Asset Management Plan
2020 – 2030

CEO'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 is MainPower's pledge to provide the energy needs of our communities, now and in the future, as well as contributing to the growth of a vibrant and prosperous region while fulfilling our obligation as responsible custodians of the MainPower electrical distribution network.

This reporting year MainPower completed a review of its asset management practices, which highlighted an increased need for maintenance and asset renewals. At the same time the industry is facing significant transformation, driven by decarbonisation, decentralisation and digitisation (new energy future).

MainPower has committed to this future by investing in world-class technology for managing our network, including the need to achieve compliance with ISO 50001 for all business systems and processes.

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

This plan details how MainPower will invest prudently in our electrical 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 Kaikoura.

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').

Due to changes in the sector, our role is also changing. This requires a new approach and refreshed thinking of our strategic direction that ensures 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.

Our vision is to provide safe, secure, reliable and sustainable services for current and future generations.

Our mission is to partner in our consumers' energy future.

Our strategy seeks to strengthen the core business for the future, while generating new investments in the wider energy sector that leverage existing capability and resources to create opportunities and enable growth:

- **Strengthening our core business for the future**
  This means that asset management is fully aligned with our corporate goals. It also means that our business objectives and network performance is delivering what our consumers are telling us they want, while ensuring the network is ready for a 'new energy future', including operational readiness and effectiveness.
- **Creating new opportunities**
  This recognises that, in a new energy future, services beyond that of a typical electricity distribution network will present other opportunities that are possibly non-regulated, leveraging off our core business. Strategically, it is expected that such services will be that of a Distribution Energy Resource Management system (DERMs).

This reporting year (financial year ending 2019) saw strong demand growth on the network, including the highest coincident peak ever recorded on the MainPower electricity distribution network. MainPower continues to invest in the network while balancing cost, risk and performance.

The 'New Energy Future' remains a key focus for MainPower and we remain committed to investing in new technologies, including an Advanced Distribution Management System (ADMS) for enhanced network operations and reporting. This technology will also enable new technologies on the network, providing MainPower consumers with choice while enhancing the value of their assets.

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 to ISO 55001. During the year we embarked on a state of infrastructure review to understand holistically our network assets, linking condition and risk, while enabling a review of the High Impact Low Probability (HILP) risk of the electricity distribution network. We also commenced our journey to develop an organisation-wide Master Plan that will include a Networks Strategic Asset Management Plan. The Master Plan will align our asset management policy with our asset management practises.

We noted ambiguity when translating consumer requirements into actual electricity distribution network service levels. This year saw MainPower change the way we engage with our consumers and we now interact with them more directly on a range of topics that include quality of supply, resilience, pricing and the New Energy Future. This engagement will allow MainPower to make investment decisions based on what our consumers are telling us they want, now and in the future.

During the year ending 2019 we completed a redefinition of our maintenance across MainPower's entire asset portfolio. Results for the financial year to date remain positive including reducing SAIDI and SAIFI, increasing quality of supply and improving service levels to our consumers. This work also contributed towards enhanced capital investment decision-making, linking maintenance data to investment decisions across all asset portfolios, addressing cost, performance and risk.

A stronger emphasis has also been placed on understanding and managing safety and business critical risks. A workstream completed over four months involving more than 60 MainPower Staff identified ten safety-critical and four business-critical risks. This work also included the implementation of critical control observations (CCOs) in our risk and incident management system (Vault) that will provide better transparency of "work as done" and enable more accurate risk analysis of the effectiveness of our controls.

Currently, electricity distribution network performance (quality of supply) is unduly affected by planned works, which require MainPower to isolate power for the safety of our staff, contractors and public. As MainPower's electricity distribution network is predominantly rural, there is limited interconnectivity which sometimes limits our ability to redirect power.

MainPower also has embedded industry-based security of supply and asset maintenance standards. These have resulted in MainPower's continued investment in its network assets and, in the short term, resulted in increased outages as we replace high risk assets.

MainPower is committed to network performance and the quality of supply to our consumers. To assist in managing network performance in the future, MainPower is also investing in world-class network management technology that will allow MainPower to manage planned works more effectively. Furthermore, as our approach to asset management is embedded and as assets are renewed, the impact on network performance from unplanned outages will decrease.

Changing consumer behaviours, new technologies and a national transition to a low carbon economy will influence the way in which 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 now forms part of the Master Plan or Strategic Asset Management Plan.

2 Purpose of Our Asset Management Plan

This Asset Management Plan (AMP) covers a ten-year planning period, from 1 April 2019 to 31 March 2029. 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 during the next decade.

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 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 information disclosure requirements set out in the Electricity Distribution Information Disclosure Determination 2012, which includes:

- A summary;
- Background and objectives;
- Target service levels;
- Details of assets covered and lifecycle management plans;
- Load forecasts, development and maintenance plans;
- Risk management, including policies, assessment and mitigation;
- Performance measurement, evaluation and improvement initiatives.

A cross reference table showing how our AMP meets the regulatory information disclosure requirements is shown in Appendix A.

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 Valley north of Kaikōura, and from the Canterbury coast inland to the Lewis Pass. 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're committed to contributing to a bright future for our region by delivering an electricity distribution network that's ready for the future.

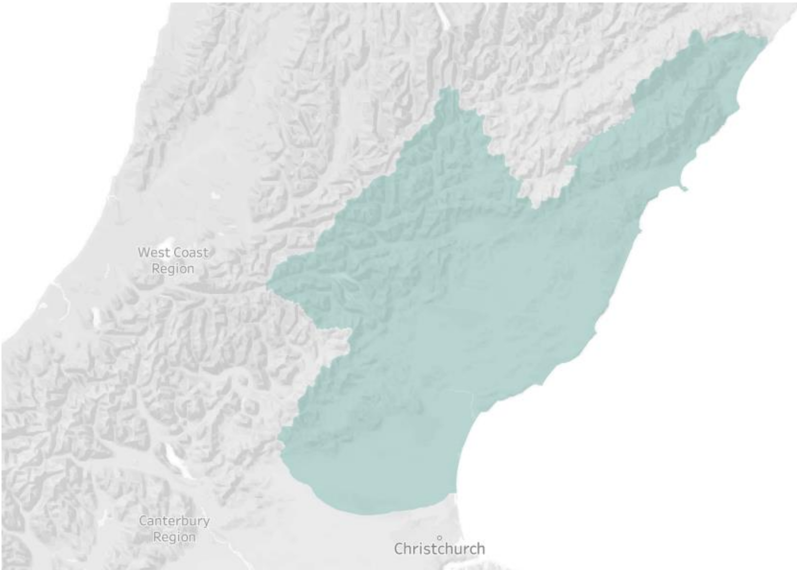

Figure 2.1: MainPower's Electricity Distribution Network Region

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

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

Our electricity distribution network connects to the New Zealand national grid at voltages of 66kV, 33kV and 11kV 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. GXP assets are owned mostly by Transpower, although we do 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 MainPower's Business Strategy

MainPower's AMP is informed by MainPower's Statement of Corporate Intent (SCI), our business plan which defines our organisational strategy, and our vision and values by which we operate. At a high level, we have two key pillars of strategic intent:

- Strengthening our core business for the future; and
- Creating new opportunities.

2.2.1 Strengthening our Core Business

Electricity distribution is our core business and the focus of our corporate goals. Readying the electricity distribution network for the New Energy Future while delivering on our consumers' expectations involves the following:

- Strategic asset management and operational excellence

  - Develop and improve our asset management and operational practices to ensure that MainPower is an effective and efficient asset management organisation that delivers value to the business, our consumers and shareholders, while achieving ISO 55001 compliance.
- Evolution to the electricity distribution network of the future
  - Continue to maintain and build on the value in our assets and services including the implementation of an Advanced Distribution Management System (ADMS);
  - Collaboration with other electricity distribution businesses (EDBs), delivering common architecture, access and competency – minimising risk across regions and developing regional resilience;
  - Transition from a Distribution Network Provider (DNP) to a Distribution System Integrator (DSI), offering an open architecture framework so that consumers can engage with other market participants that enables them to extract full value from their Distributed Energy Resources (DER);
  - Ensure that our operating systems and processes can offer Distribution System Operator (DSO) services in the future.

2.2.2 Creating New Opportunities

In a New Energy Future, services beyond that of a typical electricity distribution business (EDB) will present other opportunities. Currently it is anticipated that such services will be aligned with that of a Distribution Energy Resource Management system (DERMs). DERMs enable internal expertise and systems that provide a platform of asset management and operational excellence to deliver solutions that allow MainPower to ‘partner in our consumers’ energy future’.

2.3 MainPower’s Vision, Mission and Values

2.3.1 Our Vision

Provide safe, secure and sustainable services for current and future generations.

2.3.2 Our Mission

Partner in our customers’ energy future.

2.3.3 Our Values

2.4 Asset Management Framework

A key focus of MainPower’s approach to asset management is how we link our everyday asset management decisions and activities to our corporate objectives. This provides line-of-sight from our Statement of Corporate Intent and corporate objectives, through our asset and electricity distribution network strategies, to our implementation plans and performance evaluation. Our asset management framework is shown in Figure 2.3 below.

The key elements ensuring line-of-sight for our asset management strategy include:

- **Vision, Mission and Values:** Define how we conduct our business and underpin all that we do.
- **Asset Management Framework:** An overview of how our asset management elements fit together and the decision-making structure we employ.

- **Asset Management Policy:** Outlines MainPower's commitment to asset stewardship and guides our asset management approach.
- **Asset Management Strategy:** Defines our asset management goals and how we implement our corporate objectives.
- **Asset Portfolio Plans:** Outlines how we deliver our asset management, through 10-year investment, operating and maintenance plans. These are outlined in Section 7.

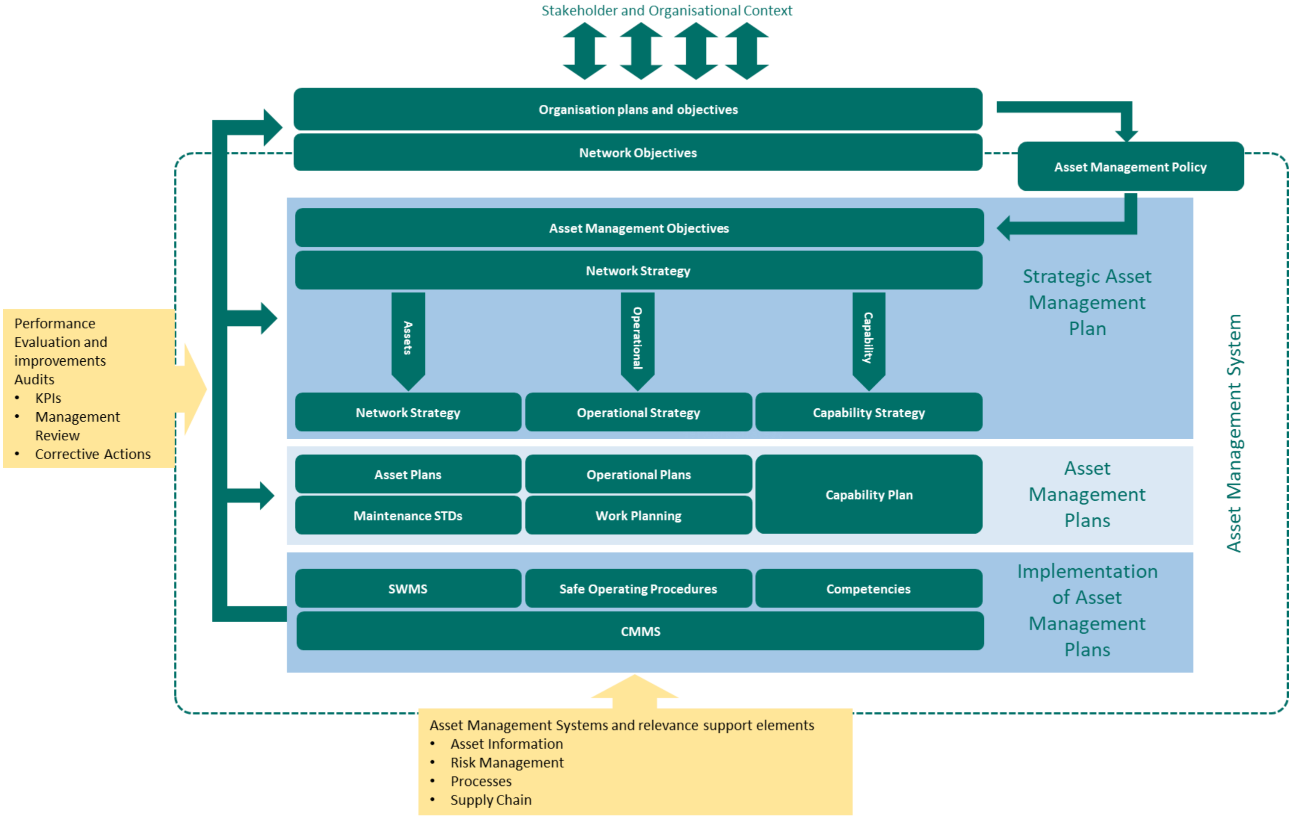

Figure 2.3: Asset Management System

2.5 Asset Management Policy

Our Asset Management Policy supports our corporate vision, values and strategic objectives. It provides a framework for efficient and effective asset management practices to consistently deliver safe, secure and sustainable energy services for current and future generations. The policy describes our commitment to asset management while our AMP sets out how we implement it. We are committed to regular review of our processes and systems to ensure continual improvement.

- Ensure we comply with laws, regulations, standards and industry codes of practice.
- Make sure customer 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 practices, systems and techniques.
- Apply performance monitoring and benchmark against industry.
- Apply a risk-based approach to managing our assets, balancing cost, performance and risk.
- Ensure network growth delivers consumer requirements, while facilitating regional development.

- Utilise effective business systems and processes, roles and responsibilities.
- Enable industry collaboration by creating industry partnerships that enable and support innovation.

- Manage competence and training.
- Plan our activities effectively.
- Optimise operations and do it right, first time.

2.6 Asset Management Strategy

2.6.1 Asset Lifecycle Framework

MainPower needs to ensure that its electricity distribution network is ready for decarbonisation, decentralisation and digitisation (New Energy Future) as New Zealand prepares for a zero-carbon economy, the onset of new technologies and multi-way energy flow. At the same time, we continue to understand and balance cost, risk and performance.

Within the last reporting period MainPower has taken a fresh look at our asset management systems, processes and practices, through both internal and external audits. Both audits identified gaps between current state and where we want to be in terms of future asset management maturity.

In the last AMP it was noted that MainPower had embarked on the critical review of our asset management systems, processes and practices. A key part of assessing our level of maturity was the use of the Commerce Commission's Asset Management Maturity Tool (AMMAT).

This year MainPower completed a review and assessed the whole organisation against ISO 55001. One of MainPower's strategic themes is 'strategic asset management and operational excellence' with a business objective of achieving ISO 55001 compliance, taking into consideration:

- The New Energy Future and our goal of delivering an electricity distribution network for the future;
- Providing a strategic approach to asset management balancing cost, risk and performance; and
- MainPower's accreditation to ISO 9001.

2.6.2 Strategic Asset Management

Asset management at MainPower means that we understand risk, cost and performance across our asset fleet over the lifetime of the assets.

The system also takes into consideration the differing resourcing constraints that occur from time to time, and clearly articulates to the business the risks impact that the constraints will have across the asset fleet.

To fully achieve this across the life of our assets requires MainPower to implement Strategic Asset Management within our Enterprise Resource Planning (ERP) system OneAsset (TechOne).

2.6.3 Asset Management Structure

The structure of MainPower's asset management system is based on the International Infrastructure Management Manual (IIMM), which defines 18 processes of asset management, grouped into three main categories.

The relationship between these categories is shown in Figure 2.4 below, which includes a summary of the associated documents that support the framework. The process is based on a continuous improvement cycle.

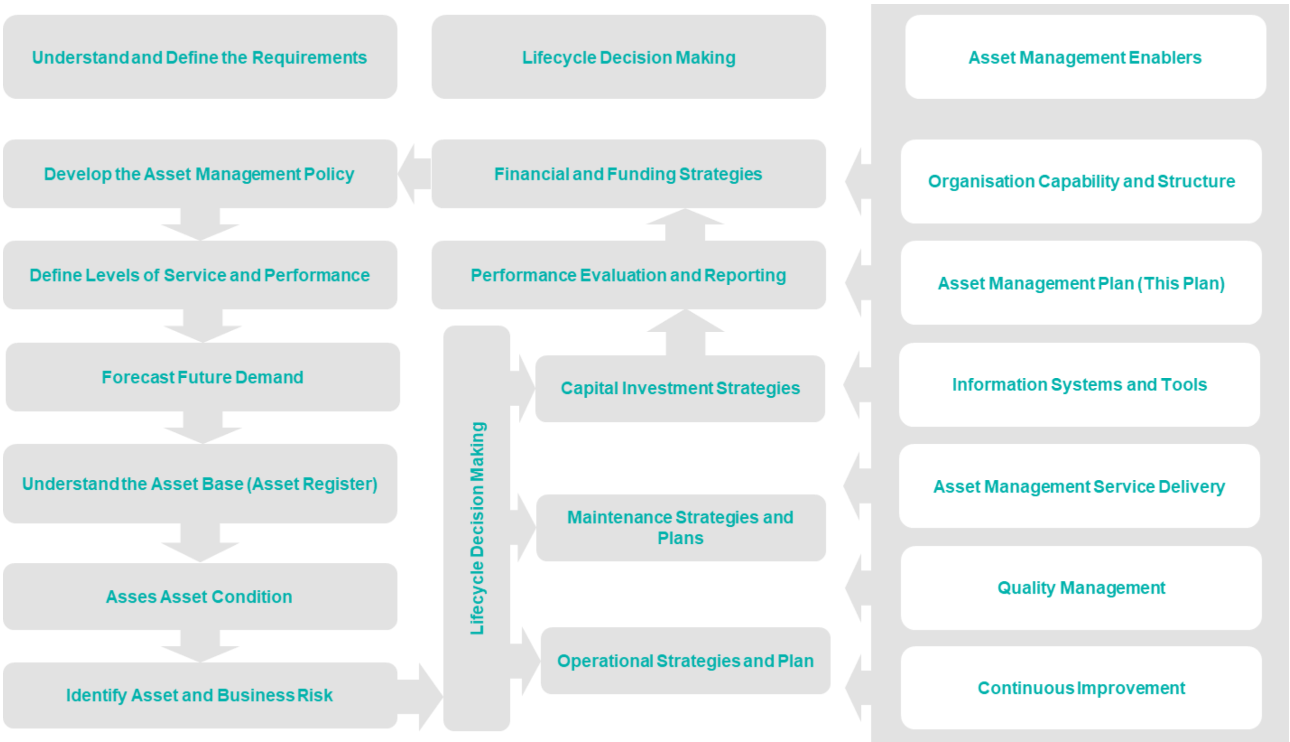

Figure 2.4: Asset Management Structure

ASSET MANAGEMENT	
Develop the Asset Management Policy	MainPower has an Asset Management Policy.
Define Levels of Service and Performance	Defined in this Asset Management Plan (Section 3).
Forecast Future Demand	Regional Master Plans are being developed as described in Section 6 of this Asset Management Plan.
Understand the Asset Base (Asset Register)	Entered and maintained within MainPower's Enterprise Resource Planning (ERP) tool (TechOne).
Assess Asset Condition	Completed and updated through general maintenance. Maintenance requirements are documented in Asset Class Maintenance Plans that are implemented in the ERP as schedules against assets.
Identify Asset and Business Risk	Detailed in Section 4 of the Asset Management Plan, risk assessment as completed by business function, activity, plant and equipment, including electricity distribution network operability risk when assessed against adverse events.

Financial and Funding Strategies	Ongoing and form part of the pricing review project currently in progress.
Capital Investment Strategies	Part of the maintenance strategies, asset condition and criticality, assesses renewals and forecasts budgets. As part of the Project Delivery System (PDS), the capital sanctioning process ensures funding is allocated in accordance with strategy, service delivery and business planning.
Maintenance Strategies and Plans	Maintenance strategies exist for all assets, detailing maintenance requirements to achieve consumer service levels and business outcomes. Maintenance strategies are implemented in the Computerised Maintenance Management System (CMMS).
Operational Strategies and Plan	All operational activities are risk assessed and, where the risk appetite of MainPower is exceeded, 'Safe Operating' procedures are developed. Other operational planning takes into consideration incident responses and emergency preparedness.

Table 2.1: Asset Management Components

2.6.4 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. These activities are outlined in Figure 2.5 below.

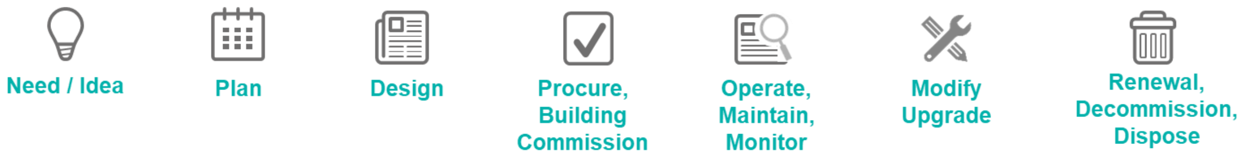

Figure 2.5: Asset Lifecycle Planning

- **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 to the project.
- **Plan a Project:** The project plan sets out the specific requirements of the project. This includes a definition of the requirements, timelines, resourcing, procurement, and risk. The project manager is responsible for the project plan and delivering the project against the plan. The project sponsor approves the plan and provides oversight throughout the project.
- **Design Phase:** A completed design is a design that is informed by the requirements of the project, design criteria and standard design. We must complete the design, only then is the design fit for achieving the outcomes of the project. The Asset Manager must approve the asset before the design process introduces it. All assets on the MainPower electricity distribution network are approved by the Maintenance Manager.
- **Construct:** The Project Management Office (PMO) is responsible for project delivery, as detailed within the MainPower Project Delivery System. Only when the assets have a Fleet Management Plan, are entered into the CMMS, have maintenance schedules against the asset and all asset data is reflected in our GIS, can 'Practical Completion' be issued and the asset put into service or energised.
- **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 asset condition and criticality inform asset renewal. Asset condition is a function of many considerations, accumulating as an Asset Health Indicator (AHI). Maintenance activities, asset condition, compliance, AHI and asset criticality determine an asset renewal that is assessed against cost and risk to the business.

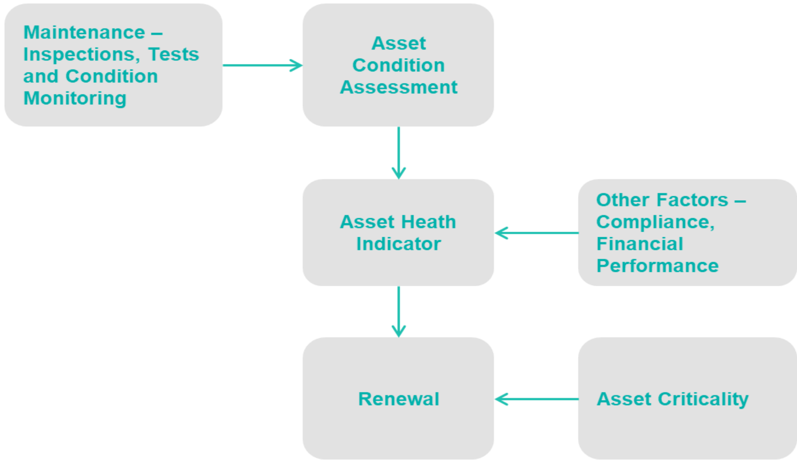

Figure 2.6: Maintenance Process for Asset Renewal

2.7 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 2.7 shows our stakeholder groups.

Figure 2.7: Our Stakeholder Groups

2.7.1 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 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 refers to our customers as consumers.

2.7.2 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 the table below.

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 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 Shareholder)	• Direct current feedback/interactions • Events (including Annual Meeting) • Operational interface • Other engagement activities
Government	• Disclosure requirements • Submissions on discussion papers
Regulators	• Adherence to corporate policies • Disclosure requirements • Operational interface
Regional Government	• 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 (Customers)	• Direct current feedback/interactions • Industry collaboration • Informal contact/discussions • One-on-one meetings • Open days • Public meetings and information sessions
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

2.7.3 Summarising the Interests of Our Stakeholders

The expectations of our stakeholders are summarised in the table below.

STAKEHOLDER	EXPECTATIONS
Connected Consumers	• Accessibility – easy to contact my provider, if needed • 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
Regional Government	• 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
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.

2.7.4 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
5. Efficiency and effectiveness

2.8 Accountabilities and Responsibilities

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

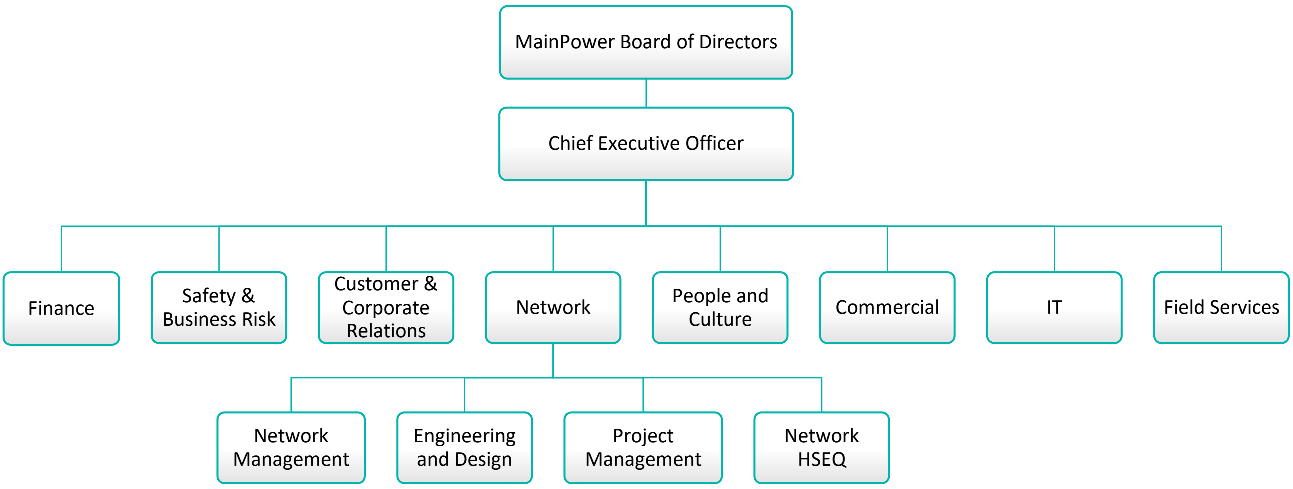

Figure 2.8: Organisational Management Structure

2.8.1 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.

2.8.2 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 Chief Executive of MainPower is accountable to the Board through an employment agreement, which includes performance criteria.

The Asset Management Plan 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 group includes a Board Director, the General Manager Network, the Chief Information Officer, General Manger People and Culture, Network Manager and Network Operations Manager. 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. To date, the group has met as required, but intends to meet quarterly in this reporting cycle.

2.8.3 Electricity Distribution Network Management

The electricity distribution network team has accountability for asset management and overall electricity distribution network performance. The electricity distribution network team is structured on a 'Plan, Build, Operate' basis.

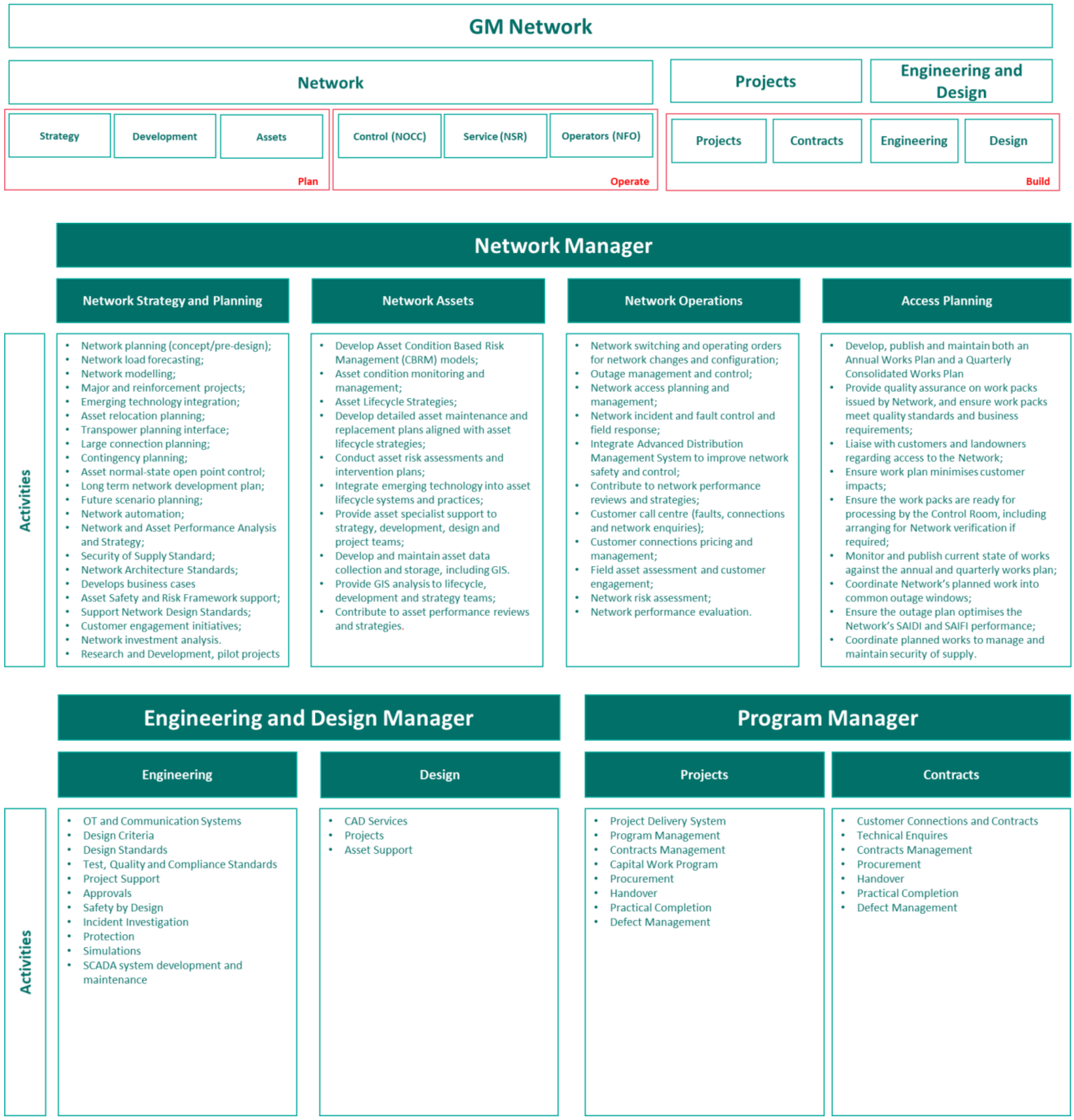

Figure 2.9: Electricity Distribution Network Management Team

2.8.4 Field Services

All field services are managed in-house including the use of external contractors. The work programme is assessed and, where resourcing gaps are identified or where MainPower does not have the in-house capability, the works will be outsourced. 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.

2.9 Assumptions Made

2.9.1 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.
- It is possible that a significant renewable energy project (Mt Cass Wind Farm) may obtain approval to proceed within the next reporting cycle. The requirements to connect Mt Cass to the grid is not documented in this AMP.
- Small grid connected Distributed Generation (DG) 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 2019, without inflation).
- Transpower continues to provide sufficient capacity to meet MainPower's requirements at the existing GXPs and undertakes additional investment required to meet future demand, as specified in the development plan.
- MainPower's existing corporate vision and strategic objectives continue for the planning period.
- Neither MainPower's electricity distribution network nor the local transmission grid is exposed to a major natural disaster during the planning period.
- Our electricity distribution network is exposed to climatic (temperature, wind, snow and rain) variation during the planning period, consistent with our experience since 2000.
- Seasonal load profiles remain consistent with recent historical trends.
- Zoning for land use purposes remains unchanged during the planning period.
- Electric vehicle charging loads are not likely to significantly impact electricity distribution network constraints within the planning period.

2.9.2 Sources of Information

The principal sources of information relevant to this AMP are listed below:

- 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.
- Interaction with consumers and the community in relation to possible future developments within the electricity distribution network region.

2.9.3 Forecasting Certainty

We have assessed the level of certainty of forecasts relevant to different consumer groups within our AMP planning period as follows:

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

2.9.4 Escalation Index

Our input prices are subject to a range of cost pressures including those that apply to skilled and unskilled labour, material components (such as 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 the table below.

Year	FY2021	FY2022	FY2023	FY2024	FY2025	FY206	FY2027	FY2028	FY2029	FY2030
Index	1.000	1.017	1.038	1.058	1.080	1.104	1.129	1.157	1.185	1.214

Table 2.5: Escalation Index based on Westpac Inflation Index

2.9.5 Sources of Uncertainty

MainPower considers the following factors could lead to material differences in actual versus planned. However, as this plan is updated annually, it is expected that any differences would exhibit as a linear (i.e. not a step) change and would be anticipated in advance.

Changes in demand factors most significantly impact future development plans. Higher than forecast growth brings forward the need for investments in additional capacity, security or reliability or increased load management, while lower than expected growth allows them to be deferred (in some cases).

Uncertainties within our demand assumptions include:

- 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 OPEX in the short term and increase or decrease OPEX or renewals allowances in the medium term. Changes may include:

- The electricity distribution network could experience major natural disasters such as an earthquake, flood, tsunami or extreme storms.
- Significant storm events that divert resources from scheduled maintenance.
- Regulatory requirements may change, requiring MainPower to achieve different service standards, health and safety standards, or design or security standards.

2.10 Information Systems, Processes and Data

MainPower's lifecycle asset management processes are informed by total cost of ownership. Asset Maintenance Standards exist for all MainPower assets as well as defined maintenance treatments for all assets. The Asset Maintenance Standards are informed by the business objectives and Asset Management Policy and are implemented within MainPower's Computerised Maintenance Management System (CMMS).

2.10.1 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 maintenance that delivers corporate objectives.

Maintenance standards that define what treatment we apply to our assets are implemented within the CMMS OneAsset system. Schedules and template work orders are applied to assets. The template work orders are developed to support all MainPower Asset Management Standards and detail the work required to be completed, including the acquisition of condition data, into the work order that support strategic asset management and enables MainPower to balance cost, risk and performance.

All resource planning can then be achieved by linking works as required, through to supply chain management, to actual business planning and forecasting.

Figure 2.10: OneAsset System

2.10.2 One Source of the Truth

The MainPower Asset Database is the single source of truth for all asset data and asset attributes. All asset data is defined and recorded against the asset in the single OneAsset system. All other systems that report asset data, such as the GIS, retrieve data from the OneAsset system. All data used for the condition assessment of assets is recorded within the OneAsset system, including the mobility solutions where data is entered by field staff.

2.10.3 Asset Operational Systems

The main system that is used to operate our assets is our SCADA (Supervisory Control and Data Acquisition) system. The SCADA system also logs historical loads on all equipment, informing our electricity distribution network development planning and ensuring load flow is within asset limits when reconfiguring the electricity distribution network for emergency response of planned outages.

2.10.4 Outage Management System

Our own, in-house developed, Outage Management System (OMS) is used to track outages and inform electricity distribution network quality performance reporting.

2.10.5 Asset Data

Asset data is critical to inform asset lifecycle and total cost of ownership, including disposal. The data required to support this is achieved within the design phase of the asset lifecycle and is typically achieved through:

- Design data.
- Compliance requirements.
- Industry experience (EEA Asset Management Group).
- Manufacturer’s requirements (operating and maintenance manuals).
- Business risk including environmental and operating risk.

Once a need for an asset is identified and approved by the Asset Manager, an Asset Fleet Management Plan is developed for all new assets or updated where existing fleet plans exist. The fleet management plans ultimately translate maintenance lifecycle requirements in the form of schedules of work. All assets are implemented in MainPower's Computerised Maintenance Management System (CMMS). Once in the system, it is the Maintenance Manager's role to implement the Fleet Management Plan against the asset, i.e. applying schedules of work against the asset.

When assets are enabled in the CMMS and schedules are assigned to the assets, the CMMS develops 'work orders' for the ongoing management of assets. Work order templates define the work required, including the data collection points for capturing works completed and maintenance outcomes that inform the condition of the asset.

2.11 Limitation of Asset Data and Improvements

MainPower has good information on our assets. The main focus in the future is to centralise all asset data into a single source of information (OneAsset / OneEnergy ERP), including vegetation. This will provide the foundation for automated logging of maintenance and condition assessment of all maintenance activities. All maintenance activities allow for asset data to be updated through inspections or routine maintenance.

MainPower has completed a review of our asset data, including consistency of data across multiple systems and the ability of data to support future strategic asset management. While the data currently supports MainPower's AMP and work programme, a number of gaps were identified. Also, our asset data needs to improve given the requirement to consider the 'New Energy Future'. This is discussed further in Section 3 – Asset Maturity.

2.12 Planning and Maintenance Processes

2.12.1 Electricity Distribution Network Planning

All electricity distribution network projects are assessed against:

- Capacity constraints; and
- Security of supply and reliability classification for feeders and zone substations.

At this point the following treatments are applied:

- Electricity distribution network constraints are identified by reviewing the capacity and the security of the electricity distribution network on a regular basis against electricity distribution network standards and policies.
- Should a constraint be identified, options for addressing it through reconfiguration of the electricity distribution network (e.g. by moving an open point) will be considered first, to optimise the use of existing electricity distribution network capacity.
- Should no reconfiguration options be available using the existing electricity distribution network infrastructure, then other options will be investigated as part of the investment selection process.
- The options may include both electricity distribution network (installation of new lines, cables and transformers, voltage regulators or capacitors to create new capacity or allow utilisation of nearby capacity) and non-electricity distribution network solutions (such as localised generation or demand-side management initiatives).
- Key inputs to the capacity and reliability review are the overarching planning criteria and load forecasts, which are updated on a yearly basis.
- The Development Plan includes potential projects identified to meet a need. This plan continually evolves.
- Each year, the immediately prioritised projects are developed in more detail, including business case assessments against alternatives.
- Project approvals are sought (refer below) and scheduled.
- Most development projects are delivered by MainPower's own field staff.

2.12.2 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 below, including the need to work within a controlled environment, the issuing of authorisation and receiving of asset condition data that is used to manage defects, inform renewals, etc.

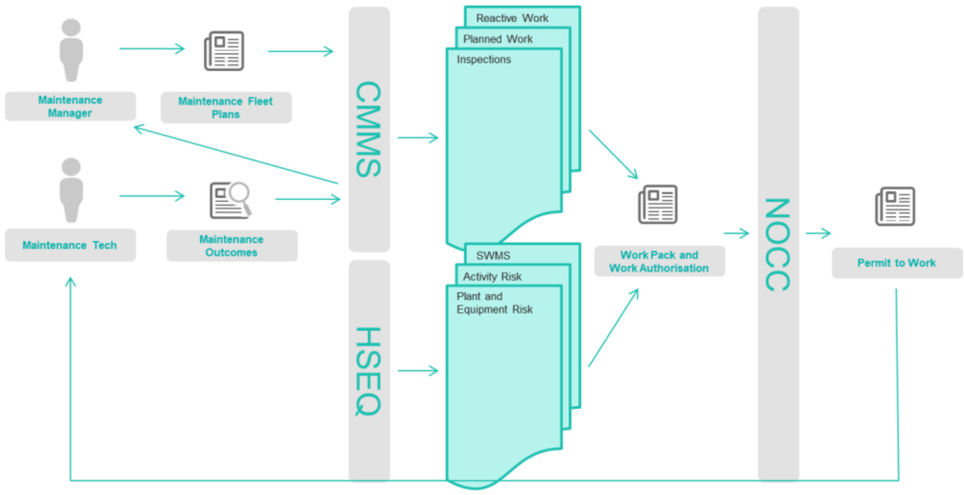

Figure 2.11: Asset Management Workflow Process

- The CMMS, either through preventative maintenance, faults (reactive) or defects, generates work orders detailing the work to be completed on the asset. Defects are managed in accordance with MainPower's defect management policy.
- All work activities are predefined within MainPower's work management system as rate cards. Activities are also linked to maintenance schedules. All activities are risk assessed, and appropriate controls and competencies determined.
- Work is issued to field services via the work order system within the CMMS. Work orders are linked to schedules that are linked to assets. The work orders contain data collection points to record maintenance activity outcomes, informing compliance, asset condition, defects and future renewal.
- Permits to work (or 'Work Authorities') are issued for all work via MainPower's Network Operation and Control Centre (NOCC). For all works, competency is assessed then authority is issued.
- All costs associated with completing the works are logged against the work order and reflected back through to the asset. This information is used to inform total cost of ownership. Service levels are assessed against maintenance outcomes and cost. Fleet asset management plans are then updated as required, as part of our commitment to continuous improvement.

