leader	The peak load cannot be supplied in the event of a transformer outage.	The Cheviot–Oaro 66 kV Upgrade will increase the capacity of the Leader Substation from 2 MVA to 4 MVA in FY22. There are currently no plans to provide full switchable back-up within the planning period.
Hawarden	The peak load cannot be supplied in the event of a transformer outage. The substation is supplied from a 33 kV spur without a back-up.	The substation is planned to be rebuilt as a dual transformer supply in FY24–FY25. Load-transfer capacity from Mouse Point will be increased to 4 MW in FY25–FY26, providing full back-up for the existing load plus normal growth. A substantial increase in irrigation could exceed this capacity.

Load Affected	Major Issues	Growth and Security Projects
Mouse Point	The peak load is above the N-1 transformer rating. Switching of the 33 kV supply following a cable fault is local and would require more than 45 min.	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 back-up. Summer cyclic ratings will be established to maximise the contingency rating. The substation will be rebuilt as 66/22 kV, in a full N-1 configuration, in FY26–FY27.
Hanmer	The peak load is above the capacity of the installed spare transformer. The substation is supplied from a 33 kV radial spur.	The second transformer and upgraded 11 kV switchboard will provide back-up at peak loads in FY23. The 33 kV line will be upgraded over FY20–FY24 to maximise its strength and minimise the risk of prolonged outages in an extreme event.

Table 6-8: Hurunui Area Network Constraints

6.8.2.3 Major Projects

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

Amberley 66/11 KV Zone Substation Upgrade	
Estimated cost (concept)	$6.7 m
Expected project timing	FY22–FY23 (design), FY28–FY30 (build)
Project driver	Capacity, security and asset end of life

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 spur connection. It will be configured as a N-1 substation, similar to the Swannanoa and Burnt Hill Substations. This will remove the capacity and security constraints and replace the end-of-life transformers with newer 33/11 kV transformers for the medium term. The long-term plan is to convert the 33 kV sub-transmission line from 33 kV to 66 kV beyond 2031. Land acquisition is planned for FY22.

Hawarden Zone Substation Replacement	
Estimated cost (concept)	$6.53 m
Expected project timing	FY22–FY25
Project driver	Capacity, security and asset end of life

The Hawarden Substation has reached end of life. It will be replaced with a dual transformer substation designed for 66/22 kV operation, to mesh with Mouse Point, and initially operated at 33/11 kV. MainPower has suitable existing transformers. Site procurement is planned for FY22 with detailed design in FY23 and then procurement and construction in the following two years.

There is potential for the proposed irrigation development of the Hawarden area to change the scope and timing of this project.

Mouse Point Substation Upgrade	
Estimated cost (concept)	$7.6 m
Expected project timing	FY24–FY27
Project driver	Security of supply

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 at either the GXP site or neighbouring land. The substation will be constructed at 66/22 kV, although initially operated at 33/22 kV. It is expected that Transpower will replace the 220 kV/33 kV transformers at the GXP with 220/66 kV transformers around FY35. 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.

Hanmer Sub-Transmission Line Upgrade	
Estimated cost (concept)	$3.25 m
Expected project timing	FY22–FY25
Project driver	Asset end of life, growth and security of supply

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 line and build a second sub-transmission circuit to achieve the security of supply level is very high; therefore, this project is to improve the reliability of the existing line with stronger conductors and poles. The line route and pole footings will also be reviewed, to mitigate the impact of potential natural hazards where possible.

Hanmer Zone Substation Upgrade	
Estimated cost (concept)	$0.63 m
Expected project timing	FY23–FY24
Project driver	Security of supply and growth

The Hanmer Zone Substation does not meet MainPower's Security of Supply Standard of restoration within 45 minutes following a single sub-transmission failure. The zone substation peak load currently exceeds the peak rating of the second transformer, leaving part of the Hanmer region load at risk of prolonged outage following a fault. This project is to upgrade the second transformer to provide an N-1 zone substation. The 11 kV oil-filled switchgear is also at end of life and unable to be extended to properly connect the second transformer. This would be replaced as part of the upgrade.

6.8.2.4 Reinforcement Projects

FY	Project Title	Description	Cost ($,000)
FY23	Amberley North Load Transfer	Extend and upgrade 11 kV lines in Georges Rd, Waipara to enable transfer of load in the Mound Rd area from the Amberley Substation to the Mackenzies Rd Substation.	227
FY22	Amberley Y43 Urban/Rural Circuit Breaker	Install a circuit breaker on the urban fringe of Amberley to improve reliability to the Amberley township.	67
FY22	Amberley North Regulator	Increase load transfer between Amberley and Waipara by installing a voltage regulator on SH1 Glasnevin.	160
FY24	Amberley Beach Link	Build 800 m of new line in Hursley Terrace Rd to provide an alternative supply to Amberley Beach.	145
FY23	Greta–Cheviot 22 kV Link	Improve security of supply to the Cheviot and Greta Zone Substations by extending the Cheviot South feeder T43 1,500 m to link to Greta feeder G31. Convert 14 km of 11 kV line to 22 kV and install tie switches.	740
FY24	Cheviot–Leader Upgrade	Improve security of supply of Cheviot and Leader by upgrading the 11 kV conductor between Parnassus and the Waiau East/West Rds.	379

FY	Project Title	Description	Cost ($,000)
FY24	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).	525
FY25	Hawarden–Mouse Point Link Upgrade	Install a voltage regulator and switches to enable increased remote load-transfer capacity between Hawarden and Culverden (Mouse Point Substation).	360
FY26	Mouse Point Feeder	Create a Mouse Point feeder to Culverden to provide security of supply for the existing Culverden South loads (P25 & P35) and increase transfer capacity to Hawarden, to meet the Security of Supply Standard.	1,250
FY26	Lowry Peaks 22 kV	Build the Lowry Peaks spurs into a meshed supply by converting to 22 kV and adding automated switches to increase security and reliability.	350
FY25	Hanmer Feeder	Install 1 km of new cable to create a new western feeder to the Hanmer township, to enable full supply with loss of one feeder at peak load.	250

Table 6-9: Hurunui Area Reinforcement Projects

6.8.3 Kaikōura Regional Overview

The Kaikōura area plan covers the region north of the Conway river to the Puhi Puhi Valley north of Kaikōura, and between the South Island's east coast and the Main Divide. The area extends north 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 earthquake damage and associated access constraints. Future growth is uncertain. Kaikōura's isolated location on SH1 may make it a key charging location for electric vehicles 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 6.8. The small coastal communities south of Peketa are supplied from the 33 kV and 66 kV interconnection between Kaikōura and the Waipara GXP.

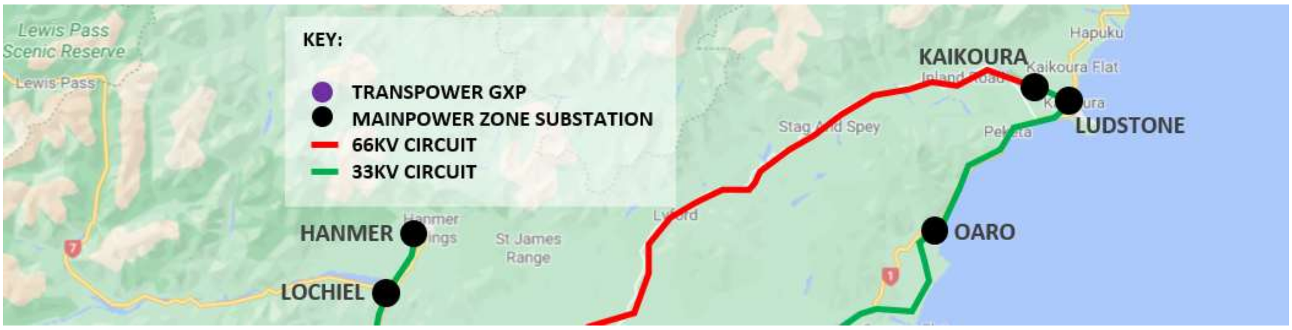

Figure 6.8: Kaikōura Region Sub-transmission Network

6.8.3.1 *Demand Forecasts*

Demand forecasts for the Kaikōura zone substations are shown in Table 6-10.

Substation	Security Class	Class Capacity	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Ludstone Rd	AA	6 MVA	5.5	5.5	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9
Oaro	A1	0.5 MVA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Table 6-10: Kaikōura Area Network Demand Forecasts

6.8.3.2 *Network Constraints*

Major constraints affecting the Kaikōura area are provided in Table 6-11.

Load Affected	Major Issues	Growth and Security Projects
Kaikōura township and surrounding rural region	The required 45 min. security of supply switching time for a sub-transmission fault cannot be met at peak load times. In addition, the back-up N-1 capacity from Waipara GXP has reached full capacity. Growth is also likely to exceed the cyclic rating of each transformer by FY30.	Upgrade of the existing 33 kV sub-transmission system from Cheviot to Oaro to 66 kV in FY21. This will increase the back-up capacity and reduce switching times during high load. Sub-transmission capacity can be further upgraded by the addition of 11 kV capacitors at Ludstone Zone Substation. This is planned for FY24. At the end of the planning period, the Ludstone Zone Substation will be rebuilt at the Kaikōura 66/33 kV Substation site.

Table 6-11: Kaikōura Area Network Constraints

6.8.3.3 *Major Projects*

The tables below summarise the major growth and security projects planned for the Kaikōura area.

Cheviot–Oaro Sub-Transmission Line Upgrade	
Estimated cost (concept)	$1.1 m
Expected project timing	FY21–FY22
Project driver	Security of supply

The line between Cheviot and Oaro is constructed at 66 kV but is currently operating at 33 kV. This project shifts the 66/33 kV transformer from Cheviot to Oaro, allowing the line to operate at 66 kV. Land has been purchased for the relocation of the Oaro Zone Substation to a new site where the new 66/33 kV transformer will be located.

Ludstone Zone Substation Capacitors	
Estimated cost (concept)	$0.25 m
Expected project timing	FY25
Project driver	Security of supply, quality of supply

The sub-transmission system between Culverden and Waipara is long and constrained by reactive voltage drop. This project is to add capacitors at the Ludstone Zone Substation 11 kV bus and provide voltage support during high-load periods.

6.8.3.4 *Reinforcement Projects*

We do not currently have any reinforcement projects identified for this region.

6.9 Project Summary

The overall summary of the major, reinforcement and GXP projects for the 10-year planning period across all planning regions is summarised below. Several large projects create a "lumpy" major project expenditure, balanced by activity in the minor works.

