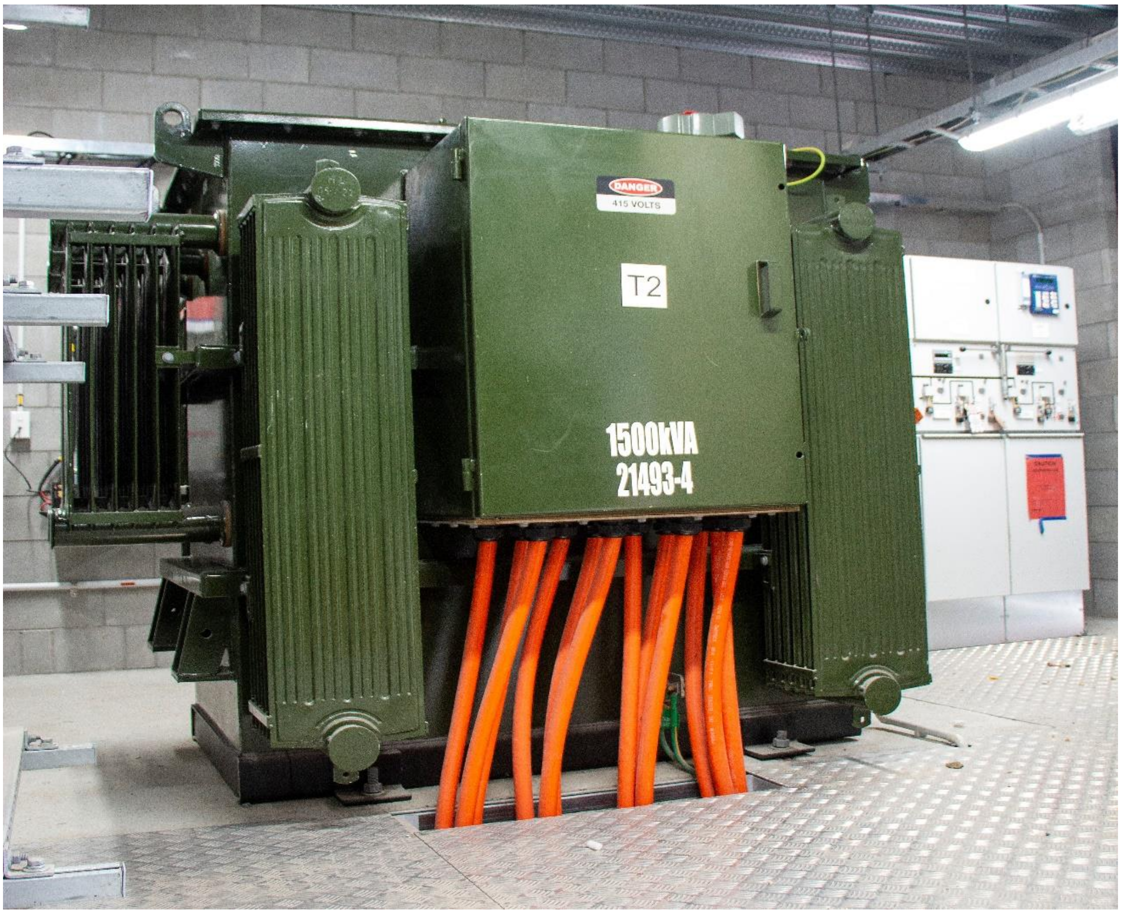
Electricity Invercargill Ltd



Invercargill City Substation

Asset Management Plan 2024 - 2034

Publicly disclosed in March 2024

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Foreword

About Electricity Invercargill Limited (EIL)

Electricity Invercargill Limited (EIL) delivers safe, efficient, and reliable energy solutions to Invercargill City and Bluff, providing a secure and future-proofed power supply to over 17,700 homes and businesses across the region.

Recognised as one of the best-performing networks in New Zealand, EIL is committed to continuing its efforts to drive innovative ways of providing critical infrastructure to the regions it serves. Formed in 1991, EIL is wholly owned by the Invercargill City Council through its subsidiary company, Invercargill City Holdings Ltd. The network has provided power to Invercargill since 1905, most notably in the past as the Invercargill Municipal Electricity Department.

With 90 percent of EIL's connected customers being residential, most of the network was converted to underground over a 50-year period from the 1960s, making it one of New Zealand's most reliable networks. This future-focused planning ethos continues today with EIL's commitment to reducing the overall age of its network through ongoing renewals and maintenance, continuously improving the condition of its assets, and supporting innovative approaches to network management.

This Asset Management Plan (AMP) outlines EIL's approach to managing its electricity distribution assets during the period from 1 April 2024 to 31 March 2034. Our AMP showcases how we plan to invest in our network over this period to continue providing a safe, efficient, and reliable power supply to customers across our network.

About our Network Manager, PowerNet

PowerNet is an electricity management company with head offices based in Invercargill. It is a joint venture company owned (50/50) by EIL and The Power Company Limited (TPCL).

EIL and TPCL established PowerNet in 1994 to achieve economies of scale through integrated network management across the Southern region's Electricity Distribution Businesses (EDBs). It manages the non-exempt EDBs of EIL and OtagoNet Joint Venture Limited (OJV), the exempt EDB of TPCL, and the non-grid connected Stewart Island Electric Supply Authority (SIESA).

PowerNet manages an asset base and investments over NZ$1.1 billion. It provides services to over 76,000 customers through more than 14,200 circuit kilometres and manages the fourth-largest suite of EDB assets in New Zealand. In addition to EIL operating in Invercargill and Bluff, TPCL operates in Southland and West Otago, OJV in Frankton, Cromwell and Wānaka (and the rural and coastal Otago region that surrounds Dunedin City), and SIESA on Stewart Island.

PowerNet has long term management agreements in place with EIL, TPCL, OJV and Lakeland Network (LNL). With the benefit of integrated business management systems in place, significant people capability and capacity, and a core purpose and expertise in asset management, PowerNet has remained a high-performing asset manager for EIL. This has been judged by the value and efficiency in managing the EIL network and the delivery against the key performance indicators (KPIs) regularly reviewed and re-set as part of the management agreement.

PowerNet's continued commitment to improvement across asset management, workplace safety and operational efficiency, coupled with a focus on commercial growth and business development, ensures customers continue to receive a safe, reliable, and efficient power supply.

Asset Management Capability

Central to PowerNet's lifecycle asset management approach is the ability to balance cost, risk, and performance according to stakeholder requirements. Asset management is at the core of PowerNet's business capability, and its importance is reflected in the continued management of intergenerational assets across a number of local network companies in the Southern region.

PowerNet's network management maturity and capability provide strong asset management practices and a structured approach to asset management - from fleet plans for asset classes, to structured inspection and testing regimes for ground-mounted assets (poles, transformers, ring main units, air break switches) and underground assets such as cables.

PowerNet's development of this AMP ensures EIL's objectives will be met, together with meeting our regulatory reporting obligations. It outlines asset renewal and maintenance plans for our network, conformance to quality and safety standards, how our network will develop to meet new connection needs and manage customer growth, together with how we intend to monitor, measure, and evaluate the performance of our assets, now and into the future.

This AMP is a ten-year forward plan of major work on our asset portfolio to ensure that asset criticality and risks are understood and managed, and opportunities availed. It has a strong focus on the future, particularly as we look towards the impacts of decarbonisation, the increasing reliance on electrification and the growing uptake of electric transportation in our region, as well as the need for a resilient network in the face of the effects of climate change.

This AMP reflects how the use of technology to manage the network on a day-to-day basis, improving our low-voltage network visibility, and the growing requirement to manage Distributed Energy Resources as part of the make-up of our future network, is part of the long-term planning now needed to deliver against the needs of our customers - today and tomorrow.

AMP Network Development Projects

Key Achievements for EIL's Asset Base over the Past 5-10 Years

We remained focused on developing our network to ensure the provision of a resilient, reliable, and safe electricity supply for our region.

Optimising the network to meet the needs of our community saw a significant upgrade of EIL's zone substations over the past 5-10 years. The commissioning of the Spey Street substation in 2015 was part of a $12.2 million capital programme to replace the Doon Street substation, which was deemed an unacceptable location risk. Assets from the former Doon Street substation were later used in Invercargill's Southern Zone substation upgrade during the 2021-22 year, which became a dual transformer substation to cater for forecasted electricity load increases and to provide a more resilient supply. Leven Street substation roof replacement was completed in 2022/23.

Our regular replacement work continued to maintain a reliable electricity supply across the region and to ensure the safety and integrity of the network – seeing PowerNet replace a number of underground distribution substations and Ring Main Units (RMUs) across the EIL network which had reached their end of life, as well as replacing aged inground link boxes and relocating them above-ground.

In addition, all EIL zone substation sites were seismically strengthened to ensure security of supply in the event of a major earthquake.

<u>EIL's Asset Management Focus for the Next 5-10 Years</u>

The focus of EIL's AMP future programme is on initiatives that will support growth in our region, together with plans to maintain and improve network safety, efficiency, and reliability.

For the 10-year period reported in this 2024 AMP, we are forecasting a Total Spend of 151.3m(capital and operational spend).

Driving these changes, and captured in more detail throughout our AMP document, is the programme of work we have identified over the next 10-year planning period to mature our asset management capability, support customer growth, and improve our service provision for customers, to include:

- Enabling growth in our region through supporting major developments – including the Te Puāwai residential housing development (set to be the biggest housing development for Invercargill in decades, creating more than 600 sections and including a commercial hub and retirement village) and the construction of new $31.5m Hawthorne Care Facility, destined to be a world-class and a leading dementia care village in Invercargill.
- Meeting customer requests for new connections;
- Improving safety at zone substations and on the distribution network – Doon Street reconfiguration, Racecourse Road switchboard, Leven Street roof replacement;
- Upgrading the network across the region where needed to maintain voltage quality;
- Renewing those assets at the end of their life, and extending the life of assets with replacements, i.e. the oil-filled cable programme;
- Improving the efficiency of our network by replacing assets with high losses and exchanging overloaded distribution transformers with units that have sufficient capacity;
- Extending remote monitoring and control to distribution devices;
- Routine inspections, testing and maintenance across all assets;
- Safety, environmental, and other projects.

Given EIL's network is urban and largely residential, extra demand from electrification is expected primarily from space heating and transport electrification, as opposed to large industrial process heat conversions that are occurring in other parts of the region. As a result, EIL does not foresee significant network constraints on its HV/MV networks, and this is reflected in a relatively low system growth capital expenditure.

It is recognised that as the uptake of EVs and other technologies increases in Invercargill, some parts of EIL's LV network may become constrained. EIL has invested in smart meters across its network, completed the deployment and is seeing the benefits of Low voltage (LV) network visibility. This is further enhanced due to EIL's relationship with SmartCo (of which EIL is a shareholder). That has enabled the development of electronic tools to provide this greater visibility of the LV network, providing valuable information for PowerNet as network manager to monitor network loading and congestion and forecast future growth, including use of wider data analytics. Having this insight will enable us to seek the most efficient solution to LV congestion, which may be either a network upgrade or a non-network solution.

Our Regulatory Environment

EIL is regulated under the electricity industry framework set by the Commerce Commission, which alongside defined regulatory reporting requirements, means there are commercial restrictions and penalties as a non-exempt network.

The regulatory period, from 2020-2025 (DPP3), has been extremely challenging from an asset owner perspective. The allowable returns from the Commerce Commission have not been sufficient to adequately fund the network as anticipated. Since the returns were set for DPP3, there have been significant cost pressures impacting the business, such as equipment and materials costs, international shipping and freight costs, increased compliance costs (e.g. traffic management regulations), significant increases in the cost of debt funding, and a very tight labour market. None of these factors were adequately provided for it in the DPP3 returns.

For EIL, working within the revenue cap and expenditure allowances provided by the Commerce Commission over the current DPP3 period has made it increasingly difficult for the industry to respond with the flexibility needed to enable an equitable transition for electrification and decarbonisation of the NZ economy.

PowerNet, as the network manager for EIL, is in a unique position with its management of three networks (one exempt and two non-exempt), as it can compare the differences this creates and better understand the challenges for non-exempt networks like EIL.

There is now clear evidence that the regulatory framework does not provide the required flexibility to meet the challenges and opportunities that electrification and decarbonisation of the New Zealand economy will present. PowerNet continues to share its concerns with industry stakeholders and has been able to compare the flexibility and ability to respond to customers' needs on its exempt network, verses non-exempt networks. Changes are required to the regulatory framework in order to ensure an equitable transition to a net-carbon zero economy.

Developing the right regulatory settings for a changing environment is critical to a robust level of service and flexibility for changing customer needs, and EIL looks forward to ongoing collaboration and engagement by PowerNet with the regulator and other stakeholders.

In Conclusion

EIL's Asset Management Plan (AMP) outlines how network assets will be managed and developed to provide a safe, efficient, and reliable electricity supply and service to Invercargill and Bluff communities over the next 10 years. It sets out planned capital and maintenance expenditure on the network from 2024-2034 and also reflects the continued focus on customers and developers to better understand their plans to ensure this AMP caters to, and supports, the growth projections of our region.

As outlined in the Executive Summary which follows, this AMP focuses on ensuring the EIL network continues to deliver for customers through a dedicated investment programme that includes information on performance and service targets, justification for planned investments, together with the risks and how those will be mitigated through careful and considered asset management practices over the next ten years.

EIL is committed to continuing to provide a network that meets the needs of our community, and welcome ongoing input with stakeholders to ensure the assets and services provided are fit for purpose - now and into the future.

Enquiries

Enquiries, submissions, or comments about this Asset Management Plan (AMP) can be directed to:

General Manager: Asset Management ***OR*** Engineering Manager (Networks)
PowerNet Limited,
PO Box 1642,
Invercargill, 9840

Phone (03) 211 1899
Fax (03) 211 1880

Email amp@powernet.co.nz

Liability Disclaimer

The information and statements made in this AMP are prepared on assumptions, projections, and forecasts. It represents Electricity Invercargill's intentions and opinions at the date of issue (31 March 2024).

Due to global uncertainties, assumptions and forecasts in the AMP may prove to be wrong, events may occur that were not predicted, and Electricity Invercargill could decide to take different actions than planned. Electricity Invercargill may also change any information in this document at any time. EIL accepts no liability for any action, inaction, or failure to act based on this AMP.

Abbreviations, Acronyms and Definitions

ABC	Aerial Bundled Conductor
ABP	Annual Business Plan
ABS	Air Break Switch
ALARP	As Low as Reasonably Practicable
AMIS	Asset Management Information System
AMP	Asset Management Plan
AWP	Annual Works Program
CAPEX	Capital Expenditure
CBD	Central Business District
CCTO	Council Controlled Trading Organisation
CES	Customer Engagement Survey
CIMS	Coordinated Incident Management System
ComCom	Commerce Commission
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DIN	Deutsches Institut für Normung (the German Institute for Standardization)
DPP3	Default Price Path 3
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association
EIL	Electricity Invercargill Limited
ENA	Electricity Network Association
ESL	Electricity Southland Limited
GIS	Geographic Information System
GPS	Global Positioning System
GXP	Grid Exit Point
HILP	High Impact Low Probability
Holdco	Invercargill City Holdings
HRC	High Rupture Capacity
HVBT	High Voltage Busbar Insulation Tape
ICP	Interconnection Point
IED	Intelligent Electronic Device
IoT	Internet of Things
KPI	Key Performance Indicator
LSI	Lower South Island
LV	LV
MAR	Maximum Allowable Revenue
MBIE	Ministry of Business, Innovation and Employment

MD	Maximum Demand
MDI	Maximum Demand Indicator
MV	Medium Voltage
NEM	Network Equipment Movement
NEM	Network Equipment Movement
NER	Neutral Earthing Resistor
O&M	Operations and Maintenance / Operate and Maintain
ODV	Optimised Deprival Valuation
OHUG	Overhead to Underground
OJV	OtagoNet Joint Venture
OPEX	Operating Expenditure
PILC	Paper Insulated Lead Covered
PNL	PowerNet Limited
RCP	Regulatory Control Period
RMU	Ring Main Unit
ROI	Return on Investment
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SLT	Senior Leadership Team
SOI	Statement of Intent
SWHT	Southland Warm Homes Trust
TCOL	Tap Change on Load
TOU	Time of Use
TPCL	The Power Company Limited
TPM	Transmission Pricing Methodology
UILP	Utilities Industry Liability Programme
VRR	Voltage Regulating Relay
XLPE	Cross-Linked Polyethylene

Commerce Commission (ComCom) means the agency responsible for enforcing laws relating to competition, fair trading, and consumer credit contracts, and has regulatory responsibilities in the electricity lines, gas pipelines, telecommunications, dairy and airport sectors.

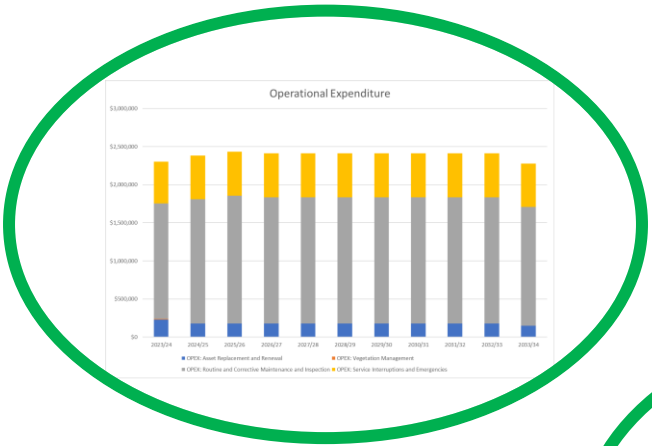
Customers means the entities connected to the local lines company, which can be households or businesses. Most customers do not have a direct relationship with their local lines company. Rather, they will engage with an electricity retailer to which they pay their bill.

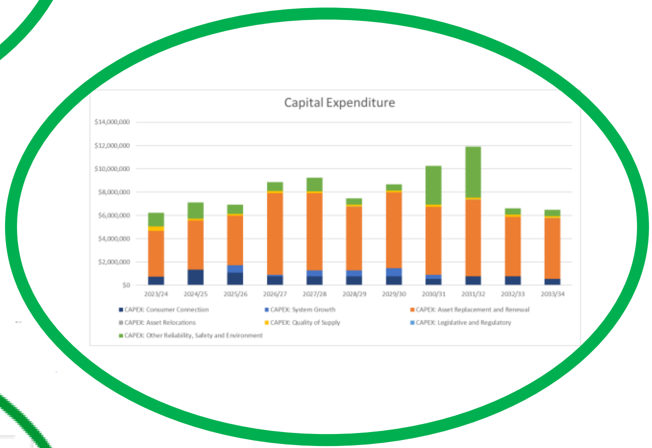
DPP3 means the price-quality standards that regulated EDBs have to comply with during the regulatory time period 1 April 2020 – 31 March 2025 as set by ComCom

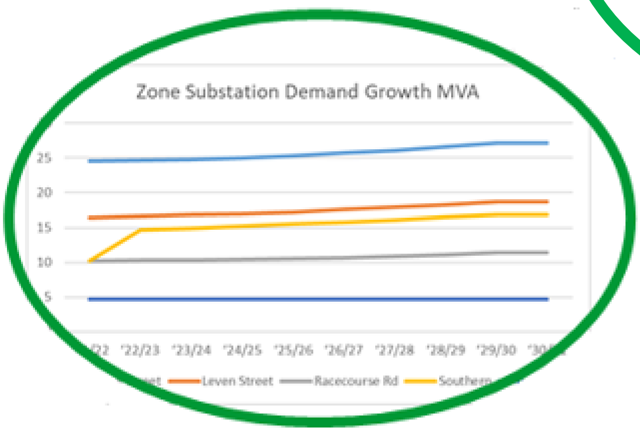
At a Glance


EIL SAIDI
SAIDI B Planned
SAIDI C Unplanned
Total SAIDI


EIL SAIFI
SAIFI B Planned
SAIFI C Unplanned
Total SAIFI


Operational Expenditure


Capital Expenditure


Zone Substation Demand Growth MVA
Leven Street
Racecourse Rd

Executive Summary

The information and statements made in this AMP are prepared on assumptions, projections, and forecasts. It represents Electricity Invercargill Limited's (EIL) intentions and opinions at the date of issue (31 March 2024).

There are residual effects of the worldwide Covid-19 pandemic impacting New Zealand. This has an impact on EIL's supply chain and it influences the cost of resources available to execute this asset management plan. The AMP assumes that the pandemic will remain controlled and that it will not have any additional significant effect on the availability of skills, equipment, and material. Should this not be the case, the plan will be subject to change.

Due to the current global uncertainties caused by events such as the war in the Ukraine, assumptions and forecasts in the AMP may vary from what actually happens. Further events may occur that were not predicted and EIL could decide to take different actions than planned. EIL may also change any information in this document at any time. EIL accepts no liability for any action, inaction, or failure to act based on this AMP.

Introduction

The introductory section in the main document describes the process to prepare the annual asset management plan updates. The alignment with the Annual Works Program (AWP) is outlined and the role-players that participate in the asset management planning processes are portrayed. The participation processes are related to:

- management and operations participation;
- governance participation; and
- post disclosure communication.

Planning assumptions and implications are described. Planning is based on the expectation that the most likely scenario will occur, except for ongoing but sporadic (typically reactive) work. This philosophy is used to minimise variation to financial performance targets. The standard life of assets is based on the Commerce Commission's Optimised Deprival Valuation (ODV) asset life, with actual replacement done based on condition, economic life, and work efficiency.

The potential variation factors that specifically influence this AMP are the residual impact of the Covid-19 pandemic and the impact of the war in Ukraine, particularly on fuel prices. There remains a possibility of closure of the Tiwai Point smelter in 2024 (other variation causes and implications are detailed in the AMP), however this has become less likely due to improvements in international commodity prices for aluminium.

Most challenges related to Covid-19 are being addressed, but there are cost and project schedule implications, in particular delivery times for electrical equipment sourced overseas.

The impact of the war in the Ukraine is currently mostly felt through the increase in operating cost caused by rising fuel prices, but the worldwide increase in the cost of energy will eventually flow through to equipment and equipment transport prices. The impact of the conflict in Gaza is still uncertain, but an escalation in the conflict may affect fuel supply. EIL does not supply the aluminium smelter at Tiwai Point (Tiwai) with energy, so the direct impact of a potential closure of the smelter will be minimal. It is expected that the Tiwai Smelter will be operational for the foreseeable future and that no investment is required to counteract any negative effects on the networks that may be caused by the loss of load.

The EIL Business Environment

EIL's vision, corporate strategies and asset management strategies have been designed to accommodate the interests and expectations of various stakeholders while recognising the need to work within constraints imposed by both stakeholders and wider issues that affect asset management. EIL's business goals are driven by meeting shareholders' and customers' expectations. The context for business operations is also shaped by drivers ranging from governmental and regulatory strategies to natural events such as the unpredictability of weather.

Key corporate drivers from EIL's Strategic Plan are incorporated in the AMP and the guiding principles for EIL's asset management strategy are described in Section 2. EIL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in the next figure.

Table 1: Corporate and Asset Management Strategy Linkages

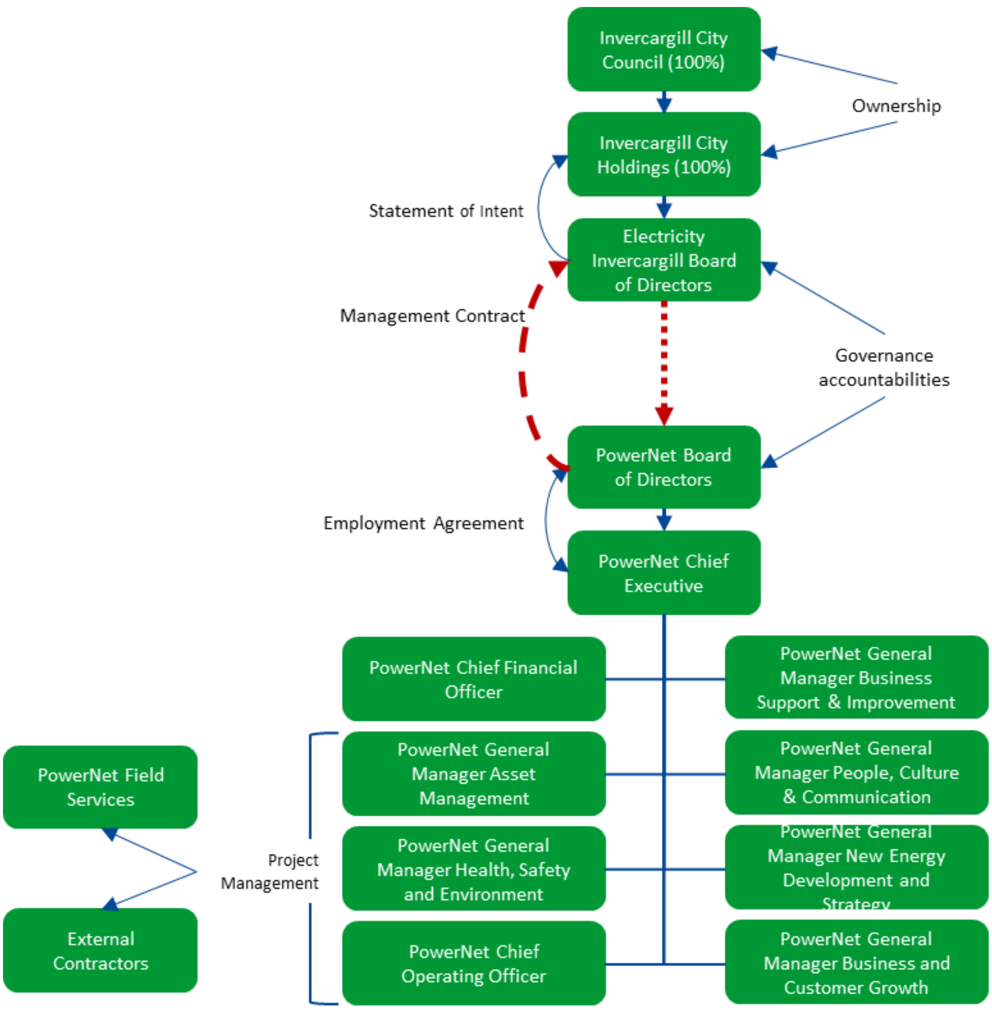
Asset Management Strategies \ Corporate Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with reliable and affordable service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
No material deterioration in the condition or performance of the networks	✓	✓			✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓
Undertake initiatives to increase existing asset life or capacity	✓	✓			

Asset Management Strategies \ Corporate Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with reliable and affordable service.
Consider alternatives to status quo solutions	✓	✓			
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

EIL's commercial goal is to deliver a stream of sustainable earnings to Invercargill City Holdings. This creates a primary driver for EIL and formal accountabilities to the shareholder are in place for financial and network performance. However, there are various role-players in EIL's business and the management of role-players' expectations and how conflicting interests are dealt with is described in detail in this section of the AMP.

Section 2 also details the planning processes and related documents, the organisational structure and accountabilities, as well as the extent of the supply area and quality of service. Business planning take place within the overall framework of Quality, Occupational Health and Safety and Asset Management. An overview of the governance and management accountabilities is presented in the next figure.

Figure 1: Governance and Management Accountabilities



The Network and Asset Base

EIL owns and operates two separate electrical networks that are both supplied by the Grid Exit Point (GXP) at Invercargill. The Bluff network comprises two 11kV feeders supplied by TPCL zone substation situated just west of Bluff Township. EIL also owns interconnectors to TPCL Otatara and Seaward Bush 33kV lines that provide alternative supplies to the Leven Street and Southern zone substations respectively. The networks supply the following (details are available in Section 3).

- The part of Invercargill bounded by Racecourse Road to the east, the Waihopai Stream to the north and west (except for Invercargill Airport which is in EIL's area) and Elizabeth, Moulson and Brown Streets and Tramway Road to the south.
- The Bluff township extends as far west as the former Ocean Beach freezing works. Bluff (having less than 25km of distribution lines and less than 2000 ICPs connected) is not considered a sub network and therefore values presented in this AMP for EIL are inclusive of the Bluff area network except stated otherwise.

The topography is densely urban and built-up in both Invercargill and Bluff. Invercargill is a flat area (lying about 3m to 5m above sea level), whilst Bluff varies from flat to steep hills. EIL's largest customer is Southport Limited, the large port in the Bluff distribution area which regularly peaks at about 1.6MW and consumes approximately 6.5GWh per year. The Bluff distribution area also includes port associated heavy industries as well as residential and commercial customers.

The following network aspects are described in detail in the AMP (Section 3).

- Network Configuration.
- Load Characteristics.
- Energy and Demand Characteristics.

Areas on the network have differing load densities and rates of growth which are more likely to influence asset management planning. Growth rates on the network are relatively low and connections for new large customers are unpredictable so planning for this can be challenging. There are not any individual customers considered large enough to have any significant impact on network operations or asset management planning other than ensuring that adequate supply capacity is maintained.

Risk Management

Risk is defined as any potential but uncertain occurrence that may impact on EIL's ability to achieve its objectives and ultimately the value of its business. EIL is exposed to a wide range of risks and risk management techniques are used to keep risk within acceptable levels. Risks can often not be fully eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment measures. In Section 4 EIL's risk exposures, the management of the exposures and activities to reinstate service levels should disaster strike are described.

The following significant risks (company-wide) were identified and are described in Section 4 of the AMP.

- Cyber Security - Events were detected but intentional damage was prevented by the IT security systems. Notable is the increase in electronic security events.

Risks related to asset management are provided in the next table (details on these risks are provided in Section 4). The projects and actions described in this AMP are intended to mitigate these risks.

Table 2: Asset Management Risks

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure; ineffective maintenance; ineffective fleet plans; budget constraints; lack of future network planning	Reliability Collapse/fall causing harm Voltage causes harm	Treat	Implement AMMAT improvements; resourcing; fleet plans; business management framework; information systems
Network Performance	**Operational systems failure due to breakdown in telecommunications**	SCADA communications has one centralised communications point that all information is passed through.	Loss of SCADA would require resorting to manual oversight of the networks	Treat	3 yr. Project underway to provide further links - due for completion 2023
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism Reputation	Damage to equipment Damage to systems/data Change in network configuration SAIDI/SAIFI Impacts Reputation Impacts	Treat	Programme to replace locks and improve security implemented
Network Performance	**Loss of right to access or occupy land**	Risk of assets losing / not having the right to occupy locations (e.g., Aerial trespass, subdivision)	Objection of landowner where line or cable is over boundary Demand for removal of assets and/or legal action	Tolerate	
Operational Performance	**Damage due to extreme Physical Event (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Limited staff, facilities or equipment available; localised or wide spread loss of the ability to supply power	Treat	Completion of seismic strengthening Design of networks to avoid high event probability areas
Operational Performance	**Potential liability for private lines and connections**	Regulatory change Poor historical process/records Fatality with some repercussion for PowerNet - legal advice has not been tested in court	Obligation to maintain assets vested in the network	Treat	Association to ENA and MBIE: *(currently reviewing situation with aim of a consistent industry solution)*

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact events causing high spares usage Supply chain disruptions	Inability to supply	Treat	Review critical spares process Stocktake critical spares Record spares in Maximo Education of staff on spares process and locations Comparison of existing assets to critical spares (and update with changes to the network) Supplier relationships. Alternative suppliers. Leverage Corys' international partnerships
Operational Performance	**Loss of key critical service provider**	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Inability to build or maintain assets Unable to service existing contracts	Treat	Improved identification of critical suppliers Identify alternative suppliers Diversify the workforce Internalise and grow internal workforce Diversify into new markets (create a larger pool)
Operational Performance	**Major event triggering storm gallery activation**	Damage caused by wind, snow, storm events	Delayed or limited provision of power to customers Loss of ability to provide power to customers for extended periods	Treat	Develop improved contingency plans for network events
Health & Safety	**Public encountering live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Serious injury or fatality Prosecution under H&S Act	Treat	Asset Lifecycle risk management Increase public awareness through various media Asset design and operation
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Breaches of environmental legislation Cost of rehabilitation	Treat	Design standards take environmental risk into account. Asset do not contain hazardous substances or hazardous substances are controlled

Equipment risks to the electricity system are related to the following assets or network.

- 33kV Oil Filled Cables.
- Oil Filled RMUs.
- Other Systemic Issues.

Service Levels

A broad range of service levels are created for EIL's stakeholders, ranging from those paid for (for their own benefit) by connected customers such as capacity, continuity and restoration to those subsidised by connected customers such as ground clearances, earthing, absence of electrical interference, compliance with the District Plan and submitting regulatory disclosures.

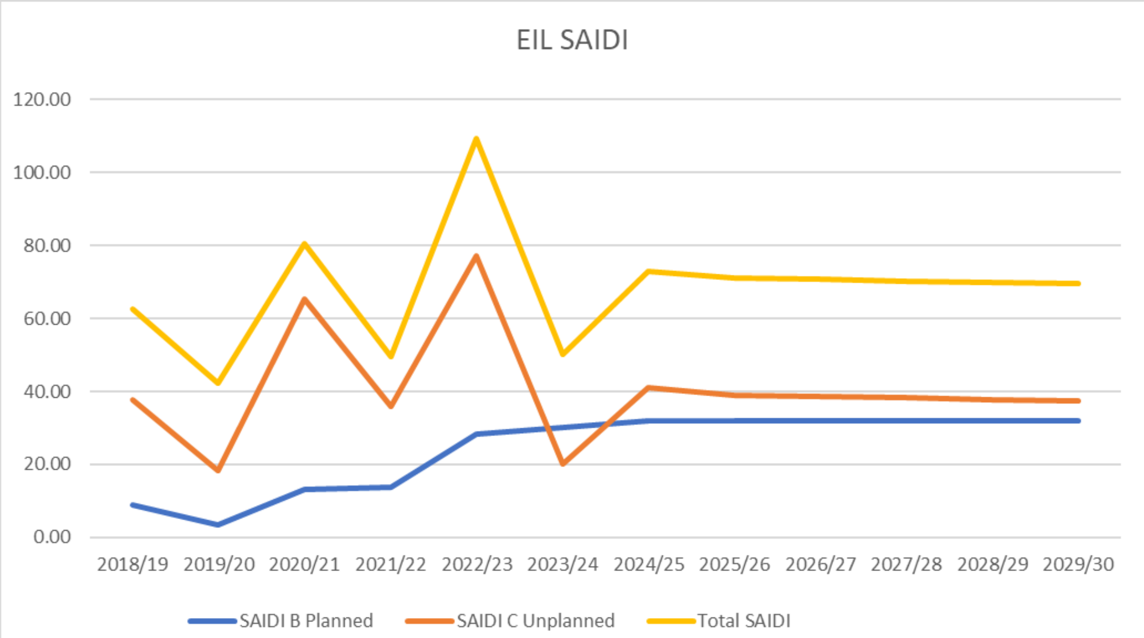
This Section in the AMP describes how EIL sets its various service levels according to the safety, viability, quality, compliance, and price objectives that are most important to stakeholders. It details how well EIL is meeting these objectives and what trade-offs exist between differing stakeholders. Considerations include; the desire for Return on Investment (ROI) versus desire for low price with good reliability, safety as priority versus acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance.

Safety is EIL's top priority and is a primary consideration in the AMP. However, safety has always been a key consideration in network design and the residual risk that can be addressed through asset management planning is extremely low. Operational factors tend to dominate the year-to-year variation in safety incidents and near hits. Safety KPIs are not presented in the AMP, but are available to interested parties upon request.

The section on customer-oriented service levels describes customer surveys, primary and secondary customer service levels, as well as other service levels. The section also details the following:

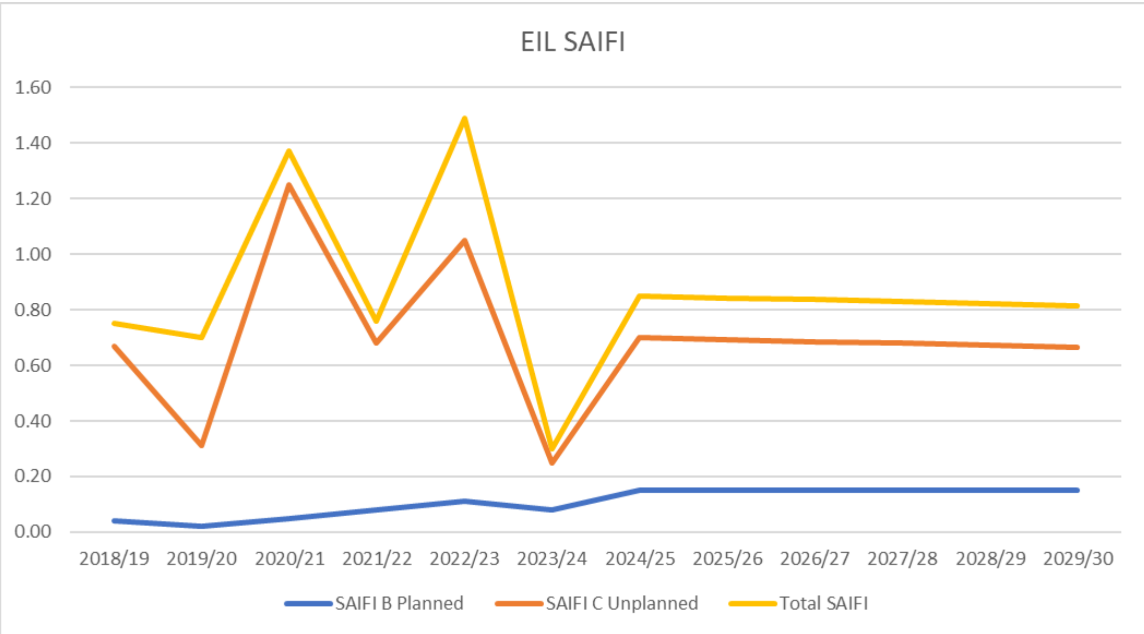
- regulatory service levels;
- service level justification; and
- service level targets.

Figure 2: Historical and predicted SAIDI



Customers on average can expect to be without electricity for around 70 minutes each year.

Figure 3: Historical and predicted SAIFI



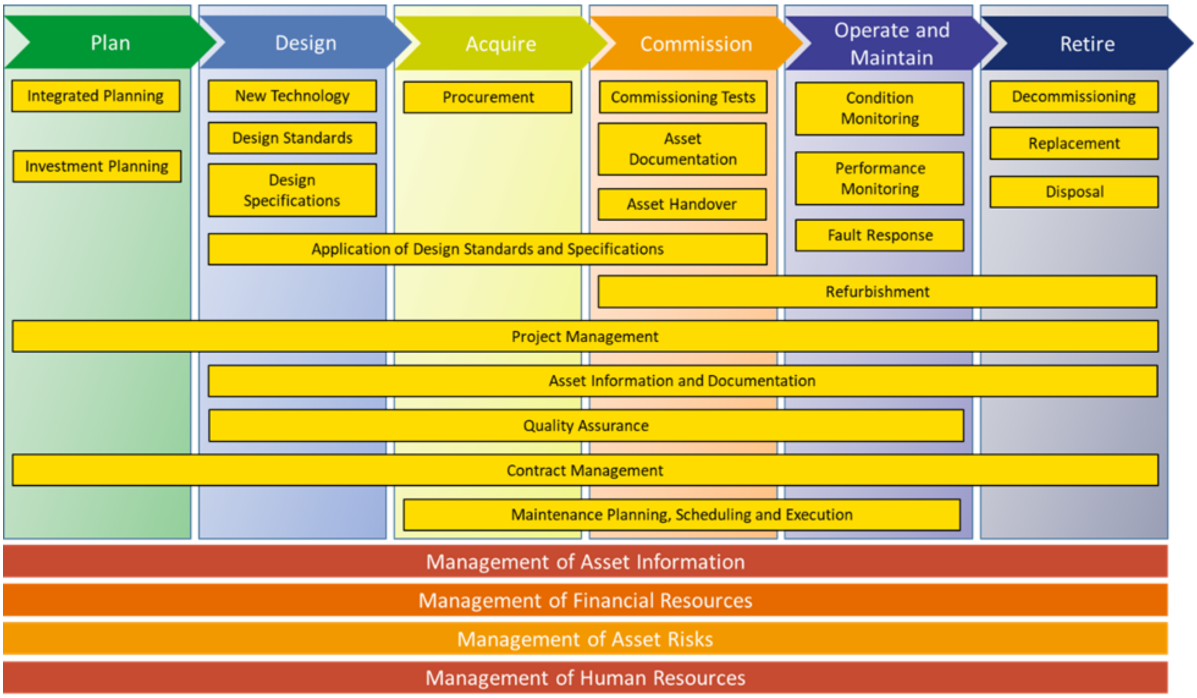
Customers will on average experience an interruption every 15 months.

Asset Management Strategy

EIL's Asset Management Strategy is based on PowerNet's asset management model (focusing on a lifecycle management approach). The defined strategic objectives and initiatives are aligned with the relevant stakeholder' business plans. These are aimed at achieving continuous business improvements through balancing risk, performance, and cost.

The strategy is structured to address the main activities and challenges faced in each lifecycle stage as well as the support processes. It defines objectives for each activity and recommends initiatives to achieve the stated objectives. In each case, responsibilities are defined, and realistic timeframes are suggested. Figure 4 charts the various asset lifecycle stages and support processes that cut across the entire lifecycle.

Figure 4: Lifecycle Model for Asset Management



Details for each of the asset lifecycle stages are described in Section 6 of the AMP. In addition, the following lifecycle support processes are explained.

- Management of Asset Risks.
- Management of Asset Information.
- Management of Human Resources.
- Management of Financial Resources.

Asset management requires processes for defining and capturing as built, maintenance and renewal unit costs and methods for the valuation and depreciation of its assets. Areas the present normal business challenges include the management of human and financial resources. The strategic objective for the management of human resources is that:

> *the necessary resources and skills to plan, acquire, operate, and maintain the assets that PowerNet manage, be attracted, developed, retained and be available when required.*

Financial resources are required to manage assets efficiently over their entire lifecycle. The major strategic objective for the management of financial resources is that:

> *the necessary resources to plan, acquire, manage, operate, and maintain assets that PowerNet manage shall be developed, and finances made available when required.*

Capital Expenditure

Capital Expenditure (CAPEX) is required to increase the capacity of assets or networks, to extend the life of assets, to install new assets for safety or reliability purposes or to replace aging assets. CAPEX is categorised according to the following ComCom requirements.

- Customer Connection.
- System Growth.
- Asset Replacement and Renewal.
- Asset Relocations.
- Reliability, Safety and Environment.

The following risks are relevant to capital expenditure are detailed in Section 7 of the AMP.

- Planning Phase Risks.
- Network Development Drivers.
- Current Demand Profiles.
- Demand History.
- Public and employee safety.

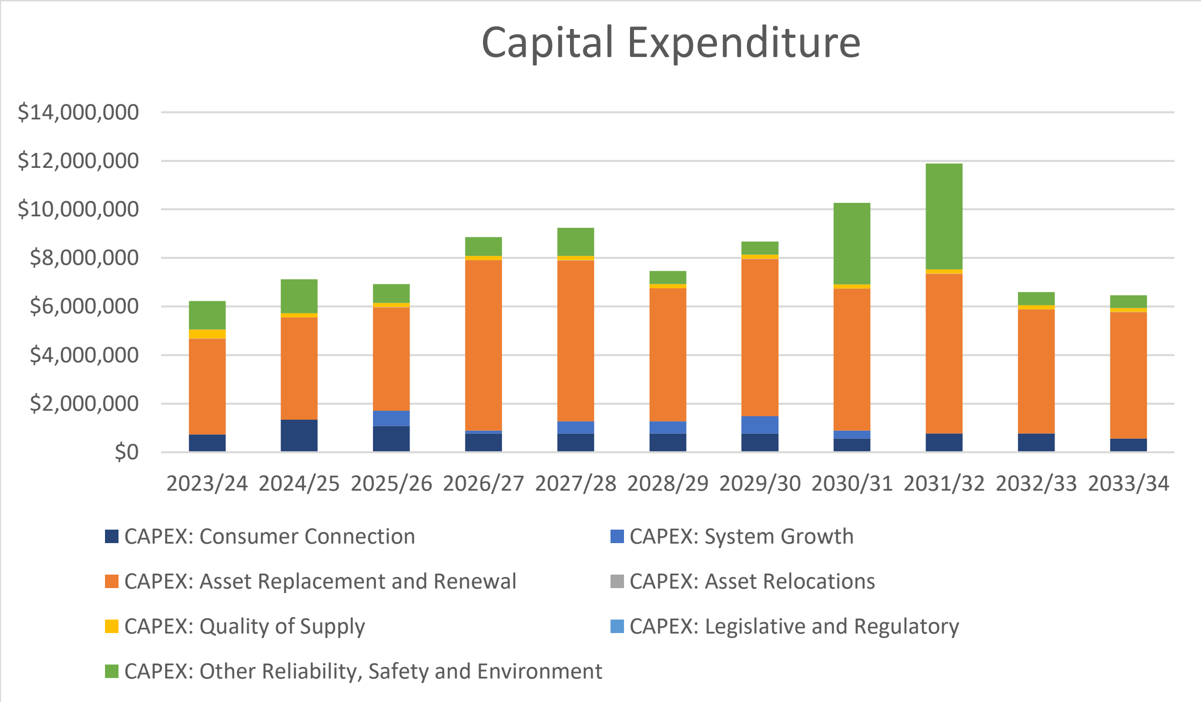
The proposed Capital Expenditure is reflected in the next table and figure.

Table 3 Proposed Capital Expenditure

Proposed Future Capita Expenditure ($000)											
	DPP3		DPP4					DPP5			
CAPEX: Consumer Connection	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	732	1343.749	1080.018	780.3965	780.3965	780.3965	780.3965	563.4376	773.5906	780.3965	559.8973
CAPEX: System Growth	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	0	0	635.7441	111.6771	489.7709	495.6161	704.9126	335.0314	0	0	0
CAPEX: Asset Replacement and Renewal	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	3947.03	4205.144	4253.131	7016.801	6634.373	5471.226	6472.444	5840.654	6574.309	5100.9	5206.032
CAPEX: Asset Relocations	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	6.812717	7.173556	7.173556	7.173556	7.173556	7.173556	7.173556	7.173556	7.173556	7.173556	7.173556
CAPEX: Quality of Supply	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	363.0442	169.567	169.567	169.567	169.567	169.567	169.567	169.567	169.567	169.567	167.9442
CAPEX: Legislative and Regulatory	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	0	0	0	0	0	0	0	0	0	0	0
CAPEX: Other Reliability, Safety and Environment	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	1177.714	1397.304	776.9629	776.9629	1155.044	538.1526	538.1526	3350.253	4364.453	536.0733	525.4275
Total Network CAPEX	6226.516	7122.937	6922.597	8862.578	9236.324	7462.132	8672.646	10266.12	11889.09	6594.11	6466.474
CAPEX: Non-Network Assets	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	0	0	0	0	0	0	0	0	0	0	0

Values are fully marked up, no inflation, base year dollars

Figure 5: Capital Expenditure per ComCom categories.



Operating Expenditure

Operating Expenditure (OPEX) is required to operate and maintain EIL's networks. OPEX is categorised according to the following ComCom requirements.

- Asset Replacement and Renewal.
- Vegetation Management.
- Routine and Corrective Maintenance and Inspection.
- Service Interruptions and Emergencies.

The following risks are addressed through operating expenditure and detailed in Section 8.

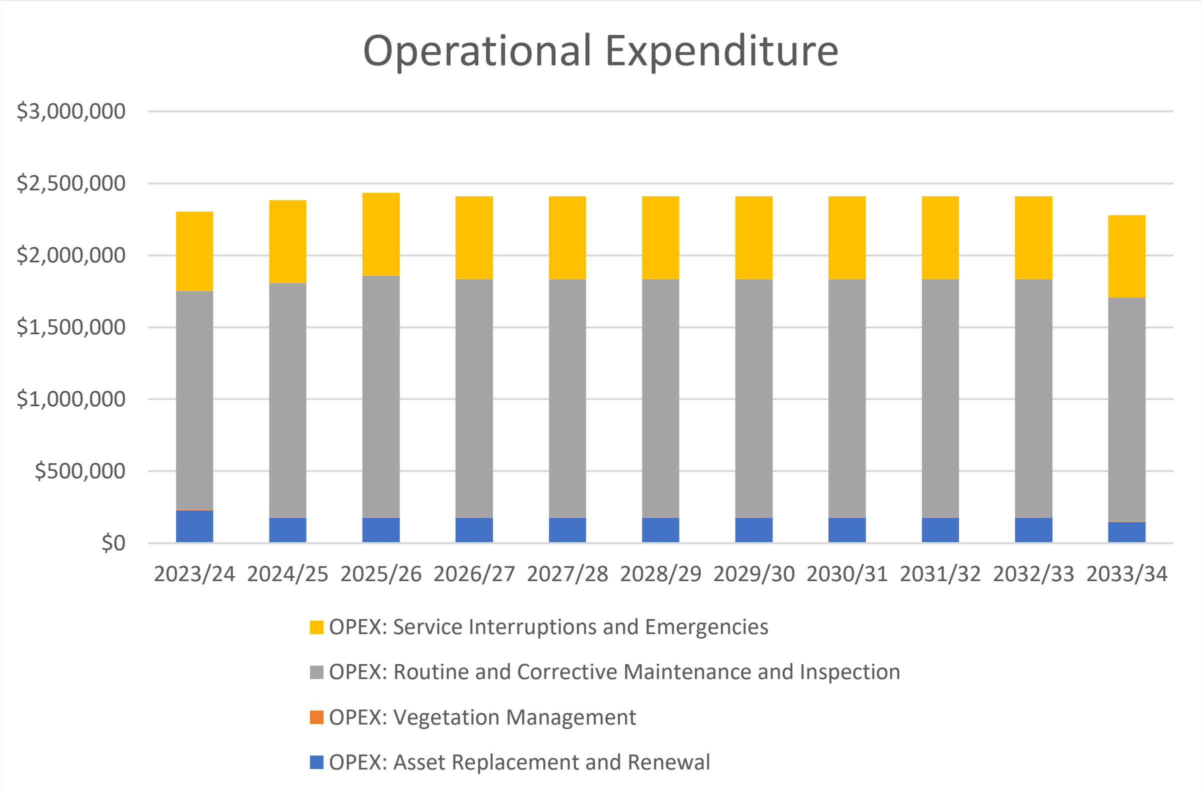
- Maintaining asset health.
- Operating the assets.
- Service Interruptions.
- Public and employee safety.
- Business continuity.

The proposed operating expenditure is displayed in the following table and figure.

Table 4: Proposed Operating Expenditure

Proposed Future Operational Expenditure ($000)											
	DPP3		DPP4					DPP5			
OPEX: Asset Replacement and Renewal	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	228.1414	176.7993	176.7993	176.7993	176.7993	176.7993	176.7993	176.7993	176.7993	176.7993	147.0549
OPEX: Vegetation Management	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	2.290912	2.390566	2.390566	2.390566	2.390566	2.390566	2.390566	2.390566	2.390566	2.390566	1.471353
OPEX: Routine and Corrective Maintenance and Inspection	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	1517.804	1628.732	1678.797	1655.526	1655.526	1655.526	1655.526	1655.526	1655.526	1655.526	1558.289
OPEX: Service Interruptions and Emergencies	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	549.7545	576.1147	576.1147	576.1147	576.1147	576.1147	576.1147	576.1147	576.1147	576.1147	570.236
Operational Expenditure Total	2297.99	2384.037	2434.102	2410.831	2410.831	2410.831	2410.831	2410.831	2410.831	2410.831	2277.051
Values are fully marked up, no inflation, base year dollars											

Figure 6: Operating Expenditure per ComCom categories.



Execution Capacity

The requirements to execute the AMP successfully centres around the following enablers.

- People Culture and Leadership.
- Funding the Business.
- Managing the data and information in our systems.

The way we determine the work execution requirements is by determining the man hours and other resources required to execute each item of work or project. This information is captured in the Fleet Plans. The individual items of work is costed and consolidated into the Annual Works Programme. The planned works programme is analysed to determine the overall resource requirements for the work execution. Adjustments are then made based on resource availability. These adjustments may be delaying work until resources become available, using contractors or, if there is a long-term resource requirement, appointing additional staff, contractors or procuring the required plant or equipment.

There are the normal business challenges relating to skilled resources. This applies to all levels of staff, but particularly to technical and field staff. These challenges are being managed by PowerNet and they have strategies in place relating to this.

EIL's revenue comes primarily from retailers who pay for the conveyance of energy over EIL's network but also from customers providing contributions for the uneconomic part of works. Revenue is set out in a "price path", aligned to determinations by the Commerce Commission.

Expenditure is incurred to maintain the asset value of and to expand or augment the network to meet customer demands. In addition, there is a Management Agreement in place between PowerNet and EIL, where a management fee paid to PowerNet for managing the networks on behalf of EIL.

There are a variety of information management tools which capture asset data and can be used to create summary information from the data. Based on this foundation, EIL has sufficient knowledge about almost all the assets; their location, what they are made of, how old they are in general and their performance.

Evaluation of Performance

In 2021/22 capital expenditure was 30% over budget due to large commercial connections including a new CBD Mall and a safety clothing manufacturer but operating expenditure was 1% under budget.

Over expenditure of operating funds related to increased network inspections and an initiative to replace potentially defective cable terminations. This negatively affected financial measures.

Customer satisfaction was determined through telephone surveys and face to face interactions and remains high.

Network reliability decreased mainly due to the increase in planned interruptions to replace cable terminations.

Asset Management Maturity was assessed and in most areas the scores improved. The exceptions related to training, awareness, and competence; information management; and use and maintenance of asset risk information. Initiatives for improvement in these and other asset management areas are in progress and PowerNet have achieved the ISO 55001 certification.

Benchmarking performance against other utilities shows that EIL remains one of the top performing utilities in the country on almost any measure.

1 Introduction

1.1 Asset Management Plan and Annual Works Program

Electricity Invercargill Limited (EIL) is the disclosing entity for the electricity lines businesses that conveys electricity to the majority of Invercargill and Bluff, supplying approximately 17,595 customers.

EIL's Asset Management Plan (AMP) provides an internal governance and asset management framework for EIL's network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination as amended on 25 November 2023 for the ten-year planning period from 1 April 2024 to 31 March 2034.

The purpose of EIL's Asset Management Plan (AMP) can be summarised as follows.

The plan:

- documents the nature, extent, age, utilisation, condition, performance and value of the infrastructure;
- identifies existing and proposed levels of service to be achieved over a five year period, as well as any expected changes in demand;
- identifies the life-cycle management needs (development, renewal, operations and maintenance and any disposal) over the five year period;
- assesses capital and operational budget needs and funding implications; and
- assesses the prevailing infrastructure asset management practice and identifies further improvements.

Other key asset management documents for EIL are.

- The Annual Works Programme (AWP) detailing the capital and operation expenditure forecasts for the next ten years being produced as part of the development of the AMP.
- The Annual Business Plan (ABP) which consolidates the first three years of the AMP along with any recent strategic, commercial, asset or operational issues from the wider business. The ABP defines the priorities and actions for the year ahead. It also forms the principal accountability mechanism between EIL Board and its shareholders.