2.12.3 Network Development Process

- Network constraints are identified by reviewing the capacity and the security of the network on a regular basis against network standards and policies.
- Should a constraint be identified, options for addressing it through reconfiguration of the network (e.g. by moving an open point) will be considered first, to optimise the use of existing network capacity.
- Should no reconfiguration options be available using the existing network infrastructure, then other options will be investigated as part of the investment selection process.
- The options may include both network (installation of new lines, cables and transformers, voltage regulators or capacitors to create new capacity or allow utilisation of nearby capacity) and non-network solutions (such as localised generation or demand-side management initiatives).
- Key inputs to the capacity and reliability review are the overarching planning criteria and load forecasts, which are updated on a yearly basis.

- The Development Plan includes potential projects identified to meet a need. This plan continually evolves.
- Each year, the immediate prioritised projects are developed in more detail, including business case assessments against alternatives.
- Project approvals are sought (refer below) and scheduled.
- Most development projects are delivered by MainPower's own field staff.

2.12.4 Measuring Electricity Distribution Network Performance

- Our outage management system is GIS based, with all planned shutdowns managed with traces across the GIS to identify all affected consumers 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.
- Where supply is restored progressively through switching over a period of time, the switching sequence will be recorded and used as the basis for recording the actual SAIDI impact on consumers.
- Other measures are recorded with information extracted from GIS (such as line length), consumer surveys, metering information, financial systems, and our health and safety and risk management databases.

Currently MainPower is delivering an Advanced Distribution Management System (ADMS) project that links our Outage Management System (OMS), Supervisory Control and Data Acquisition (SCADA) and Distribution Management System (DMS). The goal of the project is to ensure MainPower's electricity distribution network is ready for a New Energy Future, within a safe, secure and sustainable management system that allows MainPower to drive continuous improvement through performance monitoring.

2.13 Documentation and Controls

2.13.1 Asset Management Documentation

Asset management documentation links organisation context through to business goals and objectives to operation and maintenance and includes:

- Assets;
- Asset management policies;
- Asset Management Plan;
- Asset Maintenance Standards;
- Standard designs;
- Construction specifications;
- Operational requirements;
- Operating standards (SOP, SWMS etc.);
- Process flows;
- Work instructions;
- Business continuity planning;
- Capability;
- Individual development plans;
- Competency and training registers;
- Contractor management controls.

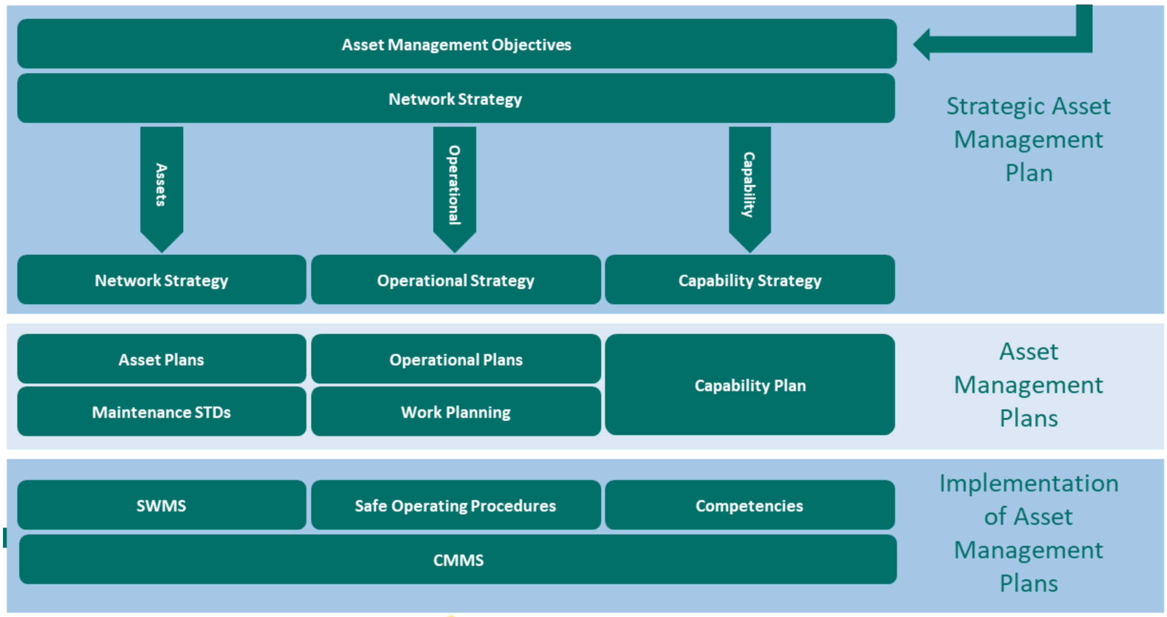

Figure 2.12: Asset Management Documentation

2.13.2 Document Management and Review

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

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

2.13.3 Outsourcing

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.

2.14 Communication and Participation

MainPower communicates its Asset Management Strategy, objectives and outcomes to stakeholders as follows:

REPORTING 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	• Company Annual Report includes Chair and Chief Executive’s statements and audited accounts. • Annual information disclosure. • Twice-yearly presentation includes financial and operational performance.
Chief Executive to MainPower Board	• Chief Executive’s statement in Annual Report includes narrative of year’s highlights. • Monthly Board report, includes progress on capital and maintenance program. • 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 includes 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 report team meetings. • One-on-one with direct managers. • Daily updates during brief meetings including health and safety updates. • Annual 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 electrical 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, our stakeholders and better understanding their needs. This allows us to continuously monitor and improve the services we provide 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. Partners include retailers as well as distributed generation (DG) owners and operators. Understanding consumer expectations, monitoring and improving the service MainPower provides is vital if we are to establish and maintain trust and goodwill with consumers and our stakeholders throughout our region. We do this by actively consulting with our consumers and seek to better understand their needs now, and in the future. The electricity industry is entering a time of transformation as emerging technologies change the way consumers use and manage energy.

Consumer Type	No. of ICPs	% of ICPs	Units Delivered (GWh)	% of Units Delivered
Residential	33,492	80.6%	267	45%
Commercial	6,269	15.1%	122	21%
Large commercial or industrial	48	0.1%	62	10%
Irrigators	1,418	3.4%	62	10%
Council Pumps	203	0.5%	12	2%
Streetlights	113	0.3%	3	1%
Individually managed Consumer	1	0.0%	65	11%
Total	**41,544**	**100%**	**593**	**100%**

Table 3.1: Consumption and Consumers by Category

3.1.1 Consumer Engagement Workshops

During the past year we held a series of workshops with consumers across our three main regions: Waimakariri, Hurunui and Kaikōura. Groups of around 20 consumers in each region explored 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. The workshops were designed to further enhance MainPower engagement with its consumers in relation to asset management. The engagement has provided great insights into how MainPower will balance cost, risk and performance of its electrical distribution network.

3.1.2 Online Consumer Surveys

MainPower commissioned an independent organisation during 2019 to conduct an online survey with more than 1200 respondents to further 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 have contacted MainPower over the past year regarding services such as faults, new connections, network extensions or asset relocations. This information has helped us provide a better consumer experience when our consumers contact us and ensure that we continually improve and meet their expectations.

3.2 What Consumers Have Told Us

Our engagement workshops and surveys 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 following key components of our asset management strategy:

- **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).

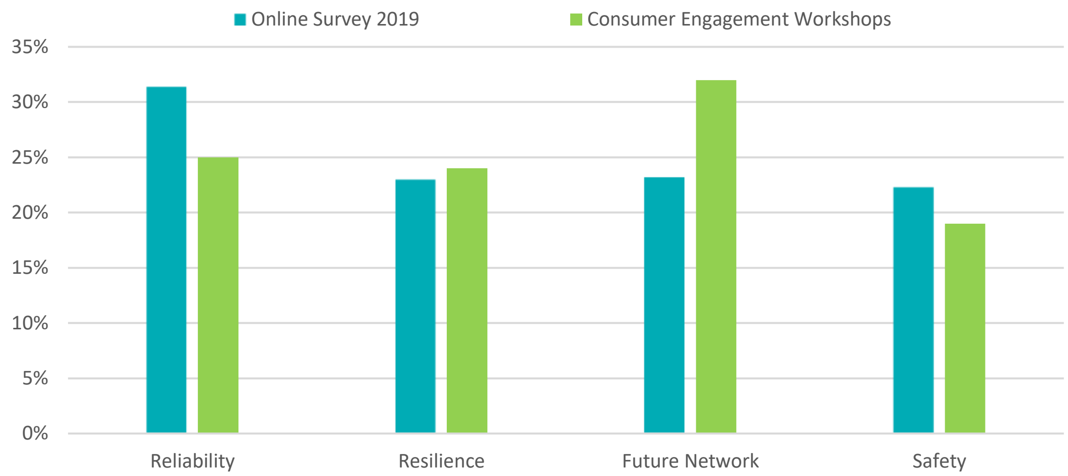

Figure 3.1: Overall Importance of Asset Management Focus Areas (Note: as this was focused on network investment, pricing was excluded)

3.2.1 Consumers - Reliability

Overall, consumers viewed network reliability as the top priority. As an electricity distribution business, consumers are reliant on MainPower and 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 showed that more than 90% of 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.

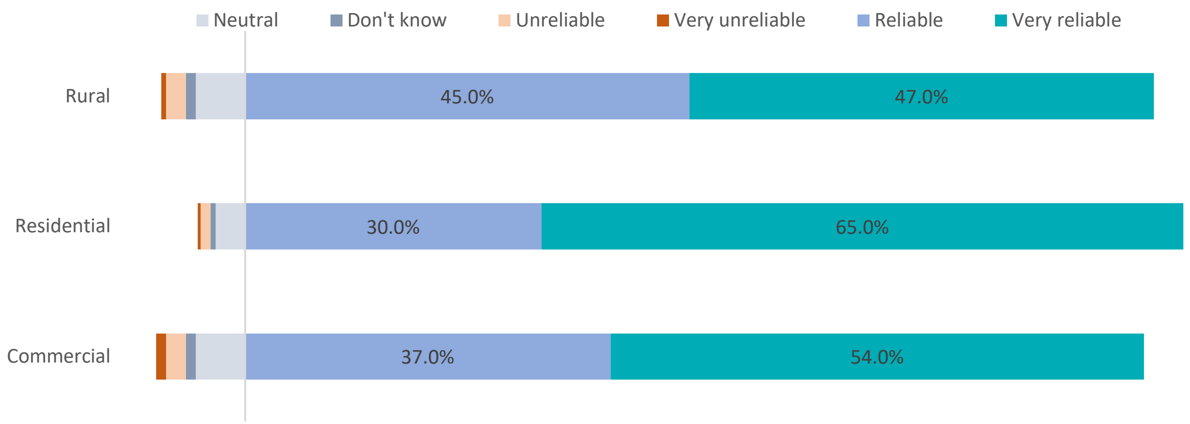

Figure 3.2: MainPower Consumers' Perception of Network Reliability (Online Survey 2019)

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, and often occur in timeframes that do not allow retailers to contact their consumers. As shown by Figure 3.3 below, more than 60% of consumers expect notification of an unplanned outage in less than an hour, with key information indicating what caused the outage and when supply will likely be restored. This indicates consumers expect MainPower to be proactive and timely with its communication.

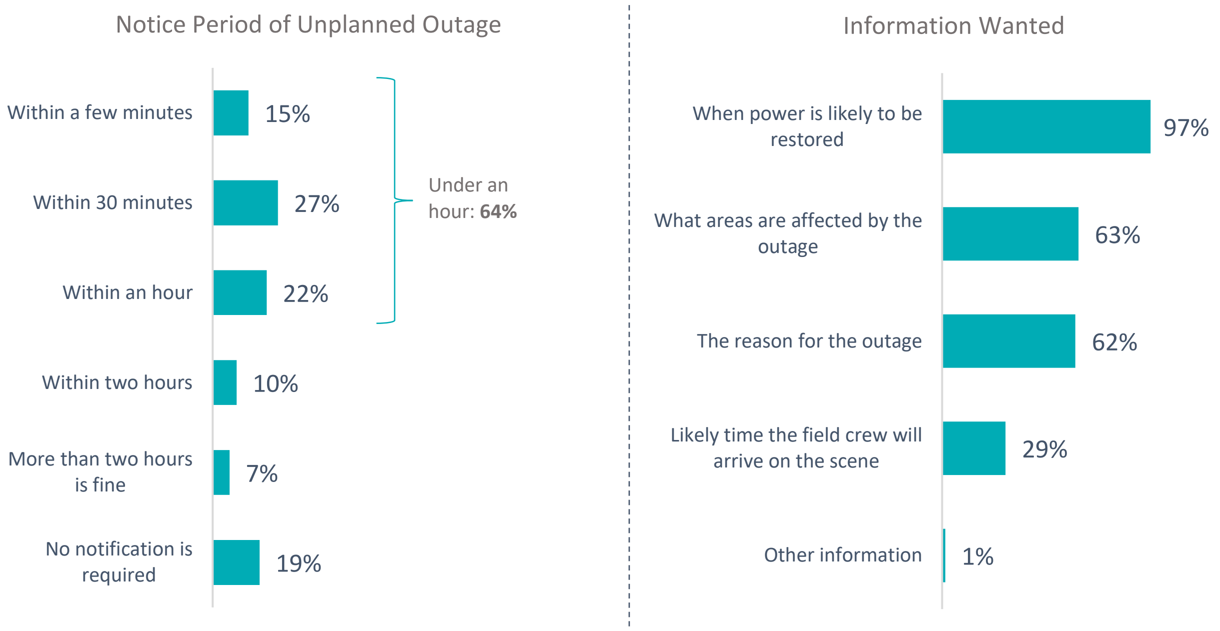

Figure 3.3: MainPower Consumers' Expectations for Unplanned Outage Notifications (Online Survey 2019)

3.2.2 Consumers - Resilience

Our customers are telling us our level of resilience is meeting their expectations and MainPower's balanced investment in resilience is worthwhile. Nearly three-quarters of consumers surveyed indicated that a reasonable restoration time following a significant rare event such as an earthquake or snowstorm is between 12 and 48 hours, rather than weeks. Rural consumer groups throughout the engagement workshops tended to be slightly more self-resilient during longer periods without power than the commercial consumers, who tended to be less resilient and felt they would need power restored sooner.

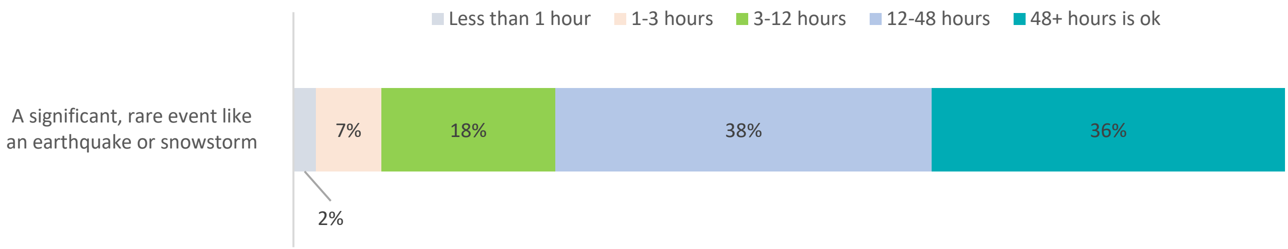

Figure 3.4: MainPower Consumers' Expected Restoration Time Following a Significant Event (Online Survey 2019)

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 impact 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 and interest in emerging technologies and are driven 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, with 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.

Survey respondents showed high levels of awareness in interest in solar technology and electric vehicles. However despite their awareness of solar energy, all respondents show lower levels of knowledge of complementary technologies like energy management systems and peer-to-peer energy trading.

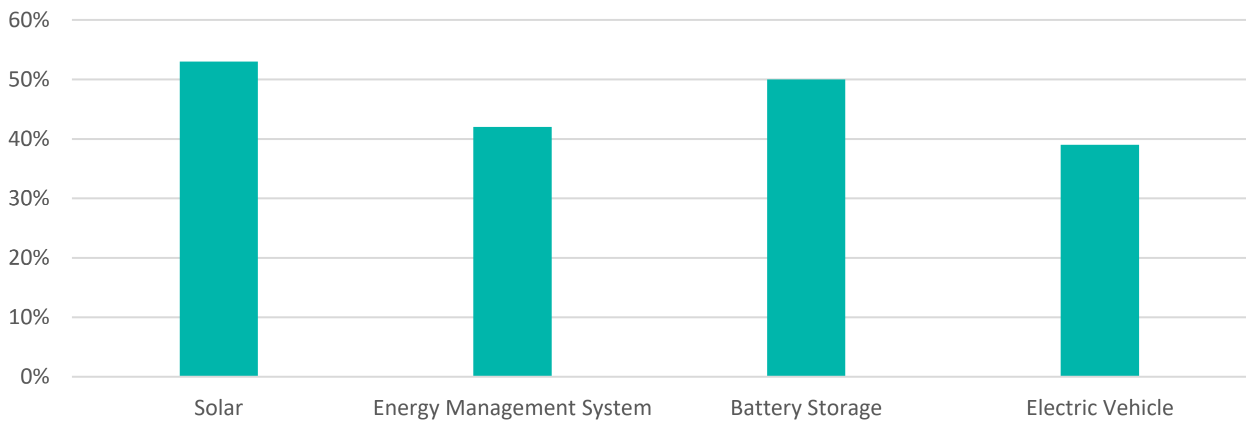

Figure 3.5: MainPower Consumers who either Currently Own or are Considering Owning the Respective Technologies Within the Next 10 Years

Along with interest in new technologies, our consumers also indicated they are considering ownership of these technologies within the 10-year period. Solar, followed closely by battery storage, are currently the most considered technologies with consideration of electric vehicles sitting just below 40%. Consumers identified cost of these technologies 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 90001. This is applied against the Performance Indicators as described below.

Figure 3.6: MainPower's Performance Indicator Continuous Improvement Process

3.3.1 Inputs

- Consumer expectations from consumer engagement surveys and workshops (discussed in section 3.2).
- Analysis and industry benchmarking across our peer group (discussed in section 3.6).

3.3.2 Planning

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

- Security of Supply Standard.
- Asset Portfolio Strategies, including Asset Health (CBRM) models.
- Project and Works Delivery Planning and Processes.
- Network Operating Standards.
- Network Architecture Standards (To Be Completed 2020).
- Network Reliability Strategy (To Be Completed 2020).

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.
- Refined network engineering and design practices.

3.3.4 Performance Monitoring

- Internal data analytics of historical service levels, including feeder reliability, root cause and common mode failure analysis, and applying predictive modelling.
- Network service level performance is continuously monitored with analysis of network outages, monthly reporting of SAIDI and SAIFI 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 Electrical 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:

- **SAIFI** (System Average Interruption Frequency Index), which measures the average supply interruptions for each consumer during the year.
- **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 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 are exploring ways to better measure MainPower's network and business resilience and response capability.

We are investing in an Advanced Distribution Management System to help provide better visibility and control of our network. We also see an opportunity to further improve both network restoration and resilience performance through improved network architecture aligned with our Security of Supply Standard (Section 6), and enhancing our remote sensing and switching capability throughout the network.

3.4.4 Health Safety and 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.

AWARENESS OF SAFETY MESSAGING

Figure 3.7: Customer Pulse Survey 2019

Our objectives are to:

- Identify, manage and communicate hazards and 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 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 the responsibility we have to strive for environmental sustainability. In addition to our business environmental sustainability drivers, our current network environment measures include:

- **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:** We have assets on our network that use oil as an insulating medium. We use a range of containment and mitigation solutions to prevent or minimise the impact of potential spills. Our annual target is zero 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 will 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 engaging with consumers through our pulse survey where we monitor:

- Engagement Effort – how easy is doing business with MainPower?
- Staff Friendliness – ensure that the engagement is proactive and result oriented.
- Quality of Work – we deliver a standard of work that is aligned with our consumers' expectations.
- Timeliness – work is delivered in accordance with our consumers' expectations.
- Communication – we communicate with our consumers proactively.
- Staff Reliability – our staff deliver services to our consumers as agreed.
- Price – 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 how we are tracking to achieve the required maturity level. We also review overall organisational financial indicators and how we performed 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:

- 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 Target**		**Future Performance Target**				
			FY19	**FY20**	**FY21**	**FY22**	**FY23**	**FY24**	**FY25-FY31**
Reliability	SAIDI – System Average Duration Index	Average minutes lost per customer per year	124	340	332	318	306	294	260
	SAIFI – System Average Frequency Index	Average number of times a customer's supply is interrupted per annum	1.58	1.73	2.18	2.07	1.96	1.87	1.6
	Feed Reliability	None – forward indicator only							
	Unplanned interruptions restored within 3 hours	% of unplanned interruptions where the last customer restored in less than 3 hours	No Targets Set (New)		81%	83%	59%	75%	72%
HSEQ	Safety of workers	No injuries related to a Safety Critical Risk	None						
	Safety of public	No injuries to members of the public	None						
	SF6 gas lost	Gas lost as % 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	> 2.5	> 3	> 3	> 3.5	> 4
	Staff friendliness		4	4.5	> 4	> 4	> 4	> 4	> 4
	Quality of work		4	4.5	> 4	> 4	> 4	> 4	> 4
	Timeliness of service		4	4.5	> 3.5	> 4	> 4	> 4	> 4
	Communication		4	4.5	> 3.5	> 4	> 4	> 4	> 4
	Staff reliability		4	4.5	> 4	> 4	> 4	> 4	> 4
	Final price		3.5	4	> 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%
	Financial performance								
	Industry benchmarking	Assess ourselves against • Operating Expenditure per ICP • Capital Expenditure per ICP • Quality of Supply (SAIDI and SAIFI) • Non network Opex per ICP	<75th Percentile	<75th Percentile	<75th Percentile	<75th Percentile	<75th Percentile	<75th Percentile	<75th 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. 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 inform forward network related projects and internal workstream improvements.

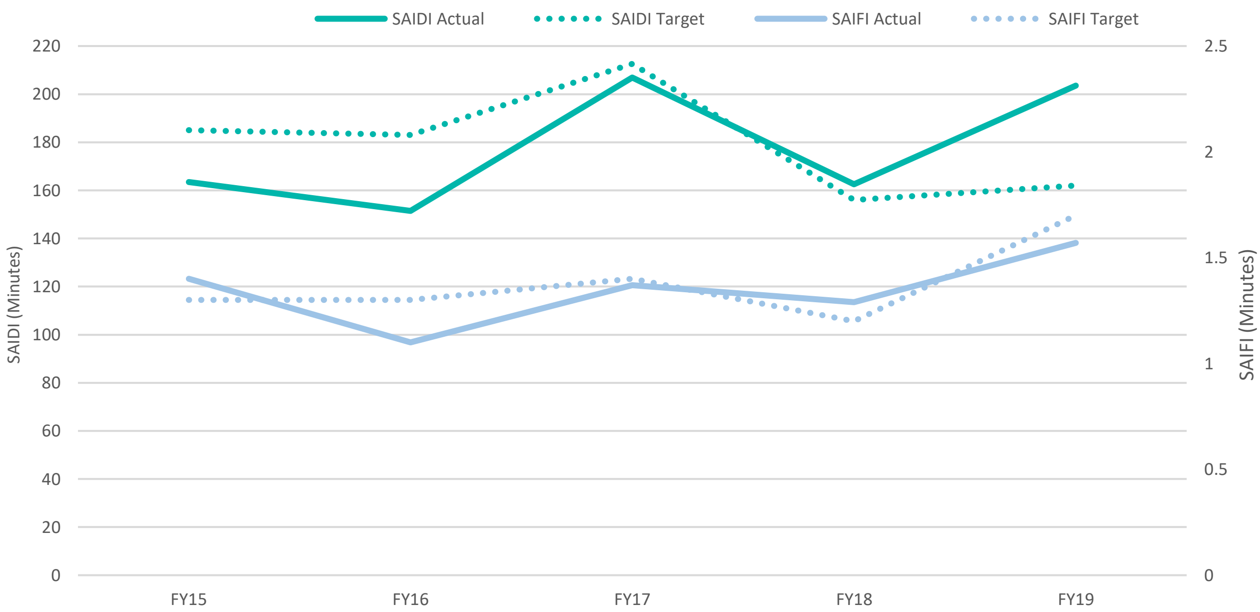

Figure 3.8: MainPower's Network Reliability SAIDI and SAIFI over 5 years

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 is below the target performance and that overall reliability is deteriorating. To understand the cause of the deteriorating trend it is helpful to breakdown reliability into both planned and unplanned events.

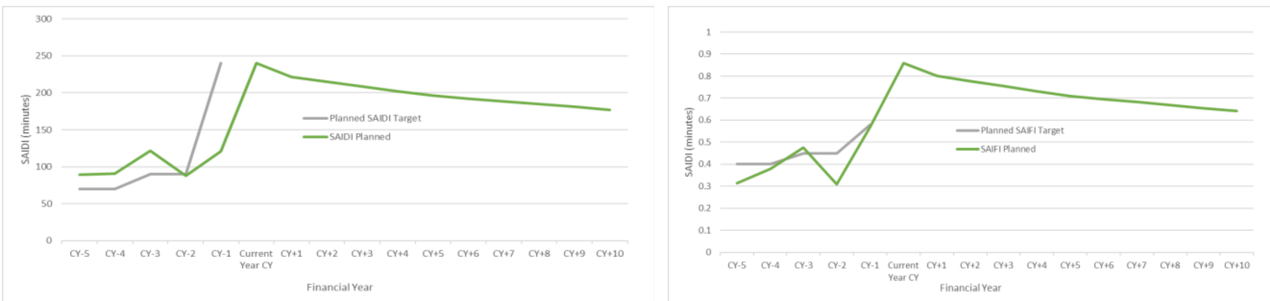

Figure 3.9: Network Reliability – Planned (Current year is identified as FY2019)

It can be demonstrated that it is not the number of times planned outages occur that has impacted overall planned outages, it is the duration of the outages. This indicates that when planning outages for works, MainPower is either under-estimating required outage durations or outages are extending beyond the initial expected and planned period.

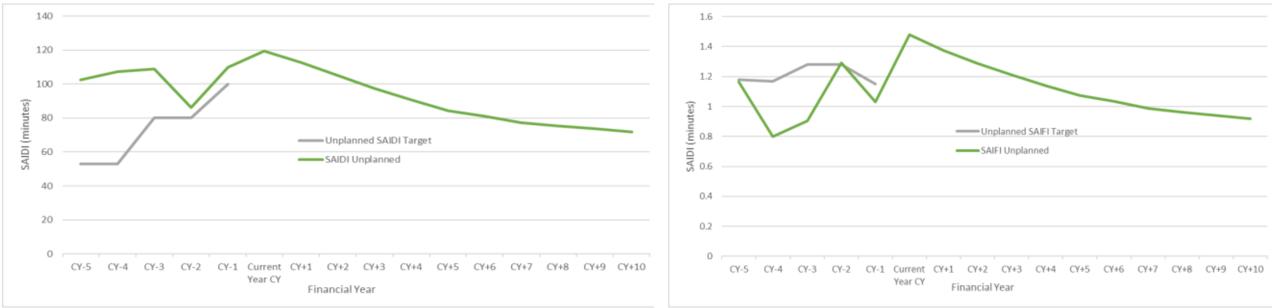

Figure 3.10: Network Reliability Unplanned

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

In summary, MainPower exceeded its reliability targets for FY19. Over 50% of our SAIDI was due to planned works and is reflective of our risk-targeted renewals program and our network architecture. Our network architecture is based on a rural, radial configuration with limited ability to supply consumers via alternative sources. These both negatively impact the frequency and duration of outages.

To highlight and better understand what contributes to unplanned electrical distribution network reliability, we analyse all outage data by cause. We analyse outage statistics over time to illustrate any underlying trends, which we have done using a 5-year rolling average across all outage categories.

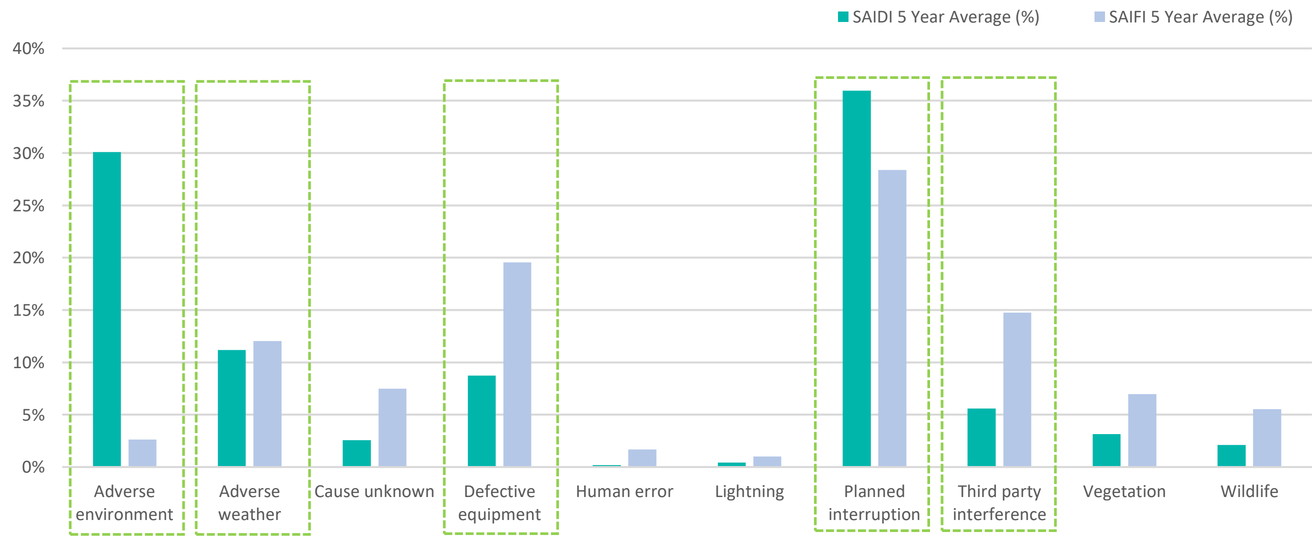

Figure 3.11: Network Reliability by Cause (5 Year Rolling Average)

It can be demonstrated from Figure 3.11 that overall network reliability is adversely affect by:

- Planned outages
- Defective equipment
- Adverse environment
- Adverse weather
- Third party interference

While this data is useful to understand overall contributors to deteriorating network performance, trends can be impacted by single events. To better understand the impact to network reliability, MainPower reviews the outage, by cause over time.

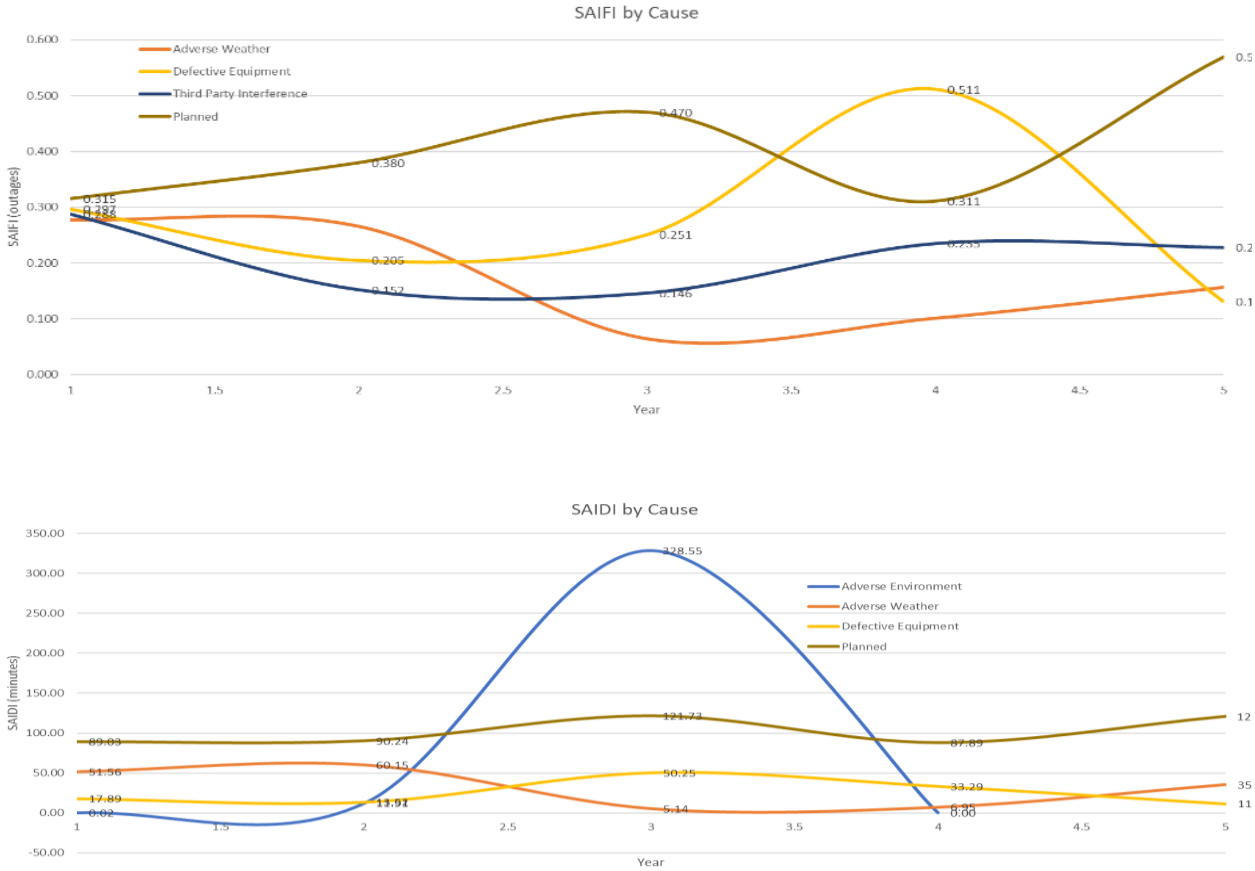

Figure 3.12: Network Reliability by Cause Trend

The peaking of 'adverse environment' in Year 3 (FY17) was due to the Waiau Earthquake. This is a single event and for this reason 'adverse environment' is not considered a significant contributor to overall network performance. The top contributors to adverse reliability over the last 5 Year period remain:

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

Category	Analysis	Initiatives	Target Date
Planned Works	Currently MainPower plans works across its Network using multiple systems which can lead to sub optimal planning. This year MainPower intends to 'Go Live' with its Advanced Distribution Management System which should enhance planning in the future.	Go Live and embed the ADMS project into the organisation. Review works planning post go live, monitor and make improvements as required.	FY21
Defective Equipment	Reviewing defective equipment by asset class yields that reliability is adversely affected by: 1. Switchgear; 2. Ring Main Units; and 3. Cable Faults.	Work Program: 1. Switchgear replacement – Ludstone zone substation and Southbrook zone substation; 2. Ring Main Unit replacement – network-wide.	FY21
Adverse Weather	Adverse weather reporting appears to be inconsistently used as MainPower has not had many major weather events.	Review of internal process for the allocation of reliability categories enabling consistent and more detailed reporting.	FY21
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 if additional steps need to be implemented.	FY21

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 5 years at a distribution feeder level. This helps us understand where parts of our network might be experiencing higher than normal interruption frequency or duration. The two graphs in Figures 3 and 3 show that the reliability impact starts to increase from the top 5 worst performing feeders.

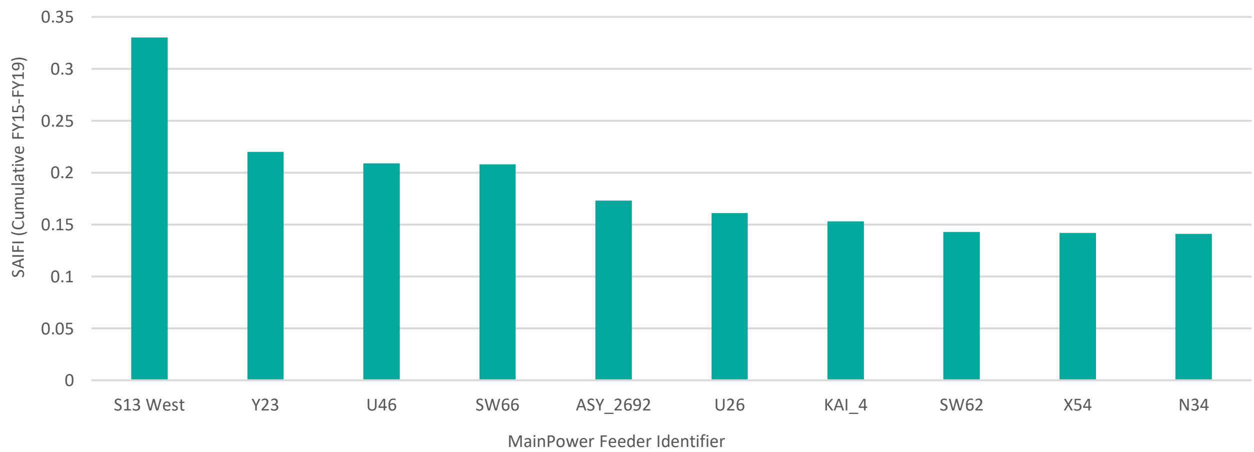

Figure 3.13: Top 10 Feeders with Highest Cumulative Unplanned SAIFI (FY15-FY19 Average)

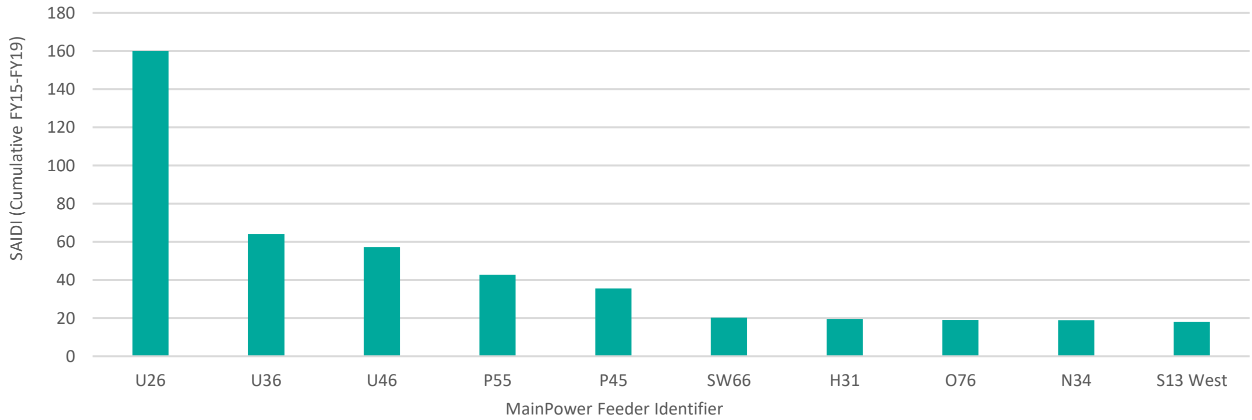

Figure 3.14: Top 10 Feeders with Highest Cumulative Unplanned SAIDI (FY15-FY19 Average)

Feeder	Analysis	Initiatives	Target Date
S13 West	This feeder supplies southern Rangiora and Waikuku township from our Southbrook zone substation. Investigation into the feeder highlighted it has urban and commercial loads which are being impact from 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 due to the size of the feeder with minimal downstream protection and isolation.	In response we are undergrounding 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.	FY21
U26, U36 and U46	These 11kV feeders supply the Kaikoura region from our Ludstone zone substation. These feeders experienced significant interruptions due to damage caused by the Waiau Earthquake in 2017, and due to 11kV switchgear failure at the Ludstone zone substation. These interruptions consisted of a range of causes, but mainly focusing around cable faults and asset failures.	Due to the nature of the single Waiau earthquake 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.	-
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 which analysis of the interruptions over the past 5 years indicates they are prone to unplanned outages caused by vegetation and weather events.	As these are both large overhead rural feeders, we are looking to reconfigure the network in the region to limit the impact of single events and improve and target our vegetation management program to prevent vegetation related outages.	FY21
S66	This feeder supplies the West Eyreton region from our Swannanoa zone substation. This feeder is also a large rural overhead feeder which has experienced a high number of vegetation and weather-related interruptions over the past 5 years. Although a rural feeder, this region of the network is more densely populated than a typical rural feeder and therefore interruptions have a higher impact due to the larger number of connections.	In FY21, we are planning to install an intermediate circuit breaker and reconfigure the feeder to minimize the number of customers impacted by outages. We are also looking to improve and target our vegetation management program to prevent vegetation related interruptions.	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 indicate a trend of vegetation, weather and wildlife causes, reflective of the environment the feeder passes through in the foothills of North Canterbury.	In FY21, we have an identified network reinforcement project to separate this large feeder into two smaller feeders. This will minimise the overall consumer impact of single outages. As mentioned above, we are also looking to improve and better target our vegetation management program to prevent vegetation related interruptions.	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. 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	FY19 Target	FY2019 Actual
No injuries related to a Safety Critical Risk	None	None
No injuries to members of the public	None	None
SF6 Loss (% to total gas volume)	<1%	<1%
Oils Spills	None	None

Table 3.5: HSEQ Evaluation

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.