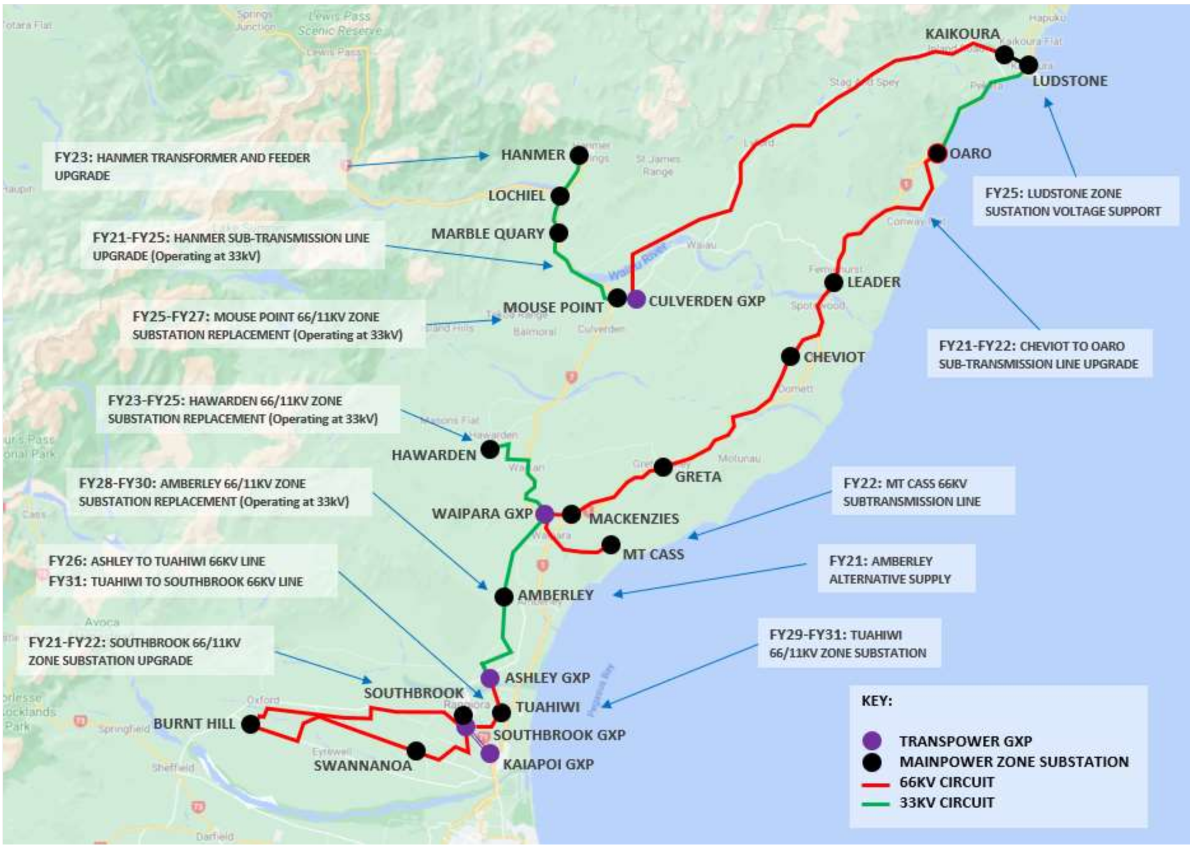

Figure 6.9: 10-year AMP Projects

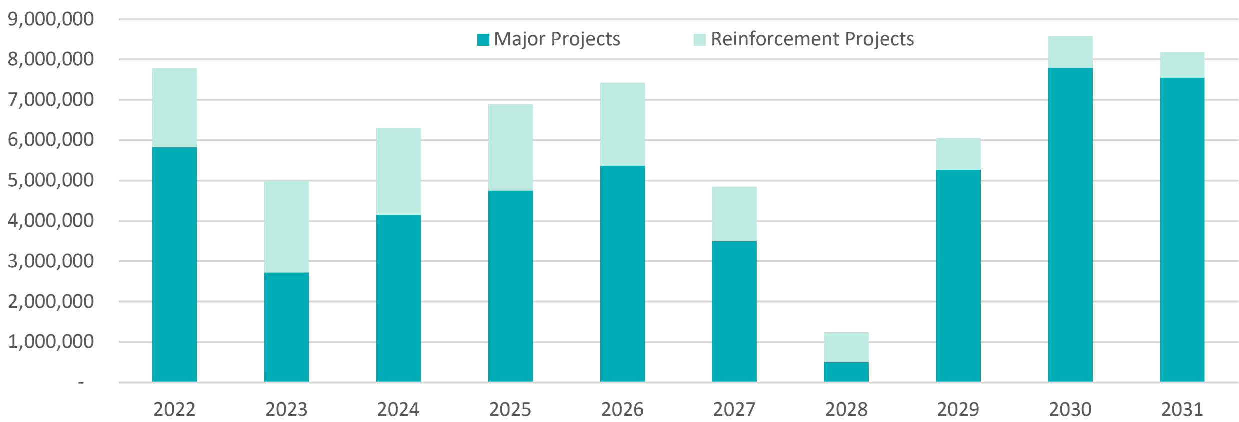

Figure 6.10: MainPower Network Development Capital Expenditure Summary

6.9.1 Major Projects Summary

Network Major Projects	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Cheviot–Oaro Sub-Transmission Line Upgrade (Completion)	200									
Ludstone Zone Substation Voltage Support				250						
Southbrook 66 kV Substation Upgrade	4,900									
Southbrook 33 kV Substation Decommissioning		350								
Rangiora North Substation Decommissioning		120								
Ashley to Tuahiwi 66 kV Sub-Transmission Line	150	100	50		1,870			770		
Tuahiwi 66/11 kV Zone Substation								1,500	4,800	4,800
Southbrook to Tuahiwi 66 kV Line										2,750
Hanmer Sub-Transmission Line Upgrade	500	750	1,000	1,000						
Harwarden Zone Substation Replacement	25	600	3,000	3,000						
Hanmer Zone Substation Upgrade		600								
Hanmer Zone Substation Concept	30									
Mouse Point Zone Substation Upgrade			100	500	3,500	3,500				
Amberley 66/11 kV Zone Substation Upgrade	25	200					500	3,000	3,000	
Totals	**5,830**	**2720**	**4,150**	**4,750**	**5,370**	**3,500**	**500**	**5,270**	**7,800**	**7,550**

Table 6-12: Major Projects Budget Summary

6.9.2 Reinforcement Projects Summary

Network Reinforcement Projects	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Pegasus Feeders	950									
Kippenberger Ave Circuit Breaker	72									
Kippenberger Ave Kiosk	154									
Amberley North Regulator	160									
Amberley Y43 Urban/Rural Circuit Breaker	67									
Townsend Rd Feeder	130	375								
Reinforce X52 Burnt Hill		228								
Amberley North Load Transfer		227								
Greta–Cheviot 22 kV Link		740								
Kaiapoi K7 Feeder Split		232								
Reinforce SW63 and SW66			187							
Greta–Hawarden Link Upgrade			525							
Amberley Beach Link			145							
Loburn Feeder			407							
Cheviot–Leader Upgrade			379							
Kaiapoi–Island Rd Upgrade				500						
East Belt–Railway Link				178						
Marsh Rd Feeder				450						
Hawarden to Mouse Point Link Upgrade				360						
Hanmer Feeder Cable				250						
Mouse Point Feeder					1,250					
Lowry Peaks 22 kV					350					
Burnt Hill X53–X56 Link						606				
Loburn Link						190				
Tuahiwi–Rangiora Feeders							300	300	300	250
Network Automation	50	100	105	100	100	150	150	150	175	100
Network Innovation (IoT)	50	75	100	75	125	150	75	125	100	75
Project Pre-Design and Consenting	150	150	160	80	80	100	60	60	60	60
Network Reinforcement – Unscheduled	175	150	150	150	150	150	150	150	150	150
Network Reinforcement Subtotals	**1,958**	**2,277**	**2,158**	**2,143**	**2,055**	**1,346**	**735**	**785**	**785**	**635**

Table 6-13: Reinforcement Projects Budget Summary

6.9.3 Alternatives and Differed Investment

Projects presented within the AMP are subjected to internal approval. 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 at www.mainpower.co.nz under “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 though 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 back-up line is unable to transmit the normal daily peaks.

6.12.2 Demand-Side Management

Demand-side management involves measures to manage power system load and optimise its use. In 2004, MainPower embarked on a programme to implement several demand-side management initiatives. To date, the benefits of implementing this programme have included:

- Reduction in peak loads on the network;
- Reduction in costs associated with Transpower peak charges and deferred network capital investment;
- Providing consumers with opportunities to reduce their energy costs;
- Demonstrating a commitment to energy efficiency; and
- Raised awareness of MainPower in the community.

6.12.3 Distributed Energy Resources

Aligned with MainPower’s Demand-Side Management scheme, “non-network” solutions such as Distributed Energy Resources (solar, 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 though 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 5 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 plan to further improve on this by implementing CBRM models.

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
	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
Secondary Systems	DC systems
	Protection systems
	Earthing systems

Asset Portfolio	Asset Fleet
	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 location of each pole, giving an overall geographic view of the electricity distribution network.

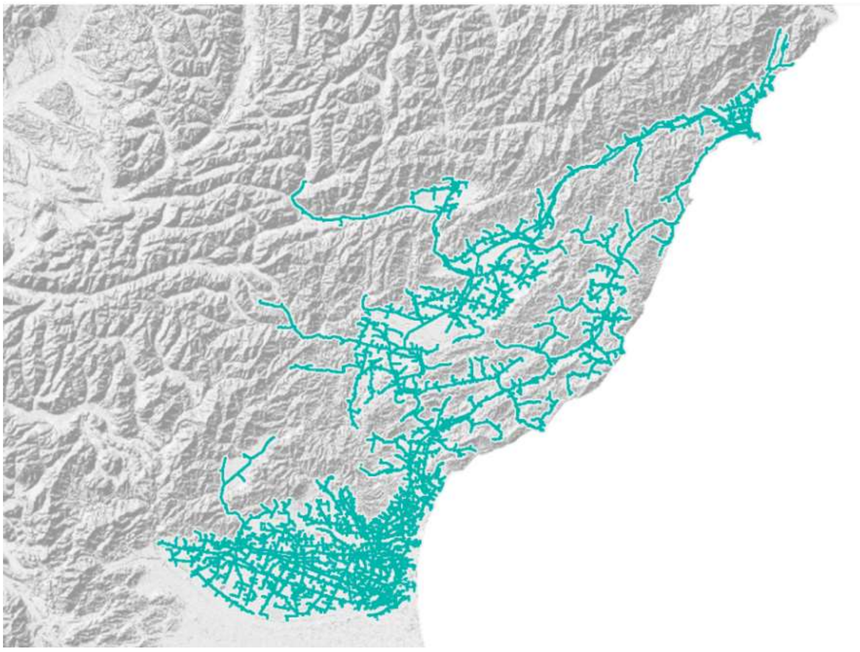

Figure 7.1: MainPower's Electricity Distribution Network's Geographical Distribution

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); and
- Concrete (post 1960s).

The main pole types used today are H5-treated Radiata Pine and pre-stressed concrete.

There are approximately 8,500 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.

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 40 years, and insulators including porcelain, glass and polymer types.

Based on on-going monitoring, the number defects of pole top equipment is found to be increasing steadily, part due to the increased number of ageing population, 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.

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 (HV) distribution overhead conductors; and
- Low-voltage (LV) 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, summarised 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.

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 and 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).

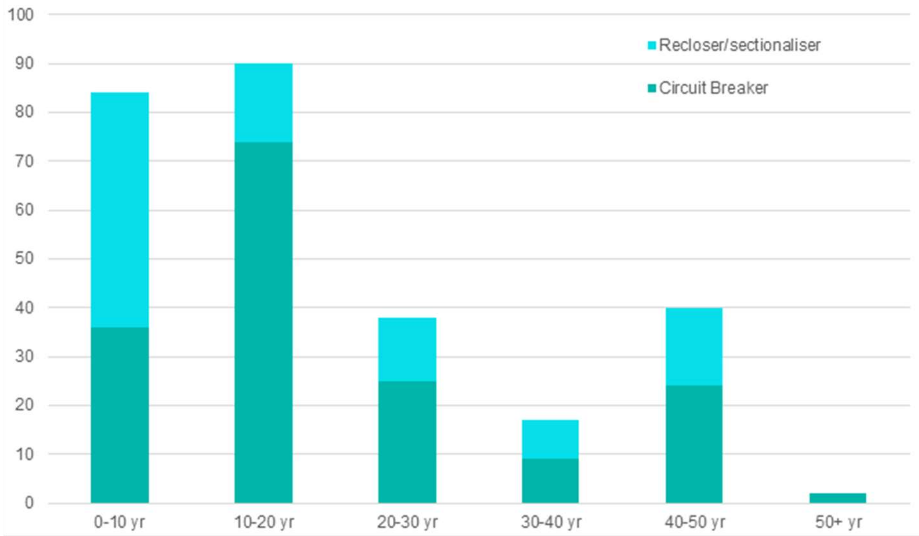

Figure 7.2: Switchgear Age Profile

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 guidance note Asset Health Indicator guide has been developed for all circuit breakers (excluding reclosers and sectionalisers), shown in Figure 7.3.

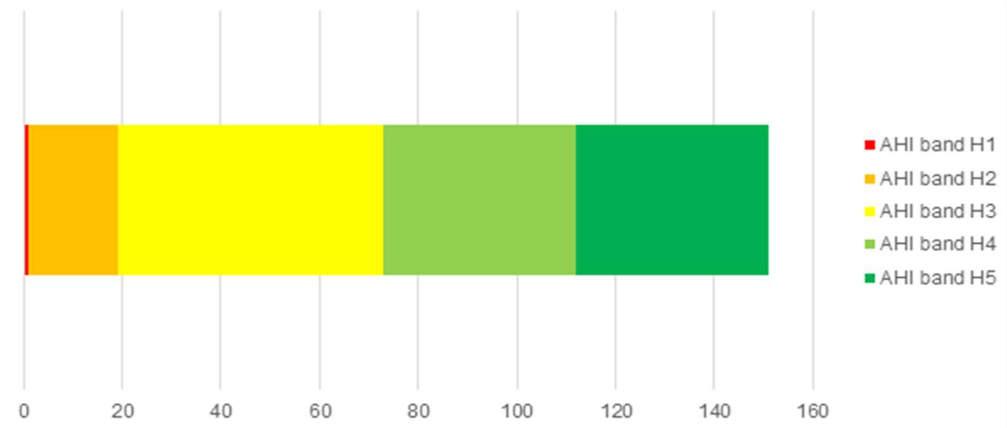

Figure 7.3: Circuit Breaker Current Asset Health Profile

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; and
- H3, H4 and H5 indicate good condition but still requires 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.