The first draft of the Asset Management Plan (AMP) is usually created by November each year and is circulated amongst management for review and comment. The Annual Works Program (AWP) is developed concurrently as part of the AMP process and has generally been through several revisions by the time it is circulated with the first draft AMP.

Customer perceptions and expectations are compiled from surveys and customer consultations. These results are compared with the performance targets set in the previous year's AMP. Any improvements or changes deemed appropriate are incorporated into the AMP and AWP as necessary. The survey used for this document is the July 2022 survey.

1.2 AMP Communication and Participation Processes

The role-players that participate in the asset management planning processes and to whom information is communicated, are described in the following paragraphs.

Management and Operations Participation

The planning team is in regular contact (throughout the year) with those responsible for implementing the current AWP. Progress is monitored and variations supervised as they arise with large capital projects. These are addressed in formal monthly review meetings. Any changes are consolidated into the initial AWP revision. Further revisions are developed in consultation with management, project managers and field staff who will be involved in the implementation processes.

Through this consultation the costs and resources for the desired work in the year ahead are estimated. The process tends to be iterative with a level of trade-off reached between what is considered an optimal level of works against realistic expectations of the work force available. Should the required work exceed internal resources, contractors are utilised. “Smoothing” of the year to year works variations is utilised to keep a relatively constant and manageable work stream for both internal and external workforce resources; however longer-term variations need to be met by adjusting the resources available. Additionally, this process tends to be one of moving goal posts as variations generally need to be accounted for up until the information disclosure date.

Governance Participation

The initial consolidated AWP is submitted to the EIL Board supported by a presentation. Any business cases required for large capital projects or other papers covering any non business-as-ususal projects are submitted in advance and will be included in the AWP presentation. After their initial review the Board may request clarifications or changes which are then incorporated into the AWP. These changes reflect both asset management and commercial aspects, and always recognise the need to address any identified health and safety related issues as the highest priority. Any recommended changes to the wider AMP that the Board may need to consider, for example strategy updates, may be presented at this stage for review.

The AMP is then updated to reflect changes to the AWP (development planning and lifecycle management) incorporating any other changes required by management before being submitted in full to the EIL Board for review in February. The Board may request further changes to be completed before giving final approval for disclosure at the end of March.

Post Disclosure Communication

Once the first draft of the AMP has been submitted to the Board, network engineers start producing project scopes for routine and non-routine projects that will be initiated in the next year. These scopes are passed to the relevant project managers to ensure that sufficient detail has been provided for each project in the AWP to proceed in line with the planner’s expectation.

An initial communication meeting is held with internal field staff and key contractors to highlight the body of work for the year ahead, especially for large or crucial projects. Future years as set out in the AMP are also presented to assist contractors in preparing their resources and their ability to compete for any tendered work in the short to medium term.

Planners (Network Engineers) are in contact with the project managers throughout the year to monitor execution of the AWP and ensure agreement on any significant variations as design and implementation progresses.

The progress against the AMP objectives is measured as follows:

- Monthly Major Project review meetings to assess progress on significant projects;
- Monthly Business Review meetings to assess business performance;
- Quarterly Management reviews to assess the effectiveness of the various management systems as well the integrated Business Management System;
- Monthly Safety meetings per depot and a monthly Safety Leaders meeting,

Outcomes of these meetings are presented to the Board in the monthly Chief Executive report and Management Report. This reporting contains information on safety performance, network performance and asset health for specific asset classes identified by the Board.

1.3 Assumptions

During the planning process we develop various growth and asset replacement scenarios. These scenarios are evaluated against their likelihood of occurrence based on what we know of the external environment and our knowledge of the network asset health. In our planning we assume that the most likely scenario will eventuate. This minimises variation to performance targets (especially financial) over the short to medium term. Exceptions are for example building additional capacity early resulting in a slight overinvestment, where building additional capacity too late may have much greater consequences such as equipment damage or inability to supply customer load.

The standard life of assets used to initiate asset replacement investigations is based on the Commerce Commission's Optimised Deprival Valuation (ODV) asset life, with actual replacement done based on condition, remaining economic life and work efficiency. Generally, the ODV asset life is conservative as borne out by the actual failure rates of equipment. Equipment housed indoors will often exceed ODV life, whereas in the harsh coastal environment assets tend to have a shorter life. The replacement and maintenance decision making framework is constantly being refined to more accurately reflect the risk per individual asset. This is envisaged to be in line with the UK regulator's (OFGEM) disclosure requirements but adapted to also fit New Zealand's regulatory requirements. This will be a three-year process.

Changes in Traffic Management requirements and the Tree Regulations are adding additional cost to both Capital and Operational activities. In some instances, the cost of Traffic Management now exceeds 50% of the total project cost. This has lead to most Local Authorities in Southland not adopting the new guidelines.

Project costs and timeframes are estimated based on previous experience and anticipated resourcing. Other than the disclosure schedules included in Appendix 3, all figures are represented as 2024 dollars and assume an exchange rate of 1 NZ$ to 0.56 US$ (where applicable).

Table 5: Assumptions and Implications

Assumption	Discussion & Implications
General demand growth for existing customers tracks close to projected rates. New housing developments and decarbonisation initiatives is additional to the general growth.	Prediction of demand growth based on "ground-up" analysis is uncertain, due to the many variables that affect potential growth. The way this is being addressed is through developing scenarios that take the variables into account and choosing the most likely outcome. Actual future demands may depart significantly from short term forecasts but becomes more predictable in the longer term. This is due to uncertainty in the timing of developments which in turn is due to market conditions and supply chain constraints. Decarbonisation initiatives have been driven by government funding, causing additional uncertainty in the timing of these projects. Static or declining growth rates in specific areas mean investments to accommodate previously projected growth are deferred and funds are reallocated. The higher growth rate scenario require adjustment in EIL's resourcing and/or work scheduling to be able to respond to these opportunities.
Single large customer driven growth (such as supplies to data centres and electrode boilers) is likely to continue, albeit under a different funding mechanism. This may not occur on the EIL network but will affect the bulk supply to EIL. However, the aggregate of a large number of smaller decarbonisation initiatives will affect demand across the network.	Customers such as Open Country Dairy and Alliance are making huge investments to replace coal fired thermal processes with electricity-based processes, driven by GIDI funding. Southland is seen as an attractive environment within which to establish data centres. This is due to the colder climate, reducing cooling needs as well as the geographical location relative to Sydney which increases the viability of submarine fibre optic cable. The scenarios that were developed are for load increases of between 20MVA and 150MVA on Invercargill and North Makarewa GXPs with a likely scenario of 100MVA in the area. This will take up the spare capacity at the GXPs and on the subtransmission networks, decreasing the overall resilience of the network. Increased numbers of applications are leading to resource constraints for the analysis and implementation of supply options
Small scale (household) distributed generation is expected to have little coincidence with network peak demand, and therefore will have little impact on network configuration within the ten-year planning horizon	Increased injection of generation, especially during periods of low demand, could create voltage issues. Increased connection requests for distributed generation will require increased resourcing to analyse potential issues arising from connection (particularly safety and voltage) This assumption will need to be reviewed should battery storage become more economical. This will allow usage to be shifted into peak times and reduce peak load on the LV network.
Electric Vehicles (EVs) adoption rate is within the national forecast range. Customers respond well to price signals so that vehicle charging occurs mainly off-peak	EV charging may have a large impact on networks. If customers do not respond well to price signals or if retailers do not send the right price signals, EVs charging may exacerbate peak demand, triggering greater investment. This effect will be greatest on the LV network where issues are more likely due to lower diversity. Given the cost of EVs, the effect

Assumption	Discussion & Implications
	is expected to initially be localised in more affluent areas. The ever-increasing range of EVs, reducing EV prices, a developing market for second hand EVs and fossil fuel taxes may change the vehicle distribution and make it more difficult to predict where issues may arise.
Service life of assets tend towards industry accepted expected life for each specific asset type and operating environment	Long term projected service life of asset fleets is based on expected service life for the asset type, operating environment, expected duty cycles and maintenance practices. Actual replacement and maintenance works are short term programmed and are driven by condition and safety for the specific asset. Actual failure rates are utilised to determine the useful life boundaries for each specific asset type. Investment may be deferred if condition analysis provides reasonable certainty of extended asset life.
No material deviation from historical failure rates	Asset reliability deterioration compared to expected failure rates would require accelerated asset replacement (to maintain service levels to customer expectations)
Resourcing is sufficient for projected works programme	Considerable effort has been made to ensure work volumes are deliverable by PowerNet staff and service providers. Recurring Covid-19 outbreaks still affect availability of resources and the local, national and international market demand for skilled resources creates difficulty in staff attraction and retention. These and other unanticipated labour constraints may cause works to be delayed, and/or labour costs to rise.
Little change in safety & work practice regulations	Increases in health & safety requirements will have corresponding increases in cost and duration of works
Inflation for electricity industry input costs track close to expected (CPI forecasts by Treasury where sector specific forecasts are unavailable)	Positive deviation from expected material, labour and overhead input costs will result in increased costs of works programmes. The projected treatment of network constraints may change, depending on the specific changes to each input cost factor.
Future technologies that may impact work methodologies are not priced into cost estimates	Cost savings may occur if technologies develop to a stage where implementation is feasible and economic.
Significant changes in national energy policy	Changes to central government energy policy may affect customer and/or industry behaviour in such a way that EIL investment decisions become un-economic. Many of these initiatives such as GIDI funding are driven by decarbonisation programmes which are dependent on ruling party policy. In particular, decarbonisation projects driven by GIDI funding may be affected.
No significant changes to the shift towards cost-reflective pricing	There is an expectation for electricity distributors to progress towards more service-based and cost-reflective pricing. Challenges from external parties to pricing reform may affect revenue and cause currently proposed investments to be reconsidered.
No significant changes to requirements regarding resource consenting, easements, land access (private, commercial, local, and national authorities)	Increased requirements are likely to result in increased costs, conversely decreased requirements may facilitate more development and reduce costs

Assumption	Discussion & Implications
No material changes to domestic and small customer expectations of service levels	Changes to domestic and small customer expectations will require adjustment to service levels and subsequent investments. The customer survey shows that these customers are happy with the current price/quality balance and few customers are willing to pay more for increased service levels.
No material changes to large customer expectations of service levels	Changes to large customer expectations will require adjustment to service levels and subsequent investments. Large customers using thermal storage devices are in some instances willing to accept a lower reliability of supply to these facilities.
No significant changes to local and/or national government development policies	Developmental policies have the potential to affect aggregate and local demand. Investment levels will be adjusted to suit.
Improving industry co-operation	Deterioration in industry co-operation may result in duplicated and uncoordinated efforts and higher costs. Potential areas of improvement are standardisation (this usually leads to decreasing production cost) and coordination of bulk supply upgrades.
Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.	Historic trend expected to continue.
Step changes in underlying growth are possible, should significant investments in the region materialise. Population growth for sizing of equipment is based on the high projection.	Lower than planned population growth may result in some equipment, mainly transformers being oversized. Likely impact on total project cost is minor as the incremental cost of using a larger standard size transformer is minimal while energy losses are reduced. Higher population growth may initiate capacity improvement works earlier.
Abnormal price movements caused by major external events (war, terrorism, union action, natural disaster) affecting pricing of equipment or labour substantially are difficult to predict and not allowed for in estimates except for the effects of known events (Covid, Ukraine).	These major external events are unable to be predicted with any certainty and EIL must react accordingly to any changes.
Establishment of Distribution System Operator (DSO) services may enable additional load factor improvements to be achieved, mainly on the Transmission network. This could lead to a decrease in bulk supply costs.	Cost savings may occur if services develop to a stage where implementation is feasible and economic. Managing the maximum load may enable capacity increase projects to be deferred.

1.4 Potential Variation Factors

The following factors have the potential to cause significant variation between the forecasts in this AMP and the actual information that will be included in future disclosures.

Table 6: Variation Causes and Implications

Cause of Variation	Implications
Cost and time estimate inaccuracies	The external international environment is volatile making accurate cost predictions difficult and may lead to higher than budgeted project cost. Supply chains into and within New Zealand are still under pressure, Project timing may vary, resulting in lower work efficiencies. These may trigger review of project approval if variations are sufficiently large.
Variation in inflation rates and exchange rates	Higher input costs than forecast, leading to lower work volumes being executed.
High staff turnover and/or inability to recruit required resources	Labour cost increases in an attempt to attract or retain competent people. Potential deferment of parts of the investment programme, or outright cancellation of certain works if resources to execute the work cannot be found.
Reactive work varying from that estimated	Deferment of capital or planned maintenance work, if those works are dependent on the asset being in-service. Deferment of capital or planned maintenance work may also arise from staff resourcing constraints due to staff utilised on reactive work.
Equipment failure of especially large capital plant	Increased replacement costs and additional costs to maintain supply to customers until replacement. (E.g., generators may have to be deployed) Increased failure rates on specific classes of assets triggers a review of equipment selection and work methodologies.
New safety issues identified, and initiatives created	Higher labour or material costs. Triggers reviews of work methodologies.
Reprioritisation of projects as new work activities are identified	Require revision of the longer-term investment programme and funding requirements.
Obvious short term project options may not be the best long-term solutions.	Inefficient investment and potential fruitless expenditure.
Greater demand growth than anticipated levels, especially new large industry, or customers	May cause capital investments to be accelerated, or advanced. May constrain staffing resources.
Lower demand growth than anticipated levels, especially loss of existing industry or customers	May cause certain capital investments to be deferred or cancelled.
Changes in central government energy policies	Reducing funding levels for decarbonisation projects will reduce network growth but will also free up resources for other projects. The opposite will be true should funding levels increase.

Possible closure of the aluminium smelter at Tiwai point (referred to as the Tiwai smelter) may have a long-term influence on all the assumptions, but it is regarded as unlikely in the short to medium term.

Impact of a possible Tiwai Point smelter closure

EIL does not supply the aluminium smelter at Tiwai Point (Tiwai) directly, so the direct impact of a potential closure of the smelter will be minimal. However, the regional economy benefits greatly by the presence of Tiwai. Tiwai employees and their families live and shop in the region and many smaller support companies rely on income from services they render to the smelter. The economic impact of a potential closure could be significant, and the knock-on effect will have an effect on EIL.

The load from the Tiwai Smelter has a stabilising effect on the transmission system voltage. Should this load be removed from the network, voltage control may become challenging, and customers may experience voltage fluctuations.

At the moment the international demand for aluminium is high and indications are that Tiwai will be operational for the foreseeable future and that no investment is required to counteract any negative effects on the networks that may be caused by the loss of load.

Potential Data Centre loads

We have received a number of enquiries to supply data centres, although there have been no firm agreements as yet. The data centres have unique requirements around redundancy. Should one or more of these initiatives materialise it will require significant reconfiguration of the subtransmission networks to cater for these requirements and it will also trigger further Transpower GXP upgrades.

2 The EIL Business Environment

EIL's business goals are driven by its stakeholder's interests - primarily meeting shareholders' and customers' expectations. The context for business operations is also shaped by drivers ranging from governmental and regulatory strategies (that may create incentives or impose constraints), to natural events such as the unpredictability of weather or the laws of physics.

2.1 Vision and Strategies

EIL's vision, corporate strategies and asset management strategies have been designed to accommodate the interests and expectations of various stakeholders while recognising the need to work within constraints imposed by both stakeholders and wider issues that affect asset management. Managing conflicts between stakeholders and numerous risks to the business are acknowledged.

Vision Statement

> *To be one of the top performing New Zealand electricity distribution businesses, with an integrated investment portfolio.*

Corporate Strategy

The following are key corporate drivers from EIL's Strategic Plan.

- Manage operations in a progressive and commercial manner.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Provide its customers with reliable and affordable service.
- Understand and effectively manage appreciable business risk.
- Strive to be an efficient but effective operation.
- Pursue alternative technologies and energy forms within the current regulatory requirements.

Asset Management Strategy

EIL's asset management strategy is based on the following guiding principles.

- Use Risk as the fundamental decision-making criterion in all expenditure decisions.
- Safety by design using the ALARP (as low as reasonably practicable) risk principle.
- Minimise long term service delivery cost through condition monitoring and refurbishment.
- Replace assets at their (risk considered) economic end of life.
- No material deterioration in the condition or performance of the networks.
- Facilitate network growth through timely implementation of customer driven projects.

- Maintain supply quality and security with network upgrades to support forecast growth.
- Set performance targets for continuous improvement.
- Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather.
- Utilise overall cost benefit at all investment levels including the “do nothing” option.
- Standardise and optimally resource to provide proficient and efficient service delivery.
- Follow new technology trends and judiciously apply to improve service levels.
- Undertake initiatives to increase existing asset life or capacity.
- Consider alternatives to status quo solutions.
- Improve efficiency of electricity distribution for the net benefit of the customer.
- Achieve 100% regulatory compliance.
- Minimise environmental harm.

Health, Safety and Environmental Strategy

People and equipment can be put at risk if safety is not foremost in our thinking. The protection of people and the environment is considered in every decision we make, and in every action we take. EIL is committed to:

- Providing a safe and healthy work environment
- Supporting our people to stop work and pause for safety when someone feels unsafe
- Contributing as individuals to our safety first culture
- Ensuring the electricity networks that we manage do not put communities or businesses at risk
- Managing any activities with high potential injury consequence by implementing critical controls
- Ensuring our vehicles, plant and equipment are fit for purpose, well maintained, and safe for use
- Engaging our people through leadership, consultation, communication and partnerships
- Having well trained people that understand what they do and how they do it
- Engaging with the public to increase their awareness of risks
- Collaborating with the industry to enhance safety standards
- Committed to fulfil all legal requirements
- Continually striving for improvement of the Health and Safety Management System to create a safer workplace and networks
- Implementing effective systems

Interaction of Goals/Strategies

EIL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 7.

Table 7: Corporate and Asset Management Strategy Linkages

Corporate Strategies

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with reliable and affordable service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
No material deterioration in the condition or performance of the networks	✓	✓			✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓
Undertake initiatives to increase existing asset life or capacity	✓	✓			
Consider alternatives to status quo solutions	✓	✓			
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

2.2 Business Role-players

This section describes the role-players in EIL's business and their interests. The paragraphs explain how interests are met and how conflicts between role-players' expectations are managed.

Associations

EIL conveys electricity to the majority of Invercargill and to Bluff for approximately 17,595 customer connections. Sixteen energy retailers on sell this electricity. The EIL business entity includes the following associations.

- A 50% shareholding in PowerNet, an electricity management company jointly owned with The Power Company Limited (TPCL).
- A 24.9% stake in Lakeland Network Limited (LNL), which distributes electricity in the Frankton, Cromwell and Wanaka areas of Central Otago. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the LNL assets along with those of EIL, TPCL, and OJV.
- A 24.9% stake in OtagoNet. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of EIL, TPCL, and LNL.
- A 25% stake in Southern Generation Ltd, a generation company with wind and hydro assets in New Zealand jointly owned with TPCL and Pioneer Energy Limited.

The inter-relationship of these entities with the various holding companies and shareholders (along with the accounting treatment of results), is described in EIL's annual report.

Ownership

EIL has a single shareholder – Invercargill City Holdings (ICHL) acting for Invercargill City Council as a CCTO (council-controlled trading organisation). The CCTO (as at 31 March 2024) has five directors:

- Brian Wood (Chair);
- Linda Robertson
- Peter Carnahan;
- Mervyn English; and
- William John Schol.

Directors are appointed to ICHL. Subsidiary company directors are appointed by ICHL and approved by Invercargill City Council.

Governance

EIL's uses PowerNet as their contracted asset management company.

- The main governance accountability is between EIL's Board and shareholder with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes EIL's Board ultimately accountable to EIL's shareholder for these important asset management outcomes, whilst the inclusion of financial targets in the statement makes EIL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI. EIL (as of 31 March 2024) has five directors:
  - Rob Jamieson (Chair);
  - Emma Ihaia;
  - Peter Carnahan;

  - Stephen Lewis; and
  - Simon Young.

- The second level of accountability is between EIL's Board and PowerNet, specifically the PowerNet Chief Executive, with the principal mechanism being the management agreement that specifies a range of strategic and operational outcomes to be achieved.

Stakeholders and their Interests

A stakeholder is identified as any person or organisation that does or may do any of the following.

- Have a financial interest in EIL (be it equity or debt).
- Pay money to EIL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to EIL's network.
- Use EIL's network for conveying electricity.
- Supply EIL with goods or services (includes labour).
- Is affected by the existence, nature, or condition of the network (especially if in unsafe condition).
- Has a statutory obligation to perform an activity in relation to the EIL network's existence or operation (such as request disclosure data, regulate prices, investigate accidents or District Plan requirements).

EIL's identified stakeholders are listed in the following tables - stakeholder's interests (Table 8) and how these interests are identified (Table 9). Table 10 describes how stakeholder's interests are accommodated in EIL's asset management practices.

Table 8: Interests of Key Stakeholders

Stakeholder \ Interests	Viability	Price	Quality	Safety	Compliance
Invercargill City Holdings (Shareholder)	✓	✓	✓	✓	✓
Connected Customers	✓	✓	✓	✓	
Potential Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Ministry of Business, Innovation & Employment		✓	✓	✓	✓
Commerce Commission	✓	✓	✓		✓
Utility Disputes					✓
Electricity & Gas Complaints Commission			✓		✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Energy Safety				✓	✓
Industry Representative Groups	✓	✓	✓		
Public (as distinct from customers)				✓	✓
Mass-market Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Energy Retailers	✓	✓	✓		
Suppliers of Goods and Services	✓				

Land owners				✓	✓
Bankers	✓	✓		✓	✓
Transpower	✓	✓	✓		

Table 9: Identification of Stakeholders' Interests

Stakeholder	How Interests are Identified
Invercargill City Holdings (Shareholder)	• By their approval or required amendment of the SOI • Regular meetings between the ICHL and EIL boards • Regular meetings between the directors and executive
Connected Customers	• Regular discussions with large industrial customers and generators as part of their on-going development needs • Customer contracts • Customer consultation evenings (meetings open to public) • Annual customer surveys • Contact by customers, • Consultants
Potential Customer	• Connection requests • Feasibility study requests • Contact by customers' consultants
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets at least 6 times per year with Chief Executive, Chief Financial Officer and General Manager Asset Management • PNL Staff attend Board meetings when required
Ministry of Business, Innovation & Employment	• Legislation, regulations, and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website • Default Price Path and information disclosure feedback
Electricity Authority	• Weekly updates and briefing sessions • Regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity & Gas Complaints Commission	• Reviewing their decisions about other lines companies
Councils (as regulators)	• Formally as necessary to discuss issues such as assets on Council land • Formally as District Plans are reviewed • Formally to discuss development needs
Transport Agency	• Formally as required
Energy Safety	• Promulgated regulations and codes of practice • Audits of EIL's activities • Audit reports from other lines businesses
Industry Representative Groups	• Informal contact with group representatives
Public (as distinct from customers)	• Word of mouth around the city • Feedback from public meetings • Newspapers and social media
Mass-market Representative Groups	• Informal contact with group representatives
Staff & Contractors	• Regular staff briefings

Stakeholder	How Interests are Identified
	• Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Suppliers of Goods & Services	• Regular supply and demand meetings • Contractual arrangements • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet's CE & CFO • EIL's treasury/borrowing policy • Banking covenants
Transpower	• Regular meetings at various organisational levels • Transpower Customer Services representatives

Table 10: Accommodating Stakeholder's Interests

Interest	Description	How EIL Accommodates Interests
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient confidence to keep investing in EIL.	Stakeholder's needs for long-term viability are accommodated by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital. In general terms this will need to be at least as good as the stakeholders could obtain from a term deposit at the bank plus a margin to reflect the ever-increasing risks to the capital in the business. Earnings are set by estimating the level of expenditure that will deliver the returns. Service Level are maximised within those constraints while still keeping the electricity price at affordable levels.
Price	Price influences revenue and signals underlying costs. Getting prices wrong could result in levels of revenue that could not sustain supply reliability to the levels demanded by customers,	EIL's total revenue is determined by the regulated price path threshold. Prices will be managed to within the limits prescribed unless doing so would comprise safety or viability. Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders and affect business customer's viability. Insufficient revenue will compromise the long term sustainability and ability to render services. EIL's pricing methodology is intended to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this. This charge is being passed-out through Government regulatory changes.
Supply Quality	Emphasis on continuity, restoration of supply and voltage wave form management (amplitude, flicker, harmonics) is essential to minimising interruptions to customers' businesses and eliminate the risk of damage to customer equipment.	Stakeholder's needs for supply and service quality are accommodated by having a pool of resources focussed on continuity and restoration of supply. Growth related network upgrades are implemented in time to prevent adverse supply quality. The most recent mass-market survey indicated satisfaction with the present supply quality but also that many customers would be willing to accept a reduction in supply quality in return for lower line charges.
Safety	Staff, contractors, and the public at large must be able to move around in the	The public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach,

Interest	Description	How EIL Accommodates Interests
	vicinity of network assets and work on the network in total safety.	protection systems are working, all enclosures are kept locked and all exposed metal within touching distance of the ground is earthed. The safety of staff and contractors is ensured by providing all necessary equipment, improving safe work practices, and ensuring that they are stood down in unsafe conditions. New assets are subjected to the Safety in Design process. Motorists will be kept safe by ensuring that above-ground structures are kept as far as possible from the carriage way within the constraints faced regarding private land and road reserve.
Compliance	Compliance with the many statutory requirements, ranging from safety to disclosing information is compulsory.	All safety issues are documented and available for inspection by authorised agencies. Performance information is disclosed in a timely and compliant fashion. Any non-compliances are documented, submitted to and approved by the relevant authority following the approved processes.

EIL's commercial goal is to deliver a stream of sustainable earnings to Invercargill City Holdings. This is a primary commercial driver for EIL, together with the network performance. The Statement of Intent and the Network Management Agreement formalises these accountabilities to the shareholder.

Connected Customers (via electricity retailers) provide EIL's revenue in return for the services provided by the EIL network assets. Due to the importance EIL places on meeting customer's expectations, annual customer surveys are undertaken to monitor customer satisfaction, with service level targets set to ensure standards are maintained or improved. See Section 6 (Service Levels) for details of these surveys, customer feedback and performance targets.

EIL is required to compile and publicly disclose performance and planning information (including the requirement to publish an AMP). In addition, EIL is subject to price and quality regulations and there should not be any substantial decline in network reliability measures. These requirements are listed under Part 4 of the Commerce Act 1986 and in the ComCom's disclosure requirements.

Regulatory restrictions on generating and retailing energy is established under the Electricity Industry Act 2010 and requirements for the connection of distributed generation established under the Electricity Industry Participation Code. Electricity lines businesses are increasingly being required to give effect to many aspects of government policy.

Managing Conflicting Interests

When conflicting stakeholder interests are identified, an appropriate resolution needs to be determined. The following prioritisation hierarchy is used to analyse conflicting issues and to establish available options.

1. **Safety**. Safety is always first priority. The safety of staff, contractors and the public are of paramount importance. These factors are highly ranked in asset management decisions.

2. **Viability**. EIL's long term financial and technical viability is the second consideration, as EIL is expected to deliver the electricity distribution function to its customers for the foreseeable future.

3. **Pricing**. EIL gives third priority to pricing (noting that pricing is only one aspect of viability). EIL recognises the need to adequately fund its business to ensure that customers' businesses can operate successfully, whilst ensuring that there is not an unjustified transfer of wealth from its customers to its shareholders.

4. **Supply Quality.** Supply quality is the fourth priority. Good supply quality makes customers, and therefore EIL, successful.

5. **Compliance**. Compliance that is not safety and supply quality related is important but ranks lower than the criteria above.

Once an appropriate resolution has been determined, a recommendation is presented to management. A decision may be taken by the management team or matters be escalated to the EIL Board if required.

2.3 External Business Influences

There are several other issues (listed below) that are not directly related to stakeholders but have a significant impact on EIL's asset management practices. Strategies are in place to effectively manage these concerns.

- Competitive pressures from other lines companies that might try to supply EIL customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with gas or biomass at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, which could potentially strand conventional distribution assets.
- Local, national, and global economic cycles which affect growth and development.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- Interest rates which can influence the rate at which new customers connect to the network.
- Ensuring sufficient funds and skilled people are available long term to resource EIL's service requirements.
- Technical regulations including such matters as limiting harmonics to specified levels.
- Safety requirements such as earthing of exposed metal and line clearances.
- Asset configuration, condition, and deterioration. These parameters will significantly limit the rate at which EIL can re-align their large and complex asset base to fit ever-changing strategic goals.

- Physical risk exposures: exposure to events such as flooding, wind, snow, earthquakes, and vehicle impacts.
- Regulatory issues: for example, if the transport agency required all poles to be moved back from the carriage way.

2.4 Commerce Commission Determination – Financial Impact

Part 4 of the Commerce Act 1986 (the Act) requires the Commerce Commission to reset the current DPP for EDBs that are subject to price-quality regulation four months before the end of the current DPP period. From 1 April 2020, EDBs were subject to new requirements set out in the DPP determination. The new DPP period starts on 1 April 2025.

Changes in the way customers and other industry participants make use of distribution networks, innovations in the way EDBs deliver services, electrification driven by decarbonisation, and the risk of increasingly severe weather events all have the potential to reshape investment needs and quality expectations in unpredictable ways. In addition, the drive to move away from fossil fuels are creating some challenges to the electricity distribution industry. The stated intent of the Commerce Commission is to provide sufficient flexibility to accommodate increasing uncertainty and change across the electricity distribution sector.

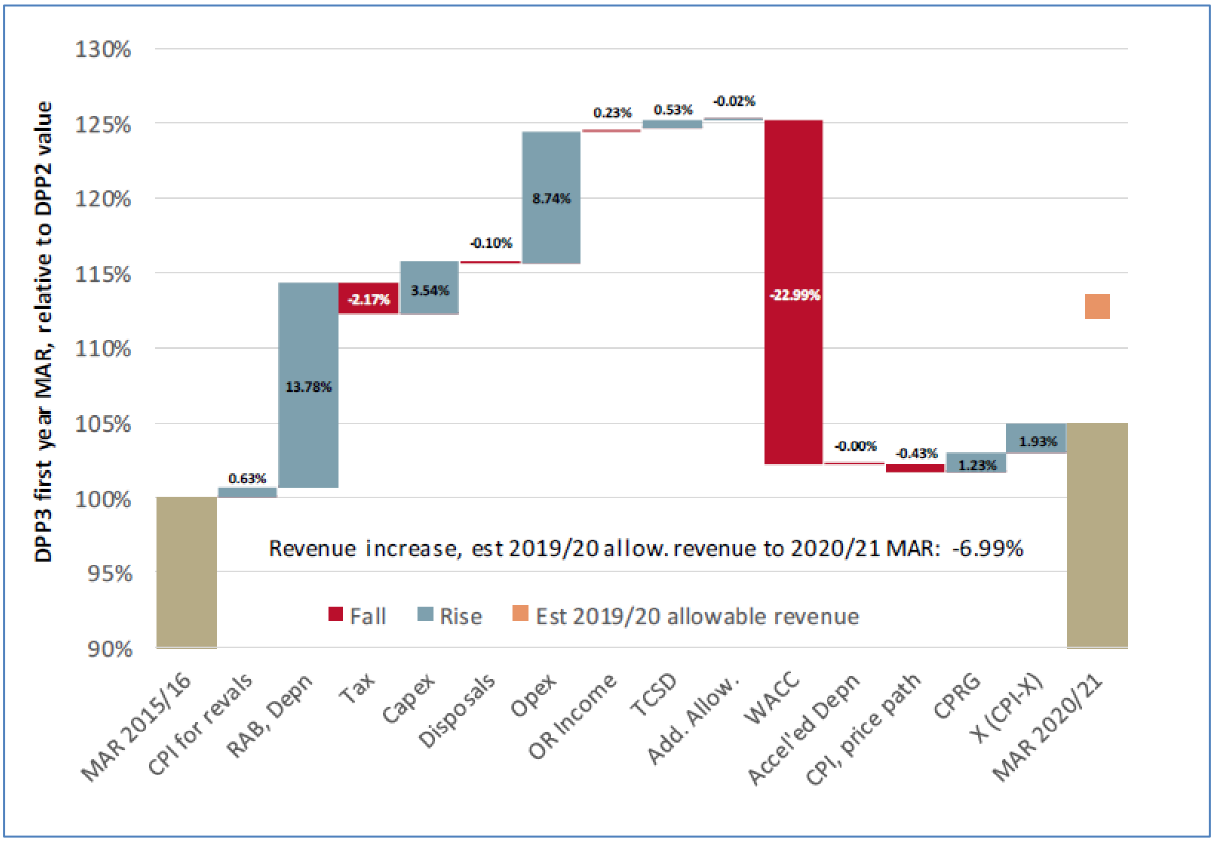
DPP3 introduced a revenue cap as opposed to the previous price cap. This is intended to give EDBs the flexibility to price in ways that offer more choice to customers and that enhance incentives for energy efficiency and demand-side management as well as to give EDBs greater certainty about revenue recovery. Setting revenue limits means that profitability depends on the extent to which EDBs control costs.

DPP3 revenue caps assumed a reduction in the weighted-average cost of capital, as was reflected in the state of the broader economy at that time. However, the international and national economic scenarios have changed significantly after the Covid pandemic, and many countries are experiencing the highest interest and price inflation rates in decades and are hovering on the brink of recession.

The Commerce Commission has set a net revenue allowance of $1.01 billion in the first year of the DPP3 period across the 15 regulated EDBs. This is an overall decrease of 6.7% relative to allowances in the final year of DPP2.

The methodology followed was to add the forecasts of each EDBs over the DPP3 period together, then spreading this revenue out over the period such that they increase at a consistent rate of forecast CPI-X, resulting in the ‘maximum allowable revenue’ (MAR). The overall result is presented in the following figure (copied from the Commerce Commission’s Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision document).

Figure 7: Financial Impact of DPP3



The result for EIL is allowable revenue in 2020/21 ($m) of $12.26 million. This is a reduction of 12% in revenue. Directly related to the revenue targets are the operating expenditure targets. The total allowable OPEX for 2020-2025 is $27.24 million and it is distributed as follows:

2020/21	2021/22	2022/23	2023/24	2024/25
5.18	5.31	5.45	5.59	5.68

The total allowable CAPEX for 2020-2025 is $25.98 million and it is distributed as follows.

2020/21	2021/22	2022/23	2023/24	2024/25
4.66	5.05	5.57	5.58	6.55

Expenditure is being managed taking both the allowable levels as well as the cash flows in the EDBs into account. ComCom has introduced reopeners for significant unforeseen or uncertain capital expenditure projects that will allow EDBs to undertake investments in response to changing conditions without risking capital under-recovery.

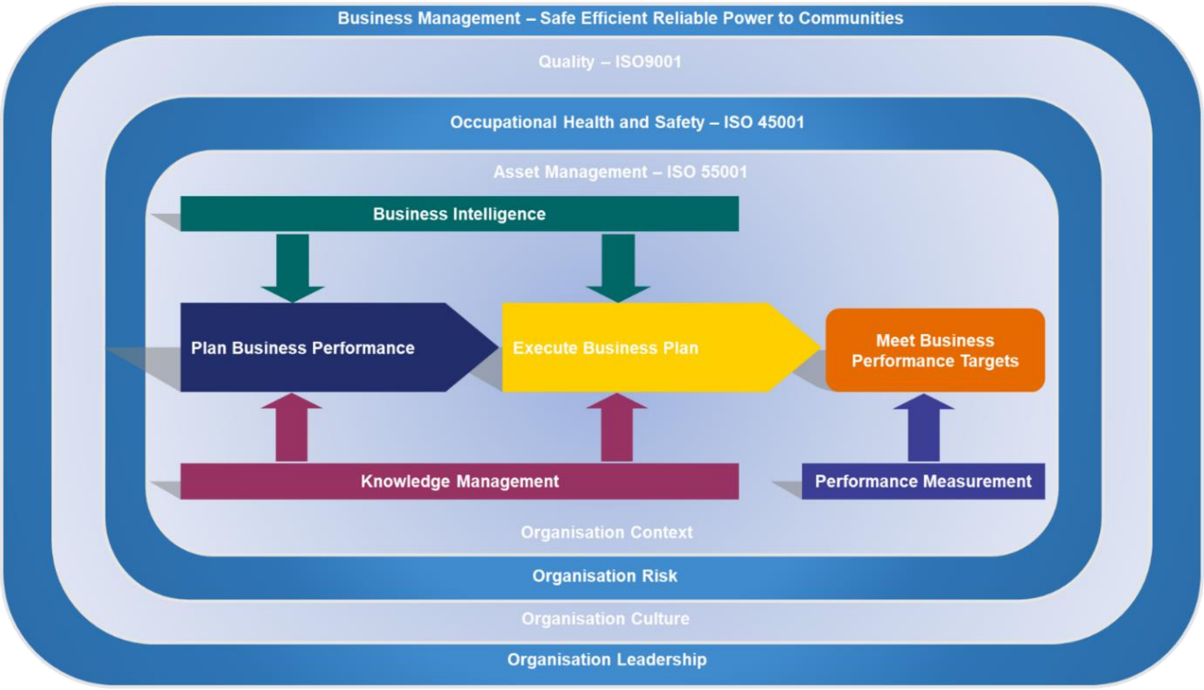
2.5 Planning Processes

EIL's planning processes and associated documents are described in the next sections.

Business Planning

The business planning, execution and performance measurement processes are presented in the next figures.

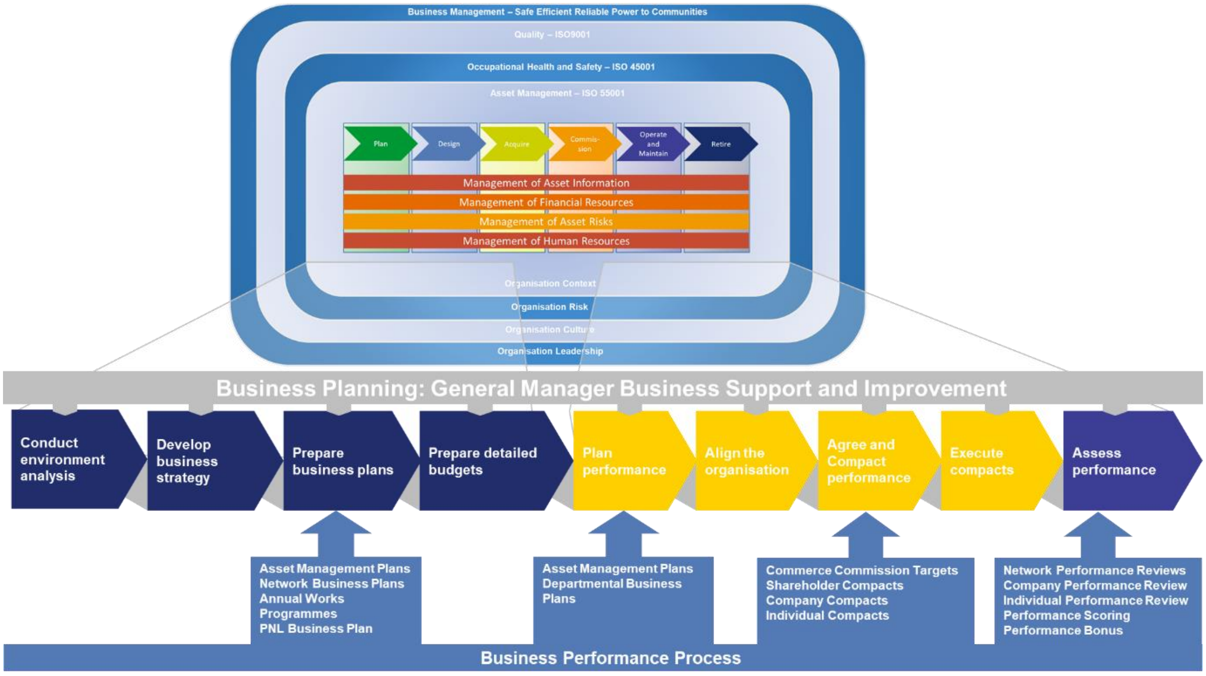
Figure 8: Business Planning and Execution Processes



Business planning take place within the overall framework of Quality, Occupational Health and Safety and Asset Management. The environment is scanned to determine threats and opportunities and gather other business intelligence. This is combined with knowledge around the strengths and weaknesses of internal processes. Business performance is planned to meet stakeholder requirements. The stakeholder requirements are embodied in targets EIL must meet. The business plan is executed, and the results are measured against the targets to evaluate business performance.

Figure 9 shows the process in more detail and indicates the performance elements from company level through to individual performance compacts. Individuals' performance against the compacts are evaluated for the performance incentive program.

Figure 9: Business Support and Improvement Processes



In addition to the AMP, PowerNet annually produces the following documents on behalf of EIL. These documents are approved by EIL as part of the company's planning processes.

Statement of Intent

EIL's Statement of Intent (SOI) is a requirement under the constitution of the company and forms the principal accountability mechanism between EIL's Board and the shareholder, Invercargill City Holdings. The SOI includes financial performance projections for the following metrics.

- EBIT% (Percentage Group Earnings Before Tax and Interest on Assets Employed).
- NPAT% (Percentage Group Tax Paid Profit on Equity).
- Percentage of Consolidated Equity to Total Assets.

- The quality performance projections for SAIFI and SAIDI are also included. These projections are over a three-year period and form the heart of asset management activities. The inherent trade-off between price and supply quality are acknowledged. The SOI is available at http://www.powernet.co.nz in the Line Owners area under Electricity Invercargill Limited, Company Information.

Annual Business Plan

Each year, the first three years of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into EIL's Annual Business Plan (ABP). The AWP for the three years ahead is an important component of the ABP.

The ABP defines the priorities and actions for the year ahead which will contribute to EIL's long-term alignment with their vision, objectives, and strategies, while fully understanding that this alignment process must at times cater for "moving goal posts".

The ABP contains the following.

- Core Business, Vision Statement and Critical Success Factors.
- Commercial Objectives, the Nature and Scope of Commercial Activity and Company Policies.
- Annual Works Programme (first three years).
- Business Plan Financials and Business Unit Reports.

Progress updates are reported monthly to assist in monitoring of performance and delivery to plan.

Annual Works Programme

The Annual Works Programme (AWP) is produced as part of the AMP development process and is included in the AMP's development and lifecycle planning sections. It covers the same ten-year planning horizon and lists the works to be undertaken for each financial year.

The AWP details the scope for each activity or project identified, sets the associated budget for the first year and forecasts expenditure for future years. Critical activities are to firstly ensure that this annual works program accurately reflects the projects in the AMP and secondly to ensure that each project is implemented according to the scope prescribed in the works program. Ensuring the AWP is achievable requires careful consideration of the available workforce and management capabilities which is discussed in Section 9.

Interaction between Objectives, Drivers, Strategies and Key Documents

The interaction between EIL's corporate vision, asset management objectives, business drivers, strategies and key planning documents is presented in the next figure.

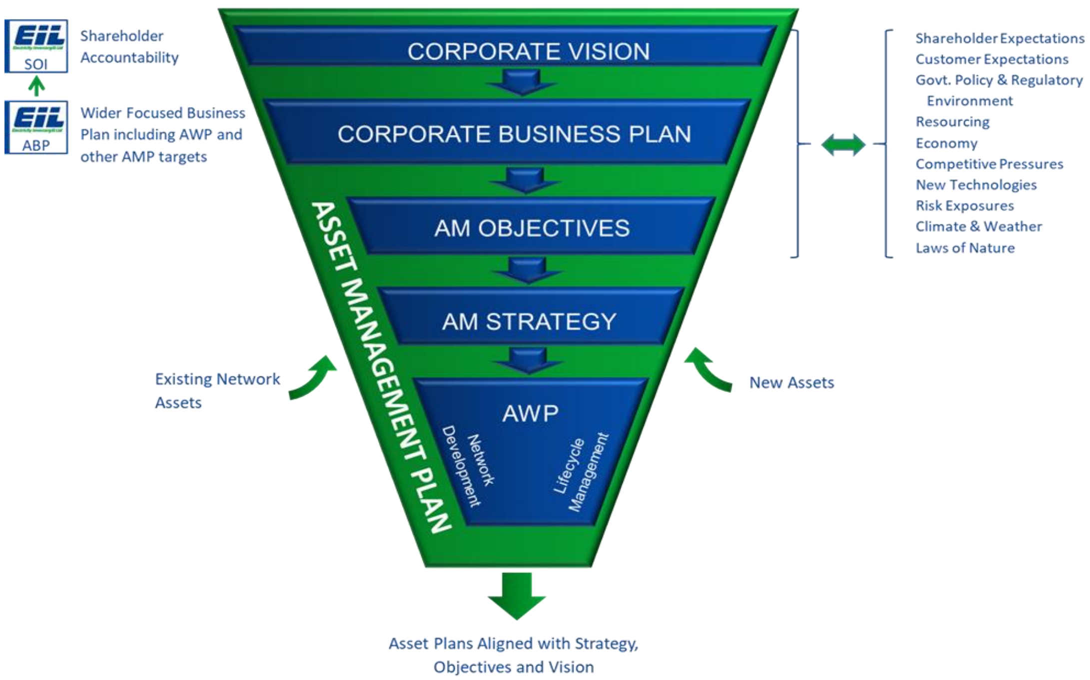
The vision leads to the objectives for EIL's asset management processes. These asset management processes are documented in the AMP which serves as a guidance and communication mechanism ensuring understanding and consistency within EIL's asset management company PowerNet and for the EIL board.

The asset management strategies are designed to provide guidance to achieve the asset management objectives while aligning with EIL's vision and corporate strategies. Stakeholder interests and expectations as well as other external influences create business drivers which drive the strategy development. They also shape the asset management objectives and the corporate vision. However, these tend to remain relatively consistent whereas strategies tend to be more flexible and evolve as the driving factors change with time. The asset management strategies are applied to the existing network assets to meet the asset management objectives including realising development opportunities as they arise. This involves the setting of performance targets which leads the AWP development.

The AMP (and especially the AWP incorporated into the AMP) sets and drives asset management works and expenditure to extract maximal value from network assets and is prepared in a format that assists communication of the key deliverables. Delivery of the AWP projects over time creates a network closely aligned with the asset management strategies, objectives and EIL's corporate vision whilst meeting stakeholder expectations, especially those of the shareholder and network customers.

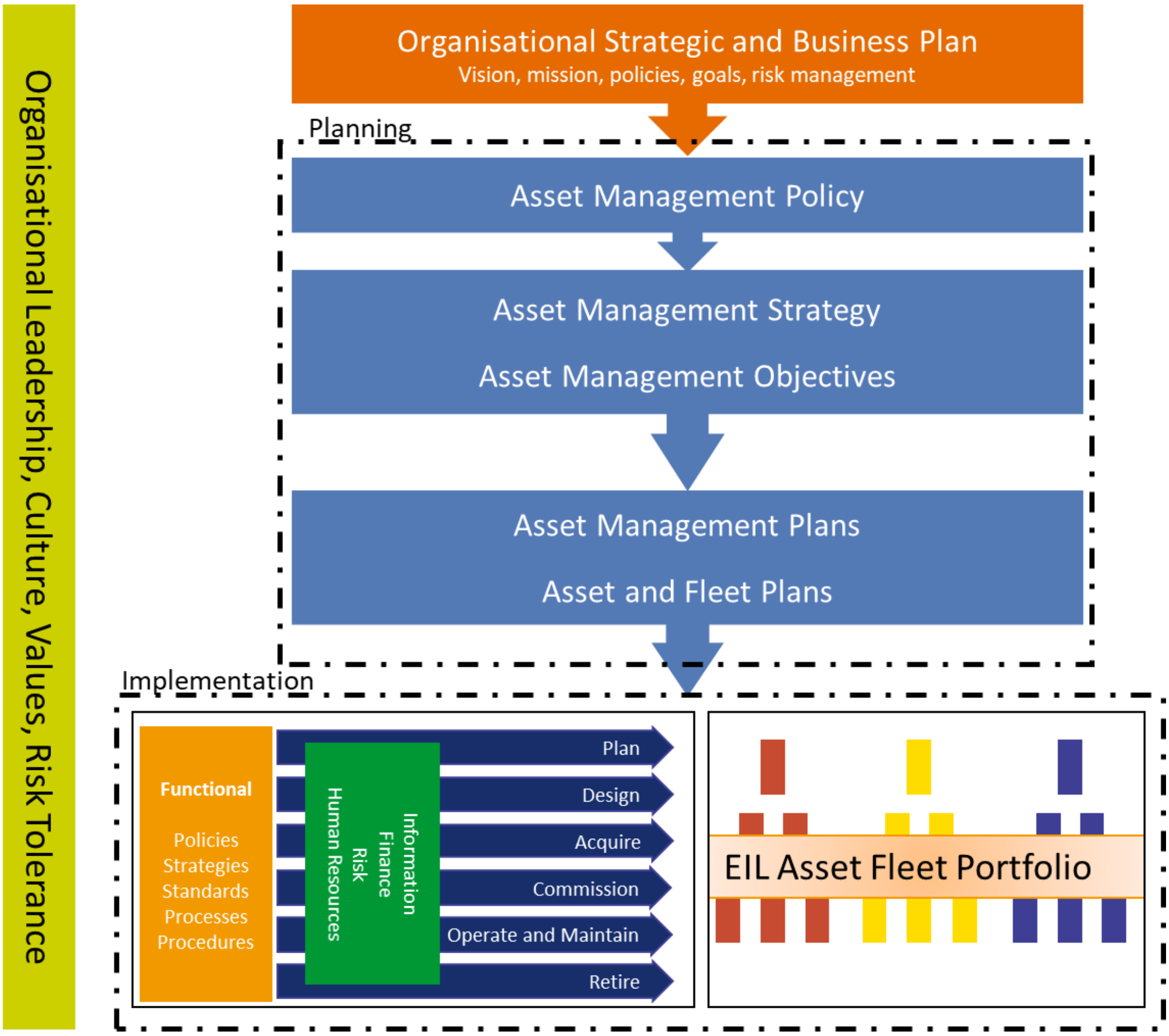
Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP; these together with any wider business issues provide the overall business planning summary used by the wider management team and EIL Board. The SOI incorporates performance targets (including key asset management targets) from the AWP, forming the accountability mechanism between the EIL Board and the shareholder.

Figure 10: Interaction between Objectives, Drivers, Strategies and Key Documents



This happens within the framework of our asset management policy, asset management strategy and asset management objectives. Figure 11 shows the framework we use to manage our assets.

Figure 11: Asset Management Framework



Asset Management Planning

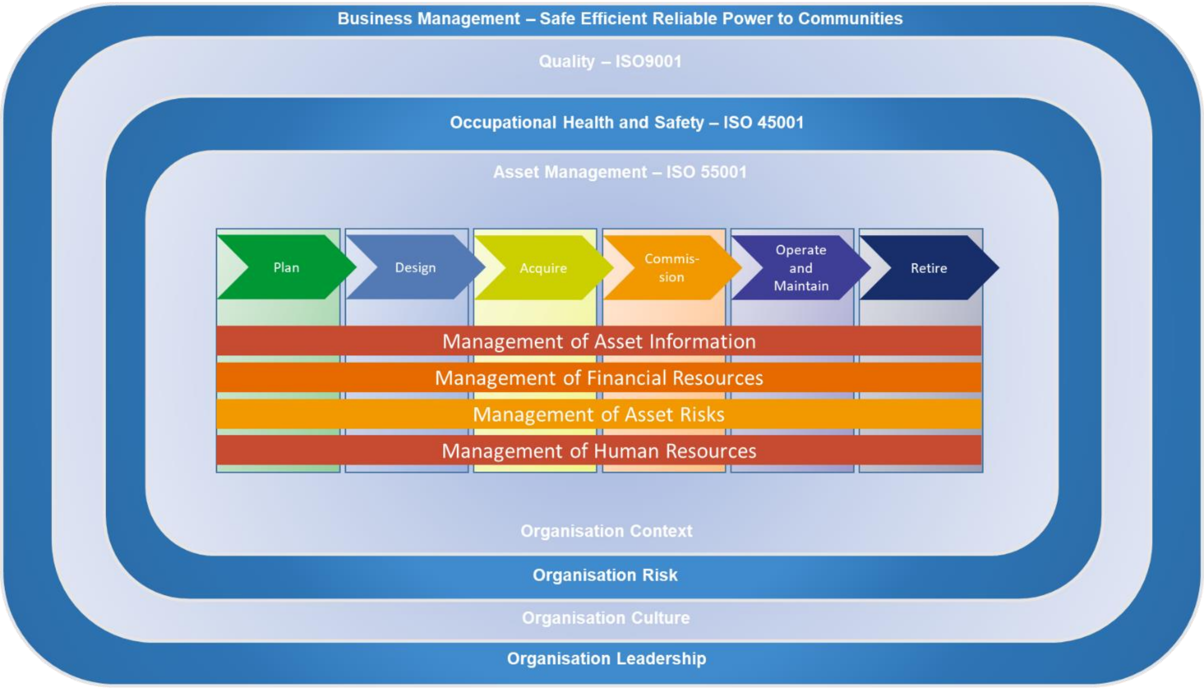
Asset life cycle management processes are demonstrated in the next figure. The asset life cycle phases are the following:

- plan;
- design;
- acquire (including construction);
- commission;

- operate and maintain; and
- dispose.

These phases are underpinned by the foundations of asset information management, financial resource management, risk management and human resource management. These are discussed in further detail in Chapter 6.