Our customer satisfaction scores have continued to improve over time however we are not meeting our targets in some areas.

CONSUMER 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

Category	Analysis	Initiatives	Target Date
Engagement Effort	MainPower is aware that consumers interact with MainPower for a number of 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 a number of consumer's interaction into our CRM package. Continue to monitor this target and identify new workstreams throughout 2020.	2020
Timeliness of Service	We are aware that the way MainPower is currently responding to consumer needs requires further work and 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 improvement and implementation plan.	2020
Communication	Reflected in both the consumer-oriented and engagement sessions, communication has presented as an issue when engaging with consumers and as it related to outages.	There are a number of initiatives to address this issue: 1. New website – complete 2. Workstream development for consumer interactions within CRM (vegetation is the first workstream) 3. Integration of the ADMS system and automation of outage notification to the website.	2020

Staff Reliability	Customers are indicating that MainPower staff are not responding to their needs consistently.	We believe this relates more to communication (as per above) and setting expectations early. We are currently working on initiatives to improve this in 2020.	2020

Table 3.7: Customer performance measures

3.6.5 Physical and Financial

3.6.5.1 Maintenance

MainPower continued to deliver on its safety-critical maintenance throughout the year. The works also included asset data collection that has enabled MainPower to assess overall asset portfolio heath as detailed in the 'Assets' section of this document. Expenditure is within the performance target for the year.

3.6.5.2 Capital Programme Delivery

Capital expenditure remains below target for the year as MainPower continued to ensure that asset renewal was informed by asset condition and criticality and relevant security of supply standard. This work has been completed and elevated levels of capital expenditure will be demonstrated for the FYE 2020.

Class	Description	Status	Update
GXP	Review purchase of the Kaiapoi GXP from Transpower, assess against the overall transmission and sub-transmission strategy.	Planning	Developing the transmission and sub-transmission strategy.
	Southbrook Substation capacity upgrade.	Planning	Develop concept designs and engage with stakeholders. Price project and seek funding.
	New feeder required to support load growth in Woodend and Pegasus. Forms part of the new Rangiora East Zone Substation.	Planning	Required for network upgrade 2023.
Sub Transmission and Zone Substation	Renewal of Ludstone switchgear restoring n-1 supply, as determined by MainPower design and security of supply criteria.	Early Works	Early works completed and funding obtained.
	Waipara - Kaikōura capacitor installation to improve voltage stability, as determined by MainPower design and security of supply criteria.	Deferred	Voltage constraint alleviated due to 2020 project run 66kV to Oaro.
	Culverden to Hanmer upgrade of conductor enabling security of supply for 1 in 10-year snow event.	Planning	Engagement with stakeholders complete and easements sought for 2020-2023 delivery.
	Tuahiwi Substation to achieve voltage compliance and security of supply into Rangiora East and Pegasus. This project includes the Ashely river crossing.	Planning	Engagement with Stakeholders in 2020 commencing.
Distribution	Cheviot North Voltage Regulator and Capacitor Installation to improve voltage stability, as determined by MainPower design and security of supply criteria.	Delivery	In progress for 2020 completion.
	Cheviot South Voltage Regulator Installation to improve voltage stability, as determined by MainPower design and security of supply criteria.	Delivery	In progress for 2020 completion.
	Ashley Regulator and Capacity Installation and Conductor Upgrade to improve voltage stability, as determined by MainPower design and security of supply criteria.	Delivery	In progress for 2020 completion.

Table 3.8: Capital Programme Summary

3.6.5.3 Financial Performance

Revenue	Target ($000) [1]	Actual ($000)	% variance
Line charge revenue	$ 57,485.00	$ 57,571.87	0%
Expenditure on Assets	Forecast ($000) [2]	Actual ($000)	% variance
Consumer connection	$ 5,060.00	$ 4,352.44	-14%
System growth	$ 1,181.00	$ 586.87	-50%
Asset replacement and renewal	$ 5,142.00	$ 3,140.29	-39%
Asset relocations	$ -	$ 15.38	0%
Reliability, safety and environment:			
Quality of supply	$ 750.00	$ -	-100%
Legislative and regulatory	$ -	$ -	0%
Other reliability, safety and environment	$ -	$ 214.65	0%
Total reliability, safety and environment	$ 750.00	$ 214.65	-71%
Expenditure on network assets	$ 12,133.00	$ 8,309.63	-32%
Expenditure on non-network assets	$ 3,712.00	$ 2,251.00	-39%
Expenditure on assets	$ 15,845.00	$ 10,560.63	-33%
Operational Expenditure			
Service interruptions and emergencies	$ 1,566.00	$ 1,535.39	-2%
Vegetation management	$ 1,010.00	$ 715.42	-29%
Routine and corrective maintenance and inspection	$ 2,588.00	$ 1,966.56	-24%
Asset replacement and renewal	$ 261.00	$ 717.00	175%
Network opex	$ 5,425.00	$ 4,934.37	-9%
System operations and network support	$ 4,199.00	$ 5,076.74	21%
Business support	$ 6,795.00	$ 5,902.00	-13%
Non-network opex	$ 10,994.00	$ 10,978.74	0%
Operational expenditure	$ 16,419.00	$ 15,913.11	-3%

Figure 3.15: Financial performance

Category	Analysis	Initiatives	Target Date
Revenue	No Target.	None	N/A
Customer	Contestable in nature and slightly below target.	None	N/A
Expenditure on Assets	Below target, reflective of MainPower reassessing its Asset Management systems.	Restored to 90% budget in 2020.	2020
Operational Expenditure	Aligned with budget and reflective that MainPower continues to perform critical maintenance while it reviewed its Asset Management system.	Restored to 90% budget in 2020.	2020

Table 3.9: Financial performance analysis and initiatives

3.6.5.4 Asset Management Maturity

Owning the right assets, managing them well, funding them sustainably and managing risks is critical to the ongoing provision of 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 improvements plans.

Progress is summarised below.

Defining the Requirements	Improvement	Actual	Target Date
Asset Management Policy and Strategy	MainPower's approach to asset management has been clearly defined and linked to the Statement of Corporate Intent and business strategy, through the Asset Management Policy to the Asset Management Plan.	Completed.	2018
Levels of Service and Performance Management	MainPower has introduced the Voice of the Customer Programme that has enabled MainPower to translate consumer requirements into network performance.	Customer engagement completed – work remains translating what our customer are telling us into actual service levels.	2020
Demand Forecasting	This remains a key focus for MainPower, taking into consideration consumer segments, location and network impact of emerging technology and a low carbon economy.	To be completed.	2020
Asset Register Data	Major advancements have been made in ensuring asset data, including condition data, is 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 CY2020.	2020
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 2021.	2021
Risk Management	Risk has been integrated into the Network, including division or team risk, plant, equipment and activity risk, as well as documentation of controls. High risks are introduced in the Corporate Risk Register.	Completed.	2019

Table 3.10: Understanding Defining Requirement's Improvements

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.	2022
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.	2022
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 CIMS training for our staff for event management.	2021
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.	2020
Capital Investment Strategies	Capital expenditure is prescribed, linking cost, risk and network performance.	To be completed	2022
Financial and Funding Strategies	Funding for capital expenditure exists on a 10-year cycle, informed by asset performance, reliability and supporting assumptions.	To be completed	2021

Table 3.11: Lifecycle Decision Making Improvements

Asset Management Enablers	Improvement	Actual	Target Date
Asset Management Teams	The Assets and Capital Works team has been created within MainPower. Staff understand their roles and asset management best practice is supported by the Executive Leadership Team.	Completed.	2019
Asset Management Plan	MainPower's AMP describes service levels, assets and includes a 10-year forecast of expenditure. Asset management improvement plan created.	Completed annually.	2020
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 one source of the truth for all our assets.	2019
Service Delivery Models	Service Level Agreements are currently being implemented, defining minimum levels of service required from internal crews and, where external providers are required, formal contracts exist.	To be completed.	2021
Quality Management	MainPower is accredited to ISO 9001 and all asset management processes are documented.	Completed.	2019
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.	2020

Table 3.12: 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 Tech 1 for all asset classes.
Asset Portfolio Strategies	To be started.	MainPower to have Asset Portfolio Strategies for all assets.
Asset Health	Asset health indicators are implemented for three asset classes.	Establish and monitor asset health for all asset classes.
Asset Maintenance and Replacement	Health index will inform condition and risk-based approach to Asset Management.	Apply condition and risk-based maintenance and replacement programmes.
Regional Planning	AMP contains 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 3.13: Areas of Focus for Asset Management Indicators

3.6.6 Industry Benchmarking

The objective of benchmarking is to observe and seek understanding how MainPower is performing as an organisation when compared with other EDBs. MainPower benchmarks itself against seven network business.

Organisation	ICP/km	ICPs
Alpine Energy	7.7	33,200
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 3.14: Benchmark Organisations (2018 data)

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. This reflects 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.

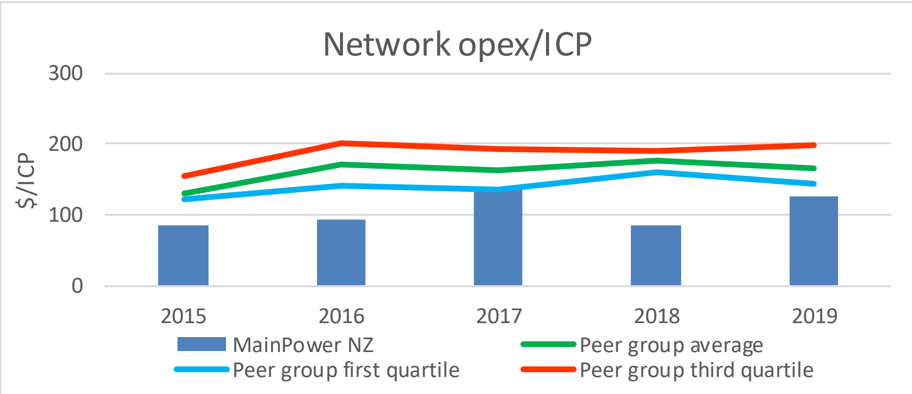

Figure 3.16: Benchmarking Network Operating Expenditure

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

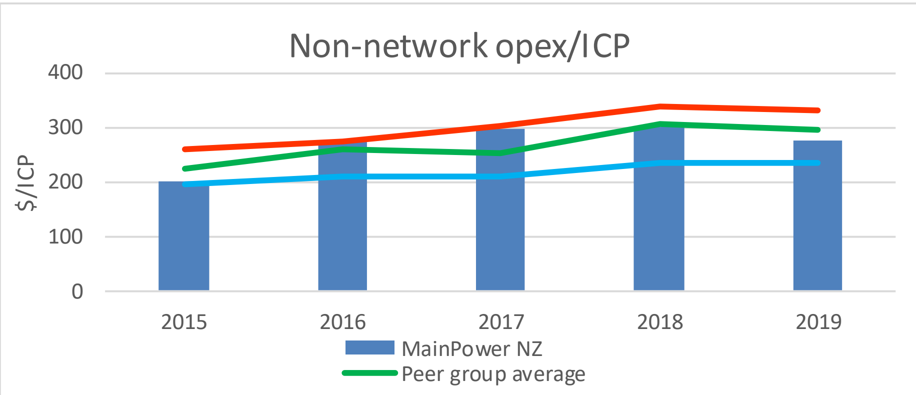

Figure 3.17: Benchmarking Non-Network Operating Expenditure

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 Renewals.

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

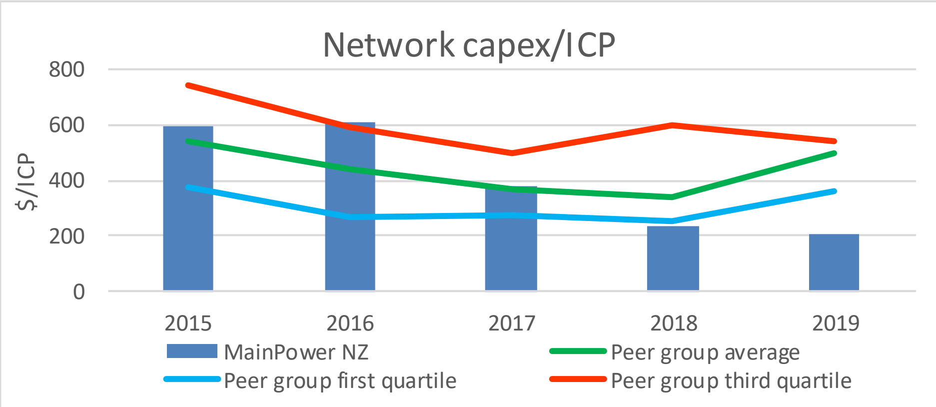

Figure 3.18: Benchmarking Network Capital Expenditure

3.6.6.4 Reliability

Reliability for MainPower remains within our industry peers. However forecast SAIDI and SAIFI means that we are trending towards to the 75th percentile. Initiatives have been identified to address Quality of Supply for MainPower in the future and return Quality of Supply to within historical norms.

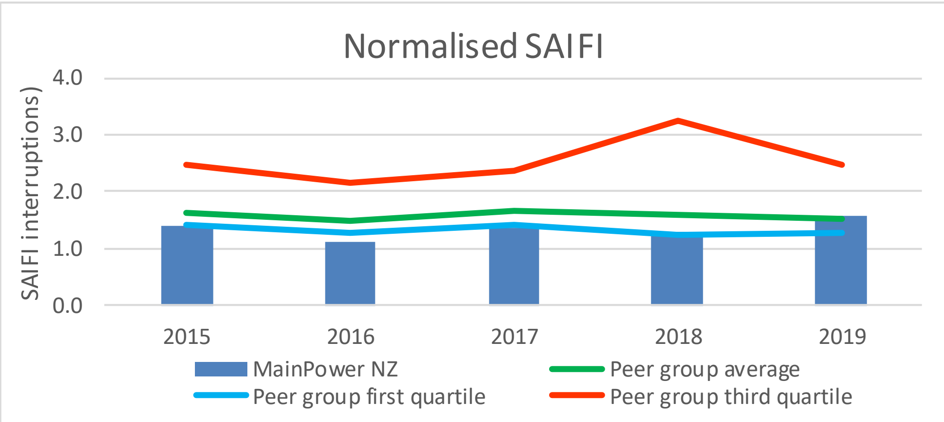

Figure 3.19: Benchmarking Quality of Supply SAIFI

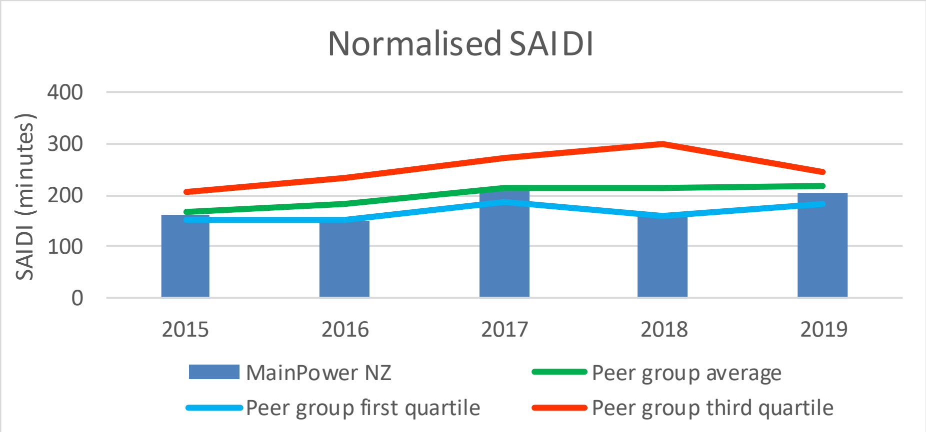

Figure 3.20: Benchmarking Quality of Supply SAIDI

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 internal response 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.

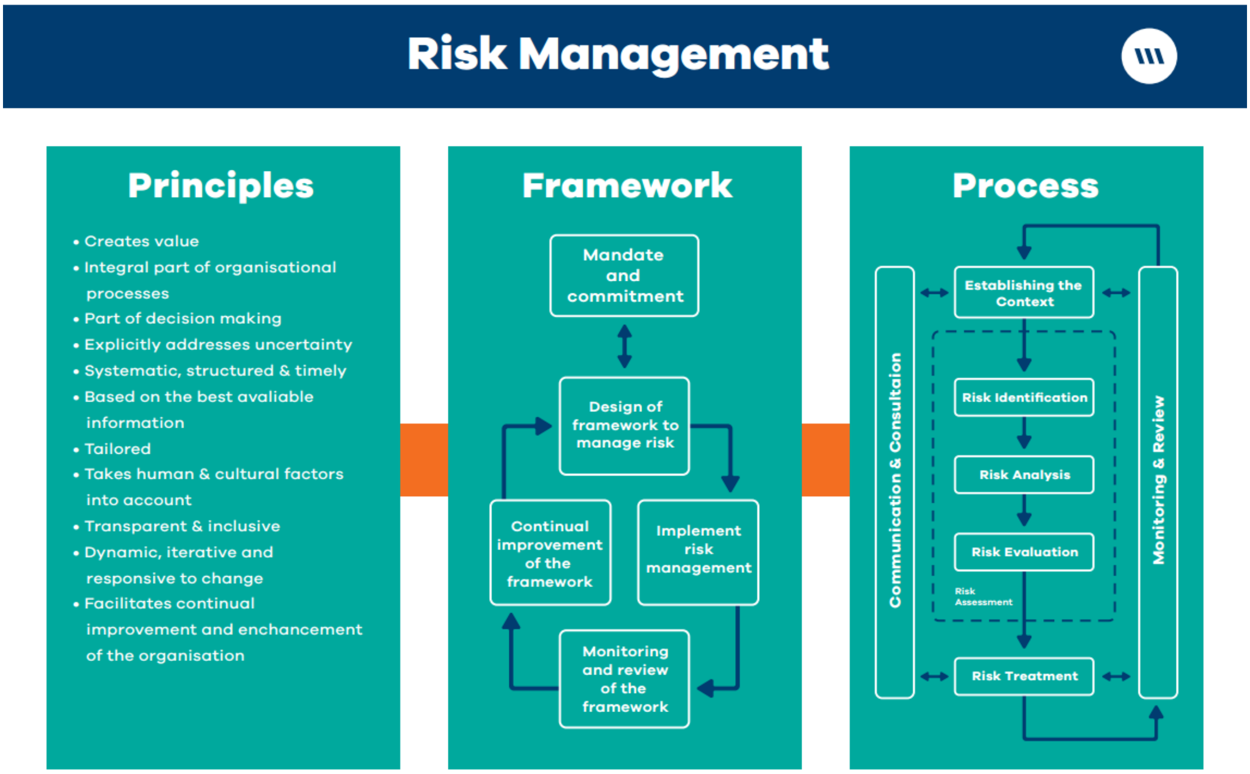

Figure 4.1: Risk Management Framework (Drawn from ISO 31000:2018)

The principles in the above diagram 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, and also determine 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 focussing 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 to cause death to employees, contractors or members of the public, cause significant property damage or cause MainPower to be severely impacted as a business.

MainPower uses '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 that helps assess and analyse risk. It includes four levels of risk – minor, moderate, major and catastrophic.

LIKELIHOOD	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	L 7	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 from 1-7)**	**Medium** **(Range from 8- 13)**	**High** **(Range from 14-23)**	

Table 4.1: Matrix Ranking Risk by Likelihood and Consequence

Assessing the likelihood and consequence of a risk provides an overall score. The risk appetite table provides guidance on the required risk treatments to reduce the risk so far 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 and internal audits and observations.
Medium (8 to 10)	Escalation to Executive Leadership Team to review appropriate risk mitigations. Action plan developed and implemented.
Medium (11 to 13)	Reduce risk, if not possible manage through risk controls and audit control effectiveness. Approved by Executive leadership Team.
High (14 to 17)	Reduce risk, if not possible risk management plan must be in place, approved by Board and audited and monitored.
High (18 to 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 (there is a process in place and people are trained);
- Applicable to the hazard and are independent (not reliant on other controls);
- Reliable (they 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 included below.

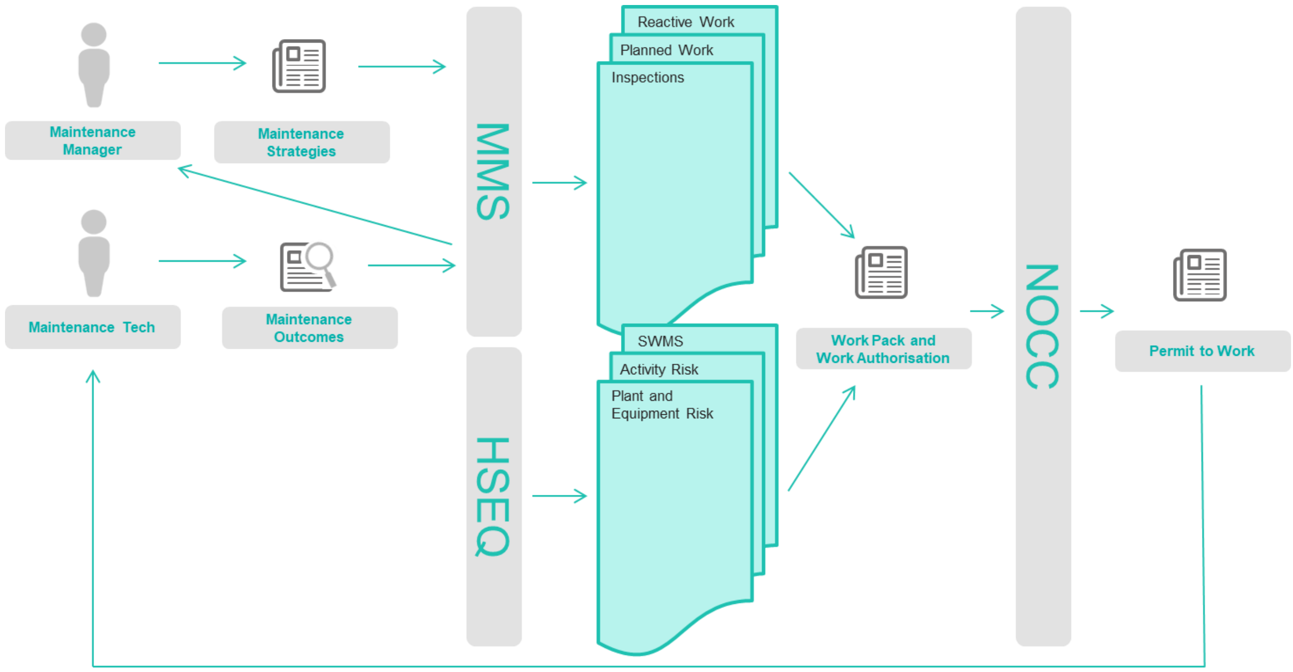

Figure 4.2: Permit to Work Control

Assurance of risk treatment for activity, plant and equipment risk is demonstrated by the figure below.

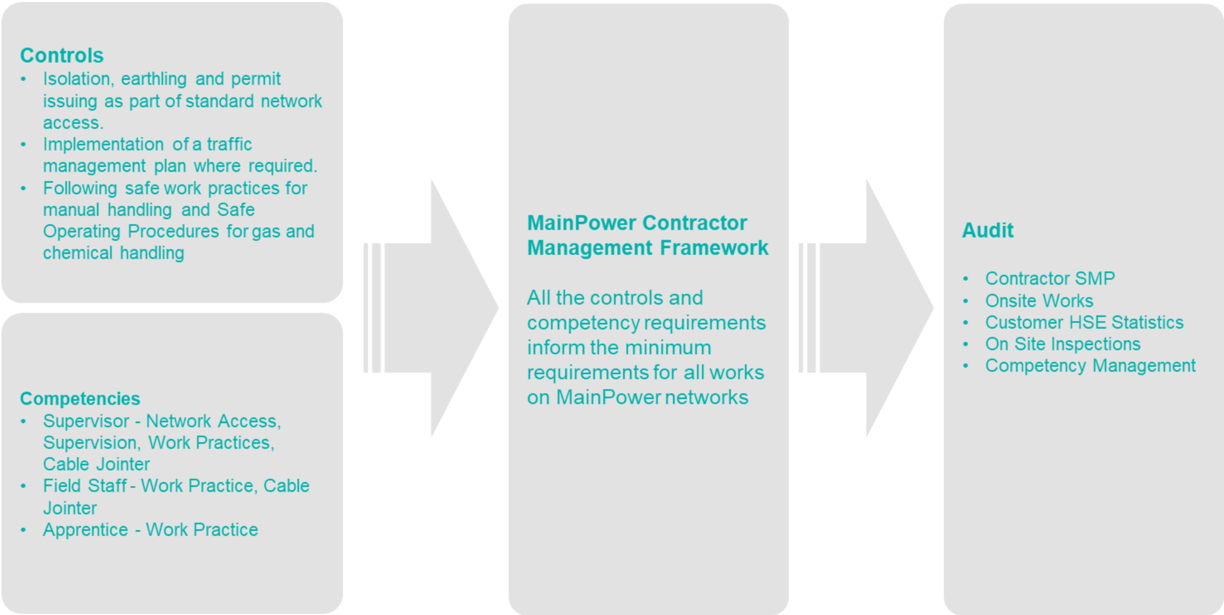

Figure 4.3: Assessment of Risk for Activity, Plant and Equipment

4.3 Project Risk

Critical projects are risk assessed using bow tie methodology which includes safety in design, procurement, planning and operational aspects. It is the role of the Project Manager to update and maintain the project risks periodically, including the control effectiveness through monitoring. The plan moving forward is to incorporate a wider risk-based approach across all projects.

4.4 Network Risk

MainPower has conducted the following risk assessment studies:

- High Impact, Low Probability (HILP) event assessment;
- Physical risk to Grid Exit Points (GXPs), zone substations, transmission and distribution systems; and
- Compliance with the RMA.

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:

- 66kV and 33kV sub-transmission systems;
- Zone substations; and
- Communications systems.

	Earthquake	Avalanche	Landslide	Tsunami	Volcanic	Flood	Snow	Wind	Lightning	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 Substations	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

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 includes MainPower's GXPs. The assessment concludes that Transpower's assets can 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 below 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 are assessed at a ratio above 10% under certain earthquake scenarios, overall damage to the sub-transmission and distribution systems does 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 the table below. Information is 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 Consequence: Low

Windstorm	Damage to overhead lines is routinely caused by high winds. Historically this results in minor and isolated damage. 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 northwest (these occurred in 1945, 1964, 1975, 1988 and 2013). The peak wind speed of 193km/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.	Probability: High Consequence: Low
Electrical storms	Most parts of Canterbury experience few electrical storms. Over the plains, fewer than five thunder days on average occur each year, with the highest frequencies occurring from September to March. Near the Alps, an average of 20 thunder days occur each year, with the highest frequencies during April and May. Zone substations, transformers and communications equipment are protected with lightning arrestors.	Probability: Moderate Consequence: 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 Consequence: Low
Tsunami	Tsunami hazards are uncertain, however it is recognised as realistic 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 Consequence: 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 due 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 consequence for these assets is 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 backup 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 impacts on 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 backup 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
- Creaks 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 a vehicle impact on the 33kV pole line feeding the Rangiora North Zone Substation; and
- The fortieth 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 reduced this number of risks, or mitigated the risks, so that only eight now have a risk score greater than 200, as shown in the table below. 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 assesses each type of asset and explains how the impact of failure is further 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 settings. Protection systems are simplified or removed when appropriate. The risk of damage occurring to a transformer or to 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 11kV 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 would use diesel generation sets where appropriate. Planned upgrade projects will improve cover when 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. The table below shows the amount of load control available on each GXP station.

GXP	Load reduction available assuming water heating has been on all day	Load that must be restored assuming that water heating has been off for three 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 66kV and 33kV Sub-transmission System

The sub-transmission system between Southbrook and Waipara and between Waipara and Kaikōura can transfer load either way. This flexibility offers an alternative supply to major and minor zone substations located along this route. The same now also applies to the two sub-transmission circuits between Southbrook and Swannanoa and Burnt Hill. 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 33kV 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 22kV supply from Mouse Point can back up the Waipara Hawarden 33kV line for most of the year.

4.4.9 Ensuring Alternative Supply Routes for our Distribution System

Major 22kV and 11kV feeders are backed up by alternative supply routes. Where more than two major feeders supply an area, generally each feeder is designed to carry a maximum of 75% of its rating. This allows some spare capacity for backup. Where only two feeders are available, then 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 also 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 the table below.

Location	Supply Options
Rangiora	The level of interconnection between all six feeders is high. Two feeders from Southbrook are capable of 9 MW each, one is capable of 8 MW, and one is capable of 7 MW. The two feeders from Rangiora North are capable of 4 MW each. At peak times, the network is capable of meeting load 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 Road and Greys Road. We can shift load to Mackenzies Road and the Rangiora North Substation to ensure backup 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 22kV supply from two feeders out of Mouse Point Substation. Another 22kV supply is available from Hawarden Substation to the south if needed.
Hanmer	Hanmer is supplied from either of 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. A new paralleling point to the east of the town gives greater supply security to the Hanmer Springs business district.
Kaikōura	The Ludstone Substation has four feeders that can supply into the Kaikōura town. The north and south feeders are lightly loaded, and can back each other up, or either of the two town feeders. The Churchill Street 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	Most of the 11kV distribution system in the town of Oxford is overhead. We can easily isolate a fault and quickly restore supply to consumers. All three feeders from the Oxford Substation can take over the town supply if necessary. Alternatively, Bennetts Substation can supply the town area, but this depends on the level of system loading (which is high in summer due to irrigation load).
Woodend	The main alternative supply to the town of Woodend is via the Waikuku feeder out of Southbrook Substation. During emergencies the Kaiapoi Substation can also supply the town, but this involves a phase shift across the Southbrook and Kaiapoi GXP Substations.

Table 4.9: Alternate 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 the table below.

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 the vehicles.
Ensure that the spare 33/11kV transformers and one of the two 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 on stock. 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 backup facility.
Ensure sufficient spare lengths of 66kV and 33kV single-core XLPE cable are stored at Rangiora – suggest a minimum of 3 lengths (each of 10 metres), along with two complete sets of jointing kits, two complete termination kits, six jointing sleeves, six termination lugs and a compression tool.	Jumper cable sets are made up and stored in the yard.
Ensure sufficient spare lengths of 22kV and 11kV single-core XLPE cable are stored at Rangiora – suggest a minimum of three lengths (each of 10m), along with two complete sets of jointing kits, two complete termination kits, six jointing sleeves, six termination lugs and a compression tool.	Jumper cable sets are made up and stored in the yard.
Ensure three spare 66/33kV 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 33kV breaker and a reasonable array of spares for all makes are held at Rangiora.	Spare 11, 22 and 33kV 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 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 of its GXP stations in North Canterbury are shown in the table below. Recent upgrades mean that MainPower now has four 66kV 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 OFAF	66/11	N-1 capacity 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 40 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 the EEA Asset Criticality Guide in combination with CBRM principles from the UK. 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 5.5.3), 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);
- 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 is 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.

Simulations are practiced 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 (CIMS) Five R's

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 in the north of Christchurch City, through the Waimakariri, Hurunui and Kaikōura Districts, up to the Clarence River and inland to the Lewis Pass.

The geographic extent of the network is represented in the map below, where every blue dot represents a consumer connection.

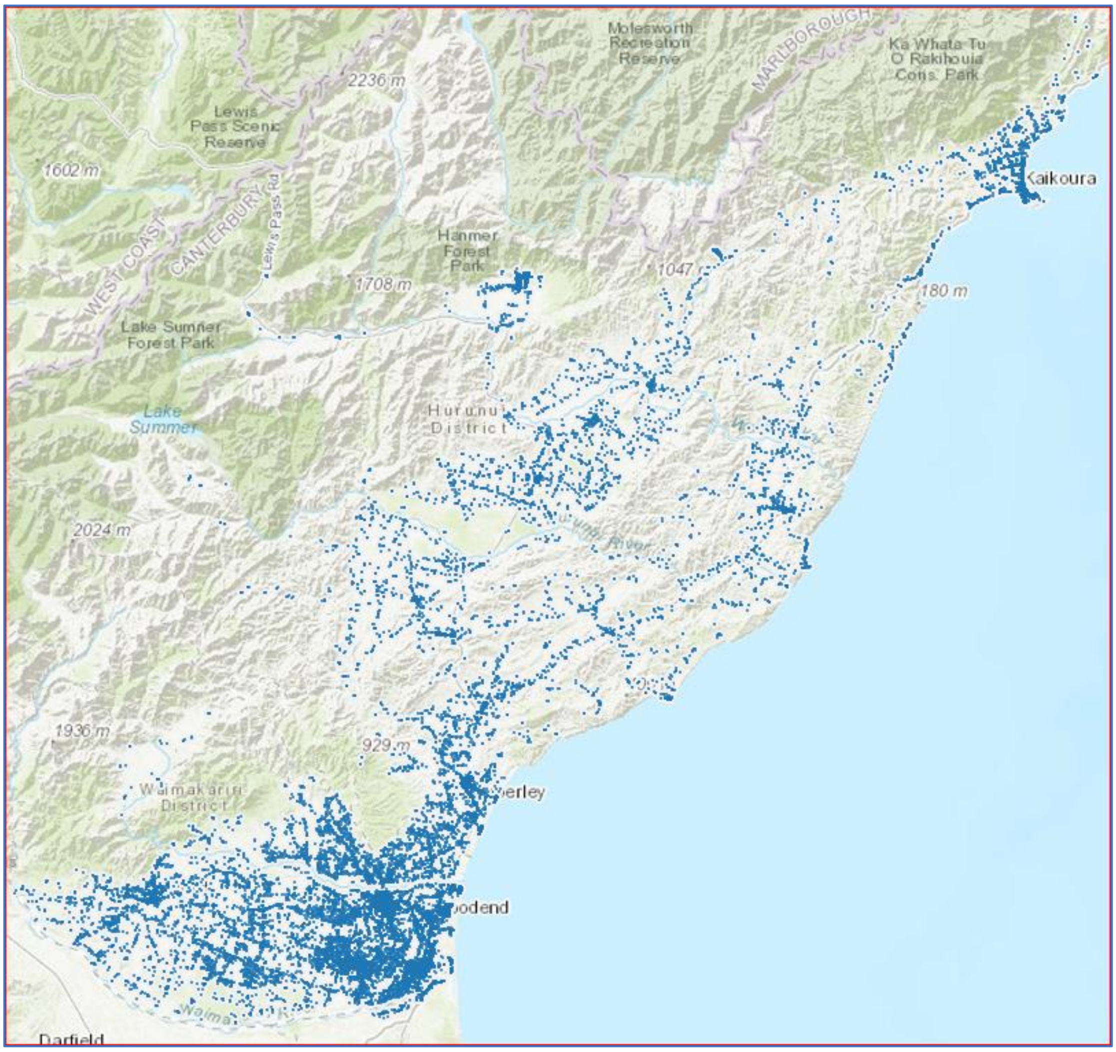

Figure 5.1: MainPower's Electricity Network Consumer Geographic Distribution

5.1.1 Large Consumers

Our large consumers are:

- **Daiken NZ medium density fibreboard mill at Ashley:** The Daiken mill is supplied from the Ashley GXP via four 11kV feeders, which provide reasonable levels of security. The Daiken controllers are able to 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 is able to be switched between two 11kV feeders. Hellers has also installed a backup generator for critical supply during emergencies.
- **Patience and Nicholson tool manufacturing plant in Kaiapoi:** This plant can be supplied from either of two 11kV supplies from the Kaiapoi switching station, and one of these can also be swapped to an independent backup feeder.
- **McAlpines sawmill at Southbrook:** Recently this mill has been transferred onto a new high security dual feeder supplied switchboard, which has reduced the risk of power interruptions to the site.
- **Mitre 10 Megastore at Southbrook:** This site has an alternative 11kV feeder.
- **Belfast Timber Kilns at Coutts Island:** This plant is connected near the end of a rural 11kV 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

Year	16	17	18	19	Peak
Substation	MVA	MVA	MVA	MVA	
Southbrook	23	22.5	23	22.8	Winter
Swannanoa	15	14.8	16	15.2	Summer
Burnt Hill	14	14.8	15	15.0	Summer
Rangiora North	7	5.2	6	5.6	Winter
Amberley	5	5.2	6	6.0	Winter
MacKenzies Rd	2	2.5	2	1.6	Summer
Greta	1	1.3	1	1.3	Summer
Cheviot	3	3.3	3	3.2	Summer
Leader	1	1.5	2	1.5	Summer
Ludstone Rd	6	6.0	6	5.9	Winter
Mouse Point 22	19	20.1	15	15.6	Summer
Hanmer	5	4.3	5	4.8	Winter
Lochiel	0	0.1	0	0.1	Summer
Hawarden	3	3.4	4	3.7	Summer
Kaiapoi S1 *	8	9.0	9	8.9	Winter
Rangiora West *	8	8.1	9	8.3	Winter
Pegasus *	3	2.5	3	2.8	Winter
Kaiapoi North *	12	7.0	8	7.2	Winter

Table 5.1: MainPower Network Load Characteristics

5.1.3 Peak Demand and Total Energy Delivered

System Measure	FY2018	FY2019
Peak Load	113 MW	117 MW
Energy Entering the System	630 GWh	633 GWh
Energy Delivered	604 GWh	597 GWh
Loss Ratio	4.1%	5.7%%
Load Factor	64%	62%
Consumers	38,233	39,624
Zone Substation Capacity (base ratings)	135 MVA	135 MVA
Distribution Transformer Capacity	554 MVA	554 MVA
Distribution Transformer Capacity Utilisation	19.9%	20.6%
Circuit length lines (kms)	5020	5,021

Consumer Group ICPs (Installation Control Points)	FY2018	FY2019
Residential	31,360	32,205
General	5,189	5,711
Irrigation	1,279	1,347
Council Pumping	185	198
Streetlight	174	116
Large User	46	47

Table 5.2: Key MainPower Network Statistics

5.2 Network Configuration

5.2.1 Transmission Network Configuration

The 220kV South Island transmission network is owned and managed by Transpower New Zealand Limited. Four 220kV 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 220kV and 66kV transmission circuits out of Islington. The following table provides a summary of the GXP substations in the North Canterbury region.