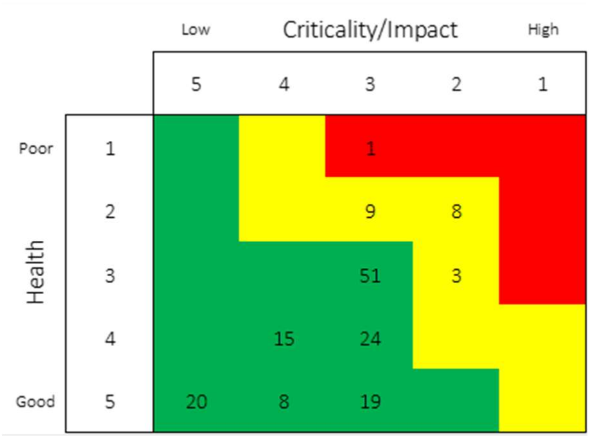

Figure 7.4: Circuit Breaker Criticality/Health Matrix

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	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)	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.

MainPower's key drivers for this replacement programme are minimising risk and improving network reliability, as well as 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 (post 2000); and
- SF_6 (post 2000).

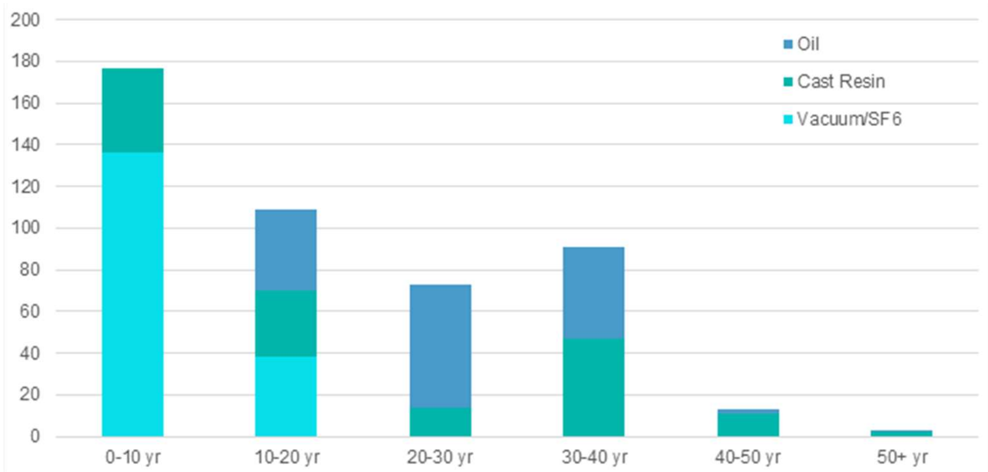

Figure 7.5: Ring Main Unit Quantities and Age Profile

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.

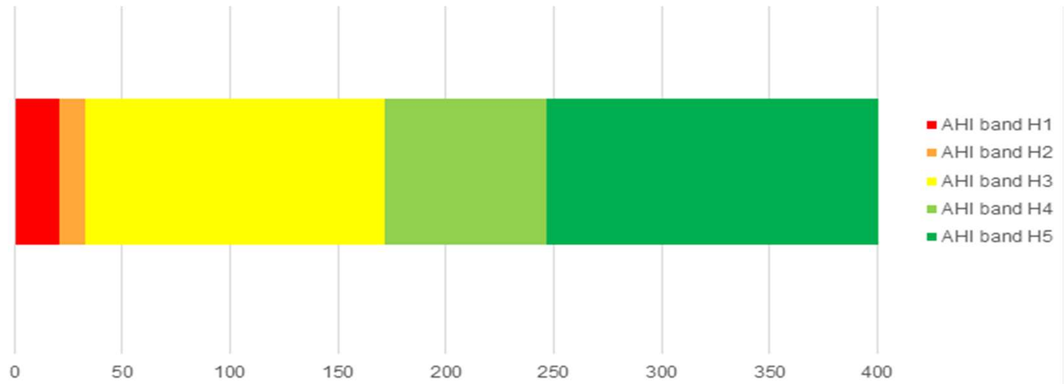

Figure 7.6: Ring Main Unit Current Asset Health

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 present;
- H3, H4 and H5 indicate good condition but still require regular inspection and maintenance.

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

Table 7-4: 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. These target units are imposed with operation restrictions and do not meet MainPower's long-term safety requirement

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.

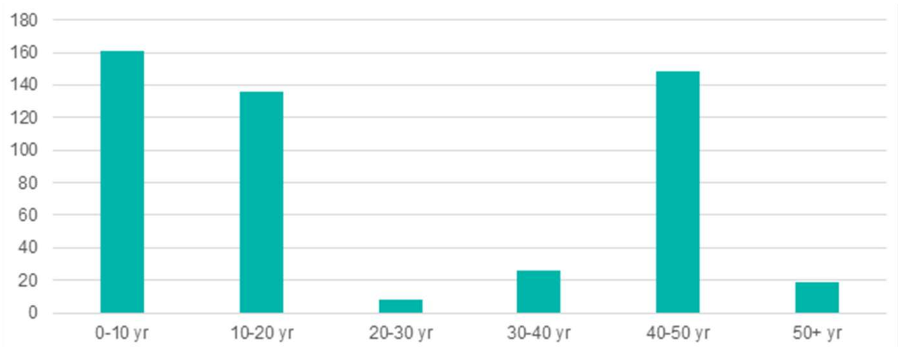

Figure 7.7: Pole Mounted Switch Quantities and Age Profiles

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 and 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 Advanced Distribution Management System (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; and
- 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	Porcelain fuse handles, which can be the cause of localised heating Exposed bus-work
D&S fused switches	Incomplete switching risk
Terasaki circuit breakers	Incomplete switching risk
ABB Fastline (SLK) fuse gear	Localised heating due to poor cable terminations
DIN-style fused switches	Localised heating due to poor cable or fuse terminations

Table 7-6: Low Voltage Switchgear Common Defects

7.3.4.1 Maintenance

A visual inspection every 12 months is used to identify any hotspots and units in poor condition, as well as operational issues (see Table 7-7). 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

Because of the lack of asset data, replacement of LV switchgear is mainly reactive and generally initiated from the electricity distribution network defect system. When collection of the type and condition of switchgear is completed, as mentioned above, a scheduled replacement programme will be created to systematically replace the older, less reliable units. The units most likely to be prioritised for replacement will be the exposed panels, D&S fused switchgear and Terasaki circuit breakers, owing to their issues.

7.4 Transformers

The sub-categories and quantities of MainPower's transformers are summarised in Table 7-8.

Transformer Fleet	Quantity
Power transformers	26 (plus 5 strategic spares)
Distribution transformers	8,307
Voltage regulators	22

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 23 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 they 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.

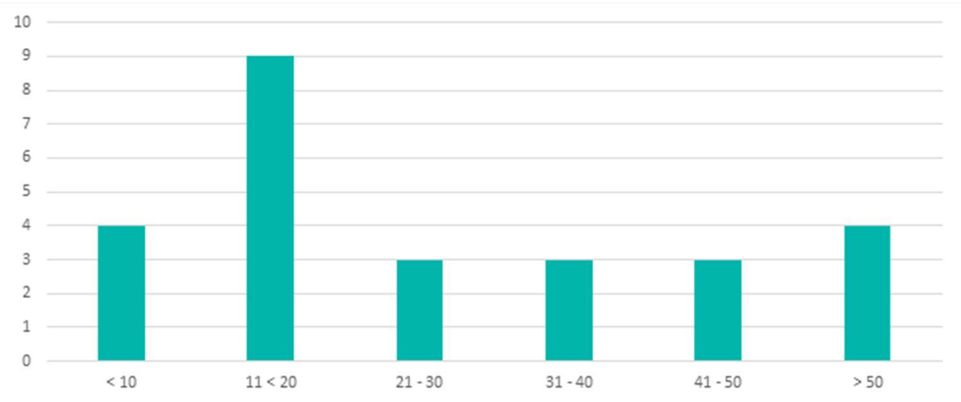

Figure 7.8: Power Transformer Age Profile

The power transformer fleet is managed using MainPower's Power Transformer AHI Model. The model has been improved during 2019, resulting in a realignment of some transformers across categories, with three units moving out of Band 4 into Band 5, and one unit moving from Band 4 to Band 3, giving a better representation of the asset fleet health (see Figure 7.9).

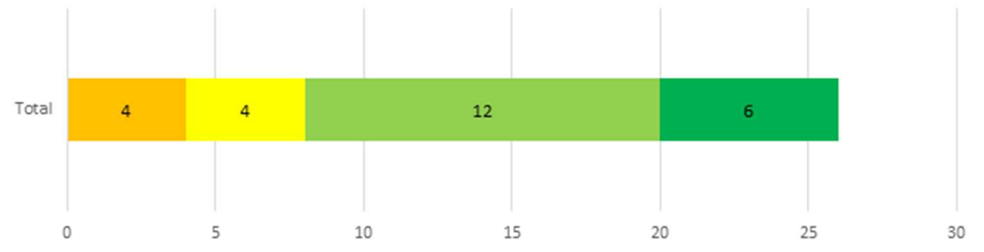

Figure 7.9: Power Transformer Current Asset Health

Three of the units with the lowest AHI scores are in the 41 to 50-year age bracket and have end-of-life indicators showing they likely have less than 10 years life remaining. The other low-scoring unit on the AHI Model shows a bushing defect that is scheduled for repair during the current financial year. Further investigations will be carried out during the maintenance to obtain better data on the internal condition of the transformer. The remaining units are showing no major defects and are aging in accordance with their typical lifespans and loadings.

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 (DGA) is carried out annually, with the strategic spare transformers included in the annual DGA assessment 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
	3 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 aging. This was suspended in 2019 to enable DGA results that are more accurate. This activity may be re-established for some units following DGA results in the 2020 year, where warranted.

7.4.1.2 Replacement and Disposal

No immediate replacements are planned for the 2021/22 financial year. Close monitoring of the aging 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 kiosk substations or as standalone units. These transformers supply end users with single-phase 230 V or three-phase 400V. The age profile of these is shown in Figure 7.10.

Failure modes that drive distribution transformer replacement are:

- Oil leaks;
- Significant rust; and
- Electrical failure.

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, with the ratings, quantities and age profiles summarised in Table 7-10 and Figure 7.11.

Rating	Number of Transformers	% of Total
> 15 and ≤ 30 kVA	18	2%
> 30 and ≤ 100 kVA	128	15%
> 100 and ≤ 500 kVA	596	73%
≥ 500 kVA	78	10%
Total	820	100%

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 5-yearly cycle (see Table 7-11). Oil samples are taken for analysis on units over 500 kVA on a 5-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 + 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	2,961	40%
> 15 and ≤ 30 kVA	1,889	25%
> 30 and ≤ 100 kVA	2,164	29%
> 100 kVA	473	6%
Total	7,487	100%

Table 7-12: Pole Mounted Transformer Quantities

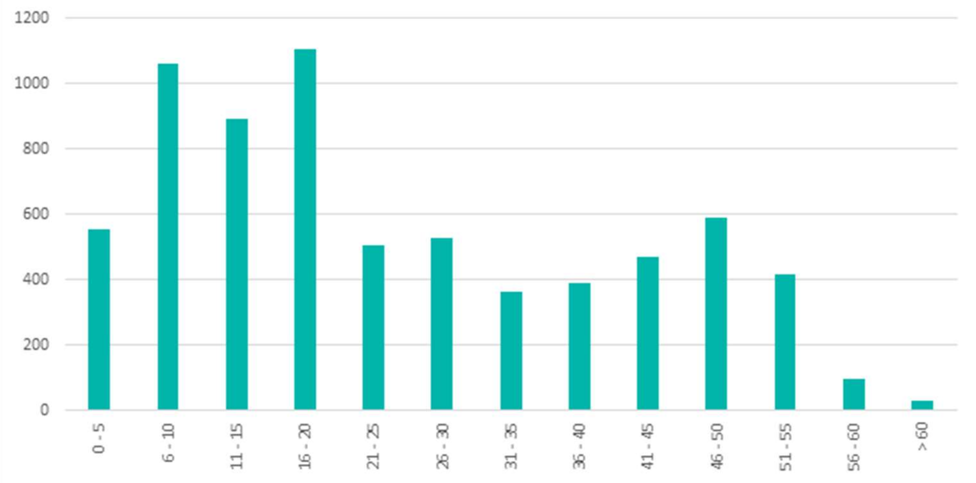

Figure 7.12: Pole Mounted Distribution Transformer Age Profiles

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 all 220 kVA General Electric devices with automatic controllers. The age profile is between one and 17 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 Grid Exit Points (GXPs) from the Transpower 220 kV and 66 kV transmission circuits passing through the region. There are 17 MainPower zone substations that operate at 66 kV and/or 33 kV to supply the 11 kV and 22 kV distribution network. A pictorial view 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).