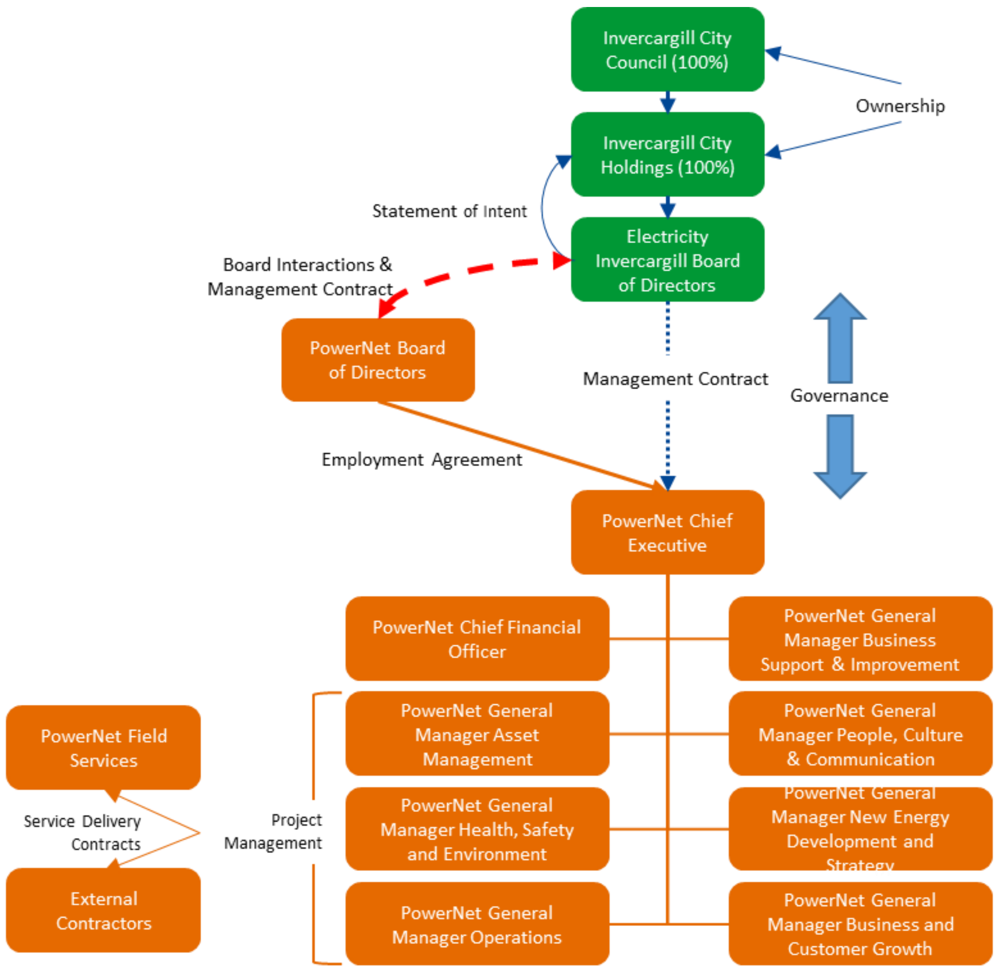
Figure 12: Asset Management Processes



2.6 Structure and Accountabilities

EIL's ownership, governance and management structure is depicted in Figure 13. Each level of management has defined financial authority limits set out in the PowerNet Financial Authorities Policy. It includes general financial authority levels and increased levels specifically for project work previously approved in the AWP. Most projects in the AWP are approved by the EIL Board as part of ABP process in the previous year.

Figure 13: Governance and Management Accountabilities



EIL Board

Any new project over $100,000 added or variation by more than +10% or -30% (for projects over $100,000) to the approved AWP needs approval from the EIL Board. Large projects with capital budgets exceeding $1,000,000 are required to be supported by a business case explaining the project scope and justification. The business case will generally include a detailed cost-benefit analysis of the recommended scope over alternative options. Projects between $500,000 and $1,000,000 requires a short form business case to be submitted to the Board.

The EIL Board receives monthly reports that cover the following items.

- Health and Safety – Incident summaries and progress measures.
- Network Reliability – this lists all outages over the last month, and trends regarding the SOI reliability targets.
- Network Quality – detail of outstanding supply quality complaints and annual statistics thereof.
- Network Connections – monthly and yearly details of connections to the network.

- Use of Network – trend of the energy conveyed through the network.
- Revenue – detail on the line charges received.
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network.
- Works Programme – Summary expenditure actuals and forecasts by works programme category with notes on major variations.
- Works Programme – Physical progress on specific works programme categories as identified by the Board.

Accountability at Executive Level

Overall accountability for the performance of the electricity network rests with the Chief Executive of PowerNet. The principal accountability mechanism is the Chief Executive's employment agreement with the PowerNet Board which reflects the outcomes specified in the management contract between EIL's Board and PowerNet.

Accountability at Management Level

There are eight level two managers reporting directly to PowerNet's Chief Executive. Their respective employment agreements are the principal accountability mechanisms. The General Manager Asset Management has the most influence over the long-term asset management outcomes, through his responsibility for preparation of the AMP. The AMP guides the nature and direction of the other managers' work.

Accountability at Operational Level

PowerNet's Network Assets and Major Projects Team (under the General Manager Asset Management), Operations (Technical) Team and Operations (Distribution) Team each manage their respective major projects, technical projects and distribution projects which make up the AWP. Their objectives are to deliver the AWP projects on time, to scope and to budget while also delivering to the AWP works category and overall CAPEX and OPEX budgets. Major Projects typically tenders the work out to external consultants and contractors through open tender, while technical and distribution projects utilise PowerNet's in-house field services.

Utilisation of external contractors are contractual and structured as follows.

- Purchase Order – generally only minor work.
- Fixed Lump Sum Contract – generally on-going work.
- Term Service contract – where we require regular services from a contractor.
- Engineering Contract – specific project work.

Each type details the work to be undertaken, the standards to be achieved, detail of information to be provided and payments schedule.

Accountability at Work-face Level

PowerNet's internal field staff are managed within PowerNet's Operations Team to deliver work divided into technical and distribution projects. External contractors are used for vegetation management (Asplundh) and communications network maintenance and projects (Ventia). Civil works including cable trenching and earthworks for zone substations are typically completed by external contractors. External contractors are typically used to deliver major projects and occasionally when necessary to supplement workforce capacity or skillsets and include the following.

- DECOM Limited.
- Ventia Limited.
- Electrix Limited.
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper).
- Asplundh Tree Expert (NZ) Limited.
- Corys Limited.
- Consultants (Beca, Edison, Mitton Electronet, ProTechtion Consulting, Mitchell Daysh, Ergo Consulting, Decom, Utility Consultants).

2.7 EIL's Supply Area

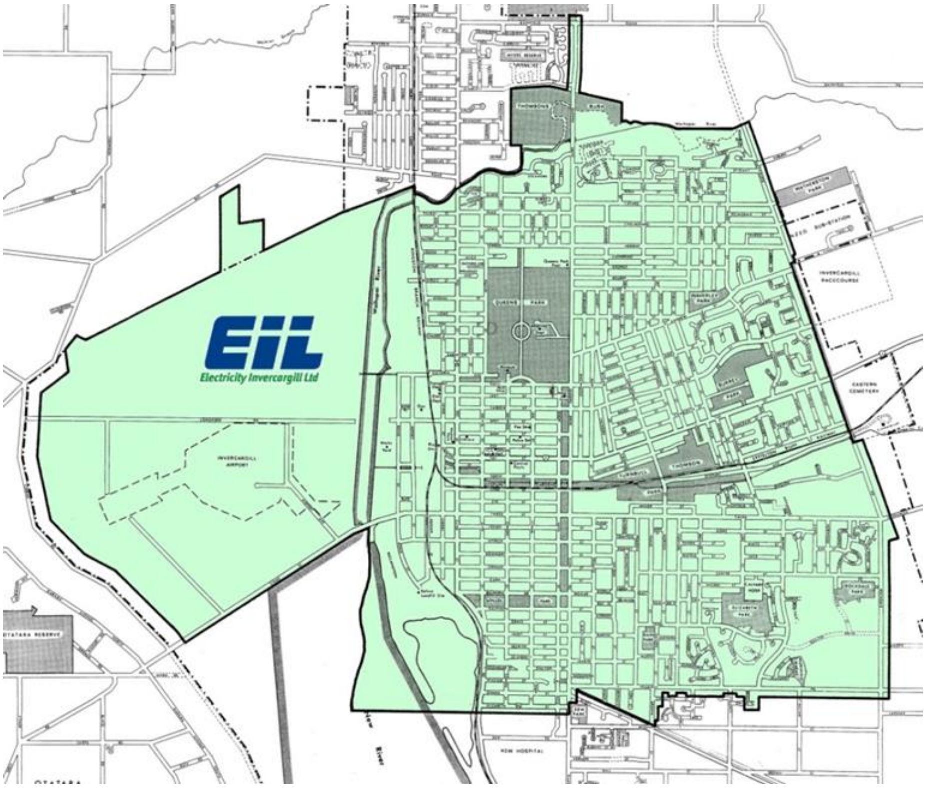
EIL's service area includes two geographically separate areas.

- The part of Invercargill bounded by Racecourse Road to the east, the Waihopai Stream to the north and west (except for Invercargill Airport which is in EIL's area) and Elizabeth, Moulson and Brown Streets and Tramway Road to the south, as shown in Figure 14.
- The borough of Bluff extending as far west as the former Ocean Beach freezing works, as shown in Figure 15.

Bluff (having less than 25km of distribution lines and less than 2000 ICPs connected) is not considered a sub-network and therefore values presented in this AMP for EIL are inclusive of the Bluff area network except where explicitly stated otherwise. The topography is densely urban and built-up in both Invercargill and Bluff. Invercargill is a flat area (lying about 3m to 5m above sea level), whilst Bluff varies from flat to steep hills.

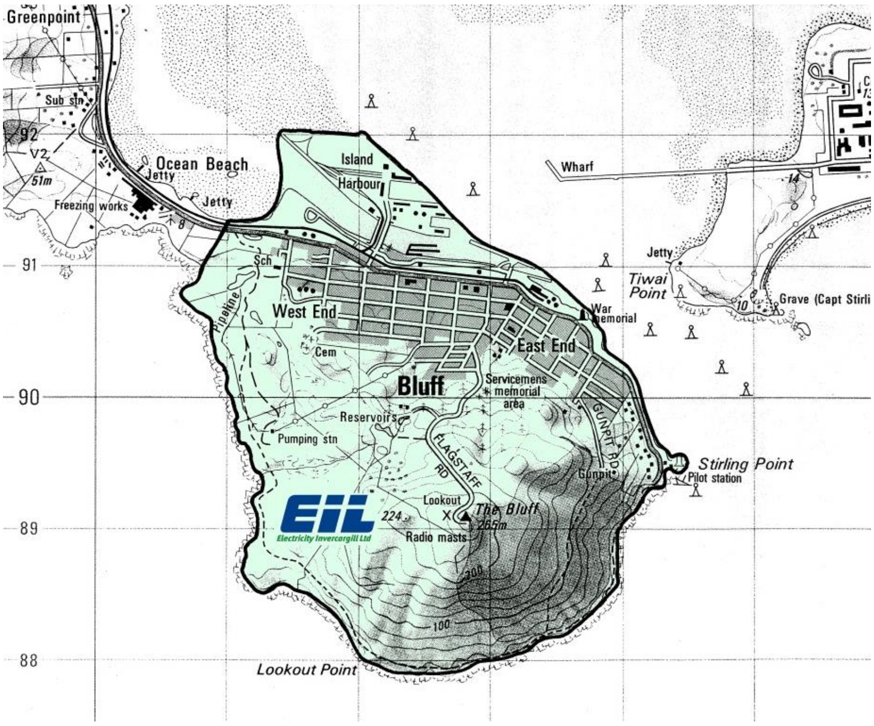
Areas on the network have differing load densities and rates of growth which are more likely to influence asset management planning. Historically growth rates on the network however were relatively low, however, with decarbonisation and potential new commercial and industrial developments close to the city this is foreseen to change for the next two to five years. Connections timeframes for new large customers are generally unpredictable as the large customers approach EIL for new connections as late as possible to try and keep their competitive advantage. Planning in these instances tends to be more reactive than proactive to avoid over investment. However, this does impact the effectiveness with which developments can be planned holistically. The known and firm development currently is the housing development off Racecourse Road entailing a potential 600 new houses and some commercial and educational facilities. There are not any individual customers considered large enough to have any significant impact on network operations or asset management planning other than ensuring that adequate supply capacity is maintained.

Figure 14: Invercargill Distribution Area



The Invercargill distribution area is predominantly residential but does include a medium-sized CBD, a heavy industrial area immediately west of the CBD and a light industrial area in the southeast. The criticality of supply for the CBD is recognised with additional protection and automatic sectionalisation provided in this area.

Figure 15: Bluff Distribution Area



Currently EIL's largest customer is Southport Limited, a large port in the Bluff distribution area which regularly peaks at about 1.6MW and consumes approximately 6.5GWh per year. Decarbonisation initiatives involving the change from coal boilers to electricity powered heating systems may change this. The Bluff distribution area also includes port associated heavy industries as well as residential and commercial customers.

2.8 Quality of Service (Regulated Service Levels)

Quality of service incentives is a major focus area of the Commerce Commission's DPP3 determination. The approach followed is one of '*no material deterioration*'. The stated intent is that aligning reliability incentives to the value customers place on reliability frees EDBs (within certain bounds) to target the level of reliability and of price that best meets the expectations of their customers. Additionally, normalisation is intended to prevent the effects of severe storms being mistaken for signs of deterioration. The principles embodied within the ComCom quality standards are the following.

- Separating planned and unplanned reliability standards.
- Setting the unplanned reliability standards at 2 standard deviations above the normalised historical average, and defining contraventions on an annual basis, rather than a 'two-out-of-three' year basis.
- Setting the planned reliability standard at three times the historical average and assessing it on a regulatory period basis.
- Capping the inter-period (DPP2 to DPP3) movement in unplanned standards at ±5%.

3 The Network and Asset Base

EIL owns and operates two separate electrical networks that are both supplied by the Grid Exit Point (GXP) at Invercargill. The Bluff network comprises two 11kV feeders supplied by TPCL zone substation situated just west of Bluff Township. EIL also owns interconnectors to TPCL Otatara and Seaward Bush 33kV lines that provide alternative supplies to the Leven Street and Southern zone substations respectively.

3.1 Network Configuration

The EIL asset base can be summarised as per the following table:

Asset Class	Group	Total number in EIL
Distribution Transformer	OH (Up to 100kVA)	5
Distribution Transformer	UG (up to 1MVA) + Platform	438
Power Transformer	1-4MVA	0
Power Transformer	4-8MVA	0
Power Transformer	8-16MVA	0
Power Transformer	> 16MVA	7
Overhead Switch	ABS	33
Overhead Switch	LBS (Solid Mould)	2
Protection Relay	G1 - Substation	123
Protection Relay	G2 - Field	39
Battery	G1 - Substation	70
Battery	G2 - Field	54
Distribution Earth	G1	569
RMU	Oil + Solid Insulation	447
RMU	Gas Insulation	0
Metalclad Switchgear	All	4
Field CB	Field	2
Field CB	Zone	0
Poles	Wood	220
Poles	Concrete/steel	816
Cables	HV Cable XLPE	15
Cables	HV Cable Oil Pressurised	12
Cables	MV Cable XLPE / PVC	64
Cables	MV Cable PILC	96
Cables	LV Cable < 1000V	424
Instrument Transformers	VT	19
Instrument Transformers	CT	135
Neutral Earthing Resistor	Zone Subs	4
Regulators	Zone Subs	0

Asset Class	Group	Total number in EIL
VRR	All	9
PLC	All	0
Injection Station	All	1
Capacitor Banks	All	0
CT-VT Units	Field	2
CT-VT Units	Zone	0
Generators	network-owned, <=600kVA	0
LV Outdoor Cubicles	All	8687
OHL	km	77883
Statcom	All	0
Battery Chargers	Zone	26
Battery Chargers	Field	0
Fibre	All	41
Fault Indicator	All	538
Power Supply	All	0
RTU	Zone	13
RTU	Field	0
Earth Mat	Zone	5
Earth Mat	Field (regulator site)	0
Fault Throw Switch	All	0
Oil Separator	All	3
Surge Diverter	Zone	73
Surge Diverter	Field	5
Zone Substation	Buildings	4

Bulk Supply Points and Embedded Generation

Invercargill GXP comprises a strong point in the 220kV grid which is tied to Roxburgh and Manapouri power stations and to the North Makarewa GXP. Invercargill is also a major supply node for the Tiwai Point Aluminium Smelter.

The 33kV supply arrangement at Invercargill comprises an indoor switchboard that is energised by two three-phase 120MVA 220/33kV transformers. There are eleven 33kV feeders, each supplied through its own circuit breaker. EIL takes supply from seven of these feeders in normal operation, including the two parallel TPCL feeders which supply Bluff. Back up supplies are available from other TPCL feeders and are used from time to time.

EIL owns the segments of 33kV line (but not the circuit breakers or bus) that run within the GXP land area and accommodates a backup control room for PowerNet's System Control. EIL also owns one of the two 33kV 216⅔Hz ripple injection plants on the west side of the GXP site. The second plant is owned by TPCL with each providing backup capability to the other.

Table 11: Bulk Supply Characteristics

Supply	Voltage	Rating	Firm Rating	Maximum Demand 2021/22	LSI* Coincident Demand 2021/2
Invercargill GXP	220/33kV	240MVA	109MVA	107.671MW (17:30 28/06/2021)	101.728MW (8:00 15/10/2020)
EIL	*(GXP assets shared with TPCL)*			63.602MW (17:30 28/06/2021)	48.934MW (8:00 15/10/2020)

*LSI = Lower South Island

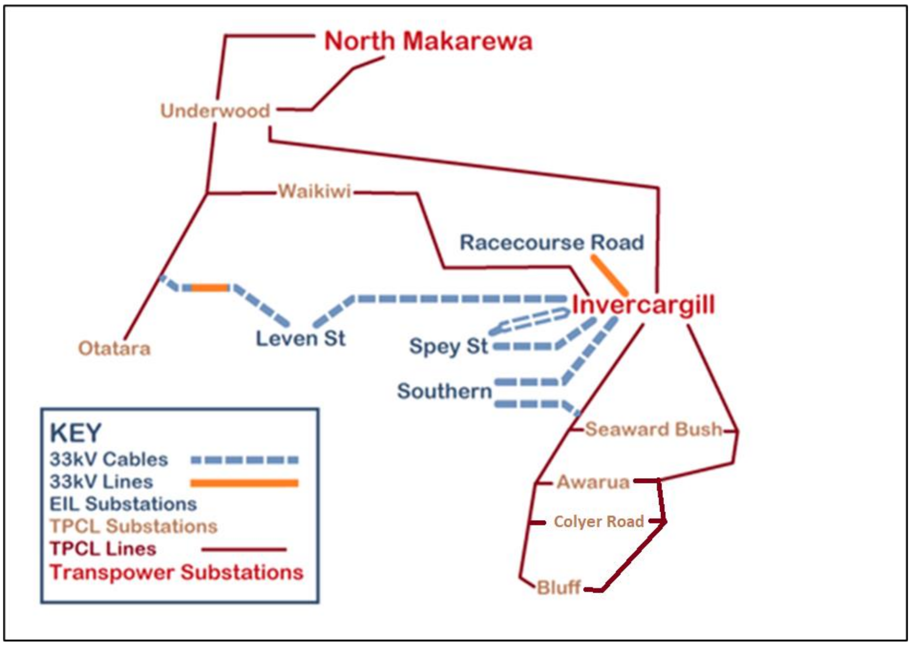
There is no significant generation embedded within EIL's network, but the wind farm at Flat Hill near Bluff (6.8MW installed capacity) is connected at TPCL's Bluff substation, from which the Bluff area network takes its supply. A small number of distributed generation connections exist but are only a few kW each in size. These generators with generation profiles (tied to sunlight conditions) have negligible effect on GXP loading.

Subtransmission Network

EIL's subtransmission network is a 33kV network that is supplied from a single GXP at Invercargill and can take emergency supply from the North Makarewa GXP through TPCL's 33kV network as depicted in the next figure (EIL's two Bluff 11kV feeders are supplied from TPCL's 33kV subtransmission network). The network comprises 1.4 km of 33kV line and 26.8km of 33kV cable and has the following characteristics:

- two points of interconnection with TPCL's 33kV network which provides alternative supplies to Leven Street and Southern zone substations.
- it is almost completely underground except for short lengths of overhead line between Invercargill GXP and Racecourse Road zone substation (about 300 m long) and in the middle of the tie between Leven Street zone substation and TPCL's Otatara 33kV feeder; and
- it is predominately a ring topology except for Racecourse Road which is a spur.

Figure 16: Subtransmission Network



Basic details for EIL's subtransmission circuits are provided in the following table. All circuits are 33kV and operate within their respective ratings. Stated remaining lives are based on Optimised Deprival Valuation (ODV) standard lives; but in practice EIL subtransmission cables (being lightly loaded) are expected to last significantly longer than ODV standard life and will be replaced based on their condition.

Table 12: Subtransmission Circuit Details

Location	Type	Length	Manufactured	Remaining Life	Condition
Invercargill GXP to Southern	Oil Cable	4.7 km	1968	16 yrs.	Good, only lightly loaded, some concerns of joints and terminations.
Invercargill GXP to Doon Street ex T1	Oil Cable	3.5 km	1970	18 yrs.	Good, moderately loaded.
Invercargill GXP to Doon Street ex T2	Oil Cable	3.5 km	1975	23 yrs.	Good, only lightly loaded, some concerns of joints and terminations.
Doon St to Spey St	XLPE Cable	0.6 km	2016	49 yrs.	As new, lightly loaded.
Invercargill GXP to Spey Street	XLPE Cable	4.1 km	2015	48 yrs.	As new, lightly loaded.
Invercargill GXP to Racecourse Road	O/H Line	0.3 km	1975	13 yrs.	Good, short cross country, concrete poles.
Invercargill GXP to Leven Street	XLPE Cable	5.3 km	1983	6 yrs.	Good, lightly loaded.

Location	Type	Length	Manufactured	Remaining Life	Condition
Seaward Bush Line to Southern	XLPE Cable	1.4 km	1999	32 yrs.	Good, not normally loaded.
Otatara Line to Leven Street	XLPE Cable O/H Line	3.7 km 1.1 km	2000	33 yrs. 23 yrs.	Good, not normally loaded.

Subtransmission Cables

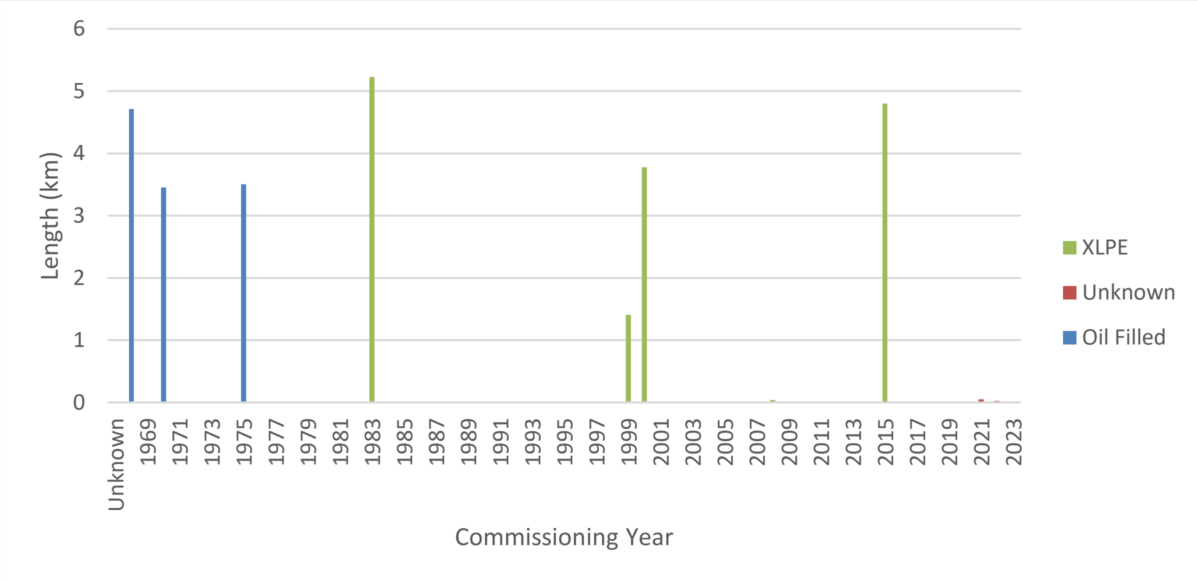
EIL has three oil filled cables taking supply from the Invercargill GXP substation, the oldest of which has approximately 16 years life remaining and is expected to be in sound condition. One of the oil cables supplies Southern substation and operates up to about half of its rating. The other two cables previously supplied Doon Street and were similarly operated up to about half of their capacity. However, these cables have now been paralleled and extended with XLPE cable to supply Spey Street which has reduced typical loading to low levels.

There have been some concerns with the rating of the cables due to poor thermal resistivity backfill used. Temperature and thermal resistivity transducers were installed on the cables in 2015 to better understand their in-service capacity. The data to date indicates no concerns although the opportunity has not yet arisen to gather data during worst-case conditions, i.e., over an extended dry spell. Some maintenance work is being completed on the oil tanks and associated piping.

There is also some concern over the integrity of the cable joints which have been found to be trending toward premature failure by other distribution companies. Some cables joints are to be exposed and terminations replaced to ensure the cable can be reliably operated for the remaining life of the cables The risk of failure has been mitigated through the installation of a new XLPE cable in parallel to the oil-filled cables formerly supplying Doon St; all oil-filled cables on the network now have an alternate supply option through an XLPE cable.

The other cables are XLPE cables, lightly loaded and in good condition. Some of these are unloaded cables used occasionally for backup. Earlier XLPE cables (pre-1985) have a shorter life expectancy, however for lightly loaded cables it is more appropriate to replace on condition than on age, particularly where a parallel supply option exists. Figure 17 shows the commissioning year and installed length for EIL's subtransmission cables (as of the end of March 2023).

Figure 17: Subtransmission Cables (33kV Cables)



Zone Substations

EIL owns and operates four zone substations in Invercargill which have either AA or AAA security levels (see Development Criteria for security level definitions). However, the network area in Bluff also takes an 11kV supply from a TPCL owned substation. Descriptions for EIL's zone substations are provided in Table 13.

Table 13: Zone Substations

Substation	Nature of load	Description
Spey Street	CBD, Urban Residential	Spey Street is a modern urban substation with dual transformers providing a capacity of 72MVA and a firm rating of 36MVA. This substation was constructed as a relocation and replacement for the Doon Street substation which had many assets at end of life and was at risk of third-party damage from a potential earthquake. It is a fully indoor site built to blend inconspicuously into its semi-commercial environment. The substation is supplied via a new 33kV XLPE cable and a second cable feeder consisting of the oil filled cables (that previously supplied Doon Street) paralleled and extended with a 33kV XLPE cable to Spey Street. The 11kV switchboard has 12 feeders and is split by two bus coupler circuit breakers, with each half located in separate fire rated rooms for added security.
Leven Street	CBD, Heavy Industrial, Urban Residential	Leven Street is an urban substation with dual transformers providing a capacity of 46MVA and a firm rating of 23MVA. It is supplied by a single 33kV XLPE cable from Invercargill GXP but has an alternative 33kV supply from TPCL's Otatara 33kV feeder (which can be supplied from an alternative GXP). This alternative supply achieves the necessary AAA security for the substation however due to its supply being from another GXP the 33kV back-feed cannot be 'normally in service' and therefore a short interruption (i.e., break before make) has to be accepted. The 11kV switchboard has 9 feeders and is split by a bus coupler circuit breaker.
Southern	Urban Residential,	Southern is an urban substation with a dual transformer providing a capacity of 46MVA with a firm 23MVA capacity. It is supplied by a single 33kV oil filled cable from Invercargill

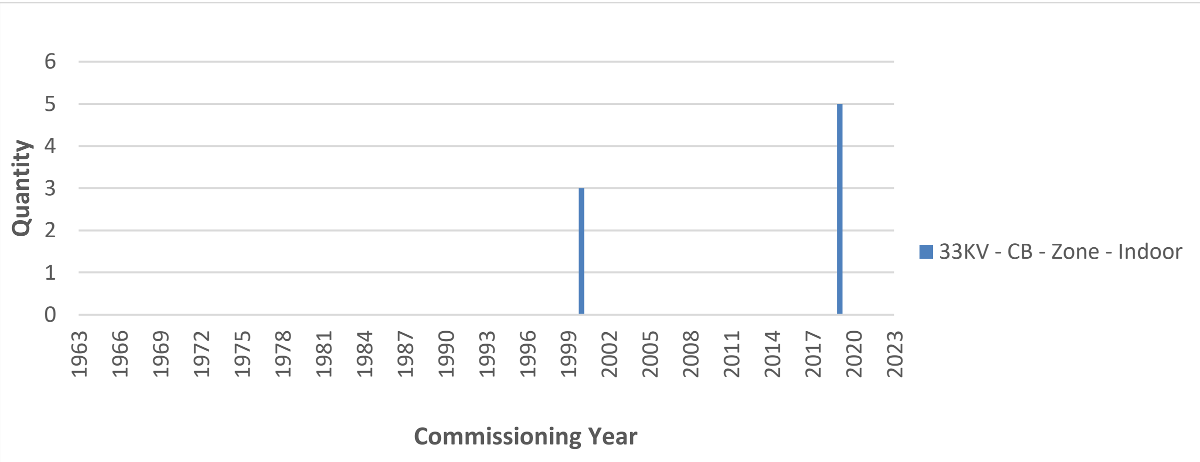
Substation	Nature of load	Description
	Light Industrial	GXP. An alternative 33kV supply is available from TPCL's Seaward Bush 33kV feeder as backup if required. The 11kV switchboard has 5 feeders, one of those feeders is split from the other by a bus coupler circuit breaker.
Racecourse Road	Urban Residential, Rural Residential	Racecourse Road is an urban substation with a single transformer providing 23MVA capacity. It is supplied by a short 33kV overhead line from Invercargill GXP. The substation supplies predominantly residential areas but also has two metered feeders which supply a small semi-rural area of TPCL's network. The 11kV switchboard has 9 feeders and is split by a bus coupler circuit breaker.
Bluff	Port, Heavy Industrial, CBD, Urban Residential	EIL's Bluff area is supplied from two metered 11kV feeders from TPCL's Bluff substation to the Northwest of the town. Two other feeders are used as a supply to rural customers North of Bluff and as a connection point for Southern Generation's Flat Hill Windfarm. The Bluff substation has two transformers providing a capacity of 26MVA and a firm rating of 13MVA. Bluff substation is supplied from two 33kV overhead lines from Invercargill GXP via TPCL's Colyer Road substation. The size of the total load on the Bluff substation is technically only large enough to justify AA security, but due to the lack of 11kV backup capacity, it is more economic to provide AAA security at the site.

Subtransmission Voltage Switchgear

The 33kV switchboard at Leven Street Substation is indoor, relatively modern and in good condition. At Southern substation EIL's an indoor 33kV switchboard was installed in 2019. The switchboard consists of 5 circuit breakers. The switchboard is split into two sections via a bus coupler. Two relatively young circuit breakers are located at Doon Street, but have now been removed from service, and options for their reuse are being considered.

Outdoor equipment at Southern Substation has been damaged by vandalism in the past. Protective barriers have been installed around critical equipment, but without fully enclosing equipment there remains a risk of insulators being damaged by thrown stones.

Figure 18: Subtransmission Voltage Circuit Breakers (33kV)



Power Transformers

The power transformers at EIL's Leven St, Southern, and Racecourse Rd zone substations are all rated to supply load up to 23MVA with forced cooling, based on an ambient temperature of 5°C (as peak load in EIL generally occurs at the coldest times when heating requirements are greatest).

The power transformers at EIL's remaining substation, Spey St, are relatively new and are rated up to 36MVA with forced cooling. The Spey St substation replaces the Doon St substation. The ex Doon St 23MVA transformer has been installed at Southern substation as T1 which upgrades the substation to a dual transformer site. The existing Southern transformer 23MVA is labelled T2. Both transformers have reasonable life, and Furan analysis suggests the insulation is in sufficiently good condition to provide an extended life. Due to the good condition of the older units, there are no power transformer replacements expected within the next 10 years.

The transformer at Racecourse Road was refurbished in 2017 (major rust), with condition assessment of the insulation showing that it too can provide an extended life.

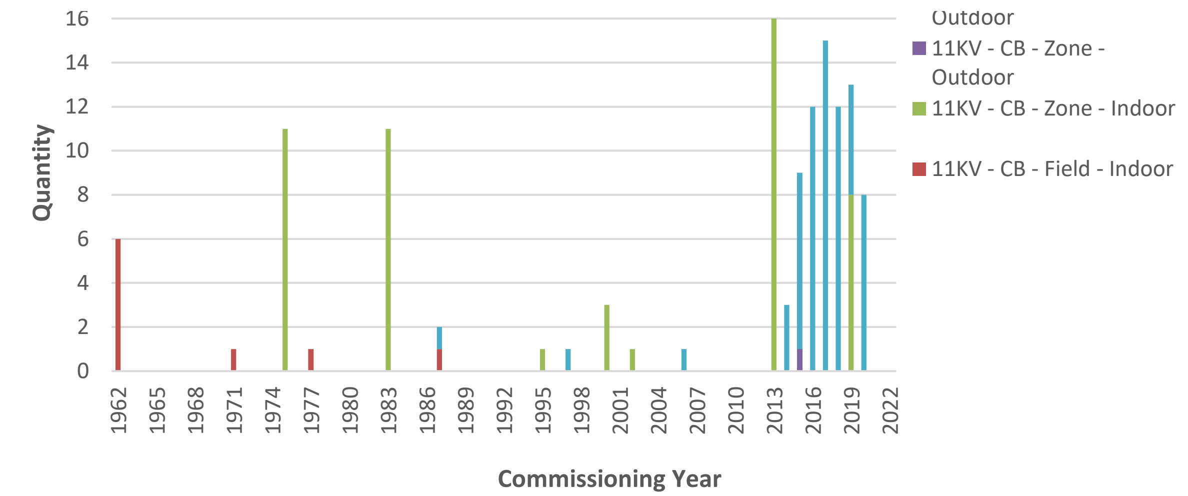
Table 14: Power Transformers

Transformer Location	Rating	Installed	Remaining Life
Spey Street T1	18/36 MVA	2015	57
Spey Street T2	18/36 MVA	2012	54
Leven Street T1	11.5/23 MVA	1983	25
Leven Street T2	11.5/23 MVA	2002	44
Southern T1 (Ex Doon St)	11.5/23 MVA	1970	12
Southern T2	11.5/23 MVA	1967	09
Racecourse Road T1	11.5/23 MVA	1975	17

Distribution Voltage Switchgear

The 11kV circuit breakers installed at EIL's zone substations and in the field with their year of manufacture are shown in Figure 19 (as of the end of March 2023).

Figure 1: Circuit Breakers in EIL



The Spey Street substation has modern switchgear and has no known issues with its switchboard.

The Southern substation switchboard was replaced as part of a recently completed (2021) upgrade project at this substation. The new switchboard has also enabled dual transformer supply.

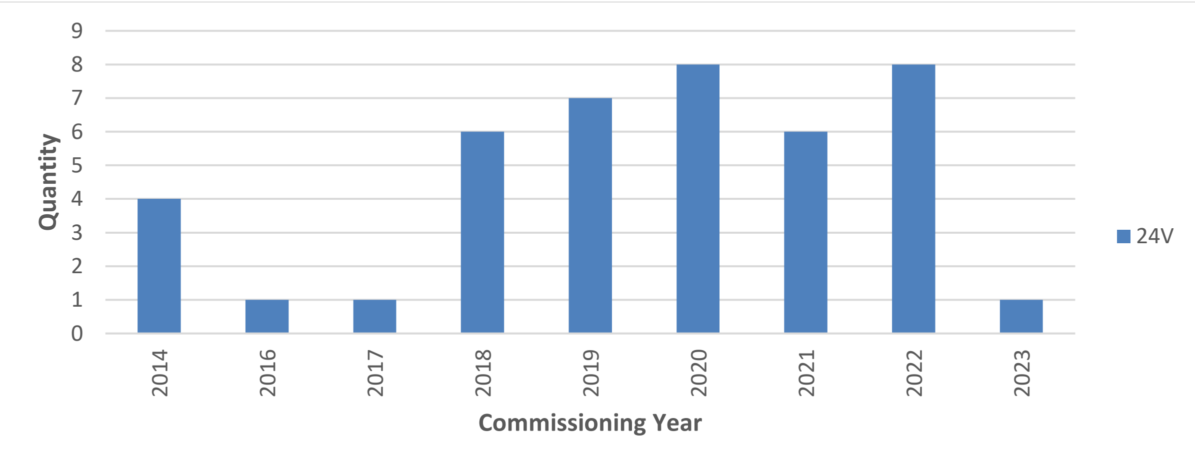
The Racecourse Road substation switchboard was installed in 1975 and a replacement project is currently underway with design stage in 2022-24 and replacement in 2026/27 and 2027/28.

The 11kV switchboard at Leven Street was installed in 1983 with an additional incomer installed in 2000 when the second transformer was installed. There are no issues noted with any of the switchboards' circuit breakers.

DC Power Supplies

DC batteries are essential to the safe operation of protection devices, therefore regular inspections are carried out and each battery is replaced as conditions dictate.

Figure 20: DC Batteries



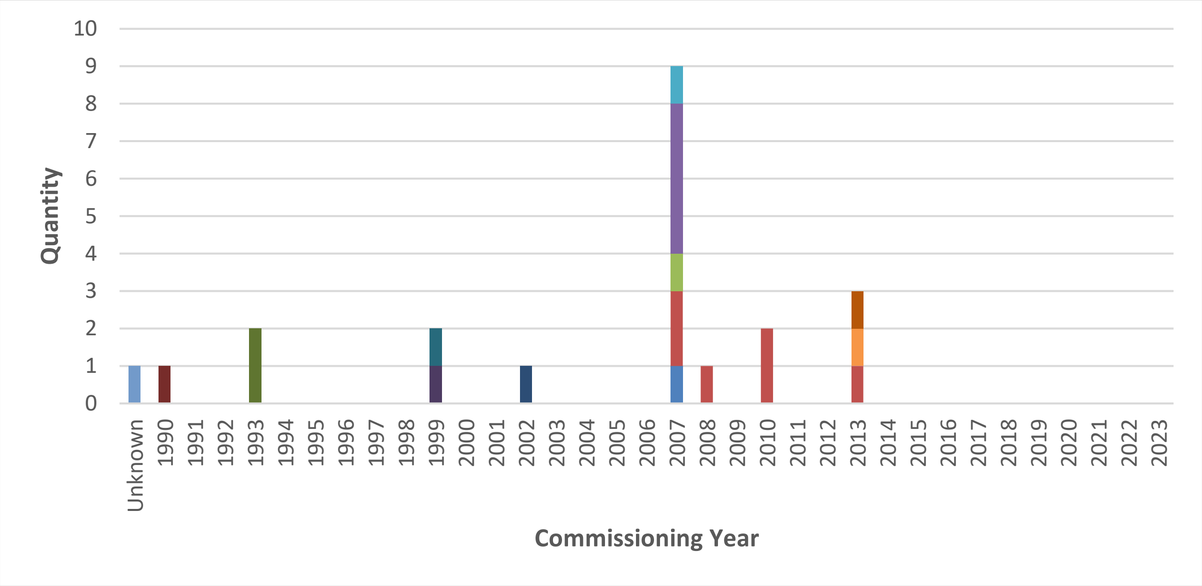
Tap Changer Controls

Seven voltage regulating relays are in operation having been installed with their associated transformers and are in good condition. Replacements will coincide with transformer replacements when due. Unexpected failures may require replacement with the modern voltage regulating relay standardised solution based on a SEL controller.

Metering

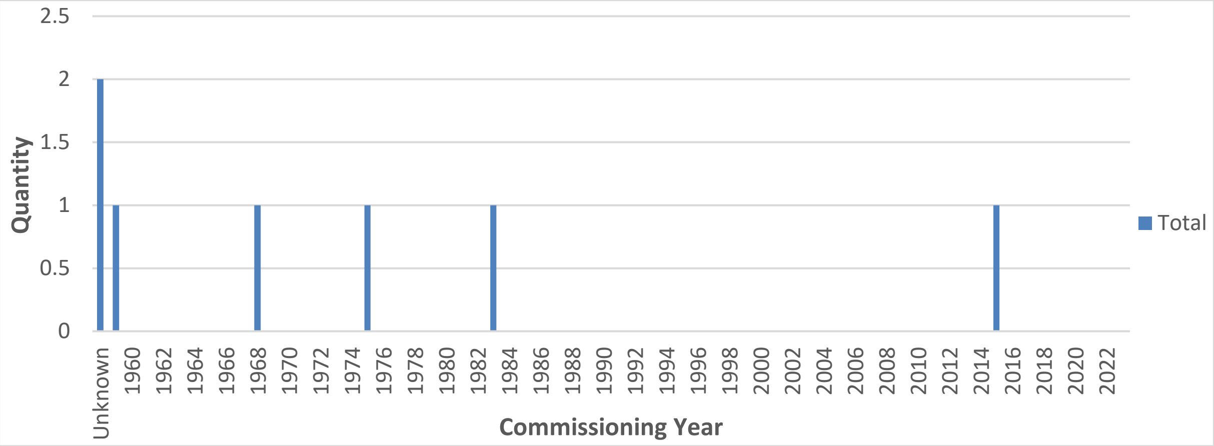
EIL has 'Time of Use' (TOU) meters on its incoming circuit breakers to provide accurate loading information on each zone substation. There are TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these is shown in Figure 21.

Figure 21: Metering Assets



Substation Buildings

Figure 22: Substation Buildings



Distribution Network

EIL's distribution network has a total length of 178 km to supply its 17,664 customers giving an overall customer density of 95 customers per kilometre. The 11kV distribution network is heavily meshed throughout the entire Invercargill area, with almost all distribution transformers having two separate 11kV supplies. Distribution in Bluff is largely meshed except at feeder extremities. The distribution network has the following layout.

- All underground cabling within the Invercargill CBD. Cable type (PILC – Paper Insulated Lead Covered, or XLPE – Cross-Linked Polyethylene) largely depends on date of installation.
- Suburban areas of Invercargill are either XLPE cable or overhead line. A gradual overhead to underground (OHUG) program has been implemented over several decades leaving less than 10 km of overhead construction that will remain overhead.
- The Bluff network is almost completely overhead construction due to the shallow soil over rock substrata geological profile, which makes undergrounding difficult. The Bluff area was originally operated at 3.3kV distribution, with conversion to 11kV taking place after EIL took over the assets.

The split of the distribution network per substation is presented in Table 15. Safety and reliability are EIL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

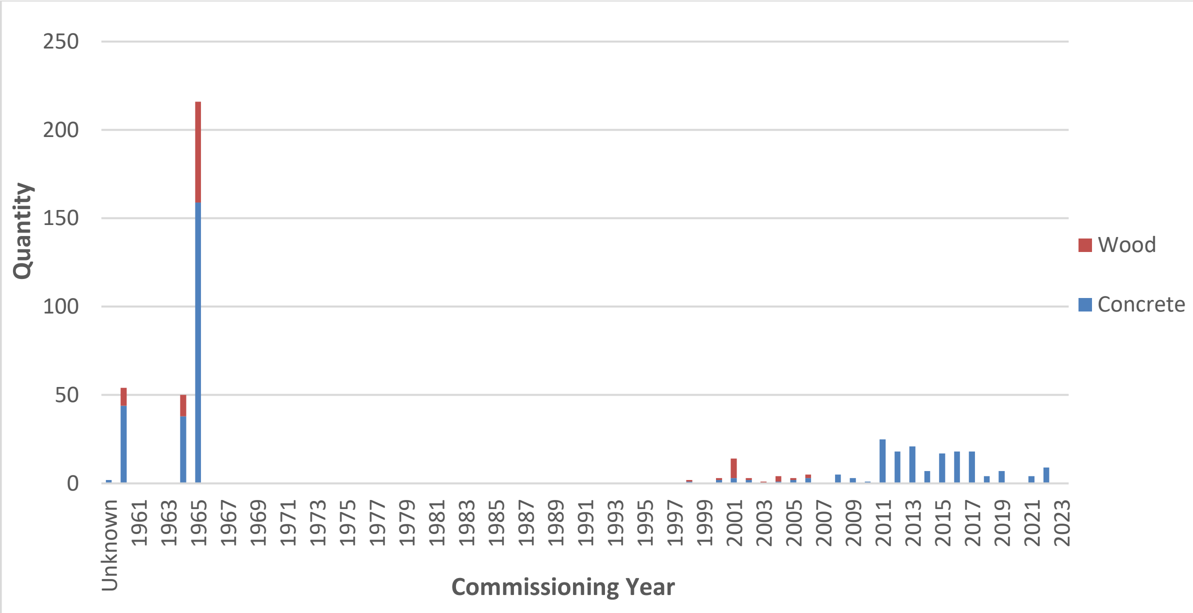
Table 15: Distribution network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Spey Street	-	54.8	6663	124/km
Leven Street	4.8	29	2048	62/km
Racecourse Road	3.1	26.7	3171	109/km
Southern	1.6	38.6	4648	118/km
Bluff – EIL feeders	13.2	5	1065	60/km
Total/average	22.7	155	17,595	95/km

Overhead Distribution

EIL's overhead distribution network uses a mix of concrete and wooden poles as shown in Figure 23. Most of the Invercargill network has been undergrounded as part of an extensive undergrounding programme with only a few overhead circuits remaining in industrial areas. The Bluff area remains overhead network, as Bluff's rocky sub-surface makes undergrounding difficult and cost prohibitive.

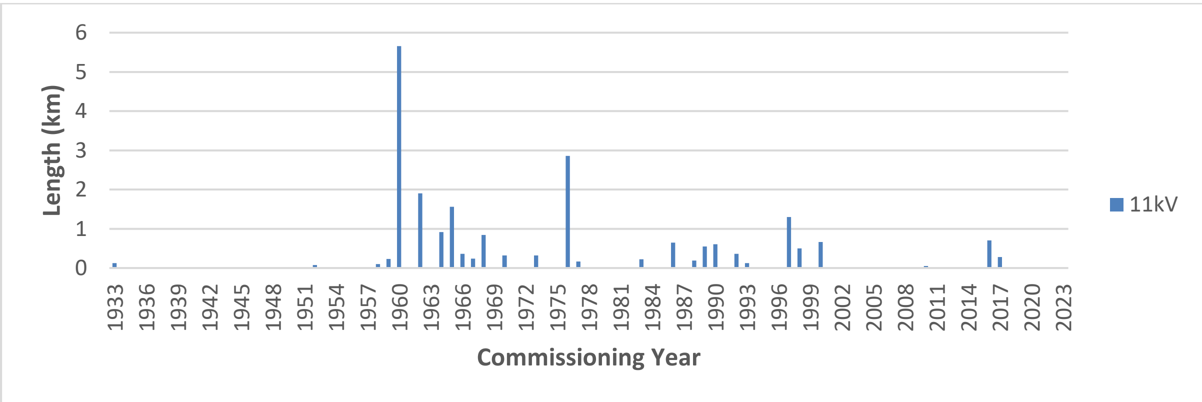
Figure 23: Distribution Poles



The nominal life of poles varies with pole type - 45 years for wooden poles and 60 years for concrete. Industry experience has shown that poles can last substantially longer than nominal life. Therefore, condition-based replacement is more appropriate than age-based replacement. The replacement and renewal programme are based on five-yearly condition assessments carried out on all distribution lines.

The commissioning year for distribution line conductors is displayed in Figure 24. Conductors are generally replaced based on condition determined through routine inspections.

Figure 24: MV Line Conductors (11kV Overhead)

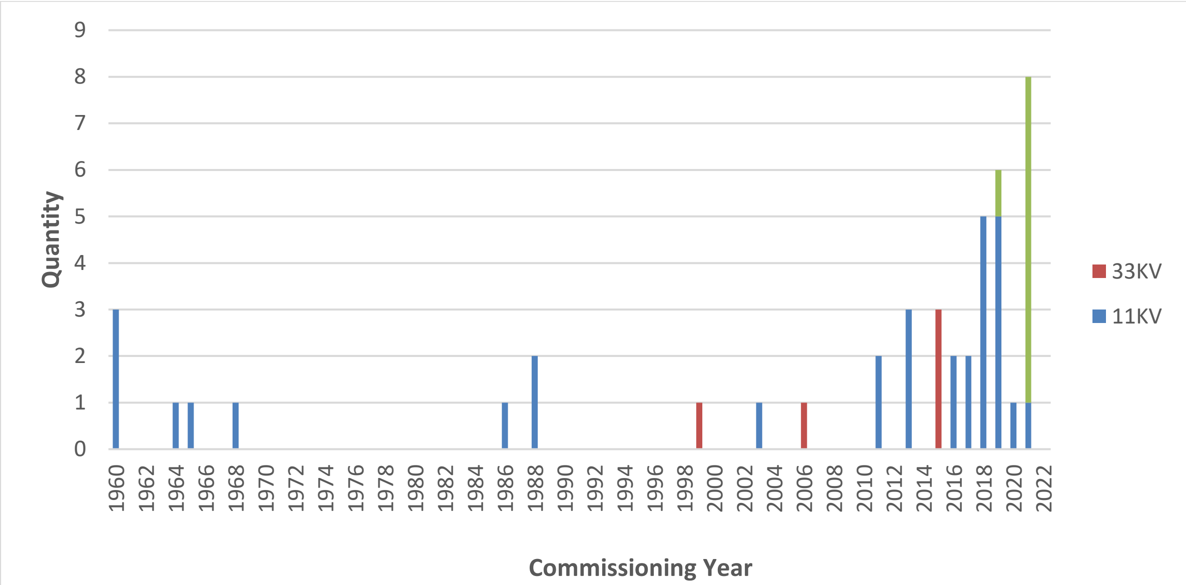


EIL has two 11kV pole mount field circuit breakers and an enclosed load break switch in service on the Bluff area network, located respectively at Gore, Bann and Palmer Streets. This switchgear was installed as part of network automation and reliability enhancements and is detailed as follows:

- The circuit breaker in Gore Street is a Nulec N24 reclosing circuit breaker manufactured in 1997. It was relocated in 2015 to an optimal location. It has minor signs of aging but is in satisfactory condition.
- The Bann Street circuit breaker is a Nova 15 reclosing circuit breaker manufactured in 2006 and kept in spares before being installed in 2015. It is basically in "as new" condition.
- The Palmer Street load break switch is an Entec solid insulation vacuum breaking switch and was installed new in 2015.

Figure 25 shows the number of 11kV and 33kV Air Break Switches (ABS) by commissioning year. Eighteen switches are in service in Bluff.

Figure 25: Air Break Switches

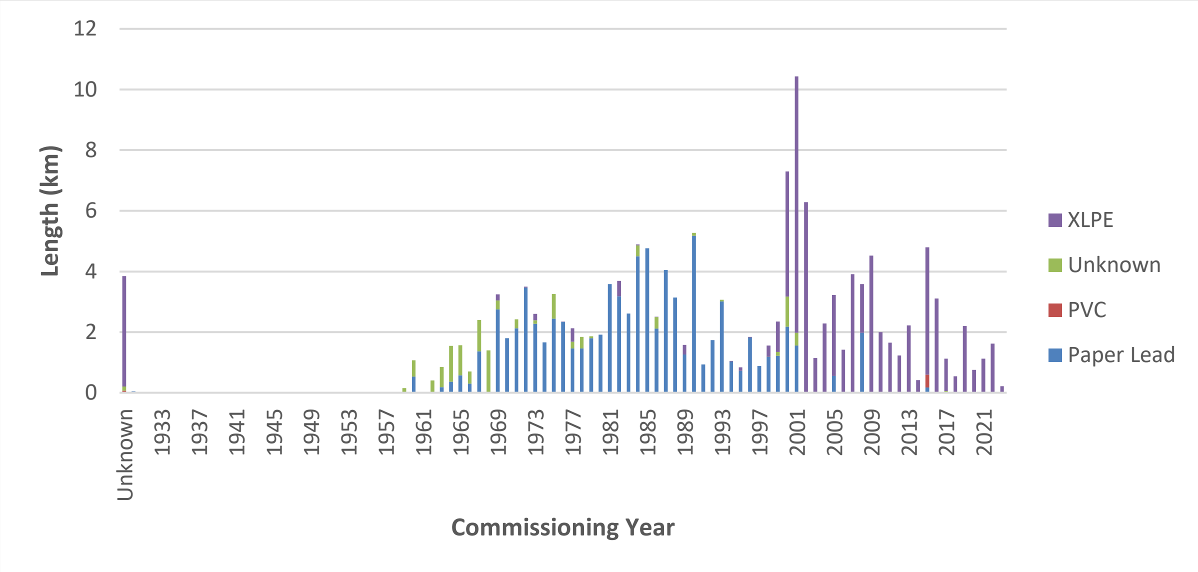


Most of the drop-out fuses on the network have been removed but there are a relatively small number remaining in Bluff. These fuses are most often used where a transformer is supplied from overhead lines.

Underground Distribution

Distribution cables were installed gradually on the Invercargill network as part of an undergrounding programme. Some cables have been installed in Bluff, but the Bluff network remains mostly overhead because the rocky subsurface makes undergrounding work difficult. Figure 26 shows the lengths of cables on EIL's distribution network.

Figure 26: MV Cables (11kV)



Paper lead cables were predominantly used up to about year 2000 after which XLPE became the preferred cable type due to the ease of installation and subsequent works. Actual practical life for any cable is likely to be greater than the standard life. A cable fleet plan has been implemented in late 2022 which requires periodic condition assessment of cables. Planned future replacements will be based on these assessment data.

Distribution Substations

Just as zone substation transformers form the interface between the subtransmission and the 11kV distribution networks, distribution substations form the interface between the 11kV distribution and 400V distribution networks. The distribution substations range from a few remaining pole-mounted transformers to 3-phase 1,000kVA ground-mounted transformers supplied via circuit breaker ring main units that may include remote indication and control. These larger substations typically supply Invercargill CBD customers or special customers like the ILT Stadium.

Distribution Transformers

Each distribution transformer has medium voltage (MV) protection, usually provided by fuses, although some larger units are protected by circuit breakers with basic overcurrent and earth fault relays. Generally individual protection is applied at each site, although occasionally group protection is used where a single fuse is located at the take-off from the main feeder cable, with up to five downstream units permitted. LV protection is by the DIN1 standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

[1] Deutsches Institut für Normung e.V. (DIN; in English, the German Institute for Standardization). This is Germany's national organisation for standardization and an ISO member body.

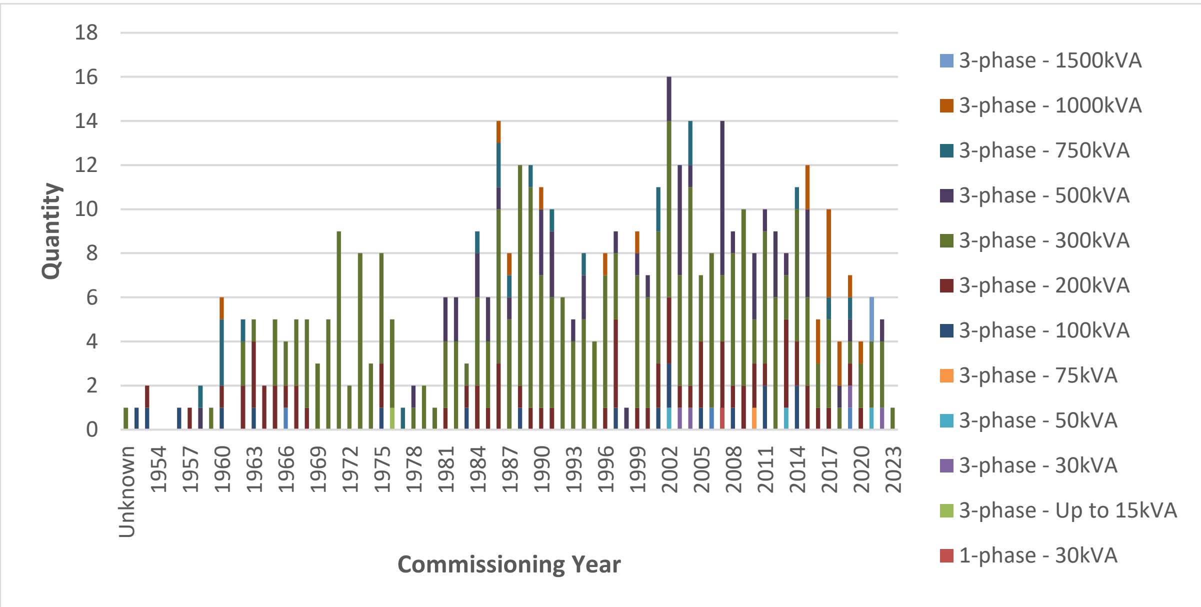
Table 16 shows the number of distribution transformers by size on EIL's network. Transformers larger than 100kVA are installed at ground level, and after the extensive undergrounding programme only a few pole mounted transformers remain.