GXP	DESCRIPTION	
Kaiapoi	Transformer Capacity	76 MVA
	Firm Capacity	38 MVA
	Peak Load	29 MW
	Configuration	Two 38 MVA 66/11kV three phase transformers
	Supply to MainPower	Eight 11kV circuit breakers
Southbrook SBK0331 and 0661	Transformer Capacity	80 MVA at 33kV
	Firm Capacity	40 MVA at 33kV
	Peak Load	27.6 MW at 33kV
	Configuration	Two dual-rated 30/40 MVA 66/33 kV three phase transformers

	Supply to MainPower	Two 33kV circuit breakers Two 66kV circuit breakers
Ashley **ASY011**	Transformer Capacity	80 MVA
	Firm Capacity	40 MVA
	Peak Load	21 MVA
	Configuration	Two dual-rated 40 MVA 66/11kV three phase transformers
	Supply to MainPower	One transformer normally feeding five 11kV circuit breakers supplying the rural area. One transformer normally feeding four 11kV circuit breakers for the Daiken plant (a plant that produces Medium Density Fibreboard)
Waipara **WPR0331 and 0661**	Transformer Capacity	160 MVA
	Firm Capacity	80 MVA to the 66kV bus
	Peak Load	14.2 MW total at 66kV, 8.2 MW at 33kV
	Configuration	Two 80 MVA 220/66kV transformers directly connected to the Islington-Kikiwa 220kV circuits. The 66kV supply from these transformers feed a single 66/33kV dual-rated 10/16 MVA three phase transformer.
	Supply to MainPower	Two 33kV and one 66kV feeder circuit breakers and one 66kV load plant circuit breaker.
Culverden **CUL0331 and 0661**	Transformer Capacity	60 MVA
	Firm Capacity	30 MVA to the 33kV bus
	Peak Load	22.3 MW
	Configuration	Two 30MVA 220/33kV transformers directly connected to the Islington-Kikiwa 220kV circuits. A 10/20 MVA 33/66kV transformer rated at 13.09 MVA with no fans has been installed to supply 66kV to Kaikōura.
	Supply to MainPower	33kV via two feeder circuit breakers and cables, 66kV feeder circuit breaker.

Table 5.3: 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 66kV and 33kV sub-transmission circuits are shown below.

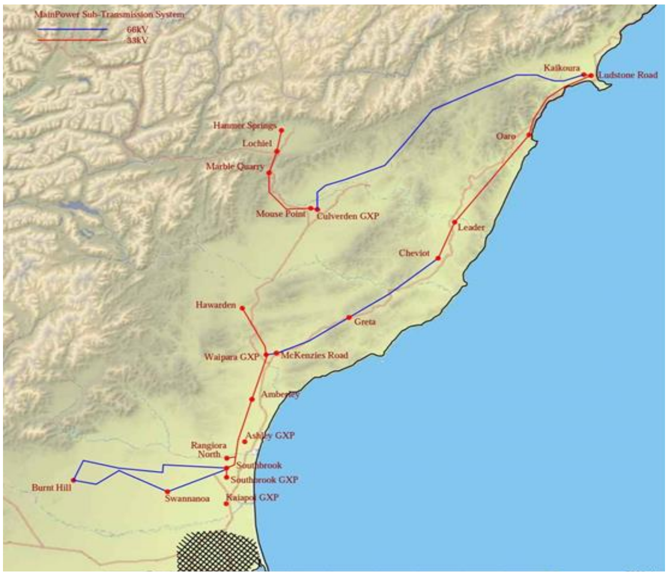

Figure 5.2: MainPower's Sub-transmission Network

5.2.3 Distribution Configuration

MainPower’s distribution system is largely rural with many long radial spurs. The 22kV and 11kV distribution is approximately 90% overhead line network. The only areas of significant underground reticulation are the townships of Rangiora and Kaiapoi where 11kV reticulation in Rangiora and Kaiapoi is approximately 90% underground. The table below provides a summary of key information for each of MainPower’s zone substations.

	General						Transformers			
Zone Substation	Peak Load (MVA)	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	22.8	44	22	22.5	Yes	6	2 x 16/22	Yes	Yes	Indoor	6 Reyrolle vacuum
Swannanoa	15.2	46	23	26	Yes	5	2 x 11.5/23	Yes	Yes	Indoor	5 Tamco vacuum
Burnt Hill	15.0	46	23	26	Yes	6	2 x 11.5/23	Yes	Yes	Indoor	7 ABB UniGear ZS1
Rangiora North	5.6	7	0	5.2	Yes	3	5/7	Yes	Yes	Outdoor	3 Nulec SF6
Amberley	6.0	8	4	6	Yes	3	2 x 3/4	Yes	Yes	Indoor	3 Reyrolle oil
MacKenzies Rd	1.6	4	0	1.6	Yes	3	2/4	Yes	Yes	Outdoor	3 Nulec SF6
Greta	1.3	4	0	0.5	Yes	3	2/4	Yes	Yes	Outdoor	3 Nulec SF6
Cheviot	3.2	4	0	0.5	Yes	3	2/4	Yes	Yes	Outdoor	3 Nulec SF6
Leader	1.5	2	0	0	Yes	3	1/2	Yes	Yes	Outdoor	3 Nulec SF6
Oaro	0.3	0.5	0	0	No	1	0.5	No	No	Outdoor	1 ME KFE vacuum
Ludstone	5.9	12	6	6	Yes	4	2 x 4/6	Yes	Yes	Indoor	4 South Wales oil
Hawarden	3.7	4	0	2.5	Yes	3	3/4	Yes	Yes	Outdoor	2 GPC oil, 1 Nulec SF6
Mouse Point	15.6	26	13	14	Yes	4	2 x 10/13	Yes	Yes	Outdoor	4 W&B SF6
Marble Quarry	0.2	0.2	0	0	No	1	0.2	No	No	Outdoor	1 GPC oil
Lochiel	0.2	0.2	0	0	Yes	1	0.2	No	Yes	Outdoor	1 Nulec SF6
Hanmer	4.8	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 5.4: Zone Substation Key Information

5.2.4 Distribution Substations

As our high voltage distribution network is predominantly overhead, the majority of 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 HRC fuses where practical.

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 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 11kV 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 11kV HRC fuse protecting the transformer. The box design allowed for a maximum transformer size of
  500 kVA, however, these have to be de-rated because of reduced cooling. Low voltage panels were 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 practical, increasing security of supply.

Overhead low voltage systems are located in smaller townships and in 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 33kV and 66kV 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 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 eleven years a large number of lines have been converted from 11kV to 22kV 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

The majority of the high voltage underground cables are either 95mm^2 or 185mm^2 aluminum although more recently 300mm^2 aluminum cables are being 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 11kV or 22kV. A small number of customers are supplied from SWER systems operating at 6.6kV or 11kV, and a very small number of remote customers from distribution transformers on the 33kV sub-transmission system. However, as this arrangement constrains the operation of the sub-transmission system, they are being removed progressively.

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 HV and LV cable boxes and a separate shell for the HV and LV switchgear.

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

5.3.6 Distribution Switchgear

There are several different types of circuit breakers and reclosers on the system, including bulk oil, SF6 and vacuum types. All circuit breakers purchased since 1995 are remote controllable.

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

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

The majority 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 Street Lights

Most street lights are controlled by ripple relays located at local low voltage distribution substations, where the relays receive a signal by ripple injection initiated from a light level sensor. Dedicated street light supply cables loop around a 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 SCADA

The Schneider Wonderware SCADA system will be replaced by an OSI Monarch platform by 2020. This is part of implementing the OSI Advanced Distribution Management System.

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 a lone worker and worker down function was added to the voice radio platform via 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. A number of 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

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

5.3.13 Property and Buildings

MainPower owns substation buildings, offices, administration buildings and operational buildings. All of 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, which 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.

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 or can be connected to overhead lines at 11kV or 22kV 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

Electricity distribution and the wider electricity energy sector is embarking on unprecedented change due to the decarbonisation of the economy (transportation and process heat sectors), new technologies (solar, batteries, EVs) and changing consumer needs (consumers transitioning to prosumers).

This change will impact MainPower's electricity distribution network and the services we provide that support our network. For example, additional services that MainPower may be required to deliver to be ready for a New Energy Future could include:

1. A service that operates and develops an active distribution system comprising networks, demand, generation and other flexible Distributed Energy Resources (DER).
2. Becoming a neutral facilitator of an open and accessible market that will enable competitive access to markets and the optimal use of DER in distribution networks – delivering security, sustainability and affordability in the support of whole system optimisation.
3. Enabling consumers to be both producers and consumers; facilitating consumer access to networks and markets, consumer choice and great consumer service.

MainPower has already embarked on two main workstreams to ensure that our electricity distribution network systems and processes are ready for a new energy future:

- Asset Ownership (transitioning from a DNP to a DSI); and
- Operation (transitioning from a DNO to DSO).

The need for two workstreams signifies MainPower's view that within a new energy future there may need to be some separation of operational control and network asset management activities.

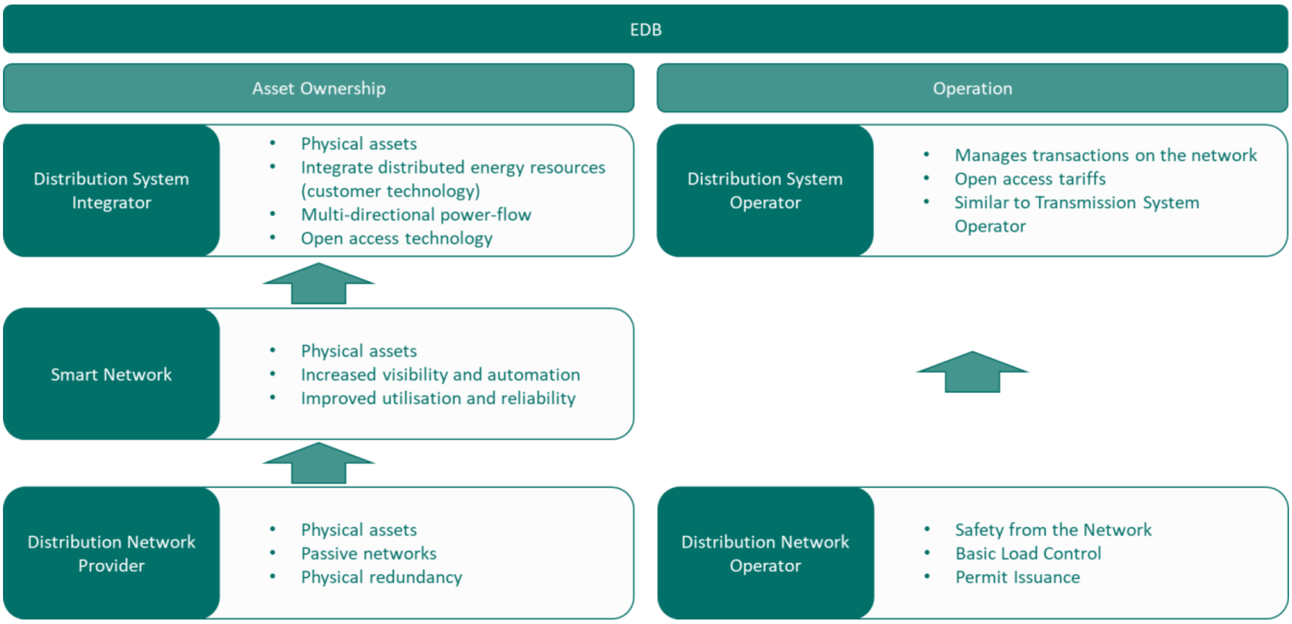

Figure 5.3: Transformation Road Map Programme

Note: It is unlikely that every EDB will transition into a DSO. While this remains to be determined, it is likely that a DSO will be formed in regions. EDBs that have transformed their businesses into DSI will interface with DSO service providers, i.e. a DSO will provide DSO services to several EDBs in the future.

5.4.1 Electricity Distribution Business (EDB)

In New Zealand, an Electricity Distribution Business (EDB) 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. In New Zealand today, an EDB is typically a Distribution Network Provider (DNP) and Distribution Network Operator (DNO) combined into a single entity.

5.4.2 Distribution Network Provider (DNP)

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.

5.4.3 Distribution Network Operator (DNO)

A Distribution Network Operator (DNO) operates the network day-to-day to ensure the network conforms to safety requirements, controls the electrical load and controls access to the network. The DNO normally transacts between and connects suppliers and consumers of electrical energy with bulk supply points or grid exit points (GXPs) by means of the electricity distribution network.

5.4.4 Distribution System Integrator (DSI)

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.

5.4.5 Distribution System Operator (DSO)

A Distribution System Operator (DSO) securely operates and develops an active distribution system comprising networks, demand, generation and other flexible Distributed Energy Resources (DER). As a neutral facilitator of an open and accessible market it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables consumers to be both producers and consumers; enabling consumer access to networks and markets, consumer choice and great consumer service.

5.4.6 Smart Network

A smart network is much the same as a network that a Distribution Network Provider would own and, in many cases, operate. The network is extended with monitoring, measurement, control and automation capabilities. This includes extended data and communications technology required to support the increased automation. Typically, there is a shift to decentralised control, allowing areas within the network to operate/self-heal, etc, in accordance with some predefined rules.

5.4.7 Function and Participant Interaction

New Zealand EDBs must transition their services to that offered by a DSI in order to remain relevant and to protect shareholder asset value. The transformation roadmap to realise and deliver value from new market opportunities is not trivial – it requires investment in the way EDBs currently do business, in their technology and in their people, adding an unprecedented level of complexity to the EDB business.

Function	EDB	DSO	SO
Network Operation	Deliver safety and reliability (i.e. keep the lights on) through the maintenance and operation of distribution network assets. Respond to customer needs.	Operate the electricity distribution network to maintain a safe and secure system. Coordinate and collaborate with the SO to manage potential conflicts to support whole system optimisation. Respond to customer needs.	Operate the transmission network to maintain a safe and secure system. Manage potential conflicts to enable whole of system optimisation.
Security of Supply and Resilience	Support local and whole of system resilience and security.	Enhance whole system security through the provision of local and regional flexible services.	Coordinate whole of system security of supply and resilience through restoration plans agreed with government, the regulator, other relevant agencies, DSOs and service providers (Aggregators).
Connections	Provide fair and cost effective distribution network access.	Provide fair and cost effective distribution network access that includes a range of connection options that meet customer requirements, and system needs efficiently.	Provide fair and cost effective transmission network access for customers through a range of connection options. Address the transmission impacts of distribution connections where required.

Table 5.5: Function and Participant Interaction

Function	EDB	DSO	SO
Services / Market Facilitation	Limited at present, for example, enable the flexible connection of DER to provide wider system services.	Interface with the SO (including information and control infrastructure) to enable development of distribution capacity products, creation of local network service markets and enable DER access/participation in wider balancing services for whole system optimisation. Facilitate local and national markets to access services through auctions and other market arrangements for whole system efficiency. Provide data / information to facilitate distribution markets and service provision.	Facilitate markets to provide services through the operation of market arrangements. Provide data / information to facilitate markets and service provision. A potential further role includes interfacing with DSOs (including information and control infrastructure) to enable the development of distribution capacity products, the creation of local network service markets, and to enable DER participation in wider balancing services for whole system optimisation.
Investment Planning	Deliver a network that securely operates through efficient, coordinated and economical network assets.	Coordinate with the SO and Transmission Owner to identify whole system options. These would include commercial DER options as well as distribution network investments.	Coordinate with DSOs and Transmission Owners to determine optimal whole of system investment options. These would include whole of system and commercial/operability options as well as network investment options.

Revenue	Adopts common methodologies and principles to set pricing for Distribution Use of System and Connections.	Sets Distribution Use of System prices for local network. Determines Point of Connection. Determines connections charges and informs connectees of Transmission reinforcement charges (if applicable). Considers impact of Exit Charging (dependent on size, variations and apportionment)	Set and administer Connection and Use of System charges for parties connecting to and using the Transmission system
Service Provision	Minimal at present.	A DSO to access services on behalf of others (e.g. SO or other EDBs and other DSOs), or provide services to others, where doing so is necessary to maximise whole system efficiency, and protects competition	Procure services from transmission connected resources, distributed energy resources (DER) and potentially, in the future, distribution and transmission networks. The SO would have no role in the direct provision of services but would invoke emergency Grid Code provisions if required to address market shortfalls.
Balancing	None	A DSO could operate local and regional balancing areas for whole system optimisation. This could include local actions to manage constraints, minimise losses and provide capability to contribute to maintaining the national energy balance.	Act as residual balancer for the System. Define and procure energy and network balancing services ahead of time (in market timescales) and close to real-time to balance generation and demand and ensure security and quality of supply. Work with DSO's to coordinate local and regional balancing areas and to utilise residual distribution capability for wider system balancing and whole system optimisation.

Table 5.6: Function and Participant Interaction Continued

5.5 Asset Management Excellence

To achieve asset management excellence and to provide confidence to market participants and consumers alike within a new energy future, MainPower has decided to ensure our asset management systems, process and practices are compliant with ISO 55001.

Within the last reporting period, using an external service provider, MainPower assessed our asset management maturity against ISO 55001. The following describes the current status including the roadmap to achieve certification in the future.

5.5.1 ISO 55001 Current State

MainPower was assessed against 161 maturity assessment criteria within the ISO 55001 framework. MainPower was evaluated as being:

- 22% compliant;
- 26% in progress of being compliant;
- 41% partially compliant – no evidence of becoming compliant; and
- 11% nil compliance, providing an overall compliance.

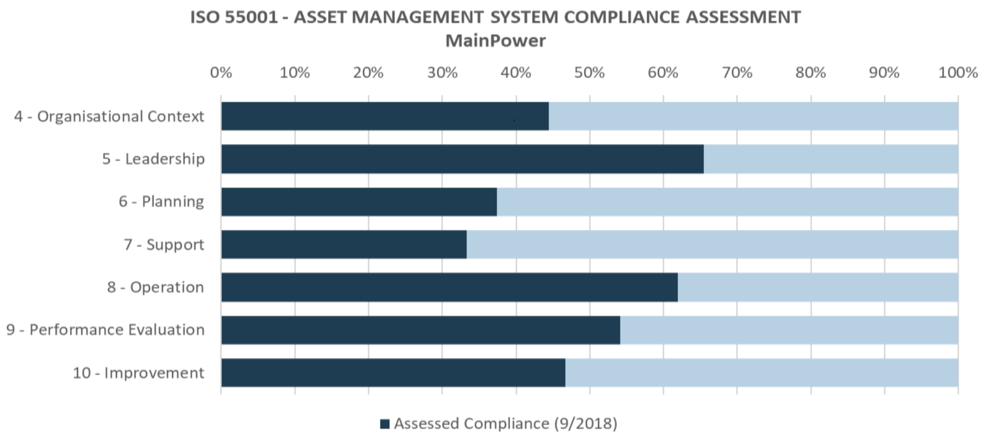

Figure 5.4: ISO 55001 Current State

5.5.2 Asset Maturity Roadmap

Recommendations required to achieve ISO 55001 alignment and certification have been mapped and are proposed to be implemented during the next 3-4 years as per Figure 5.5, which includes percentage compliance:

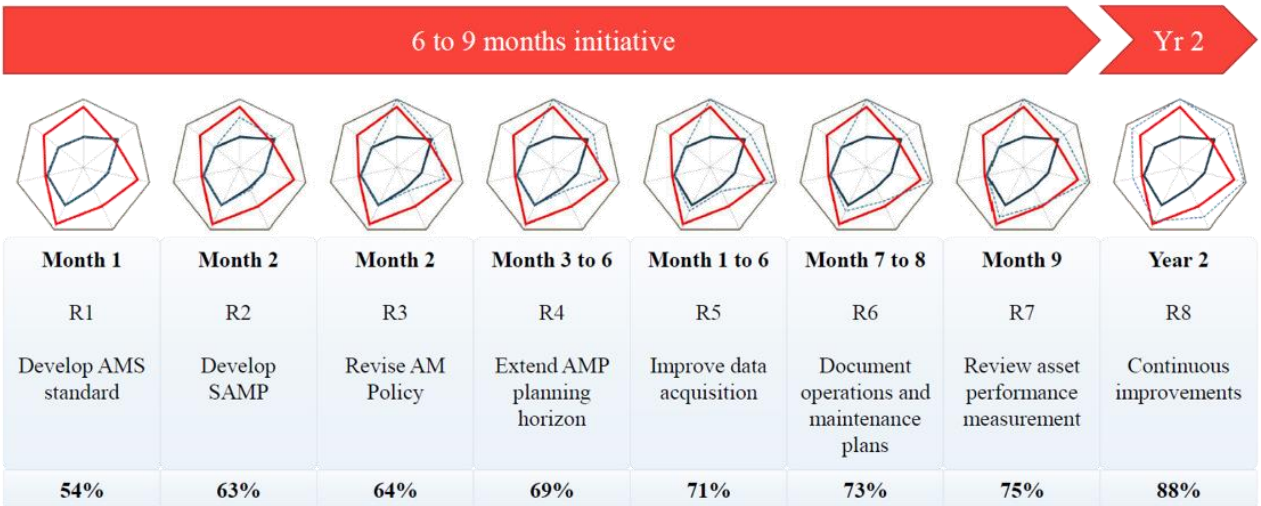

Figure 5.5: ISO 55001 Maturity Road Map

Recommendation	Improvement
R1	Document the AMS (Asset Management Standard) to provide clarity on the management system that has been designed to manage MainPower assets. This could be a short document that describes the scope of assets managed and the key components to the AMS, including people, process and technology. The relevant requirements in the Standard are 4.3, 4.4.1, 5.1.2, and 7.6.1. Improvement 5%
R2	Develop and implement a Strategic Asset Management Plan (SAMP) that clearly links the organisational asset management objectives to the tactical asset management practice. This could be implemented using digital technology, rather than hardcopy documents, to create a 'live' asset management environment and to readily engage stakeholders in the AMS, particularly the future planning of renewal works. The SAMP would also include clarification and/or development of asset management objectives that cover technical (asset) and service delivery (stakeholder) outcomes. Improvement 9%
R3	Amend the current Asset Management Policy to confirm top management commitment to asset management and to guide the context of the AMS. The relevant requirements in the Standard are 5.1.8 and 5.2.

	Improvement 1%
R4	Review and extend the current asset planning horizon, for asset renewal works, to improve visibility on the future financial liabilities relating to asset performance and risk. This is typically referred to as a 10-Year Capital Plan or Forward Works Plan. The relevant requirements in the Standard is 6.2.2. Improvement 5%
R5	Review the current asset data acquisition and management practices. The relevant requirements in the Standard is 7.5, which addresses information for asset management decision-making. Improvement 2%
R6	Documented Operations and Maintenance Plans to capture practice knowledge for continuity in practice. The relevant requirements in the Standard are 7.6.2 and 8.1, which address creating and updating information for asset management purposes. Improvement 2%
R7	Reviewing and refining the method of service and asset performance measurement, and monitoring including evaluation and analysis. The relevant requirements in the Standard is 9.1, which addresses monitoring, measurement, analysis and evaluation. Improvement 2%
R8	Review the progress made to the AMS, assess the resources, ensure staff are competent and continue to champion better asset management practices to build awareness and foster continuous improvements. The relevant requirements in the Standard are 5.1, 5.3, 7.2, 7.3, 7.4, 8.2, 9.3 and 10, which address continuous improvement. Improvement 13%
Total	Implementing all the recommendations will have the following effect to the compliance assessment: Improvement 39% Assessment Against Compliance 88%

Table 5.7: ISO 55001 Compliance Recommendations

5.5.3 Comparison with the Commerce Commission's Asset Management Maturity Assessment Tool

There are some similarities between the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT) and the ISO 55001 standard. The ISO standard assesses compliance against a fixed standard as compared to AMMAT, which focusses on maturity and compares the utility to other similar utilities in the industry. The AMMAT is based on PAS55, which focusses on the actions that people take, whilst ISO 55001 has a wider focus on governance, systems, thorough understanding of principles and compliance to established standards.

5.6 Operational Excellence

The kernel of the MainPower network is the Network Operations and Control Centre (NOCC). Taking into consideration the day-to-day operational control of the electricity distribution network, a New Energy Future and the transformation of services to enable an Open Network Framework, MainPower reviewed its NOCC practices in the last reporting period.

The review assessed our NOCC against:

- Industry best practice;
- Compliance with Safety Manuals for the Electricity Industry (SMEI); and
- The Health and Safety at Work Act.

The review covered:

- Processes that govern activities undertaken by the Control Room;
- Compliance against requirements of SMEI (industry rules);

- Processes for issuing authorities/permits to staff for HV and LV access, as well as minor works apart from the network itself;
- Processes for managing staff competency to hold authority documents;
- Processes for ensuring safety of the works prior to issuing authority to work;
- Identifying any gaps, failings and non-compliance with the processes;
- Identifying areas of our processes that are not properly documented; and
- Selected incident reports to look for common themes and gaps in processes these may highlight.

5.6.1 Operational Maturity Roadmap

	Improvement		Target Date
Roles and Responsibilities	1. Using process to identify skills across the NOCC and ensure that these skills are spread across the team – not reliant on individuals. 2. Start targeting specific workstreams within the NOCC (WP, RP and Controller) so that roles can concentrate on their areas of responsibility only.	It is proposed to comprehensively process map all NOCC process. The introduction of specific roles within the NOCC will be introduced.	2020
Consumer Interfaces	3. Implement improved outage communications to consumers, for both planned and unplanned outages. 4. Automation of outage communications to consumers. 5. Enable consumers to access their own information – consumer portal.	A more sophisticated Outage Management System is required. This is already in progress as part of the ADMS project.	2020
Functional Arrangement	6. Introduce a flat operating model, single screen for all system enhancing situational awareness. 7. Map control room processes.	This initiative is supported and forms part of the ADMS project.	2020
Business Metrics	8. Introduce increased levels of automation within the NOCC for both operational effectiveness and performance reporting. 9. Examine options to ensure key data is available to all departments who plan access to the network (lines personnel/underground/substation/live-line activity/ external works personnel).	Detailed reporting suffers within the NOCC due to the limited number of systems that support the NOCC. It is proposed in 2020 to understand what performance metric MainPower should monitor and to subsequently implement these metrics.	2021
People	10. Develop a succession plan for NOCC staff that includes attracting talent (future controllers). 11. Schedule regular workshops for Controllers and Field Operators to identify and understand issues leading to NOCC process enhancement including the NOCC Competency Framework. 12. Continue review of hours worked, implement plans to manage staff hours worked against risk, i.e. the resource risk management plan has been implemented and this must be maintained to manage the associated risk.	The people that support NOCC operations are sought after across the country. Documentation of current risk within the Control Room has been completed and we are currently working our way through the controls required to mitigate	2022

	Improvement		Target Date
		the high and extreme risks. Future work remains to ensure that an effective succession plan and a continuous improvement programme are in place to address longer term issues.	
Systems, Process and Practices	13. Document thoroughly all NOCC processes. 14. Identify key roles (WP, RP and Controllers) and understand the interfaces between the key roles, including simplification of some of the processes. 15. Review process for assuring field staff competency – for example, a database that reflects the competency of the staff receiving a permit or carrying out an activity on the network. 16. Review the tagging process. The current process and issuance of single 'Do Not Operate' tag relies on the Control Room and increases the complexity of the Controller's roles. 17. Consider a process of managing the 'Whiteboard' including requesting and confirmed action. Whiteboards are typically limited to manage 30 operations; this solution may not be sustainable to support the business in the future. 18. There is an opportunity to improve Controller familiarity by undertaking refresher courses on a more regular and planned basis to ensure all personnel including the NOCC are refreshed in all relevant processes and procedures, and to ensure a consistent understanding across all Controllers and field operating personnel. 19. Basic safety controls for network access could be enhanced through development of the current systems or investment in a system that would provide better integration among the current processes. 20. Training and procedures need to clearly articulate each of the Network Access permit's requirements and constraints, i.e. Entry Approval, Work Authority, Close Approach, Access Permit (HV), Test Permit (HV), Live Line (HV), LV Permit. 21. The two databases (WORM and Logbook) are potentially single points of failure due to the unsupported in-house design of each system.	Systems process and practise are about to undergo transformational change as MainPower implements its ADMS project. This requires MainPower to reassess these improvements upon go-live of the new system.	2021
Load Management	22. There is an opportunity for the system HMI to be revised to enable the Controller to have improved visibility of the system. Consideration should be given to exploring energy management systems that many distribution networks operate. 23. Need to review how the system is supported. 24. Look to integrate Load Management functionality into a future ADMS to reduce overhead of maintaining a separate system.	System HMI and SCADA will also be upgraded in the future as part of the ADMS project. Load management – the benefits of and better utilisation of negative generation –remains a strategic focus for MainPower. Once strategy is formulated and business objectives and planning are completed, these	2022

	Improvement		Target Date
		improvements will need to be reassessed.	
SCADA	25. Work closely with the Controllers to better determine requirements for desktop configuration. Undertake site visits to view possibilities. Also consider the remote work and disaster scenario. 26. There is always an opportunity to enhance the existing system by reviewing alarm priorities and grouping from an operational perspective. 27. Consider if there are critical aspects of system management that can benefit from modern notifications via SCADA e.g. Load Management. 28. In considering SCADA HMI improvements, all monitored devices on a 'normal' configuration of a feeder should be presented on a single page to provide improved situational awareness. 29. SCADA/ADMS are critical systems deserving of redundancy in design and implementation. However, the scale of operations at MainPower does not necessitate a full back-up Control Room. Consider a DR plan that provides for loss of access to SCADA/ADMS.	Forms part of the ADMS project.	2020
Incident and Event Management	30. Develop a restoration process/procedure that provides a detailed response for prioritising fault activity based on good risk management practices. 31. Consider deploying a knowledge management system appropriate to the need of the Control Room. As a minimum, this should provide ready access to: a. Company operational and OH&S procedures; b. Industry guidelines; c. Technical support manuals; d. Single-line Network and Station diagrams; e. Protection settings; f. Transformer and feeder circuit load ratings; g. Contact listings (internal and external); h. Escalation processes; i. Contingency plans, etc.	Improvements to be revised, plans developed and integrated into the next business planning cycle.	2020
Supporting Systems	32. Recommend reviewing the phone system in terms of its current use and foreseeable future with a view to provisioning a redundant system that will meet MainPower's future needs. 33. Investigate and confirm that the existing Corporate VOIP Server has limited or no redundancy and assess the importance of upgrading to ensure a redundant system is in place. 34. Review the VOIP Server in terms of the number of incoming lines, the priority of incoming lines (via Caller Line Identification, CLI), and the number of lines allocated to the IVR. 35. Being a VOIP System enables the NOCC to make better use of the many user configurable settings that may help facilitate and streamline Control Room processes. 36. Consider replacing email systems with more real-time, SMS-based systems. 37. When considering new technologies (IoT), consider how they will integrate into core systems and functions. Assess	Improvements to be revised, plans developed and integrated into the next business planning cycle.	2020

	Improvement		Target Date
	the burden vs benefit this imposes on the Controller and Control Room processes. 38. Undertake cross-team familiarisation between OT and IT teams to develop understanding of the requirements and drivers for each of these teams and consider what skills may be cross-functional.		
Environment	39. There is value in having the current design of the Control Room assessed for fatigue and general ergonomics. 40. Several of the desks face the external windows and it is recognised that the competing lighting from the external source and the computer screens results in increased fatigue and eye strain. Consider facing desks away from external light sources.	Improvements to be revised, plans developed and integrated into the next business planning cycle.	2020
Resilience	41. Develop/review the generator testing regime. Ensure that generator testing includes extended onload testing to confirm all elements of the motor operation are ready for service (i.e. thermostat operation, etc). 42. Develop/review the UPS testing regime. Ensure the UPS can undertake a 50% discharge operation on an annual basis. 43. An active DR plan was not available and needs to be developed. Consider the requirements for a Disaster Control Room and the systems that would need to be implemented. Note however that it is not recommended that a 'fully' redundant Control Room be established due to cost. Consideration of multiple options for a backup facility will maintain flexibility – a strength of MainPower's culture. 44. Develop a (simple) plan that lists options for a Disaster Control Room and the systems required to support a room for sustained operation. A 'Grab and Go' box with key documents would be a requirement, preferably securely located offsite and updated every 3-6 months. 45. Examine the option to have after hours fault calls directed to a call centre in either New Zealand or Australia that has experience in surge type call activity and/or undertakes electricity fault calls. This would enable the Controller to focus on network activities. This process would require an electronic transfer of information from the Call Centre to the Control Room.	Improvements to be revised, plans developed and integrated into the next business planning cycle.	2020
Data Accuracy	46. Continue with the process of field checking all ICPs prior to a network interruption. Over time this will provide benefits with respect to Low Voltage control. The management decision to invest in this process recognises the importance of compliance in this area.	Improvements to be revised, plans developed and integrated into the next business planning cycle.	2020

Table 5.8: NOCC Operational Effectiveness

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 seen as:

- 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 observed to be creating serious challenges on networks internationally;
- The impact of new commercial parties, models and business platforms working through both the distribution network and through 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 EV chargers, on standard network infrastructure and the ability to manage the significant demand peaks and power quality issues these introduce at the low voltage distribution level;
- The potential for use of separated distribution micro grids where these are the most economical solution when considering renewals or new supplies; 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 in order to deliver and help minimise the risk of uneconomic network development.

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

While we review our network development planning process, our network development plans are primarily driven by safety, security of supply, reliability and compliance requirements – these will evolve to include future requirements for the North Canterbury region.

The following section identifies the current deterministic planning process with some innovation based on our future thinking 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 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 11kV and 22kV to assist in maintaining the voltage within the statutory voltage limits. 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 – 11,300V band. Line drop compensation is rarely used because of the large consumer spread along the distribution lines.

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 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 consumers' point of view, as specified in Section 2. 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 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 should the project not proceed or be 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 the following table:

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 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 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 the following table:

Classification	Description
L1	Large Industrial (>5MW / 15 GWh of Industrial load)
L2	Commercial / CBD (>5MW / 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 shall be arranged so that the security criteria in the table below 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 one 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 two hours. Restoration of supply via LV connection is acceptable for this. The isolated section shall be limited to 750 kVA unless it is a single consumer with a load in excess of this.
L3	After a fault is located, supply can be restored to all but the isolated section in three 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 four 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;
- 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 11kV to 22kV will cause a replacement transformer to be installed that meets the new Minimum Energy Performance Standard (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 in regard to 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 $0.5m, generally involving sub-transmission, zone substation or grid exit points (GXP) works.
- **Reinforcement Projects** – below $0.5m, including distribution feeder capacity and voltage upgrades, security (N-1) reinforcements, distribution substation and transformer upgrades, and LV reinforcement.
- **Open-Access Network Investments** – investments to support the transition towards an open-access network, including network monitoring, communications and power quality management.
- **Reliability and Automation** – includes network automation projects to help manage the reliability performance of our network. These are currently integrated within our major and reinforcement projects.

6.6.2 Demand Trends

Our network demand forecasting process forecasts demand at Transpower's North Canterbury Grid Exit Points (GXP) and MainPower's zone substations over the next ten years.

When developing demand forecasts, a number of 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 impacts on peak demand;
- Expected economic developments; and
- Emerging technology adoption, such as electric vehicles.

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

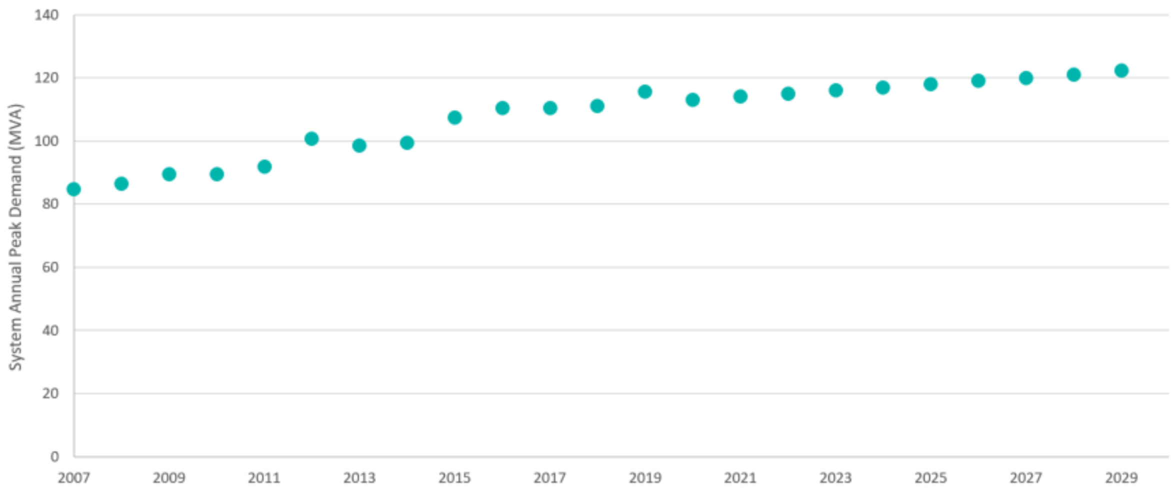

Figure 6.1: Historical and Forecast Total System Demand

The consistent growth exhibited is mainly a result of:

- 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 due to 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.

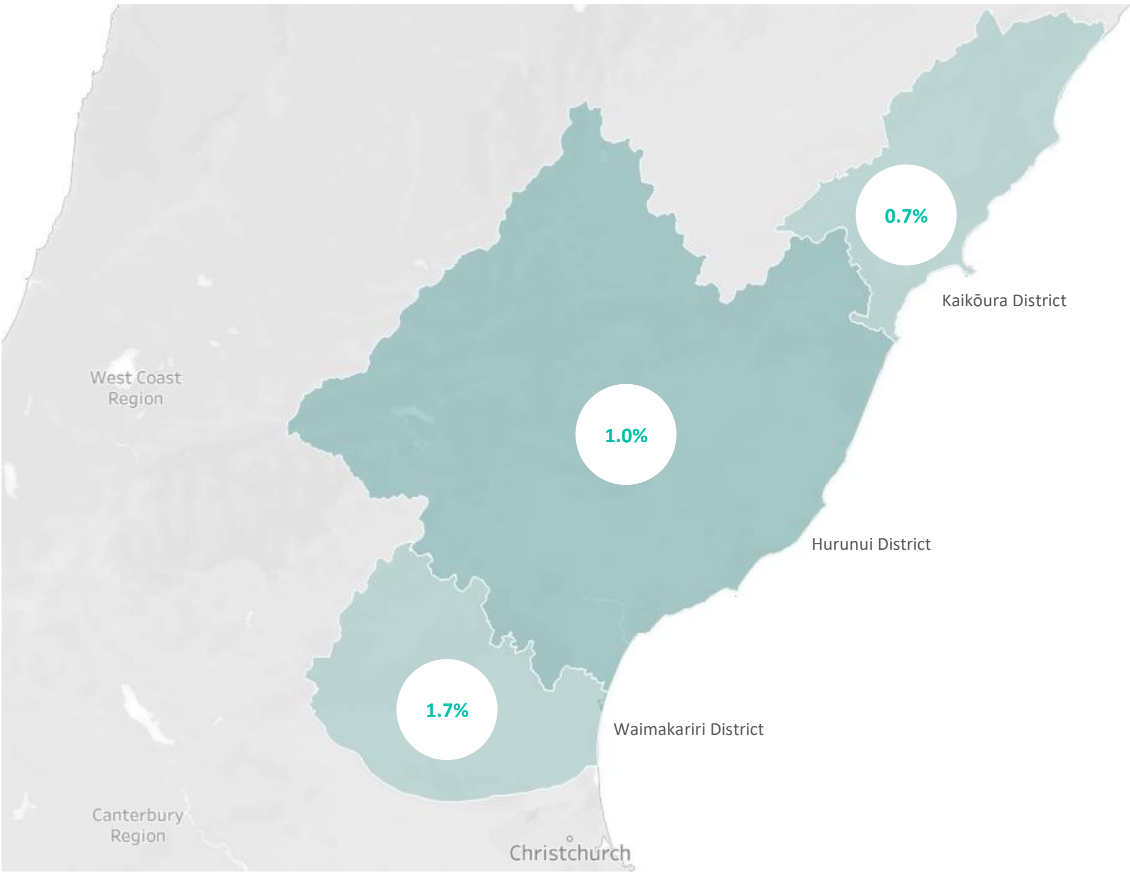

Figure 6.2: Annual Forecast Energy Growth Rates by Planning Area

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 MainPower already employs.