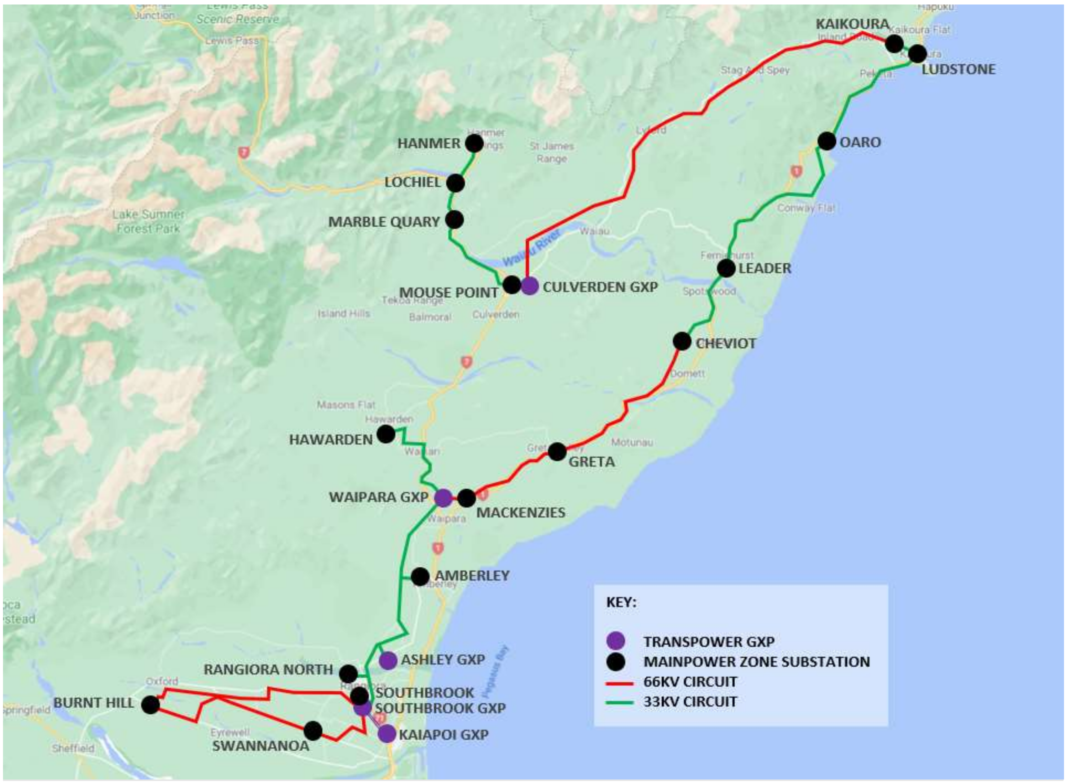

Figure 7.13: Zone Substation Locations

Site	Voltage	Substation Capacity (MVA)	# Feeders	Type
Southbrook	33/11 kV	44	6	Indoor
Swannanoa	33/22 kV	46	5	Indoor
Burnt Hill	66/22 kV	46	6	Indoor
Rangiora North	33/11 kV	7	3	Outdoor
Amberley	33/11 kV	8	3	Indoor
Mackenzies Rd	66/11 kV	4	3	Outdoor
Greta	66/22 kV	4	3	Outdoor
Cheviot	66/11 kV	4	3	Outdoor
Leader	33/11 kV	0.3	3	Outdoor
Oaro	33/11 kV	4	1	Outdoor
Ludstone Rd	33/11 kV	12	4	Indoor
Hawarden	33/11 kV	4	3	Outdoor
Mouse Point	33/11 kV	26	4	Outdoor
Marble Point	33/11 kV	2	1	Outdoor
Lochiel	33/11 kV	0.2	1	Outdoor
Hanmer	33/11 kV	12	2	Indoor
Kaikōura	66/33 kV	16	1	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
	3 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 Substations

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	# Feeders	Type
Pegasus	11 kV	5	Indoor
Kaiapoi North	11 kV	6	Indoor
Rangiora West	11 kV	4	Indoor
Percival St	11 kV	8	Indoor
Oxford	11 kV	3	Indoor
Bennetts	11 kV	3	Indoor
Kaiapoi S1	11 kV	4	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

Oxford Switching Station is scheduled for decommissioning during 2020, with the assets being replaced by a modern, compact, ground mounted kiosk. This will remove three old oil-filled circuit breakers from the fleet.

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	337 km
Low-voltage underground cables	1,149 km
Low-voltage service boxes	Approx. 10,000
Low-voltage link boxes	618

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, 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, historic "pothead"-type terminations are replaced proactively because of known age-related failures.

7.5.1.1 Maintenance/Inspections

The main 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.

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 cables. Replacement for cables is typically the result of inspection data and/or identified defects as noted by field staff.

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.

Following the Canterbury earthquakes, higher failure rates have been observed in the Kaiapoi area. This is mainly due to the stretching of these cables and failure of in-ground joints, probably caused by ground movement. During 2019, the final work was completed to replace or decommission the affected assets in the Kaiapoi red zone area.

7.5.2.1 Maintenance/Inspections

The main 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	2.5 yearly – High-criticality location cable termination inspection
	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 cables. Replacement for cables is typically the result of inspection data and/or identified defects as noted by field staff.

7.5.3 Low-Voltage Distribution Boxes

MainPower's low-voltage distribution boxes consist of:

- **Service boxes:** These are plastic boxes manufactured by either Gyro Plastics or TransNet. They typically house up to 12 standard domestic service fuses and are used for single- or three-phase consumer connections. Some historic service box types exist on the network which are constructed of metal frames with fibreglass lids.
- **Link boxes:** These are made of thermoplastic and typically house 4–10 vertically mounted service fuses. They provide alternative supply points between distribution transformers and allow reconfiguration of the network. Some historic steel boxes exist on the network.

Low-voltage distribution boxes incorporate safety features into box design, and access is restricted and controlled via our Network Operations and Control Centre.

MainPower recently initiated a new condition assessment programme to document the condition of our link box assets. This programme is underway and will collect condition data electronically on all link 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 the next five years and repaired as defects are identified.

7.5.3.1 Maintenance

A criticality-based approach is employed to low-voltage distribution box locations where higher-criticality areas, such as business districts, parks, public amenity areas and schools, involve a more frequent inspection programme (see Table 7-20).

Type	Frequency
Low-voltage distribution boxes	2.5 yearly – High-criticality location, low-voltage distribution box inspection
	5 yearly – Visual inspection of box and contained equipment

Table 7-20: Low-Voltage Distribution Box Inspection Summary

7.5.3.2 Replacement and Disposal

MainPower currently has a programme to replace historic metal frame service boxes, driven by asset condition. Other low-voltage distribution box replacements are primarily driven by defects noted 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 sources, including local 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

Inspections are split into three groups, depending on the criticality of the overhead lines. Criticality is determined by several factors, including the number of connections and the connected load that would be interrupted by an outage (see Table 7-21).

Type	Frequency
Vegetation	12 monthly – Criticality 1
	1.5 yearly – Criticality 2
	3 yearly – Criticality 3

Table 7-21: Vegetation Inspection and Maintenance Summary

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; and
- 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; and
- Battery chargers.

There are a range of different manufacturers and models of batteries across the network, typically installed in zone and switching substations, pole mounted reclosers sites and communication and repeater sites (see Table 7-22).

Asset	Nominal Life	Quantity
DC batteries	10 years	193
	5 years	255
	2 years	3
	Total	**451**

Table 7-22: DC Battery Quantities Based on Nominal Life

MainPower has recently standardised to one battery supplier, to provide efficiencies in procurement, installation and operation. Some known defects across the battery fleet include a shorter-than-expected asset life of the Powerware-type batteries 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 7-23).

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 7-23: 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 immediately replaced. DC charger replacement is primarily driven by either 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, ring main units (RMUs) and reclosers. Figure 7.14 shows the number and age of the current protection relays.

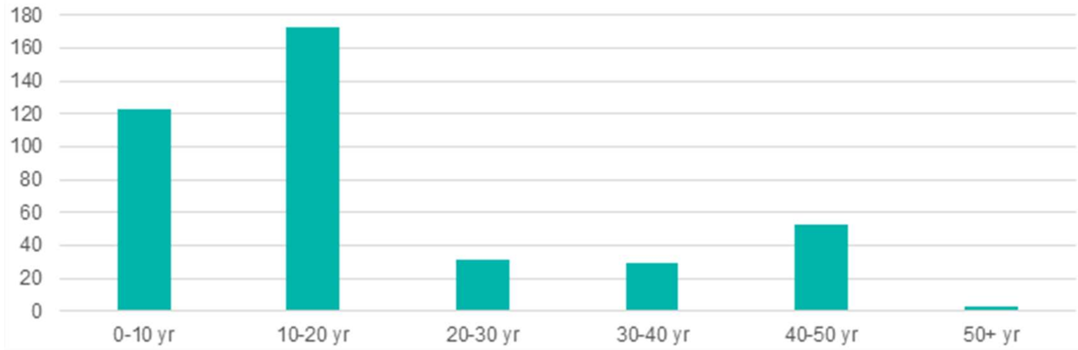

Figure 7.14: Protection Relay Age Profile

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 7-24).

Location	Frequency
Zone/switching substation	3 monthly – Visual inspection 3 yearly – Full system test (electromechanical) 6 yearly – Full system test (digital)
Recloser	12 monthly – Visual inspection 5 yearly – Full system test
RMU	12 monthly – Visual inspection 5 yearly – Full system test
All sites	Real time – Relay fail and other diagnostics (where available with digital relays)

Table 7-24: 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 standalone repeater sites. A visual representation of the radio communications, which currently uses Tait voice radios and Mimomax data radios, is shown in Figure 7.15.

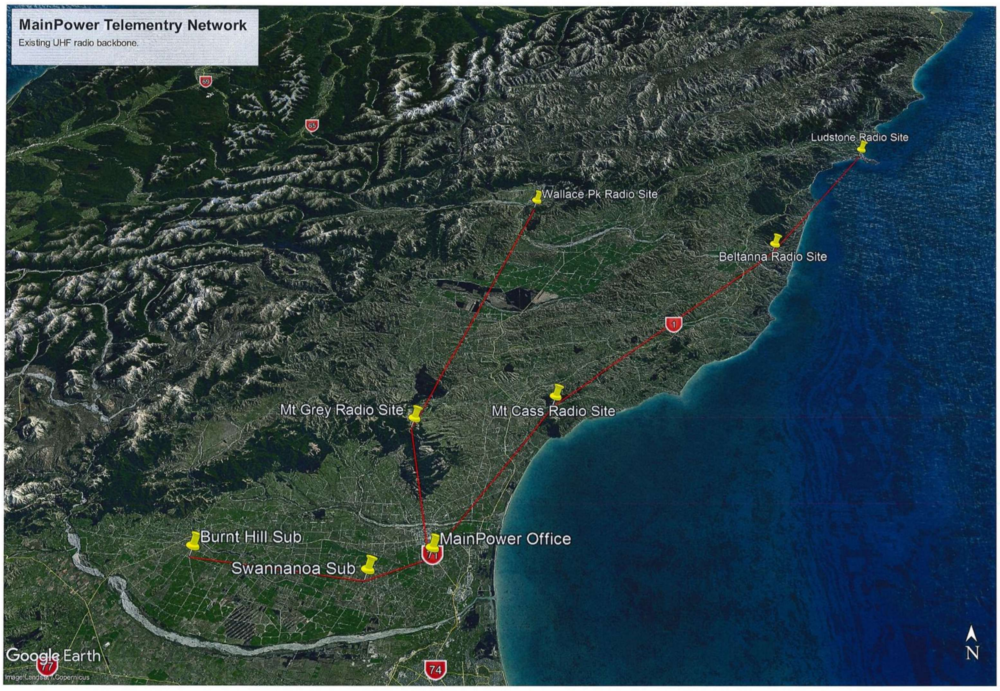

Figure 7.15: MainPower's Voice and Data Communications Network

MainPower's SCADA system is an Open Systems International (OSI) Advanced Distribution Management System. 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 360kbit/s and is 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

Asset Fleet	Frequency
Communications and SCADA	6 monthly - visual inspections
	12 monthly – diagnostic testing and servicing

Table 7-25: 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 7-26).