Table 16: Number of distribution transformers

Phases	Rating	Pole Mount	Ground Mount
1 phase	up to 15 kVA	3	-
	30 kVA	1	-
3 phase	up to 15 kVA	-	1
	30 kVA	-	4
	50kVA	-	3
	75 kVA	-	1
	100 kVA	1	17
	200 kVA	3	65
	300 kVA	3	252
	500 kVA	-	56
	750 kVA	-	20
	1,000 kVA	-	18
	1,500 kVA	-	2
Total		**11**	**439**

Figure 27 provides an overview of the age profiles of distribution transformers. Transformers found to be in poor condition after planned inspections will be replaced, sometimes with units removed from service and refurbished for reuse. Many grounds mounted units are enclosed and the reduced exposure to the weather has kept these transformers in above average condition for their age.

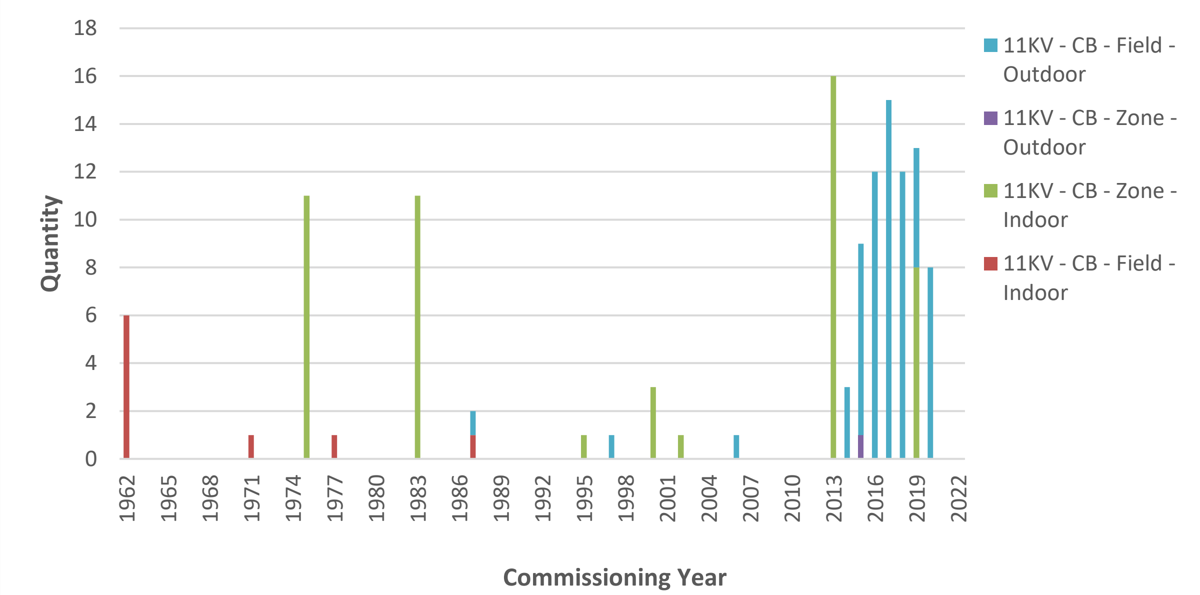
Figure 27: Age Profile of Distribution Transformers



Switchgear

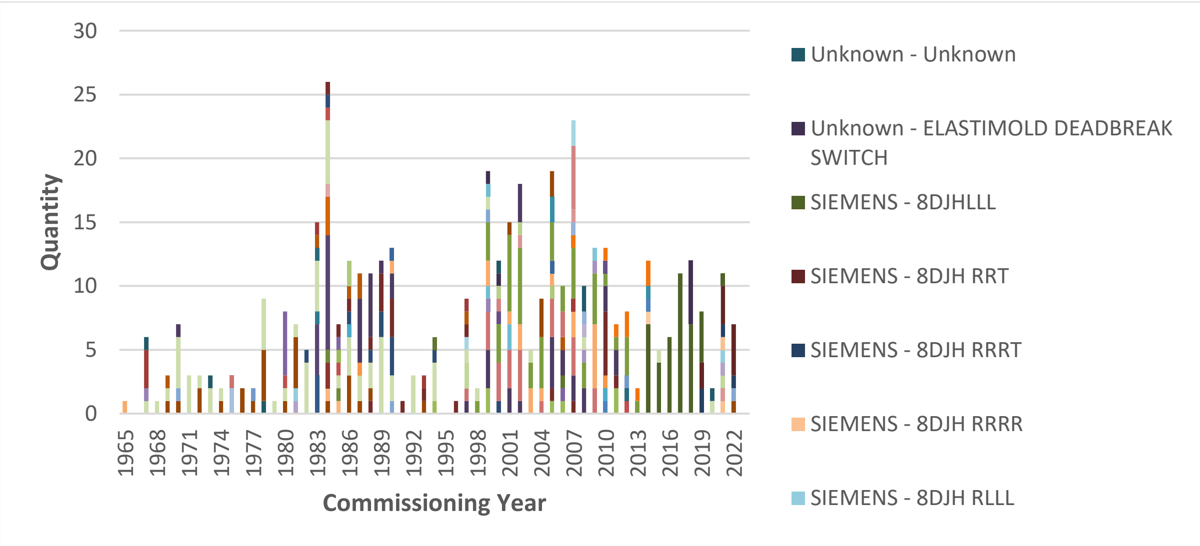
The circuit breakers installed at the distribution substations (which are located within the Invercargill CBD) are shown in the next figure.

Figure 28: Field Circuit Breakers at Distribution Voltage (11kV)



The age profile of ring main units (RMUs) is displayed in Figure 29. It should be noted that the quantities in this graph are expressed in terms of RMU modules – modern RMUs are individual modules sharing a common bus, while some older models of RMU integrate all connections into a single housing.

Figure 29: Age Profile of Ring Main Units



Operating restrictions are placed on some RMU equipment. This is to reduce risks and to manage hazards associated with oil filled switchgear (as identified by incidents occurring in the wider industry).

A solution has been developed that allows safe operation of suitable models of equipment without compromising arc-flash boundaries. A RMU fleet plan was implemented in 2022 which requires periodic condition assessments. Planned future RMU replacements will be based on these assessment data.

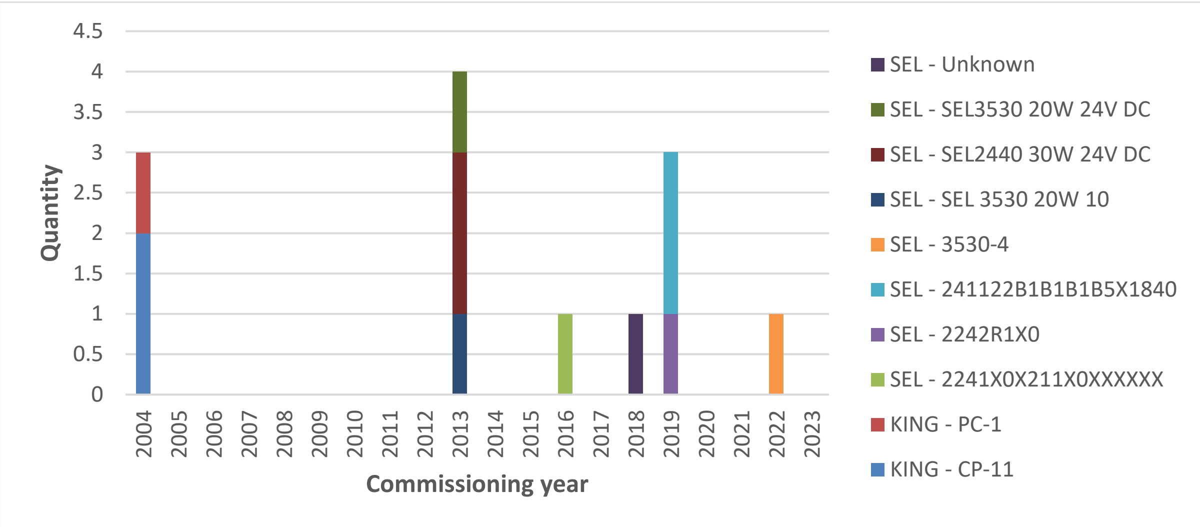
Remote Terminal Units

The early GPT mini RTUs were installed in 1995-98 to automate circuit breakers at distribution substations in the CBD. These units are at end-of-life and have proven unreliable. Replacements are done in tandem with switchgear replacements where most of these RTUs are located.

The Doon Street RTU has been retained to provide indications for the oil filled cables after the decommissioning of the power transformers, 11kV switchboard and associated auxiliary equipment. Another smaller Kingfisher PC-1 RTU was installed in 2004 at a distribution substation in the CBD and will be replaced at end of life.

Two modern SEL RTUs were installed at the Spey St zone substation in 2013 for secure remote indications and control for each half of the AAA security substation. A third SEL unit was installed at Leven St substation in 2016 to replace an end-of-life Harris RTU. An overview of the quantity and commissioning years of RTUs are presented in the next figure.

Figure 30: Number of Remote Terminal Units



LV Network

EIL's LV network (400/230 V) has a total length of 449.6km to supply its 17,664 customers giving an overall customer density of 40 customers per kilometre. The proportions per substation of overhead and underground network, customer count and density are presented in Table 17.

The 230/400 LV network almost totally overlays the 11kV distribution network and is present on virtually every street. The coverage of each individual distribution transformer tends to be limited by volt-drop to about a 200m radius.

The LV network has a moderate degree of interconnection that enables many customer connections to be supplied from "either end" in the event of a transformer failure. Transformer loading and volt drop tend to be the limiting factors in utilising these backups.

The reticulation of Invercargill CBD and most of the suburban areas is underground cable (mostly PVC with some older PILC cables). A couple of areas have overhead lines remaining. Bluff has overhead construction with underbuilt LV reticulation on most 11kV poles. Some undergrounding has occurred in a few locations.

Table 17: LV Network Characteristics per Substation

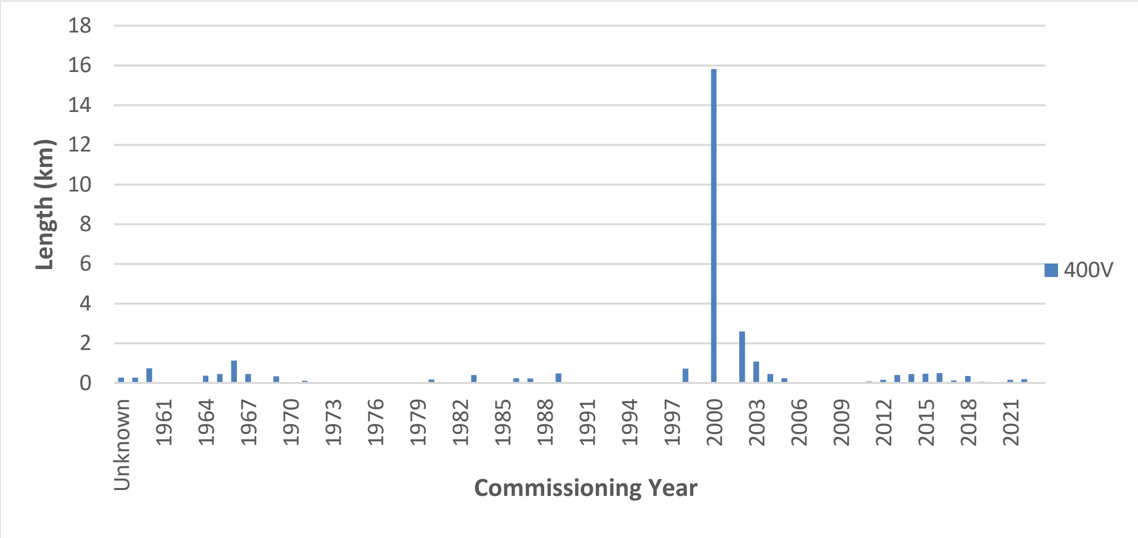
Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Spey Street	0.2	166.4	6663	41/km
Leven Street	3.3	54	2048	37/km
Racecourse Road	0.8	79.1	3171	41/km
Southern	1.2	116.8	4648	40/km
Bluff – EIL feeders	24.7	3.1	1065	39/km
Total/average	30.2	419.4	17,595	40/km

Overhead LV Conductors

EIL's age profile for overhead LV conductors and poles are shown in Figure 31 and Figure 32, respectively. Almost all LV lines in the city have gradually disappeared from the Invercargill network as the services have been undergrounded with less than 6 km line length remaining. Most of the LV line length is on the Bluff area network where undergrounding is difficult due to the rocky subsurface.

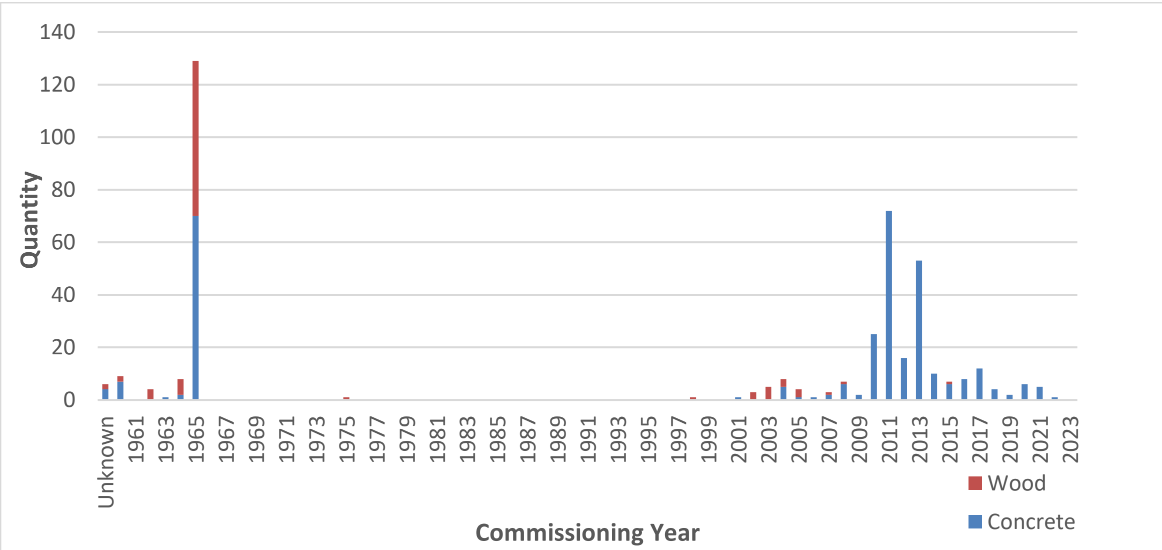
Overhead LV conductors are replaced based on their condition. New overhead lines are ABC (Aerial Bundled Conductors) which do not require cross arms or insulators and has PVC insulation which improve line safety.

Figure 31: Overhead LV Conductors



LV Poles are renewed as required based on their condition as identified during the regular inspections of the network. The number of poles and their commissioning year is presented below.

Figure 32: LV Poles

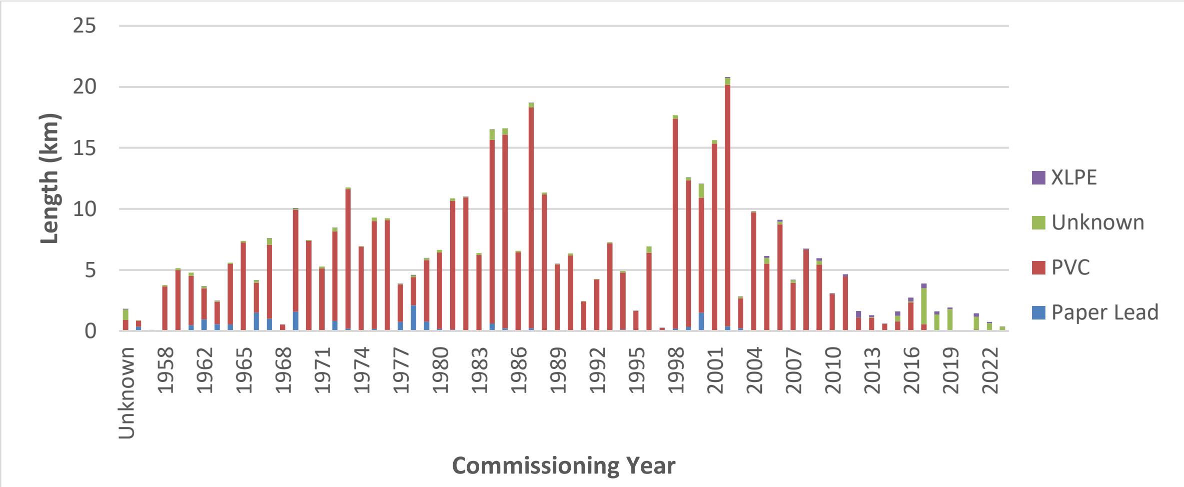


Underground LV Cables

The LV cable commissioning year profile is shown in Figure 33 and shows several assets beyond nominal life. In practice, cables are left in service until performance deteriorates and impacts on service levels.

Several 400 V cables installed in the early 1970s are now reaching capacity due to in-build and greater demand per household. This is typically seen as an increase in voltage complaints received due to excessive volt drop during periods of peak loading. Smart meters installed at customers' premises improve the network's ability to monitor voltage quality and proactively address issues before they are noticed by customers.

Figure 33: LV Cables



Customer Connections

EIL provides a connection to the network via sixteen retailers which convey electricity over the network. Customer connections generally involve assets ranging in size from a simple fuse on a pole or in a suburban distribution pillar to dedicated lines and transformer installations supplying single large customers. There are 17,664 customer connections for which revenue is earned. In most cases the fuse forms the demarcation point between EIL's network and the customer's assets (the "service main") and this is usually located at or near the physical boundary of the customer's property. All "other assets" convey energy to customers and are a cost that must be matched by the revenue derived from customer connections. The number and classes of customer connections are listed in Table 18.

Table 18: Classes of Customer Connections

Date	Small (≤ 20 kVA)				Medium (21 – 99 kVA)				Large (≥100 kVA)			Total
	1 kVA 1ph	8 kVA 1ph	Low User	15 kVA Mixed Phase	15 kVA 3ph	30 kVA 3ph	50 kVA 3ph	75 kVA 3ph	100kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	
Mar-21	49	309	6479	9124	75	654	385	133	74	48	123	17,453
Mar-22	46	311	6386	9275	76	654	390	136	78	41	131	17,524
Mar-23	45	308	6367	9370	79	650	388	137	81	38	132	15,595

Assets for Control and Auxiliary Functions

EIL has a range of other assets to provide control or other auxiliary functions as described in the following tables and paragraphs.

Bulk Supply Assets

The company owns an injection plant at Invercargill GXP which was commissioned in 1989, with all plant enclosed within the building. This provides protection from the elements and therefore an extended life is expected for the non-electronic components. The electronic components continue to provide good service with the power supply unit upgraded in 2005, after failures at other sites. While the plant has reached end of ODV standard life, the 2005 upgrade and the general condition indicate that the plant will last until the completion of smart meter rollout makes it redundant.

Load Control Assets

Load Control Assets	
Ripple Injection Plant and Receivers	EIL currently owns and operates a 33 kV 216⅔Hz 125 kVA ripple injection plant at Invercargill. Ripple relays at customer's premises respond to the injected ripple signal and switch controllable load (such as hot water cylinders and night-store heaters) providing effective load control for the network. The ripple injection plant is backed up from the adjacent TPCL plant and vice versa.

Protection and Control

Protection and Control	
Circuit Breakers	Circuit breakers provide switching and isolation points on the network and generally work with protection relays, to provide automatic detection, operation, and isolation of faults. They are usually spring charged or DC coil operated and able to break full load current as well as interruption of all faults.
Protection Relays	Protection relays have always included over-current and earth-fault functions, but more recent equipment also includes voltage, frequency, directional and circuit breaker fail functionality in addition to the basic functions. SOLKOR differential protection is also used extensively on 11kV cables in the Invercargill CBD. Other relays or sensors may drive circuit breaker operation. Examples include transformer and tap changer temperature sensors, gas accumulation and surge relays, explosion vents or oil level sensors.
Fuses	Fuses provide fault current interruption of some faults and may be utilised (by manual operation) to provide isolation at low loading levels. As fuses are simple over-current devices, they do not provide a reliable earth fault operation, or any other protection function.
Switches	Switches provide no protection function but allow simple manual operation to provide control or isolation. Some switches can interrupt considerable load (e.g., ring-main unit load break switches) but others such as air break switches may only be suitable for operation under low levels of load. Links generally require operation when de-energised, and so provide more economic but less convenient switch points.
Batteries and Chargers	Batteries, battery chargers, and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions and allow continued operation of plant throughout any power outage.
Voltage Regulating Relays	Voltage Regulating Relays (VRRs) provide automatic control of the 'Tap Change on Load' (TCOL) equipment integral to power transformers and regulate the outgoing voltage to within set limits.
Neutral Earthing Resistors (NERs)	Neutral Earthing Resistors (NERs) installed at zone substations limit earth fault currents on the 11kV network. These significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs.

SCADA and Communications

The PowerNet owned SCADA was updated and re-commissioned in 2017. Planned upgrade for Racecourse Road substation in 2023/24 and will be completed in 2024/2025 include communication upgrade to fibre. This will be the last zone substation to be changed over to fibre communications in EIL. The fibre installation project will complete in 2024/25.

SCADA and Communications	
SCADA Master Station	Supervisory Control and Data Acquisition (SCADA) is used for control and monitoring of zone substations and remote switching devices, and for activating load control plant. EIL's SCADA is provided as a service by PowerNet Ltd, with the master station located at Findlay Road GXP with backup at PowerNet office at Racecourse Road. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide full Power Industry functions.
Communication Media	EIL currently owns and operates a fibre optic network to communicate between all zone substations except Racecourse Road substation which is due to be changed in 2023/24 and will finish in 2024/25. Communication is mostly fibre between CBD distribution substations and the SCADA master station at System Control from where control commands may be issued. Mesh radio used for communication to other distribution sites outside the CBD, including Bluff.
Remote Terminal Units	Spey Street zone substation has a modern SEL based RTU. Leven Street and Southern substation RTUs have been upgraded from the older Kingfisher RTUs. Kingfisher RTUs are only used in Doon Street substation and Racecourse Road substation (planned upgrade to new RTU in 2023/24). All RTUs communicate with DNP3.0 protocol.

Mobile Plant/ Load Correction/ Generation

EIL does not own any mobile substations, power factor correction plant, mobile generation, or standby generation plant; however, PowerNet own three mobile diesel generators rated at 500 kW, 350 kW and 275 kW which EIL utilise to maintain supply to customers when assets are removed from service for maintenance.

Other Assets	
Generation	EIL do not own any mobile generation plant but may utilise three diesel generators owned by PowerNet. These are rated at 450 kW, 350 kW and at 220 kW. There are no stand-by generators owned or able to be utilised by EIL.
Power Factor Correction	Customers are required to draw load from connection points with sufficiently good power factor to avoid the need for network scale power factor correction. As such EIL does not own any power factor correction assets.
Mobile Substations	EIL can utilise a TPCL owned trailer mounted 3 MVA 11kV regulator and circuit breaker with cable connections though it is unlikely to be required due to the excellent backup capability of the 11kV network. EIL can utilise a TPCL owned trailer mounted 5 MVA 33/11kV mobile substation with cable connections.
Metering	Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

3.2 Load Characteristics

Load profiles for domestic households and the CBD are described in the following paragraphs.

Domestic Load Profiles

Standard household demand peaks in the morning (10:30am) and evening (6:30pm). The use of heat pumps is increasing electricity usage, with no noticeable impact over the summer hot period yet. Peaks normally occur in the winter months as heating requirements increase. A typical daily domestic load profile and a typical annual domestic load profile are shown in Figure 34 and Figure 35, respectively.

Figure 34: Domestic Feeder Daily Load Profile (July, Racecourse Road CB8)

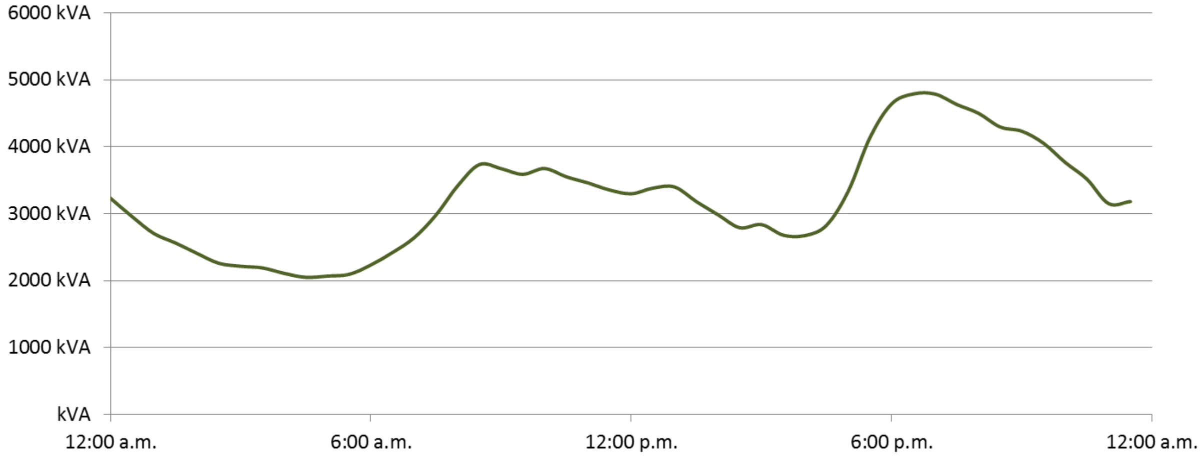
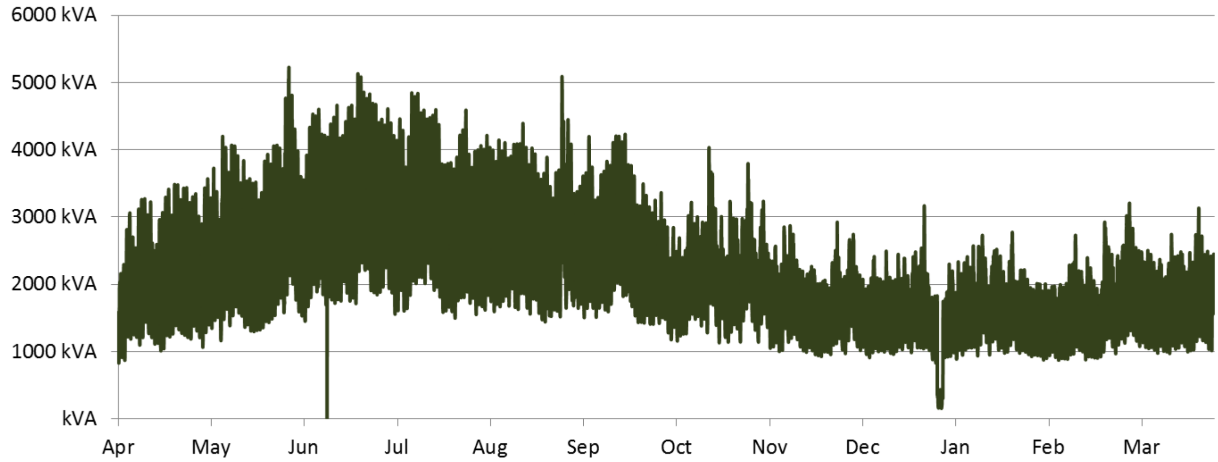


Figure 35: Domestic Feeder Yearly Load Profile (Racecourse Road CB8)



CBD Load Profiles

Load peaks in the CBD later in the day (10am-12pm) as people migrate into the area for their workday. Weekday loading is typically significantly higher than over the weekends corresponding to work patterns of the businesses in the CBD. Seasonal variation in the CBD load profile is similar to that of domestic loading with peak load occurring over the winter months. The CBD profiles shown in Figure 36 and Figure 37 include some industrial load which tends to follow similar consumption patterns.

Figure 36: CBD Feeder Daily Load Profile (July, Leven Street CB10)

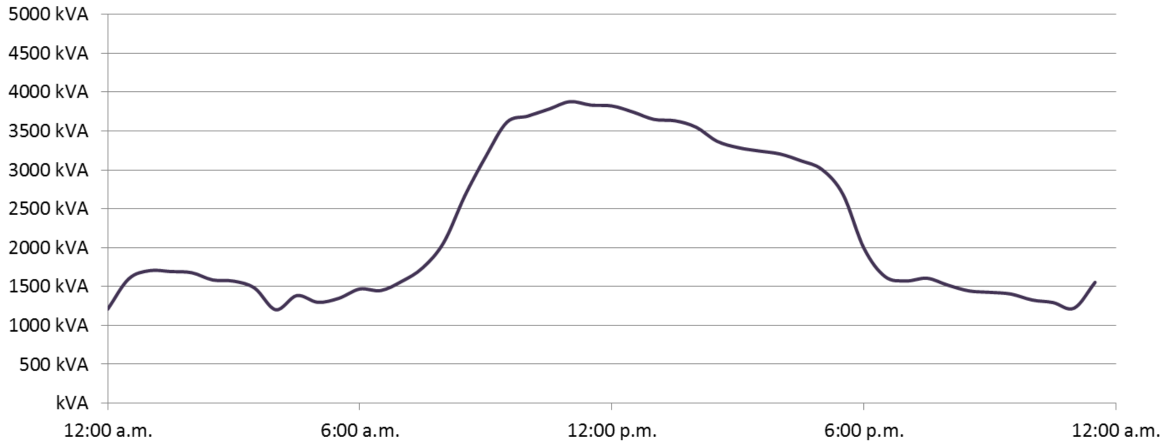
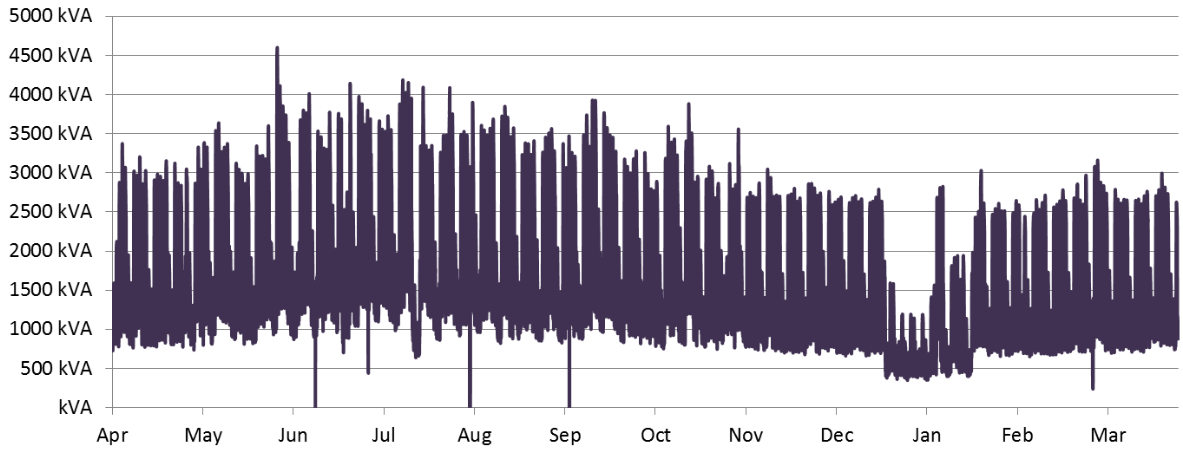


Figure 37: CBD Feeder Yearly Load Profile (Leven Street CB10)



Energy and Demand Characteristics

Key energy and demand values for the year ending 31 March 2023 are presented in Table 19.

Table 19: Energy and Demand Values

Parameter	Value	Long-term trend
Energy Conveyed	240 GWh	Variation around minimal growth
Maximum Demand[2]	64 MW	Large variation around minimal growth
Load Factor	43%	Reasonably constant
Losses	3.2%	Varying

[2] This is different from the sum of the individual demands at each GXP, which will be greater than the coincident demand due to diversity.

Maximum demand and total energy conveyed (as recorded for any year) are greatly affected by the weather and determining growth rates from this historical data is challenging. Mathematical treatment such as "best fit" curve application yields completely different results when applied to different past time periods, for instance five (5), ten (10) or twenty (20) years. Shorter time periods give variable results due to the large influence of each calendar year, while longer time periods do not account for recent trends. Growth rates are often based on an educated estimate from the planning engineer and confidence in the growth rates shown in Table 19 is low.

4 Risk Management

In this AMP, risk is defined as any potential but uncertain occurrence that may impact on EIL's ability to achieve its objectives and ultimately the value of its business.

EIL is exposed to a wide range of risks and utilises risk management techniques to keep risk within acceptable levels. This section examines EIL's risk exposures, focussing on the asset management risks. It describes the management of these exposures and activities to reinstate service levels should disaster strike.

4.1 Risk Strategy and Policy

"Understand and Effectively Manage Appreciable Business Risk" is a key corporate strategy and critical business task within EIL. As such, EIL's asset management strategies (directly or indirectly) also incorporate risk management.

PowerNet developed a risk management policy that informs the risk management framework to formalise the practices for the effective management of risks that EIL's business faces. The policy was approved by the PowerNet and EIL Boards. This ensures greater consistency in the quantification of various risks and correct prioritisation of their mitigation, as well as ensuring regularity of review. The framework is consistent with the ISO Standard ISO 31000:2018 Standard: Risk Management - Guidelines.

4.2 Risk Management Methods

PowerNet's risk management methods are used to manage EIL's risk to acceptable levels. Decision making related to EIL's asset management risks is guided by the following principles.

- Risk plans will in general only focus on one major event occurring at any given time.
- Safety of the public and staff is paramount.
- Essential services are the next priority.
- Large impact work takes priority over smaller impact work.
- Switching to restore power supply takes priority over repair work.

Risk Identification

Risks need to be identified before they can be mitigated. Many risks might seem obvious, yet the identification of other ones require experience and insight into the many factors that could have a significant impact on business objectives. The following risk categories have been established to ensure that various risk types are considered, and review responsibility be allocated to the applicable manager.

- Health and Safety.

- Environmental.
- Financial.
- Network Performance.
- Operational Performance.
- Reputation.
- Governance.
- Regulatory Change and Compliance.

This top-down approach is supplemented by a less formal bottom-up process where staff are encouraged to consider and report any risks as they become evident. The Health and Safety category is an exception as a formal policy exists to ensure as many incidents as possible are proactively reported (including near hits) to help identify hazards and control measures as a priority.

Risk categories are reviewed when there is a change in perception of the risks that EIL faces, especially following events which may affect local networks, other catastrophic events which might have global impact, or a change in regulations which may require risk to be considered in greater detail.

Risk Quantification

Once a risk has been identified it is quantified by determining the following.

- The severity of consequences associated with the risk.
- The probability that the consequences will manifest.

These factors are categorised using relative terms as indicated in the following tables to encourage an intuitive assessment of consequence and probability. This categorisation also allows for the use of more robust calculations where practical (especially regarding probability).

Table 20: Consequence Descriptions

Consequence	Description
Insignificant	Operational impact easily handled through normal internal control processes
Minor	Some disruption possible; able to be managed with management input
Moderate	Significant disruption possible; managed with additional management input and resources
Major	Business operations severely damaged or disrupted; requires extraordinary management input and resources
Extreme	Disaster; extreme impact on staff, plant, and/or operations

Table 21: Event Consequence Categorisation

	Consequence				
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Health and Safety	First aid treatment	Medical treatment injury or illness	Lost time injury or illness	Serious permanent disabling injury/illness	Fatality/fatalities
Environmental	Reversible impact, addressed immediately, remediated < 24 hours	Reversible impact, addressed short term, remediated < 1 week	Reversible impact, addressed medium term, remediated < 1 month	Long term recovery typically taking years	Irreversible widespread damage to environment
Financial	Asset impact of < 0.1% or revenue impact of < 0.1%	Asset impact > 0.1% and < 0.2% or revenue impact > 0.1% and < 1%	Asset impact > 0.2% and < 1% or revenue impact > 1% and < 10%	Asset impact > 1% and < 20% or revenue impact > 10% and < 50%	Asset impact of > 20% or revenue impact of > 50%
Network Performance	Exceeding SAIDI/SAIFI limits during a year, actively managing performance	Exceeding SAIDI/SAIFI limits during year, increased management effort and intervention required	Recoverable and explainable breach of SAIDI or SAIFI regulation (no underlying asset condition issues)	Significant breach of SAIDI/SAIFI regulations triggering investigation and penalties (underlying systemic asset condition issues)	Ongoing repeated significant breaches resulting in loss of control of AMP programme due to regulatory intervention
Operational Performance	Operational impact easily handled through normal internal control processes	Some disruption possible; able to be managed with management input	Significant disruption possible; managed with additional management input and resources	Business operations severely damaged or disrupted; requires extraordinary management input and resources	Disaster; extreme impact on staff, plant, and/or operations
Reputation	Social media attention - one-off public attention	Attention from recognised regional media - short term impact on public memory	Ongoing attention from recognised regional media and/or regulator inquiry	Attention from recognised national media and/or regulator investigation - medium-term impact on public memory	International media headlines and/or government investigation - long-term impact on public memory

	Consequence				
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Governance	Board awareness	Board and shareholder awareness	Perception of systematic underperformance, shareholder concern	Ongoing shareholder dissatisfaction	Dysfunctional governance - major conflicting interests or fundamental change in governing board of directors
Regulatory Change and Compliance	Audit provisional improvement notice	Minor non conformance	Breach with risk of prosecution or emerging regulatory change with potential to affect business	Prosecution of Director and/or officers or regulatory change enacted	Breach resulting in imprisonment of Director and/or officers or appointment of statutory board to a network or impact of regulatory change resulting in complete business transformation

Table 22: Event Probability Categorisation

Likelihood	Description	Frequency
Almost Certain	The consequence is expected to occur in most circumstances	Occurs three times or more per year
Likely	The consequence has a reasonably high chance of occurring in many circumstances	Occurs once or twice per year
Possible	The consequence could conceivably occur in some circumstances	Typically occurs in 1-10 years
Unlikely	The consequence is unlikely to occur in most circumstances	Typically occurs in 10-100 years
Rare	The consequence would occur only in exceptional circumstances	Greater than 100-year event

Risk Ranking

Consequence and probability provide an overall measure of a risk. The risk matrix in Table 23 indicates how these factors can be combined to present a relative risk level.

Table 23: Risk Ranking Matrix

		Consequence				
	Risk Rating	Insignificant	Minor	Moderate	Major	Extreme
Likelihood	Almost Certain	3	4	6	7	8
	Likely	3	3	5	6	7
	Possible	2	3	4	5	7
	Unlikely	1	2	3	4	6
	Rare	1	1	2	3	5

The figures in the cells in the table indicates the relative risk level.

The risk matrix inherently recognises High Impact Low Probability (HILP) events and gives them a high-risk level ranking so that they receive appropriate attention as described below.

Table 24: Management attention to risk rankings

Low	Medium	High	Critical
Risk managed through routine management/internal control procedures	Risk to be reported to relevant manager, may require additional risk treatment actions	Risk to be reported to chief executive and senior leadership team to approve and monitor risk treatment actions	Risk to be reported to the board to approve and monitor risk treatment actions
Levels 1 & 2	Level 3	Level 4 & 5	Level 6, 7 & 8

Risk Treatment and Mitigation

Risks can often not be eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment measures. Often several treatment options are available, and each is likely to have different cost, effort and timeframes associated. Furthermore, each treatment option could be more or even less effective than another option. Treatment options are not necessarily mutually exclusive and may be used in combination where appropriate. Table 25 summarises the types of treatment options that are considered for any risk. These options are ordered by effectiveness for the control of risk.

Table 25: Options for Treatment of Risk

Option	Description
Terminate	Deciding not to proceed with the activity that introduced the unacceptable risk, choosing an alternative more acceptable activity that meets business objectives, or choosing an alternative less risky approach or process.

Option	Description
Treat	Implementing a strategy that is designed to reduce the likelihood or consequence of the risk to an acceptable level, where elimination is excessive in terms of time or expense.
Transfer	Implementing a strategy that shares or transfers the risk to another party or parties, such as outsourcing the management of physical assets, developing contracts with service providers, or insuring against the risk. The third-party accepting the risk should be aware of and agree to accept this obligation.
Tolerate	Making an informed decision that the risk rating is at an acceptable level or that the cost of the treatment outweighs the benefit. This option may also be relevant in situations where a residual risk remains after other treatment options have been put in place. No further action is taken to treat the risk; however, ongoing monitoring is recommended.

Good risk management recognises that limited resources are available and that not all risks can be effectively mitigated immediately. The desired outcome for risk treatment is the lowest-cost option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe. A low-cost option providing very effective mitigation compared with a higher cost option providing less effective mitigation might be an obvious choice but deciding between high cost but effective treatments and low cost, but less effective risk treatment options may be difficult and requires careful evaluation of all factors involved.

Depending on the magnitude of risk identified a large-scale programme may be initiated to quickly reduce risk. Often asset management related risks will have mitigating solutions that become a part of design standards used on the network. The level of risk will determine if standards are retrospective i.e., applied to shape the existing network rather than only applying to new assets installed.

Effective risk management requires prioritisation of the many risk reduction actions identified and to do this the "*greatest risk reduction utilising available resources*" is used as a guiding principle. Appropriate resourcing needs to be considered and adjustment of available resources may be required to control risk appropriately. This is explicitly recognised as part of the Health and Safety at Work Act where sufficient resources to reduce hazards "*as far as reasonably practicable*" must be provided.

PowerNet has developed and operates a Business Continuity Plan that gets activated in the event of a significant risk materialising. This plan is being updated to utilise the national Coordinated Incident Management System (CIMS) (3rd edition). CIMS represents New Zealand's official framework to achieve effective co-ordinated incident management across responding agencies. A number of the Senior Leadership Team members and staff have been trained in CIMS to manage the Business Continuity Team should any such events occur. Training is continuing to ensure sufficient resources will be available in any high-risk event. The Business Continuity Plan is tested on a regular basis using real life scenarios to ensure that it functions effectively. CIMS will also be activated at a regional or national level should a High Impact, Low Probability event affecting more than just the network occur.

Company related risks (general)

Significant company related risks that were identified are described in the next paragraphs.

Cyber Security

Cyber security events were detected, and intentional damage was prevented by the IT security systems. There is however a notable increase in these types of events. Staff awareness has been raised through regular testing of staff.

The detected events were targeting the corporate systems and not the operational systems. The SCADA systems would be of particular concern. However, these systems are stand-alone systems with limited connectivity to outside systems and regular penetration checks are done to ensure that the systems remain secure.

Industry Regulation

Risks pertaining to industry regulation have been identified as the following.

- Investment – providing business processes that ensure appropriate contracts and guarantees are agreed prior to undertaking large investments.
- Loss of revenue – loss of customers through by-pass or economic downturn could reduce revenue.
- Management contract – failure of PowerNet as EIL's asset manager.
- Regulatory – failure to meet regulatory requirements.
- Change in central government policy on any number of industry related issues:
    - Decarbonisation
    - Industry structure
    - Electricity pricing, etc.

International Labour Market

Internationally many economies are hovering on the brink of a major recession. Interest rates are generally at the highest level in decades. Governments are trying to mitigate the effects of the economic conditions by spending more money on infrastructure. In addition, there is an increase in capital expenditure to try and keep climate change under control. A high percentage of the increased expenditure is energy sector related, increasing the demand for competent staff in all worker categories.

Staff working on the EIL network is being approached and offered sometimes significant increases to move to other utilities in New Zealand but also Australia. This leads to:

- Unavailability of Field Staff required to undertake operation, maintenance, renewal, up-sizing, expansion, and retirement of network assets.
- Unavailability of other technical staff such as engineers and project managers that must plan and manage the work issued to the field staff.

Increases in the cost of equipment

A significant percentage of material and equipment used in the electricity supply is imported. Equipment prices are still rising at higher than CPI, driven by national and international supply and demand. Demand is driven by international and national decarbonisation initiatives. Manufacturers are also operating in an environment where covid still affects their supply of labour and many factories are not able to operate at full capacity. This leads to increased equipment prices.

War in the Ukraine

Although the war in the Ukraine is not directly affecting EIL, it has led to cost increases, especially in the price of fuel. These increases flow through to the cost of work. Given the revenue cap under which we operate which influences the amount of money we can spend, any cost increase negatively affects the volume of work that can be done.

Conflict in Gaza

At the time of writing the effects of the conflict in Gaza is still unknown, but it has the potential to affect the supply of crude oil, should the conflict escalate.

Table 26: Industry Regulation Risks and Responses

Event	Likelihood	Consequence	Responses
Uncompetitive Return on Investment	Likely	Major	• Cut cost to a level where reliability of supply will not materially deteriorate but will also not improve.
Failure of the Management Contract	Rare	High	• Continue managing the management contract with PowerNet; noting that it operates a Business Continuity Plan • PowerNet investment in improving its business management systems and processing
Regulatory breaches	Unlikely	High	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to a Business Continuity Plan.
Inadequate Resource to execute required work	Likely	High	• PowerNet utilises internal staff allowing effective planning and management of recruitment training and retention of skilled staff. • Endeavour to provide a reasonably constant stream of work for key external contractors to assist in their continued viability.

4.3 Asset Management Risks

The following extract from the corporate risk register indicates risks specifically relating to Asset Management.

Table 27: Asset Management Risks

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Network Performance	**Failure of Asset Lifecycle Management**	Inadequate network planning; Safety in Design principles not incorporated in designs; incorrect materials and equipment utilised; poor workmanship in building of assets; incorrect commissioning; ineffective fleet plans; budget constraints; incorrect disposal of assets.	Reliability Collapse/fall; Voltage limits not maintained; Safety compromised; mechanical or electrical failure; ineffective maintenance and operations leading to loss of value; networks cannot supply future loads; environmental issues	Treat	Implement AMMAT improvements towards ISO 55001 certification; Ensure SiD process is followed; competency framework and resourcing; robust fleet plans; commissioning process; incident investigations; business management framework
Network Performance	**Operational systems failure due to breakdown in telecommunications**	SCADA communications has one centralised communications point that all information is passed through.	Loss of SCADA would require resorting to manual oversight of the networks	Treat	3 yr. Project underway to provide further links - due for completion 2023. Use of external service providers until own network is fully developed
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism	Damage to equipment; Compromise or damage to systems/data; requirement for change in network configuration; SAIDI/SAIFI Impacts; Reputational Impacts	Treat	Programme to replace locks and improve security underway; maintain fencing
Network Performance	**Loss of right to access or occupy land**	Easements not acquired timeously; change in land use rights; change in legislative requirements	Risk of assets losing / not having the right to occupy locations (e.g., Aerial trespass, subdivision); objection of landowner where line is over boundary; Demand for removal of assets and/or legal action	Tolerate	Easement process incorporated into project stage gate processes
Operational Performance	**Damage due to extreme Physical Event (i.e.,**	Damage caused by force majeure to our infrastructure or	Limited staff, facilities or equipment available due to	Treat	Completion of seismic strengthening; Design of

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
	Christchurch earthquake)	equipment (e.g., floods, earthquakes)	access issues; safety compromised; SAIDI/SAIFI impact; loss of assets		networks to avoid high event probability areas
Operational Performance	**Full sector reputation damage**	Loss of stakeholder confidence due to nationwide issues	Significant dissatisfaction with electricity industry due to adverse impacts for customers, such as price shock through changes in sector pricing. Could be triggered by electricity shortage, change in pricing methods impacting on specific customer groups	Treat	Participate in industry forums such as ENA, EEA etc. Ensure that we give feedback to government on issues when we have the opportunity.
Operational Performance	**Potential liability for private lines and connections**	Regulatory change; Poor historical process/records	Obligation to maintain assets vested in the network; Fatality with some repercussion for PowerNet - legal advice has not been tested in court	Treat	Association to ENA and MBIE: *(they have been reviewing thesituation with aim of a consistent industry solution)*
Operational Performance	**Major Contractual Breach**	Insufficient resources to fulfil contractual obligations; difference in interpretation of contractual obligations; non-standard contracts	Breach of agreement results in loss of ability to continue to provide the service. This results in a significant reduction in value the business; legal action with potential serious financial implications and/or reputational damage	Treat	Effectively manage all contracts we enter into; ensure resources are available before entering into a contract; charter for the contract; utilise standard suite of contracts
Operational Performance	**Unavailability of critical spares**	Poor future work planning; High impact low prob; ability events causing high spares usage; Supply chain disruptions due to	Inability to supply	Treat	Review critical spares process; Stocktake critical spares; Record spares in Maximo; Education of staff on spares process

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
		covid or other factors			and locations; Comparison of existing assets to critical spares (and update with changes to the network)
Operational Performance	**Loss of key critical service provider**	Economic environment; Lack of sufficient work to sustain contractors; unexpected inability of contractor to complete work; Major health event/pandemic	Inability to build or maintain assets; Unable to service existing contracts	Treat	Improved identification of critical suppliers; Identify alternative suppliers; Diversify the workforce; Internalise and grow internal workforce; Diversify into new markets (create a larger pool)
Operational Performance	**Major event triggering storm gallery activation**	Wind, snow, storm or other events causing significant network disruption events	Delayed or limited provision of power to customers; Loss of ability to provide power to customers for extended periods; safety compromised	Treat	Develop improved contingency plans for network events; Implementation of CIMS
Financial	**Change to EDB Environment**	External decision makers trigger industry disruption and change; Regulatory intervention in industry structure and/or economic return framework	Forced amalgamation of EDBs with asset value and sales transaction set/influenced by third parties with risk of significant shareholder value destruction	Treat	Ensure that we develop the systems and processes that will make us a leading EDB and put us in a position to be the lead party in any restructure.
Regulatory Change & Compliance	**Gaps or breaches in Industry regulation**	Changes to the industry environment result in uncertainty of accountability and authority to operate	Ability to operate in part of the industry restricted or removed due to regulatory gap, for example, own / operate new technology and gain value from that opportunity	Tolerate	
Health & Safety	**Public encountering live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Serious injury or fatality; Prosecution under H&S Act	Treat	Asset Lifecycle risk management; Increase public awareness through various media; Asset design and operation

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach; unsafe disposal of assets	Breaches of environmental legislation Cost of rehabilitation	Treat	Design standards take environmental risk into account Asset do not contain hazardous substances or hazardous substances are controlled

Asset management risks are in the categories of Network and Operational Performance, Health & Safety and Environmental. These risks can partly or in full be addressed through the asset management system. A summary of the risk assessment under each of these categories is described in the next paragraphs.

Network and Operational Performance

The following network and operational performance risks were identified, and the quantification and treatment responses are summarised in Table 28.

- **Equipment Failures** – equipment failures can interrupt supply or prevent systems from operating correctly, e.g., failure of a padlock could allow public access to restricted areas.
- **Fire** – transformers are insulated with flammable mineral oil and buildings contain combustible materials. Fire could be triggered by internal or external sources and will impact electricity supply.

Table 28: Risks Associated with Equipment Failures

Event	Likelihood	Consequence	Responses
33 kV & 66 kV Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by ringed sub transmission or through the distribution network. • All new lines designed to AS/NZS 7000:2016
Power Transformer	Unlikely	Low to medium	• At dual power transformer sites, one unit can be removed from service due to fault or maintenance without interrupting supply. • Continue to undertake annual DGA to allow early detection of failures. • Relocate spare power transformer to site while damaged unit is repaired or replaced.
11 kV Switchboard	Unlikely	Medium	• Annual testing including PD [3]and IR[4]. • Replacement at end of life and continue to provide sectionalised boards. • Able to reconfigure network to bypass each switchboard.

3 PD = Partial Discharge, indication of discharges occurring within insulation.

4 IR = Infrared, detection of heat of equipment that highlights hot spots.

Event	Likelihood	Consequence	Responses
11 kV & 400 V Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by meshed distribution network.
Batteries	Unlikely	Medium	• Continue monthly check and six-monthly testing. Dual battery banks at critical sites.
Circuit breaker Protection	Unlikely	Medium	• Continue regular operational checks. • Engineer redundancy/backup into protection schemes. • Regular protection reviews. • Mal-operations investigated.
Circuit Breakers	Unlikely	Low	• Backup provided by upstream circuit breaker. • Continue regular maintenance and testing.
SCADA RTU	Unlikely	Low	• Monitor response of each RTU at the master station and alarm if no response after five minutes. • If failure then send faults contractor to restore, if critical events then roster a contractor onsite.
SCADA Master-station	Very Unlikely	Low	• Continue to operate as a Dual Redundant configuration, with four operator stations. This requires both Servers to fail before service is lost. • Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.
Load Control	Unlikely	Medium	• Provide backup between EIL and TPCL ripple injection plants at Invercargill. • Manually operate plant with test set if SCADA controller fails.
Fire	Very Unlikely	High	• Supply customers from neighbouring substations. • Maintain fire alarms in buildings.

The impact of equipment failure is unpredictable, therefore PowerNet provides a central control room which is staffed 24 hours a day. Engineering staff are always on standby to provide backup assistance for network issues. PowerNet staff and other Contractors provide onsite support for the repair of minor failures. For the repair of medium to large failures or when storms occur, ‘on-call’ PowerNet staff and contractors are available. Inspection results and equipment failures are reported to the Board in the monthly management report.

The following additional network and operational performance risks were identified, and their treatment responses are described in the next table.

- **Animals** – could physically connect with overhead conductors (e.g., birds, possums) or cause conductor clashing (e.g., cattle against stays).
- **Third party accidental damage to network** – e.g., car versus pole, over-height loads breaking conductors. The presence of a pole may also increase the damage done to a car and its occupants if the driver veers off the road.

Table 29: Other Network and Operational Performance Risks

Event	Likelihood	Consequence	Responses
Animal	Highly Likely	Low	• Possum guards all poles • Cattle guards, bird spikes as required
Third party accidental	Possible	High (Safety) Low (Network)	• Design (assets, protection settings) to minimise electrical safety consequences of failure • Underground particularly vulnerable areas • Approval process for railway crossings, etc. • Regular inspections for sag etc. • Protection review and testing • Resource available to bypass and repair.

Health and Safety

Health and safety risks that were identified are listed below with treatment responses indicated in Table 30.

- **Accidental public contact with live equipment** – whether through using tall equipment near overhead lines or through excavating near cables.
- **Step & touch** – faults/lightning strikes causing a voltage gradient, across surfaces accessible to the public, which can cause electric shock.
- **Arc flash** – potential for significant injury to staff from a fault on or near equipment they are using/working on.
- **Underground assets** – safety risks amplified by close proximities and confined space.
- **Staff error** - causing worksite safety risk.
- **Historical assets** - not meeting modern safety requirements.
- **Site security** – unauthorised persons approaching live components through unlocked gate.