The graphs below show the growth of small scale (<100kW capacity) distributed generation within the network. The connection rate is increasing very slowly. On average, approx. 500kWh 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 (0.12kW, 784 consumers or 2.7%), Hurunui (0.08kW, 166 consumers or 1.7%), Kaikōura (0.02kW, 16 consumers or 0.6%).

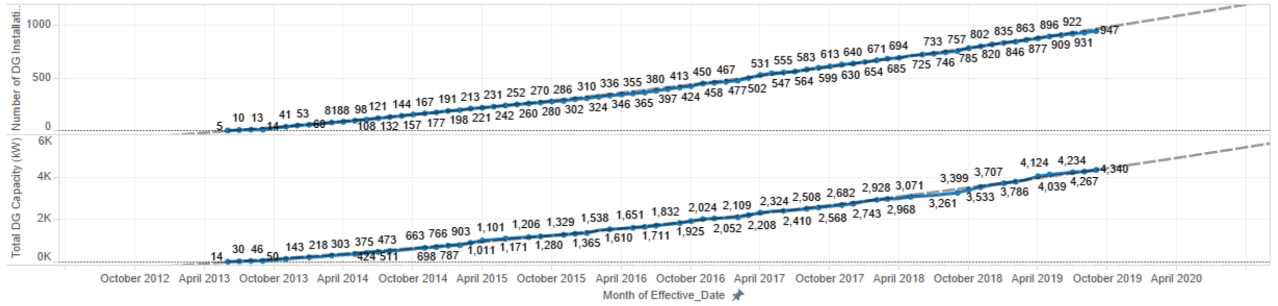

Figure 6.3: Distributed Generation Trends

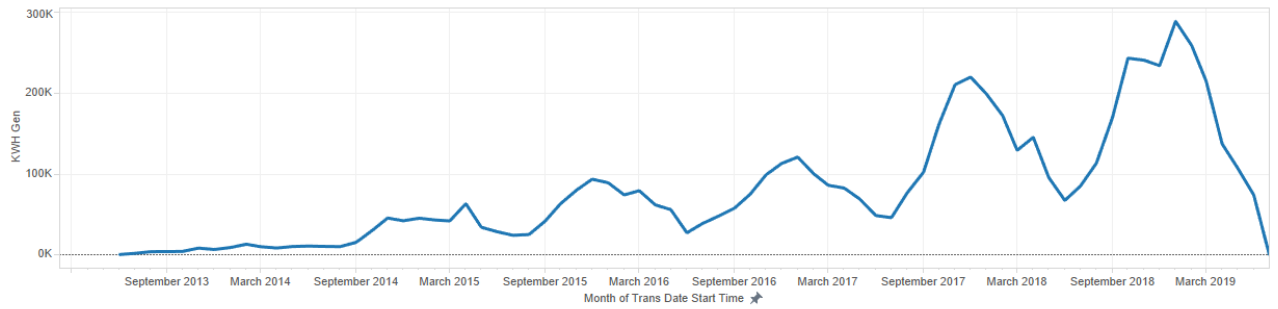

Figure 6.4: Distributed Generation Exported Volume

6.6.4 Distribution Innovation

MainPower's future focus in network development planning includes 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, 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. Solutions do not necessarily need to be delivered by MainPower; they can be supplied, maintained and operated by others.

6.7 Area 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 in the sections below. In demand forecast tables, grey shading indicates that peak demand exceeds current security class capacity.

6.7.1 Waimakariri Regional Overview

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

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

The region is characterised by flat open plains used for a range of farming activities combined with an increasing number of small to medium-sized lifestyle blocks. Seasonal weather extremes, including snow and strong winds can impact 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 33kV to Transpower's Waipara GXP in the Hurunui region. The area uses a combination of 66kV and 33kV sub-transmission voltages. We are transitioning away from 33kV.

The sub-transmission network is dominated by a large overhead 66kV ring circuit, serving Burnt Hill and Swannanoa, with a double circuit 66kV tower line feeding Kaiapoi. The 66kV 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.

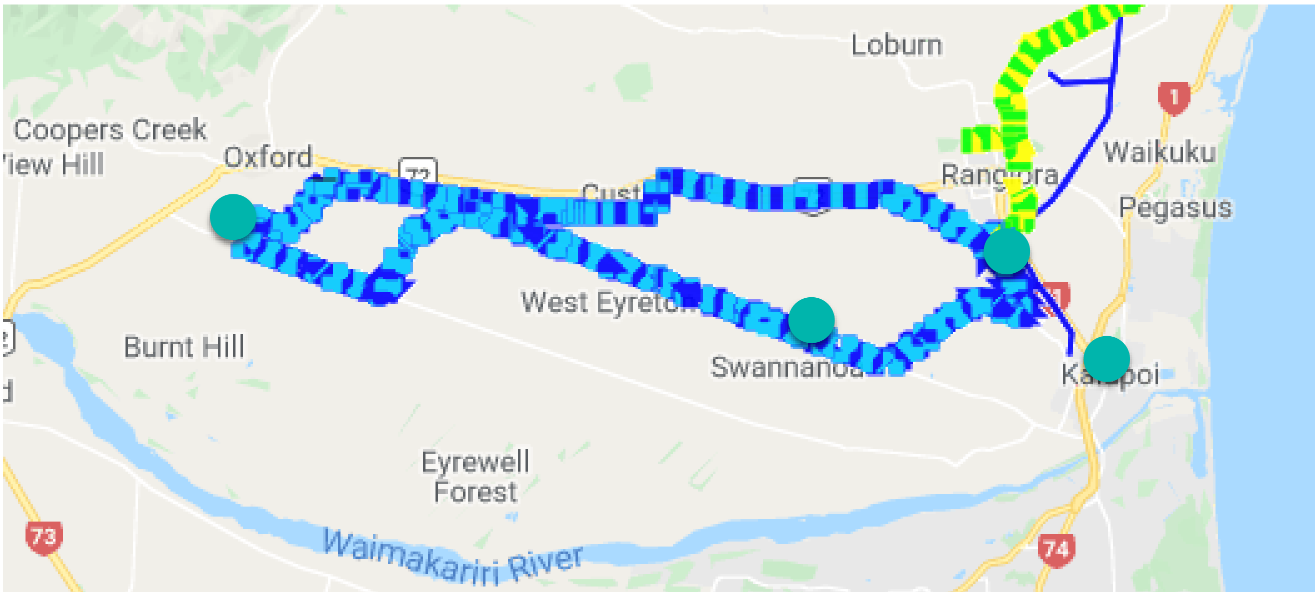

Figure 6.5: Waimakariri Region Sub-transmission Network

6.7.1.1 Demand Forecasts

Demand forecasts for the Waimakariri zone substations are shown below in Table 6.4.

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Ashley GD	AA+	0 MVA	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
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	15.7	16.0	16.3	16.6	17.0	17.3	17.6	17.9	18.3	18.6
Kaiapoi	AAA	40 MVA	29.0	29.5	27.0	25.5	26.0	26.5	27.0	27.5	28.0	28.5
Rangiora	AA	7.0 MVA	7.0	0	0	0	0	0	0	0	0	0
Southbrook	AAA	22.0 MVA	22.0	33.2	35.1	36.9	38.7	40.6	42.5	44.3	46.3	48.2
Swannanoa	A1	23.0 MVA	16.0	16.3	16.6	16.9	17.2	17.5	17.9	18.2	18.5	18.9

Table 6.4: Waimakariri Area Network Demand Forecast

6.7.1.2 Network Constraints

Major constraints affecting the Waimakariri area are shown below 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 33kV 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) combined with 11kV 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 33/11kV to 66/11kV (FY21) and develop further 66kV interconnections between Waipara, Southbrook and Kaiapoi.
Southbrook (Rangiora, Pegasus, Woodend)	The Southbrook zone substation exceeds its 22MVA 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. Approximately 2MW of load will be transferred to Ashley before winter 2020. The Southbrook zone substation will be upgraded to 66/11kV (completed FY21).

Table 6.5: Waimakariri Area Network Constraints

6.7.1.3 Major Projects

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

SOUTHBROOK 66KV SUBSTATION UPGRADE	
Estimated Cost:	$10.6m
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 33/11kV zone substation as a 66/11kV zone substation. This will:

- Increase the N-1 capacity at 11kV from 29 MVA to 45 MVA, to meet existing and future loads in this region;
- Remove the phase shift between the Southbrook 11kV 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 33kV switchgear;
- Improve network reliability and security of supply in the surrounding Southbrook and Rangiora regions;
- Reduce the arc flash risk of the Southbrook zone substation.

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

SOUTHBROOK 33KV SUBSTATION DECOMMISSIONING	
Estimated Cost (concept):	$0.25m
Expected Project Timing	FY22
Project Driver	Asset End of Life/Redundancy

The project leads on from the Southbrook 66kV 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):	$0.05m
Expected Project Timing	FY23
Project Driver	Asset End of Life/Redundancy

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

KAIAPOI ZONE SUBSTATION 11KV SWITCHBOARD RENEWAL	
Estimated Cost (concept):	$3.05m
Expected Project Timing	FY23
Project Driver	Asset End of Life Replacement

MainPower is currently investigating options to purchase the Kaiapoi GXP from Transpower. Transpower is currently planning the end of life replacement of the 11kV switchboard, where we would subsequently inherit this liability with the substation purchase. We plan to replace the 11kV switchboard in FY23.

ASHLEY TO TUAHIWI 66KV SUB-TRANSMISSION LINE	
Estimated Cost (concept):	$1.98m
Expected Project Timing	FY26-FY27
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 four-year series of projects to construct the 66kV sub-transmission network to support a new Tuahiwi 66kV zone substation. The first stage of this is the 66kV overhead supply circuits from the Ashley GXP to the Tuahiwi 66kV zone substation site. Construction will be timed to be completed ready for the new substation.

SOUTHBROOK TO TUAHIWI 66KV SUB-TRANSMISSION LINE	
Estimated Cost (concept):	$2.75m
Expected Project Timing	FY28-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 is to construct the second 66kV overhead supply circuit from the Southbrook GXP to the new Tuahiwi 66kV zone substation site. Construction will be timed to be completed in the year following the Tuahiwi zone substation.

TUAHIWI 66/11KV ZONE SUBSTATION	
Estimated Cost (concept):	$7.78m
Expected Project Timing	FY24-FY28
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.

ASHLEY GXP – 66KV BAY FOR TUAHIWI CIRCUIT	
Estimated Cost (concept):	$0.90m (Transpower)
Expected Project Timing	FY29
Project Driver	Growth and Security of Supply

This project will be undertaken by Transpower as a connection asset upgrade for MainPower. The scope includes adding a new 66kV feeder with metering at the Ashley GXP site. Completion will be required in conjunction with the Ashley-Tuahiwi 66kV sub-transmission line project.

SOUTHBROOK GXP – 66KV BAY FOR TUAHIWI CIRCUIT	
Estimated Cost (concept):	$1.50m
Expected Project Timing	FY29
Project Driver	Growth and Security of Supply

This project will be undertaken by Transpower as a Connection Asset upgrade for MainPower. The scope includes adding a new 66kV feeder with metering at the Southbrook GXP site. Completion will be required in conjunction with the Southbrook-Tuahiwi 66kV sub-transmission line project.

6.7.1.4 Reinforcement Projects

MainPower invests in tactical network reinforcement projects to improve network reliability, security of supply and help defer higher capital projects. Below are summaries of the reinforcement projects in the Waimakariri area.

FY	Project Title	Description	Cost ($,000)
FY21-24	Northbrook Feeder	Extend a 300mm2 AL XLPE 11kV feeder cable to increase capacity to eastern and northern Rangiora	335 60
FY22	Kippenberger Avenue Circuit Breaker	Install a circuit breaker on the fringe of urban Rangiora to improve the reliability in eastern Rangiora	65
FY21-22	Flaxton Road Undergrounding	Install duct in Flaxton Road in conjunction with WDC road improvements. Underground 11kV from under 66kV to reduce risk and improve reliability.	50 141
FY22	Pegasus Feeders	Extend the 300mm 11kV cables for the Pegasus switching station from west of the SH1 roundabout to the vicinity of Okaihau Rd to enable the Southbrook substation capacity to directly Pegasus.	702
FY21	Reinforce SW63 & SW66 Swannanoa	These are large, highly loaded feeders with limited switching capability. The project improves safety and reliability by installing two circuit breakers and three remote controlled switches.	312
FY22	Reinforce X52 Burnt Hill	The project will increase the security of supply of feeder X52 by upgrading 660m of conductor in North Eyre Road.	228
FY21	Loburn Feeder Reliability Improvement	The project will improve reliability in the Loburn area by enabling transfer of part of the very large Loburn feeder to the small neighbouring feeder.	210
FY21	Loburn Overhead Reconductoring	Reconductor part of the Loburn feeder to improve quality of supply.	187
FY23	Kaiapoi - Island Road Upgrade	Install a 300mm2 AL XLPE 11kV cable from the Kaiapoi GXP to beyond the urban area to increase capacity into the region.	200
FY23	Rangiora - East Belt North	Install a kiosk substation on an existing easement in Kippenberger Ave. This will improve operational flexibility as eastern Rangiora continues to develop.	80
FY26	Townsend Road Feeder	Install 300mm2 AL XLPE 11kV cable to Pentecost Road to create a new feeder route to south western Rangiora, increasing capacity and security of supply.	500
FY28-30	Tuahiwi to Rangiora Feeders	Install 300mm2 AL XLPE feeder cables between the new Tuahiwi 66kV zone substation and the eastern side of Rangiora to improve security of supply.	900

Table 6.6: Waimakariri Area Reinforcement Projects

6.7.2 Hurunui Regional Overview

The Hurunui area covers the region from the north of the Balcairn, to the Hundalee and Stag & Spey on the Inland Road to Kaikōura. The main towns include Amberley, Cheviot, Hawarden, Culverden, Rotherham, Waiau, and Hanmer.

Amberley's location on SH1 and 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 established significant vineyard developments. 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 combined with an increasing number of small-to-medium sized lifestyle blocks. Seasonal weather extremes, including snow and strong winds can impact 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 66kV and 33kV sub-transmission voltages, and we are transitioning away from 33kV. The sub-transmission network consists of a very long 66kV and 33kV interconnection between Waipara and Culverden GXPs which supplies the Mackenzies Road, Greta, Cheviot & Parnassus substations in the Hurunui area and also Oaro and Kaikōura/Ludstone Rd substations in the Kaikōura area. Hanmer is on a 33kV spur from the Culverden GXP, while Amberley is on a 33kV spur from the Waipara GXP which also ties through to the Southbrook GXP.

The Kate Valley landfill site has significant and growing landfill gas generation (currently up to 4MW). The neighbouring Mt Cass is also likely to be the site of a large wind farm. Both would feed back to the Waipara GXP.

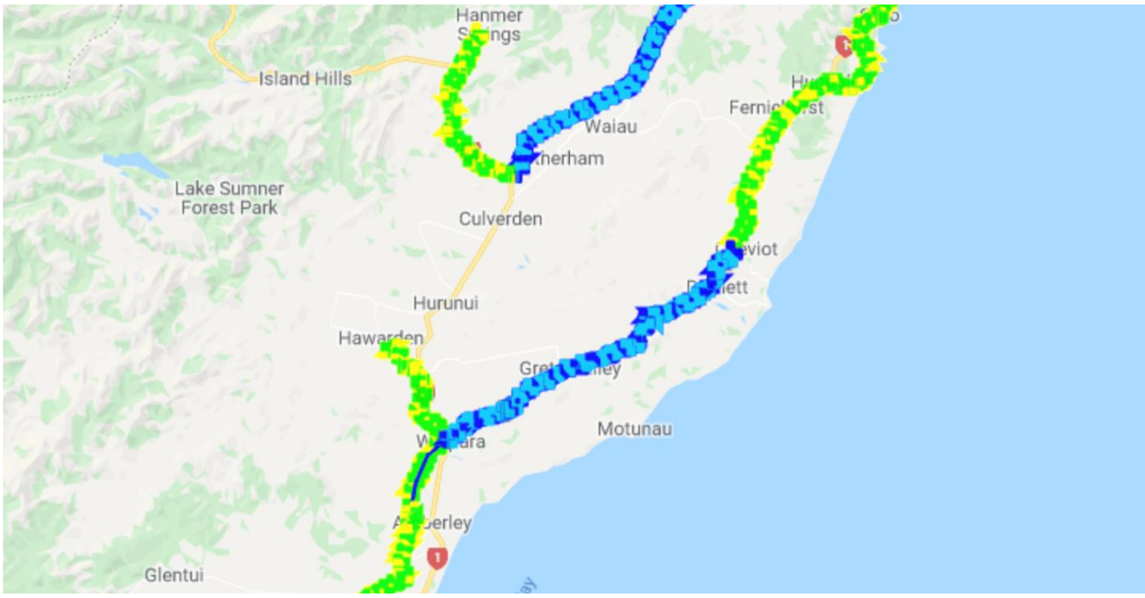

Figure 6.6: Hurunui Sub-transmission Network

6.7.2.1 Demand Forecasts

Demand forecasts for the Hurunui zone substations are shown below in Table 6.7.

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
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	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Cheviot	A1	4 MVA	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7	3.7	3.8
Leader	A1	2 MVA	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	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	5.2	5.3	5.4	5.4	5.5	5.6	5.7	5.7	5.8	5.9

Table 6.7: Hurunui Area Network Demand Forecasts

6.7.2.2 Network Constraints

Major constraints affecting the Hurunui area are shown below 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 33kV spur without a backup. The 33kV alternative supply to the spur from Southbrook will be removed by the planned Southbrook upgrade.	Planned load transfer to Mackenzies Rd to minimise the capacity shortfall. Replace the Southbrook alternative 33kV supply with an approx. 6 MVA 33kV supply from Ashley. The substation will be rebuilt as 66/11kV in a full n-1 configuration in FY28-29.
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 backup at 22/11kV in FY23.
Cheviot	The peak load cannot be supplied in the event of a transformer outage.	The Cheviot to Oaro 66kV upgrade in FY21 will increase the capacity of the Leader substation to supply the northern Cheviot area at peak summer loads. The Cheviot area will be linked to the Greta substation to provide switchable backup at 22/11kV in FY23.
Leader	The peak load cannot be supplied in the event of a transformer outage.	The FY20 projects will enable Cheviot to supply Leader for winter loads. The Cheviot to Oaro 66kV upgrade will increase the capacity of the Leader substation from 2 MVA to 4 MVA in FY23. There are currently no plans to provide full switchable backup within the planning period.
Hawarden	The peak load cannot be supplied in the event of a transformer outage. The substation is supplied from a 33kV spur without a backup.	The substation is planned to be rebuilt as a dual transformer supply in FY24-25. There are no plans to provide backup for the 33kV sub-transmission line within the current planning period.
Mouse Point	The peak load is above the n-1 transformer rating. Switching of the 33kV 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 8MVA transformer is held as a backup Summer cyclic ratings will be established to maximise the contingency rating. The proposed partial purchase of the Culverden Transpower GXP in FY22 would reduce the required switching time. The substation will be rebuilt as 66/22kV in a full N-1 configuration in FY29 and FY30.
Hanmer	The peak load is above the capacity of the installed spare transformer. The substation is supplied from a 33kV radial spur.	The second transformer will be upgraded to provide peak loads in FY23. The 33kV line will be upgraded over FY20-24 to maximise its strength and minimise the risk of prolonged outages in an extreme event.

Table 6.8: Hurunui Area Network Constraints

6.7.2.3 Major Projects

Below are summaries of the major projects (growth and security) planned for the Hurunui area.

AMBERLEY SUBSTATION SECURITY	
Estimated Cost (concept):	$0.80m
Expected Project Timing	FY21
Project Driver	Security of Supply

The Southbrook zone substation upgrade will remove the 33kV N-1 supply to Amberley. This project is to restore 6 MVA of alternative supply capacity from the Ashley GXP by installing an 11/33kV auto transformer on one of the Ashley 11kV feeders. A short 66kV line, operated at 33kV, will be built to connect this to the existing Southbrook-Amberley 33kV line. Installation and commissioning will be completed in FY21, prior to decommissioning of the Southbrook zone 33kV.

AMBERLEY SUBSTATION CAPACITY AND SECURITY	
Estimated Cost (concept):	$6.0m
Expected Project Timing	FY28-FY29
Project Driver	Capacity, Security and Asset End of Life.

This project involves replacement of the Amberley 33kV zone substation, rebuilding it at 66/11kV 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 renew the end of life transformers. Transpower will create 66kV GXP feeders at Waipara and Ashley as separate connection asset projects.

HAWARDEN SUBSTATION RENEWAL	
Estimated Cost (concept):	$5.0m
Expected Project Timing	FY24-FY25
Project Driver	Capacity, Security and Asset End of Life.

This project involves replacement of the Hawarden 33kV zone substation on a new site. The substation will be constructed as an N-1 substation with a single sub-transmission line input. The zone substation will also be built for future operation at 66/22kV. This will remove the capacity constraints, improve security and renew the remaining end of life assets.

MOUSE POINT SUBSTATION UPGRADE	
Estimated Cost (concept):	$6.0m
Expected Project Timing	FY29-FY30
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 and MainPower is currently investigating purchase of part of the Transpower Culverden GXP. This upgrade project is to rebuild the zone substation on part of the existing GXP site. The substation will be constructed at 66/22kV, although initially operated at 33/22kV. It is expected that Transpower will replace the 220kV/33kV transformers at the GXP with 220/66kV transformers around FY32. 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 SUBTRANSMISSION LINE UPGRADE	
Estimated Cost (concept):	$4.5m
Expected Project Timing	FY21-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 TRANSFORMER UPGRADE	
Estimated Cost (concept):	$0.10m
Expected Project Timing	FY23
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 following a fault. This project is to upgrade the second transformer to provide an N-1 zone substation.

6.7.2.4 Reinforcement Projects

FY	Project Title	Description	Cost ($,000)
FY22	Amberley North Load Transfer	Extend and upgrade 11kV lines in Georges Road, Waipara to enable transfer of load in the Mound Road area from Amberley zone substation to Mackenzies Road zone substation.	224
FY23	Amberley Y43 Urban/Rural Circuit Breaker	Install a circuit breaker on the urban fringe of Amberley to improve reliability to the Amberley township.	59
FY23	Greta - Cheviot 22kV Link	Improve security of supply of Cheviot and Greta zone substations by extending the Cheviot South feeder T43 1,500m to link to Greta feeder G31. Convert 14km of 11kV line to 22kV and install tie switches.	487
FY24	Cheviot - Leader Upgrade	Improve security of supply of Cheviot and Leader by upgrading the 11kV conductor between Parnassus and the Waiau East/West Roads.	379
FY26	Amberley South De-loading	Install voltage regulator and conductor upgrades to enable Ashley to provie a backup supply for Leithfield town and Leithfield Beach to meet MainPower's security of supply standard.	200

Table 6.9: Hurunui Area Reinforcement Projects

6.7.3 Kaikōura Regional Overview

The Kaikōura area covers the region north of the Hundalee and east of Stag & Spey on the Inland Road to Kaikōura. The area extends north up the coast to Half Moon Bay, with Kaikōura 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 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 and strong winds and rain can impact 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 66kV, transitioning to 33kV at Kaikōura. The small coastal communities south of Peketa are supplied from the 33kV and 66kV interconnection between Kaikōura and the Waipara GXP.

Figure 6.7: Kaikōura Region Sub-transmission Network

6.7.3.1 Demand Forecasts

Demand forecasts for the Kaikōura zone substations are shown in Table 6.10.

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Ludstone Rd	AA	6 MVA	6.2	6.3	6.3	6.4	6.5	6.5	6.6	6.7	6.8	6.9
Oaro	A1	0.5 MVA	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5		0.5

Table 6.10: Kaikōura Area Network Demand Forecasts

6.7.3.2 Network Constraints

Major constraints affecting the Kaikōura area are provided below 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 backup 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 33kV sub-transmission system from Cheviot to Oaro to 66kV in FY21. This will increase the backup capacity and reduce switching times during high load. Sub-transmission capacity can be further upgraded by the addition of 11kV 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 66/33kV substation site.

Table 6.11: Kaikōura Area Network Constraints

6.7.3.3 Major Projects

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

CHEVIOT TO OARO SUBTRNSMISSION LINE UPGRADE	
Estimated Cost (concept):	$0.90m
Expected Project Timing	FY21
Project Driver	Security of Supply

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

LUDSTONE ZONE SUBSTATION CAPACITORS	
Estimated Cost (concept):	$0.23m
Expected Project Timing	FY24
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 11kV bus and provide voltage support during high load periods.

6.7.3.4 *Reinforcement Projects*

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

6.8 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. A few large projects create a 'lumpy' major project expenditure, which is balanced by activity in the minor works.

Figure 6.8: MainPower Network Development Capex Summary

6.8.1 Major Projects

Network Major Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Cheviot to Oaro Sub-transmission Line Upgrade	912									
Ludstone Zone Substation Capacitors				228						
Kaikōura Zone Substation Capacity Upgrade										5,645
Southbrook 66kV Substation Upgrade	5,679	4,899								
Ashley Zone Substation 33kV Security Upgrade	815									
Southbrook 33kV Substation Decommissioning		248								
Rangiora North Zone Substation Decommissioning			50							
Kaiapoi Switchboard Replacement			3,048							
Tuahiwi 66/11kV Zone Substation	50			100	100	1,000	5,000	1,526		
Ashley to Tuahiwi 66kV Sub-transmission Line - Stage 1						1,241				
Ashley to Tuahiwi 66kV Sub-transmission Line - Stage 2							739			
Southbrook to Tuahiwi 66kV Sub-transmission Line - Stage 1								1,242		
Southbrook to Tuahiwi 66kV Sub-transmission Line - Stage 2									1,512	
Hanmer Sub-transmission Line Upgrade	500	1,000	1,000	1,000	1,000					
Hawarden Zone Substation Rebuild				2,500	2,500					
Hanmer Transformer Upgrade			100							
Amberley Zone Substation Rebuild								3,000	3,000	
Mouse Point Zone Substation Rebuild									3,000	3,000
Major Project Subtotals	**7,956**	**6,147**	**4,198**	**3,828**	**3,600**	**2,241**	**5,739**	**5,768**	**7,512**	**8,645**

Table 6.12: Major Projects Budget Summary

6.8.2 GXP Projects

GXP Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Kaiapoi GXP Purchase	300									
Culverden GXP - GXP Purchase (CAPEX)		3,500								
Southbrook GXP - 66kV Bay - Tuahiwi Circuit (CIC)						1,500				
Ashley GXP - 66kV Bay for Tuahiwi Circuit (CIC)							912			
Ashley GXP - 66kV Bay for Amberley Circuit (CIC)								1,440		
Waipara GXP - 66kV Bay for Amberley Circuit (CIC)								1,440		
GXP Project Subtotals	**300**	**3,500**				**1,500**	**912**	**2,880**		

Table 6.13: GXP Projects Budget Summary

6.8.3 Reinforcement Projects

Network Reinforcement Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Reinforce SW63 and SW66 Swannanoa	312									
Loburn Overhead Reconductoring	187									
Loburn Feeder Reliability Improvement	210									
Northbrook Feeder	335			60						
Flaxton Road Undergrounding	49	141								
Pegasus Feeders		702								
Kippenberger Avenue Circuit Breaker		65								
Reinforce X52 Burnt Hill		228								
Amberley North Load Transfer		224								
Amberley Y43 Urban/Rural Circuit Breaker			59							
Rangiora - East Belt North			80							
Kaiapoi - Island Rd Upgrade			200							
Greta - Cheviot 22kV link			487							
Cheviot - Leader Upgrade				379						
Amberley South Deloading						200				
Townsend Road Feeder						500				
Tuahiwi to Rangiora Feeders								300	300	300
Network Automation		100	100	100	100	100	100	100	100	100
Network Innovation (Low Voltage Monitoring)	98	150	150	150	150	150	150	150	150	150
Network Reinforcement - Unscheduled	146	200	424	811	1,250	550	1,250	950	950	950
Reinforcement Subtotals	**1,337**	**1,809**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**

Table 6.14: Reinforcement Projects Budget Summary

6.8.4 Alternatives and Deferred 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.

6.9 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 10kW and greater than 10kW) and general safety requirements. We also comply with Part 6 of the Electricity Industry Participation Code in this respect.

6.10 Uneconomic Lines

The remote nature of parts of our network results in network assets that test the bounds of economic investment. As part of our network development planning processes, we would like to 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. This may include trials of options such as deployment of alternative micro-grid solutions where these are the preferred economic solution. Where any new technologies deployed are proven to provide reliable and cost-effective supply, our preference will be to decommission uneconomic lines in the future.

6.11 Non-Network Solutions

6.11.1 Load Control

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

The introduction of the Upper South Island Load Control system has resulted in a flat load profile for the upper South Island transmission system. Additional controls are being used to ensure that individual GXP and zone substation peaks are managed. In particular, the 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 66kV line. At these times our 66kV/33kV coastal backup line is unable to transmit the normal daily peaks.

6.11.2 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.

6.11.3 Distributed Energy Resources (DER)

Aligned with MainPower's 'Demand Side Management' scheme, 'non-network' solutions such as the Distributed Energy Resources (solar, storage, energy efficiency) are seen as a way to offset or delay traditional network augmentation. MainPower is already deploying enabling technologies within its network that can also be used for the management of DER in the future. The purpose of the technology is to aggregate DER that is typically deployed close to the load and behind the meter.

6.12 Grid Exit Point Forecasts

6.12.1 Southbrook Grid Exit Point

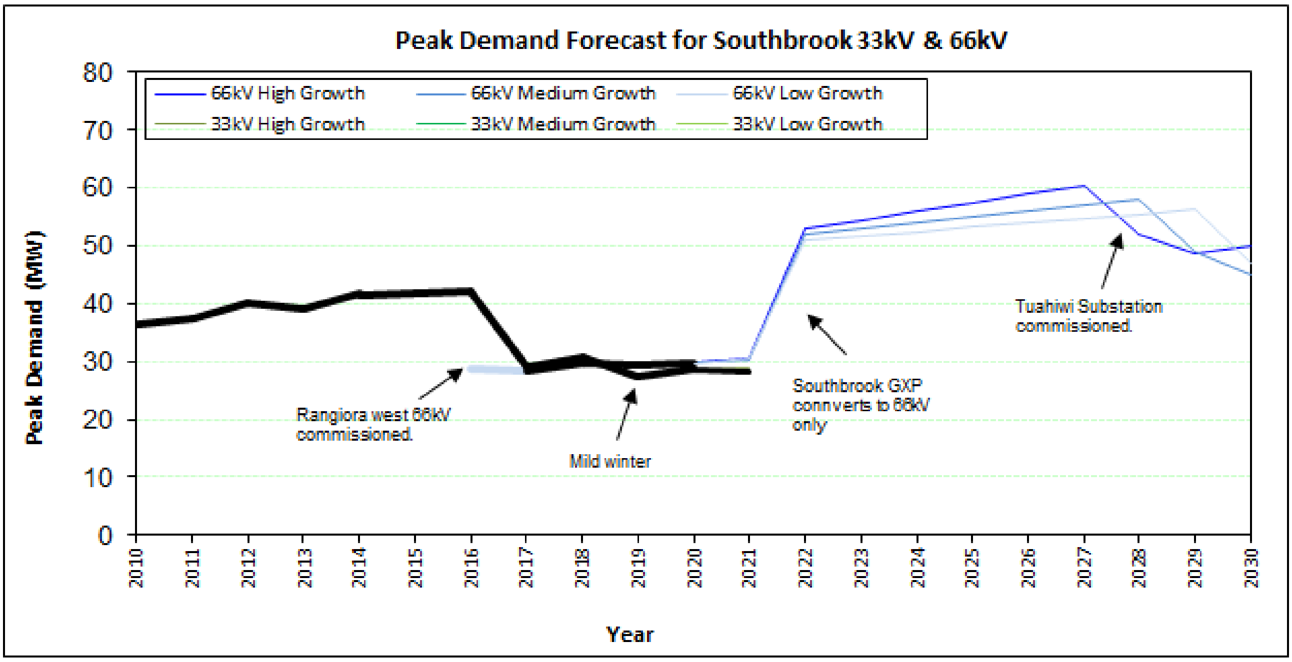

Figure 6.9: Southbrook GXP Forecasting

6.12.2 Kaiapoi Grid Exit Point

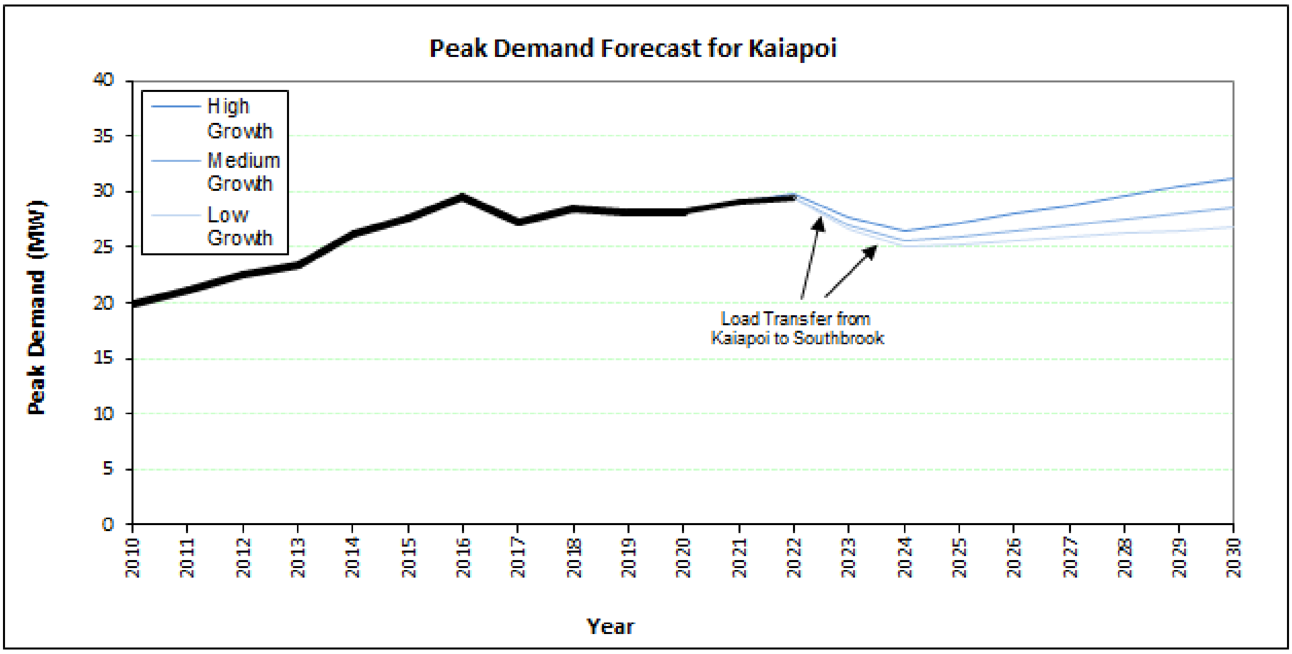

Figure 6.10: Kaiapoi GXP Forecasting

6.12.3 Ashley Grid Exit Point

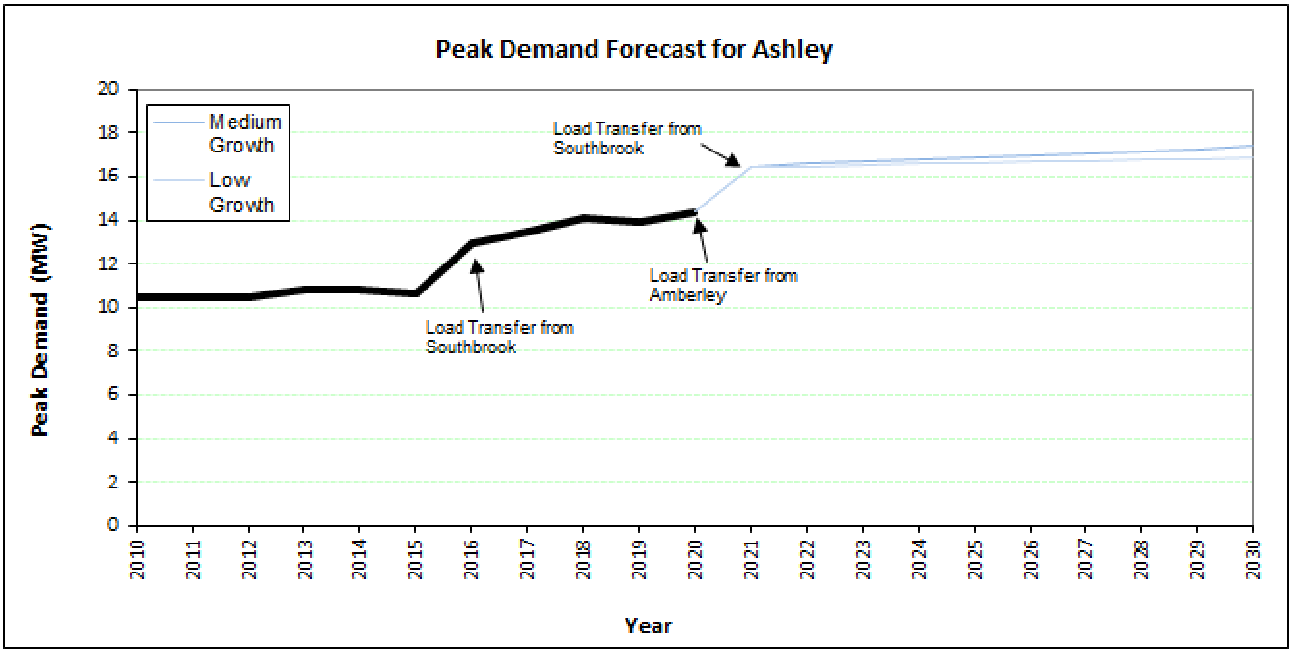

Figure 6.11: Ashley GXP Forecasting

6.12.4 Culverden Grid Exit Point

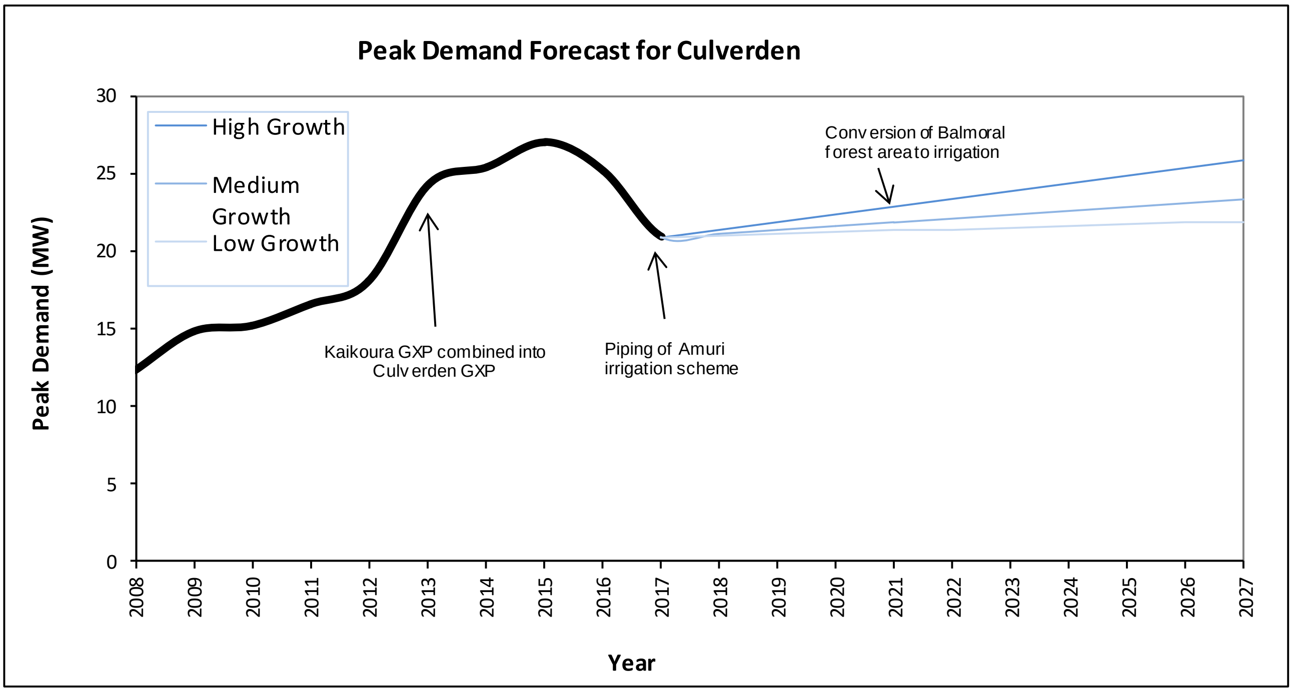

Figure 6.12: Culverden GXP Forecasting

6.12.5 Waipara Grid Exit Point

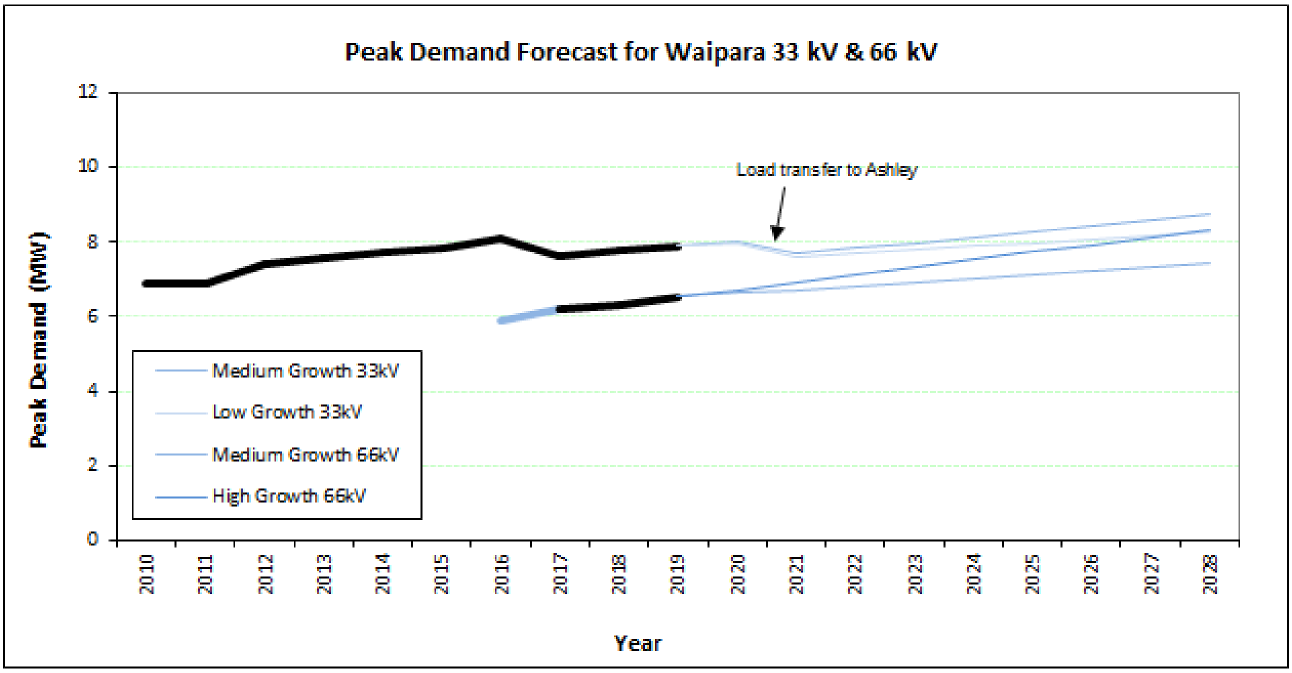

Figure 6.13: Waipara GXP Forecasting

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 the 'MainPower's Network' section of this AMP.