Location	Age	Operating Voltage
Kaiapoi GXP	25	11 kV
Ludstone Rd	12	11 kV
Mouse Point	14	33 kV
Southbrook	14	33 kV
Waipara GXP	13	33 kV
Ashley GXP	22	11 kV
Swannanoa	30	22 kV
Burnt Hill	30	22 kV

Table 7-26: Load Plant Age, Location 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 is being replaced with an 11 kV containerised unit during the zone substation rebuild in 2021. This will make available an SFU-K transmitter that will be used to replace the obsolete Kaiapoi SFU-G unit. The remaining Southbrook components will be assessed for their suitability as spares for other sites, following detailed assessment post decommissioning.

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 7-27.

Building Type	Quantity
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 7-27: MainPower's Property and Building Assets

7.8.1 Zone Substation Buildings

There are 22 control buildings located across MainPower's zone substations. 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 7-28.

Construction Type	Control Only	Control + HV* Switchgear
Timber framed	5	2
Concrete block	4	2
Concrete tilt slab	0	7
Container	0	2
Totals	**9**	**13**

Table 7-28: Zone Substation Building Types

Note: HV = high voltage

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 7-29.

Asset Fleet	Frequency
Zone substation buildings	3 monthly – Visual inspection

Table 7-29: 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 outcome of this assessment will 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 standalone 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.

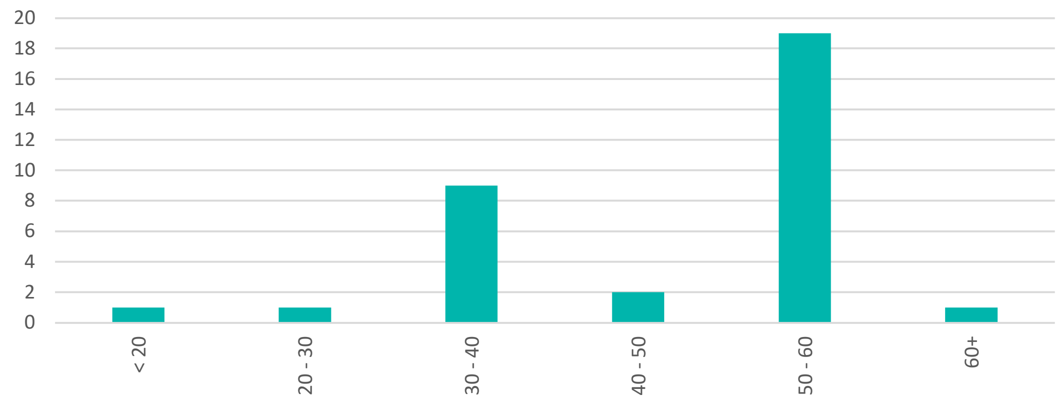

Figure 7.16: Kiosk Building Age Profile

These buildings are considered in generally good condition, given their age. However, MainPower undertook a detailed structural assessment during 2019 to determine their suitability for future use. Initial results indicate 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 kiosk buildings are of solid concrete or masonry construction and require little ongoing maintenance. Repairs and maintenance are carried out following issues raised during routine kiosk inspections or in field defect reports.

7.8.2.2 Replacement and Disposal

Structural assessments of the kiosk substation buildings have not indicated 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).

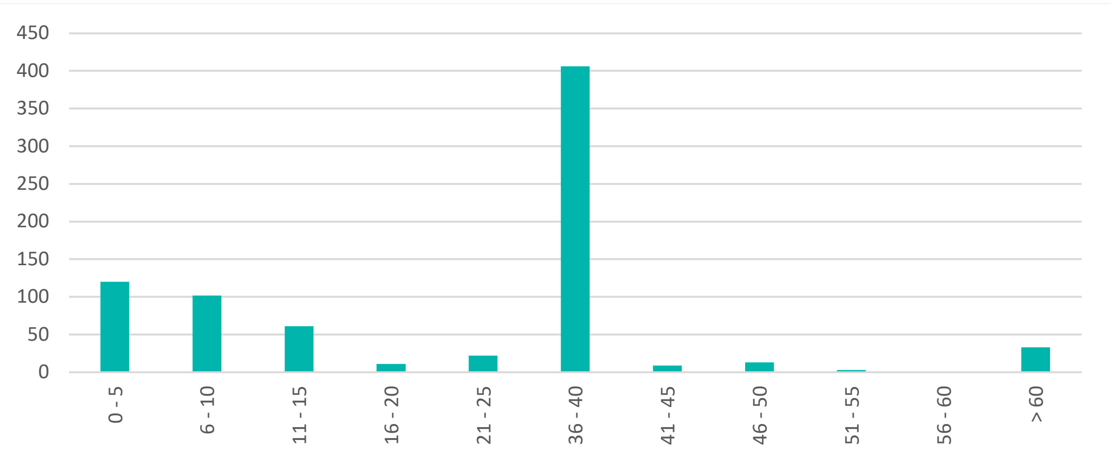

Figure 7.17: Age Profile of Kiosk Covers (Enclosures)

While the covers are considered as being in generally 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 following identification.

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, staff and holiday housing throughout the North Canterbury region (see Table 7-30). MainPower relocated to a new, purpose-built head office and works facility in Rangiora in June 2014.

Description	Location	Age (Years)
Staff Housing – #1	Culverden	3
Staff Housing – #2	Culverden	2
Staff Housing – #3 (unoccupied, to sell)	Culverden	50
Office building	Culverden	41
Storage shed/workshop	Culverden	41
Holiday home	Hanmer Springs	41
Holiday home	Kaikōura	41
Corporate office and operational facilities	Rangiora	6

Table 7-30: 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 2,100m² office building constructed to an Importance Level 4 standard;
- A single-storey 320m² café constructed to an Importance Level 3 standard; and
- A 2,000m² single-storey stores, garage and workshop building with 660m² of mezzanine storage area, constructed to an Importance Level 3 standard.

MainPower's electricity distribution network operation control centre 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 back-up Emergency Response Centre for local authorities in the event those authorities' main facilities are not occupiable.

MainPower recently had installed at our site a peak ground acceleration monitor, which 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 FY2050, with major replacement scheduled for FY2025 and FY2028, mainly consisting of renewing internal finishes such as carpet and paint, and external finishes such as wall cladding.

7.9 Electricity Distribution Network Expenditure

7.9.1 Electricity Distribution Network Planned and Corrective Maintenance Expenditure

Asset Portfolio	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Overhead Network	1,694	1,669	1,644	1,577	1,553	1,398	1,375	1,352	1,330	1,308
Zone Substations	723	722	716	723	720	717	714	711	709	706
Kiosks and Building Substations	545	545	545	545	545	545	545	545	545	545
Transformers	308	303	298	293	287	281	275	270	265	259
Switchgear	315	315	315	315	314	313	312	311	310	309
Communications	78	78	78	78	78	78	78	78	78	78
Vegetation	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Low-Voltage Network	722	513	513	507	502	497	492	488	484	480
High-Voltage Cables	142	141	140	139	134	130	125	121	117	113
Network Property	151	149	146	144	142	140	138	136	134	133
Network Maintenance Subtotal	**5,679**	**5,435**	**5,395**	**5,322**	**5,276**	**5,099**	**5,055**	**5,013**	**4,971**	**4,931**

Table 7-31: Electricity Distribution Network Maintenance Planned and Corrective Expenditure

7.9.2 Corrective Maintenance Expenditure

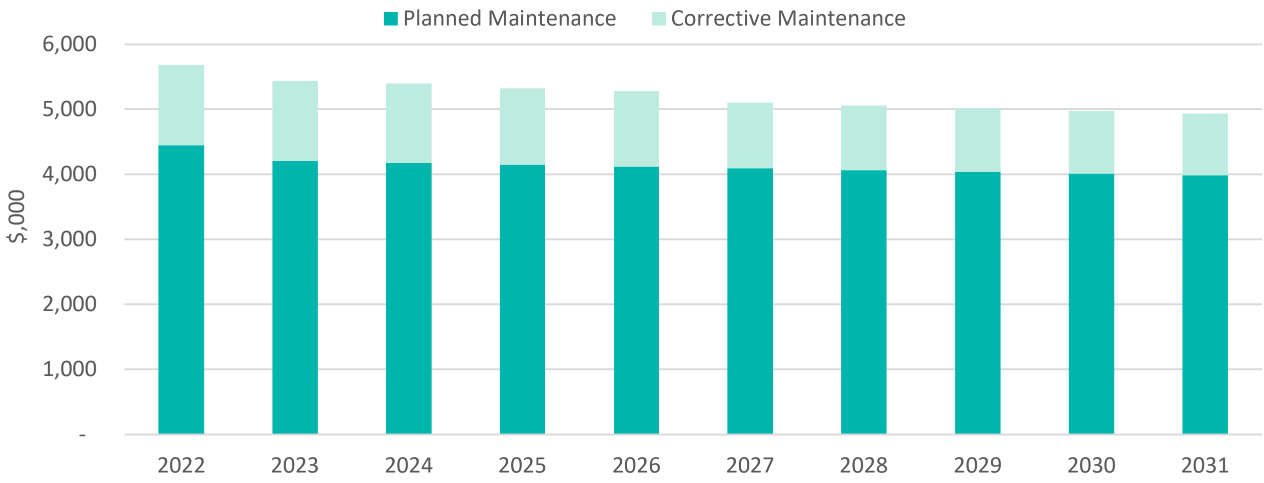

Figure 7.18: 10-Year Network Maintenance Expenditure Forecast

7.9.3 Electricity Distribution Network Planned and Corrective Replacement Expenditure

Asset Portfolio	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Overhead Network	7,595	7,952	7,952	7,518	7,550	7,544	7,433	7,394	7,192	7,211
Kiosks and Building Substations	1,108	1,108	1,108	1,108	1,108	970	970	970	970	970
Transformers	420	420	420	420	420	420	420	420	420	420
Switchgear	276	311	261	311	311	261	311	501	383	250
Secondary Systems	319	625	580	60	280	60	185	355	330	550
Underground Assets	818	793	793	793	793	793	793	793	750	750
Network Property	293	291	290	290	293	256	256	256	256	256
Corrective Replacement	300	285	271	257	244	232	221	210	199	189
Network Replacement Subtotal	**11,129**	**11,785**	**11,674**	**10,757**	**10,999**	**10,535**	**10,587**	**10,897**	**10,498**	**10,595**

Table 7-32: Electricity Distribution Network Replacement Expenditure

7.9.4 Replacement Expenditure Summary

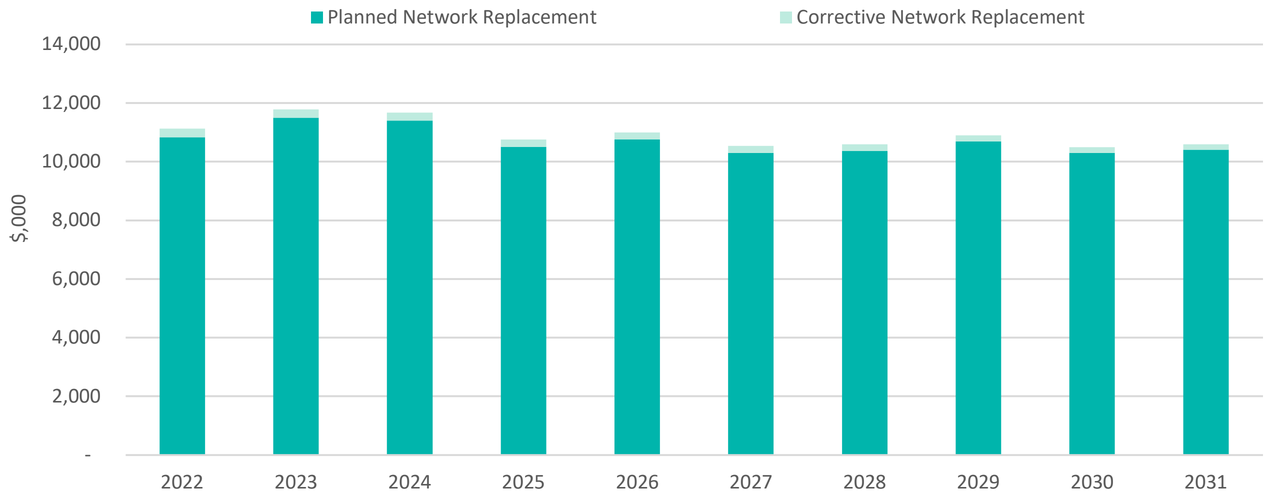

Figure 7.19: 10-Year Replacement Expenditure Forecast

7.10 Innovations

MainPower has initiated the process of implementing maintenance schedules against assets within the CMMS – TechnologyOne EAM. Template work orders will be set up for each asset fleet, with data collection points to record the outcome of maintenance activities. Data collection points will also be used to record information to help determine the condition of the assets. The increased accuracy of the data relating to our assets will lead to the optimisation of renewing our assets.