Table 30: Health and Safety Risks

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Possible	High	• Public awareness program – social media, radio, print, signage at high-risk areas • Offer cable location service and Before U Dig • Emergency services training • Relocate/underground near high-risk areas e.g., waterways where feasible • Include building proximity to lines in local body consent process • Audit new installations for correct mitigation, e.g., marker tape/installation depth/Magslab for cable • Regular inspections of equipment to detect degraded protection of live parts
Step & Touch	Unlikely	High	• Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2010
Arc Flash	Very Unlikely	High	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations

Event	Likelihood	Consequence	Responses
			• De-energise installation before switching where PPE inadequate
Staff Error	Possible	High	• Standardised procedures • Training • Worksite audits • Certification required for sub entry, live-line work, etc. • Monitor incidents and investigate root causes
Historical Assets	Possible	Medium to High	• Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, check specifications and replace if risk significant
Site Security	Very Unlikely	High	• Monthly checks of restricted sites • Alarms on underground sub hatches • Standardised exit procedures in 3rd party building • Above ground sub clearances to AS2067 s5 • Design to avoid climbing aids etc.
Broken Neutral	Possible	High	• Detection through Smart Meter analysis

Environmental

The following environmental risks have been identified and their quantification and treatment responses are presented in the next tables.

High Impact Low Probability (HILP) Events

- **Earthquake** – no recent history of major damage. The November 2004 **7.2** Richter scale quake 240 km south-west of Te Anau caused no damage to the network. The earthquakes in Christchurch demonstrated that large and unexpected events may occur, and these would have a significant impact on the network.
- **Tsunami** – may be triggered by large offshore earthquake.
- **Liquefaction** – post Christchurch's 22 February 2011 **6.3** magnitude earthquake, the hazard of liquefaction as a risk needs to be considered.

Table 31: High Impact Low Probability Risks

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Very Unlikely	High	• Disaster recovery event. • Projects underway to investigate and improve survivability through large seismic events.
Earthquake (6 to 7)	Very Unlikely	Low to High	• Specify so buildings and equipment will survive. • Review existing buildings and equipment and reinforce if necessary.
Tsunami	Very Unlikely	Low to Medium	• Review equipment in coastal areas and protect or reinforce as necessary.
Liquefaction	Very Unlikely	Low to Medium	• Specify buildings and equipment foundations to minimise impact. • Locate equipment outside of liquefaction zones.

Other Potential Environmental Risks

- Oil spills from transformers or oil circuit breakers

- Release of SF6 into the atmosphere

Table 32: Other Environmental Risks

Event	Likelihood	Consequence	Responses
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met

Weather Related Risks

The following are potential weather-related risks, and their quantification and treatment responses are summarised in Table 33.

- **Wind** – strong winds that either cause pole failures or blow debris into lines.
- **Snow** – impact can be by causing failure of lines or limiting access around the network.
- **Flood** – experience of 1984 floods has caused Environment Southland to install flood protection works, but still need to consider if similar water levels do occur again. Flood prone areas have been identified and is indicated on the GIS system to assist in the placement of new infrastructure.

Table 33: Weather Related Risks

Event	Likelihood	Consequence	Responses
Wind	Possible	Low	• Impact is reduced by undergrounding of lines. • Design standard specifies wind loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements.
Snow	Unlikely	Low	• Impact is reduced by undergrounding of lines. • Design standard specifies snow loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements. • If access is limited then external plant is hired to clear access or substitute.

Event	Likelihood	Consequence	Responses
Flood	Unlikely	Low	• Impact is reduced by undergrounding of lines. • Transformers and switchgear in high-risk areas to be mounted above the flood level. • Zone substations to be sited in areas of very low flood risk.

Resilience

Reliability and resilience are two important but distinct concepts when it comes to electricity distribution networks. They both pertain to the ability of the grid to provide continuous and dependable electric service, but they address different aspects of the network's performance and response to various challenges. Here's an explanation of the key differences between reliability and resilience:

Reliability:

Reliability refers to the consistency and predictability of electricity supply within the distribution network. It focuses on the network's ability to deliver power to customers without frequent or extended interruptions. Key characteristics of reliability include:

- Minimal Outages: A reliable network experiences minimal power outages, and when outages do occur, they are typically short in duration.
- Consistent Voltage and Frequency: Electricity is delivered with stable voltage and frequency, ensuring that it meets the quality and quantity requirements for various electrical devices.
- High Uptime: A reliable grid has a high uptime, which means it operates without significant disruptions for extended periods, providing continuous service to customers.
- Low Frequency of Failures: Infrequent equipment failures, such as transformer or circuit breaker malfunctions, indicate a reliable network.

Resilience:

Resilience, on the other hand, focuses on the grid's ability to withstand and recover from various disruptions, including unexpected events and extreme conditions. Resilience addresses how quickly the network can bounce back from disruptions and continue to provide electricity. Key characteristics of resilience include:

- Rapid Recovery: A resilient network can quickly recover from outages, damage, or disturbances and restore power to affected areas in a timely manner.
- Adaptability: Resilience includes the ability to adapt to changing circumstances, whether it's severe weather, equipment failures, or other unforeseen challenges.
- Redundancy: Resilient networks often incorporate redundancy in their design, allowing for alternative pathways and resources to deliver electricity in case of disruptions.
- Robustness: Resilience involves robust infrastructure and operational practices that can withstand extreme conditions, such as hurricanes, wildfires, or cyberattacks.

In summary, reliability primarily focuses on the prevention of power outages and the consistent delivery of electricity, emphasizing the quality and stability of service. Resilience, on the other hand, focuses on the grid's ability to recover and adapt to disruptions, ensuring that power can be restored quickly after incidents or adverse events. Both reliability and resilience are critical for maintaining a dependable and secure electricity distribution network, and they often go hand in hand to provide a high level of service to customers, especially in the face of changing climate conditions and other external challenges.

A further resilience complication is introduced by decarbonization. The impact of power outages will increase significantly when the society switches from using gas and petrol for transportation and heating to using electricity as the primary source of energy for homes. In contrast, by using their batteries to power essential home appliances, EVs can improve the resilience of their households.

The adoption of any new technology on the distribution network must first be thoroughly examined via the resilience lens. One must allow the failure of communication systems, such as the hot water control system used for emergency load shedding, which is essential to maintaining network security and its recovery after an incident. The operation of these systems would be placed at risk if they transitioned to new technology that was reliant on cell phone networks, due to the inevitable overloading of cell phone networks that occurs following a major event, and the short battery backup times at cell towers. This vulnerability has been demonstrated by the Christchurch and Kaikoura earthquakes, and again during Cyclone Gabrielle. It is essential that telecommunications network operators, as providers of critical infrastructure, adjust their contingency plans to accommodate the long outages on the electrical supply network that can occur during major events, rather than continuing to optimise their systems for business as usual operation.

Climate Change

Climate change is reshaping our planet in profound ways, and one of its less-discussed but critical consequences is the impact on electricity distribution networks. As global temperatures rise and extreme weather events become more frequent and severe, the reliability and resilience of our electrical grids are being put to the test. This article explores the effects of climate change on electricity distribution networks, the challenges it poses, and the strategies being adopted to mitigate these impacts.

Extreme Weather Events

One of the most immediate and tangible effects of climate change on electricity distribution networks is the increase in extreme weather events. Hurricanes, tornadoes, floods, and wildfires have become more common and destructive. These events can damage power lines, substations, and other critical infrastructure, leading to widespread power outages. The cost of repairing and upgrading the grid to withstand such extreme weather is a significant burden on utility companies and, ultimately, customers.

Temperature Extremes

Climate change also brings temperature extremes. Hotter summers and more severe winter storms can strain electricity distribution networks. In hot weather, the demand for electricity spikes due to increased use of air conditioning, potentially overloading the system. During cold spells, heating demands similarly increase. To meet these demands, grid operators must continually adjust generation and distribution, which can stress the infrastructure and raise operational costs.

Sea Level Rise

Sea level rise, driven by climate change, poses a unique threat to coastal electricity distribution networks. Many power stations, substations, and transmission lines are situated near the coastlines. As sea levels rise, these facilities are at greater risk of inundation and saltwater damage. Even minor flooding can disrupt electricity supply and result in costly repairs or upgrades to protect these assets from saltwater intrusion.

Renewable Energy Integration

While renewable energy sources like solar and wind power are essential for mitigating climate change, they also introduce new challenges for electricity distribution networks. These sources are intermittent and variable, making grid management more complex. Climate change can exacerbate this intermittency, affecting the consistency of renewable energy generation. This requires better grid infrastructure and energy storage systems to manage the fluctuations effectively.

Mitigation and Adaptation Strategies

To address the challenges posed by climate change, EIL employs various strategies:

a. Infrastructure Resilience: Reinforcing and upgrading existing infrastructure to withstand extreme weather events.
b. Improved Monitoring and Analytics: Investing in advanced monitoring and data analytics to predict and respond to weather-related disruptions and optimize grid operations. To this effect the deployment of an OMS/ADMS system is under investigation.
c. Renewable Energy Integration: Expanding and modernizing the electricity distribution networks to accommodate the growing role of renewable energy sources, including smart grids and energy storage systems.
d. Disaster Preparedness: Developing robust disaster recovery and preparedness plans to respond quickly to extreme weather events, minimizing service interruptions and recovery costs. To this end, CIMS is being deployed.
e. Public Awareness: Raising awareness among customers about the importance of energy conservation and grid reliability and encouraging energy-efficient practices.

In Invercargill, the summers are cool; the winters are short and very cold; and it is wet, windy, and partly cloudy year-round. Over the course of the year, the temperature typically varies from 3°C to 18°C and is rarely below -1°C or above 23°C.

The warm season starts from 7 December to 19 March, with an average daily high temperature above 16°C. The hottest month of the year in Invercargill is January. The cool season starts from 30 May to 19 August, with an average daily high temperature below 11°C. The coldest month of the year in Invercargill is July. In Invercargill, the average percentage of the sky covered by clouds experiences mild seasonal variation over the course of the year. The clearest month of the year in Invercargill is February, during which on average the sky is clear, mostly clear, or partly cloudy 50% of the time.

Invercargill does not experience significant seasonal variation in the frequency of wet days. The month with the most days of rain alone in Invercargill is May. Rain falls throughout the year in Invercargill. The month with the least rain in Invercargill is August. The length of the day in Invercargill varies significantly over the course of the year. The wind experienced at any given location is highly dependent on local topography and other factors, and instantaneous wind speed and direction vary more widely than hourly averages. The average hourly wind speed in Invercargill experiences mild seasonal variation over the course of the year. Invercargill experiences an average of 109 days per year with wind gusts exceeding 61 km/hr. The windiest month of the year in Invercargill is October, with an average hourly wind speed of 21.0 kilometres per hour. The calmest month of the year in Invercargill is July, with an average hourly wind speed of 18.2 kilometres per hour.

In order to get the region ready for the effects of climate change, utilities and local authorities must coordinate their reaction. To effectively defend the network against these threats, PowerNet is updating its policies and guidelines. PowerNet rules and standards must be closely matched to a cohesive plan throughout, which will necessitate more collaboration with local authorities to comprehend their defence measures and impact revisions to the District Plan. Climate change is having a profound and multi-faceted impact on electricity distribution networks. Extreme weather events, temperature fluctuations, sea level rise, and the integration of renewable energy sources are all challenging the resilience and reliability of the grid. Utility companies and policymakers must work together to implement mitigation and adaptation strategies to ensure a sustainable and secure energy future. As we confront the effects of climate change, our electricity distribution networks must evolve to meet the changing demands of a warming planet.

4.4 System Risks

Existing risks to the electricity system are described in the following sections.

33kV Oil Filled Cables

There is a potential systemic vulnerability in the 33kV oil filled cables which supply Spey St and Southern substations. Similar cables on other distribution companies' networks are showing signs of insulation damage due to weakness in the cable joints allowing movement of the cores with thermodynamic expansion and contraction. The associated reliability risk has been mitigated through ensuring that all oil-filled cables on the network have an alternate supply option through an XLPE cable. Mitigation of environmental and repair risks are under way.

Oil Filled RMUs

Many oil filled RMUs have operating restrictions in place to mitigate safety risks due to arc flashes. Short term solutions were developed for some models of RMU, which allow safe operation without the inconvenience and reliability impact of operating restrictions. Where these solutions are not available or not practical, operation of these RMUs has been suspended. This mitigates the risk to field staff operators, however, in-situ risk to the public remains and the network has reduced capacity to segment resulting in wider outage areas. Longer term management of these issues is likely to require early replacement of many RMUs.

Some models of RMUs have exhibited faster than usual corrosion which is likely to adversely affect the service life of the assets. Repairs will be carried out where economic and practical to do so, but it is expected that many of these assets will need to be replaced ahead of their nominal life, causing their replacement to overlap with the older but sturdier models that preceded them. It is expected that the majority of the “Unspecified Projects” budget in years 6 to 10 of forecast CAPEX will be devoted to RMU and cable replacements.

EIL has experienced water ingress issues with early ABB SD type RMUs that utilise high voltage busbar insulation tape (HVBT) in the bus couplings. All such RMUs had their bus coupling boxes converted to the Guroflex insulating filling compound that succeeded the original HVBT bus coupling kit.

Other Systemic Issues

There are no other systemic issues presently being investigated.

4.5 Asset Criticality

Good practice asset management decisions should not be solely based upon asset health either from condition or non-condition factors. Good practice decision making should also consider the operating context and how failure can affect outcomes such as safety and environment, customer service levels, and lifecycle costs.

The EEA Asset Criticality Guide defines Criticality as “A measure reflecting the relative seriousness of the Credible Consequences of Failure”. The EEA guidelines are not yet fully operationalised within EIL. We do however take the location of assets into account when we make asset management decisions.

The plausible consequence of an asset failure next to a school or public facility is the same as when the same asset would be installed somewhere in a paddock. However, the credible consequence of the asset failure in the first location is much higher than the credible consequence of the asset failing in the second location, so more intensive risk mitigation measures will be applied to the first asset.

PowerNet’s stated intention is to base all asset related decisions on risk (of which criticality is one component). To give effect to this intention, various systems based on the UK Regulator’s (Ofgem) DNO Common Network Asset Indices Methodology. This a comprehensive and common framework of definitions, principles, and calculation methodologies, adopted across all GB Distribution Network Operators, for the assessment, forecasting and regulatory reporting of Asset Risk.

The EEA Asset Criticality Guide draws heavily on the principles embodied in this document.

5 Service Levels

EIL delivers a broad range of services such as capacity, continuity, restoration, ground clearances, earthing, absence of electrical interference, compliance with the District Plan and submitting regulatory disclosures.

This section describes how EIL sets its various service levels according to the safety, viability, quality, compliance, and price objectives that are most important to stakeholders. It details how well EIL is meeting these objectives and what trade-offs exist between differing stakeholders. Considerations include; the desire for Return on Investment (ROI) versus desire for low price with good reliability, safety as priority versus acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance.

Safety is EIL's top priority and is a primary consideration in the AMP. However, safety has always been a key consideration in network design and the residual safety risk that can be addressed through asset management planning is extremely low. Operational factors tend to dominate the year-to-year variation in safety incidents and near hits. Safety KPIs are not presented in the AMP but are available to interested parties upon request.

5.1 Customer Oriented Service Levels

Customer surveys and the outcomes thereof are described in the following section.

Customer Surveys

Annual customer engagement surveys measure customer perceptions around a range of service levels. This involves contacting a large sample of customers telephonically and asking a predetermined set of questions. Research First independently surveys EIL customers and collates the results into a customer satisfaction report for presentation. Research First was also engaged to conduct interviews with major customers to help understand service level requirements and satisfaction with current service levels.

EIL keeps statistics around complaints to measure how often customers experience voltage quality issues. Issues are dealt with at the time of complaint, but these statistics give an indication of how voltage quality and the response services are trending over time. In the last two years, EIL has generally received 10-13 formal complaints, with only a small percentage of them due to voltage issues. The results of these surveys are monitored, and any comments received are reviewed and responded to as appropriate.

Survey results show that customers are mostly happy with the current levels of service and rated EIL high in service response Targeted improvement initiatives could address some expressed dissatisfaction. Based on the 2022 Customer Engagement survey, 88% of customers in EIL indicated that reliability of power supply was good.

Telephonic surveys indicate that customers value continuity and restoration of supply more highly than other attributes such as answering the phone quickly or quick processing of new connection applications. It also appears that customers increasingly value the absence of flicker, sags, surges and brown-outs. Other customer research indicates that flicker is probably more often noticed than causing real inconvenience.

The highly valued services have the following challenges.

- Limited substitutability between services – for example, customers prefer EIL to keep the power on rather than answer the phone quickly.
- Averaging effect - all customers connected to an asset (or chain of assets) will receive more or less the same level of service.
- Free-rider effect - some customers may want to pay for improved service levels, however, all customers would receive the improved service due to their common connection. For example, Invercargill and North Makarewa GXP's are more secure than their size would normally deserve based on the reliability required by the New Zealand Aluminium Smelter at Tiwai point.

We tested EIL customers on their willingness to pay extra in line charges to maintain the same level of reliability of supply. It was found that EIL customers were willing to increase their line charge fees on average 4.11% of to maintain the same reliability of power supply.

Primary Customer Service Levels

As described in the previous section, customers value continuity and restoration most, therefore, these are EIL's primary service levels. EIL uses two internationally accepted indices to measure performance for these service levels.

- SAIFI (system average interruption frequency index) is a measure of how many system interruptions occur per year per customer connected to the network.
- SAIDI (system average interruption duration index) is a measure of how many system minutes of supply are interrupted per year per customer connected to the network.

These indices are also used by the Commerce Commission in their regulation of local EDBs (including EIL). EIL's projections for these measures over the next six-year period ending 31 March 2030 are shown in Table 34: Reliability Projections

The historical SAIDI and SAIFI indices are presented in Table 35: Reliability History as reference.

The calculation methodology of the 2020 Default Price-Quality Path Determination was utilised for the projections. The forecasts include impacts from changing work practices or asset management strategies with average values used to normalise the significant variation due to the random occurrence of a low number of faults and weather impacts which can significantly impact performance each year.

Planned work has less year-to-year random variation, but projections can differ from previous years due to the influence of new initiatives that improve safety yet increase the reliability impact of network maintenance/renewal.

One such initiative which has significantly modified the target SAIDI and SAIFI for planned work is the change in philosophy to complete more RMU and distribution transformer maintenance tasks under planned shutdown instead of LV offloads / generators previously provided for most customers.

The factors considered for the prior to committing to an increase planned outages included:

- RMU and transformer fleets maintenance requirements
- Resourcing constraints
- High cost of keeping customers energised via LV offloads or generators.

The increase in planned work results an increase in the target SAIDI and SAIFI measures to accommodate the higher volume of planned outages for this work. EIL's network reliability has been extremely good due to the underground nature of the Invercargill network. Parts of the underground network are starting to reach end of life, and these are incorporated in the forecasts. Distribution automation can counter some of the effect on SAIDI, but it becomes less cost efficient with higher saturation on the network and is less effective at countering the SAIFI impact of deteriorated equipment. The Reliability forecast has been adjusted to reflect the average performance of unplanned SAIDI and SAIFI in the past 5 years and is expected to stay at this level. The SAIDI and SAIFI forecast is expected to slowly improve as the testing of the cable, remote control of Ring Main Units and installation of fault locators reduce the number of outages and improve the restoration time in the medium to long term.

The treatment of outages that are needed for planned work but where the customer notification timeframes could not be adhered to or where the planned work had to be cancelled is unclear. We have adopted an approach whereby these outages are classified as unplanned outages – cause unknown. This has caused an increase in this reliability category.

Table 34: Reliability Projections

Measure	Class	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
SAIDI	B (Planned)	30.0	32.0	32.0	32.0	32.0	32.0
	C (Unplanned)	20.0	41.0	39.0	38.6	38.2	37.8
	Total	**50.0**	**73.0**	**71.0**	**70.6**	**68.2**	**69.8**
SAIFI	B (Planned)	0.08	0.15	0.15	0.15	0.15	0.15
	C (Unplanned)	0.25	0.70	0.69	0.69	0.68	0.67
	Total	**0.33**	**0.85**	**0.84**	**0.84**	**0.83**	**0.82**

(All figures in this table assume that there will not be any normalisation event days as these are difficult to predict. Historically normalisation varies between 0 and 25% of annual SAIDI)

Table 35: Reliability History

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	B (Planned)	4.42	4.50	1.69	6.58	13.77	28.18
	C (Unplanned)	9.05	22.98	16.29	40.57	35.90	77.06
	Total	**13.47**	**27.48**	**17.98**	**47.15**	**49.67**	**105.24**

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
SAIFI	B (Planned)	0.03	0.02	0.01	0.02	0.08	0.11
	C (Unplanned)	0.26	0.45	0.30	0.89	0.68	1.05
	Total	**0.29**	**0.47**	**0.31**	**0.91**	**0.76**	**1.15**

(All figures in this table are normalised)

The frequency of faults and estimated restoration levels for significant network areas are summarised in Table 36: Expected fault frequency and restoration time

Table 36: Expected fault frequency and restoration time

General location	Frequency of faults	Estimated restoration[5]
Invercargill CBD		
33 kV Fault	One every 15 years	1 min
11kV Fault	2 every year	30 min
Invercargill other than CBD		
33 kV Fault	One every 7 years	15 min
11kV Fault	5 every year	45 min
Bluff		
33 kV Fault	3 every year	1 min
11kV Fault	6 every year	75 min

Surveyed customers in all market segments prefer to pay more or less the same line charges to receive similar supply reliability levels. Table 37: Reliability Thresholds - DPP3 displays the thresholds which the Commerce Commission applied to EIL's reliability performance from 1 April 2020. The following descriptions apply.

Boundary values	Boundary values represent the threshold for normalising major events. If the sum of SAIDI or SAIFI for unplanned interruptions in any 24-hour rolling period (commencing in any half-hour period) exceeds the respective boundary, the contribution to the overall annual SAIDI or SAIFI is capped at 1/48th of that boundary value (for each half hour of the event).
Limit	Limit values are the values set by ComCom for planned and unplanned SAIDI and SAIFI which an EDB shall not exceed. Planned values are set to apply over the five year regulatory period while unplanned values are the annual limits measured in every regulatory year.

Table 37: Reliability Thresholds - DPP3

Index	Class	Target	Collar	Cap	Limit	Boundary	Extreme Event	Incentive Rate (per SAIDI)
SAIDI	C (Unplanned)	15.39	0	25.86	25.86	4.13	120	$ 2,544
	B (Planned)	7.63	0	22.9	114.49 (5-year)	-	-	$ 1,272
SAIFI	C (Unplanned)	-	-	-	0.6956	0.0804	-	-

[5] Except if supplied directly off the faulty section of line or cable.

	B (Planned)	-	-	-	0.5183 (5-year)	-	-	-

Historically EIL's reliability performance was good and the number of annual faults were low. The averaging effects on a random fault pattern were not strong in any particular year. The DDP3 limits apply from 1 April 2020 to 31 March 2025.

The Cap, Target and Collar are used as part of a revenue incentive scheme for improving reliability on the network where it may be cost effective. A total of $94,916 (equivalent to 0.75% of the starting price maximum allowable revenue for the regulatory period) is the "revenue at risk" for SAIDI. For performance at the Target level (which is calculated as average historical reliability levels), there is no adjustment to EIL's revenue. For performance not meeting target, EIL incurs a pro rata revenue loss up to the Cap (limit of acceptable reliability) where the maximum penalty is imposed. Performance exceeding the reliability target leads to a pro rata revenue gain. No losses or gains are achieved for performance beyond the cap or collar.

Secondary Customer Service Levels

Secondary service levels have lower customer satisfaction rankings than the primary attributes of supply continuity and restoration. These attributes include how satisfied customers are with communication regarding tree trimming, connections or faults, the time taken to respond to and remedy justified voltage complaints and the amount of notice before planned shutdowns. Table 38: Secondary Service Level Projections sets out targets for these service levels for the next ten years. Some of these service levels are process-driven which has the following implications.

- Solutions tend to be cheaper than fixed asset solutions. For example, staff could work a few hours overtime to process a back log of new connection applications; an over-loaded phone system could be diverted, or the shut-down notification process could be improved.
- Improved service levels could be provided exclusively to customers who are willing to pay more. This contrasts with fixed asset solutions which will equally benefit all customers connected to an asset regardless of whether they pay.

A developing trend is for large customers doing process heat energy source conversions to request a lower level of security to their plant. This takes the form of N security or interruptible load. A typical example is a plant where boilers are used to generate steam. In Most cases there is an alternative fuel source (coal) to allow the generation of steam that can be brought online for extended electrical outages. The SAIDI and SAIFI treatment under these scenarios is unclear, but as it is a single customer that gets affected, the impact is not material.

Table 38: Secondary Service Level Projections

Attribute	Measure	2023/24	2024/25	2033/34
Planned Outages	Provide sufficient information. {CES}	>80%	>80%	>80%
	Satisfaction regarding amount of notice. {CES}	>80%	>80%	>80%

	Acceptance of one planned outage every two years lasting four hours on average. {CES}	>80%	>80%	>80%
Unplanned Outages (Faults)	No impact or minor impact of last unplanned outage. {CES}	>50%	>50%	>50%
	Information supplied was satisfactory. {CES}	>80%	>80%	>80%
	PowerNet first choice to contact for faults. {CES}	>35%	>35%	>50%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<6	<6	<6
	Number of customers having justified supply quality complaints {IK}	<3	<3	<3

{} indicates information source; CES = Customer Engagement Survey using independent consultant to undertake phone survey, IK = Internal KPIs.

Other Service Levels

In addition to the primary and secondary service levels described in the sections above, there are a number of service levels that benefit stakeholders. These include safety, amenity value, absence of electrical interference, and performance data as presented in Table 39: Other Service Levels. Many of these service levels are imposed on EIL by statute and while they are for the public good – i.e., necessary for the proper functioning of a safe and orderly community – EIL absorbs the associated costs into its overall cost base.

Table 39: Other Service Levels

Service Level	Description
Safety	Various legal requirements require EIL's assets (and customer's plant) to be compliant to safety standards which include earthing exposed metal and maintaining specified line clearances from trees and from the ground: • Health and Safety at Work Act 2015. • Electricity (Safety) Regulations 2010 • Electricity (Hazards from Trees) Regulations 2003. • Maintaining safe clearances from live conductors (NZECP34 or AS2067). • EEA Guide to Power System Earthing Practice 2019 as a means of compliance with the Electricity (Safety) Regulations.
Amenity Value	EIL is limited by several Acts and other requirements in the adoption of overhead lines. • The Resource Management Act 1991. • The Operative District Plans. • Relevant parts of the Operative Regional Plan. • Land Transport requirements. • Civil Aviation requirements. • Land Transfer Act 1952 (easements)
Industry Performance	The Commerce Act 1986 empowers the Commerce Commission to require EIL to compile and disclose prescribed information to specified standards.
Electrical Interference	Under certain operational conditions EIL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or EIL's own equipment. The following publications are used to prevent issues from interference: • Harmonic levels (NZECP 36:1993). • NZCCPTS: coordination of power and telecommunications (several guides).

5.2 Regulatory Service Levels

Various Acts and Regulations require EIL to deliver a range of outcomes within specified timeframes, such as the following.

- Ensure customer satisfaction with both pricing and reliability to avoid being placed under a restraining regime.
- Publicly disclose an AMP or AMP update (as required) each year.
- Publicly disclose prescribed performance measures each year.

In addition to these requirements, EIL is also required to disclose a range of internal performance and efficiency measures as required by the Electricity Distribution Information Disclosure Determination 2012 (consolidated as of 9 December 2021). Previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008. The complete listing of these measures is included in EIL's disclosure of 31 March 2022 and available at:

https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors..

Financial Efficiency

Financial efficiency falls into two groups, namely:

- Network OPEX metrics; and
- Non-Network OPEX metrics.

For effective benchmarking, OPEX metrics need to be measured against the relative size of another EDB. A single fair measure of the "size" of an EDB is not available, therefore EIL adopted the following measures from Information Disclosure Schedule 1.

- Interconnection Points (ICPs) as at year end.
- Total km network length.
- Total MVA of EDB-owned distribution transformer capacity.

EIL has six financial efficiency targets as shown in Table 40: Financial Efficiency Targets.

Table 40: Financial Efficiency Targets

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2023/24	$142	$3755	$16,000	$221	$6,000	$25,500
2024/25	$142	$3755	$16,000	$221	$6,000	$25,500
2025/26	$142	$3755	$16,000	$221	$6,000	$25,500
2026/27	$142	$3755	$16,000	$221	$6,000	$25,500
2027/28	$142	$3755	$16,000	$221	$6,000	$25,500

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2028/29	$142	$3755	$16,000	$221	$6,000	$25,500
2029/30	$142	$3755	$16,000	$221	$6,000	$25,500
2030/31	$142	$3755	$16,000	$221	$6,000	$25,500
2031/32	$142	$3755	$16,000	$221	$6,000	$25,500
2032/33	$142	$3755	$16,000	$221	$6,000	$25,500
2033/34	$142	$3755	$16,000	$221	$6,000	$25,500

* Dollar values as constant 2023 dollars.

Energy Efficiency

Energy delivery efficiency measures are the following.

- **Load factor** – [kWh entering EIL's network during the year] / [[max demand for the year] x [hours in the year]].
- **Loss ratio** – [kWh lost in EIL's network during the year] / [kWh entering EIL's network during the year].
- **Capacity utilisation** – [max demand for the year] / [installed transformer capacity].

Projected energy efficiency forecasts and targets are shown in Table 41: Energy Efficiency Targets. Slight improvements are targeted but changes in peak management requirements impact on the load factor. It may take several years for the Lower South Island (LSI) peak to stabilise at a predictable level. The loss ratio is wide-ranging due to reliance on annual sales quantities from retailers. Retailers do not read customers' meters at midnight on 31 December, and an estimation methodology is therefore utilised.

Table 41: Energy Efficiency Targets

Measure	2023/24	2024/25	2025/26	…	2033/34
Load Factor	50%	50%	50%	…	50%
Loss Ratio	5.5%	5.5%	5.5%	…	5.5%
Capacity Utilisation	40%	40%	41%	…	45%

5.3 Service Level Justification

The justifications for the values set for EIL's service levels are .

- Customers have indicated preference for paying the same line charges for the same service levels.
- Improvements provide positive cost benefit within revenue capability.
- Customers make specific requests to receive a different mix of reliability and pricing from what would otherwise be available. E.g., customer contributions fund uneconomic portions of upgrade or alteration expenses to achieve a desired service level for an individual or group of customers.
- There are constraints on what can be achieved due to skilled labour and technical shortages.

- External agencies impose service levels either directly or indirectly where an unrelated condition or restriction manifests as a service level e.g., a requirement to place all new lines underground, or a requirement to increase clearances, or cost recovery allowances do not permit renewal rates.
- Customer expectations of service levels set by historic investment decisions and resultant network performance.

Over the last four years customer surveys indicated that preferences for price and service levels are reasonably constant and a general requirement for increased supply reliability is absent. However, the following challenges exist.

- The default price-quality path methodology requires "no material deterioration" in network reliability and now includes a revenue incentive for improving reliability.
- The service level called "Safety" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- EIL's cold storage customers require higher levels of continuity and restoration with interruptions to cooling and chilling being less acceptable as food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets.
- Economic downturn may increase the incidence of theft of materials and energy.

5.4 Service Level Target Setting

Service level targets are based on historical trends and benchmarking against other local distribution networks. These aspects are described in the following sections.

Historical Trends

In setting service level targets the recent history of service level measures are considered. These measures are slow to change and not easy to influence. Trends are determined from the historic results and then projected to forecast future service levels. Projections are adjusted to rationalise initiatives or other issues that might affect service levels.

Network reliability, financial and energy efficiency targets are generally based on forecast levels to support performance enhancement initiatives. Targets for customer satisfaction are based on the desired outcome of achieving positive customer experiences. Results from the last five years for reliability and energy efficiency targets are listed in Table 42. Customer satisfaction outcomes from past surveys are presented in Table 43.

Table 42: Reliability and Energy Efficiency History

Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	13.5	31.1	21.6	47.2	49.67	105.24
SAIFI	0.29	0.77	0.33	0.92	0.76	1.15
Load Factor	49%	48%	48%	48%	47%	47%
Loss Ratio	5.6%	5.2%	4.9%	5.7%	4.8%	3.2%

Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Capacity Utilisation	41.8%	41.7%	42.0%	42.0%	41.4%	40.2%
Network OPEX / ICP	$87	$76	$92	$119	$89	$105
Network OPEX / km	$2,286	$2,005	$2,443	$3,145	$2,341	$2,763
Network OPEX / MVA	$10,181	$8,834	$10,818	$13,785	$10,288	$11,709
Non-Network OPEX / ICP	$190	$188	$191	$117	$183	$189
Non-Network OPEX / km	$4,971	$$4,986	$5,061	$4,671	$4,795	$4,972
Non-Network OPEX / MVA	$22,140	$21,969	$22,411	$20,475	$21,074	$21,071

SAIDI and SAIFI disclosures for the year ending in 2015 were calculated according to the methodology applicable to the 2010-15 Regulatory Control Period (RCP). Disclosures for the following years were calculated according to the revised methodology applicable to the 2015-20 RCP, as laid out in the 2015 Default Price-Quality Path Determination.

DPP3 encourages EDB's to do move towards doing more planned work and in so doing to change the ratio between planned and unplanned work. This is done by setting planned work limits and incentivising planned work by allowing deductions on SAIDI minutes for notified planned interruptions. EIL is taking advantage of this opportunity by increasing the Routine and Corrective Maintenance and Inspection Operating Expenditure budget as well as increasing the 11kV Cable Replacement allocations in the Capital Expenditure Forecasts. This will lead to an increase in planned work and planned interruptions and will in the longer term have a positive impact on unplanned interruptions. This will be assisted by the increase in the Network Automation budget that will allow faster restoration of power under fault conditions. The overall impact will be an increase in planned SAIDI and SAIFI but a decrease in the unplanned figures.

Table 43: Customer Satisfaction History

Attribute	Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Planned Outages	Provided sufficient information {CES}	90%	97%	98%	93%	96%	92%
	Satisfaction regarding amount of notice {CES}	95%	97%	89%	96%	95%	91%
	Acceptance of one planned outage every two years {CES}	95%	-	-	31%	43%	98%
	Acceptance of planned outages lasting four hours on average {CES}	89%	-	-			85%
	Acceptance of one planned outage every two years lasting four hours on average {CES}***	-	86%	85%			84%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time {CES}*	61%	-	-		63%	78%
	No impact or minor impact of last unplanned outage {CES}***	-	49%	64%		57%	46%

Attribute	Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
	Information supplied was satisfactory {CES}*	75%	78%	86%		72%	55%
	PowerNet first choice to contact for faults {CES}**	15%	25%	6%		21%	17%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	1	4	7	11	7	13
	Number of customers having justified supply quality complaints {IK}	0	2	3	3	4	8

{} indicates information source: CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs

* As these questions are limited to customers experiencing an unplanned outage in the last six months, the sample size is very small for a network as reliable as EIL. This can lead to substantial year-to-year fluctuations.

**Noting that each year a proportion of responses (12% in 2022) simply state that the customer would not call anyone.

***Survey questions were changed from the 2017/18 surveys and onwards. The modified questions provided a wider range of options compared to previous surveys, which has influenced the response.

Benchmarking

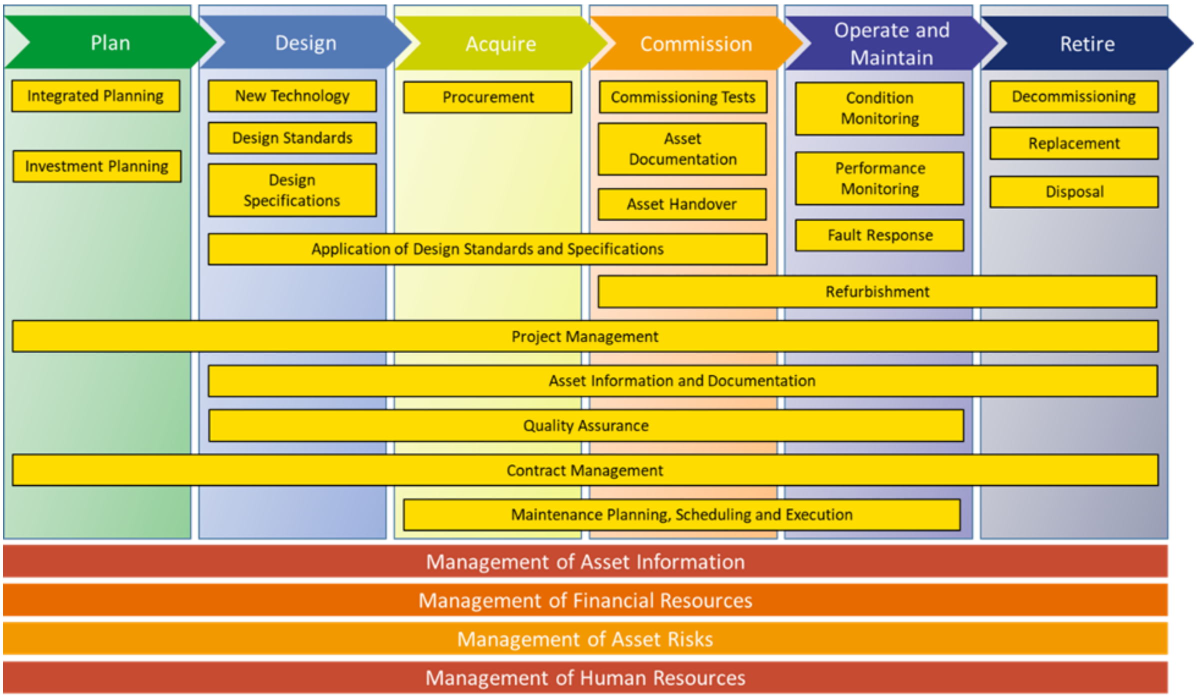
Benchmarking against other local distribution networks assist with the identification of potential improvements in the current service levels that EIL offers. Comparisons with Nelson Electricity (and to a lesser extent Orion and Wellington Electricity), are useful as these networks are like EIL in terms of density and asset base. Several indicators are benchmarked against other EDB's performance in Chapter 10.

6 Asset Management Strategy

EIL's Asset Management Strategy is based on PowerNet's asset management model (focusing on a lifecycle management approach). The strategy is structured to address the main activities and challenges faced in each lifecycle stage as well as the support processes. It defines objectives for each activity and recommends initiatives to achieve the stated objectives. In each case, responsibilities are defined, and realistic timeframes are suggested. Figure 38 charts the various asset lifecycle stages and support processes that cut across the entire value lifecycle.

The defined strategic objectives and initiatives are aligned with the relevant stakeholder' business plans. These are aimed at achieving continuous business improvements through balancing risk, performance, and cost.

Figure 38: Lifecycle Model for Asset Management



6.1 Lifecycle Stages

The asset lifecycle stages are described in the following sections.

Planning – Network Development

The function of network planning ensures that the optimal expansion of the power system can sustain demand. Expansion needs to occur at the right time to balance optimal investment of capital, but at the same time avoid network overloading. The power network needs to continuously meet power quality, reliability, statutory, safety and environmental requirements.

The planning philosophy is that least economic (lifecycle) cost be implemented. This entails decision-making to balance CAPEX and OPEX spending. There should be a formal correlation between capital planning (CAPEX) and maintenance planning (OPEX) and the investment in assets should produce the expected network reliability and performance. The major strategic objectives for network planning are the following.

- Asset planning and management are the foundation of EIL's business plan and enable the integration of CAPEX and OPEX budgets.
- Planning for network expansion, strengthening and/or refurbishment is based on whole life cost.
- Planning incorporates the connection of new customers.
- Capital projects are prioritised based on risk.
- Non-asset solutions take priority.

Plant or Network Design

The design lifecycle stage includes the design and specification of plant, as well as the design and engineering of the power network. There are several standards and guidelines available that covers the design and engineering of the power network. PowerNet creates and maintains many accessible standards, specifications, and guidelines for power as well as control plant. Where an internal standard is not available, PowerCo standards are used.

Standards and specifications are often developed around technical, safety, environmental and statutory requirements without considering lifecycle cost, maintenance, risk, or reliability necessities. Spares distribution and asset disposal arrangements are often also not considered during the design and/or specification of a specific asset. This is contrary to our Asset Management Policy which focuses on the full life cycle of assets. EIL's major strategic objectives for the Design lifecycle are the following.

- Efforts are focused on improving asset life and performance while minimising cost and risk.
- Equipment standards and designs support network reliability and performance at lowest lifecycle cost and risk.

Acquire

The acquisitioning stage includes the procurement of new plant and equipment (based on specifications developed during the design stage). It also includes obtaining construction services from contractors. This is followed by activities such as project management, contract management, construction and/or installation of the asset and quality assurance. This lifecycle stage is supported by PowerNet's commercial services and supply chain processes.

The physical construction and installation of assets are critical activities that influence the life expectation and lifecycle cost of a specific asset. Incorrect construction and installations can lead to equipment failures. This makes quality assurance in terms of both equipment and installation of vital importance. The following major strategic objectives for the acquire lifecycle stage were identified.

- Procurement Policies support lifecycle costing and risk management.

- Construction and installation quality will not compromise the asset life.

Commission

The commissioning phase starts when the contractor has completed the implementation of an asset or plant (based on the design stage) and indicates that the asset or system is ready for utilisation. Final testing of the installation needs to be carried out, the as-built data be recorded/captured and the maintenance as well as operating staff needs to be instructed in the requirements of the new plant. The phase ends when the new asset is put into commercial operation. The following are EIL's major strategic objectives for the commissioning lifecycle stage.

- The quality of networks and assets handed over for operation is to specification.
- As-built documentation and records are properly generated and managed.
- Maintenance requirements are well understood, maintenance staff have been trained and the required manuals, tools and equipment are available.

Operate & Maintain

During the operate and maintain lifecycle stage, physical assets are expected to perform their designed function at (or above) the specified performance and reliability parameters. Operating and maintenance practices greatly influence the performance, reliability, and life expectancy of the asset. Good management of assets during this lifecycle phase will extend life expectancy, reduce overall lifecycle costs, and ensure availability and reliability. When there is collaboration between asset operators and maintainers, the best performance (at the optimum cost) of the asset will be experienced. Deterioration and poor performance are often the result if either operations or maintenance teams work in isolation of each other. The following are EIL's major strategic objectives for the O&M lifecycle stage.

- Assets are operated and maintained in a manner that minimises system lifecycle cost with consideration of risk.
- Electricity delivery networks and associated electrical systems are maintained in such a manner that the requirements of customers, internal stakeholders and legal authorities are met at minimum lifecycle cost.
- Defect and liability periods as well as equipment guarantees are documented and managed.

Retire

This lifecycle stage includes the following potential activities.

- **Replacement** – The planned replacement of assets for reasons other than system expansion e.g., degraded performance experienced at the end of its useful life.
- **Retirement** – The removal of equipment from service due to system expansion, but retention of the asset for strategic reasons such as spares.
- **Disposal** – The complete removal and disposal of an asset when it is no longer required.

EIL's major strategic objectives for the retire cycle stage are the following.

- Assets replacement decisions are based on reliability, operating cost, condition and predicted end-of-life.
- Asset disposal will create minimal long-term safety risks or risks to the environment.

6.2 Lifecycle Support

Lifecycle support activities are described in the following sections.

Management of Asset Risks

Risk Management can be defined as:

> *"The continuous, proactive and systematic process to understand, manage and communicate risk from an organisation-wide perspective. It is about making strategic decisions that contribute to the achievement of an organisation's overall corporate objectives. Risk refers to the uncertainty that surrounds future events and outcomes. It is the expression of likelihood and impact of an event with the potential to influence the achievement of an organisation's objectives."*

Risk is the product of "*consequence*" and "*probability*". Consequence refers to the potential impact of a failure incident on the business. In the context of asset management, this relates to the criticality (its importance to the business) of each asset. Risk is not limited to a single stage in the asset lifecycle, but cuts across all the phases. Risk Management is applied to all relevant business activities and is the fully inclusive basis for prioritising all activities, including engineering projects and investments.

Management of Asset Information

PowerNet has very good information systems, but several information related projects overlap, and overall prioritisation and co-ordination are lacking. This leads to unnecessary expenditure and inefficiencies. In addition, the selection and implementation of information systems are mostly focused on financial and regulatory compliance and asset management requirements are not sufficiently addressed.

Integration between asset management information systems (e.g., MAXIMO, FINANCE 1 and GIS) is inadequate and the use of decision support tools are therefore restricted. In the design of systems such as Maximo, the focus was mostly on primary plant information, while the requirements for secondary plant information have been largely overlooked. Data accuracy and completeness thereof is generally inconsistent.

The strategic objectives for asset information management are the following.

- Asset management information systems shall link asset history, technical design, performance, and risk information, as well as financial data of individual assets.
- Data and information shall be consistent across all systems.

Management of Human Resources

Effective asset management requires that personnel responsible for the design, construction, operation, and management of assets have appropriate education, training and/or experience. Procedures should be in place to ensure that employees or third parties such as contractors are aware of the following.

- The importance of compliance with the requirements of the asset management system, including the asset management policy, processes, and procedures.
- Their roles and responsibilities in achieving compliance including emergency preparedness and response requirements.
- The potential consequences of deviating from stipulated operating procedures.
- Long-term asset management training requirements need to be identified and adequately planned for.

Like most industries in New Zealand and world-wide, PowerNet is experiencing some shortages in skilled roles. As Network Manager, PowerNet is responsible to ensure they can resource the business, through their internal and contracted resources, to deliver across the Networks they manage. Through various short-, medium- and long-term strategies, PowerNet will manage resourcing to ensure they deliver.

The strategic objective for the management of human resources is that: - *the necessary resources and skills to plan, acquire, operate, and maintain the assets that PowerNet manage, be attracted, developed, retained and be available when required.*

Management of Financial Resources

Financial resources are required to manage assets efficiently over their entire lifecycle. Asset management requires processes for defining and capturing as built, maintenance and renewal unit costs and methods for the valuation and depreciation of its assets. Unfortunately, the Operating and Maintenance budget is often cut when an organisation is facing financial constraints.

The following is the major strategic objective for the management of financial resources: - *the necessary financial reporting to plan, acquire, manage, operate, and maintain PowerNet's managed assets shall be developed, and finances made available when required.*

6.3 Lifecycle Management and Network Development

Growth is the increase in the demand for electricity, either due to an increase in the number of customers or to an increase in demand by a single customer, or a combination of both. Customers are considering electricity as an alternative to coal or other carbon-based fuels due to the drive towards cleaner sources of energy in industrial processes. Supplying this increased demand often requires utilisation of the full spare capacity of network. Redesign and development of networks are needed to accommodate these load increases.

Maintenance (and operation) of assets is the prominent lifecycle process post installation (commissioning). Maintenance can be defined as a combination of all technical and administrative actions (including supervisory actions), intended to retain an asset in, or restore it to a condition that allows it to perform a required function. Maintenance does not extend the life of an asset or increase its capacity, but it is an essential function to ensure that an asset reaches its expected life.

There is a correlation between network development, lifecycle management practices and network service levels. Over time, supply reliability is impacted by the increased demand on fixed network assets. More customers and associated service levels are affected with supply interruptions. In the long-term, lifecycle maintenance counteracts declining reliability in the face of network aging and deterioration. Similarly, network development offsets declining reliability when demand growth occurs.

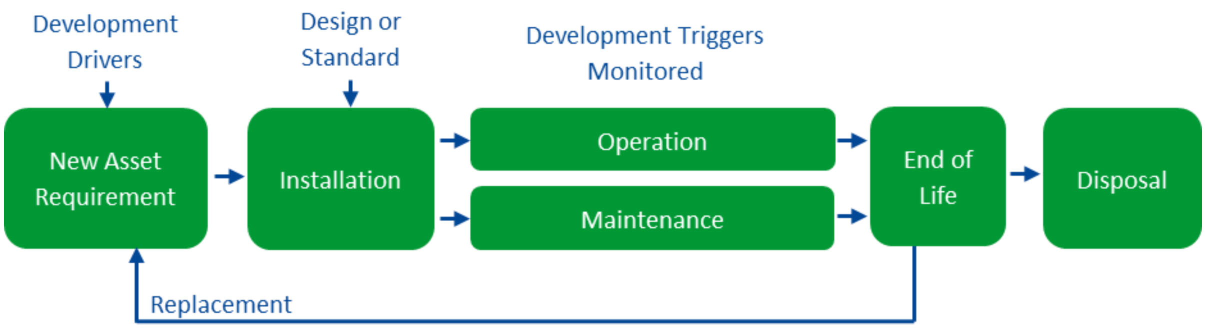
6.4 Lifecycle Management Processes

EIL adheres to several asset management processes to manage network assets throughout the lifecycle stages. Following procurement of equipment and materials, assets are constructed or installed as per design or a specific network standard. The commissioning process ensures that the asset can operate as intended. From there, the asset enters its service life (useful life) during which it will be operated (usually over a considerable period). In general, maintenance activities are undertaken throughout an asset's operational life to support ongoing reliability while it is economically feasible to do so. The maintenance drivers over the lifecycle of an asset are the following.

- Support continued reliable service to customers.
- Economic viability when compared to replacement.
- Continued safety.
- Operational efficiency.
- Rate and extent of deterioration.
- Criticality.
- Probability of failure.

At some point in the future, an asset will reach its end of life and will be retired from service. The asset will be replaced if the need remains. The retired asset will responsibly and appropriately be disposed of. This process is outlined in Figure 39.

Figure 39: Lifecycle Management Processes



6.5 Fleet Plans

A Fleet Plan is a description of how a specific asset or type of asset will be managed over its entire lifecycle. For each asset the material cost and time required to execute the following activities, need to be determined.

- Installation of the asset.
- Execution of each type of maintenance action, as well as the time interval between the activities.
- Decommissioning and disposal of the asset.

Through the development of Fleet Plans, EIL can:

- determine capital funding requirements for the next 10-20 years;
- establish the number of people required, their skill levels and equipment needed to operate and maintain the electricity networks for the next 10-20 years;
- determine operational expenditure requirements for the next 10-20 years; and
- plan for accessing all network assets within a reasonable period for testing and maintenance.

These requirements are aggregated across the Annual Works Program for each CAPEX and OPEX category.

7 Capital Expenditure

Capital Expenditure (CAPEX) is required to increase the capacity of assets or networks, to extend the life of assets, to install new assets for safety or reliability purposes or to replace aging assets. CAPEX is categorised according to ComCom requirements as follows.

- Customer Connection.
- System Growth.
- Asset Replacement and Renewal.
- Asset Relocations.
- Reliability, Safety and Environment.

7.1 Asset and Network Development Planning

Long term asset and network expenditure requirements are determined in the planning asset life cycle stage. The following aspects are considered during this phase.

- Network configuration.
- Asset and asset system redundancy.
- Capacity of the assets and the systems.

EIL monitors the existing network assets and ensures that they operate within limits imposed by capacity constraints and service level requirements. Regular updating of demand forecasts enables predictions for future network operation and in line with EIL's development criteria helps identify the need for network development.

Planning Phase Risks

The following risks are addressed during the planning phase.

Table 44: Planning Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment
Operational Performance	**Damage due to extreme High Impact Low Probability (HILP) Physical Event**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Determining areas prone to physical events such-as earthquake (liquefaction), tsunami and flood zones Plan networks to avoid high probability HILP event areas. Substations in flood risk areas are designed for the critical assets to be located higher than the surrounding area
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Environmental scans to determine potential growth industries and geographical growth areas. Determine the impact of potential technology changes on the networks, e.g., electrification of fossil fuel process heat, distributed generation as well as changes in distribution asset technology.

Category	Risk Title	Risk Cause	Risk Treatment
			Plan the networks to cater for the envisaged growth and technology changes
	Operational systems failure due to breakdown in telecommunications	SCADA communications has one centralised communications point that all information is passed through.	Enhancement project was planned and is now underway that will provide further links - due for completion 2023
	Loss of right to access or occupy land	Risk of assets losing / not having the right to occupy particular locations (e.g., Aerial trespass, subdivision)	Plan any new networks along public service corridors as far as possible. Ensure that rights of way and easements are obtained as part of the planning process
Health and Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Plan the networks and asset locations to reduce the probability of incidents to a minimum

Network Development Drivers

EDBs across New Zealand are aware that they have a key role to play as their networks enable the decarbonisation and electrification of society, particularly in the transport and industrial sectors. As EDBs confront this challenge, they recognise the importance of providing clear signals to their customers, communities, and other stakeholders, of the likely medium to long term implications of this transition. It is important for stakeholders to understand that this is not 'just' an EVs story – different EDBs will experience increased demands for investment in their networks for a range of different reasons. The following paragraphs describe what are anticipated to be the most significant sources of this demand that EIL anticipates will occur over the next three decades, out to 2050. It should be noted that for many EDBs, ongoing 'business as usual' maintenance and renewal of their existing distribution network is, and will continue to be, a very significant driver of investment, however this is not presented here as it is not a 'new' driver of investment of the type of the sector wishes to highlight. Lastly, readers should appreciate that while certain elements of the transition are well-understood and reasonably well-fixed (e.g., the net zero by 2050 target), other elements which may have a significant impact on EDBs (e.g., the phase-out of reticulated gas for home heating, hot water and cooking), are still uncertain. EIL has made an educated assessment of what might be expected on their network, but there are significant uncertainties and assumptions built into this. The EDB sector will, via its association the Electricity Networks Association, be developing a more rigorous and structured set of demand forecasts and scenarios out to 2050 in the coming months.

Development demands include the following.

- Large generation or an aggregation of small generators may require increased capacity on some areas of the network.

- Requirements for maintaining or improving service levels (whether statutory, customer and other stakeholders' needs or internal strategic initiatives).
- Connection requests from potential customers require an increase in network capacity to match their additional load requirements.
- Load growth exceeding a threshold for increased security – the threshold is based on a predetermined strategic "line in the sand" which is designed to provide particular service levels when applied consistently across the network.
- While asset renewal is generally a lifecycle management requirement, it may present an opportunity as the most economic time for development initiatives such as additional capacity, the introduction of new technology, or more efficient alternative solutions.

Development projects can take many months or even years to complete, therefore a good understanding of trigger points and when they may be exceeded in the future is required. This is to ensure that capacity can be made available by the time it is needed. The network development process involves demand forecasting (based on historical trends) as well as consideration of the various demand drivers which may cause deviation from status quo trends. Some of these trigger points are discussed below.

Customer behavioural changes

While many factors could change our future operating environments, of particular importance is the way our customers will use, generate, and manage energy in the future. Our approach is to understand and address changing customer requirements and energy use patterns. These changes on the customer side will likely be driven by a combination of factors, including the increased use of new technology (including own generation, EVs, and new types of appliances), increasing efforts to reduce carbon emissions, and an ongoing drive to reduce energy costs. We have a responsibility to help facilitate these changes, allowing our customers to achieve their goals.