We recognise the need to migrate from traditional age-based replacement and reactive renewals of assets to a holistic approach to portfolio management. In 2020, we are moving to a more prescribed forecasting method of asset replacement through the adoption of the Industry Guidance Notes, Asset Health Indicator (AHI) guide to quantify and inform our replacement. 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, more effective in reducing outages and for optimising our asset portfolios.

Our asset management drivers are informed by a number of reviews and consumer consultation. 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 the following table, 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, 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
	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 key information which informs our asset management decisions. The key points covered include:

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

7.2 Overhead Lines

MainPower has more than 55,000 poles in service carrying over 4,300 km of high and low voltage overhead conductor. The figure below shows the locations of each pole, giving an overall geographic view of the electricity distribution network.

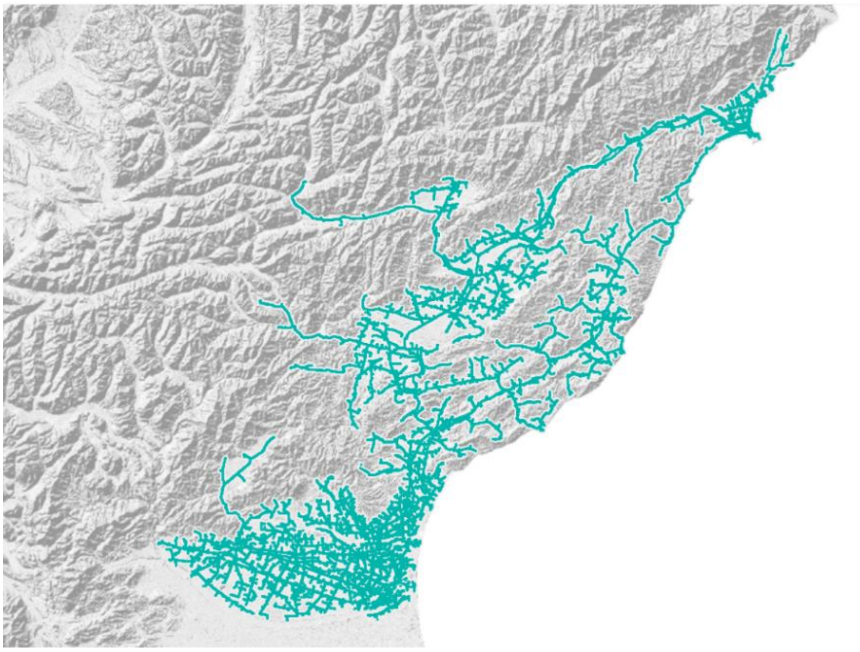

Figure 7.1: MainPower's Electricity Distribution Network's Geographical Distribution

MainPower's pole inspection and renewal programme aims to proactively minimise the risks from pole failures, whilst 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

MainPower has a large range of pole types including:

- Hardwood (Pre mid-1970s);

- Larch poles impregnated with creosote (late 1950s to 1960s);
- Treated pine (post mid-1970s);
- Concrete (post 1960s).

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

There are approximately 8,980 concrete poles in use on the network today, including reinforced and pre-stressed concrete. Reinforced concrete poles contain reinforcing steel bars covered by concrete and were regularly used 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 and around 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, pole attachments including 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 below 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 inspection programme undertaken in early 2018, where MainPower tested poles over 35 years of age. The resulting replacement works are expected to be completed in mid-2020.

Pole replacements are also triggered by the need to upgrade conductors due to condition, capacity or to improve the environmental resilience of the line structure. As part of conductor upgrade projects, we identify poles 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 which have a nominal asset life of 40 years, and insulators including porcelain, glass and polymer types.

Known defects include older overhead line structures with a narrow 75mm crossarm face against the pole, resulting in a weaker construction that is more susceptible to lichen build up and rot.

7.2.2.1 Maintenance

Inspection and maintenance of crossarms is included in MainPower's Overhead Inspection and Maintenance Standard, MPNZ 393S049, summarised below in Table 7.2.

7.2.2.2 Replacement and Disposal

Crossarms and insulators are both replaced in conjunction with the pole replacement programme, through either coordinating works during outages or replacing entire structures due to 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;
- Low Voltage (LV) overhead conductors.

The type of conductors used is influenced by economic, location, environmental and performance factors. Due to its rural nature, overhead conductors are a significant component of our network 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 below 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 below in Table 2 for poles, conductors, cross arms 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 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
Cross Arms	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 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 Electrical 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;
- Ring main units;
- Pole mounted switches;
- Low voltage switchgear.

7.3.1 Circuit Breakers, Reclosers and Sectionalisers

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

The figure below shows the number and age of circuit breakers, reclosers and sectionalisers.

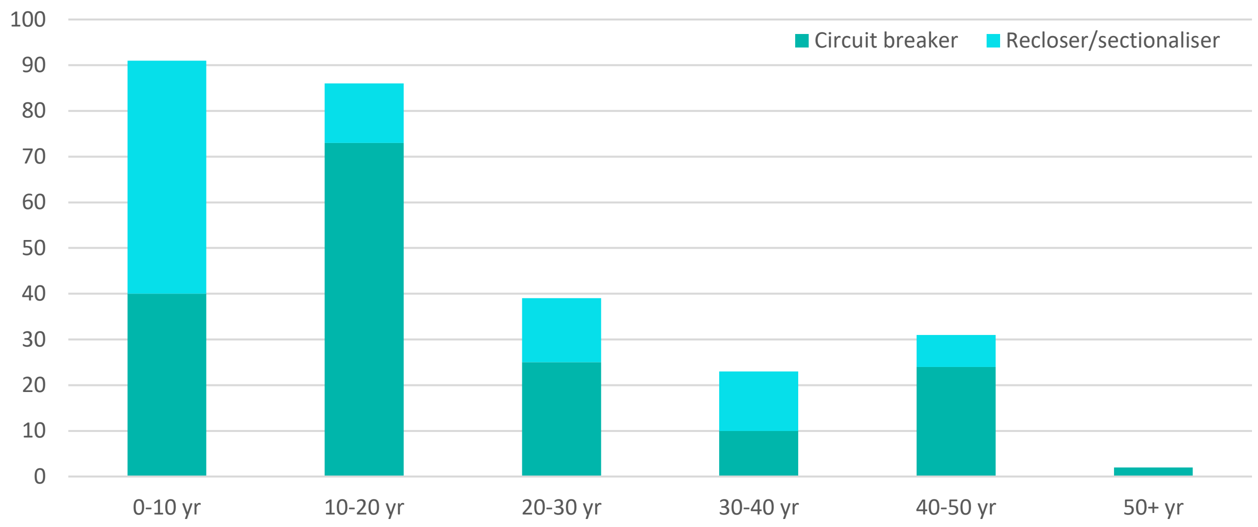

Figure 7.2: Switchgear Age Profile

MainPower's older circuit breakers are predominately 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 below.

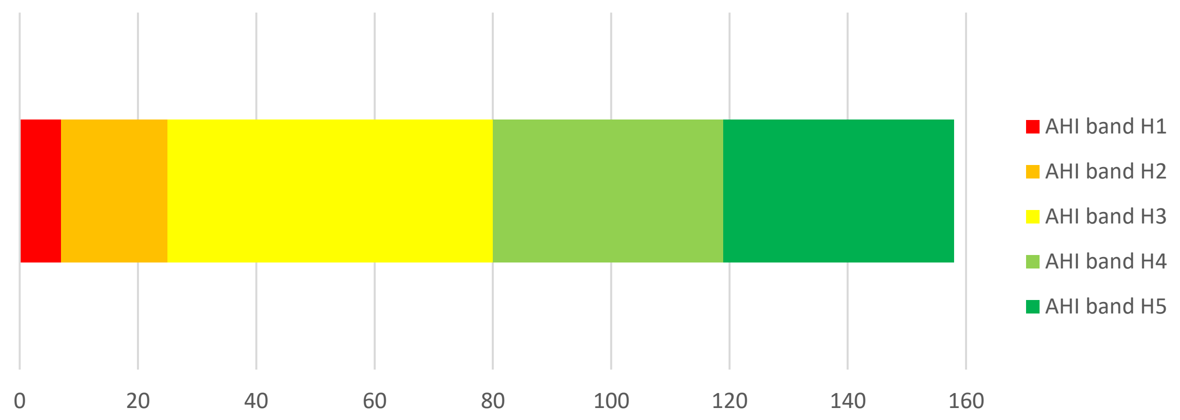

Figure 7.3: Circuit Breaker Current Asset Health Profile

The general guide is that:

- H1 is at end of serviceable life and immediate intervention is required;
- H2 likely requires intervention within 3 years;
- H3, H4 and H5 indicates good condition but still requires regular inspection and maintenance.

7.3.1.1 Maintenance

Routine maintenance is important to ensure satisfactory operation of the switchgear throughout its intended serviceable life. Maintenance includes visual inspections to identify units or structures in poor condition, partial discharge and infrared testing to locate units showing signs of deterioration, as well as 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. The following table summarises the maintenance types and frequencies for the different types of switchgear.

Type	Frequency
Circuit breakers	3 month – Visual inspection 12 month – Operation test, partial discharge and infrared test 3 year – Full service (including clean and oil change if required)
Reclosers and sectionalisers (all)	12 month – Visual inspection 2.5 year - Infrared scan
Reclosers and sectionalisers (distribution)	5 year – Service 10 year – Full service (including clean and oil change if required)
Reclosers (sub-transmission)	10 year – Full service (including clean and oil change if required)

Table 7.3: Switchgear Maintenance Program 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 include minimising risk and improving network reliability, and operational control of the network. We expect unscheduled replacement works to reduce during the next five years as the maintenance and replacement programme matures.

7.3.2 Ring Main Units

MainPower's ring main units include:

- Cast Resin (1960s through to early 2000s);
- Oil filled (1960s through to early 2000s);
- Vacuum (Post 2000);
- SF6 (Post 2000).

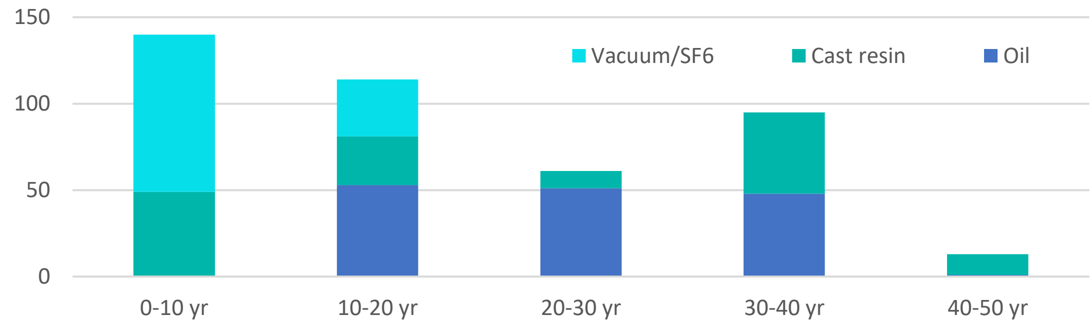

Figure 7.4: Ring Main Unit Quantities and Age Profile

MainPower's older oiled filled ring main units currently have operational restrictions to reduce any inherent risk and our replacement programme is targeting these assets to remove them from the network over the next two years. A MainPower Ring Main Unit Asset Health Model has been developed to help optimise the replacement and maintenance programme for this asset fleet.

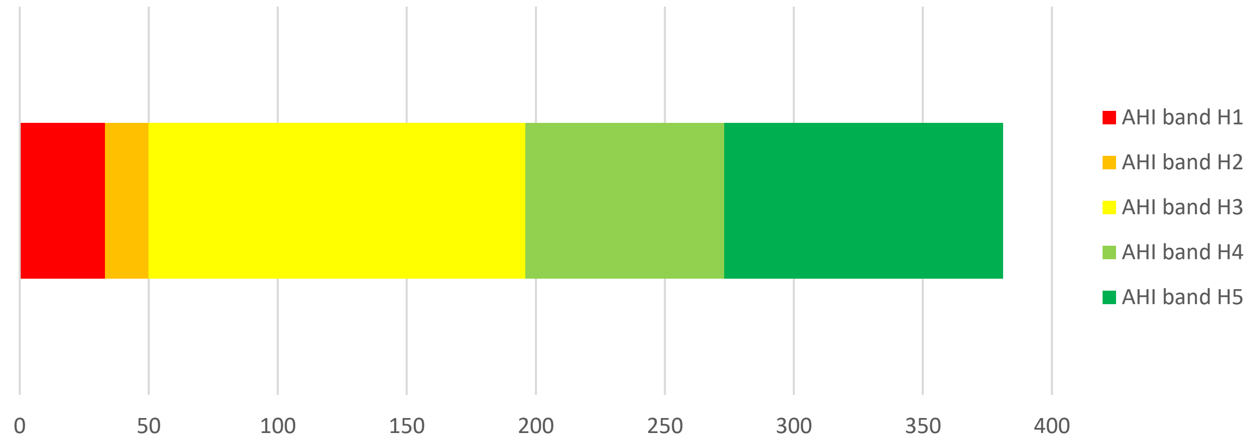

Figure 7.5: Ring Main Unit Current Asset Health

The general guide is that:

- H1 is at end of serviceable life and immediate intervention is required;
- H2 likely requires intervention within 3 years;
- H3, H4 and H5 indicates good condition but still requires regular inspection and maintenance.

7.3.2.1 Maintenance

Regular maintenance is important to ensure the safe and efficient operation of ring main units. 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.

The following table shows the maintenance types and frequencies for the different types of units.

Type	Frequency
Oil filled	12 months – Inspection + Partial discharge test 5 years – Service (including oil change) + Infrared test
Cast resin	12 months – Inspection + Partial discharge + Infrared test 5 year – Service (including full clean of contacts)
Vacuum/SF_6	12 months – Inspection + Partial discharge test 5 years – 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 ring main unit replacement programme is targeting the 33 units with a low health score, which includes:

- 23 units scheduled for replacement during the 19/20 financial year;
- 10 units forecast for replacement during 20/21 financial year.

It is proposed to then replace approximately 10 units per year for the subsequent 8 years.

7.3.3 Pole Mounted Switches

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

- Canterbury Engineering Type (1950s to 1980s);
- Dulmison, Electropar and ABB (1980s to Present);
- Entec Fully Enclosed Vacuum Break (Present).

The majority of 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 improve network visibility, and provides opportunity for increased automation.

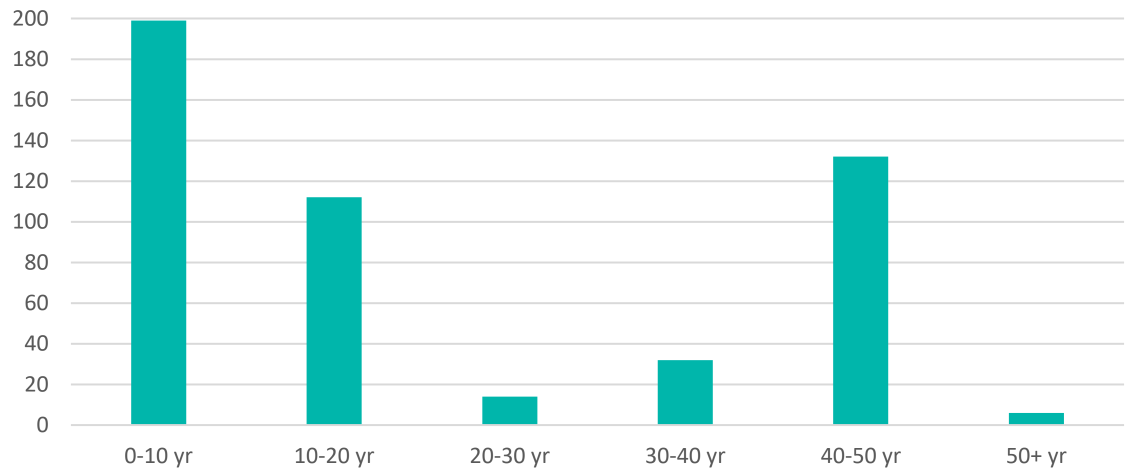

Figure 7.6: Pole Mounted Switch Quantities and Age Profile

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 doesn't open or close correctly. This is addressed through a regular inspection and maintenance programme outlined below.

7.3.3.1 Maintenance

Pole mounted switches are maintained every five years and includes a condition assessment of the switch which is combined with inspection and asset data to inform the replacement programme.

Type	Frequency
Pole mounted switches	5 years – visual inspection, full service and 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 both feed into an asset health replacement model to better prioritise the programme.

7.3.4 LV Switchgear

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

- Exposed (skeleton) panels;
- D&S fused switches;

- Terasaki circuit breakers;
- ABB Fastline (SLK) fusegear;
- DIN style fused switches (current type for new installations).

There is currently limited data in our asset database for quantities and types of low voltage switchgear, however in 2019, MainPower initiated a collection programme to collect asset attribute and condition information. The known issues for the switchgear types outlined above include:

LV 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) fusegear	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 and operational issues. Any defects are investigated, with the condition and criticality of the switchgear used to prioritise either corrective maintenance or schedule replacement.

Type	Frequency
Low voltage switchgear	12 month – visual inspection and infrared scan and condition assessment

Table 7.7: Low Voltage Switchgear Inspection Summary

7.3.4.2 Replacement and Disposal

Due to 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 systemically 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 due to their issues.

7.4 Transformers

MainPower's transformers are divided in the following sub-categories, with quantities summarised below:

Transformer Fleet	Quantity
Power Transformers	26 (plus 6 strategic spares)
Distribution Transformers	8328
Voltage Regulators	11

Table 7.8: MainPower's Transformer Quantities

7.4.1 Power Transformers

MainPower's zone substation power transformers transform sub-transmission voltages of 66kV or 33kV down to distribution voltages of 11kV, 22kV or 400V. Their power ratings range from 0.3kVA for isolated rural supplies up to 23MVA within the more densely populated parts of the network. MainPower also has six power transformers held as strategic spares. These are surplus units typically made available from network upgrades and are held to support network resilience and emergency response.

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 below. The power transformer fleet have a typical nominal life of 45 years however this can vary significantly, depending on the loading and operating conditions.

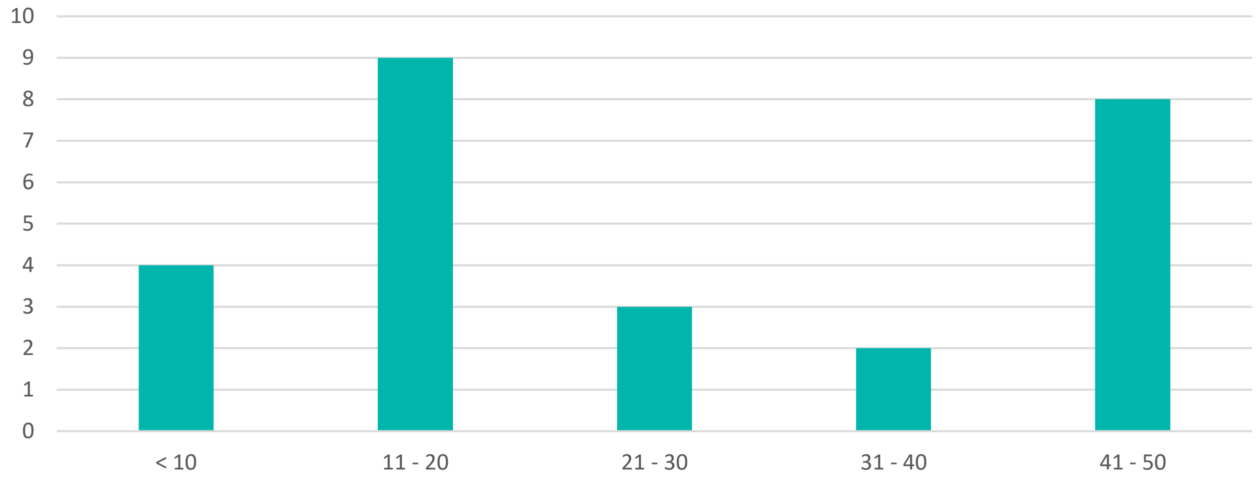

Figure 7.7: Power Transformer Age Profile

The power transformer fleet is managed using MainPower's Power Transformer Asset Heath Indicator (AHI) Model. While the model is new and will require tuning over time, the results were generally aligned with expectations.

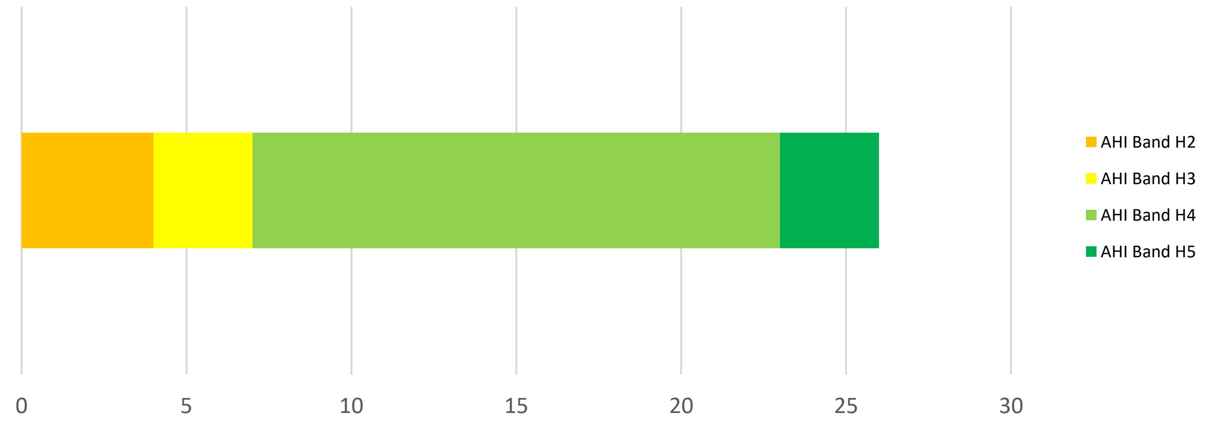

Figure 7.8: Power Transformer Current Asset Health

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 is showing a bushing defect which requires further investigation. The remaining units are showing no major defects and are aging in accordance with their typical lifespan 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. 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 month - visual inspection as part of zone substation inspection schedule
	12 month - dissolved gas analysis (DGA)
	12 month - thermographic and acoustic partial discharge tests
	3 year – 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 is found to affect the chemical tracers for aging. This has been suspended and will be re-established where appropriate once aging trends are sufficiently established.

7.4.1.2 Replacement and Disposal

No immediate replacements are planned for the 2020/21 financial year. Close monitoring of the aging trends and paper strength on the three units showing end-of-life indicators is underway. The timing for replacement will be coordinated with planned 66kV 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 in either kiosk substations or as standalone units. These transformers supply end users at single phase 230V or three phase 400V.

Failure modes that drive distribution transformer replacement include:

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

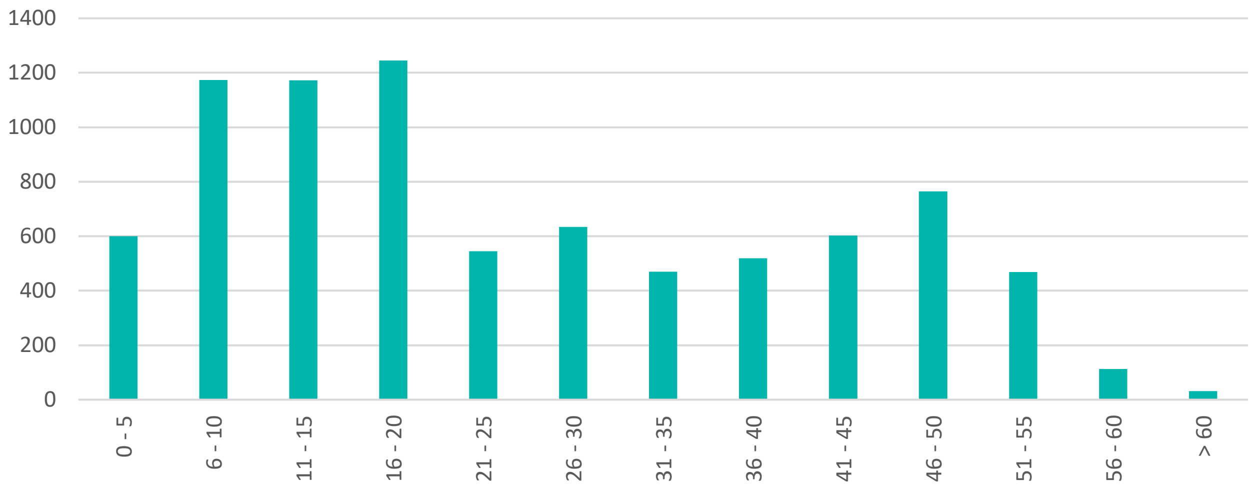

Figure 7.9: Distribution Transformer Age Profile

7.4.3 Ground Mounted Distribution Transformers

MainPower operates approximately 1,400 ground mounted distribution transformers. All units are mineral oil filled with the rating and quantities and age profile summarised below.

Rating	Number of Transformers	% of Total
> 15 and ≤ 30kVA	10	< 1%
> 30 and ≤ 100kVA	565	43%
> 100 and ≤ 500kVA	686	57%
≥ 500kVA	111	8%
Total	1372	100%

Table 7.10: Ground Mounted Distribution Transformer Quantities

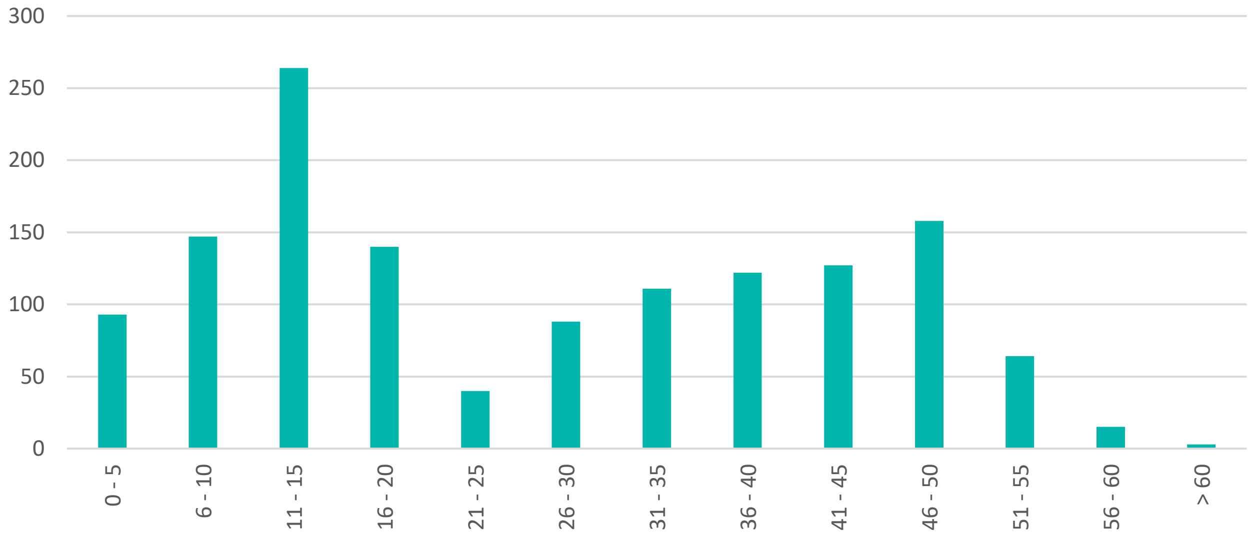

Figure 7.10: Ground Mount Distribution Transformer Age Profile

7.4.3.1 Maintenance

Ground mounted distribution transformers are inspected on both an annual and a 5-yearly cycle. Oil samples are taken for analysis on units over 500 kVA on a 5 yearly basis due to the size and criticality of these units.

Type	Frequency
Ground mounted transformers	12 month - general external condition assessment and labelling
	5 year - full visual check of all components and testing of the earthing systems

Table 7.11: Ground Mounted Transformer Inspection and Maintenance Summary

7.4.3.2 Replacement and Disposal

Ground mounted transformers are replaced as they meet end-of-life criteria, informed by the inspection programme and reported defects. Scrap units are drained of oil, then sold to approved scrap dealers. Used oil is stockpiled until enough volumes are accumulated, then 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 with the rating, quantities and age profile summarised below.

Rating	Number of Transformers	% of Total
≤ 15kVA	3042	44%
> 15 and ≤ 30kVA	329	5%
> 30 and ≤ 100kVA	3297	47%
> 100kVA	288	4%
Total	6956	100%

Table 7.12: Pole Mounted Transformer Quantities

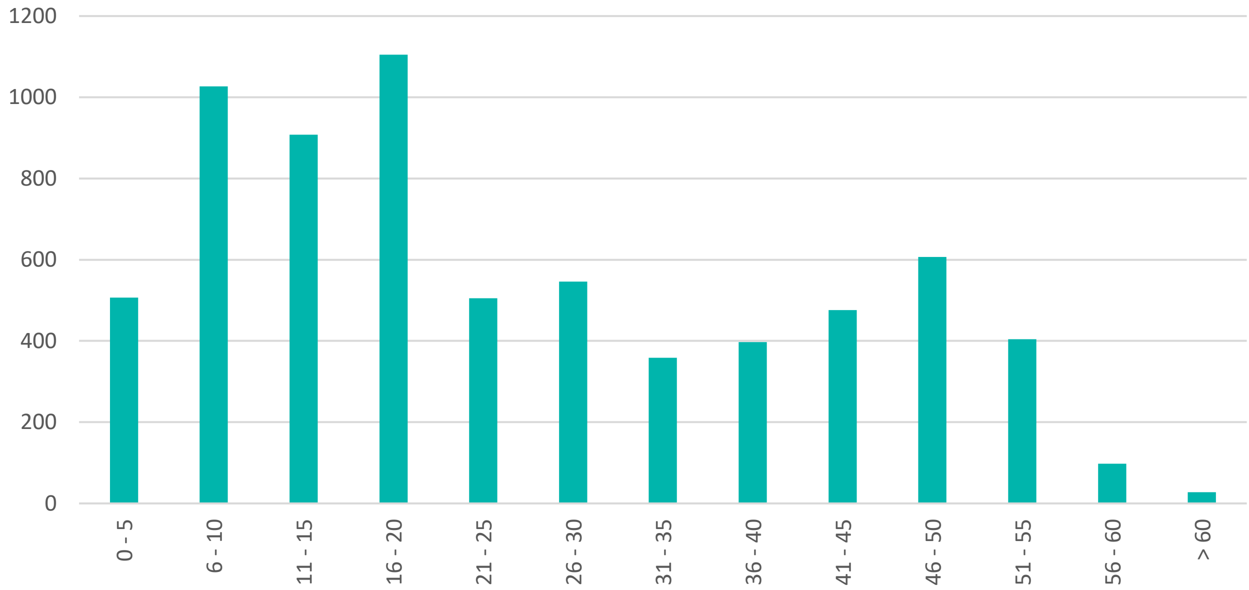

Figure 7.11: Pole Mounted Distribution Transformer Age Profile

7.4.4.1 Maintenance

Pole mounted distribution transformer inspections are carried out from the ground and include testing of the earthing system.

Type	Frequency
Pole mounted distribution transformers	5 year – full visual check of all components and 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, then sold to approved scrap dealers. Used oil is stockpiled until enough volumes are accumulated, then disposed of using approved used oil dealers.

7.4.5 Voltage Regulators

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

The voltage regulators are all 220 kVA General Electric devices with automatic controllers. The age profile is between twelve to seventeen 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.

Type	Frequency
Regulators	5 year – 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.

7.5 Zone Substations

MainPower's electricity distribution network is supplied via five Grid Exit Points (GXPs) from the Transpower 220kV and 66kV transmission circuits passing through the region. There are 17 MainPower zone substations that operate at 66kV and/or 33kV to supply the 11kV and 22kV distribution network. A pictorial view of the electricity distribution network is shown below followed by a summary of the zone substation capacity and feeders.

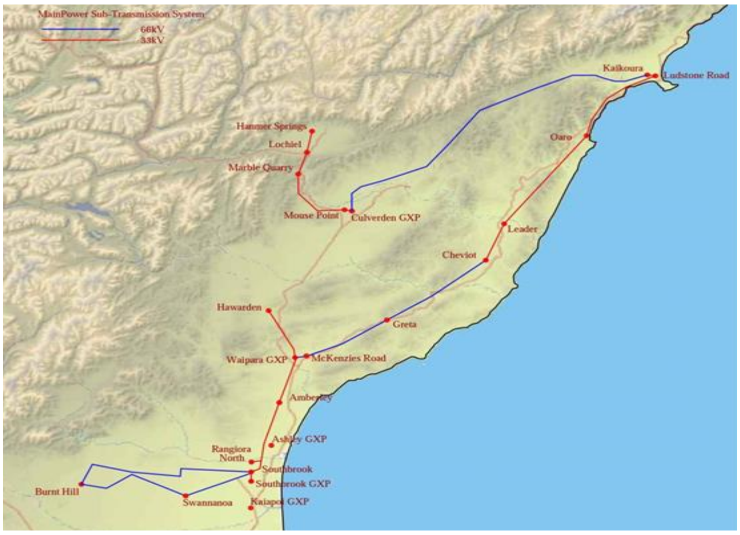

Figure 7.12: Zone Substation Locations

Site	Voltage	Substation Capacity (MVA)	# Feeders	Type
Southbrook	33 / 11kV	44	6	Indoor
Swannanoa	33 / 22kV	46	5	Indoor
Burnt Hill	66 / 22kV	46	6	Indoor
Rangiora North	33 / 11kV	7	3	Outdoor
Amberley	33 / 11kV	8	3	Indoor
McKenzies Road	66 / 11kV	4	3	Outdoor
Greta	66 / 22kV	4	3	Outdoor
Cheviot	66 / 11kV	4	3	Outdoor
Leader	33 / 11kV	0.3	3	Outdoor
Oaro	33 / 11kV	4	1	Outdoor
Ludstone Road	33 / 11kV	12	4	Indoor
Hawarden	33 / 11kV	4	3	Outdoor
Mouse Point	33 / 11kV	26	4	Outdoor
Marble Point	33 / 11kV	2	1	Outdoor
Lochiel	33 / 11kV	0.2	1	Outdoor
Hanmer	33 / 11kV	12	2	Indoor
Kaikoura	66 / 33kV	10	1	Outdoor

Table 7.15: Zone Substation Statistics

7.5.1 Maintenance

Zone substations are maintained on three overlapping cycles, ranging from regular visual inspections through to a major zone substation service requiring substation shutdowns.

Type	Frequency
Zone substations	3 monthly – visual inspections / 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

7.5.2 Replacement and Disposal

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

7.5.3 Switching Substations

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

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

Table 7.17: 11kV Switching Stations

7.5.3.1 Maintenance

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

7.6 Underground Assets

The underground assets portfolio is made up of the following three asset fleets:

Asset Fleet	Length / Quantity
High voltage underground cables	329km
Low voltage underground cables	1,045km
Low voltage service boxes	Approx. 10,000
Low voltage link boxes	618

Table 7.18: Underground Asset Quantities

7.6.1 High Voltage Underground Cables

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

The majority 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" types are replaced when identified across the network.