MainPower is also moving towards strategic asset management and portfolio optimisation within the TechnologyOne platform to renew assets based on asset condition and criticality. All data collection points, determined when completing the maintenance activities, are assigned against the assets within the OneAsset system. Assets will be tested using offline technology that syncs once the device is brought back into the coverage area.

7.11 Non-Electricity Distribution Network Assets

7.11.1 IT 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). Future application road maps are focused around SaaS as the primary application deployment methodology, to reduce hardware requirements and application management needs. Disaster Recovery is provided via replication of the internally hosted systems to Computer Concepts' 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 (includes standard modules for finance, payroll, stores, reporting, etc.);
- GE Digital's Smallworld GIS, which is used as the primary data repository for electricity distribution asset data; and
- A CRM from Salesforce for managing ICP data, including registry obligations, billing history, and so on and manages shareholder information on behalf of the Trust.

7.11.1.1 IT Software

In 2018, MainPower implemented Microsoft Office 365 to replace on premise Exchange and all desktop Microsoft Office licensing. This has moved a potential three-yearly capital cost (to upgrade to the latest version) into an operational cost on a "per active user" basis.

7.11.1.2 IT Hardware

In March 2017, MainPower moved from purchasing printers and faxes to a leased model through Ricoh NZ, moving these capital costs to operational costs on a 48-month contract.

7.11.1.3 Maintenance and Renewal Policies for IT Systems

MainPower has the following replacement policies for IT systems:

- 3 years for desktop PCs (approx. 45 PA);
- 3 years for laptops (approx. 12 PA);
- 3–4 years for tablets and mobile devices (approx. 50 PA); and
- 3–4 years for server infrastructure, dependent on warranty costs and capacity requirements.

Major software applications are patched regularly and maintenance/application releases are deployed annually to remain within vendor warranty frameworks (e.g. TechnologyOne is updated twice yearly, GIS annually and Salesforce quarterly).

Future maintenance and replacement decisions are based on GAAP but a strategic directive of "cloud first" for all software applications is in place, including future deployments of TechnologyOne.

7.11.1.4 Advanced Distribution Management System Replacement

MainPower's existing SCADA system has reached end of life; the latest version of the incumbent SCADA solution is not capable of delivering the functionality needed by MainPower. The focus of this project is to implement and integrate the OSI ADMS for the operational control of the MainPower electricity distribution network.

7.11.1.5 Enterprise Resource Process Upgrade

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

7.11.1.6 Technology Integration

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

7.11.1.7 Data Warehouse and Decision Support Expansion

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

7.11.1.8 Integrated Management System and Current State Management

A capability to leverage the current state of the organisation will be implemented to enable service improvement. The organisation has implemented the Promapp and State3 technologies to create and maintain visibility of the organisation's current state from process, people, technology and consumer experience perspectives.

7.11.1.9 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 the project aims to implement an integrated, modern and secure document management solution.

7.11.2 Assets Owned at Transpower Grid Exit Points

MainPower owns metering and communications equipment at Transpower GXPs which connect to our network, to monitor load for load management and for revenue metering. All have Ion-type meters, installed after 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.

7.11.3 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 and 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.

7.11.4 Other Generation

MainPower owns and operates a 1 MW generation asset 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 chapter 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 chapters.

8.1 Total Network Expenditure

8.1.1 Total Network Expenditure

Title	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Major Projects	5,830	2,720	4,150	4,750	5,370	3,500	500	5,270	7,800	7,550
Reinforcement Projects	1,958	2,277	2,158	2,143	2,055	1,346	735	785	785	635
Network Replacement	11,129	11,785	11,674	10,757	10,999	10,535	10,587	10,897	10,498	10,595
Network Maintenance	5,679	5,435	5,395	5,322	5,276	5,099	5,055	5,013	4,971	4,931
Customer Works (Network)	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Customer Works (Customer Funded)	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Network Operations and Faults	1,450	1,405	1,385	1,365	1,345	1,350	1,355	1,360	1,365	1,370
Non-Network	3,135	3,005	1,908	1,958	1,863	1,613	1,613	2,013	1,613	1,613
Total	**34,181**	**31,627**	**31,670**	**31,295**	**31,908**	**28,443**	**24,845**	**30,338**	**32,032**	**31,694**

Table 8-1: Total Expenditure Summary

8.2 Network Growth and Security

8.2.1 Network Major Projects

Network Major Projects	Expenditure ($,000)									
	FY22	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
Cheviot to Oaro Sub-Transmission Line Upgrade	200									
Ludstone Zone Substation Voltage Support				250						
Southbrook 66 kV Substation Upgrade	4,900									
Southbrook 33 kV Substation Decommissioning		350								
Rangiora North Zone Substation Decommissioning		120								
Ashley to Tuahiwi 66 kV Sub-Transmission Line	150	100	50		1,870			770		
Tuahiwi 66/11 kV Zone Substation								1,500	4,800	4,800
Southbrook to Tuahiwi 66 kV Sub-Transmission Line										2,750
Hanmer Sub-Transmission Line Upgrade	500	750	1,000	1,000						
Harwarden Zone Substation Replacement	25	600	3,000	3,000						
Hanmer Zone Substation Upgrade		600								
Hanmer Zone Substation Concept	30									
Mouse Point Zone Substation Upgrade			100	500	3,500	3,500				
Amberley 66/11 kV Zone Substation Upgrade	25	200					500	3,000	3,000	
Major Projects Subtotals	**5,830**	**2,720**	**4,150**	**4,750**	**5,370**	**3,500**	**500**	**5,270**	**7,800**	**7,550**

Table 8-2: Network Major Project Expenditure Summary

8.2.2 Network Reinforcement Projects

Network Reinforcement Projects	Expenditure ($,00)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Pegasus Feeders	950									
Kippenberger Ave Circuit Breaker	72									
Kippenberger Ave Kiosk	154									
Amberley North Regulator	160									
Amberley Y43 Urban/Rural Circuit Breaker	67									
Townsend Rd Feeder	130	375								
Reinforce X52 Burnt Hill		228								
Amberley North Load Transfer		227								
Greta–Cheviot 22 kV link		740								
Kaiapoi K7 Feeder Split		232								
Reinforce SW63 and SW66			187							
Greta–Hawarden Link Upgrade			525							
Amberley Beach Link			145							
Loburn Feeder			407							
Cheviot–Leader Upgrade			379							
Kaiapoi–Island Rd Upgrade				500						
East Belt–Railway Link				178						
Marsh Rd Feeder				450						
Hawarden–Mouse Point Link Upgrade				360						
Hanmer Feeder Cable				250						
Mouse Point Feeder					1,250					
Lowry Peaks 22 kV					350					
Burnt Hill X53–X56 Link						606				
Loburn Link						190				
Tuahiwi–Rangiora Feeders							300	300	300	250
Network Automation	50	100	105	100	100	150	150	150	175	100
Network Innovation (IoT)	50	75	100	75	125	150	75	125	100	75
Project Pre-Design and Consenting	150	150	160	80	80	100	60	60	60	60
Network Reinforcement – Unscheduled	175	150	150	150	150	150	150	150	150	150
Network Reinforcement Subtotals	**1,958**	**2,277**	**2,158**	**2,143**	**2,055**	**1,346**	**735**	**785**	**785**	**635**

Table 8-3: Network Reinforcement Expenditure Summary

8.3 Network Replacement

8.3.1 Network Replacement Expenditure

Asset Portfolio	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Overhead Network	7,595	7,952	7,952	7,518	7,550	7,544	7,433	7,394	7,192	7,211
Kiosks and Building Substations	1,108	1,108	1,108	1,108	1,108	970	970	970	970	970
Transformers	420	420	420	420	420	420	420	420	420	420
Switchgear	276	311	261	311	311	261	311	501	383	250
Secondary Systems	319	625	580	60	280	60	185	355	330	550
Underground Assets	818	793	793	793	793	793	793	793	750	750
Network Property	293	291	290	290	293	256	256	256	256	256
Corrective Replacement	300	285	271	257	244	232	221	210	199	189
Network Replacement Subtotal	**11,129**	**11,785**	**11,674**	**10,757**	**10,999**	**10,535**	**10,587**	**10,897**	**10,498**	**10,595**

Table 8-4: Network Replacement Expenditure Summary

8.4 Network Maintenance

8.4.1 Network Maintenance Expenditure

Asset Portfolio	Expenditure ($,000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Overhead Network	1,694	1,669	1,644	1,577	1,553	1,398	1,375	1,352	1,330	1,308
Zone Substations	723	722	716	723	720	717	714	711	709	706
Kiosks and Building Substations	545	545	545	545	545	545	545	545	545	545
Transformers	308	303	298	293	287	281	275	270	265	259
Switchgear	315	315	315	315	314	313	312	311	310	309
Communications	78	78	78	78	78	78	78	78	78	78
Vegetation	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Low-Voltage Network	722	513	513	507	502	497	492	488	484	480
High-Voltage Cables	142	141	140	139	134	130	125	121	117	113
Network Property	151	149	146	144	142	140	138	136	134	133
Network Maintenance Subtotal	**5,679**	**5,435**	**5,395**	**5,322**	**5,276**	**5,099**	**5,055**	**5,013**	**4,971**	**4,931**

Table 8-5: Network Maintenance Expenditure Summary

8.5 Non-Network Expenditure

8.5.1 Non-Network Expenditure

	Expenditure ($,000)									
Title	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
Protection Systems Database	190									
SINCAL Development	25	85								
Line Design Software		75	20	95						
TechnologyOne Development	500	250	150	150						
ADMS Development	325	425			250			400		
CBRM Development	85	100	100	100						
Network BI and Analytics	50	50	50	25	25	25	25	25	25	25
Computer Hardware	150	150	150	150	150	150	150	150	150	150
Unified Communications	500	500	68	68	68	68	68	68	68	68
Non-Network System Maintenance	1,310	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370
Non-Network Subtotal	**3,135**	**3,005**	**1,908**	**1,958**	**1,863**	**1,613**	**1,613**	**2,013**	**1,613**	**1,613**

Table 8-6: Non-Network Expenditure Summary

9 Capacity to Deliver

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 during the lifetime of the physical asset. These activities are outlined in Figure 9.1.

Figure 9.1: Asset Lifecycle Planning

The interaction of the roles throughout the asset lifecycle activities are detailed in Figure 9.2. Clear definitions of the roles are translated into position descriptions for relevant individuals. Where there is a gap between the role requirements and the competencies of the individual, a personal development programme is required to address the gap.

Figure 9.2: Alignment of Roles and Responsibilities Against Lifecycle Activities

These positions cover the following responsibilities:

- **Project Sponsor:** Person with a business need (e.g. renewal of asset, procurement of infrastructure). Project sponsor completes the sponsor's brief and steers the project to completion (practical completion including hand over).
- **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 is 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.

- **Network Operations & Control Centre (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 time.