Effective demand management, energy storage and tariff incentives will help maximise the utilisation of existing energy infrastructure and defer or minimise future investment. Electricity should also offset other, less environmentally friendly, forms of energy, and the network should facilitate this, for example EVs offsetting the demand for petroleum.

Transitioning to this future will require considerable effort and investment in providing the required visibility, controllability, flexibility, and stability of all parts of the network – particularly in LV networks where the needs and impacts will be most severe. However, the timing at which this investment will be required is highly uncertain.

Declining costs of distributed energy resources and increasing digitisation and smart technology will drive a more distributed electricity system. Declining costs of distributed energy resources (DER): As the cost of DER, such as residential and commercial solar and batteries decline, their uptake is forecast to increase significantly. Between 2010 and 2020, the cost of a residential solar PV system declined by 65%, with a further decline of 60% predicted in the 2020s, according to the National Renewable

Energy Laboratory (NREL). NREL also predicts residential batteries will continue declining in cost, reducing by up to 50% this decade. While purchased primarily for their transport services, EVs can also act as DER across networks.

New smart technologies like automation, AI, Internet of Things (IoT), real-time communication, and network visibility by household will revolutionise the way electricity systems are operated. As technology improves and the cost of IoT sensors decline, it is likely that DER will be able to interact in real-time with the electricity system. This provides a significant opportunity to increase customer participation in markets and more effectively manage complex multi-directional electricity flows that will emerge in future.

Ongoing electricity demand growth (residential, commercial, and industrial)

The majority of our customers continue to use centrally generated electricity as their key energy source. We do not predict this changing significantly in the foreseeable future. Importantly, our networks provide the "last mile" connection to customers. Even when renewable generation or grid-connected energy storage becomes much more widespread, it would not reduce customers' reliance on our networks to access these. Likewise, to fully realise the potential benefit of locally generated electricity, customers will still need the distribution network to export their excess electricity, or to import at lean times. Therefore, it would be imprudent to materially adjust investment and asset management plans now to make provision for uncertain needs that may arise in future. For the AMP planning period, we see most of our network expenditure remaining on conventional electricity network assets and practices. Accordingly, we will continue to keep a strong focus on the health, capacity, and operation of our existing network, as well as expand the network to meet the increased demand of new – and existing – customers. In terms of this AMP, it means that investment on asset renewal, maintenance and growth of conventional network assets will also remain paramount.

Electrification of transport

Road transport accounts for about 17% of carbon emissions in New Zealand. The electrification of these fleets, starting with passenger vehicles, is therefore another obvious focus area to reduce emissions in New Zealand. While current uptake of EVs is relatively low, we expect it to accelerate, especially if more government incentives emerge to support this. The impact of increasing numbers of EVs on electricity demand is highly uncertain, as it is subject to multiple factors such as:

- Number of EVs in a network area.
- Average distance travelled per day (and hence energy required to recharge).
- Use of charging infrastructure structure (public infrastructure v residential charging).
- Time of charging (off-peak charging will have little impact, but should it coincide with the early evening demand peak, it will add to total network demand).
- Energy required by the type of vehicle.
- Rate of charging.
- The expected demand increase can be largely avoided if we can encourage charging during off-peak hours. Various means of achieving this are being investigated.

Demands for decarbonisation

One of the main focus areas for reducing New Zealand's carbon footprint is the decarbonisation of process heat. Industrial processes and waste represent about 11% of New Zealand's carbon emissions.

When point demands start to exceed about 30MVA, it becomes generally impractical or uneconomic to connect to distribution networks, even at 33kV. Direct grid connections are generally necessary, even where these may still be provided by distribution utilities. Where large processes are electrified, we therefore foresee that these will be directly connected to the transmission grid. However, there are still significant numbers of smaller industrial and commercial heat processes, such as heating for hospitals and schools, operating at lower temperature levels, where converting to electricity from current carbon-based heat sources is viable. At least part of the additional electricity capacity required to achieve this will be drawn from distribution networks. As the pressure on business and other entities to reduce emissions increases, we see potential for significantly higher electricity demand associated with process heat conversion. This impact can be even more substantial on those parts of our network where heat loads are concentrated.

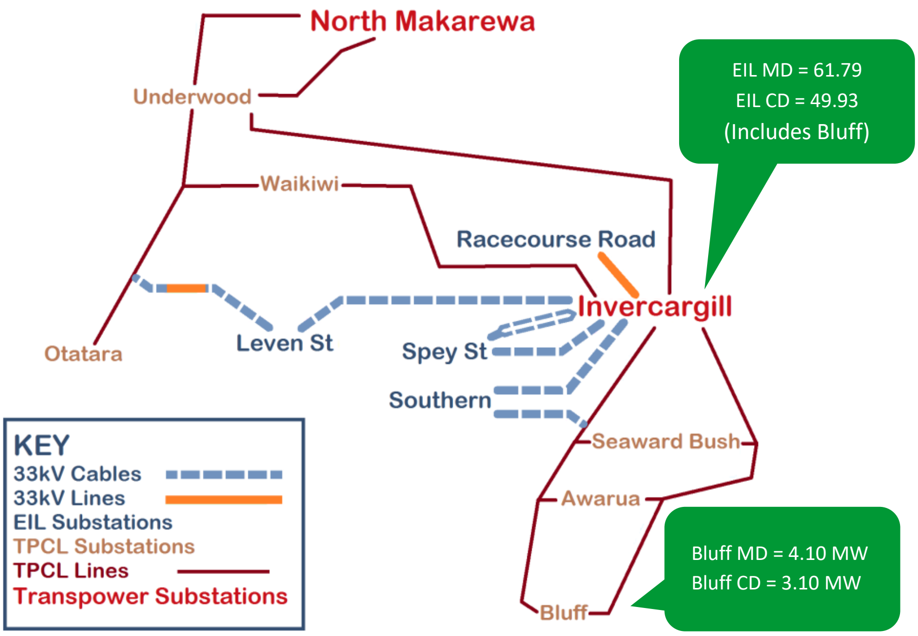
Greater reliance on renewable energy

Networks Investment in electricity networks will need to increase significantly to enable electrification and renewable energy. A significant number of large-scale renewable power stations will need to be connected to the transmission grid over the next 30 years. Modelling shows that the country needs 4.8 GW in the next 8 years (Concept Consulting modelling). New core grid interconnections will be required to enable these new connections and electrification. Historically, transmission connections have been in very large, centralised power stations, which has kept the number of required connections low and has enabled greater predictability in the associated core grid upgrades required. As the pace of change accelerates, the future needs of the grid will become more uncertain. Annual investment of about $1 billion in transmission is needed to enable renewable generation and electrification.

Current Demand Profiles

Maximum demand (MD) for individual areas do not occur at the same time. The Lower South Island (LSI) peak occurred at 08hr00 on the 15th of October 2020 and the Bluff MD of 4.096 MW occurred at 18h00 on the 18th of May 2021. The EIL coincident demand at the time of the LSI peak was 48.93 MW with 3.104 MW of that load contributed by Bluff EIL. The individual maximum demands are displayed in Figure 40.

Figure 40: GXP and Generation Demands



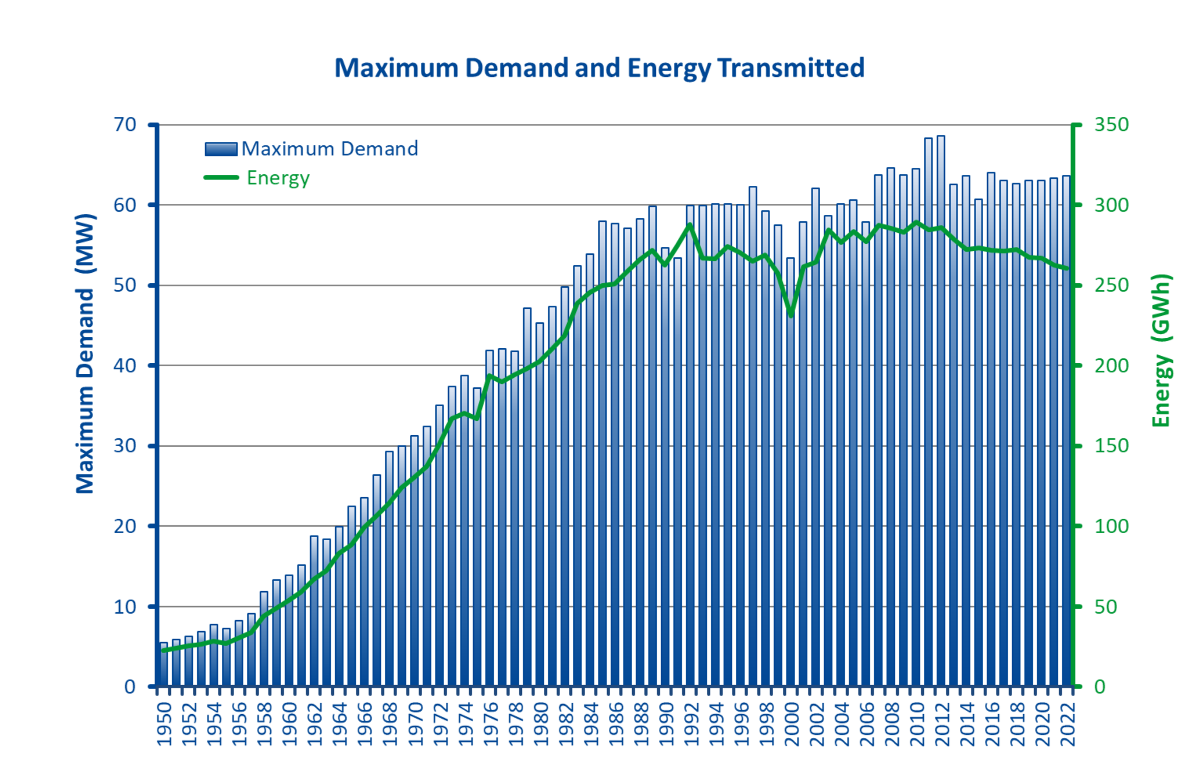
Demand History

Random variations over and above the main growth patterns impacts the accuracy of growth trends. In general, a ten-year rolling average will vary substantially between successive years. Longer term trends tend to average out random variations but also obscures recent changes to underlying growth. Some causes of variations might be identified with hindsight, but these are difficult to predict, for instance a drought initiating irrigation load increases.

Growth patterns over various time periods need to be considered including known events that impacts consumption before a reasonable estimate of growth can be determined (to be used for forecasts of future demand and consumption).

Analysis of historic demand and energy usage indicates maximum demand growth has been stabilising in recent years after an increasing trend at the start of the decade, while energy consumption is showing a clear and consistent downward trend. Figure 41 shows the overall maximum demand from 1950 and highlights the flattening out of demand since the late '80s. The data presented is for supply to customers' connection points and excludes transfers between networks. Recent increases in maximum demand have been affected by changes in Transpower's transmission pricing methodology (TPM); these changes are not apparent in energy growth.

Figure 41: Maximum Demand and Energy Transmitted



Demand Trends

The following sections examine the most significant drivers of the network demand over the next 10 to 15 years in detail.

Each zone substation recorded the maximum demand as listed in Table 45. The 99.9 percentile demand is applied to compensate for short term load transfers and to produce a more accurate figure of actual maximum demand (per area). In recent years, extended or permanent load transfers between the zone substations have distorted these numbers. When conducting analysis at substation level, allowance must be made for these load transfers. The overall EIL maximum demand gives a good representation of growth, but extended load transfers outside the network (e.g., from TPC's Seaward Bush substation to Southern substation) still needs to be considered.

Table 45: Zone Substation Demand

Zone Substation	99.9 Percentile Demand (MVA)							
	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17	2015/16	2014/15
Spey St*	23.1	24.4	23.9	25.5	24.8	21	19	17
Leven St	14.5	16.3	14.3	14.2	11.7	16.1	15.3	15.2
Racecourse Rd	11.0	12.8	10.0	10.2	10.1	10.6	9.7	9.2
Southern	12.4	11.1	12.0	12.9	14.2	14.8	14.5	14.7

Zone Substation	99.9 Percentile Demand (MVA)							
	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17	2015/16	2014/15
Bluff (TPCL)	5.3	5.1	5.2	5.4	4.7	4.4	4.7	4.7

*Load was transferred to the new Spey Street substation from Doon St sub over 2015/16.

In the past, growth rates were slightly higher in the commercial and industrial areas of the network. In recent years, substation loads and security risks around staging of development projects were managed by shifting loads between substation feeders. This impacts on the accuracy of trends for these areas. However, regardless of the variation of growth affecting the distribution network areas, the loading on each zone substation can be monitored and managed by shifting loads as required.

Development Triggers (based on growth)

Demand is basically created by individual customers withdrawing (or introducing) energy through their individual connection points. The demand at each connection aggregates “up the network” through LV reticulation to the distribution transformer, then through the distribution network, the zone substation, the subtransmission network to the GXP and ultimately through the grid to the power stations. As the load aggregates through the network, load diversity tends to support better load factor and capacity utilisation.

Demand growth is the predominant driver for network development. Growth triggers were identified, and corresponding thresholds set to achieve desired service levels (where appropriate). In meeting future demand (while maintaining service levels), the first step is to determine if the projected demand will exceed any of the trigger points for asset location, capacity, reliability, security, or voltage. The trigger points for each asset class and typical network solutions are outlined in Table 46.

Table 46: Development Triggers

Development	Trigger Point	Typical Network Solution
Extension	New customer requests a connection outside of the existing network footprint; often within network area but not immediately adjacent to existing infrastructure.	New assets are required to extend the network to the new customer. Additional capacity may also have to be built into the nearest existing network and upstream assets depending on customer size.
Capacity	Load exceeds capacity rating of network assets (or encroaches on spare capacity required to be maintained) or voltage drops below acceptable levels, i.e., below 0.94pu at customer’s premises. Proactively identified through network modelling and monitoring load data from meters or MDIs* but may occasionally manifest as overload protection operation, temperature alarms or voltage complaints. The current roll out of smart meters will vastly improve ability to estimate loading and utilisation of asset capacity.	Replace assets with greater capacity assets. May utilise greater current ratings or increase voltage level (extension of higher voltage network, use of voltage regulators to correct sagging voltage or introduction of new voltage levels). Alternative options are considered prior to these capital-intensive solutions but generally provide a means to delay investment; may be network based such as adding cooling fans to a zone substation transformer or non-network e.g., controlling peak demand with ripple control.

Development	Trigger Point	Typical Network Solution
Security and Reliability	Load reaches the threshold for increased security as defined by EIL's security standard. Customers (especially large businesses) may request and be willing to provide a capital contribution for increased security or accept a reduced level of security for their own facility.	Duplicating assets to provide redundancy and continued supply after asset failures. Increase meshing/interconnection to provide alternative supply paths (backups). Additional switching points to increase sectionalising i.e., limit amount of load which cannot have supply reinstated by switching alone after fault occurrence. Automation of switching points for automatic or remote sectionalising or restoration.

*MDI = Maximum Demand Indicator – device that monitors the highest demand on the equipment

EIL will identify a range of options to bring the asset's operating parameters back to within the acceptable range of trigger points when a trigger point is exceeded. New capacity has an impact on the balance sheet, depreciation, and ROI. There is an overall preference for avoiding new capital expenditure and EIL endeavours to meet demand by other, less investment-intensive means. The following potential responses and options are considered.

- Pricing reform (recently completed).
- Demand side management.
- Partnerships for non-traditional solutions.

If the extent of changes is substantive, assets may become underutilised to such an extent that EIL may be unable to fully recover regulated investments. The Commerce Commission has endorsed an asset stranding risk mitigation option for those EDBs subject to price control. This allows EIL to apply for accelerated depreciation recovery (up to 15% reduction in asset lives), subject to the Commerce Commission's approval prior to the next regulatory period.

There is a low likelihood of asset stranding for EIL, due to the uneconomic nature of deployment on dense urban networks. This is based on the assumption that markets, regulations, and customer behaviour are supportive of peak shifting efforts.

Future Demand

Future demand forecasts are determined by an understanding of historical trends and then projecting these into the future. Projections are adjusted by factors which are likely to cause demand deviations from current trends.

Population, Demographics and Lifestyle Drivers

Demographics and lifestyle drivers of future demand is provided in the next table and population projections in Table 47.

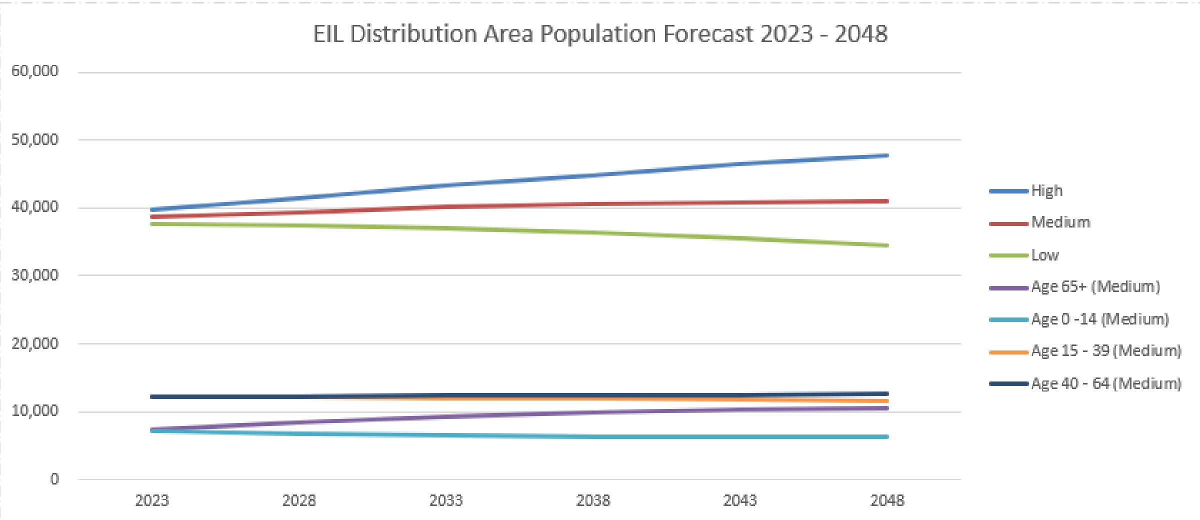
Table 47: Demographics and Lifestyle Drivers

Population Growth and Decline	**Effect:** Population increasing in future years by ~3.6% by 2033. This corresponds to a similar increase in demand of 3.6% assuming similar housing and living arrangements–assuming that employment is available under a similar business profile.
Description: The population of EIL's distribution area is approximately 38,726 (2023) of which the Bluff area accounts for approximately 4.6%. Statistics NZ estimates that the population under EIL's distribution network would have grown by approximately 0.7% per annum from 2018 to 2023. Long term growth is expected to be relatively flat with medium growth rate assumptions. The upper bound projection of population growth for EIL's distribution area is 12% by 2033 (with an assumed growth rate of 0.8% per annum), a lower bound of -4.4% by 2033 (with an assumed growth rate of -0.3% per annum), and a mean estimate of 3.6% growth by 2033 at an assumed growth rate of 0.3% per annum. It is expected that most of the growth would occur in urban areas of which Invercargill is Southland's largest metropolitan area. Invercargill would attract the majority of potential migrants however the Invercargill area supplied by EIL is surrounded by TPCL which supplies the outer regions of the city. Expansion of Invercargill for additional housing would therefore often be outside of EIL's network boundary. EIL does have some undeveloped land suitable for housing and there is further potential for in-build with subdivided sections which if increased demand eventuates would be utilised to some extent. Business expansion is also a target for the Southland Regional Development Plan and again Invercargill would expect to be a key location for this to occur. Commercial subdivision to support any potential new commercial building is available within EIL's Invercargill network area. Concerns about the closure of the Tiwai smelter and its effects on the local economy remain. Although the smelter is not directly supplied by EIL, the potential economic impact of losing the Tiwai employees as customers as well as energy consumption of support businesses servicing Tiwai could be significant. The central government initiative to centralise certain functions of NZ Polytechnics may diminish the attractiveness of Southland Institute of Technology as a tertiary education provider to potential migrants, leading to a decline in student numbers and domestic load.	
Housing Density and Utilisation	**Effect:** Overall support of domestic power demand growth from increasing population as described above. Effects of increased housing density is somewhat offset by increasing housing utilisation as more people share heating and other power requirements.
Description: Housing density and utilisation can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand. An increase in the student population may increase demand for higher density student accommodation facilities near central Invercargill.	
Rural Migration to Urban Areas	**Effect:** EIL Population growth especially from retirees (baby boomers) is expected to be a limited driver for increased demand. Effect is captured in population growth effect above discussed above.
Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has also been seen in Southland. Farming has been shedding jobs for some time as improved technology means fewer people are required per unit of production. This supports the above assumption that Southland's urban areas, particularly Invercargill is likely to see the vast majority of population. The number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2026. The impact of farmers retiring to urban areas increases demand for townhouses in desirable locations. Building in new areas on the outskirts of Invercargill, outside of EIL's network area or demolishing older houses to replace with more efficiently heated homes may be common for these retirees. Some additional support for retail business in Invercargill may result but overall, this would have a minor impact on power demand. As this is not a new effect it is largely included in previous years trending.	
Increasing Energy use per Customer	**Effect:** Growth minimal and included in existing demand trends.
Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However, this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months.	

Customer goods including appliances and electronic technology are generally becoming more affordable however while the numbers of these goods per household may be increasing, they are often not used at the same time. Energy efficiency is also improving for many of these items offsetting any increases in household demand.	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for EIL over the next ten years. Incorporates growth anticipated from council fuel burner constraints.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. Around 8% of energy consumption comes from gas and solid fuel-based space heating and has the potential to be replaced by electrical heating. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. For EIL's customers, concerns with loss of heating during outages are negated by the high supply reliability these customers receive. However, heat pump installation cost is a barrier for many people, and some prefer the ambience of other heat sources. Therefore, complete conversion to electrical heating cannot be expected and further conversions will occur over an extended period. The additional demand that arises will be partly offset by increased use of heat pumps over other traditional electric heaters which can use three to four times the power to run. Conversion will be both driven and constrained by the Breath Easy clean air initiative.	
Electricity Affordability	**Effect:** Minimal change in demand for power supply is expected due to changes in electricity prices. Future change is likely to be a continuation of current demand trends.
Description: Consumption and demand are relatively inelastic to changes in power price as it is seen as an essential service for most people. Improving energy efficiency for heating and appliances and future technology such as smart meters and appliances are expected to counteract effects of increasing electricity prices.	

The current population projections for EIL's network area are based on estimates from the 2018 Census data from Statistics New Zealand. Projections for the 65+ age group indicates a significant aging of the population as highlighted in the following figure.

Figure 42: Population Projections



Environmental and Climate Drivers

Drivers of future demand based on changes in the environment and climate is discussed in Table 48.

Table 48: Environment and Climate Drivers

<table>
<tr><td>Council Fuel Burner Constraints</td><td>Effect: Continuation of existing trends towards electrical space heating</td></tr>
<tr><td colspan="2">Description: The Regional Air Quality Plan have been advised and includes prohibition of open fires since 1 January 2017 in the Invercargill airshed area. Further prohibition of non-approved burner/boilers in the Invercargill airshed area occurs from the following dates.
<table>
<tr><th>Burner installation date</th><th>Prohibition date</th></tr>
<tr><td>Before 1 January 1997</td><td>1 January 2019 (wood)
1 January 2017 (other fuels)</td></tr>
<tr><td>1 January 1997 – 1 January 2001</td><td>1 January 2022</td></tr>
<tr><td>1 January 2001 – 1 September 2005</td><td>1 January 2025</td></tr>
<tr><td>1 September 2005 – 1 January 2010</td><td>1 January 2030</td></tr>
<tr><td>1 January 2010 – 6 September 2014</td><td>1 January 2034</td></tr>
</table>
Approved boilers and burners are those which meet the national environmental Standards for emissions and thermal efficiency. Any burners installed after September 2005 may be on the Ministry of the Environment’s list of approved burners and not require replacement. This phase-out of inefficient heating will require replacement and some degree of conversion to electrical heating with heat pumps is to be expected.</td></tr>
<tr><td>Energy Conservation Initiatives</td><td>Effect: Customers are responding to marketing, strategies, and the availability of energy efficient products to reduce their consumption. Considered a significant driver of demand contraction however is mostly recognised within existing trends. Energy savings are likely to increase to some degree estimated at 0.5% (demand contraction) over the next ten years.</td></tr>
<tr><td colspan="2">Description: Energy efficiency in customer appliances is increasingly popular due the combination of government or local council drivers, marketing, and customer demand. Replacement of appliances with improved energy efficiency provides customers with the same benefits or standard of living while requiring less power consumed and so reduces power bills. Similar drivers are contributing to further installations of insulation which also assists in reduced power requirements for heating (see above section Energy Efficiency).</td></tr>
<tr><td>Increasing Average Ambient Temperature</td><td>Effect: No impact on maximum demand but potentially some improvement in load factor.</td></tr>
<tr><td colspan="2">Description: Increasing average ambient temperature predicted by climate scientists may create increased demand for cooling systems. This increased consumption would occur in the warmer months and therefore not coincide with the current peak demand occurring in the winter months being dominated by heating requirements. It would take a very large change in ambient temperature for peak consumption to be dominated by cooling in summer months and is expected to simply improve load factor by a small degree.</td></tr>
<tr><td>Wider Range in Weather Variations</td><td>Effect: Potential impact on maximum demand, and worsening load factor. Some impact on network reliability.</td></tr>
<tr><td colspan="2">Description: Climate scientists forecast a potential for increasing frequency and/or intensity of storms, along with wider variations in seasonal weather. Colder periods may increase heating load, adding to current peak demand. Hotter and dryer summers will lead to an increased garden irrigation demand that will manifest itself as an increase in the water purification load.</td></tr>
</table>

Economic Drivers

Economic drivers of future demand include major industry growth as well as $NZ variation and commodity cycles. These drivers are presented in the next table.

Table 49: Economic Drivers

Major Industry Continuance or Growth	**Effect:** The most likely scenario is considered that in which existing industries will continue or grow in load, some new major new industries will eventuate in the region but this will not affect EIL therefore no change from existing trends forecasted.
Description: Dairy Industry, Tiwai, Major Petrochemical Extraction or Processing etc. The Tiwai aluminium smelter takes supply directly from the transmission grid; but it helps support many businesses and individuals in the EIL area, both directly and indirectly. Approximately 1000 full time equivalent employees and contractors work at the smelter. Concerns about the smelter closure have resurfaced, however as of time of writing it has been confirmed that the smelter will continue to operate until the end of 2024. Loss of this business would have a major impact on the local economy and therefore growth on EIL's network in Invercargill and Bluff. There are a number of industries that have lodged enquiries for connections in the Southland region. These industries will have an indirect effect on the EIL network, in that the demand for housing in the EIL area may grow, causing an increase in domestic load growth. This has been taken into account in load growth projections.	
$NZD Variation & Commodity Cycles	**Effect:** The improving economy will support the growth initiatives discussed in population growth and lifestyle.
Description: Economic downturn and recovery affects investment by customers and therefore the rate of growth. The global financial crisis affected the rate of growth causing a temporary stalling of new connections. A gradual recovery with growth increasing slowly has been evident. Recent foreign exchange developments have not been favourable to the NZD, resulting in higher import prices for equipment.	

Technology Drivers

Electric and autonomous vehicles, distributed generation, energy efficiency and storage as well as the Internet of Things (IoT) are included in technological drivers of future demand. These are discussed in the following table.

Table 50: Technology Drivers

EVs	**Effect:** Some demand growth toward the end of the ten-year planning horizon.
Description: EVs have the potential to have a large impact on network. EVs are becoming more widely used, it is forecast that by 2030, 10% or more of the light passenger fleet could be electric. EIL intends to use strategies such as cost-reflective pricing to encourage EVs owners to charge their vehicles during off-peak hours, thus reducing the impact on peak demand and increasing load factor. However, EIL must allow for the possibility that customers may not respond well to price signals, causing vehicle charging to occur on-peak. In this scenario modelling shows that the EIL medium voltage network will be able to cope with the increased demand, with minor adjustments to normal configuration. However, the lower diversity on the LV network makes it both more likely that voltage issues will occur, and more difficult to predict in advance where those issues will occur. EIL, through PowerNet, has planned an upgrade of data analysis of ICP smart meters to provide increased visibility of power flow on the network. This data when analysed together with supplementary Maximum Demand Indicators at distribution substations, will better enable EIL to identify vulnerable points on the LV network and proactively upgrade to remove the constraints.	

Autonomous Vehicles	**Effect:** Potential for residential customer density to spread. Potential clustering of EVs charging during business hours, and greater loading on lines further from zone substations. Some impact expected toward the end of the ten-year planning period.

Description: Autonomous vehicles have the potential to have a large impact on the spread of network demand if there is regulatory acceptance and sufficient penetration into the passenger transport sector.

Autonomous vehicles lower the costs of commuting and may make living further from centres of business more viable for customers. The economic case for uptake is further weighted by higher housing costs in target destinations.

Adoption and network impact is highly correlated to uptake of EVs, as the technology is often packaged into newer EVs. Housing cost drivers are viewed as less urgent in Southland, compared to other areas of New Zealand. So, the impact of this technology on network demand is expected to be less rapid.

Fully autonomous vehicles will also likely reduce the rate of personal car ownership.

Progress will be monitored through the same smart meter data programme described in the EVs section above.

Distributed Generation	**Effect:** DG could have significant customer and market benefits. From the distribution network, their impact is expected to be more limited, particularly if effectively managed. Almost all of new generation is from Solar PV, whilst the network peak is historically on winter evenings.

Description: As of November 2023, there are 147 distributed generation (DG) connections in EIL. This is approximately 0.76% of the total connected customers. 144/147 (98%) of the DG connections seen so far has been solar installations and this trend is expected to continue for the foreseeable future.

Through our annual customer engagement survey, intentions to buy and installing solar panels on rooftops across all PowerNet managed networks in the next five years has increased to 38%; an increase of 5% from 2021. The main barriers to adoption related to economic reasons where projected payback period was a large influence on the purchase intention. Other considerations that may limit solar uptake are property ownerships and energy cost reduction options such as home insulation and EVs now receiving increasing attention and better returns.

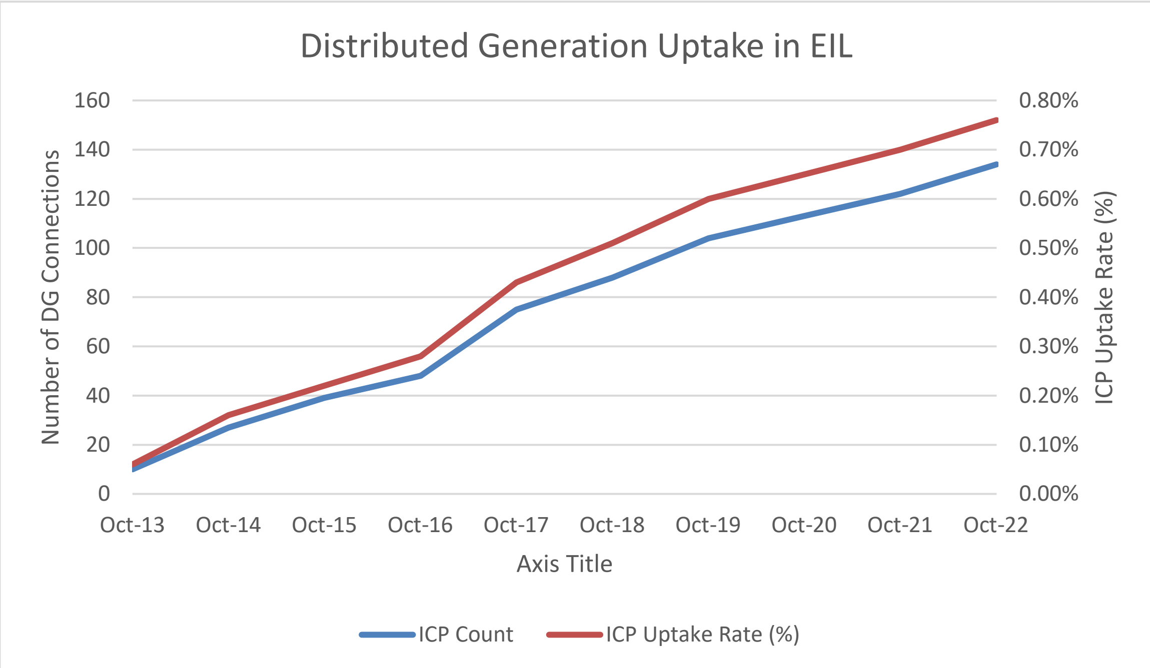


Figure 43 Distributed Generation Uptake on EIL

The LV network can be vulnerable to solar DG installations which, without energy storage, depresses the midday trough in demand (or even reverse power flow) whilst leaving the evening peak unaffected. This increases the range of load currents (and therefore voltage drops) under which the LV network must operate. A network tuned to deliver the minimum acceptable voltage in the evening may still exceed the maximum acceptable voltage at midday if customers connect sufficient solar generation without sufficient storage and controls.

The impact of DG installations on the network can be significantly reduced when the inverters employ Volt-VAr compensation, so PowerNet has made it a requirement for the majority of connections. Similarly, to EVs, the concentration of effects on the LV network makes the location of future voltage problems difficult to predict. Availability of smart metering data allows us to predict economic viability of DG installations such as solar to better understand potential clusters that may emerge in the future. Conducting congestion studies by running multiple penetration levels of DG scenarios on the LV network can also be useful to identify network capacity thresholds and constraints prior to approving new DG connections or requiring controls to be in place so that voltage problems are minimised.	
Energy Storage	**Effect:** Not expected to have a significant presence within the ten-year planning horizon and therefore negligible effect on network demand.
Description: As mentioned above, almost all new DG is from solar PV, while EIL network peak is historically on winter evenings. Coupling solar PV generation with energy storage could change this dynamic, but at present rates the storage capacity provided is immaterial. Storage gives customers some control over their demand without impacting their consumption and could make it feasible for customers to go “off-grid” with a sufficiently sized generation source. However, there is significant uncertainty in this area around the viability of alternative battery chemistries and the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able to promote/utilise/market storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals. Under the status quo this technology is not economic except in exceptional circumstances, and it is not expected that there will be major developments in this area for the next five years. If any such developments occur in the second half of the planning period, it is expected that they will take several years to have an impact at the network level, during which time EIL can respond in a focused manner. Any impact these devices have is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets.	
Energy Efficiency	**Effect**: Negative growth driver accounted a part of the energy conservation initiatives.
Description: Improving energy efficiency has been a government strategy for several years (energy conservation initiatives). It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.	
On-line shopping	**Effect:** Likely to negatively affect the business sector in EIL’s network area however the overall effect on demand is expected to be relatively insignificant.
Description: Shopping online continues to become more and more popular, with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within EIL’s network area. However, there is also some opportunity for local businesses to connect with customers outside of Invercargill or even worldwide and this will somewhat offset the potential loss of business. It is expected the overall effect will be a loss for the business sector in EIL’s area.	
Internet of Things	**Effect:** This technology is becoming more widespread with a significant number of applications being developed, however there are few products that are targeted at reducing demand therefore not affected demand forecasts. In the case that it does eventuate in the next ten years the uptake of this technology is likely to be gradual and so network plans would be able to react sufficiently quickly.
Description: The internet of things refers to the interconnection of the internet and many electronic enabled devices. In particular smart appliances may enable centrally controlled management of a dwellings or business’s consumption so that maximum demand may be minimised by staggering load to make the most of potential load diversity. This could enable customers to reduce line charges in line with a reduced network capacity requirement for their supply.	

Demand Forecasts

The overall impact of the future demand drivers is a 1.2% per annum maximum demand growth rate. Growth per substation is the most appropriate level for identifying constraints on the network.

The projected substation demands indicate the expected growth forecast. This is the most likely outlook, and these projections are the basis for EIL's network development planning. EIL also carries out an internal prudent growth forecast with appropriate contingency planning. Actual future demands may deviate significantly from the growth projections. Potential causes could include lower peak demand due to changing customer habits. Increased energy efficiency in homes is likely to be balanced by increased demand through the conversion of end-of-life burners to electrical heating [Environment Southland have aligned their Regional Air Plan (released Sep 2014) to the National Environmental Standards]. Forecasts are updated annually to ensure that plans can rapidly respond to changes from previous assumptions.

EIL endeavours to realise growth opportunities as they arise, which means developing the network to alleviate constraints as required within the parameters of acceptable risk. With declining growth rates, project to address capacity constraints are postponed, minimising over-investment risks. The risk of stranding of new assets is managed through capacity guarantee contracts with new customers (where appropriate). Risk is also minimised through avoidance of investment until necessary yet still maintaining the desired service levels. Higher than anticipated growth rates present a risk of missed opportunity for growth for both EIL and EIL's customers.

It is expected that growth affecting the entire network will be determined with sufficient timing to allow for resource adjustments. Large scale developments are likely to be funded by external investors through capital contributions. In general, EIL has the ability to quickly respond to unforeseen large-scale developments that occur once-off. Limits to this capability might be negotiated around timing of project delivery. While all efforts are made to inform customers of potential lead times for providing additional network capacity, requests for supply are often made late in customers' planning processes due to commercial sensitivities.

Network Constraints

The Invercargill GXP has a firm capacity of 143 MVA with the historical GXP maximum demand at 96.5 MW. There is capacity for growth well beyond the ten-year planning horizon based on the growth rate estimates, however, this GXP is shared with the TPC network where they are experiencing abnormally high load growth due to decarbonisation initiatives. This growth will potentially trigger capacity upgrades at the GXP.

There are no constraints on the sub transmission network that could prevent the zone substation capacities being utilised. In addition, load control could potentially be utilised to limit EIL load if required.

Table 51 displays the projected maximum demand for zone substations at the end of the ten-year planning horizon and the expected provisions for future growth. The assumption is that unforeseen changes in growth rates or step changes due to connection or loss of large customers will not occur.

Table 51: Substation Demand Growth Rates

Substation	MD '21/22	MD '30/31	Provision for Growth
Spey Street	23.1	27.7	Spey Street substation replaces the old Doon Street substation as part of a major development project for EIL. Spey Street has a capacity of 72MVA and a firm rating of 36MVA and is adequate for the anticipated load over the ten-year planning horizon.
Leven Street	14.5	18.7	Leven Street has a capacity of 46MVA and a firm rating of 23MVA. The firm rating is unlikely to be exceeded by the end of the ten-year planning period; if a capacity constraint did arise, it could be managed through load transfer to Spey St substation. The Invercargill CBD redevelopment is expected to have slightly net positive increase on long term electricity demand, as older buildings are replaced with newer buildings (more energy efficient but larger floor area).
Southern	12.4	16.9	Southern substation has a capacity of 23MVA available from its single transformer. Supply security is being addressed with the Southern Substation project, which will bring security to the required AAA level. Load transfer to neighbouring zone substations has been utilised to reduce loading to manage risk in the interim. On completion of the Southern Substation project, the optimal network configuration and normal loading will be restored. Remaining work is the refurbishment of the second transformer installed at the substation.
Racecourse Road	11	11.4	Racecourse Road substation has a capacity of 23MVA available from its single transformer. Maximum demand has exceeded the 12MVA security trigger in recent years, due to load transfers from other substations. As the Southern Substation project has been completed, the load is being re-balanced between the Invercargill substations. This will avoid triggering development of the Racecourse Road substation till after the planning period.
Bluff (TPCL)	5.3	4.7	Demand in Bluff is historically flat. Recent increases in demand are attributed to activity at SouthPort, which may reduce back to historic levels if an economic downturn were to occur. The introduction of Flat Hill wind farm produced a downward trend in the annual demand totals. The influence of the wind farm must be removed for forecasting purposes, due to the intermittent nature of wind generation. The economics of EVs will be particularly attractive to Bluff residents who regularly commute to Invercargill. On-peak charging of these vehicles would lead to growth beyond the expected level, however Bluff substation has a firm capacity of 13 MVA, which is sufficient for a prudent growth forecast well beyond the ten-year planning horizon.

Projected annual maximum demands incorporating growth provisions is presented in Table 52. Sites with high loads will be closely monitored to determine if capacity will be exceeded in the short term. Annual preparation of data will highlight sites with capacity constraints and the planned works will be adapted for each situation. This would entail that some capacity upgrades be delayed or brought forward.

Table 52: Substation Maximum Demand (incorporating growth)

Substation	'23/24	'24/25	'25/26	'26/27	'27/28	'28/29	'29/30	'30/31	'31/32	'32/33
Spey Street	24.5	24.6	24.8	25.0	25.3	25.7	26.1	26.6	27.1	27.1
Leven Street	16.4	16.6	16.8	17.0	17.2	17.6	17.9	18.3	18.7	18.7
Racecourse Rd	10.2	10.3	10.3	10.4	10.6	10.7	10.9	11.1	11.4	11.4
Southern	10.2	14.7	14.9	15.2	15.5	15.8	16.1	16.5	16.9	16.9
Bluff	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7

EIL also manages other general constraints on its network as described in Table 53.

Table 53: Network Constraints and Intended Remedy

Constraint	Description	Management Approach
MV Cables	Some MV cables operate near full capacity and would be unable to supply load in backup scenarios.	When cables are replaced, the capacity is reviewed to ensure new cables have capacity for forecast growth and load transfers. Operational measures ensure cables are not overloaded and smaller MV cables are protected with fuses.
MV Transformers	Some transformers are near full capacity.	Maximum Demand Indicators (MDIs) are monitored, and transformers will be upsized or supplemented with additional units as appropriate. MDIs will be upgraded in the medium term to provide improved data for transformer loading and LV network analysis. Underutilised transformers may be relocated before purchasing new.
LV Switching in CBD	Limited locations are available for above ground equipment.	Communication with the Council to determine appropriate locations for above ground link boxes has worked well.
Overhead Lines	The District Plan prohibits new overhead lines in the Invercargill City area.	Underground cables have been utilised throughout Invercargill. (Bluff is still supplied through an overhead network)

Distributed Generation and Demand Management

Distributed Generation (DG) influence on maximum demand is negligible due to the estimated low connection density of DG and the prevalent winter conditions in the area. The probability exists that only a small percentage of the capacity will be available during winter peaks.

Load Management is used when substation equipment is nearing overload as well as with load transfers for maintenance purposes. The assumption is that load management have a minimal influence on projected demand, although historical demand records will include these effects.

Service Level Changes

The general approach of monitoring network demand, and initiating projects when standardised development triggers are reached, serves to maintain existing service levels. Where a change in service level is desirable, this may be undertaken either directly (e.g., targeted seismic remediation program to improve safety and resilience under earthquake conditions), or indirectly through the adjustment of the thresholds used for the triggers (e.g., lowering the minimum number of downstream customers required to justify a dual transformer substation). These decisions tend to be strategic in nature and go beyond the general approach of monitoring network demand and initiating projects when standardised development triggers are reached.

These projects may be triggered by a complex interaction of many factors or driven (or required) by external influences. Examples are the shifting perceptions around staff/personnel safety or acceptable levels of risk, and these will create drivers for network development projects which are not a requirement arising from demand growth.

Development Programme

Development projects underway or planned for the next 12 months, the following four years and those that are considered for the remainder of the planning period are presented in the following tables.

Table 54: Non-routine Development Projects (next 12 months)

Project Description	24/25 CAPEX Cost
Customer Connection Projects: This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements. Scope and timing of works are adjusted to customers' works plans as communicated to EIL. Expenditure and timing may differ from that published as customer developments progress.	$1,343,749
Asset Relocation Projects: This budget captures costs for general minor relocation works required such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long-term average with actual spend being reactive and typically above or below budget in any year.	$7,174
Quality of Supply Projects: On the LV network, operation beyond capacity typically manifests as decreased voltage levels experienced by customers during periods of peak loading. This may occasionally require a new transformer site with associated 11 kV extension if required. However, in most cases replacing LV cables with larger cables will be a more economic option to maintain acceptable voltage for all customers. The minimum standard cable size which provides the existing and spare capacity for expected growth will be used.	$169,567
Reliability, Safety and Environment (including Pillar Box Lid Upgrades): EIL has traditionally used concrete pillar boxes with aluminium lids on the front to enclose the fusing for individual customers' supplies. However, in very rare cases the internal cables can come into physical contact with the lid, and the cable insulation can be gradually abraded, e.g., because of minute vibrations caused by nearby traffic. If the insulation were to abrade sufficiently between pillar box inspections, this situation could result in livening of the aluminium lid. A supplier has been sourced for plastic lids that offer similar mechanical protection to the aluminium lids whilst being electrically nonconductive. These plastic lids are being installed as a part of the pillar box inspections.	$1,397,304

Table 55: Non-routine Development Projects (next five years)

Project Description	CAPEX Cost & Timing
Customer Connections: This budget provides allowance for new connections to the network including subdivisions where many customers may require connection. Each specific solution will depend on location and customer requirements. Connection's activity has increased in recent years 2020-2023 and is expected to continue into 2024-25 due to the Invercargill CBD redevelopment and other known customer-initiated works. Capital expenditure has been increased for EIL to provide the required supporting electrical infrastructure. In Scope and timing of works are adjusted to customers' works plans as communicated to EIL. Expenditure and timing may differ from that published as customer developments progress. Planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate. However, customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance. Various options are considered to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised. The district plan requires all new network to be underground in Invercargill, however, Bluff may utilise overhead construction which tends to be a lower cost option. Distributed generation as a network alternative tends to be intermittent so cannot be relied on without energy storage, which could make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the upfront cost is generally not attractive to most customers and generally a connection to the network is still desired as backup, supplementation and sometimes the ability to sell surplus energy. Customers may be encouraged to better manage diversity of load within their facilities where details are known and there is perceived benefit to the customer or network. Budgets for subdivisions and distributed generation are separated from other connections to support trending analysis; however, these budgets are set low as it is expected that spend will occur against them only once every few years.	$4,764,957 '24/25-28/29
Earth Upgrades: Ineffective earthing may create, or fail to control, hazardous voltage that may occur on and around network equipment affecting safety for the public and for staff. Ineffective earthing may prevent protection systems from operating correctly which may affect safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades. The analysis to determine what upgrade options are appropriate can be quite complex but essentially it looks to find the best trade-off between cost and risk reduction. Generally, in EIL the earthing upgrades required will be minimal with safety being achieved by simple connection to the large urban MEN (multiple earthed neutral) system. However, for sites where risk of potential exposure to EPR is high additional measures for example insulating barriers will be required to ensure public safety. Routine testing is completed five yearly with the entire network tested in one year. This project has been increased to cover remediation of non-compliant / un-maintainable sites discovered in the most recent earth inspection / testing round.	$1,089,036 '24/25 and onwards

Project Description	CAPEX Cost & Timing
LV Tie Point Disconnectors: Distribution substations are routinely de-energised to carry out necessary maintenance on the ring main units. At times, when justified to prevent disruption of supply to customers, the substation's load is transferred to neighbouring substations prior to de-energisation. This load transfer is currently carried out by manually connecting live conductors together at tie points using cable taps. While the risks of this procedure are largely mitigated by the use of administrative controls, insulating mats, and personal protective equipment (PPE), the residual safety risk may be deemed inappropriate for a modern electricity distribution business working under current health and safety legislation. This project provides for the installation of disconnector switches at all LV tie points on the network. In addition to the safety benefit, this project is expected to reduce the switching time associated with a de-energisation by over 75% and reduce wear / tear from manual handling of cables. The project will focus on two-way and three-way pillars, where a method has been devised to retrofit disconnectors into the existing pillar boxes. Retrofit installations will be aligned with the distribution substation maintenance servicing cycle and transformer replacements. Upon completion of the pillar retrofits, the focus will shift to switches that require pillar replacement. This will most likely involve replacing existing pillars with a larger injection moulded pillar box. Overall, nearly 1000 pillars will be upgraded in a project that extends beyond the end of the planning period.	$1,359,821 '24/25 and onwards
Supply Quality Upgrades: On the LV network, operation beyond capacity typically manifests as decreased voltage levels experienced by customers during periods of peak loading. This may occasionally require a new transformer site with associated 11 kV extension if required. However, in most cases replacing LV cables with larger cables will be a more economic option to maintain acceptable voltage for all customers. The minimum standard cable size which provides the existing and spare capacity for expected growth will be used. An alternative to network upgrade is demand side management, however cost incentives to reduce demand are proving ineffective due to the retailers repackaging of line charges into their billing. As EIL's 11 kV feeders have high load density supplied over a relatively short distance, LV is not seen as an issue on these feeders. Costs budgeted represent a long-term average with actual spend varying around this average from year to year. Once smart meter LV information is more readily available, EIL anticipates an increase in supply quality related work, in advance of customer complaints. The allowance for this work will be adjusted with more accurate projections of work volume.	$89,251 p.a.
Network Automation Projects: This budget is to allow implementation of network automation initiatives on the Invercargill and Bluff networks to add additional remote controllable switching points and automation technologies. The resulting improvements in reliability are intended to offset the reduction in reliability that is to be expected as the cable network is allowed to age back to the optimal average asset life remaining of 50%; the extensive underground programme and other recent or near future capital intensive projects have made EIL into an unusually young network.	$188,645 '24/25 onward

Table 56: Non-routine Development Projects (under consideration)

Project Description	CAPEX Cost & Timing
Unspecified Projects: This budget is an estimate of costs for projects that are yet unknown but are considered likely to arise in the longer term. Certainty for these estimates is obviously low.	$No provision

Project Description	CAPEX Cost & Timing
These projects and this expenditure will eventuate based on customer driven developments and engineering evaluation of network capacity.	

Non-network Development

IT and management services support are provided through the services contract with PowerNet. EIL does not directly develop the GIS or AMIS (Maximo) systems, but in conjunction with PowerNet develop interfaces and processes around these systems.

7.2 Asset and Network Design

The design life cycle stage addresses the following aspects.

- Type of assets used on the networks.
- Network configuration.
- Interactions between various assets and asset systems on the network.
- Physical location of assets.

Design Phase Risks

The following risks are partially addressed in the design life cycle phase.

Table 57: Design Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment Plan
Operational Performance - 1	**Damage due to high impact low probability extreme physical events (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Locating assets and networks to avoid high event probability areas. Design structures and buildings to cater for seismic events.
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance, ineffective fleet plans Budget constraints Lack of future network planning	Designs take maintenance and operations requirements into account. A lower equipment purchase price should not be cost of reliability and should not lead to increased maintenance requirements. Design takes asset retirement and disposal into account.
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism	Asset and system design takes physical security into account.
Operational Performance	**Unavailability of critical spares**	Poor future work planning, high impact low probability events causing high spares usage, Supply chain disruptions	Designs are standardised to minimise stock levels and create interchangeability of assets.
Operational Performance	**Loss of key critical service provider**	Economic environment, Lack of sufficient work to sustain contractors; unexpected inability of contractor to complete work, Major health event/pandemic	Standardised design does not lead to single supplier dependencies. A limited number of asset options are available. Designs can be implemented by any of several competent contractors.

Category	Risk Title	Risk Cause	Risk Treatment Plan
Operational Performance	**Major event triggering storm gallery activation**	Damage caused by wind, snow, storm events	Design to reduce or eliminate faults due to inclement weather.
Health and Safety	**Public meeting live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Safety in Design process takes public exposure to live equipment into account. Asset placement reduces public interaction with the assets. Any new assets are evaluated in terms of safety before they are approved for use on the network.
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Design standards take environmental risk into account. Asset do not contain hazardous substances or hazardous substances are controlled.

Cost Efficiency

In the interests of cost efficiency, EIL aims to minimise capital expenditure when determining the most appropriate development option for the network. Being cost-efficient with network development requires a "just enough, just in time" approach for the determination of appropriate new capacity, and an appropriate level of standardisation. Other works within the locale may be brought forward and combined to achieve economies of scale for design, safety, and traffic management costs.

Before capital-intensive upgrades are required, the following options, in a broadly descending order of preference, are considered when development triggers have been reached:

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. Do nothing options would only be adopted if the benefit-cost ratios of all other reasonable options were unacceptably low and if assurance was provided to the Chief Executive that the do-nothing option did not represent an unacceptable increase in risk to EIL. An example of where a do-nothing option might be adopted is where the voltage at the far end of a remote rural feeder drops below the network standard minimum level for a short period at the height of the holiday season – the benefits of correcting such a constraint are simply too low to justify the expense.
- Operational activities, in particular switching on the distribution network to shift load from heavily loaded to lightly loaded feeders to avoid new investment or winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.
- Demand management using load control or using other methods to influence customers' consumption patterns so that assets operate at levels below trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain customers so that overloaded assets can be relieved or assist a customer to adopt a substitute energy source to avoid new capacity. EIL notes that the effectiveness of line tariffs in influencing customer behaviour is diminished by the retailer's practice of repackaging fixed and variable charges.
- Install generation or energy storage units so that an adjacent asset's performance is restored to a level below its trigger points. These options would be particularly useful where additional capacity

could eventually be stranded or where primary energy is going to waste e.g., waste steam from a process.

- Modify an asset so that the asset's trigger point will move to a level that is not exceeded e.g., by adding forced cooling. This approach is more suited to larger classes of assets such as power transformers. Installation of voltage regulating transformers may be economic where voltage drops below acceptable levels, but current capacity is not fully utilised.
- Retrofitting high-technology devices that can exploit the features of existing assets including the generous design margins of old equipment. An example might include using advanced software to thermally re-rate heavily loaded lines, using remotely switched air-break switches to improve reliability or retrofit core temperature sensors on large transformers to allow them to operate closer to temperature limits.

Installing new or greater capacity assets is generally the next step to increase asset capacity to a level at which the relevant trigger point is not exceeded. An example would be to replace a 200 kVA distribution transformer with a 300 kVA unit so that the capacity criterion is not exceeded.

For meeting future demands for capacity, reliability, security, and supply quality there may be several options within the above range of categories and identifying potential solutions is dependent on the experience and ingenuity of the Engineers undertaking the planning.

Standardisation

Standardisation is an important strategy used by EIL to achieve cost efficiencies. It may not always be obvious that standardisation achieves this outcome; standardised equipment sizes will often mean larger equipment is used than would otherwise be strictly necessary. However, standardising assets allows efficient management of stock and spares, operator familiarisation, standardisation of operation procedures, and simplified selection of equipment and materials. Standardised designs or design criteria also avoid "reinventing the wheel", simplifies the design process, and can incorporate more learnings than could otherwise not be practically managed. The benefits of standardisation easily outweigh the oversizing of assets where significant repetition of a particular network solution occurs.

PowerNet's Quality Systems (policies, standards, and procedures) provide for the documentation and communication of the standards that are applied to EIL's network. EIL benefits from their close working relationship with the other line owners whose networks are managed by PowerNet, with the standardisation able to be maintained across networks for increased efficiencies. Examples include the keeping of critical spares, which can be more efficiently achieved when shared across the combined network's asset base; or lessons learnt on one network that can be incorporated into standards which then benefit the other networks. Standardised design is used for line construction with a Construction Manual and standard drawings in use by planners, designers, and construction staff.