7.6.1.1 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 to support and educate the local community and contractors about the risks of excavating near underground cable assets. We are a member of the beforeUdig online service and provide cable locate and stand over services to local contractors or individuals.

7.6.1.2 Replacement and Disposal

MainPower does not currently have a scheduled replacement programme for underground cables. Replacement for cables is typically the result of inspection data and/or identified defects from field staff.

7.6.2 Low Voltage Underground Cables

MainPower's low voltage underground cables are primarily 185mm² aluminium cables with some 120mm² aluminium cables, historically installed in smaller subdivisions due to lower load requirements and their radial nature.

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

7.6.2.1 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. All end terminations are mostly 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.

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

7.6.2.2 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 from field staff.

7.6.3 Low Voltage Distribution Boxes

MainPower's low voltage distribution boxes consist of:

- **Service boxes:** Service boxes are plastic boxes made 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 fiberglass lids;
- **Link boxes:** Link boxes are made of thermoplastic and typically house 4-10 commercial or non-domestic service fuses. These boxes provide alternative supply points between distribution transformers and allow reconfiguration of the network. Some historic steel frame and lid-type 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.

We are currently deploying an additional condition assessment programme to better document the condition of low voltage distribution link boxes. Known defects mainly relate to third party damage such as vehicles, and historic boxes that have reached or surpassed their nominal technical life.

7.6.3.1 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.

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

7.6.3.2 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 returned from the inspection programme or as a result of third-party damage.

7.7 Vegetation Management

MainPower and tree owners have obligations under The Electricity (Hazards from Trees) Regulations 2003. We have a range of communication programmes to advise tree owners of their responsibilities around tree management near electricity lines and also to the general public on the risks caused by vegetation.

The majority of MainPower's distribution network is rural, with lines typically constructed parallel to property boundaries in the vicinity of boundary trees and hedges. Trees in the vicinity of our lines vary significantly in type and condition and require regular monitoring to proactively prevent contact with the electricity network.

7.7.1 Maintenance

MainPower has a programme to inspect all overhead lines on the network and maintain at least the minimum clearance from those lines at all times.

Type	Frequency
Vegetation	2.5 yearly – vegetation inspection programme
	Annual – vegetation trimming programme on recorded clearance violations

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.

7.8 Secondary Systems

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

- DC Systems;
- Protection;
- Communication / SCADA;
- Load control / ripple plant.

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

7.8.1 DC Systems

MainPower's DC systems are split into two parts:

- Batteries;
- 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.

Asset	Nominal Life	Quantity
DC Batteries	10 years	193
	5 years	250
	2 years	3
	Total	446

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 convertors, controllers and other associated hardware. MainPower has a range of types including older in-house built, through to modern SCADA connected units. As with the battery replacement, one local supplier has been chosen for all new chargers.

7.8.1.1 Maintenance

Batteries and DC chargers are frequently inspected and tested due to their importance for monitoring and controlling the network under contingency events.

Location	Frequency
Substation	3 months - Visual inspection, self-test (if available with charger model) 12 months – Electrical tests
Recloser	12 months – Visual inspection, electrical test
Communication site	6 months – 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

7.8.1.2 Replacement

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

7.8.2 Protection

The electricity distribution network has protection relays located in zone and switching substations, ring main units and reclosers. The figure below shows the number and age of the current protection relays.

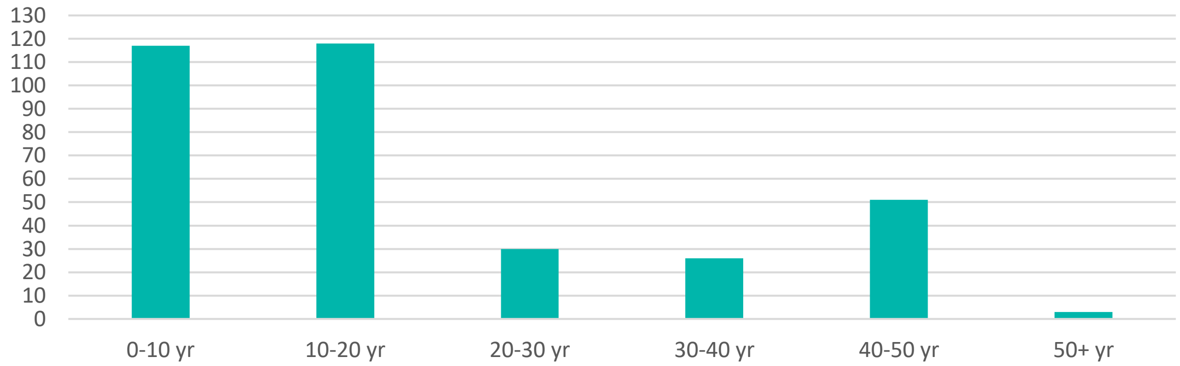

Figure 7.13: Protection Relay Age Profile

7.8.2.1 Maintenance

Regular maintenance of the protection relays is critical in verifying operation and providing protection of the electricity distribution network primary assets.

Location	Frequency
Zone/switching Substation	3 months – Visual inspection 3 years – Full system test (electromechanical) 6 years – Full system test (digital)
Recloser	12 months – Visual inspection 5 years – Full system test
Ring main unit	12 months – Visual inspection 5 years – 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

7.8.2.2 Replacement

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

7.8.3 Communications and SCADA

MainPower operates both a voice and 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 below.

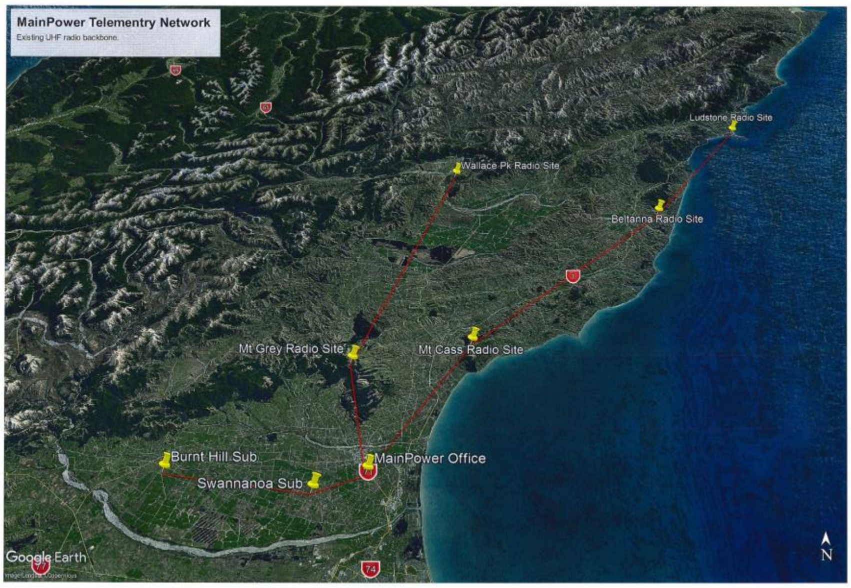

Figure 7.14: MainPower's Telemetry Electrical Distribution Network

MainPower's current SCADA system is a Schneider Wonderware system, however the system is approaching end of life and a project is underway to implement an Open Systems International Advanced Distribution Management System, due for completion in mid-2020. All remote SCADA sites use the DNP3 communication protocol and 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 multi-point. 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.

7.8.3.1 Maintenance

Communication and SCADA systems are constantly monitored by the MainPower engineering team. Equipment at both zone substation and repeater sites are regularly inspected and serviced on 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

7.8.3.2 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 increased bandwidth for improved digital services at substations.

7.8.4 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. The majority of 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.

Location	Age	Operating Voltage
Kaiapoi GXP	24	11kV
Ludstone Rd	11	11kV
Mouse Pt	13	33kV
Southbrook	13	33kV
Waipara GXP	12	33kV
Ashley GXP	21	11kV
Swannanoa	29	22kV
Burnt Hill	29	22kV

Table 7.26: Load Plant Age, Location and Operating Voltage

The load control plants are generally in good condition, however 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.

7.8.4.1 Maintenance

Load plant control and specialist equipment maintenance is contracted out to Landis & Gyr under a service agreement. This covers annual inspections and testing, and carrying of 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 a three-yearly cycle. Defects are reported and managed as per MainPower's defect management processes.

7.8.4.2 Replacement and Disposal

The 33kV load plant at Southbrook is being replaced with an 11kV 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.

7.9 Property

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

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 Covers	781
Total	958

Table 7.27: MainPower's Property and Building Assets

7.9.1 Zone Substation Buildings

There are 22 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 below.

Construction Type	Control Only	Control + HV Switchgear
Timber framed	5	2
Concrete - Block	4	2
Concrete – Tilt slab	0	7
Container	0	2
Total	9	13

Table 7.28: Zone Substation Building Types

7.9.1.1 Maintenance

Zone substation buildings are inspected on a three-monthly regime as part of the zone substation routine inspection programme.

Asset Fleet	Frequency
Zone substation buildings	3 monthly - visual inspections

Table 7.29: Zone Substation Building Inspection Summary

All zone substation buildings have 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 also been carried out on all zone substation buildings. Warning notices have been fitted where asbestos has been found or assumed to be found in the building materials, or equipment in the buildings.

7.9.1.2 Replacement and Disposal

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

7.9.2 Distribution Kiosk Buildings

MainPower has 34 distribution substations that are housed in standalone buildings. These were generally built during the 'MED' era and are of solid concrete or masonry construction. They typically contain high voltage switches or circuit breakers, an 11kV / 400V transformer and an LV distribution panel. Their ages range from 19 to 61 years old with most in the 50 to 60-year range as shown below.

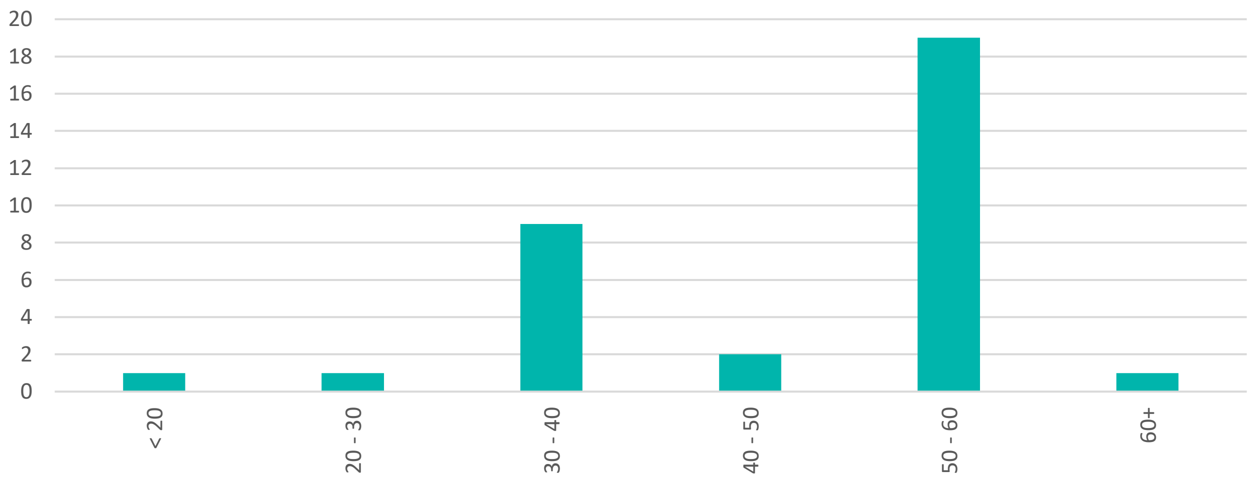

Figure 7.15: Kiosk Building Age Profile

These buildings are considered in generally good condition given their age, however MainPower has undertaken 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 raise the strength, typically in the roofing.

7.9.2.1 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 field defect reports.

7.9.2.2 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 the 10-year planning period.

7.9.3 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.

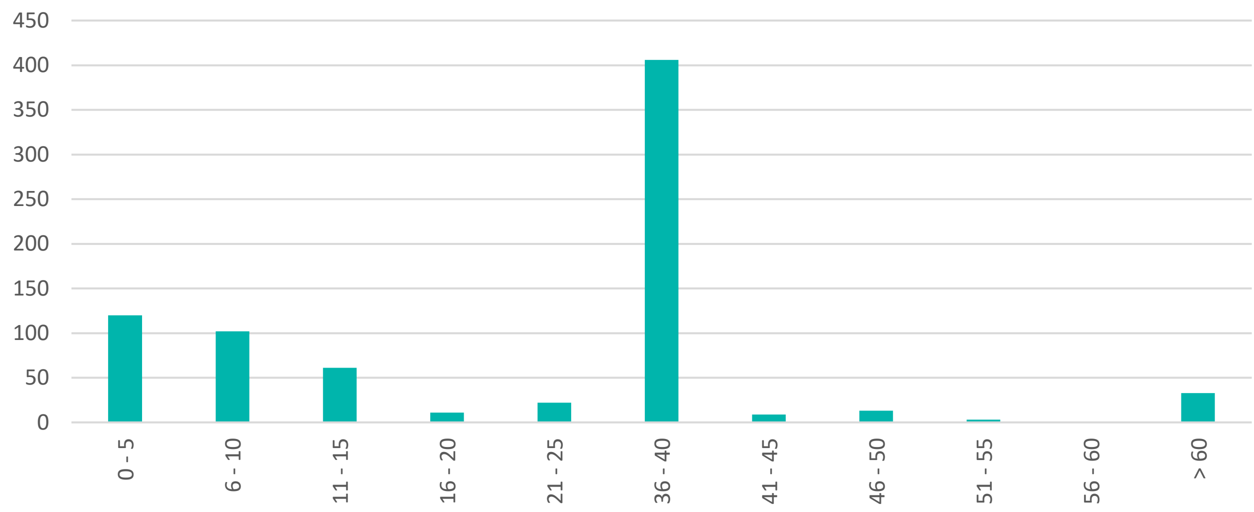

Figure 7.16: Kiosk Covers (Enclosures) Age Profile

The covers are considered in generally good condition, however 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 made following identification.

7.9.3.1 Maintenance

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

7.9.3.2 Replacement and Disposal

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

7.9.4 Non-Electricity Distribution Network Buildings

MainPower owns offices, administration buildings, operational buildings, staff and holiday housing throughout the North Canterbury region. MainPower relocated to a new, purpose-built head office and works facility in June 2014 located in Rangiora.

Description	Location	Age (Years)
Staff Housing - #1	Culverden	2
Staff Housing - #2	Culverden	1
Office Building	Culverden	40
Storage Shed/Workshop	Culverden	40
Holiday Home	Hanmer Springs	40
Holiday Home	Kaikoura	40
Corporate Office and Operational Facilities	Rangiora	5

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-story 2100m² office building constructed to an Importance Level 4 standard;
- A single-story 320m² café constructed to an Importance Level 3 standard;
- A 2000m² single-story 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 backup locations in place to ensure on-going operational capability during a major event.

7.9.4.1 Maintenance

There are a lot of facilities and equipment across MainPower's non-network property requiring regular maintenance to ensure operational functionality. On-going contracts are managed with around 25 service providers to ensure the sites are maintained.

7.9.4.2 Renewal

We have a projected renewal programme out to financial year 2050 with major replacement scheduled for 2020, 2025 and 2028 years, mainly consisting of repairs to the cracking concrete on the stores/workshop building, renewing internal finishes such as carpet and paint, and external finishes such as wall cladding.

7.10 Electricity Distribution Network Expenditure

7.10.1 Electricity Distribution Network Planned and Corrective Maintenance Expenditure

Asset Portfolio	Expenditure									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Overhead Network	1,648,061	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667
Zone Substations	686,459	745,026	745,026	745,026	745,026	745,026	745,026	745,026	745,026	745,026
Kiosks	392,679	426,181	426,181	426,181	426,181	426,181	426,181	426,181	426,181	426,181
Transformers	357,478	387,977	387,977	387,977	387,977	387,977	387,977	387,977	387,977	387,977
Switchgear	270,542	293,624	293,624	293,624	293,624	293,624	293,624	293,624	293,624	293,624
Communications	89,211	89,822	89,822	89,822	89,822	89,822	89,822	89,822	89,822	89,822
Vegetation	921,390	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Low Voltage Network	516,053	560,081	560,081	560,081	560,081	560,081	560,081	560,081	560,081	560,081
High Voltage Cables	176,664	191,736	191,736	191,736	191,736	191,736	191,736	191,736	191,736	191,736
Network Property	41,463	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000
Total	**5,100,000**	**5,528,114**	**5,528,114**	**5,528,114**	**5,528,114**	**5,528,114**	**5,528,114**	**5,528,114**	**5,528,114**	**5,528,114**

Table 7.31: Electricity Distribution Network Maintenance Planned and Corrective Expenditure

7.10.2 Corrective Maintenance Expenditure

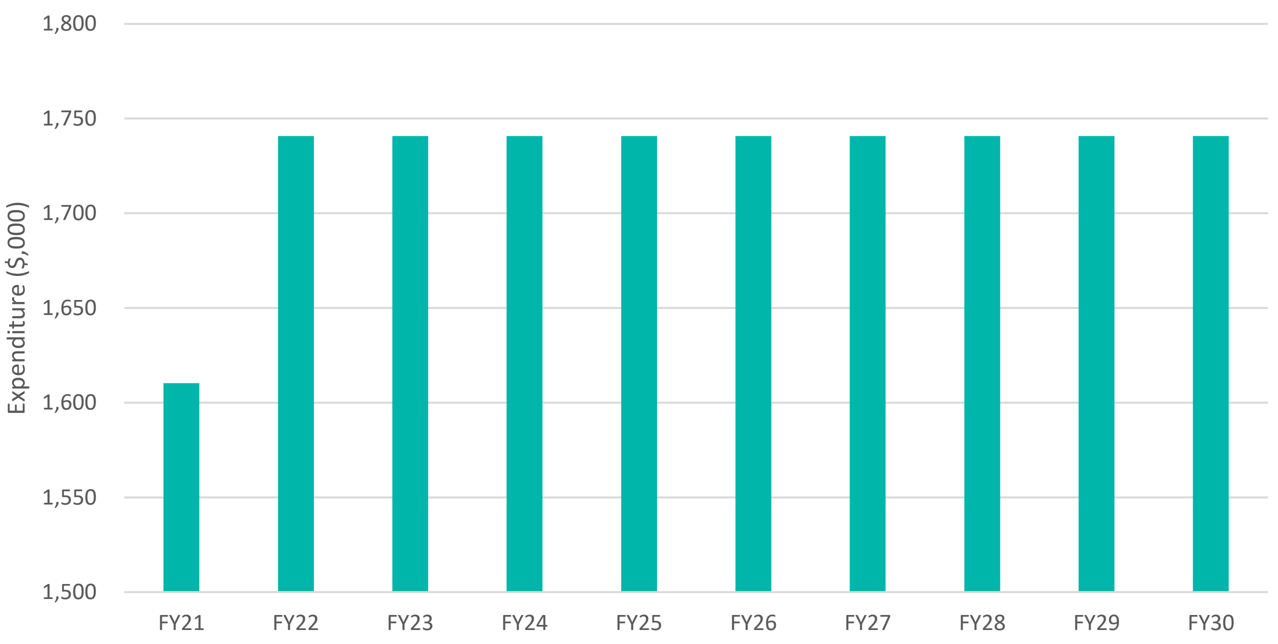

Figure 7.17: 10-Year Corrective Maintenance Expenditure Forecast

7.10.3 Electrical Distribution Network Planned and Corrective Replacement Expenditure

Asset Portfolio	Expenditure									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Overhead Network	4,802,817	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000
Zone Substations	21,214	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Kiosk Substations	797,641	940,000	940,000	940,000	940,000	940,000	940,000	940,000	940,000	940,000
Transformers	487,919	575,000	575,000	575,000	575,000	575,000	575,000	575,000	575,000	575,000
Switchgear	148,497	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Secondary Systems	331,615	390,800	390,800	390,800	390,800	390,800	390,800	390,800	390,800	390,800
Underground Assets	816,309	962,000	962,000	962,000	962,000	962,000	962,000	962,000	962,000	962,000
Network Property	424,277	500,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Corrective Replacement	169,711	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Total	**8,000,000**	**8,267,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**

Table 7.32: Electricity Distribution Network Replacement Expenditure

7.10.4 Corrective Replacement Expenditure

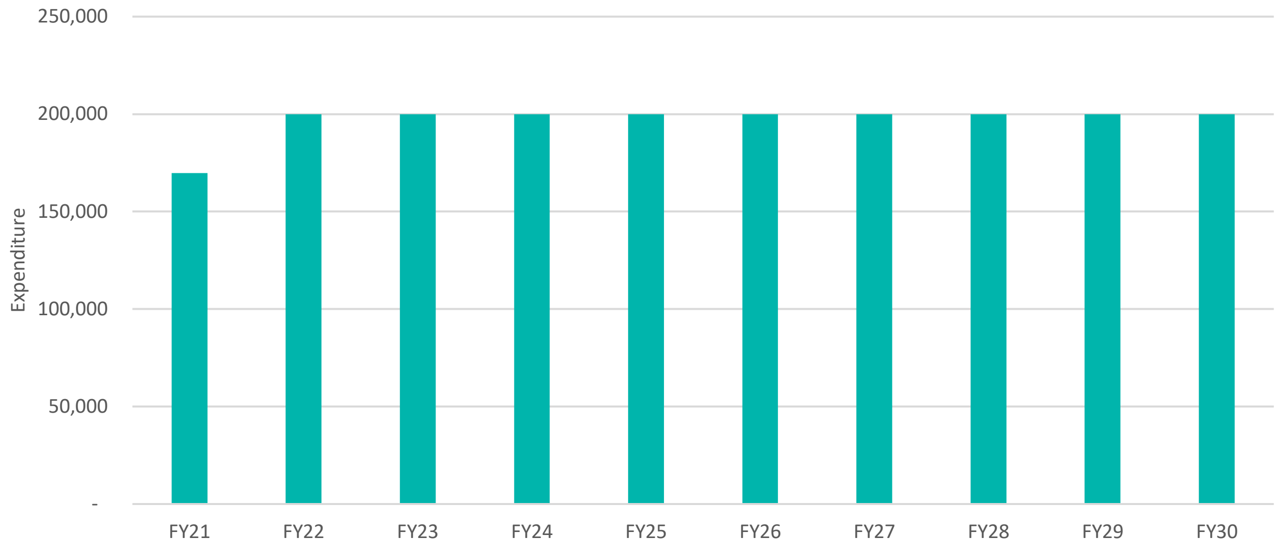

Figure 7.18: 10-Year Corrective Replacement Expenditure Forecast

7.11 Innovations

MainPower has initiated the process to implement maintenance schedules against assets within the CMMS – TechnologyOne OneAsset System. 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 are also used to record information to help determine condition of the assets. More accurate 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 coverage area.

7.12 Non-Electricity Distribution Network Assets

7.12.1 IT Systems

MainPower's 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 roadmaps are focussed 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 (which includes standard modules for finance, payroll, stores, reporting etc.);
- A 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 etc. and manages shareholder information on behalf of the Trust.

7.12.1.1 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 latest version) into an operational cost on a 'per active user' basis.

7.12.1.2 IT Hardware

In 2017 MainPower moved from purchasing printers and faxes to a leased model through Ricoh NZ. This has moved these capital costs to operational and is based on a 48-month contract commencing March 2017.

7.12.1.3 Maintenance and Renewal policies 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 deployed annually to remain within vendor warranty frameworks, i.e. 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.

7.12.1.4 Advanced Distribution Management System Replacement

MainPower's existing Supervisory Control and Data Acquisition (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.

7.12.1.5 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.

7.12.1.6 Technology Integration

The Dell Boomi Integration platform will be implemented during 2019 to replace the existing bespoke integrations, enable rapid deployment of new integrations and enable proactive operational monitoring of the integration environment.

7.12.1.7 Data Warehouse and Decision Support Expansion

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

7.12.1.8 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 will implement the Promapp and State3 technologies to create and maintain visibility of the organisation's current state from process, people, technology and consumer experience perspectives.

7.12.1.9 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 is intended to implement an integrated, modern, and secure document management solution.

7.12.2 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.

7.12.3 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 275kVA. 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 can be connected to overhead lines at 11kV or 22kV 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.

7.12.4 Other Generation

MainPower owns and operates a 1MW 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 our internal expenditure categories and forecasts provided in earlier chapters.

8.1 Total Network Expenditure

8.1.1 Total Expenditure

Title	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Major Projects	7,952	6,146	4,198	3,828	3,600	2,241	5,739	5,768	7,512	8,645
Reinforcement Projects	1,337	1,809	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Network Replacement	8,000	8,268	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Network Maintenance	5,100	5,528	5,528	5,528	5,528	5,528	5,528	5,528	5,528	5,528
Customer Initiated Works (Capex)	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Customer Initiated Works (Opex)	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Network Faults	700	700	700	700	700	700	700	700	700	700
Non-Network	7,000	2,008	1,758	1,658	1,658	1,508	1,508	1,508	1,508	1,508
Total	36,089	30,459	27,702	27,232	27,004	25,495	28,993	29,022	30,766	31,899

Table 8.1: Total Expenditure Summary Table

8.2 Network Growth and Security

8.2.1 Network Major Projects

Network Major Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Cheviot to Oaro Subtransmission Line Upgrade	912									
Ludstone Zone Substation Capacitors				228						
Kaikōura Zone Substation Capacity Upgrade										5,645
Southbrook 66kV Substation Upgrade	5,676	4,899								
Ashley Zone Substation 33kV Security Upgrade	815									
Southbrook 33kV Substation Decomissioning		248								
Rangiora North Zone Substation Decommissioning			50							
Kaiapoi Switchboard Replacement			3,048							
Tuahiwi 66/11kV Zone Substation	50			100	100	1,000	5,000	1,526		
Ashley to Tuahiwi 66kV Subtransmission Line - Stage 1						1,241				

Network Major Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Ashley to Tuahiwi 66kV Subtransmission Line - Stage 2							739			
Southbrook to Tuahiwi 66kV Subtransmission Line - Stage 1								1,242		
Southbrook to Tuahiwi 66kV Subtransmission Line - Stage 2									1,512	
Hanmer Subtransmission Line Upgrade	500	1,000	1,000	1,000	1,000					
Harwarden Zone Substation Rebuild				2,500	2,500					
Hanmer Transformer Upgrade			100							
Amberley Zone Substation Rebuild								3,000	3,000	
Mouse Point Zone Substation Rebuild									3,000	3,000
Major Project Subtotals	**7,953**	**6,147**	**4,198**	**3,828**	**3,600**	**2,241**	**5,739**	**5,768**	**7,512**	**8,645**

Table 8.2: Network Major Project Expenditure Summary

8.2.2 GXP Projects

GXP Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Southbrook GXP - Upgrade from 33kV to 66kV (CIC)	480									
Kaiapoi GXP Purchase (CIC)	300									
Kaiapoi GXP Purchase (CAPEX)	80									
Culverden GXP - GXP Purchase (CAPEX)		3,500								
Southbrook GXP - 66kV Bay - Tuahiwi Circuit (CIC)						1,500				
Ashley GXP - 66kV Bay for Tuahiwi Circuit (CIC)							912			
Ashley GXP - 66kV Bay for Amberley Circuit (CIC)								1,440		
Waipara GXP - 66kV Bay for Amberley Circuit (CIC)								1,440		
GXP Project Subtotals	**860**	**3,500**				**1,500**	**912**	**2,880**		
GXP Capital Expenditure (MainPower)	**80**	**3,500**								

Table 8.3: GXP Project Expenditure Summary

8.2.3 Network Reinforcement Projects

Network Reinforcement Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Reinforce SW63 and SW66 Swannanoa	312									
Loburn Overhead Reconductoring	187									
Loburn Feeder Reliability Improvement	210									
Northbrook Feeder	335			60						

Network Reinforcement Projects	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Flaxton Road Undergrounding	49	141								
Pegasus Feeders		702								
Kippenberger Avenue Circuit Breaker		65								
Reinforce X52 Burnt Hill		228								
Amberley North Load Transfer		224								
Amberley Y43 Urban/Rural Circuit Breaker			59							
Rangiora - East Belt North			80							
Kaiapoi - Island Rd Upgrade			200							
Greta - Cheviot 22kV link			487							
Cheviot - Leader Upgrade				379						
Amberley South Deloading						200				
Townsend Road Feeder						500				
Tuahiwi to Rangiora Feeders								300	300	300
Network Automation		100	100	100	100	100	100	100	100	100
Network Innovation (Low Voltage Monitoring)	98	150	150	150	150	150	150	150	150	150
Network Reinforcement - Unscheduled	146	200	424	811	1,250	550	1,250	950	950	950
Reinforcement Subtotals	**1,337**	**1,809**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**

Table 8.4: Network Reinforcement Expenditure Summary

8.3 Network Replacement

8.3.1 Network Replacement Expenditure

Asset Portfolio	Expenditure									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Overhead Network	4,802,817	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000
Zone Substations	21,214	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Kiosk Substations	797,641	940,000	940,000	940,000	940,000	940,000	940,000	940,000	940,000	940,000
Transformers	487,919	575,000	575,000	575,000	575,000	575,000	575,000	575,000	575,000	575,000
Switchgear	148,497	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Secondary Systems	331,615	390,800	390,800	390,800	390,800	390,800	390,800	390,800	390,800	390,800
Underground Assets	816,309	962,000	962,000	962,000	962,000	962,000	962,000	962,000	962,000	962,000
Network Property	424,277	500,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Corrective Replacement	169,711	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Total	**8,000,000**	**8,267,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**	**8,017,800**

Table 8.5: Network Replacement Expenditure Summary

8.4 Network Maintenance

8.4.1 Network Maintenance Expenditure

Asset Portfolio	Expenditure									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Overhead Network	1,648,061	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667	1,788,667
Zone Substations	686,459	745,026	745,026	745,026	745,026	745,026	745,026	745,026	745,026	745,026
Kiosks	392,679	426,181	426,181	426,181	426,181	426,181	426,181	426,181	426,181	426,181
Transformers	357,478	387,977	387,977	387,977	387,977	387,977	387,977	387,977	387,977	387,977
Switchgear	270,542	293,624	293,624	293,624	293,624	293,624	293,624	293,624	293,624	293,624
Communications	89,211	89,822	89,822	89,822	89,822	89,822	89,822	89,822	89,822	89,822
Vegetation	921,390	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Low Voltage Network	516,053	560,081	560,081	560,081	560,081	560,081	560,081	560,081	560,081	560,081
High Voltage Cables	176,664	191,736	191,736	191,736	191,736	191,736	191,736	191,736	191,736	191,736
Network Property	41,463	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000
Total	**5,100,000**	**5,528,113**	**5,528,113**	**5,528,113**	**5,528,113**	**5,528,113**	**5,528,113**	**5,528,113**	**5,528,113**	**5,528,113**

Table 8.6: Network Maintenance Expenditure Summary

8.5 Non-Network Expenditure

8.5.1 Non-Network Expenditure

Title	Expenditure ($,000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Field Services Equipment	1,200,000	500,000	250,000	150,000	150,000					
ERP Upgrade	1,700,000	824,000	824,000	824,000	824,000	824,000	824,000	824,000	824,000	824,000
LiDar Project	2,000,000	102,000	102,000	102,000	102,000	102,000	102,000	102,000	102,000	102,000
Fixed Asset Review	1,200,000									
Billing System Modifications	200,000	56,000	56,000	56,000	56,000	56,000	56,000	56,000	56,000	56,000
DERMs System Upgrade	200,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000
IT Renewals	300,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000
Sundry	200,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Total	**7,000,000**	**2,008,000**	**1,758,000**	**1,658,000**	**1,658,000**	**1,508,000**	**1,508,000**	**1,508,000**	**1,508,000**	**1,508,000**

Table 8.7: 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 the figure below.

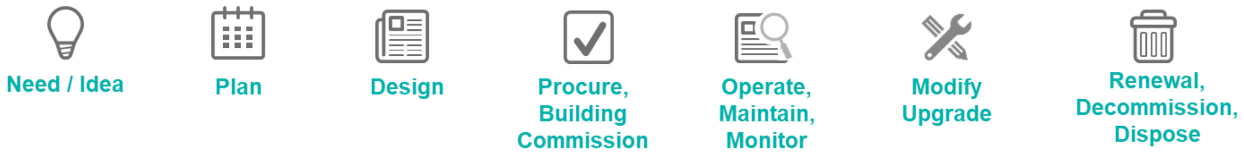

Figure 9.1: Asset Lifecycle Planning

Capability and competencies that support the asset lifecycle and the implementation of this Asset Management Plan are aligned with the asset lifecycle. The core competencies are:

- Programme and Project Management;
- Asset and Maintenance Management;
- Engineering and Design;
- Network Operations;
- Field Operators;
- Field Services – Service Delivery.

The interaction of the roles throughout the asset lifecycle activities are detailed below. Clear definitions about the roles are translated into Position Descriptions for relevant individuals. Where gaps exist between the role requirements and the competencies of the individual, a personal development programme is required to address the gap.

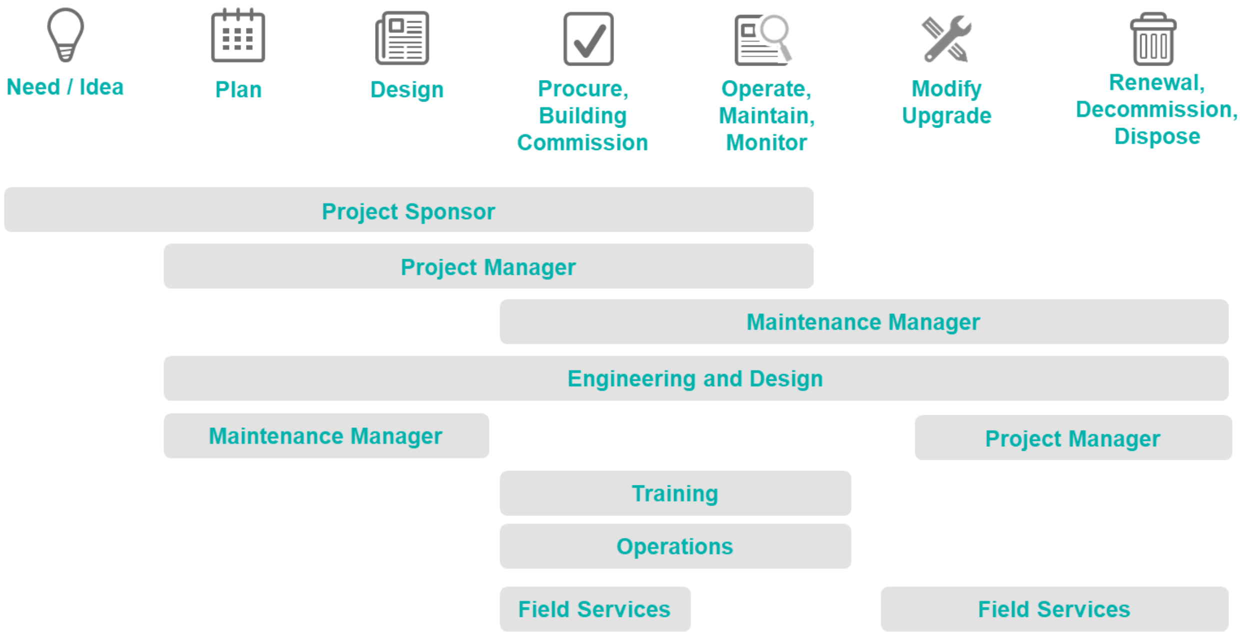

Figure 9.2: Alignment of Roles and Responsibilities Against Lifecycle Activities

9.1 Our People

MainPower's ability to deliver the Asset Management Plan and its success relies on our people having the capability and capacity to respond to the changing needs of our consumers. To meet this rapid rate of change we must maintain a strong employer value proposition (EVP) that allows us to attract and retain top talent in a competitive market.

9.1.1 Selecting People for Our Team

Our overarching position on selecting people for our team is that we will try our best to ensure that our people are competitive in attaining advancement within MainPower, while ensuring that all critical positions are also contestable. This practice meets our objective of employing the best person for each role.

We are also committed to growing diversity in our workplace. Our People and Culture Department oversee our robust selection process, with help from external search agencies as required.

9.1.2 Rewarding Our People

Our remuneration policy provides a clear and structured approach to managing remuneration for all employees. Our objective is that the policy is:

- Fair and consistent;
- Simple and easy to understand;
- Affordable and recognises the environment in which we operate;
- A transparent way to understand the value of positions within MainPower; and
- Able to ensure we have internal relativity (i.e. similar roles are paid in a similar way) and external competitiveness.

9.1.3 Developing Our People through Training, Competency and Professional Development

Our People and Culture department is responsible for developing, coordinating and monitoring our yearly training and development plan for all MainPower staff. The department is also responsible for ensuring that internal and external training providers are fit for purpose.

Individual managers are responsible for identifying and addressing training needs within their respective work areas. Only employees assessed as competent can carry out a task unsupervised. The GM – People and Culture, in conjunction with executive management, is responsible for ensuring appropriate career path planning and appropriate succession planning is in place within MainPower.

Supervisors have completed a skills matrix for all field staff positions. The matrix determines:

- What skills and other competencies are required for each position;
- When a skill needs refreshing;
- When a skill will expire; and
- Whether an expired skill needs renewing.

9.1.4 Keeping our People Well through our Employee Wellness Programme

Our Employee Wellness Programme is designed to include initiatives that encourage and assist employees to maintain their overall personal wellbeing and fitness for work. The programme includes access to:

- First Aid training;
- Ergonomic assessments;
- Our Occupational Counselling Programme (OCP); and
- Our drug and alcohol testing programme.

9.2 Network

The Network team has accountability for asset management and overall network performance. The Network team is structured on a 'Plan, Build, Operate' basis.

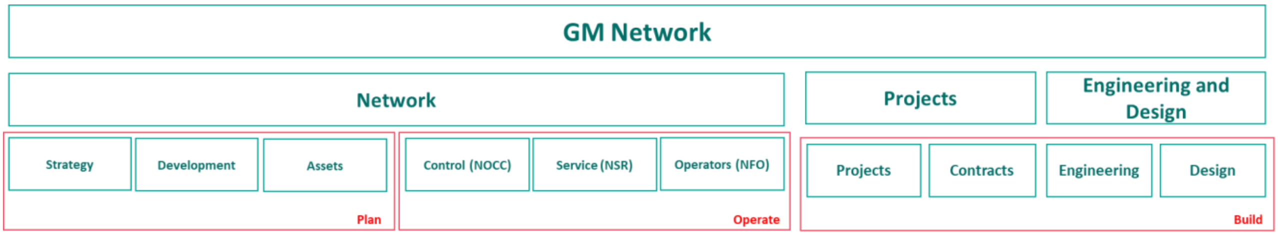

Figure 9.3: Our Assets and Capital Works

The proposed structure is designed to achieve several objectives:

- Expand our team capabilities by introducing new functions that are becoming essential for a best practice, modern asset manager;
- Create a stronger focus on our core activities, by splitting into more narrowly defined groups;
- Setting the asset management team up to be able to provide more effective guidance and support to our other business teams, including Engineering and Design, Project Management Office, Commercial, Safety and Business Risk, and Operations;
- Setting the asset management team up to be able to provide effective guidance and support to our Operations team, especially through the migration to an Advanced Distribution Management System;
- Enhance the quality of our information sources and ability to use this for optimal decision-making;
- Ensuring a focus on network-targeted research, development and pilot programmes, leading to continually improving and expanding business-as-usual products and solutions;
- Expand, using the Plan-Build-Operate platform services offered by MainPower; and
- Extend beyond network management (our core), to energy management and possible Open Network Framework in the future.