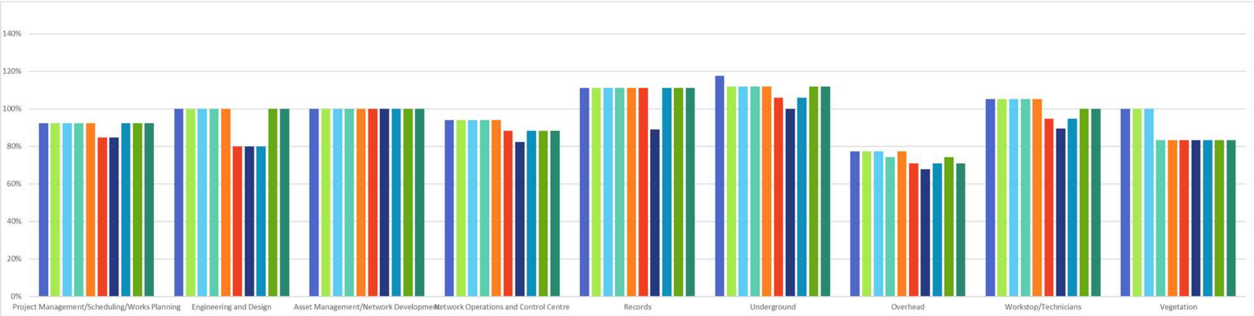

Figure 9.3: Resourcing Model

Linking asset lifecycle management resources with the 10-year work programme indicates MainPower internal resources for the management and planning of works is adequately resourced (Figure 9.3). There appears to be a deficit in overhead resources and, in later years, in resources for managing vegetation. This is consistent with existing trends where MainPower outsources the work where a resourcing gap is apparent. It is also likely that Project Management will be outsourced for growth-related projects (Reinforcements and Major Projects). It is anticipated with the delivery of the ADMS that the resource deficit in the NOCC will be addressed through better planning of works and the automation of the network systems and processes.

Asset Management Plan 2021–2031

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
CAPEX	Capital Expenditure
CBRM	Condition Based Risk Management
CDEM	Civil Defence Emergency Management
CIMS	Coordinated Incident Management System
CMMS	Computerised Maintenance Management System
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
Distribution Network	The power lines and underground cables that transport electricity from the national grid to homes and businesses
DMS	Distribution Management System
DNO	Distribution Network Operator
DNP	Distribution Network Provider
DSI	Distribution System Integrator
EAM	Enterprise Asset Management
EDB	Electricity Distribution Business
EEA	Electrical Engineers' Association
ERP	Enterprise Resource Planning
FY	Fiscal Year
GAAP	Generally accepted accounting principles
GIS	Geographic Information System
GWh	Gigawatt-hours
GXP	Grid Exit Point – a point at which MainPower's network connects to Transpower's transmission network
HILP	High-Impact, Low-Probability
HRC	High Rupturing Capacity
HSEQ	Health, Safety, Environment and Quality
ICP	Installation Control Point
IoT	Internet of Things
IT	Information Technology
KPI	Key Performance Indicator
kV	Kilo-volt
Master Plan	Long-term network capacity development plan
MDF	Medium-density fibreboard

MEPS	Minimum Energy Performance Standards
MVA	Mega Volt Ampere
MW	Megawatt. One 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
QoS	Quality of Supply
RMA	Resource Management Act
RTU	Remote terminal unit
SaaS	Software as a service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
Statement of Corporate Intent (SCI)	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
SWER	Single-wire earth return
SWMS	Safe Work Method Statement
Transmission	Transpower owns and operates the national grid. 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
Zone Substation	A substation that converts energy from transmission or sub-transmission voltages to distribution voltages

Appendix 2 – Description of Asset Management Systems

System	Description
Accounting Systems	• The TechnologyOne software platform, an Enterprise Resource Planning (ERP) system, is used to integrate financial, works and asset management information. • Capital and maintenance expenditure is managed using a comprehensive financial system.
Asset Register	• The asset management suite within the TechnologyOne platform is the principal source of data related to MainPower assets.
GIS	• 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	• MainPower's hardware and server software is continually updated, consistent with modern high-capacity hardware platforms. • Information security management includes maintaining offsite back-up facilities for stored information for protection from a security breach or disaster.
Works Management System	• The Works Management System issues and tracks jobs through the TechnologyOne software platform. It also maintains cost and quality information. • A comprehensive job-reporting system provides managers with detailed information about progress of the work plan, work hours and cost against budget.
SCADA and Load Management Systems	• Invensys Wonderware "Intouch" SCADA system: o displays voltage, current, and status information in real time from remote points on the network; o receives instantaneous information on faults; and o remotely operates equipment from the control centre. • We operate Landis and Gyr ripple injection plants and On Demand load management software to control: o customer water heaters, to limit system peak loads and area loading constraints (mainly during winter months); o street lighting; and o electricity retailer tariffs.
AutoCAD	• Detailed substation plans, standard construction drawings and many subdivision plans are prepared and stored in AutoCAD. • Where applicable, these are linked to assets within TechnologyOne. • Network details such as cable locations in trenches, boundary offsets, GPS location, etc., are stored in AutoCAD to be viewed without complicating the GIS system.
Customer Information System (CIS)	• This system is used to issue and maintain installation control points (ICPs) with retailers. • It also manages customer information, lines tariff and consumption data. • Outage information is imported from the Outage Management System 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	• 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	• 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.

System	Description
Inventory Systems	• All stock and supply chain details are managed through the TechnologyOne software platform as a single entity. • MainPower maintains a separate storage facility for its own stock.
Outage Management System (OMS)	• Traces across the GIS to identify all affected customers and switching points. • For unplanned outages, all relevant fault information is entered into the GIS after the event. • Reports are run from the GIS to generate outage statistics as required.
MACK CRM	• Customer Relationship Management system to manage customer enquiries and jobs. • Includes registry integration.

Appendix 3 – Directors' Certificate

mainpower

MainPower New Zealand Limited
172 Fernside Road, RD 1, Kaiapoi 7691
PO Box 346, Rangiora 7440
T. +64 3 311 8300 F. +64 3 311 8301

CERTIFICATE FOR YEAR-BEGINNING 1 APRIL 2021 DISCLOSURE

Pursuant to Clause 2.9.1 of Section 2.9 of the Electricity Distribution Disclosure Determination 2012 (consolidated April 2018)

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.

Tony King 03/01/2021 15:08 NZDT

Stephen Lewis 02/25/2021 09:14 NZDT

Date

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
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
	$000 (in nominal dollars)										
Consumer connection	4,500	5,000	5,055	5,131	5,233	5,349	5,472	5,603	5,743	5,887	6,034
System growth	6,249	6,564	2,125	3,771	5,558	7,082	3,830	896	6,398	9,536	9,413
Asset replacement and renewal	8,000	11,629	13,148	13,006	12,306	11,766	11,529	11,864	12,517	12,360	12,786
Asset relocations	-										
Reliability, safety and environment:											
Quality of supply	192	474	1,365	1,301	343	160	372	168	172	177	181
Legislative and regulatory	-										
Other reliability, safety and environment	2,962	250	329	375	267	701	1,101	319	385	394	284
Total reliability, safety and environment	3,154	724	1,693	1,676	610	861	1,473	487	557	571	465
Expenditure on network assets	21,903	23,917	22,021	23,584	23,708	25,057	22,303	18,851	25,214	28,354	28,697
Expenditure on non-network assets	7,000	2,941	2,800	1,717	1,803	1,741	1,508	1,544	2,042	1,622	1,663
Expenditure on assets	28,903	26,858	24,822	25,300	25,511	26,799	23,811	20,395	27,257	29,976	30,360
plus Cost of financing											
less Value of capital contributions	2,000	2,500	2,528	2,565	2,617	2,674	2,736	2,801	2,871	2,943	3,017
plus Value of vested assets											
Capital expenditure forecast	26,903	24,358	22,294	22,735	22,894	24,125	21,075	17,594	24,385	27,033	27,343
Assets commissioned	16,663	18,019	16,576	16,899	17,031	17,914	15,803	13,391	18,172	20,053	20,298

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
	$000 (in constant prices)										
Consumer connection	4,500	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
System growth	6,249	6,564	2,102	3,675	5,310	6,620	3,500	800	5,570	8,100	7,800
Asset replacement and renewal	8,000	11,629	13,005	12,674	11,757	10,999	10,535	10,587	10,897	10,498	10,595
Asset relocations	-	-	-	-	-	-					
Reliability, safety and environment:											
Quality of supply	192	474	1,350	1,268	328	150	340	150	150	150	150
Legislative and regulatory	-	-	-	-	-	-					
Other reliability, safety and environment	2,962	250	325	365	255	655	1,006	285	335	335	235
Total reliability, safety and environment	3,154	724	1,675	1,633	583	805	1,346	435	485	485	385
Expenditure on network assets	21,903	23,917	21,782	22,982	22,650	23,424	20,381	16,822	21,952	24,083	23,780
Expenditure on non-network assets	7,000	2,941	2,770	1,673	1,723	1,628	1,378	1,378	1,778	1,378	1,378
Expenditure on assets	28,903	26,858	24,552	24,655	24,373	25,052	21,759	18,200	23,730	25,461	25,158

Subcomponents of expenditure on assets (where known)

Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											

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
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
	$000										
Consumer connection	-	-	55	131	233	349	472	603	743	887	1,034
System growth	-	-	23	96	248	462	330	96	828	1,436	1,613
Asset replacement and renewal	-	-	143	332	549	767	994	1,277	1,619	1,861	2,190
Asset relocations	-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	-	15	33	15	10	32	18	22	27	31
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	4	10	12	46	95	34	50	59	49
Total reliability, safety and environment	-	-	18	43	27	56	127	52	72	86	80
Expenditure on network assets	-	-	240	601	1,057	1,633	1,922	2,028	3,262	4,270	4,916
Expenditure on non-network assets	-	-	30	44	80	113	130	166	264	244	285
Expenditure on assets	-	-	270	645	1,138	1,747	2,052	2,195	3,526	4,515	5,201

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Consumer types defined by EDB**	$000 (in constant prices)					
Residential	2,616	2,907	2,907	2,907	2,907	2,907
Irrigation	1,110	1,233	1,233	1,233	1,233	1,233
Large User	329	366	366	366	366	366
Streelights	134	149	149	149	149	149
Other	311	346	346	346	346	346
**include additional rows if needed*						
Consumer connection expenditure	4,500	5,000	5,000	5,000	5,000	5,000
less Capital contributions funding consumer connection		2,500	2,500	2,500	2,500	2,500
Consumer connection less capital contributions	4,500	2,500	2,500	2,500	2,500	2,500

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission		350	100	50	-	1,870
Zone substations	5,806	4,980	1,400	3,100	3,750	3,500
Distribution and LV lines		-	227	525	-	-
Distribution and LV cables	343	1,080	375	-	1,200	1,250
Distribution substations and transformers		154	-	-	-	-
Distribution switchgear		-	-	-	360	-
Other network assets	100					
System growth expenditure	6,249	6,564	2,102	3,675	5,310	6,620
less Capital contributions funding system growth						
System growth less capital contributions	6,249	6,564	2,102	3,675	5,310	6,620

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
	$000 (in constant prices)					
Subtransmission	-	500	1,220	1,000	1,000	-
Zone substations	21	-	-	-	-	-
Distribution and LV lines	4,803	7,595	7,952	7,952	7,518	7,550
Distribution and LV cables	816	818	793	793	793	793
Distribution substations and transformers	488	1,528	1,528	1,528	1,528	1,528
Distribution switchgear	946	276	311	261	311	311
Other network assets	926	912	1,201	1,141	607	817
Asset replacement and renewal expenditure	8,000	11,629	13,005	12,674	11,757	10,999
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	8,000	11,629	13,005	12,674	11,757	10,999

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	$000 (in constant prices)					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	-	-	-	-	-	-
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	-	-	-	-	-	-

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	$000 (in constant prices)					
Network Reinforcement	192	474	1,350	1,268	328	150
[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	192	474	1,350	1,268	328	150
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	192	474	1,350	1,268	328	150

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	$000 (in constant prices)					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	$000 (in constant prices)					
Conductor Upgrades	1,412	250	325	365	255	655
Zone Substations	815					
Switchgear Upgrades						
Network Automation						
Network Reinforcement	735					
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	2,962	250	325	365	255	655
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	2,962	250	325	365	255	655