Standardised designs for projects may be used from time to time where projects with similarities occur within a short enough period. Though these opportunities do not arise often on EIL's network, similar projects are often managed by PowerNet on other networks and where project scopes overlap design "building blocks" may be utilised in several designs. Through this approach a degree of standardisation is achieved, with each consecutive design utilising these building blocks from the latest previous design. Continuous improvement is realised with lessons learnt able to be incorporated at each iteration.

Virtually all the EIL network assets are standardised to some degree either by being an approved network material or asset type or by selection and installation in line with network standards. Examples of standardisation are listed in Table 58.

Table 58: Equipment Standardisation

Component	Standard	Justification
Underground Cable	Distribution and LV network: 35, 95, 185 & 300 mm^2 Al	Stocking of common sizes, lower cost
	11 kV Cable Cross-linked Polyethylene (XLPE)	Rating, ease of use.
Overhead Conductor	Sub transmission and distribution: All aluminium alloy conductor (AAAC) - Chlorine, Helium, Iodine, Neon or	Low corrosion, low resistance, cost, stocking of common sizes
	Aluminium conductor steel reinforced (ACSR) – Flounder, Wolf	Higher strength (longer spans, snow load)
	LV Aerial Bundled Cable (ABC): 35, 50 & 95 mm^2 Al (four core).	Safety, lower cost.
Structures	Poles: Busck pre-stressed concrete	Consistent performance, long life, strength
	Cross-arms: Solid hardwood	Long life, strength.
Line equipment	Standard ratings (e.g., ABS 400 A, field circuit breaker 400 A), manufacturer/type	Cover-all specification, minimise spares, familiarity, environmental (non SF_6)
Power Transformers	Discrete ratings, tap steps, vector group, impedance, terminal arrangements etc.	Ratings match available switchgear ratings, interchangeability, network requirements.
33 kV & 11 kV Switchboards	Common manufacturers, common specification.	Interchangeability spares management.
Protection and Controls	Common manufacturer, communications interface, supply voltage etc.	Minimise spares, familiarity, proven history
Substation equipment	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history
Distribution Transformers	Standard ratings (residential areas - size based on domestic customer numbers), equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.
Ring Main Units	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.

Security

Security is the level of redundancy that is built into the network to provide improved continuity of supply when faults occur. It enables supply to be either maintained or restored independently of repairing or replacing a faulty component. EIL's security standard is therefore crucial for the maintenance of network reliability levels. Security involves a level of investment beyond what is strictly required to meet demand, but maintenance of the desired security level must account for demand growth eroding surplus capacity. Typical approaches to providing security include the following.

- **Provision of Alternative Supplies.** This is achieved by providing one or more inter-feeder tie switches (interconnection points). Urban areas can naturally achieve a high level of meshing with many tie points between feeders whereas rural area feeders may need significant line extension to meet adjacent feeders. Feeders are generally designed to be able to offload the full feeder load during a fault scenario. Exceptions are the limited number of radially fed customers. The number of switches effectively dividing up a feeder also contributes to security, with the greater the number, the smaller the section which must be isolated after a fault for the duration of the repair. This requires those adjacent feeders to maintain spare capacity.
- **Duplication of Assets.** In normal service both sets of assets share the load. When a duplicated asset malfunctions it can be isolated, and all loads can be transferred to the remaining asset. This approach generally provides the greatest security as it can completely prevent interruption to supply; but duplication of assets tends to be more expensive than merely allowing greater capacity in existing adjacent circuits.
- **Generation.** This can be used to either provide an alternate supply, or to partially supplement supply and reduce capacity requirements for backup assets. From a security perspective, generation needs to have close to 100% availability to be of benefit. Diesel generation has good availability and is used occasionally to manage network constraints, although it is too expensive to run for extended periods. Other forms of generation such as run-of-the-river hydro, wind or solar, do not provide the needed availability due to lack of energy storage and so cannot be relied on to respond to varying load or provide sufficient generation during peak demand periods.
- **Demand Management.** Use of demand management (interruptible load) can be used to avoid security triggers based on load level or avoid capacity of backup assets being exceeded.

The preferred means of providing security to urban zone substations will be by secondary sub transmission assets with any available back-feed on the 11 kV providing an extra level of security.

Table 59 summarises the security standards adopted by EIL. An exception to these standards occurs when a substation is for the predominant benefit of a single customer; in this case the customer's preference for security will be documented in their individual line services agreement and will set the minimum-security level.

Table 59: Target Security Levels

Description	Load Type	Security Level
AAA	Greater than 12 MW or 6,000 customers.	No loss of supply after the first contingent event.
AA	Between 5 and 12 MW or 2,000 to 6,000 customers.	All load restored within 25 minutes of the first contingent event.
A(i)	Between 1 and 5 MW	All load restored by isolation and back-feeding. Isolated section restored after time to repair.
A(ii)	Less than 1 MW	All load restored after time to repair.

The current security levels for Zone Substations are displayed in the next Table.

Table 60: Security Levels for Zone Substations

Substation	Current Security Level	Required Security Level	Remarks
Spey Street	AAA	AAA	Dual 33kV transformer feeders from Invercargill GXP.
Leven Street	AAA	AAA	Short interruption required to switch to alternative supply from another GXP*
Southern	AA	AAA	Short interruption required to switch to alternative supply
Racecourse Road	AA	AA	Single transformer feeder from Invercargill GXP. Short 33kV cable. Alternative supply from 11kV back feed.
Bluff	AAA	AA	More economic to provide AAA security at the site, due to the lack of 11 kV backup capacity.

* The substation itself has full redundancy. However, the two infeed are from different GXPs so to avoid paralleling the GXPs on 33kV, a “break before make” system is in place.

The Otatara power supply has only a single 33 kV line and together with 11 kV faults has a reliability concern. The backup connection from EIL Stead Street is to reinforce and regulated to provide a firm backup to minimise outage times. PowerNet are upgrading the LEV 13 11kV overhead conductor in the Bond Street/Mersey Street area of Invercargill.

The existing Mink ACSR conductor is to be replaced with Neon AAAC/1120 conductor. The standard AS/NZS 1170.2:2021 covering regional wind loading introduced a new wind region NZ4 which covers Invercargill south, with a regional speed of 47m/s (169km/h) for a 100-year return period, this is up from a 42m/s wind under the old standard. This higher wind loading is having a considerable effect on the pole utilization.

Capacity Determination

When new or increased capacity has been determined as necessary the amount of new capacity must be quantified. Appropriate asset sizing is balanced to fit within EIL’s guiding principle, which is to minimise the long-term cost to provide service of sufficient quality under foreseeable demand.

Sizing network equipment carries an investment risk for assets being underutilized if not done correctly. While sizing a particular asset for the present time is relatively straightforward, load growth makes appropriately sizing an asset more difficult, especially for asset lifetimes over periods of high growth and growth unpredictability. Installing assets with too much spare capacity means an over-investment; however, if assets are undersized, the asset will need to be replaced early before their natural end of life. In many cases, standardization will limit the options available to assist capacity selection. In general, this will mean balancing over-investment, and under-investment will result in a small amount of over-investment (i.e., increased capacity). However, this is considered optimal due to the often-marginal cost of increased capacity versus the significant cost of re-work should the investment be under-sized.

Stranding of assets is a risk where new assets are required to supply one (or few) new customers representing the worst case in overinvestment if the expected growth does not eventuate. This stranding risk is particularly significant when network extension outside the existing network footprint is required. The assets are less likely to be reutilized if the expected load disappears. Stranding risk is generally managed through capacity guarantee contracts with customers to recover expected line charges if necessary.

Relocation of assets provides a way to manage costs efficiently while limiting exposure to the above risks in areas of growth. However, this strategy is only of benefit where the material cost dominates the installation cost of establishing an asset; the installation cost cannot be recovered. For example, once load grows to a power transformers capacity the transformer can be relocated and used elsewhere so that a larger unit may be installed in its place. In comparison a cable (where trenching and reinstatement dominates installation costs) would typically be abandoned and replaced.

Examples of criteria to determine capacity of equipment in line with the above considerations are as shown in Table 61. Clearly understanding load growth into the future is crucial to making sound investment decisions.

Table 61: Capacity Selection Criteria

<table>
<tr><th>Network Asset</th><th colspan="2">Capacity Criteria Selection</th></tr>
<tr><td>Sub transmission network</td><td colspan="2">Allow expected demand growth over life time of assets</td></tr>
<tr><td>Power transformers</td><td colspan="2">Allow expected demand growth over 20 years then relocate</td></tr>
<tr><td>Switchgear</td><td colspan="2">Allow expected demand growth over life time of assets</td></tr>
<tr><td>Distribution and LV cables</td><td colspan="2">Allow growth over expected life when known or otherwise 100% growth over existing load</td></tr>
<tr><td rowspan="4">Overhead distribution and LV lines</td><td colspan="2">Build to standard volt drop from nominal:</td></tr>
<tr><td>Urban</td><td>Rural</td></tr>
<tr><td>11 kV: -3%</td><td>11 kV: -4%</td></tr>
<tr><td>LV: -5%</td><td>LV: -4%</td></tr>
<tr><td rowspan="10">Distribution transformers</td><td colspan="2">Size based on diversity and anticipated medium term load:</td></tr>
<tr><td>Domestic Customers</td><td>Transformer Size</td></tr>
<tr><td>2</td><td>15 kVA</td></tr>
<tr><td>6</td><td>30 kVA</td></tr>
<tr><td>10</td><td>50 kVA</td></tr>
<tr><td>20</td><td>100 kVA</td></tr>
<tr><td>50</td><td>200 kVA</td></tr>
<tr><td>80</td><td>300 kVA</td></tr>
<tr><td>150</td><td>500 kVA</td></tr>
<tr><td>Individual customers</td><td>Size to customer requirements</td></tr>
</table>

Best Option Identification

Of the many possible development options that may be identified for meeting demand and service levels, the possibility that best meets EIL's investment criteria is determined using various analytical approaches. Each possible approach to meeting demand will contribute to strategic objectives differently. Increasingly detailed and comprehensive analytical methods are used for evaluating more expensive options.

Table 62 summarises the decision tools used to evaluate options depending on their cost.

Table 62: Cost-based Decision Tools

Cost & Nature of Option	Decision Tools	Approval Level
Up to $75,000: commonly recurring, individual projects not tactically significant but collectively add up.	• EIL standards. • Industry rules of thumb. • Manufacturer's tables and recommendations. • Simple spreadsheet model based on a few parameters.	Project Manager & Network Engineer
$75,000 to $250,000: individual projects of tactical significance. Timing may be altered to allow resource focus on higher priority projects.	• Spreadsheet model to calculate NPV that might consider one or two variation scenarios. • Basic risk analysis including environmental and safety considerations. • Consultation with stakeholders if necessary.	GM Asset Management
$250,000 to $1,000,000: individual projects or programmes of tactical or strategic significance. Timing may or may not be flexible depending on priority.	• Extensive spreadsheet model to calculate NPV that may consider several scenarios. • Risk analysis including environmental and safety considerations with consideration to management cost. • Consultation with stakeholders if necessary.	Chief Executive
Over $1,000,000: occurs maybe once every few years, likely to be strategically significant. May divert resources from routine lower cost projects in the short term.	• Extensive spreadsheet model to calculate NPV, payback that will probably consider several variation scenarios. • Detailed risk analysis including environmental and safety considerations - represented as cost estimates within NPV and Payback calculations. • Resources (financial, workforce, materials, legal) across AWP need to be balanced across many projects and several years managed through planning meetings and spreadsheet models. • Ongoing stakeholder consultation may be required especially large customers. • Business case presented to the Board, highlighting options considered and justification of recommended option.	Board Approval

Prioritisation of Development Projects

Development projects are prioritized when competition for resources exists in managing conflicting stakeholder Interests. Safety, viability, pricing, supply quality, and compliance are priorities for managing conflicts. These factors cannot be applied generally, as each project will have its combination of these factors in various degrees. Instead, a weighting approach is used, recognizing the relative severity of these factors between projects and their importance relative to each other. Each element also implicitly recognizes risk; however, this may need to be rationalized as it affects the AWP. The resulting prioritized AWP is presented to the EIL Board for approval with supporting justification in the updated AMP.

Electrification and Energy Efficiency

EIL strives to make decisions based on the best outcome for its customers; customers pay for losses on the network in their energy bills, so it is in the customer's interest to deliver energy as efficiently as possible. However, from a customer's benefit-cost point of view, the extra expense of a more efficient asset will generally outweigh the benefit of that asset. In the few cases where there is an economic justification to reduce losses in this way EIL will use these solutions, e.g., specifying low loss cores used in the magnetic circuits of transformers.

Power consumed by EIL and its organisational partners is used responsibly, with substation buildings and PowerNet's office buildings heated using efficient heat pump technology, insulation, and draft control etc. where appropriate. EIL formed the Southland Warm Homes Trust (SWHT) in 2008 with the Southland Power Trust (TPCL's shareholder). The SWHT works in partnership with government, the Energy Efficiency and Conservation Authority (EECA) and local funders to provide subsidies for insulation and heating assessments and retrofits for warmer, healthier homes across the Deep South region. PowerNet provides administration and financial reporting services on behalf of the SWHT.

The SWHT contracts Awarua Synergy to carry out assessments and the installation of insulation and heating products on behalf of the Trust. Under EECA's Warm Up NZ Healthy Homes program which came into effect on 1 July 2013, insulation is free for eligible homeowners. Landlords with eligible tenants are also included but will be required to contribute. The Healthy Homes scheme targets those who stand to benefit most from having their homes insulated, those being low-income households with high health needs, including families with children and the elderly. EECA provides 50% of the funding conditional upon the remaining 50% funding coming from third party funders.

Distributed Generation

The value of distributed generation can be recognised in the following ways.

- Reduction of peak demand at the Transpower GXP.
- Reducing the effect of existing network constraints.
- Avoiding investment in additional network capacity.
- Making a very minor contribution to supply security where the customers are prepared to accept that local generation is not as secure as network investment.
- Making better use of local primary energy resources thereby avoiding line losses.
- Avoiding the environmental impact associated with large scale power generation.

It is also recognised that distributed generation can have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an asset's capacity.
- Raising voltage above regulated levels.
- Can cause safety issues when the network de-energises a line to carry out work.

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and EIL is actively encouraged. No distributed generators within EIL's network have an appreciable effect on development planning.

Terms and Conditions for Commercial Connections

- Connection of up to 10 kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10 kW to an existing connection may incur additional costs to reflect network up-sizing.
- Distributed generation that requires a new connection to the network will be charged a standard connection fee as if it was a standard off-take customer.
- An application administration fee will be payable by the connecting party.
- Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.
- Any benefits of distributed generation that arise from reducing EIL's costs, such as transmission costs or deferred investment in the network, and provided the distributed generation is of sufficient size (greater than 10 kW) to provide real benefits, will be recognised and shared.
- Those wishing to connect distributed generation must have a contractual arrangement with a suitable party (retailer) in place to consume all injected energy – generators will not be allowed to "lose" the energy in the network.

Distributed Generation Safety Standards

- A party connecting distributed generation must comply with all safety requirements promulgated by EIL.
- EIL reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

Distributed Generation Technical Standards

- Metering capable of recording both imported and exported energy must be installed if the owner of the distributed generation wishes to share in any benefits accruing to EIL. Such metering may need to be half-hourly.
- EIL may require a distributed generator of greater than 10 kW to demonstrate that operation of the distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control.
- All connection assets must be designed and constructed to technical standards not dissimilar to EIL's own prevailing standards.

Use of Non-Network Solutions

EIL routinely considers a range of non-asset solutions and prefers solutions that avoid or defer new investment. Effectiveness of tariff incentives is lessened with Retailers repackaging line charges in ways that sometimes remove the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels. Load control is utilised for the following.

- Transpower charges by controlling the network load during the LSI peaks.
- GXP load when maximum demand reaches the capacity of that GXP.
- Load on feeders during temporary arrangements to manage constraints.

Load shedding may be used by some customers where they accept a reduction of their load instead of investing in additional network assets. This is generally done through a Special Protection Scheme (SPS)

Other low-cost solutions

Generators (owned by PowerNet) are used where appropriate for planned work on distribution transformers or LV network, to reduce the reliability impact of the work as a temporary solution during work execution. Other typical low-cost options include the following.

- Conductor upgrades.
- Voltage regulators.
- Pumps and fans on power transformers.
- Tie point shifts.

There are limits to the capabilities of low investment options to meet growth when the capacity margins are depleted or when demand is significant or occurring in large clusters.

Responses to the impact of Technology

Changes in markets, regulations, and customer behaviour create opportunities, but also complexities and risks for EIL. Responses to these potential impacts include the following.

- Implementing detailed demand data monitoring and analysis.
- Increasing cross-industry collaboration.
- Trialling new technology to have a better understanding of potential adoption and impact.
- Continuous improvement in communications with customers.

7.3 Asset Acquisitioning

During asset acquisitioning, designed assets are bought and installed. This phase often includes civil construction activities. The prevention and treatment of safety risks are paramount. This life cycle stage partially addresses the following risks.

Table 63: Acquisitioning Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment Plan
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance, ineffective fleet plans, Budget constraints, Lack of future network planning	Ensure all new assets going onto the network are reliable – New Assets Process Manage the quality of work by contractors and own staff
Operational Performance	**Damage due to extreme Physical Event (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Ensure all assets can withstand potential events they may be subject to. Construct all buildings and structures to be seismically compliant
	Major Contractual Breach	Breach of contractual obligations in place with key counterparties, resulting in legal action with potential serious financial implications and/or reputational damage	Use of standard, vetted contracts – NEC Contract and contractor management
	Unavailability of critical spares	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Ensure that any new assets are supported by a reputable supplier. Procure strategic spares and parts when procuring the asset
	Loss of key critical service provider	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Improved identification of critical suppliers and contractors Identify alternative suppliers and contractors Internalise and grow internal workforce so that work can be executed internally
Health & Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Install barriers against inadvertent access to live assets
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Construction methodologies employed cause no environmental harm

Installation of Assets

The drivers for the installation of an asset may change during the asset's operational life. In addition, the viability of maintaining or replacing an asset at end-of-life may also change. These drivers must be monitored beyond the installation process to ensure that the objective of providing an efficient and cost-effective service is achieved.

Standards are used to guide the construction and installation of regular assets such as a distribution transformer. However, complex assets (such as a zone substation) will require substantial design work before installation.

Equipment and materials are procured (per the relevant design or standard) and implemented according to EIL's standardization requirements.

Post-installation, the commissioning process follows. This process is either specified in the design or (for standardized installations) in a commissioning checklist. The purpose is to ensure the asset has been installed and will function as intended prior to putting it into service.

Asset Replacement and Renewal

Replacement and renewal programmes aim to get the full benefit of assets by replacing them near their economic end-of-life. This is balanced by the need to manage workforce resources in the short term and the delivery of desired service levels over the long term.

Inspection and testing programmes identify assets reaching end-of-life, while critical assets may be replaced on a fixed-time basis. For example, 11kV switchboards at zone substations are generally replaced at the end of their nominal year life. Less critical assets or assets provided with redundancy (as part of security arrangements) may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to the point that complete replacement is more economic. This approach requires monitoring failure rates.

Apart from whole-of-life cost analysis, several other replacement drivers include operational/public safety, risk management, declining service levels, accessibility for maintenance, obsolescence, and new technology. Some of these may be diminished through cost analysis. The network development driver might also impact asset replacement requirements.

Innovations That Defer Asset Replacement

Although asset age is taken into account in any replacement decision, asset condition is the main driver. There are several innovations used for condition assessment that potentially could defer asset replacement. These include the following.

- Thermal (infrared) and partial discharge (Corona) camera inspections of zone substation equipment.
- Mid-life refurbishment of power transformers.
- Dissolved Gas Analysis (DGA) of large distribution transformers.
- Thor hammer analysis of poles.
- Automation of switchgear to enable faster restoration in the event of faults.

The decision-making approach for replacements or renewals applicable to each network asset category is provided in Table 64.

Table 64: Replacement and Renewal Decisions per Asset Category

Asset Category	Subcategory	Replacement & Renewal Decision Approach
Subtransmission	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally, poles, cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic. Oil cables may be damaged beyond economic repair depending on nature of failure.

Asset Category	Subcategory	Replacement & Renewal Decision Approach
	Distributed Subtransmission Voltage (ABSs)	Replacement if inspection/operation indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic
Zone Substations	Subtransmission Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers	Major refurbishment for transformers is undertaken when units reach half of their expected life. Replaced after failure causing significant damage that is not economic to repair; most units will be allowed to run to failure to utilise entire lifespan unless failure risk is unacceptable. May be replaced if tank and fittings are deteriorating, spare parts are unavailable and not economic to maintain for aged units. May be scrapped if not economic to relocate (transport and installation costs) after aged transformers displaced e.g., for a larger unit. Paper, Furan and/or DGA analysis used to indicate insulation remaining life.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g., protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors not economical to maintain.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally, poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Replaced if rusting is advanced or other deterioration/damage is significant and maintenance becomes uneconomic. Otherwise, units generally run to failure but transformers supplying critical loads may be replaced early based on age or as part of other replacements at site. Units removed from service <100 kVA and older than 20 years are scrapped; otherwise, units testing satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives.

Asset Category	Subcategory	Replacement & Renewal Decision Approach
		Significant damage from premature failure could require replacement.
	Other	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g., protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Enclosures not economic to maintain after significant accumulating deterioration or seismic resilience concerns.
LV Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally, poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally, run to failure. Replaced when condition declines to an unreliable level e.g., embrittlement of insulation.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure but security provided by backup plant.

Non-routine Replacement and Renewal Projects

Replacement and renewal projects that are once off and underway or planned are described in the following tables. These projects often represent significant assets that have reached end of life or other significant miles stone. Some projects may target several assets of similar age that will be replaced or renewed as part of short- or medium-term programme.

Table 65: Non-routine Replacement & Renewal Projects (next 12 months)

Project Description	23/24 CAPEX Cost
Otatara/Mersey Street Poles	$563,353

Table 66: Non-routine Replacement & Renewal Projects (next four years)

Project Description	CAPEX Cost & Timing
Power Transformer Refurbishment: Refurbishment is aimed at extending the expected life of transformers; the resulting deferral of replacements will achieve cost efficiencies in maintaining service for EIL's customers. Three of EIL's 23MVA zone substation transformers are beyond their midlife and un-refurbished. However, the ex-Doon Street transformer which is to be relocated to Southern substation will not	$433,671 '26/27

Project Description	CAPEX Cost & Timing
be refurbished. Furan and paper sample analysis show that this unit's insulation is consistent with its age and therefore the cost of refurbishment is considered uneconomic given the likely level of remaining life that can be achieved. Refurbishment of the other two transformers has been deferred to best manage capital investment limits. The older of the Leven Street units was scheduled for refurbishment in 2026/27. The refurbishment will only be done if condition assessments show they are required.	
Racecourse Road Switchboard Replacement: The 11 kV switchboard at Racecourse Road substation consisting of 12 circuit breaker cubicles will reach the end of its nominal life in 2020/21. Its replacement is scheduled for 2023 - 2025 with design costs allowed for in 2022/23. This is a deferment from 2020/21 to allow for replacement of RMUs at higher risk of failure. There is a consistent level of partial discharge suspected to be from a few cable boxes and CTs. Repair will be attempted in the intervening years till replacement. Risks associated with continued operation of the 11 kV switchboard near end of expected life are being mitigated by regular condition monitoring of the switchgear and the installation of on-line partial discharge monitors.	$3,091,764 26/27/28
RMU Replacements: EIL's Ring Main Unit (RMU) replacement programme had been curtailed in recent years, as limited resources have been directed at the higher priority underground substations and link box replacement programmes. Over 15% of EIL's fleet of RMUs is aged beyond industry good practice, and an operational risk analysis shows mid-level risk factors that are beyond EIL's normal tolerance for risk. While investment will be required to fully restore the RMU fleet to acceptable levels, some individual units present a disproportionate level of risk, mainly due to their location. The riskiest RMU sites will be targeted initially. Beyond 2022, the budget is increased to aggressively replace these RMU's. This programme has been reduced to manage capital limits.	$ 1,942,945 '24/25 $ 1,833,068 '25/26 $ 2,085,457 '26/27
Fibre Installation: Control and monitoring of Leven St zone substation is currently via a single communications circuit tee-d off from the Invercargill GXP - Spey St zone substation communication circuits. The single communications circuit to Leven St zone substation crosses areas that are prone to being damaged by incidental civil works. This project is to install new optical fibre between the communications network gaps. This will complete the second communications circuit between the GXP and Leven St zone substation. This reduces the risk of communications and protection failure of the sub transmission supply to the CBD, and will allow faster protection, greater visibility, and enable future automation within the CBD distribution grid. External parties may have projects involving trenching along part of the proposed route in 2022-2023. PowerNet and those parties will discuss opportunities to share the trench, reducing trenching and reinstatement costs for both parties.	$333,684 '24/25 $46,159 25/26/27

The non-routine replacement and renewal projects that are under consideration for the remainder of the planning period is described in Table 67.

Table 67: Non-routine Replacement & Renewal Projects (under consideration)

Project Description	CAPEX Cost & Timing
Condition Based Replacements and Renewals: This budget is an estimate of costs for projects that are yet unknown but from experience are considered likely to arise in the longer term (six-to-ten-year time frame). Certainty for these estimates is quite low. However, with EIL's current demand growth and asset age profile, the bulk of this expense is considered most likely to occur in the Asset Replacement & Renewal category. Other drivers include premature failures, or greater than expected deterioration of asset condition.	No provision

Ongoing Replacement and Renewal Programmes

Ongoing work that tends to recur year after year and can be capitalised, are funded from the remaining replacement and renewal budgets. These budgets are listed and described in Table 68 with the associated capital expenditure estimates.

Table 68: Ongoing Replacement & Renewal Programmes

Budget	Description	CAPEX Cost
Link Box Replacement	On-going replacement of above ground link boxes, beyond the priority replacement of the underground link-boxes described above, which have deteriorated with age or have been damaged and are unfit for service/unsafe.	$106,872 p.a.
Zone Substation Minor Replacement	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	$10,432p.a.
Transformer Replacement	On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished for use as spares.	$940,675 '24/25 $1,068,279 '25/26 $1,068,279 '26/27
RMU Replacements	On-going replacement of Ring Main Units as they reach end of life and risk of failure increases.	$ 1,942,945 '24/25 $ 1,833,068 '25/26 $ 2,085,457 '26/27
Reactive 11 kV Cable Replacement	On-going reactive replacement of 11 kV cables as identified by condition after fault occurrence.	$39,953 p.a.
Planned 11 kV Cable Replacement	An ongoing programme to proactively identify and replace 11 kV cables as they reach their economic end of life rather than continue to repair old cables beyond this point.	$667,181 '24/25 $624,290 '25/26 $1,019,087 '26/27
General Distribution Replacement	On-going replacements of distribution assets other than cables. These are identified through routine inspection.	$216,029 '24/25 $287,995 '25/26
LV Board Replacement	Replacement of hazardous old LV distribution boards with modern touch safe boards – on-going for 10 years.	$37,451 p.a.
Pillar Box Replacement	On-going replacement of pillar boxes which have deteriorated with age or have been damaged and are unfit for service or unsafe.	$88,554 p.a.
LV Cable Replacement	On-going replacement of LV cables as by age with coincident works on underlying 11 kV cable, or as they reach their economic end of life rather than continue to patch repair old cables beyond this point.	$83,411 '24/25 $41,706 '25/26
Bluff Conductor Replacement	On-going small-scale replacement of conductors in Bluff due to high wind loading and marine corrosion.	$71,641 p.a.

Asset Relocations

The following are drivers for asset relocations.

- Change in capacity requirements – move an asset that is under capacity or underutilised to a more suitable position and install a new asset in its place.
- Relocate assets due to redevelopment of the area where they are e.g., Stead St stop bank, paid for by the developer.
- Customer requests – paid for by customer.
- Changes in the risk profile.

Quality of Supply Improvements

By reducing the number of unplanned interruptions and their frequency, the impact of SAIDI and SAIFI is limited. The following quality of supply improvements are implemented.

- More control points – segmentation of the network.
- Automation e.g., reclosers.
- Remote control.
- Fault Indicators.

7.4 Commissioning of Assets

The commissioning life cycle phase addresses the following aspects and risks are presented in Table 69.

- Ensuring that the assets or asset systems functionally deliver to the design specifications.
- System integration – ensuring that the new assets integrate with the existing assets and networks.
- Communication between the new assets and the control systems.
- Documenting the asset characteristics such as capacity, settings, as-built drawings, maintenance requirements, location, test results etc.
- Updating the AMIS and SCADA system to reflect the new asset.
- Training of staff on the maintenance and operation of the equipment.

Table 69: Commissioning Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Network Performance	Failure of Asset Lifecycle Management	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	System integration is tested Asset characteristics and maintenance requirements are captured in the information systems

Category	Risk Title	Risk Cause	Treatment Plan
	Operational systems failure due to breakdown in telecommunications	SCADA communications has one centralised communications point that all information is passed through.	Testing the communication between the new assets and the control systems

7.5 Retiring and Disposal of Assets

Retiring of assets generally involves de-energising the asset and disconnecting it from the network before removal from site or abandoning in-situ (typical for underground cables). The follow risks are addressed in this life cycle stage.

Table 71: Retiring Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Assets are removed from the network when they start to affect reliability
Network Performance	**Loss of right to access or occupy land**	Risk of assets losing / not having the right to occupy locations (e.g., Aerial trespass, subdivision)	Historical land use rights are formalised should the land be required for the installation of new assets.
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Where practical, removed assets or asset components are kept being utilised in the repair of existing assets.
Environmental	Breaches of environmental legislation	Failure of assets, oil spill, bunding, hazardous goods breach	Assets containing hazardous materials are identified and disposed of using national and international guidelines

Removed assets will be eliminated from the regulatory asset base and needs to be disposed of in an acceptable manner particularly if it contains SF6, oil, lead, or asbestos. Key criteria for retiring an asset includes the following.

- It is no longer required, usually because a customer has reduced or ceased demand.
- It creates an unacceptable risk exposure, either because its inherent risks have increased over time or because emerging trends of safe exposure levels are declining. Assets retired for safety reasons will not be re-deployed or sold for re-use.
- There are no suitable opportunities for re-deployment after an asset has been replaced to increase capacity or where more economic options exist to create similar outcomes e.g., new technology offers a low-cost maintenance free replacement.
- It is uneconomical to maintain the asset and more cost effective to being replaced.
- The asset has reached end-of-life.

7.6 Capital Expenditure Forecast

The capital expenditure forecast is presented in Table 70 and provided in the Information Disclosure Schedule 11a.

Table 70: Capital Expenditure Forecast ($000 - constant 2024/25 dollars)

Category	DPP3		DPP4					DPP5			
CAPEX: Consumer Connection	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Customer Connections (≤ 20 kVA)	70	74	74	74	74	74	74	74	74	74	74
Customer Connections (21 to 99 kVA)	62	66	66	66	66	66	66	66	66	66	66
Customer Connections (≥ 100 kVA)	140	148	148	148	148	148	148	148	148	148	148
Distributed Generation Connection	3	3	3	3	3	3	3	3	3	3	3
New Subdivisions	458	489	789	489	489	489	489	272	220	489	268
Bluff LV Service Lines	0	0	0	0	0	0	0	0	262	0	0
Otatata/ Mersey Street	0	563	0	0	0	0	0	0	0	0	0
	732	**1,344**	**1,080**	**780**	**780**	**780**	**780**	**563**	**774**	**780**	**560**
CAPEX: System Growth	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Doon Street Reconfiguration	0	0	0	0	0	67	579	0	0	0	0
New SOU CB11 & 11kV feeder to Rockdale Subdivision	0	0	636	112	490	429	126	335	0	0	0
	0	**0**	**636**	**112**	**490**	**496**	**705**	**335**	**0**	**0**	**0**
CAPEX: Asset Replacement and Renewal	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Link Box Replacement	100	107	107	107	107	107	107	107	107	107	107
Southern Substation Upgrades	0	0	0	0	0	0	0	0	0	0	1
Power Transformer Refurbishment	0	0	0	434	0	0	0	0	0	0	0
Racecourse Road	0	0	0	1,726	1,366	0	0	0	0	0	0

Switchboard Replacement											
Zone Substation Minor Replacement	10	10	10	10	10	10	10	10	10	10	10
Transformer Replacement	744	941	1,068	1,068	1,337	977	977	977	977	977	977
RMU Replacements	1,290	1,943	1,833	2,085	2,085	1,833	1,500	1,833	1,833	1,833	1,833
Reactive 11 kV Cable Replacement	37	40	40	40	40	40	40	40	40	40	40
Planned 11 kV Cable Replacement	718	667	667	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,386
General Technical Replacement	0	0	0	0	0	0	0	0	0	48	48
General Dist Replacement	203	216	288	288	288	288	288	288	288	288	35
LV Board Replacement	35	37	37	37	37	37	37	37	37	37	37
Pillar Box Replacement	83	89	89	89	89	89	89	89	89	89	89
LV Cable Replacement	39	83	42	42	184	184	184	184	184	184	42
Unspecified Asset Replacement & Renewal Projects	0	0	0	0	0	397	24	397	397	397	531
Bluff Conductor Replacement	67	72	72	72	72	72	72	72	72	72	72
Leven St Substation Roof Replacement	89	0	0	0	0	0	0	0	0	0	1
Leven St 11kV Switchboard Replacement	0	0	0	0	0	418	2,126	788	0	0	0
Power Transformer Replacement - Southern Substation T2	0	0	0	0	0	0	0	0	1,521	0	0
Coachman Inn Project (CMI)	532	0	0	0	0	0	0	0	0	0	1
	3,947	**4,205**	**4,253**	**7,017**	**6,634**	**5,471**	**6,472**	**5,841**	**6,574**	**5,101**	**5,206**

CAPEX: Asset Relocations	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Asset Relocation Projects	7	7	7	7	7	7	7	7	7	7	7
	7	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**

CAPEX: Quality of Supply	2023/ 24	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30	2030/ 31	2031/ 32	2032/ 33	2033/ 34
Supply Quality Upgrades	17	18	18	18	18	18	18	18	18	18	16
Network Automation Projects	155	38	38	38	38	38	38	38	38	38	38
Fault Indicator project	191	114	114	114	114	114	114	114	114	114	114
	363	**170**	**170**	**170**	**170**	**170**	**170**	**170**	**170**	**170**	**168**
CAPEX: Other Reliability, Safety and Environment	**2023/ 24**	**2024/ 25**	**2025/ 26**	**2026/ 27**	**2027/ 28**	**2028/ 29**	**2029/ 30**	**2030/ 31**	**2031/ 32**	**2032/ 33**	**2033/ 34**
Earth Upgrades	297	313	313	313	75	75	75	75	75	75	64
Pillar Box Lid Upgrade	133	146	146	146	146	146	146	146	146	143	143
Oil-Filled Cable Work	290	333	0	0	617	0	0	2,812	3,826	0	0
LV Tie Point Disconnectors	140	272	272	272	272	272	272	272	272	272	272
Fibre Installation	318	334	46	46	46	46	46	46	46	46	46
	1,178	**1,397**	**777**	**777**	**1,155**	**538**	**538**	**3,350**	**4,364**	**536**	**525**
Total Network CAPEX	**6,227**	**7,123**	**6,923**	**8,863**	**9,236**	**7,462**	**8,673**	**10,266**	**11,889**	**6,594**	**6,466**

Values Fully Marked Up, No Inflation, Base Year dollars.

8 Operating Expenditure

Operating Expenditure (OPEX) is required to operate and maintain EIL's networks. The following objectives are pursued with operating expenditure initiatives.

- Comply with customer obligations and service standards.
- Maintain the safety of the distribution system.
- Assets are operated and maintained in a manner that minimises system life cycle cost with due consideration of risk.
- Electricity delivery networks and associated electrical systems are maintained in such a manner that the requirements of customers, internal stakeholders and legal authorities related to such networks are met at minimum life cycle cost.

8.1 The Operation and Maintenance Lifecycle Phase

The operations and maintenance (O&M) lifecycle phase starts once the assets have been commissioned and are handed over to the Operations Unit. This is the stage where the majority of life cycle expenditure occurs. The physical assets are expected to perform their function at specified performance and reliability levels.

Continuous improvement of O&M activities is a key component of the asset management process as O&M practices can significantly impact asset lifecycle costs, management of risk and service delivery performance. The manner in which an asset is operated and maintained directly determines the performance, reliability and life expectancy of the asset.

O&M Phase Risks

The following risks are addresses during the O&M phase.

Table 72: Operation & Maintenance Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Operational Performance	**Damage due to extreme Physical Event (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Structures are inspected and maintained to retain structural functionality
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Asset fleet plans outlining the maintenance actions for each type of asset is being incorporated into the AMIS (Maximo) Maintenance execution is being managed to ensure all assets are maintained. Operating instructions and manuals are accessible to ensure assets are operated correctly

Category	Risk Title	Risk Cause	Treatment Plan
	Operational systems failure due to breakdown in telecommunications	SCADA communications has one centralised communications point that all information is passed through.	Regular testing of the telecommunications systems
	Intentional Damage	Terrorism, theft, vandalism Reputation	Programme to replace locks and improve security
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Spares will be recorded in Maximo Education of staff on spares process and locations
	Loss of key critical service provider	Economic environment Lack of sufficient work to sustain viable operations Unexpected inability of contractor to complete work Major health event/pandemic	Improved identification of critical suppliers Identify alternative suppliers Grow the capabilities of the internal workforce
	Major event triggering storm gallery activation	Damage caused by wind, snow, storm events	Monitor developing weather Ensure people, vehicles, equipment, and spares are on call and/or available during storm events
Health & Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Access prevention barriers are treated as assets and maintained to be in good condition
Regulatory Change & Compliance	Major legislative breaches	Failure to meet legal obligations, for example: - Obligation to supply electricity - Price quality regulation breach - Low fixed charge regulations - Employment legislation - Metering recertification	Utilise the Planned Interruption SAIDI and SAIFI allocations optimally by planning work more effectively

Vegetation Management

Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at EIL's expense as required under the Electricity (Hazards from Trees) Regulations 2003. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. As EIL's network is mostly underground, tree issues are minimal and therefore costs are relatively low. From 2022/23 onwards the provision for vegetation management is $7,225 p.a., then 2023-2024 $2,291, and for 2024 onwards $2,391.

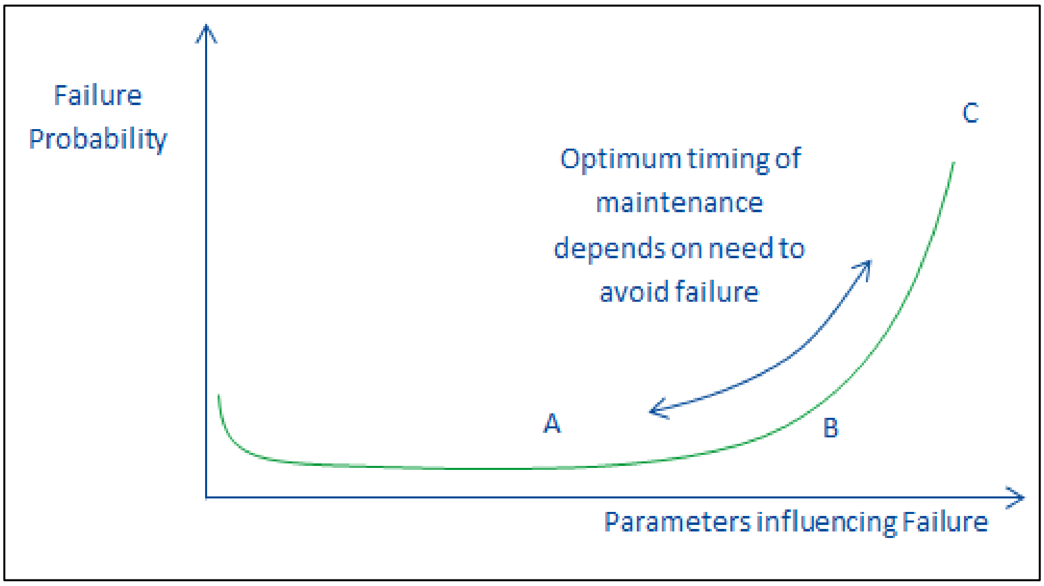
8.2 Asset Maintenance

The maintenance aspect of the O&M lifecycle phase is aimed at ensuring that assets will achieve their expected useful lives. Asset maintenance is not intended to upgrade an asset or extend its life to beyond what is expected life.

Maintenance is primarily about replacing consumable components. Many of these components will "wear out" during an asset's design life and achieving the expected service life depends on such replacements. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, or loss or contamination of lubricants.

Continued operation of such components will eventually lead to failure as indicated in Figure 44. Exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycle, ambient temperature, previous maintenance history and presence of contaminants.

Figure 44: Component Failure



The probability of failure curve can be viewed as applicable to the overall asset life in which case neglecting maintenance could result in a considerable contraction along the “parameters influencing failure” axis. Appropriate maintenance activities would stretch out the curve toward the expected design life; effectively resetting or pushing out the increasing probability of failure. There is often a significant asymmetry associated with consumables for example replacing a lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the asset’s life.

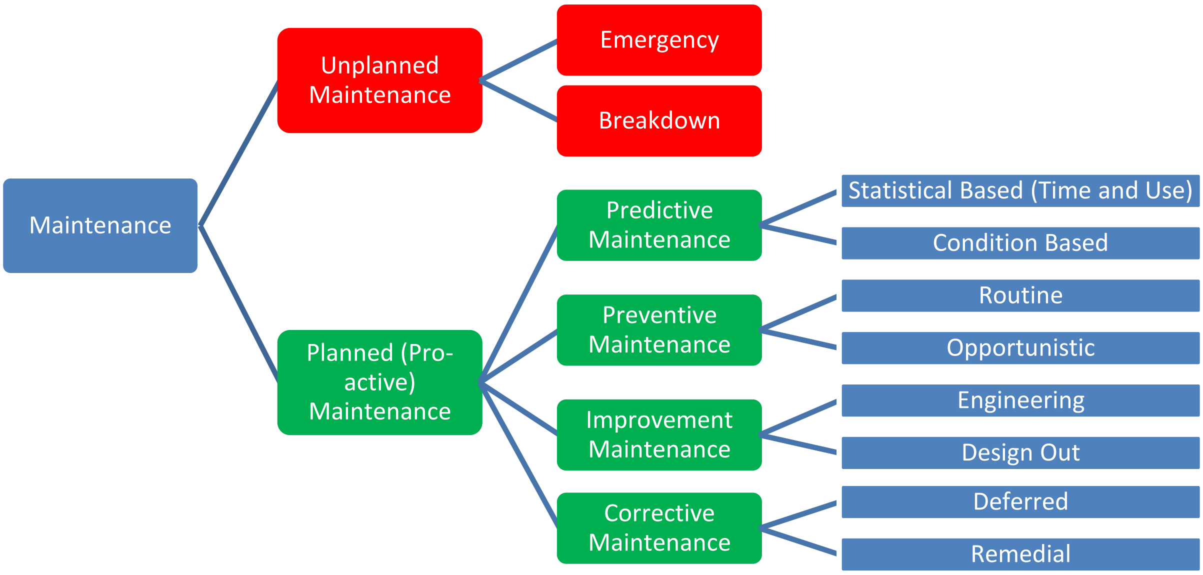
EIL’s maintenance decisions are made on cost-benefit criteria with the principal benefit being avoidance of supply interruption. Increasing maintenance costs (labour and consumables) over the asset’s lifecycle, taken together with the cost of discarding unused component life, must be traded off against the desire to avoid failure. The optimal time for maintenance depends on an asset’s criticality (impact of failure on customers) and ultimately on how much EIL’s customers are willing to pay to reduce probability of failure.

Assets such as a 33/11 kV substation transformer, supplying large customers or large quantities of customers, may only be operated to point B in Figure 44 and condition will be extensively monitored to minimise the likelihood of supply interruption. Meanwhile assets supplying merely a small customer, such as a 10 kVA transformer, will most often be run to failure represented as point C.

Maintenance Actions

Types of maintenance activities are presented in the next figure.

Figure 45: Structure of Maintenance Actions



Planned versus Unplanned Maintenance

Condition assessment is an important part of determining maintenance requirements because many components do not deteriorate at a predictable rate. Condition assessment allows deferral of maintenance cost for assets that are in good condition and permits maintenance to be focused on more deteriorated assets. Condition assessment involves inspections and testing to gather information about the condition of assets and their components and can incorporate follow-up analysis (condition monitoring) to infer the condition of the asset through establishing trends in observable criteria.

By contrast some components are maintained at fixed intervals or operation counts. An example is replacing contacts in a circuit breaker which are pitted or eroded with each operation but are unable to be inspected without dismantling the circuit breaker (by which time the contacts can be replaced with a relatively small incremental cost).

As the value and/or criticality of an asset increase, the company relies less and less on easily observable proxies for actual condition (such as calendar age, running hours or number of trips) and more and more on comprehensive analysis of component condition (through such means as dissolved gas analysis (DGA) of transformer oil).

Most technical equipment such as transformers, switchgear and secondary assets are maintained in line with manufacturer's recommendations as set out in their equipment manuals. Experience with the same types of equipment may provide reason to add additional activities to this routine maintenance. Visual inspections and testing also determine reactive maintenance requirements to maintain the serviceable life of equipment which are not routine, but across a large asset base provide an ongoing need for additional maintenance resource.

Overhead line inspections are an economic means to prevent a large proportion of potential faults, so the basic approach is to inspect these assets and perform preventative maintenance over the most cost-effective period that achieves the desired service levels. A certain frequency of failure is accepted on overhead lines where this remaining proportion of failures becomes uneconomic to avoid. This recognises customers' acceptance of a low number of outages and the increasing cost for diminishing returns in attempting to reduce fault frequency.

As cables are underground, they are unable to be visually inspected, and testing is generally not cost effective; it is difficult to obtain accurate results and to use them to predict time to failure. Cables are therefore often run to failure. However, as the relatively young cable network ages and fault frequency begins to increase a more preventive strategy will be employed based on testing to determine condition for critical cables. Currently cables are tested as part of the Ring Main Unit maintenance cycle.

In terms of cost efficiency, failures are more acceptable for lines and cables than for ring main units and zone substation assets. Significant service life can be restored to lines and cables by simply repairing the fault. Asset criticality is a consideration in determining an acceptable level of outages, however increased security (redundancy) is often a more effective strategy than attempting to determine time to failure and performing preventative maintenance.

Maintenance Approaches

Table 73 sets out the maintenance approaches applicable to each network asset category are detailed more fully in the fleet plans but have been summarised and the frequency with which these maintenance activities are undertaken indicated.

Table 73: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition assessment through periodic visual inspection. Tightening, repair, or replacement of loose, damaged, deteriorated or missing components.	3-5 yearly
	U/G	Generally, run to failure and repair.	Annual

Asset Category	Sub Category	Maintenance Approach	Frequency
		Inspection of visible terminations as part of zone substation checks, opportunistic inspection if covers removed for other work, sheath insulation IR test. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF. Partial Discharge is tested for during Ring Main Unit maintenance.	
	Distributed Subtransmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Lubrication of moving parts.	5 yearly
Zone Substations	Subtransmission Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas pressure, abnormal or failed indications and general condition. Testing: Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly
	Power Transformers	Condition monitoring through periodic inspections. Winding & insulation resistances, Function checks on auxiliaries (Buchholz, pressure relief, thermometers). Predictive maintenance - oil analysis (dissolved gases, furan) to estimate age and identify internal issues arising or trends; frequency increased if issues and trends warrant. Oil processed as necessary. Tap changer servicing: mechanism and contacts inspected – replacements as necessary, DC resistance across winding each tap, diverter resistors resistances. Clean up and repair of corrosion, leaks etc. and replacement of deteriorated or damaged components. Replacement of breathers when saturated. Paper sample may be taken to estimate age for aged transformers in critical locations at Engineers instruction or otherwise during major refurbishment at half-life. Swept frequency test at start of life and after significant events such as relocation, repaired fault, refurbishment done to check for internal movement of components.	Monthly Annual Operation count Non-periodic
	Distribution Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas pressure, abnormal or failed indications and general condition. Testing: Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly Non-Periodic

Asset Category	Sub Category	Maintenance Approach	Frequency
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures, buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Relays recertified by external technicians as regulations require. Otherwise, any other equipment visually inspected for anything untoward.	Monthly 5 yearly Non-Periodic
Distribution Network	O/H	Condition assessment through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	3-5 yearly
	U/G	Generally, run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if visible
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. Tightening, repair, or replacement of loose, damaged, deteriorated, or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500 kVA and larger. Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated. Winding resistances, Insulation resistance for older units if shut down allows. DGA for critical end of life units.	6 monthly (or 5-yearly if <150 kVA) Opportunistic Non-Periodic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge. Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	6 monthly 5-10 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. Overhead structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair, or replacement of loose, damaged, deteriorated, or missing components.	5 yearly
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting sinking etc. Internal components run to failure and repair. Some opportunistic inspections when opened for other work.	5 yearly
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Network assets are inspected routinely with the frequency dependent on the criticality of the assets and the outcome focussing on failure avoidance. Inspections are not practical for all assets, for example cables buried underground, and may be limited by the availability of outages or the added effort (labour cost) required to remove covers. Routine inspections are mostly limited to what can be viewed from a walkover of the assets.

Recognising that some deterioration is acceptable, inspections are intended to identify components which could lead to failure or deteriorate beyond economic repair within the period until the next inspection. Deterioration noted may trigger corrective maintenance if economic, especially where significant further deterioration can be avoided, for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved), for example pole rotting, and noting these issues may become a trigger for replacement or renewal depending on the extent of deterioration i.e., loss of structural integrity.

Visual or more intrusive technical inspection of an asset are often used to determine the condition of the asset. Testing supplements network inspections, and although it typically requires additional time and skilled staff, testing has strong advantages over visual inspection if cost effective. It is generally possible to gain greater detail around asset condition and often allows collection of condition data without the need to remove covers for inspection. Data gathered can be qualitative rather than quantitative, allowing more precise trending of an asset's condition over time. Care needs to be taken during testing, as testing itself may cause damage, for example DC testing of XLPE cables or even Very

Low Frequency (VLF) cable testing causes damage if the cable is not in sufficiently good condition to pass the test.

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 74. These budgets tend to be ongoing at similar levels year after year but may be adjusted from time to time to allow for improvements in maintenance practice. An increase is projected years 2025/26 onwards in anticipation of increased maintenance activity following the period of constrained renewal in 2020 – 2025.

Table 74: Maintenance Activities and Opex Costs

Budget	Description	OPEX Cost
Distribution Routine Inspections	All work where the primary driver is the five yearly network inspections (20% inspected annually), or other routine tests on distribution assets. Includes any minor maintenance works carried out during these inspections.	$161,336 p.a.
Technical Routine Inspections	All work where the primary driver is routine inspection and testing of technical assets, for example oil DGA, earth mat testing, and protection testing. Includes any minor maintenance carried out during these inspections.	$113,949 p.a.
Distribution Routine Maintenance	All work where the driver is reactive work undertaken to correct issues found during the routine inspection. Also, a general budget for all minor distribution work.	$92,520 p.a
Technical Routine Maintenance	All work where the primary driver is inspection and testing of technical assets of sufficient depth to require de-energisation of the asset. Includes any servicing activities (such as oil processing, CB oil replacement, or recalibration of relays) carried out while the equipment is de-energised for these inspections.	$430,031 p.a. thereafter
Distribution Corrective Maintenance	Permanent repairs carried out on faulted Distribution assets that had temporarily been made safe/functional during the initial incident response.	’23/24 $96,029 p.a. $100,607 p.a. thereafter.
Technical Corrective Maintenance	Permanent repairs carried out on faulted Technical assets that had been temporarily been made safe/functional during the initial incident response.	$195,029 p.a.
Zone Substation Routine Maintenance	All work where the primary driver is routine scheduled maintenance (other than preventative maintenance) on zone substations. For example, SEPA unit cleaning, mowing, and minor weed control.	$39,613 p.a.
Distribution Substation Routine Maintenance	All work where the primary driver is routine scheduled maintenance (other than preventative maintenance) on distribution substations. For example, cleaning, minor weed control, enclosure repainting.	’23/24 $68,067 p.a. $47,060 thereafter
Partial Discharge Survey	Partial discharge condition monitoring of equipment to identify abnormal discharge levels before failure occurs.	$42,431 p.a.
Infra-Red & Corona Survey	Infra-Red and Corona Discharge condition monitoring survey of bus-work, connections, contacts etc. An Infra-Red survey checks for abnormal heating as an indication of poor electrical contact between current carrying components, which may lead to voltage quality issues and/or failure of equipment; while Corona Discharge	$10,942 p.a.

Budget	Description	OPEX Cost
	testing looks for ionisation of air around insulators, as evidence of insulation defects or contamination.	
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	$3,747 p.a.
Spare Checks and Minor Maintenance	A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.	$1,254 p.a.
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	$20,046 p.a.

Asset Component Replacement and Renewal

Component renewals or refurbishments are significant maintenance activities that generally focus on the non-consumable components of assets to achieve an extension to the originally expected life. This is typically less routine work and often represents a significant milestone in the life of an asset. Renewal may ultimately be part of a full asset replacement programme where the component replacements are "staggered" over time. A typical example is an overhead line, where the components (poles, cross-arms, and conductors) wear out and are replaced at different rates, but the result is complete replacement of the original line – perhaps several times over, as long as the line asset is required.

Ultimately an asset will reach end of life when it either fails or deteriorates to the point it becomes uneconomic to repair or maintain. This will occur when failure causes significant damage to the overall asset (highly likely at distribution or subtransmission voltages) or when a part of the asset that cannot be economically replaced has significantly aged or deteriorated, for example paper insulation in a transformer.

The replacement and renewal budgets for ongoing operational work that tends to recur year after year are listed and described in Table 75.

Table 75: Component Replacement and Renewal Programmes

Budget	Description	OPEX Cost
Distribution Replacement & Renewal	All OPEX work where the primary driver is the repair of distribution assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	$73,126 p.a.
Zone Substation Replacement & Renewal	All OPEX work where the primary driver is the repair of zone substation assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like earth sticks, safety equipment, buildings, battery systems etc.	$20,874 p.a.

Budget	Description	OPEX Cost
Distribution Substation Replacement & Renewal	All OPEX work where the primary driver is the repair of distribution substation assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes work that will have a material effect on the functionality or the life of capital assets, i.e., CAPEX. Covers items like enclosure repairs, paint touch-ups, spouting & roof repairs, etc.	$82,799 p.a.

8.3 Asset Operation

The operations aspect of the O&M lifecycle phase refers to the day-to-day activities required to provide service delivery to EIL's customers. Operation of the network is effectively the service that EIL's customers pay for, so it is the customer desire which forms the driver for the continuous operation of assets the optimal balance between reliability and cost.