9.2.1 Network Operations and Control Team

The diagram below shows the tasks of our network management, fault response, consumer, reporting and monitoring operations.

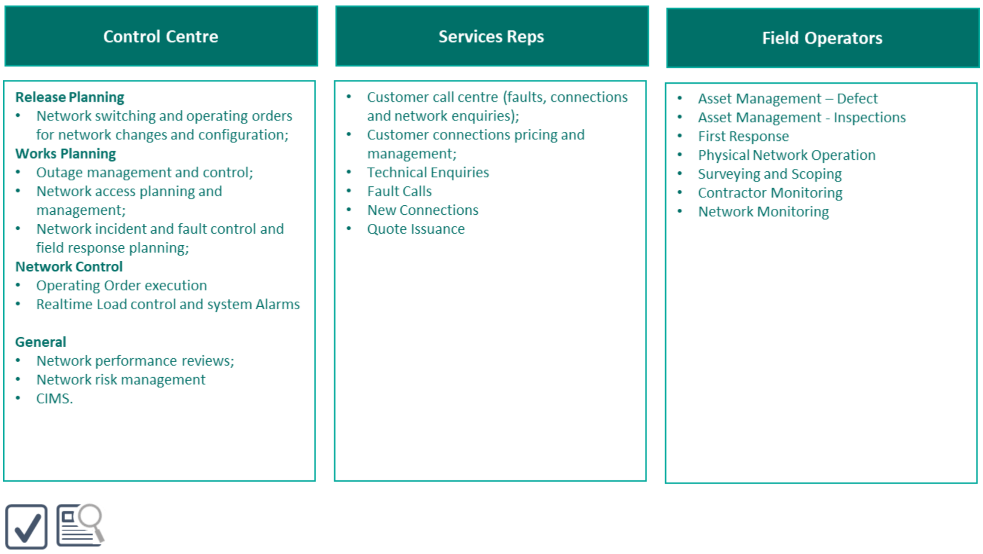

Figure 9.4: Our Network Operations

9.2.2 Planning Team

Network Development

- Area planning
- Network load forecasting;
- HV network power-flow analysis;
- LV network modelling;
- Major and reinforcement project;
- Emerging technology integration and impact assessment on network capacity and load forecast;
- Replacement network planning;
- Asset relocation planning;
- Transpower planning interface;
- Large connection planning;
- Contingency planning;
- Contribute to asset performance reviews and strategies;
- Asset capability monitoring and normal-state open point control;
- Long term network development plan;
- Network automation planning.

Network Assets

- Develop Asset Condition Based Risk Management (CBRM) models;
- Asset condition monitoring and management;
- Develop detailed asset maintenance and replacement plans aligned with asset lifecycle strategies;
- Conduct asset risk assessments and intervention plans;
- Integrate emerging technology into asset lifecycle systems and practices;
- Provide asset specialist support to strategy, development, design and project teams;
- Develop and maintain asset data collection and storage, including GIS.
- Provide GIS analysis to lifecycle, development and strategy teams;
- Contribute to asset performance reviews and strategies.

Master Planning

- Network evolution strategy;
- Asset Management Development Plan;
- Network and Asset Performance Analysis and Strategy;
- Security of Supply Standard;
- Network Architecture Standards;
- Asset Lifecycle Strategies;
- Network innovation
- Future scenario planning;
- Demand Side Management Strategy;
- Emerging Technology Strategy;
- Asset Management Plan (Contribution);
- Co-ordinate AMMAT review;
- Develops business case templates and provides business case support;
- Asset Safety and Risk Framework support;
- Support Network Design Standards;
- Customer engagement initiatives;
- Network investment analysis.
- Research and Development, pilot projects

Engineering

- OT and Communication Systems
- Design Criteria
- Design Standards
- Test, Quality and Compliance Standards
- Project Support
- Approvals
- Safety by Design
- Incident Investigation
- Protection
- Simulations

Design

- CAD Services
- Projects Support
- Asset Support

Figure 9.5: Our Planning Team

9.2.3 Build Team

Projects

- Project Delivery System
- Program Management
- Capital Work Program
- Procurement
- Handover
- Practical Completion
- Defect Management

Contracts

- Development of Work Packs
- 90+ Day Plan for
- Customer Connections
- Works Scheduling
- Site Safety Plans and Management

Figure 9.6: Our Build Team

9.3 Field Services

Most field services resourcing is completed internally within MainPower, with the works contracted by:

- Having an internal contract and service level agreements between the internal and field service resources;
- Implementation of rate cards for all contracted activities, which are pre-costed and updated regularly using supply change management; and
- Clearly defining what work is required, where it is required and what the outcomes need to be.

The main reason for reviewing the way works are contracted internally is primarily to improve productivity, efficiency and quality.

Where a gap in resourcing exists, procurement and contractor engagement processes are in place to secure external resource as required, in order to achieve the objectives of the Asset Management Plan and the Business Plan.

9.4 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.

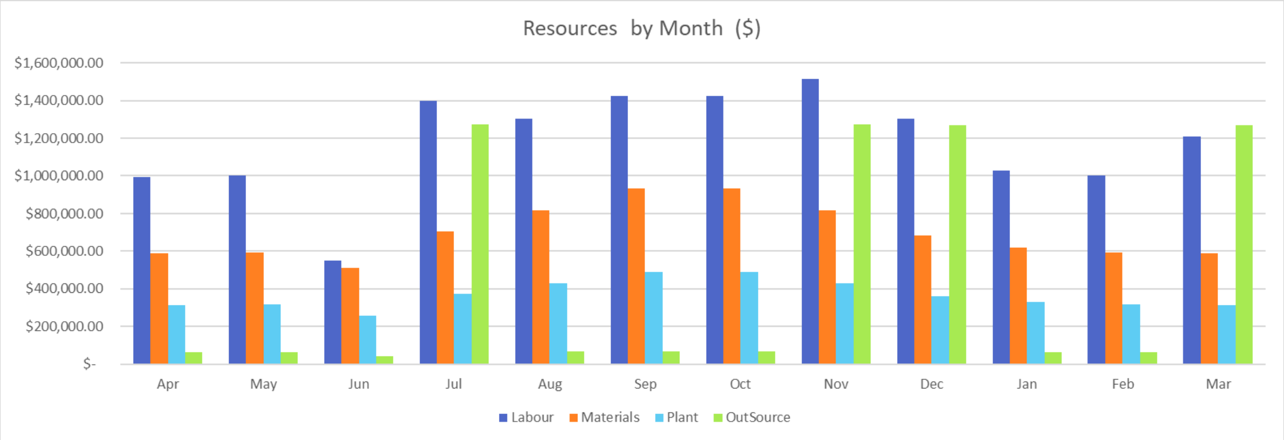

Figure 9.7: Resourcing Model

Human resourcing is then allocated across all aspects of the work by:

- Planning Team;
- Build Team; and
- Service Delivery Team.

Where gaps exist within the resourcing model, either due to capacity or capability, MainPower contracts out the works to other service providers.

Asset Management Plan 2020 – 2030

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
AHI	Asset Health Indicator
AMP	Asset Management Plan
CAPEX	Capital Expenditure
CDEM	Civil Defence Emergency Management
CIMS	Coordinated Incident Management System
CMMS	Computerised Maintenance Management System
CPG	Capital Planning Group
DG	Distributed Generation
Distribution Network	The power lines and underground cables that transport electricity from the national grid to homes and businesses
EVP	Employee value proposition
FY	Fiscal Year
GIS	Geographic Information System
GWH	Giga-watt hour
GXP	Grid Exit Point. A point at which MainPower's network connects to Transpower's transmission network.
HILP	High Impact Low Probability
HRIS	Human Resource Information System
HSEQ	Health, Environment, Safety and Quality
ICP	Installation Control Point
IIMM	International Infrastructure Management Manual
IoT	Internet of Things
IS system	Information Systems system
IT	Information Technology
KPI	Key Performance Indicator
kV	Kilo-volt
MACK	MainPower CRM (Customer Relationship Management application)
Master Plan	Long term network capacity development plan
MP network	MainPower network
MVA	Mega Volt Ampere
MW	Megawatt. One megawatt = 1,000 kilowatts = 1,000,000 watts.
MWhr	Megawatt hour
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
OCP	Occupational Counselling Programme
OGHV	Over Ground High Voltage
OGLV	Over Ground Low Voltage

PCM	Control Systems Automation
PDS	Project Delivery System
PMO	Project Management Office
RMA	Resource Management Act
ROCOF	Rate of Change of Frequency
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan (this document)
SCADA	Supervisory Control and Data Acquisition
SCI	Statement of Corporate Intent. An annual document that outlines the overall intentions of the company and the objectives which the Directors and Trustees have agreed.
SSR	Solution Study Report
Sub-transmission	An intermediate voltage used for connections between transmission connection points/bulk supply substations and zone substations. Sub-transmission is also used to connect between zone substations.
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.
UGHV	Under Ground High Voltage
UGLV	Under Ground Low Voltage
VAR	Volt Amps Reactive: a unit of the reactive component of electrical power
VoC	Voice of the Customer
Voltage	The amount of potential energy between two circuits. The greater the voltage, the greater the flow of electrical current.
WACC	Weighted Average Cost of Capital
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 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'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 backup 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 progress of the work plan, work hours and cost against budget.
SCADA and Load Management Systems	• Invensys Wonderware "Intouch" SCADA (supervisory control and data acquisition) system: o displays voltage, current, and status information in real time from remote points on the network; o receives instantaneous information on faults; 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; 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. This will include 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	• 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

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURE
Pursuant to Clause 2.9.1 of Section 2.9

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

a) The following attached information of MainPower New Zealand Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; 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.

d) An error was identified in AMP Network Faults expenditure forecast FY22-FY30 in the Asset Management Plan as notified. This translated through to an error in **Schedule 11b Line 22: Service Interruptions and Emergencies** constant dollar forecast FY22-FY30, with values shown at $1.5m per year. This has been updated to reflect correct values of $700,000 per year from FY22 to FY30 in both the Asset Management Plan and Schedule 11b, Line 22.

Anthony Charles King

18 June 2020
Date

Stephen Paul Lewis

18th June 2020.
Date

Appendix 4 – Capital Forecast

11a(i): Expenditure on Assets Forecast

for year ended	Current Year CY 31 Mar 20	CY+1 31 Mar 21	CY+2 31 Mar 22	CY+3 31 Mar 23	CY+4 31 Mar 24	CY+5 31 Mar 25	CY+6 31 Mar 26	CY+7 31 Mar 27	CY+8 31 Mar 28	CY+9 31 Mar 29	CY+10 31 Mar 30
$000 (in nominal dollars)											
Consumer connection	4,900	4,500	4,576	4,670	4,759	4,861	4,967	5,082	5,205	5,333	5,463
System growth	739	6,249	9,636	239	328	270	3,412	6,651	7,193	9,436	11,042
Asset replacement and renewal	9,110	8,000	8,660	8,372	11,124	11,362	8,851	9,055	9,275	9,502	9,734
Asset relocations	56	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	1,583	192	-	-	-	-	-	-	-	-	-
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	1,904	2,962	1,763	5,623	2,663	2,539	718	1,525	1,215	1,244	1,275
Total reliability, safety and environment	3,488	3,154	1,763	5,623	2,663	2,539	718	1,525	1,215	1,244	1,275
Expenditure on network assets	18,292	21,903	24,635	18,903	18,873	19,032	17,947	22,313	22,887	25,515	27,515
Expenditure on non-network assets	1,933	7,000	3,720	3,622	3,650	3,796	3,785	3,948	4,125	4,311	4,507
Expenditure on assets	20,226	28,903	28,356	22,526	22,523	22,828	21,732	26,261	27,012	29,826	32,022
plus Cost of financing											
less Value of capital contributions	2,439	2,000	3,559	3,632	3,702	3,781	3,864	3,953	4,049	4,148	4,249
plus Value of vested assets											
Capital expenditure forecast	17,787	26,903	24,796	18,893	18,821	19,047	17,869	22,308	22,963	25,678	27,772
Assets commissioned	14,329	16,663	16,663	15,805	14,570	14,569	14,706	15,139	17,829	19,906	19,435

for year ended	Current Year CY 31 Mar 20	CY+1 31 Mar 21	CY+2 31 Mar 22	CY+3 31 Mar 23	CY+4 31 Mar 24	CY+5 31 Mar 25	CY+6 31 Mar 26	CY+7 31 Mar 27	CY+8 31 Mar 28	CY+9 31 Mar 29	CY+10 31 Mar 30
$000 (in constant prices)											
Consumer connection	4,900	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
System growth	739	6,249	9,475	230	310	250	3,091	5,889	6,218	7,962	9,095
Asset replacement and renewal	9,110	8,000	8,515	8,067	10,518	10,518	8,018	8,018	8,018	8,018	8,018
Asset relocations	56	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	1,583	192	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	1,904	2,962	1,734	5,418	2,518	2,350	650	1,350	1,050	1,050	1,050
Total reliability, safety and environment	3,487	3,154	1,734	5,418	2,518	2,350	650	1,350	1,050	1,050	1,050
Expenditure on network assets	18,292	21,903	24,224	18,215	17,845	17,618	16,259	19,757	19,786	21,530	22,663
Expenditure on non-network assets	1,933	7,000	3,658	3,491	3,451	3,514	3,429	3,496	3,566	3,638	3,712
Expenditure on assets	20,225	28,903	27,882	21,706	21,296	21,132	19,688	23,253	23,351	25,167	26,375
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

for year ended	Current Year CY 31 Mar 20	CY+1 31 Mar 21	CY+2 31 Mar 22	CY+3 31 Mar 23	CY+4 31 Mar 24	CY+5 31 Mar 25	CY+6 31 Mar 26	CY+7 31 Mar 27	CY+8 31 Mar 28	CY+9 31 Mar 29	CY+10 31 Mar 30
$000											
Consumer connection	-	-	76	170	259	361	467	582	705	833	963
System growth	(0)	-	161	9	18	20	321	762	975	1,474	1,947
Asset replacement and renewal	0	-	145	305	606	844	833	1,037	1,257	1,484	1,717
Asset relocations	(0)	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	0	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	(0)	-	29	205	145	189	68	175	165	194	225
Total reliability, safety and environment	0	-	29	205	145	189	68	175	165	194	225
Expenditure on network assets	0	-	411	688	1,028	1,414	1,688	2,556	3,101	3,985	4,852
Expenditure on non-network assets	0	-	62	132	199	282	356	452	559	673	795
Expenditure on assets	0	-	474	820	1,227	1,696	2,044	3,008	3,660	4,658	5,647

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Consumer types defined by EDB**		$000 (in constant prices)					
Residential		2,849	2,616	2,616	2,616	2,616	2,616
Irrigation		1,209	1,110	1,110	1,110	1,110	1,110
Large User		358	329	329	329	329	329
Streelights		146	134	134	134	134	134
Other		338	311	311	311	311	311
**include additional rows if needed*							
Consumer connection expenditure		4,900	4,500	4,500	4,500	4,500	4,500
less Capital contributions funding consumer connection							
Consumer connection less capital contributions		4,900	4,500	4,500	4,500	4,500	4,500

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission						
Zone substations	200	5,806	8,623		100	100
Distribution and LV lines						
Distribution and LV cables	522	343	702		60	
Distribution substations and transformers				80		
Distribution switchgear						
Other network assets	17	100	150	150	150	150
System growth expenditure	739	6,249	9,475	230	310	250
less Capital contributions funding system growth						
System growth less capital contributions	739	6,249	9,475	230	310	250

11a(iv): Asset Replacement and Renewal

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
	1.249917695	$000 (in constant prices)					
Subtransmission			-	-	-	-	-
Zone substations		1,025	21	273	75	2,525	2,525
Distribution and LV lines		2,164	4,803	4,500	4,500	4,500	4,500
Distribution and LV cables		1,025	816	962	962	962	962
Distribution substations and transformers		455	488	575	575	575	575
Distribution switchgear		4,099	946	1,115	1,115	1,115	1,115
Other network assets		342	926	1,091	841	841	841
Asset replacement and renewal expenditure		9,110	8,000	8,515	8,067	10,518	10,518
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions		9,110	8,000	8,515	8,067	10,518	10,518
			8000	8267.8	8017.8	8017.8	8017.8

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
Network reinforcement		56					
[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		56	-	-	-	-	-
less Capital contributions funding asset relocations							
Asset relocations less capital contributions		56	-	-	-	-	-

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
Network Reinforcement		1,583	192	-	-	-	-
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - quality of supply							
Quality of supply expenditure		1,583	192	-	-	-	-
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		1,583	192	-	-	-	-

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
Conductor Upgrades		1,111	1,412	1,000	1,687	1,379	1,000
Zone Substations		106	815		100	228	
Switchgear Upgrades		44		65	3,107		
Network Automation		-		100	100	100	100
Network Reinforcement		643	735	569	424	811	1,250
**include additional rows if needed*							
All other projects or programmes - other reliability, safety and environment							
Other reliability, safety and environment expenditure		1,904	2,962	1,734	5,418	2,518	2,350
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		1,904	2,962	1,734	5,418	2,518	2,350

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
Field Services Equipment	750	1,200	500	250	150	150
Asset Management Systems	960	5,100	2,632	2,715	2,775	2,838
Dsitributed Energy Systems		200	256	256	256	256
IT Infrastructure & Eqiupment	140	300	120	120	120	120
Sundry/Other	83	200	150	150	150	150
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	1,933	7,000	3,658	3,491	3,451	3,514
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	1,933	7,000	3,658	3,491	3,451	3,514

Appendix 5 – Opex Forecast

	for year ended	*Current Year CY* 31 Mar 20	*CY+1* 31 Mar 21	*CY+2* 31 Mar 22	*CY+3* 31 Mar 23	*CY+4* 31 Mar 24	*CY+5* 31 Mar 25	*CY+6* 31 Mar 26	*CY+7* 31 Mar 27	*CY+8* 31 Mar 28	*CY+9* 31 Mar 29	*CY+10* 31 Mar 30
Operational Expenditure Forecast		**$000 (in nominal dollars)**										
Service interruptions and emergencies		1,537	700	712	726	740	756	773	791	810	830	850
Vegetation management		713	921	1,017	1,038	1,058	1,080	1,104	1,129	1,157	1,185	1,214
Routine and corrective maintenance and inspection		4,165	4,179	4,605	4,699	4,789	4,892	4,998	5,114	5,238	5,366	5,498
Asset replacement and renewal			-	-	-	-	-	-	-	-	-	-
Network Opex		6,414	5,800	6,334	6,463	6,587	6,728	6,875	7,034	7,204	7,381	7,562
System operations and network support		6,000	6,180	6,474	6,804	7,142	7,514	7,908	8,334	8,792	9,278	9,790
Business support		6,276	7,210	7,553	7,938	8,332	8,766	9,227	9,723	10,257	10,824	11,422
Non-network opex		12,276	13,390	14,026	14,742	15,474	16,280	17,135	18,057	19,049	20,101	21,211
Operational expenditure		18,690	19,190	20,360	21,205	22,061	23,008	24,010	25,091	26,254	27,482	28,773

	for year ended	*Current Year CY* 31 Mar 20	*CY+1* 31 Mar 21	*CY+2* 31 Mar 22	*CY+3* 31 Mar 23	*CY+4* 31 Mar 24	*CY+5* 31 Mar 25	*CY+6* 31 Mar 26	*CY+7* 31 Mar 27	*CY+8* 31 Mar 28	*CY+9* 31 Mar 29	*CY+10* 31 Mar 30
		$000 (in constant prices)										
Service interruptions and emergencies		1,537	700	700	700	700	700	700	700	700	700	700
Vegetation management		713	921	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Routine and corrective maintenance and inspection		4,165	4,179	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528
Asset replacement and renewal												
Network Opex		6,414	5,800	6,228	6,228	6,228	6,228	6,228	6,228	6,228	6,228	6,228
System operations and network support		6,000	6,180	6,365	6,556	6,753	6,956	7,164	7,379	7,601	7,829	8,063
Business support		6,276	7,210	7,426	7,649	7,879	8,115	8,358	8,609	8,867	9,133	9,407
Non-network opex		12,276	13,390	13,792	14,205	14,632	15,071	15,523	15,988	16,468	16,962	17,471
Operational expenditure		18,690	19,190	20,020	20,434	20,860	21,299	21,751	22,216	22,696	23,190	23,699
Subcomponents of operational expenditure (where known)												
Energy efficiency and demand side management, reduction of energy losses												
Direct billing*												
Research and Development												
Insurance		724	745	783	822	863	906	951	999	1,049	1,101	1,156

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

	for year ended	*Current Year CY* 31 Mar 20	*CY+1* 31 Mar 21	*CY+2* 31 Mar 22	*CY+3* 31 Mar 23	*CY+4* 31 Mar 24	*CY+5* 31 Mar 25	*CY+6* 31 Mar 26	*CY+7* 31 Mar 27	*CY+8* 31 Mar 28	*CY+9* 31 Mar 29	*CY+10* 31 Mar 30
Difference between nominal and real forecasts		**$000**										
Service interruptions and emergencies		-	-	12	26	40	56	73	91	110	130	150
Vegetation management		-	-	17	38	58	80	104	129	157	185	214
Routine and corrective maintenance and inspection		-	-	77	171	261	363	470	586	710	838	969
Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
Network Opex		-	-	106	235	359	500	647	806	976	1,153	1,333
System operations and network support		-	-	108	248	389	558	744	955	1,191	1,449	1,726
Business support		-	-	126	289	454	651	868	1,114	1,390	1,690	2,014
Non-network opex		-	-	234	537	843	1,210	1,612	2,068	2,581	3,139	3,741
Operational expenditure		-	-	340	772	1,202	1,710	2,259	2,874	3,558	4,292	5,074

Appendix 6 – Asset Condition

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
All	Overhead Line	Concrete poles / steel structure	No.		4.1%	5.0%	32.1%	58.8%	-	3	
All	Overhead Line	Wood poles	No.	8.3%	4.2%	7.0%	29.0%	51.6%	-	3	7.00%
All	Overhead Line	Other pole types	No.							[Select one]	
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.5%	8.7%	13.2%	47.7%	28.9%	-	2	5.00%
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							[Select one]	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km		5.5%	46.5%	5.2%	42.7%		2	1.00%
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.				66.7%	33.3%	-	3	6.00%
HV	Zone substation Buildings	Zone substations 110kV+	No.							[Select one]	
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.				30.0%	70.0%		2	30.00%
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.			20.0%	20.0%	60.0%		2	1.00%
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							[Select one]	
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.		3.7%	44.4%	24.1%	27.8%		2	10.00%
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.				6.7%	93.3%		2	
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			34.8%	65.2%			2	40.00%
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.			4.8%	9.5%	85.7%	-	2	5.00%

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.		15.4%	11.5%	61.5%	11.5%	-	3	6.00%
HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.6%	0.2%	4.2%	49.8%	44.1%		1	1.00%
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							[Select one]	
HV	Distribution Line	SWER conductor	km							[Select one]	
HV	Distribution Cable	Distribution UG XLPE or PVC	km	1.3%	1.5%	2.0%	30.6%	64.6%	-	1	1.00%
HV	Distribution Cable	Distribution UG PILC	km			0.5%	42.1%	57.5%		1	1.00%
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.		1.3%	7.7%	20.5%	70.5%	-	3	1.00%
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.		6.5%	8.7%	21.7%	63.0%	-	3	1.00%
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	21.6%	2.8%	18.2%	25.3%	32.2%	-	2	1.00%
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.	8.6%	4.7%	38.2%	20.2%	28.3%		3	14.00%
HV	Distribution Transformer	Pole Mounted Transformer	No.	0.4%	6.4%	29.1%	39.6%	24.5%		2	2.00%
HV	Distribution Transformer	Ground Mounted Transformer	No.	0.5%	3.3%	20.5%	38.7%	37.0%		3	4.00%
HV	Distribution Transformer	Voltage regulators	No.			5.0%	55.0%	40.0%		3	1.00%
HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.0%	17.9%	13.7%	34.7%	32.8%	-	2	5.00%
LV	LV Line	LV OH Conductor	km	3.4%	4.1%	45.9%	41.1%	5.6%		1	5.00%
LV	LV Cable	LV UG Cable	km	2.2%			21.7%	76.1%		1	
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.8%	0.2%	43.6%	10.5%	43.9%	-	2	1.00%
LV	Connections	OH/UG consumer service connections	No.	2.8%	2.4%	14.6%	29.1%	51.1%	-	1	1.00%
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	26.9%		10.3%	39.4%	23.4%		3	10.00%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot		2.0%	40.0%	40.0%	18.0%		3	15.00%
All	Capacitor Banks	Capacitors including controls	No.							[Select one]	
All	Load Control	Centralised plant	Lot				50.0%	50.0%		3	
All	Load Control	Relays	No.	2.6%		68.5%	16.6%	12.2%	-	2	1.00%
All	Civils	Cable Tunnels	km							[Select one]	

Appendix 7 – Capacity Forecast

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	23	22	N-1 switched	2	104%	44	68%	No constraint within +5 years	Upgrade required within 5 years
Rangiora North	6	-	N-1 switched	6	-	-	N/A	Subtransmission circuit	Single cct 33kV
Burnt Hill	15	23	N-1 switched	6	65%	23	75%	No constraint within +5 years	
Swannanoa	15	23	N-1 switched	6	66%	23	80%	No constraint within +5 years	
Amberley	6	4	N-1 switched	2	151%	4	120%	Transformer	Single cct 33kV
MacKenzies Rd	2	-	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	6	6	N-1 switched	-	98%	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	16	13	N	2	120%	13	140%	Transformer	Load reduction by emergency irrig load control
Hanmer	5	3	N-1 switched	-	192%	-	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 – Demand Forecast

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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
*Consumer types defined by EDB**							
Residential		800	800	800	800	800	800
Irrigation		12	12	12	12	12	12
Large User		1	1	1	1	1	1
Streelights		2	2	2	2	2	2
Other		140	140	140	140	140	140
Connections total		955	955	955	955	955	955
**include additional rows if needed*							
Distributed generation							
Number of connections		191	201	211	221	232	244
Capacity of distributed generation installed in year (MVA)		3	1	1	3	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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
	GXP demand		113	115	116	119	120	122
plus	Distributed generation output at HV and above		3	4	4	6	6	6
	Maximum coincident system demand		116	118	119	125	126	127
less	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
	Demand on system for supply to consumers' connection points		116	118	119	125	126	127
	Electricity volumes carried (GWh)							
	Electricity supplied from GXPs		630	636	636	636	637	646
less	Electricity exports to GXPs		-	-	-	-	-	-
plus	Electricity supplied from distributed generation		25	29	38	47	56	57
less	Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
	Electricity entering system for supply to ICPs		655	664	674	684	693	703
less	Total energy delivered to ICPs		618	627	636	645	655	664
	Losses		37	37	38	38	39	39
	Load factor		64%	64%	64%	63%	63%	63%
	Loss ratio		5.6%	5.6%	5.6%	5.6%	5.6%	5.6%

Appendix 9 – Reliability

Company Name	**MainPower New Zealand**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	240.4	221.5	214.9	208.4	202.2	196.1
12	Class C (unplanned interruptions on the network)	119.5	111.1	103.8	97.7	92.0	86.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.86	0.80	0.78	0.75	0.73	0.71
15	Class C (unplanned interruptions on the network)	1.48	1.38	1.29	1.21	1.14	1.07

Appendix 10 – AMMAT

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 eh business through training and regularly updates to the staff on Asset Management		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	As demonstrated in the Asset Management Policy there is clear line of sight between asset management polices to everything we do through to the statement of corporate intent		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 inform 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 exit for all assets. Work remains linking Asset Management plans to polices and enabling 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	Asset Managers have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this. An Asset Management Steering group is attended by Line and Executive Managers, the CE		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?	1	Currently resources, systems and reporting is in place that demonstrates MainPower is completing asset management effectively on its core assets. This remains to be applied to all assets.		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)	2	Asset Management and its importance is reported to all staff on an irregular bases through general company updates / staff engagement meetings.		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	On the most part (Work Remains) Asset Management activities are well define and assurance, in the form of data collection points are used to detail Maintenance outcomes. Work remains to audit the outcomes; this requirement is agnostic to outsourcing or insourcing.	The Construction Specifications and the Standard Construction Drawing Set have been examined (which form a key control mechanism).	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	Asset Managers have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this. An Asset Management Steering group exists, meets monthly and is attended by Line and Executive Manager, the CE and	An organisation structure (Jan 2019) has been examined. This shows a split of field services from engineering, and a realignment of skills within commercial and regulatory.	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 remains to be applied to all assets.	Budget spreadsheets, Strategic Plan & Business Plan	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 an irregular bases through general company updates / staff engagement meetings.	The revised organisation chart (Jan 2019) has been examined. Updates are available to all staff by way of email and Power Press.	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 data collection points are used to detail Maintenance outcomes. Work remains to audit the outcomes; this requirement is agnostic to outsourcing or insourcing.	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. 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 maintenance activities exist within the Asset Management plans. All maintenance 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.		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 maintenance 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. Work remains to be completed to extend this to all assets.		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?	2	Currently MainPower, through process maps describing its approach to asset management, 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?	1	Asset Management Information systems are currently being reviewed by the organisation so that the organisation can achieved 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?	2	This is achieved via the as building process, system audits, incidents corrective actions and through maintenance inspections.		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.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Information requirements are informed by the Asset Management Plan, financial and operational requirements.		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?	2	Activity risk assessment for all maintenance activities have been assessed, documented and controls identified. Work remains to be completed detailing the operational risk of all assets (Plant and Equipment Risk Assessments).	Corporate Risk Register	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?	1	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?	2	Legal statutory risk forms part of the MainPower corporate risk management framework. Controls identified are included in Asset Management plans and are implemented within the organisations CMMS.		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?	2	Process are currently being developed to fully document the addition, acquisition or enhancements made to assets. This will including Asset Creation, Schedules assigned, asbuilts updated prior to energisation.		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?	1	Process and procedures are currently being documented that detail how Asset Management plans are implemented. Individual asset management plans detail inspections, activities and the required standard. Cost, risk and performance is measured against pre-populated and agreed rate cards. The implementation of rate cards area also form part of the CMMS upgrade.		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?	1	Overall performance of the system is measured via SAIDI, SAIFI and other performance metric documented in the regulatory AMP. The performance of the approach to asset management remains to be monitored through condition assessments made against criticality.	The Control Room was observed measuring the real-time performance of assets. Field staff use cellular based data capture of asset condition.	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	There is no system in place that actively audits asset management process for efficacy and implementation.		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?	2	Incident investigations and corrective actions are undertaken in accordance with the Incident Reporting and Management operating standard.		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	All maintenance 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?	2	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.

Appendix 11 – Conformity Declaration

3.0 The AMP must include the following -	**2020**
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	CEO's Message
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes; 3.3.2 states the corporate mission or vision as it relates to asset management; 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB; 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and 3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans; The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.	3.3.1 - Section 1.0 Summary 3.3.2 - Section 2.3.1, Section 2.3.2 and Section 2.3.2 3.3.3 - Section 2.2 3.3.4 - Section 2.3 3.3.5 - Section 2.4 and Section 2.1 (Purpose)
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed; Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the AMP. The asset management planning information for the second 5 years of the AMP planning period need not be presented in the same detail as the first 5 years.	Noted
3.5 The date that it was approved by the directors;	Directors Certificate
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	Section 3.6 Stakeholder Interests
3.6.1 how the interests of stakeholders are identified 3.6.2 what these interests are; 3.6.3 how these interests are accommodated in asset management practices; and 3.6.4 how conflicting interests are managed;	3.6.1 - Section 3.7.2 3.6.2 - Section 3.7.2 3.6.3 - Section 3.7.3 3.6.4 - Section 3.7.4
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	Section 2.8
3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors; 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and 3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	3.7.1 - Section 2.8.2 3.7.2 - Section 2.8.3 3.7.3 - Section 2.8.4
3.8 All significant assumptions-	Section 2.9
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including- 3.8.3 a description of changes proposed where the information is not based on the EDB's existing business; 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and 3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	3.8.1 - Section 3.9.1 3.8.2 - Noted 3.8.3 - Section 3.9.2 3.8.4 - Section 3.9.3 and Section 3.9.5 3.8.5 - Section 3.9.4
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	Section 2.9.5
3.10 An overview of asset management strategy and delivery; To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify- - how the asset management strategy is consistent with the EDB's other strategy and policies; - how the asset strategy takes into account the life cycle of the assets; - the link between the asset management strategy and the AMP; and - processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	Section 2.6
3.11 An overview of systems and information management data; To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- - the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; - the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; - the systems and controls to ensure the quality and accuracy of asset management information; and - the extent to which these systems, processes and controls are integrated.	Section 2.10
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data; Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.	Section 2.11
3.13 A description of the processes used within the EDB for-	Section 2.12
3.13.1 managing routine asset inspections and network maintenance; 3.13.2 planning and implementing network development projects; and 3.13.3 measuring network performance;	3.13.1 - Section 2.12.1 and Section 2.12.2 3.13.2 - Section 2.12.3 3.13.3 - Section 3.12.4
3.14 An overview of asset management documentation, controls and review processes.	Section 2.13
To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should- (i) identify the documentation that describes the key components of the asset management system and the links between the key components; (ii) describe the processes developed around documentation, control and review of key components of the asset management system; (iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy; (iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and (v) audit or review procedures undertaken in respect of the asset management system.	3.14 i - Section 2.13.1 3.14 ii - Section 2.13.2 3.14 iii and iv - Section 2.13.3 3.14 v - Section 2.13.2
3.15 An overview of communication and participation processes;	Section 2.14
(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and (ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.	
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Noted
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in	Noted

4.0 Assets Covered -			2020
	4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked,		Section 5.1
		4.1.1 the region(s) covered; 4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities; 4.1.3 description of the load characteristics for different parts of the network; 4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	4.1.1 - Section 5.1 4.1.3 - Section 5.1.2 4.1.4 - Section 5.1.3
	4.2 a description of the network configuration, including-		
		4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the network's distribution substation arrangements; 4.2.5 a description of the low voltage network including the extent to which it is underground; and 4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems. To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.	4.2.1 - Section 5.2.1 4.2.2 - Section 5.2.2 4.2.3 - Section 5.2.3 4.2.4 - Section 5.2.4 4.2.5 - Section 5.2.5 4.2.6 - Section 5.3
	4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.		N/A
	4.4 The AMP must describe the network assets by providing the following information for each asset category-		Section 7 - MainPower Assets
		4.4.1 voltage levels; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	Refer to section 7 of the AMP for - Overhead Lines - Switchgear - Transformers - Zone Substations - Underground Assets - Vegetation Management - Secondary Systems - Property
	4.5 The asset categories discussed in clause 4.4 should include at least the following-		
		4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); 4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others; 4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.4 other generation plant owned by the EDB.	4.5.1 - Section 8.2 4.5.2 - Section 7.12.2 4.5.3 - Section 7.12.3 4.5.4 - Section 7.12.4

5.0 Service Levels -			2020
	5. The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.		Section 3.4 amd 3.5
	6. Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.		Section 3.5
	7. Performance indicators for which targets have been defined in clause 5 should also include-		
		7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	7.1 - Section 3.4.4 7.2 - See Shedules
	8. The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.		section 3.1 and 3.2
	9. Targets should be compared to historic values where available to provide context and scale to the reader.		Noted
	10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.		Section 3.7

11.0 Network Development Planning -	2020
11. AMPs must provide a detailed description of network development plans, including—	Section 6
11.1 A description of the planning criteria and assumptions for network development;	11.1 - Section 6.1
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	11.1 - Section 6.1
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	11.3 - Section 6.4
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; and 11.4.2 the approach used to identify standard designs;	11.4 - Section 6.4
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network; The energy efficient operation of the network could be promoted, for example, though network design strategies, demand side management strategies and asset purchasing strategies.	11.5 - Section 6.5
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;. The criteria described should relate to the EDB's philosophy in managing planning risks.	Section 6.3.1
11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	Section 6.2
11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts; 11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	11.8 - Section 6.6.2 11.8.1 - Section 6.6.1 and 6.6.2 11.8.2 - Section 6.7.1.2, 6.7.2.2, 6.7.3.2 11.8.3 - Section 6.7.1.3, 6.7.2.3, 6.7.3.3 11.8.4
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and 11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	11.9 11.9.1 - Section 6.7.1.4, 6.7.2.4, 6.7.3.4 11.9.2 - Section 6.8.4 11.9.3 - Section 6.8.4
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period;	11.10 - Section 6.8 in conjunction with section 6.7
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	Section 6.9
11.12 A description of the EDB's policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and 11.12.2 the potential for non-network solutions to address network problems or constraints.	11.12 - Section 6.11 11.12.1 - Section 6.11.2 11.12.2 - Section 6.11.3

12.0 Lifecycle Planning -	2020
12. The AMP must provide a detailed description of the lifecycle asset management processes, including—	Section 7
12.1 The key drivers for maintenance planning and assumptions;	Section 7
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	12.2, 12.2.1 and 12.2.2 -Section 7 - Overhead Lines - Section 7.2.1 and Table 7.2 - Switchgear - Section 7.3 and Table 7.3, 7.4, 7.5, 7.6 and 7.7 - Transformers - Section 7.4 and Tables 7.9, 7.11, 7.13 and 7.14 - Zone Substations - Section 7.5 and Tables 7.16 - Underground Assets - Section 7.6 and Tables 7.19 and 7.20 - Vegetation Management - Section 7.7 and Table 7.21 - Secondary Systems - Section 7.8 and Table 7.22, 7.23, 7.24 and 7.25 - Property - Section 7.9 and Table 7.29 12.2.3 - Section 7.10
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets; 12.3.2 a description of innovations that have deferred asset replacements; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and 12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	12.3 12.3.1 - Section 7 12.3.2 Section 7.11 12.3.3 Section Section 7.10 12.3.4 Section Section 7.10 12.3.5 Section Section 7.10
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Noted

13.0 Non-Network Development, Maintenance and Renewal -					2020
		13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—			
			13.1 a description of non-network assets; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; and 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.		Section 7.12 and Section 7.10.2

14.0 Risk Management -					2020
		14. AMPs must provide details of risk policies, assessment, and mitigation, including—			
			14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events; 14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and 14.4 Details of emergency response and contingency plans. Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.		14.1 - Section 4.1 14.2 - Section 4.4 14.3 - Section 4.5 14.4 - Section 4.5.3

15.0 Evaluation of Performance -					2020
		15. AMPs must provide details of performance measurement, evaluation,			
			15.1 A review of progress against plan, both physical and financial; - referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances; - commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and - commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.		Section 3.6.5
			15.2 An evaluation and comparison of actual service level performance against targeted performance; - in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.		Section 3.6.1, 3.6.2, 3.6.3 and 3.6.4
			15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.		Section 3.6.5.4 (Asset Maturity)
			15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.		Contained within the relevent sections

16.0 Capacity to Deliver -					2020
		16. AMPs must describe the processes used by the EDB to ensure that-			Section 9
			16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.		16.1 - Section 9.1 16.2 - Section 9.2

Appendix 12 – Schedule 14a

Company Name	MainPower New Zealand Ltd
For Year Ended	31-March-2020

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause **Error! Reference source not found.**.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause **Error! Reference source not found.**. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section **Error! Reference source not found.**.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

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

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

In preparing the capital expenditure forecasts MainPower has used the Westpac Economics Forecas Summary sheet December 2019 for the Inflation (CPI) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast, and extrapolated at constant CPI for the final two periods of the AMP forecast.

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast Inflation	1.7%	2.0%	1.9%	2.1%	2.2%	2.3%	2.4%	2.4%	2.4%

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

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

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

In preparing the capital expenditure forecasts MainPower has used the Westpac Economics Forecas Summary sheet December 2019 for the Inflation (CPI) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast, and extrapolated at constant CPI for the final two periods of the AMP forecast.

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast Inflation	1.7%	2.0%	1.9%	2.1%	2.2%	2.3%	2.4%	2.4%	2.4%