11a(ix): Non-Network Assets

Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
Asset Management Systems	5,100	590	340	240	240	90
Business Services & Software	1,200	885	795	223	298	103
Dsitributed Energy Systems	200	325	425	-	-	250
IT Infrastructure & Eqiupment	300	159	210	210	185	185
Sundry/Other	200					
**include additional rows if needed*						
All other projects or programmes - routine expenditure		982	1,000	1,000	1,000	1,000
Routine expenditure	7,000	2,941	2,770	1,673	1,723	1,628
Atypical expenditure						
*Project or programme**						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	7,000	2,941	2,770	1,673	1,723	1,628

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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
Operational Expenditure Forecast	**$000 (in nominal dollars)**										
Service interruptions and emergencies	700	1,100	1,062	1,052	1,047	1,043	1,067	1,093	1,120	1,148	1,177
Vegetation management	921	1,000	1,011	1,026	1,047	1,070	1,094	1,121	1,149	1,177	1,207
Routine and corrective maintenance and inspection	4,179	4,575	4,380	4,406	4,422	4,472	4,397	4,455	4,520	4,586	4,654
Asset replacement and renewal		103	104	105	102	102	89	89	89	90	90
Network Opex	5,800	6,779	6,556	6,588	6,617	6,687	6,647	6,757	6,878	7,001	7,127
System operations and network support	6,180	6,304	6,373	6,469	6,598	6,743	6,898	7,064	7,240	7,421	7,607
Business support	7,210	7,354	7,435	7,547	7,698	7,867	8,048	8,241	8,447	8,658	8,875
Non-network opex	13,390	13,658	13,808	14,015	14,295	14,610	14,946	15,305	15,687	16,079	16,481
Operational expenditure	19,190	20,436	20,364	20,604	20,913	21,297	21,593	22,062	22,565	23,080	23,609

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
	$000 (in constant prices)										
Service interruptions and emergencies	700	1,100	1,050	1,025	1,000	975	975	975	975	975	975
Vegetation management	921	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Routine and corrective maintenance and inspection	4,179	4,575	4,332	4,294	4,225	4,180	4,018	3,976	3,935	3,895	3,856
Asset replacement and renewal	-	103	103	102	98	96	81	79	78	76	75
Network Opex	5,800	6,779	6,485	6,420	6,322	6,251	6,074	6,030	5,988	5,946	5,906
System operations and network support	6,180	6,304	6,304	6,304	6,304	6,304	6,304	6,304	6,304	6,304	6,304
Business support	7,210	7,354	7,354	7,354	7,354	7,354	7,354	7,354	7,354	7,354	7,354
Non-network opex	13,390	13,658	13,658	13,658	13,658	13,658	13,658	13,658	13,658	13,658	13,658
Operational expenditure	19,190	20,436	20,143	20,078	19,980	19,909	19,732	19,688	19,646	19,604	19,564
Subcomponents of operational expenditure (where known)											
Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
Direct billing*	-	-	-	-	-	-	-	-	-	-	-
Research and Development	-	-	-	-	-	-	-	-	-	-	-
Insurance	745	783	783	783	783	783	783	783	783	783	783

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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
Difference between nominal and real forecasts	**$000**										
Service interruptions and emergencies	-	-	12	27	47	68	92	118	145	173	202
Vegetation management	-	-	11	26	47	70	94	121	149	177	207
Routine and corrective maintenance and inspection	-	-	48	112	197	291	379	479	585	691	797
Asset replacement and renewal	-	-	1	3	5	7	8	10	12	14	15
Network Opex	-	-	71	168	295	436	573	727	890	1,054	1,221
System operations and network support	-	-	69	165	294	439	595	760	937	1,118	1,303
Business support	-	-	81	192	343	513	694	887	1,093	1,304	1,520
Non-network opex	-	-	150	357	638	952	1,288	1,647	2,030	2,422	2,824
Operational expenditure	-	-	222	525	933	1,388	1,861	2,374	2,919	3,476	4,045

Appendix 6 – Schedule 12a: Report on Asset Condition

				Asset condition at start of planning period (percentage of units by grade)							
Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
All	Overhead Line	Concrete poles / steel structure	No.	-	3.7%	4.4%	30.0%	61.9%	-	3	2%
All	Overhead Line	Wood poles	No.	0.9%	14.7%	11.0%	38.9%	34.5%	-	2	7%
All	Overhead Line	Other pole types	No.	-	-	-	-	-		[Select one]	
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	10%	44%	17%	29%	-	2	0%
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	8%	5%	45%	42%	-	3	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-		[Select one]	
HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-		[Select one]	
HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	-	-		[Select one]	
HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-		[Select one]	
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	29%	71%	-	3	-
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	21%	11%	11%	58%	-	2	7%
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-		[Select one]	
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	4%	65%	2%	30%	-	3	-
HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-		[Select one]	
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-		[Select one]	
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	39%	62%	-	3	
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	12%	88%	-	-	3	
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	5%	67%	29%	-	3	

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	7.7%	19.2%	30.8%	42.3%	-	3	-
HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	3.4%	3.3%	48.6%	44.7%	-	2	-
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-		[Select one]	
HV	Distribution Line	SWER conductor	km	-	3.2%	28.7%	62.1%	6.0%	-	2	
HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.1%	5.2%	1.9%	39.8%	53.0%	-	1	1%
HV	Distribution Cable	Distribution UG PILC	km	-	2.2%	-	71.2%	26.6%	-	2	-
HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-		[Select one]	
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	1.2%	-	22.1%	34.9%	41.8%	-	2	5%
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	8.9%	8.9%	55.6%	26.6%	-	2	5%
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2.3%	23.1%	29.8%	15.6%	29.2%	-	2	5%
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-		[Select one]	
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.3%	3.3%	26.3%	32.1%	36.0%	-	3	12%
HV	Distribution Transformer	Pole Mounted Transformer	No.	0.2%	6.2%	45.2%	26.8%	21.6%	-	2	5%
HV	Distribution Transformer	Ground Mounted Transformer	No.	0.2%	3.0%	30.7%	35.0%	31.1%	-	3	5%
HV	Distribution Transformer	Voltage regulators	No.	-	-	4.5%	50.0%	45.5%	-	3	-
HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.6%	19.8%	26.4%	24.7%	28.5%	-	2	3%
LV	LV Line	LV OH Conductor	km	-	8.6%	68.9%	18.0%	4.5%	-	1	-
LV	LV Cable	LV UG Cable	km	-	4.6%	11.0%	27.2%	57.2%	-	1	-
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	53.5%	4.5%	7.7%	34.3%	-	2	-
LV	Connections	OH/UG consumer service connections	No.	-	9.8%	7.7%	21.1%	38.7%	22.7%	1	-
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	1.9%	32.6%	6.4%	47.6%	11.5%	-	2	10%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	24.3%	13.3%	43.1%	19.3%	-	3	10%
All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-		[Select one]	
All	Load Control	Centralised plant	Lot	-	-	12.5%	50.0%	37.5%	-	3	20%
All	Load Control	Relays	No.	-	66.7%	9.4%	18.8%	5.1%	-	1	-
All	Civils	Cable Tunnels	km							[Select one]	

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	25	22	N-1 switched	2	113%	44	68%	No constraint within +5 years	Upgrade required within 5 years
Rangiora North	5	-	N-1 switched	6	-	-	N/A	Subtransmission circuit	Single cct 33kV
Burnt Hill	15	23	N-1 switched	6	67%	23	75%	No constraint within +5 years	
Swannanoa	16	23	N-1 switched	6	67%	23	80%	No constraint within +5 years	
Amberley	5	4	N-1 switched	2	135%	4	120%	Transformer	Single cct 33kV
MacKenzies Rd	3	-	N	2	-	-	N/A	Transformer	Peak load is from embeded generation
Greta	1	-	N	1	-	-	N/A	Transformer	
Cheviot	3	-	N	2	-	-	N/A	Transformer	
Hawarden	4	-	N-1 switched	3	-	-	N/A	Subtransmission circuit	Load reduction by emergency irrig load control
Ludstone	5	6	N-1 switched	-	88%	6	100%	Subtransmission circuit	
Leader	2	-	N		-	-	N/A	Transformer	Load reduction by emergency irrig load control
Oaro	0	-	N	-	-	-	N/A	Transformer	
Mouse Point	15	13	N	2	117%	13	140%	Transformer	Load reduction by emergency irrig load control
Hanmer	4	3	N-1 switched	-	172%	-	N/A	Subtransmission circuit	Single 33kV cct, standby 3 MVA transfromer.
Lochiel	0	-	N	-	-	-	N/A	Subtransmission circuit	
Marble Quarry	0	-	N	-	-	-	N/A	Subtransmission circuit	Single 33kV cct, standby 3 MVA transfromer.
[Zone Substation_17]					-			[Select one]	
[Zone Substation_18]					-			[Select one]	
[Zone Substation_19]					-			[Select one]	
[Zone Substation_20]					-			[Select one]	

[1] *Extend 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

	Number of connections					
	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
*Consumer types defined by EDB**						
Residential	800	650	650	650	650	650
Irrigation	12	30	30	30	30	30
Large User	1	1	1	1	1	1
Streelights	2	2	2	2	2	2
Other	140	120	120	120	120	120
Connections total	955	803	803	803	803	803
**include additional rows if needed*						
Distributed generation						
Number of connections	201	211	221	232	244	256
Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1

12c(ii) System Demand

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Maximum coincident system demand (MW) — for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
GXP demand	115	115	116	117	118	119
plus Distributed generation output at HV and above	4	4	6	6	6	6
Maximum coincident system demand	118	118	121	122	123	124
less Net transfers to (from) other EDBs at HV and above						
Demand on system for supply to consumers' connection points	118	118	121	122	123	124
Electricity volumes carried (GWh)						
Electricity supplied from GXPs	636	654	655	656	666	675
less Electricity exports to GXPs	-					
plus Electricity supplied from distributed generation	29	35	43	52	52	52
less Net electricity supplied to (from) other EDBs	-					
Electricity entering system for supply to ICPs	664	689	698	708	717	727
less Total energy delivered to ICPs	627	653	662	672	681	691
Losses	37	36	36	36	36	36
Load factor	64%	67%	66%	66%	66%	67%
Loss ratio	5.6%	5.2%	5.1%	5.1%	5.0%	4.9%

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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
SAIDI						
Class B (planned interruptions on the network)	221.5	178.2	176.4	174.7	172.9	171.2
Class C (unplanned interruptions on the network)	111.1	145.1	137.9	124.1	122.8	121.6
SAIFI						
Class B (planned interruptions on the network)	0.80	0.65	0.65	0.65	0.65	0.65
Class C (unplanned interruptions on the network)	1.38	1.58	1.43	1.28	1.27	1.26

Appendix 10 – Schedule 13: Report on Asset Management Maturity

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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 MainPowers approach to asset management. Awareness of the policy is supported within the business through training and regularly updates to staff on Asset Managemen.		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.
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 line of sight between asset management polices 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 polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
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 MainPowers 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.
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 exit or currently being developed for all assets. Work remains to futher link Asset Management Plans to polices 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).

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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 Plan, work program and key initiatives are present to staff annually, from board of directors right through to field staff. This is done via a variety of methods, from small steering group discussions, to larger general informaiton 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 receivers role in plan delivery. Evidence of communication.
Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	MainPower now has roles specificly 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.
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 bases 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. 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.
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 CIMS framework with staff training provided and with mock incidents to furhter 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.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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 it's 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 fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
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 MainPower 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 chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
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 important is reported to all staff on a regular bases 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-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
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.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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 are 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.
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 requirement 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 plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	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 AMP.		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.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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; newsletters, etc.
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 MainPower, 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.
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 it's asset register and information held in it's ERP system. In addition, a new data warehouse has been established linking source data into a BI 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 akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
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-builting 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.

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, 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 approach to asset management.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
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	Activity 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.
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 process detailing the		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
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 compliace 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 s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	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-builting.		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.
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 are fully align with asset amangement 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.
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 SAIDI, SAIFI and other performance metric 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 staf 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 contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Asset failures are investigated depending on criticality 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 process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	MainPower engaged external support to help review and futher develop it's asset management system documentation in 2020.		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.
Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Incident investigations and corrective actions are undertaken in accordance with MainPower's Incident Reporting and Management operating standard. Asset Management work programs also include both preventative and corrective components, with the objective of preventative programs resulting in less corrective work. Corrective actions and work is reviewed annualy to inform and improve preventative work programs.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
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 costed 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 that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
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 EDBs.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.