Well-planned and executed operations allows EIL to deliver energy supply services efficiently, effectively, and economically. In the asset management context, this requires the business to set service delivery priorities through budgeting and infrastructure planning and investment processes.

Operation of EIL's assets predominantly involves creating the path for electricity to flow from the GXPs to customer's premises year after year with occasional intervention when a trigger point is exceeded. However, the workload arising from tens of thousands of trigger points is substantial enough to merit a dedicated control room. Altering the operating parameters of an asset such as closing a switch or altering a voltage setting involves no physical modification to the asset, but merely a change to the asset's state or configuration.

Contingencies to Manage Operational Risks

The following tactics have been or are being implemented to manage operational risks (especially for HILP events).

- Align asset design with current best practice.
- Regular inspections to detect vulnerabilities and potential failures.
- Remove assets from risk zone.
- Build appropriate resilience into network assets.
- Provide redundancy of supply to large customer groups.
- Involvement with the local Civil Defence.
- Prepare practical response plans.
- Operate a 24hr control centre.

In addition to the tactics listed above, EIL has the following specific contingencies in place through its management company PowerNet.

PowerNet Business Continuity Plan

PowerNet must be able to continue in the event of any serious business interruption. Events causing interruption can range from malicious acts through damaging events, to a major natural disaster such as an earthquake. PowerNet has developed a Business Continuity Plan using the nationally deployed Coordinated Incident Management System (CIMS) which has the following principal objectives:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- Planning alternate facilities.
- Minimise financial loss.
- Provide for a timely resumption of operations in the event of a disaster.
- Reduce or limit exposure to potential liability claims filed against the Company, its Directors, and Staff.
- Coordinate with other services in the event of a regional or national significant event.

In developing the business continuity plan each business unit identified their key business functions and prioritised them according to their criticality and the timeframes before their absence would begin to have a major impact on business functions. Where practicable continuity plans have been developed in line with each critical business function and preparation undertaken where appropriate to allow continuity plans to be implemented should they be required.

PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause significant numbers of staff to be unable to function in their job. The plan aims to manage the impact of an influenza type pandemic on PowerNet's staff, business, and services through two main strategies:

- Containment of the disease by reducing spread within PowerNet, achieved by reducing risk of infected persons entering PowerNet's premises, social distancing, cleaning of the work environment, managing fear, management of cases at work and travel advice.
- Maintenance of essential services if containment is not possible, achieved through identification of the essential activities and functions of the business, the staff required to carry out these tasks and special measures required to continue these tasks under a pandemic scenario.

Critical Network Spares

Critical network equipment has been identified and spares kept ensuring reinstatement of supply or supply security is achievable in an appropriate timeframe following unexpected equipment failure. Efficiencies have been achieved due to close relationship between the networks which PowerNet manage, for example a transformer was borrowed from TPCL to reinstate a firm supply following failure of a transformer at a critical Invercargill CBD zone substation.

Network Operating Plans

As contingency for major outages on the EIL network PowerNet holds network operating plans for safe and efficient restoration of services where possible. For example, a schematic based switching plan and accompanying operating order detailing steps required to restore supply after loss of a zone substation.

Insurance

EIL holds the following insurances.

- Material damage and business interruption over Substations and Buildings
- Contracts works and marine cargo
- Directors and officers' liability
- Utilities Industry Liability Programme (UILP) that covers Public, Forest & Rural Fires, Products liability, and Professional Indemnity
- Statutory liability
- Contractors working on the network hold their own liability insurance.

Service Interruptions and Emergencies

This provides for the provision of staff, plant, and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. Any follow-up actions necessary to make further repairs are charged to the appropriate Corrective Maintenance budget. The Service Interruptions & Emergencies budget is set at $576,115 per annum.

Operational Expenditure Forecast

The operational expenditure forecast is presented in Table 76 and provided in the Information Disclosure Schedule 11b.

Table 76: Operating Expenditure Forecast ($000 - constant 2024/25 terms)

Category	DPP3	DPP4						DPP5			
OPEX: Asset Replacement and Renewal	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Distribution Replacement & Renewal	69	73	73	73	73	73	73	73	73	73	43
Zone Substation Replacement & Renewal	20	21	21	21	21	21	21	21	21	21	21
Distribution Substation Replacement & Renewal	78	83	83	83	83	83	83	83	83	83	83

Locks and Security	62	0	0	0	0	0	0	0	0	0	0
	228	**177**	**177**	**177**	**177**	**177**	**177**	**177**	**177**	**177**	**147**
OPEX: Vegetation Management	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Vegetation Management	2	2	2	2	2	2	2	2	2	2	1
	2	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**1**
OPEX: Routine and Corrective Maintenance and Inspection	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Distribution Routine Inspections	154	263	263	263	263	263	263	263	263	263	263
Technical Routine Inspections	109	116	116	116	116	116	116	116	116	116	107
Distribution Routine Maintenance	88	93	93	69	69	69	69	69	69	69	34
Technical Routine Maintenance	409	430	473	473	473	473	473	473	473	473	457
Distribution Corrective Maintenance	96	101	103	103	103	103	103	103	103	103	77
Technical Corrective Maintenance	184	195	195	195	195	195	195	195	195	195	184
Zone Substation Routine Maintenance	77	40	40	40	40	40	40	40	40	40	40
Distribution Substation Routine Maintenance	68	47	52	52	52	52	52	52	52	52	52
Partial Discharge Survey	41	42	42	42	42	42	42	42	42	42	42
Infra-red & Corona Surveys	10	11	11	11	11	11	11	11	11	11	11
Supply Quality Checks	4	4	4	4	4	4	4	4	4	4	2
Spares Checks and Minor Maintenance	1	1	1	1	1	1	1	1	1	1	1
Customer Connections	19	20	20	20	20	20	20	20	20	20	20
MV Cable Testing	256	267	267	267	267	267	267	267	267	267	267
	1,518	**1,629**	**1,679**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,558**
OPEX: Service Interruptions and Emergencies	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Incident Response -	484	507	507	507	507	507	507	507	507	507	507

Distribution - Unplanned											
Incident Response - Technical - Unplanned	48	51	51	51	51	51	51	51	51	51	48
Incident Response - Technical - Fixed Fee	18	19	19	19	19	19	19	19	19	19	15
	550	**576**	**576**	**576**	**576**	**576**	**576**	**576**	**576**	**576**	**570**
Operational Expenditure Total	**2,298**	**2,384**	**2,434**	**2,411**	**2,411**	**2,411**	**2,411**	**2,411**	**2,411**	**2,411**	**2,277**
System Operations and Network Support	1,255	1,809	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959
Business Support	2,181	2,441	2,473	2,444	2,444	2,444	2,444	2,444	2,444	2,444	2,444
AMP Total Operational Expenditure	**5,734**	**6,634**	**6,865**	**6,814**	**6,814**	**6,814**	**6,814**	**6,814**	**6,814**	**6,814**	**6,680**
Grand Total Capital and Operational Expenditure	**11,960**	**13,757**	**13,788**	**15,676**	**16,050**	**14,276**	**15,486**	**17,080**	**18,703**	**13,408**	**13,146**

Values Fully Marked Up, No Inflation, Base Year dollars.

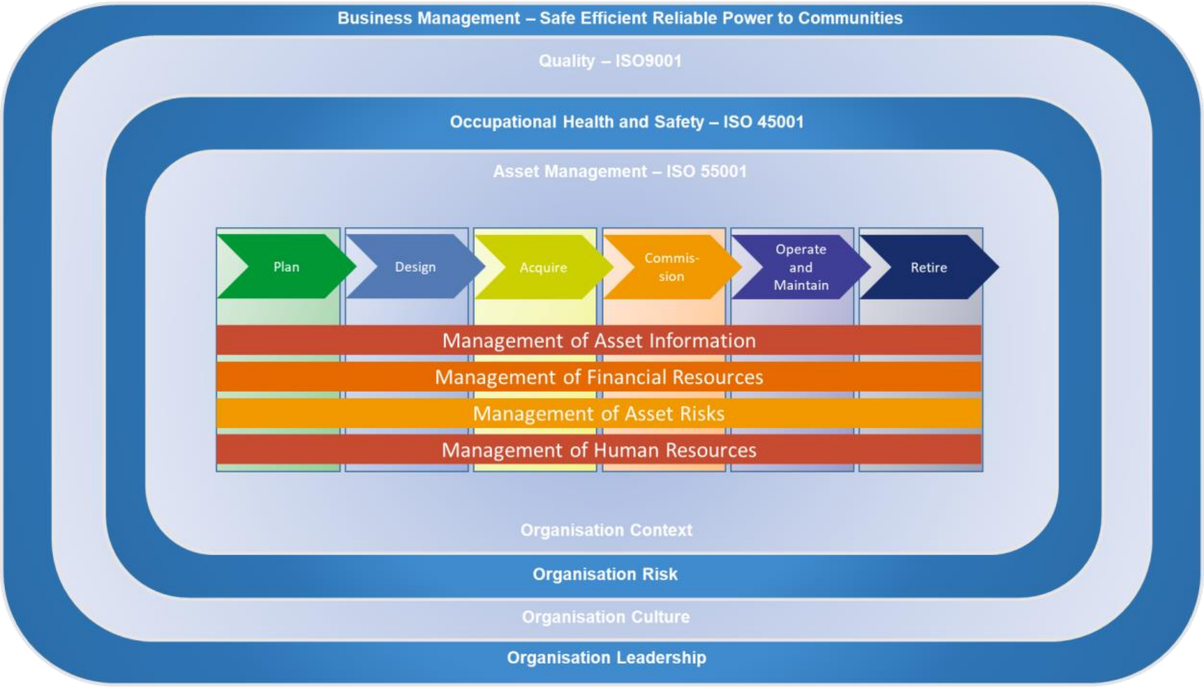
9 Execution Capacity

The core of EIL's asset management activities lies within the detailed processes and systems that reflect EIL's thinking, manifest in EIL's policies, strategies and processes and ultimately shape the nature and configuration of EIL's fixed assets.

PowerNet, like many others throughout New Zealand, both within the electricity sector and across the infrastructure industry as a whole, need to actively manage the challenges around deliverability. This relates to issues around the labour market, supply chain and economic challenges, and global factors. While we acknowledge that deliverability is not an individual EDB concern, but a concern over the aggregated deliverability of the electricity industry and wider infrastructure industry, PowerNet is actively managing any challenges around this and seeking opportunities for collaboration and greater efficiency throughout the challenges faced.

PowerNet is the contracted asset management company for EIL and uses its integrated Business Management System (BMS) to manage the networks. The BMS can be depicted as per the following figure:

Figure 46: Asset lifecycle



This figure illustrates the asset lifecycle approach that we use in managing the assets of EIL. Each of the lifecycle stages as well as the underpinning foundational elements are discussed in this AMP.

It is important to note that all asset lifecycle activities are executed within the framework of our Safety Management System. The highest priority in all decision-making is to ensure the safety of the public and our staff. This is built into every lifecycle activity.

Asset Management and Safety are both managed within our Quality Management System (QMS). The QMS ensures that approved processes are followed, and that necessary documentation is available to staff and is current. This leads to work being executed in a consistent manner across the whole company and for all managed networks.

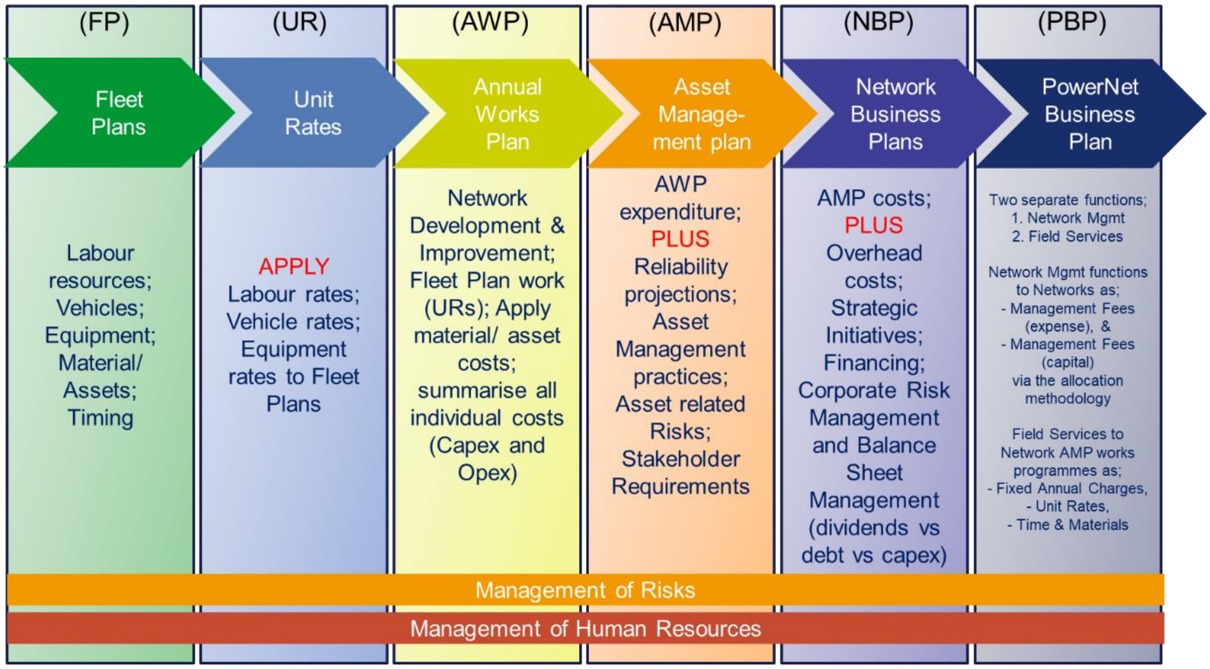
The foundation for managing the assets and determining the required resources and funding is our Fleet Plans. The Fleet Plans

- Outline how we manage each asset over its full life; and
- How we extract the maximum value from each asset by
  - Trading-off Capex with Opex; looking at the full life costs
  - Optimising maintenance tactics for each asset class and type
  - Determining risk associated with each asset class/type (e.g. safety, transformer oil spills, etc)
  - Take into account disposal cost and implications (e.g. disposing of SF6)

The Fleet Plans contain staffing and equipment requirements for each piece of work. Rates such as hourly rates and travel rates are applied to the information in the Fleet Plans to give us a cost for each piece of work. This gives us the Unit Rates that is charged to the networks by PowerNet.

The Annual Works Plan consolidates all the work that needs to be done on the network and the cost thereof into a single document that is used for the development of the AMP and the PowerNet and network Business Plans. The information is arranged into the Commerce Commission format as per Tables 70 (Capital Expenditure) and Table 76 (Operating Expenditure) in the AMP. This value chain is depicted in the following diagram.

Figure 47: Asset lifecycle



9.1 People, Culture and Leadership

EIL's work has to be planned, managed and executed by people. Organisational leadership and the culture is key determinants in the efficacy of work execution by people.

The EIL leadership consists of the EIL and PowerNet Boards and the PowerNet SLT. The EIL Board sets and monitors the network performance objectives, evaluates, and addresses network and EIL related risks and makes the funding available to PowerNet to execute the required work. The PowerNet Board sets the policies that govern work execution and employees, evaluates and addresses staff and PowerNet related risks and ensures that the requirements of the EIL Board is met.

The PowerNet SLT manages the assets of EIL on their behalf to ensure that the value generated from these assets are optimised. They also manage the employees and determine the culture and values employed in executing the required work. The SLT identifies and manages the risks associated with both EIL and PowerNet and does the medium and long term business and operational planning that is then approved by the relevant board.

Culture and Values

PowerNet SLT is striving and working to develop a culture based on the following values:

- up front and honest;
- make a difference;
- do it once, do it right;
- back each other; and
- take positive action.

We believe that this will us to achieve our critical success factors of:

- safety always
- customer focus
- continuous improvement
- passionate & empowered people
- courageous leadership

These values and critical success factors align with our vision of having asset management as the core of the organisation, encompassed by safety and quality.

Work Execution Requirements

The way we determine the work execution requirements is by determining the man hours and other resources required to execute each item of work or project. The planned Works Programme is analysed to determine the overall resource requirements for the work execution. Adjustments are then made based on resource availability. This adjustment may be delaying work until resources become available, using contractors or, if there is a long-term resource requirement, appointing additional staff or procuring the required plant or equipment. The year-to-year work volumes in the AWP is smoothed out to prevent peaks and troughs in resources required (to the extent possible acknowledging appropriate risk controls) in order to provide a relatively constant work stream.

Utilising PowerNet's works management and field services staff has great benefit in ensuring a longer term approach may be taken to resourcing. Staff numbers can be increased with added confidence that they will be fully utilised in future years given the long-term plans developed, as these resources can be utilised on all the PowerNet managed networks. The smoothing out of resource requirements can be done over a larger base load of work.

Working closely with EIL's contractors is also an important part of the AWP development process. The detailed works plan is communicated to the contractors they commit to making sufficient resources available for the years ahead. Contractors can confidently commit to hiring extra staff where appropriate, recognising EIL's on-going development and maintenance requirements.

People related constraints

It remains problematic to obtain the required numbers of appropriately skilled resources. This applies to all levels of staff, but particularly to technical and field staff. The lower South Island is not a first choice for people to work and stay, especially younger people. PowerNet generally has around 13 vacancies for field and technical staff. PowerNet has appointed 20 trainees to try and alleviate the shortage, but it will take time to get them to the required level of competency to be fully productive.

The COVID-19 pandemic and the continual rumours around the closure of the Tiwai aluminium smelter have assisted somewhat in the past few years in retaining and recruiting staff but with the borders opening up this is beginning to change. This has brought some competencies to market, but the specific experience and skills on the EIL underground network remains scarce.

9.2 Funding the Business

Revenue

EIL's revenue comes primarily from retailers who pay for the conveyance of energy over EIL's network but also from customers providing contributions for the uneconomic part of works. Revenue is set out in a "price path", aligned to determinations by the Commerce Commission. The following approaches for funding of new assets are utilised.

- Funding from revenue within the year concerned
- Funding from after-tax earnings retained from previous years
- Raising new equity (very unlikely given the current shareholding arrangement)
- Raising debt (which has a cost, and is also subject to interest cover ratios)
- Allowing Transpower to build and own assets which allows EIL to avoid new capital on its balance sheet, but perhaps more importantly also allows EIL to treat any increased Transpower charges as a pass-through cost

Expenditure

Expenditure is incurred to maintain the asset value of and to expand or augment the network to meet customer demands. In addition, there is a management fee paid to PowerNet for managing the networks on behalf of EIL.

Influences the Value of Assets

An annual independent telephone survey is undertaken each year and consistently indicates EIL's customer's price-quality trade-off preferences are as follows.

- A large majority are not willing to pay $10 per month more in order to reduce interruptions
- A small minority are willing to pay $10 per month more in order to reduce interruptions
- A small minority feel they don't know or are unsure of price-quality trade-offs

In response EIL's asset value should either remain about the same or be allowed to decline in a controlled manner (and knowing how to do this is obviously a complex issue). However, this presents EIL with the dilemma of responding to customers wishes for lower cost supply in the face of a "no material decline in SAIDI" requirement and in fact revenue incentives to improve reliability. Factors that will influence EIL's asset value are shown in Table 77 below:

Table 77: Factors influencing EIL's asset value

Factors that increase EIL's asset value	Factors that decrease EIL's asset value
Addition of new assets to the network	Removal of assets from the network
Renewal of existing assets	On-going depreciation of assets
Increase of standard component values implicit in valuation methodology	Reduction of standard component values implicit in valuation methodology

At a practical level, EIL's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However, the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

Depreciating the Assets

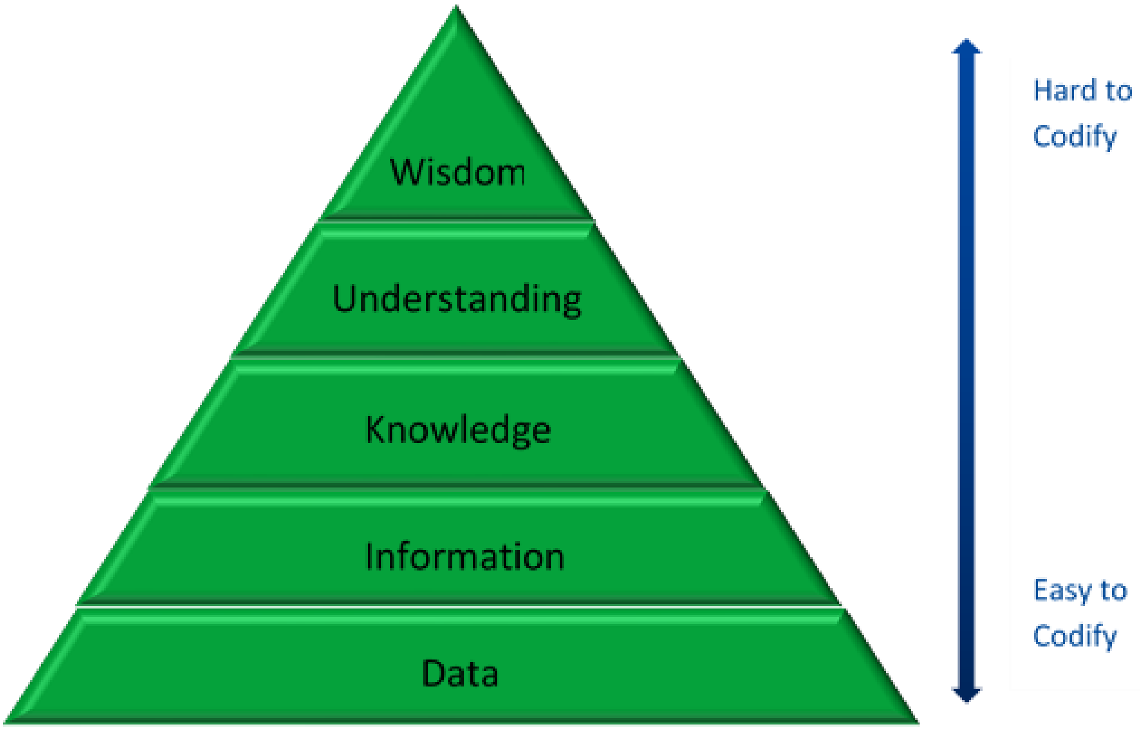
Assets are depreciated using straight line depreciation over the asset expected life. This doesn't strictly model the decline in service potential of an asset. Straight-line depreciation does, however, provide a smooth and reasonably painless means of gathering funds to renew assets reaching the end of their life.

9.3 Information Management

Information Management Model

The data hierarchy model in Figure 48 shows the typical information and knowledge residing within EIL's business (including employees from PowerNet).

Figure 48: EIL's Data Hierarchy Model



The bottom two layers of the hierarchy, '*Data*' and '*Information*' strongly relate to EIL's asset and operational data, and the summaries thereof impact EIL's decision making. The middle layer, '*Knowledge'*, tends to be general in nature and may include technical standards, policies, processes, operating instructions, and spreadsheet models. This probably represents the upper limit of what can be reasonably codified of accumulated knowledge.

The top two layers '*Understanding'* and '*Wisdom'* are extensive, often fuzzy and enduring in nature. The decision-making process involves these top two levels of the hierarchy and key organisational strategies and processes reside at these levels.

Accurate decision making requires the convergence of both information and (a lot of) knowledge to yield a correct answer. Deficiencies in either area (incorrect data, or a failure to correctly understand issues) will lead to wrong outcomes. The layers right from "*Data*" to "*Wisdom*" are difficult to codify and suitable application depends on skilled and experienced people.

The following outlines the types of investments targeted within the planning period to support improved network visibility.

LV network monitoring. This is an essential programme that will inform future investment plans, provide inputs for automation schemes, and help ensure network stability in the face of increased use of distribution edge devices. Over time, we intend to expand visibility further down into the networks – typically to include feeder endpoints and T-offs. The programme will also look at the integration of other available monitoring devices on the network – for example customers' inverters (for PV), smart meters etc.

Enhanced network condition and utilisation monitoring – incorporating new and different network condition detection methods through expanded sensor types, external sources of network specific data, and improved back-office capability.

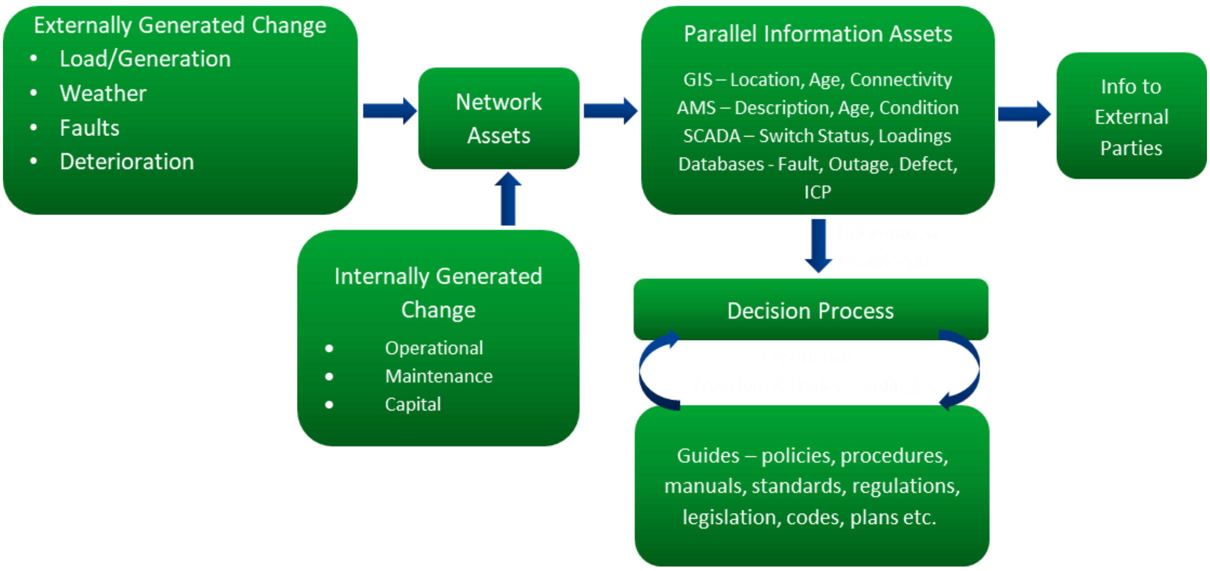
Interfacing with DER resources on the LV network – developing methods to provide network relevant data to DER resources (and their management interface) and obtain data from these sources. This will include developing methods of exchanging information with local generation, storage, and discretionary loads, such as EVs.

Expanded communications and information systems. We will also identify potential opportunities to share infrastructure with other providers, for example, should the required network insights be available from retailers' smart meters, it may obviate the need for our own investment.

EIL's Asset Management Information Systems

Figure 49 provides a high-level summary of EIL's asset management processes and systems. The role and interaction of each component of the data hierarchy model are incorporated.

Figure 49: Key Asset Management Systems & Processes



There are a variety of information management tools which capture asset data and can be used to create summary information from the data. Based on this foundation, EIL has sufficient knowledge about almost all the assets; their locations, what they are made of, how old they generally are and their performance. This knowledge will be used for either making decisions within EIL's own business or assisting external entities with resolutions. A summary of the key data repositories is listed in Table 78: Key Information Systems.

Table 78: Key Information Systems

Information System	Data Type	Data Source
Asset Management System (AMIS – Maximo)	Description, Age, Condition	Network Equipment Movement (NEM) Forms, Field Survey, Supplier Data, Commissioning Records, Test Records
Geographic Information System (GIS)	Location, Age, Connectivity	As-built information, Roading Authorities, Land Surveys
SCADA	Switch Status, Loading	Polled devices
PowerNet Connect	Customer Details	MARIA registry, GIS
PowerNet Connect	Customer calls regarding faults	Customer calls to System Control
Outage Reporting System	Regulatory recording of outages SAIDI & SAIFI	System Outage Logs
Defect Database	Equipment failures	System Control, Reports from field staff, Project Managers

In general, the completeness of data within the information systems is reasonable (acceptable) and a summary with noted limitations is provided in the next table.

Table 79: Data Completeness within Information Systems

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion and GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion and GIS update
GIS	Age	Reasonable	Equipment ages include some estimate by type (era of manufacture)
Condition Assessment Database	Condition	Acceptable	Regular inspections but some subjectivity and condition data not updated with repair
AMIS	Description	Acceptable	Some delays between job completion and Maximo update
AMIS	Details	Acceptable	Some delays between job completion and Maximo update
AMIS	Age	Acceptable	Missing age on old components, mix of installation and manufacturing dates used as age estimate

AMIS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

Data Control, Improvement and Limitations

EIL's original data capture emphasised asset location and configuration. The data was used to populate the GIS, but it did not include high-level asset condition data. As part of this original data capture, the company developed a field manual of drawings and photos to minimise subjectivity.

Records and drawings have been used to ascertain asset age, but certain asset classes such as cables, had limited supporting information. Old cables do not have a manufacturing date associated and updating the GIS system with missing data entry points is problematic. Options have been considered to get ages measured for the un-dated cables, but no economic methodology has been found. Where economical, condition data is collected, as it is useful in determining replacement timeframes.

Almost all GIS data entered for assets is standardised and selected from lists to ensure quality of data entry; and for all other data (for example electrical connectivity), thorough processes, peer reviews, and well-trained staff are used to ensure data entry quality is very good. Key process improvements will include timelier as-builts with PowerNet staff taking GPS coordinates for poles and other assets and use of electronic or scannable forms for data input.

Data for the AMIS is collected by the Network Equipment Movement (NEM) form that records every movement of serial numbered assets. Some updating of data is obtained when sites are checked with a barcode label put on equipment to confirm data capture and highlight missed assets. About 20 percent of the network (by length) is condition assessed each year to update asset condition data (noting that asset condition is continually varying), and any discovered variances are corrected.

Improvements to the AMIS are continually being undertaken to capture additional asset details to be which were historically captured in spreadsheets; especially the addition of condition-based indicators to assist in making better asset management decisions. Data validation and completeness controls are also being added over time to prevent new assets being created without all required data being captured.

Assets are assigned a unique reference common to both the GIS and AMIS. Where asset data is common to both systems it will be input into one system (deemed the master for that data) and automatically copied to the other to ensure consistency. Other systems also have some degree of interface for copying across common data such as customer data residing in both the ICP database and in GIS and referenced by the common ICP number. However, for the most part, these tools do not interact directly, with staff pulling together information from the necessary tools for their use as part of their asset management activities.

The SCADA system and monitoring completeness and accuracy is excellent at zone substations as it is critical for both safety and reliability of the network and is used for the day-to-day operation of the network. More field devices are being added to SCADA for remote monitoring and operation.

Other data repositories have very good data quality with these database systems controlling data entry through drop down lists and validation controls. Modifications may be made from time to time to better align with maintenance processes as they evolve.

PowerNet’s Software Systems

PowerNet maintains and utilises several software-based tools to manage data and knowledge of EIL’s network assets efficiently and effectively. These are described below.

- **Asset Management Information System (AMIS)** This system stores EIL’s asset descriptions, details, ages, and condition information for serial numbered components. It also provides work scheduling and asset management tools with most day-to-day operations being managed through the AMIS. Maintenance regimes, field inspections and customers produce tasks and/or estimates, that are sometimes grouped and a ‘work order’ issued from the AMIS which is linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling. The individual assets that make up large composite items such as substations are managed through the AMIS in conjunction with other more traditional techniques such as drawings and individual test reports. EIL utilises the Maximo software package for its AMIS.
- **Geographic Information System (GIS)** An Intergraph based GIS is utilised to store and map data on individual components of distributed networks. The GIS focuses primarily on geographically distributed assets such as cables, conductors, poles, transformers, switches, fuses, and similar items and provides asset description, location and age information for each asset. Locational data is used to provide mapping type displays of existing equipment for planning network upgrades, extensions, and maintenance scheduling. It allows these plans to account for distance and travel time and any other factors influenced by the geographic distribution of the assets. Electrical connectivity, capacity and ratings also form a crucial data set stored in the GIS which assists the analysis of the networks ability to supply increasing customer load or determine contingency plans.
- **Load Flow and Fault Analysis Software** Export of data from the GIS into this system allows modelling of the network. This helps predict network capability in the existing arrangement and in future “what if” scenarios considered as planning options as well as determining fault levels to assess safety and effectiveness of protection and earthing systems. Two software packages PSS Adept and Cyme are used to perform this analysis for EIL.
- **Supervisory Control and Data Acquisition (SCADA) System** The SCADA system provides real time operational data such as loadings, voltages, temperatures and switch positions. It also provides the interface through which PowerNet’s System Control staff can view the data through a variety of display formats and remotely operate SCADA connected switchgear and other assets.

Historical data is stored and provides a reference for planning. For example, network loading can be downloaded over several years allowing growth trends to be determined and extended to forecast future loading levels.

- **Finance One (F1) Financial System** Monthly reports from F1 provide recording of revenues and expenses for the EIL line business unit. Project costs are managed in PowerNet with project managers managing costs through the AMIS system. Interfaces between F1 and the AMIS track estimates and costs against assets.
- **Outage, Fault and Defect Database** These are populated by the System Control staff as information is reported by field staff or via the faults call centre to ensure efficient tracking of operational issues affecting network service levels.
  - The faults database logs all customer-initiated calls reporting power cuts or part power to store reported information and contact details. Calls are therefore able to be tracked to ensure effective response and restoration.
  - The outage database logs outage data used to provide regulatory information and statistics on network performance. As such data capture is in line with regulatory focuses, it excludes LV network outages. Reports from this system are used to highlight poorly performing feeders which can then be analysed to determine maintenance requirements or if reliability may be enhanced by other methods. Monthly reports are provided to the EIL Board for monitoring, together with details of planned outages.
  - Asset defects are captured in another database for technical asset issues which do not have an immediate impact on service levels but potentially could, if not responded to. Defects are tracked in this database and scheduled for remediation.
- **Condition Assessment Database** This database tracks the results of routine overhead line inspection rounds and is used as a basis for assigning line repair/renewal work. Severely deteriorated structures are marked as red-tagged and are prioritised for repair, and similarly with low conductor spans. The current database is being replaced as part of an overhaul of line inspections on all PowerNet-managed networks; the replacement database will permit the recording of repairs and will allow more precision in reliability analysis.
- **ICP/Customer Database** An additional database (essentially commercial in nature) containing such data as customer details, consumption and billing history. This interfaces with the National Registry to provide and obtain updates on customer connections and movements. Customer consumption is monitored by another ACE Computers system 'BILL'. BILL receives monthly details from retailers and links this to the customer database.

Processes and Documentation

EIL's key asset management processes and systems are based around the asset lifecycle activities and complies with the ISO55001 Asset Management System and the AS/NZS9001 Quality Management System standards. EIL, through PowerNet, are audited and is certified to both of these systems. The processes are not intended to be bureaucratic or burdensome but are intended to guide EIL's decisions (apart from safety related procedures which do contain mandatory instructions). Accordingly, these processes are open to modification or amendment if a better way becomes obvious.

ProMapp is used to document our processes. The asset management processes are documented and grouped in the following categories with a complete list provided in Appendix 1.

- Operating Processes and Systems.
- Maintenance Processes and Systems.
- Renewal Processes and Systems.
- Up-sizing or Extension Processes and Systems.
- Retirement Processes and Systems.
- Performance Measuring Processes.
- Other Business Processes.

Some processes are prescribed in external documents (such as the information disclosure determination which this AMP is required to comply with) and as such they are not copied onto internal documentation. Processes are often embedded within asset management tools including external requirements such as the need to produce network reliability statistics for disclosure being embedded within the outage management database.

The ProMapp process mapping software makes it easy for all employees to view our processes step-by-step so that they can better understand them and ensure consistency in the way work is being executed, continuous improvement, quality assurance, and risk management.

Document and Process Reviews

Each document or process is controlled by an owner at management level who is given responsibility for its review and update. The documents and processes are reviewed periodically to ensure they are kept up to date. Lean Management practices have recently been introduced to refine business and asset management processes with the changes identified ultimately reflected in documented procedures.

Once updates have been finalised, they are approved by the controlling manager and all staff are notified by email and where necessary by placement on notice board and direct training and communication to individuals affected. External audits of specific systems and processes are also conducted. Current external audits include the following.

- Public Safety Management System (PSMS) (AS/NZS 7901 compliance).
- Occupational Health and Safety Management (AS/NZS 4801 compliance).
- Worksite safety audits (completed by Network Compliance Ltd).
- AMMAT review.

- AMP format and compliance review.
- Spend forecast assessment.
- Spend approval process review.

10 Evaluation of Performance

10.1 Progress against Plan

The performance between estimated expenditure and actual expenditure for CAPEX and OPEX is described below.

Capital Expenditure

The variation of estimated expenditure versus actual capital spending is presented in Table 80.

Table 80: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2024/25 ($k)	Actual 2024/25 ($k)	Variance
Consumer Connection	732	1,344	84%
System Growth	-	-	
Asset Replacement and Renewal	3,341	4,205	26%
Asset Relocations	7	7	0%
Quality of Supply	243	170	-30%
Legislative and Regulatory	-		-
Other Reliability, Safety and Environment	1043	1397	34%
Capital Expenditure on Network Assets	**5,366**	**7,123**	**-25%**

Capital works was 30% over budget due to:

- Customer connections – Large commercial connections include CBD Mall and a safety clothing manufacturer.
- Otatara/Mersey Street upgrade for backup supply to Otatara in Year 1.

Operational Expenditure

The variation of estimated expenditure versus actual operational spending is presented in Table 81.

Table 81: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2024/25 ($k)	Actual 2024/25 ($k)	Variance
Asset Replacement and Renewal	228	177	-22%
Vegetation Management	2	2	0%
Routine and Corrective Maintenance and Inspection	1,455	1679	15%
Service Interruptions and Emergencies	550	576	5%

Operational Expenditure on Network Assets	**2,235**	**2,434**	9%

Operational expenditure was 1% under budget.

10.2 Service Level Performance

Customer Consultation

Key customers are surveyed annually by external consultants. PowerNet, as the defacto service provider, is used as a proxy for the network companies. Interviewees generally felt PowerNet had a very positive image in the community however there was a perception with some that PowerNet has quite a low profile. It was generally perceived that PowerNet has its customer's best interests at heart however some felt they were unable to comment on this due to lack of visibility.

Customers consistently ranked continuity of supply as the most important aspect of their provided network service and indicated that PowerNet performed very well in this regard. Other customer priorities included prompt restoration of supply, sufficient notice of planned interruptions, cost of supply, and supply quality. Again, customers indicated that they were generally satisfied with these aspects and the overall service from PowerNet. Some businesses expressed a desire for more proactive and regularly initiated contact from PowerNet staff to make them more aware of quality, efficiency, or pricing options, but the majority saw no specific need for such contact.

Reliability

Table 82 displays the target versus actual reliability performance on the network.

Table 82: Performance against Primary Service Targets

	2021/22 DPP3 Target	2021/22 Actual
SAIFI	0.59	1.15
SAIDI	24.0	105.24

Above YTD targets for planned SAIDI and SAIFI. One planned shutdown to connect a cable to a new RMU and no unplanned outages during October. No interruptions exceeded 100 customer minutes.

Customer Satisfaction

The customer engagement survey conducted by phone provides feedback to understand customer satisfaction regarding a range of aspects around their supply services. Statistics are also recorded for any customer complaints received. Table 83 shows the 2021/22 results for the service level targets.

Table 83: Performance against Secondary Service Targets

Attribute	Measure	Target 2021/22	Actual 2021/22
Customer Satisfaction on Faults	No impact or minor impact of last unplanned outage {CES}	>50%	56%
	Information supplied was satisfactory {CES}	>80%	62%

	PowerNet first choice to contact for faults {CES}	>35%	40%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	<5	13
	Number of customers having justified supply quality complaints {IK}	<2	8
Planned Outages	Provide sufficient information {CES}	>80%	88%
	Satisfaction regarding amount of notice {CES}	>80%	91%
	Acceptance of one planned outage every two years lasting four hours on average {CES}	>80%	84%

{ } indicates information source; CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs.

Performance against the service levels regarding planned outages were better than the targets set for 2021/22.

Network Efficiency

Table 84: Performance against Efficiency Targets

Measure	2021/22 Target	2021/22 Actual
Load factor	> 50%	47%
Loss ratio	< 5.5%	5.2%
Capacity utilisation	> 40%	42%

Load factor reflects the ratio of EIL's average demand to peak demand and averages around 50%. EIL's maximum demand does not coincide with the Lower South Island coincidental demand, therefore Transpower's Transmission Pricing Methodology does not drive the control of peak demand in EIL, thus having a negative impact on load factor.

Reported losses tend to vary from year to year more than can be explained by changes in operation and network assets. This variation can mostly be attributed to the retailer accrual process.

While it is desirable to have a capacity utilisation factor as high as possible, standardisation of transformer sizing, allowance for growth and the unpredictable consumption patterns of customers mean there is a practical and economic limit to how much this factor can be improved. EIL's capacity utilisation compares very well with other distribution businesses.

Financial Efficiency

Table 85: Performance against Financial Targets

Measure	2021/22 Target	2021/22 Actual
Network OPEX/ICP	$108	$105
Network OPEX/km	$2,800	$2,763
Network OPEX/MVA	$12,200	$11,709
Non-Network OPEX/ICP	$221	$189
Non-Network OPEX/km	$6,000	$4,972
Non-Network OPEX/MVA	$25,500	$21,071

Overall, the network and non-network OPEX financial efficiency results are marginally better than planned.

10.3 AMMAT Performance

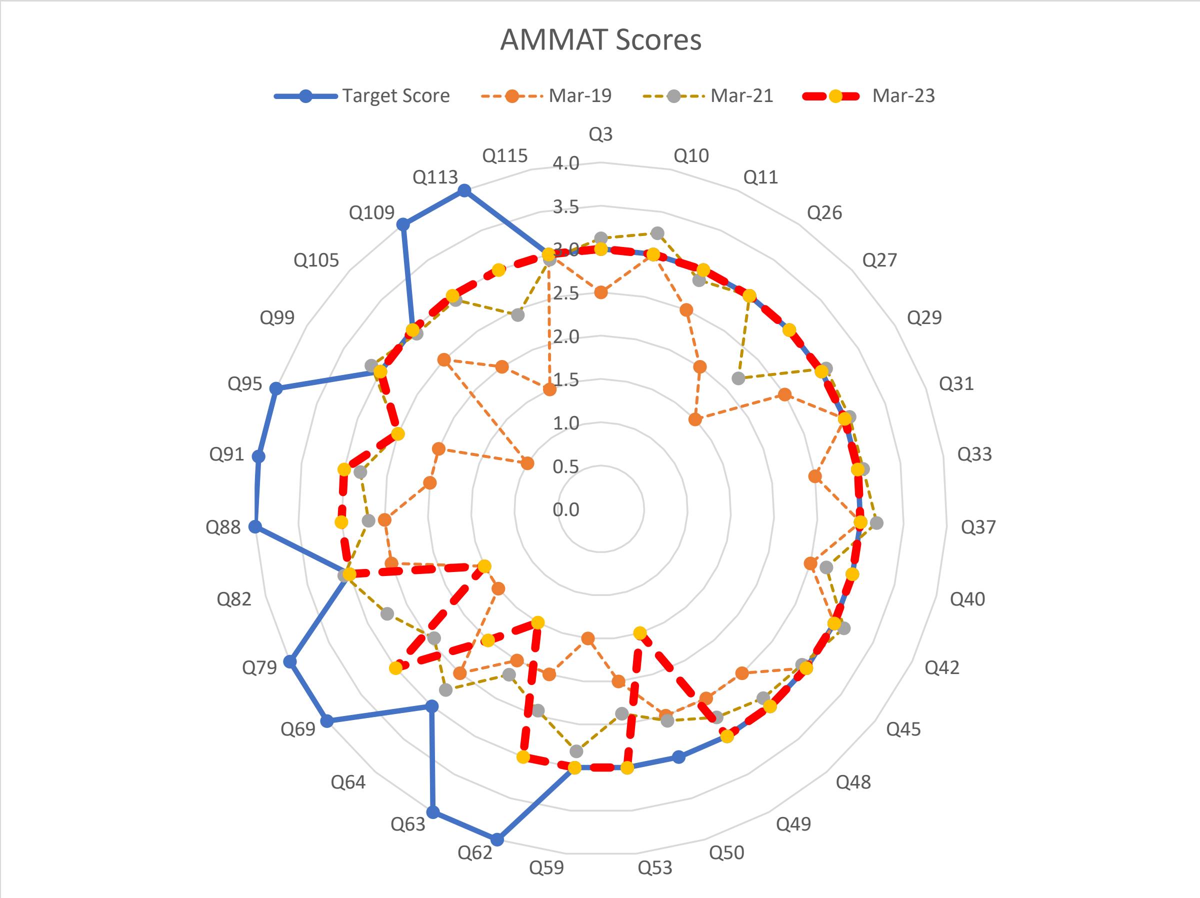
PowerNet understands the foundations of good asset management practice and endeavours to comply with international best practice as embodied in the ISO5500X suite of standards (a management system for Asset Management). In addition, the original PAS 55 principles are adopted (as this is the measurement standard still utilised by ComCom). These foundations are applied in EIL.

The AMMAT (Asset Management Maturity Assessment Tool) is based on a selection of questions based on PAS-55. It is intended to prompt consideration of performance against a number of facets of good asset management practice. Each question can be scored from '0' to '4' and each question has a series of answers to describe what is required to achieve each scoring level. Appendix 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

PowerNet commissioned Utility Consultants to do an AMMAT assessment for this AMP. The focus was on the changes that had occurred since the 2021 assessment. In scoring EIL's asset management practice against the maturity tool, scores from '1.5' to '3.0' with an average score of '2.8' were achieved as shown in Figure 50. All the areas covered in the questionnaire are not of equal importance to an EDB, so target scores were set for each area. These target scores are indicated by the blue curve.

The red curve shows the result of this assessment.

Figure 50: Asset Management Maturity Assessment Scores



10.4 Gap Analysis and Planned Improvements

Asset Management Maturity

For a distribution company of EIL's size a score of between '2' and '3' for many of the asset management functions is considered appropriate. However, as PowerNet provides EIL's asset management services as well as providing this service across other networks, EIL believes that some improvements are realisable and appropriate. The audit shows that EIL has maturity improvement in most areas, except for the following:

Q50	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?
Q63	Information management	How does the organization 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?
Q79	Use and maintenance of asset risk information	How does the organization ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?

Q50 relates to both field- and office staff. The competency requirements for field staff are well documented and managed, more so than that of office staff. Although we are satisfied that all office staff have an appropriate level of competency, documentation to prove this is not as readily available as for field staff. This is being addressed by the introduction of the Learning Management System which will make this information available to authorised staff.

Q63 relating to data is being progressively addressed through the upgrade of the Asset Management Information Systems. In addition, a Data Management Steering Group has been established to address the issue of data and to ensure that data is treated as a critical asset with its own lifecycle activities.

Q79 addresses the use of asset risk information to provide input into the identification of adequate resources and training and competency needs. This is currently done indirectly through the AWPs, but as better asset health data becomes available to inform our risk analysis, a more direct link between risk and resources will be established.

Other initiatives for improvement that are in progress or have been completed are.

- Asset Fleet Plans were being developed that will allow improved management of assets over their full life cycle. These plans are incorporated into the Asset Management Information System.
- The stage gate process for managing major projects has been adapted and will be introduced to improve capital and maintenance project implementation. This includes standardised work packs and unit rates for most jobs.
- The PowerNet organisational structure has been further refined to enhance the ability to deliver the EIL asset management objectives.
- A Data Strategy and an Information System Strategy were developed and are being implemented. Key to these strategies is recognising and agreeing that the computerised asset management information system (MAXIMO) will be the single source of truth around assets. Further implemented improvements to the system are:
  - Including a Risk Management module into the system.
  - Expanding work scheduling to more systematically and efficiently schedule and track asset maintenance activities to additional asset types.
  - Developing more compatible units to allow standardisation common asset types including cost by materials and labour to enable efficient costing and scheduling of future work.
  - Integration of EIL's financial management system to efficiently track costs supporting compatible units and understanding whole of lifecycle costs for these assets.
  - Rolling out field devices to operational staff that will allow the direct capturing of data from the field. This also includes automating the risk management framework used in works by field staff.
- A new drawing management system that allowing access to drawings from the field.
- A system to keep everybody abreast of legal, regulatory, and statutory requirements.

ISO 55001 Asset Management System implementation

PowerNet's Asset Management System has been certified to ISO 55001.

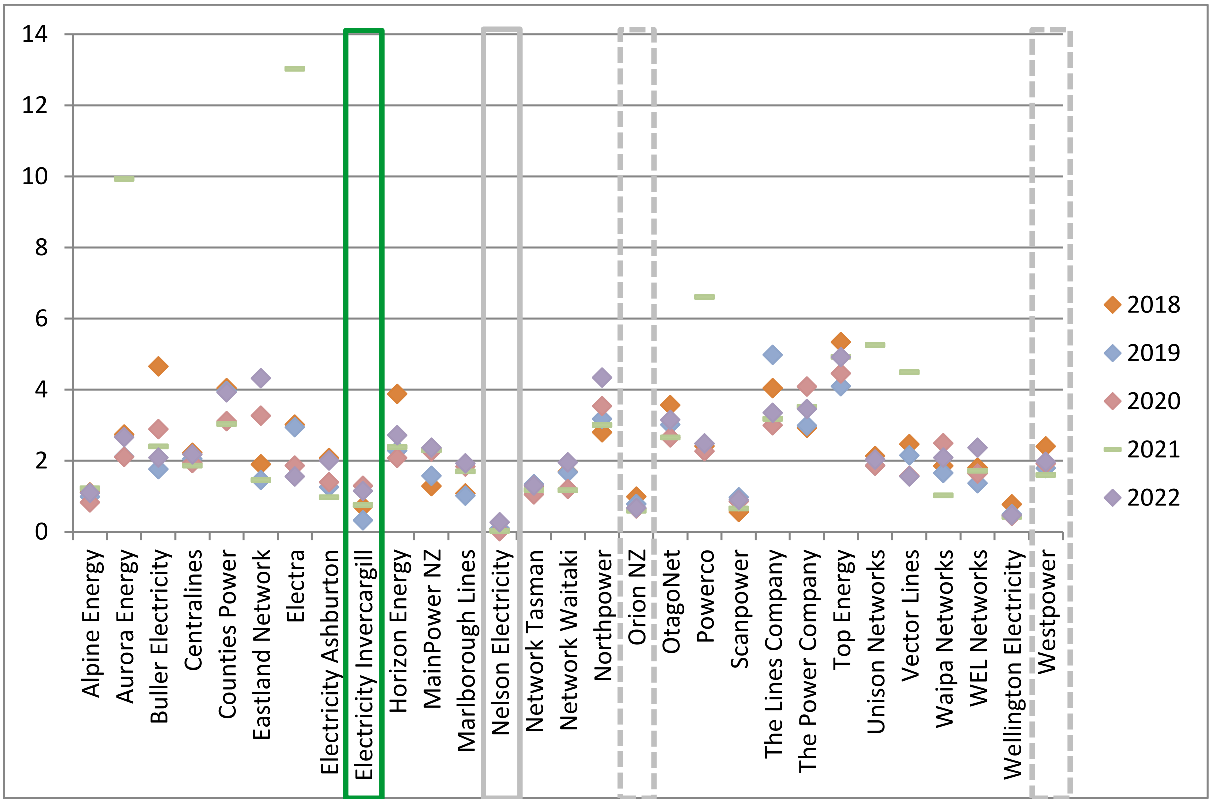
10.5 Benchmarking

Benchmarking against other local distribution networks assist with the identification of potential improvements in the current service levels that EIL offers. Comparisons with Nelson Electricity (and to a lesser extent Orion and Wellington Electricity), are useful as these networks are similar to EIL in terms of customer density and types of assets.

SAIFI

EDB reliability results as published by ComCom since 2016 show EIL is a leading network in minimising the number of supply interruptions to customers. Generally specific actions to improve SAIFI are not required.

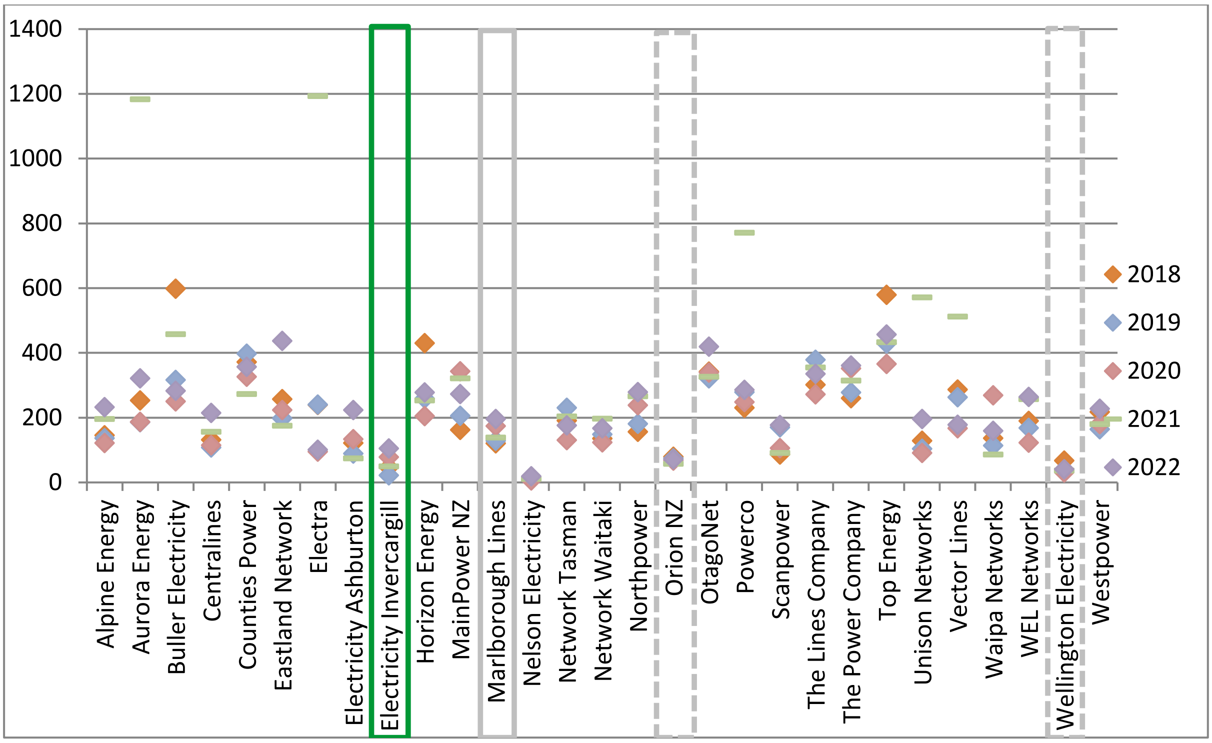
Figure 51: SAIFI Benchmarking



SAIDI

Similar to SAIFI, SAIDI reliability results, suggest that no specific actions to improve SAIDI are required, as EIL is a leading network in minimising the amount of time that customers have no supply.

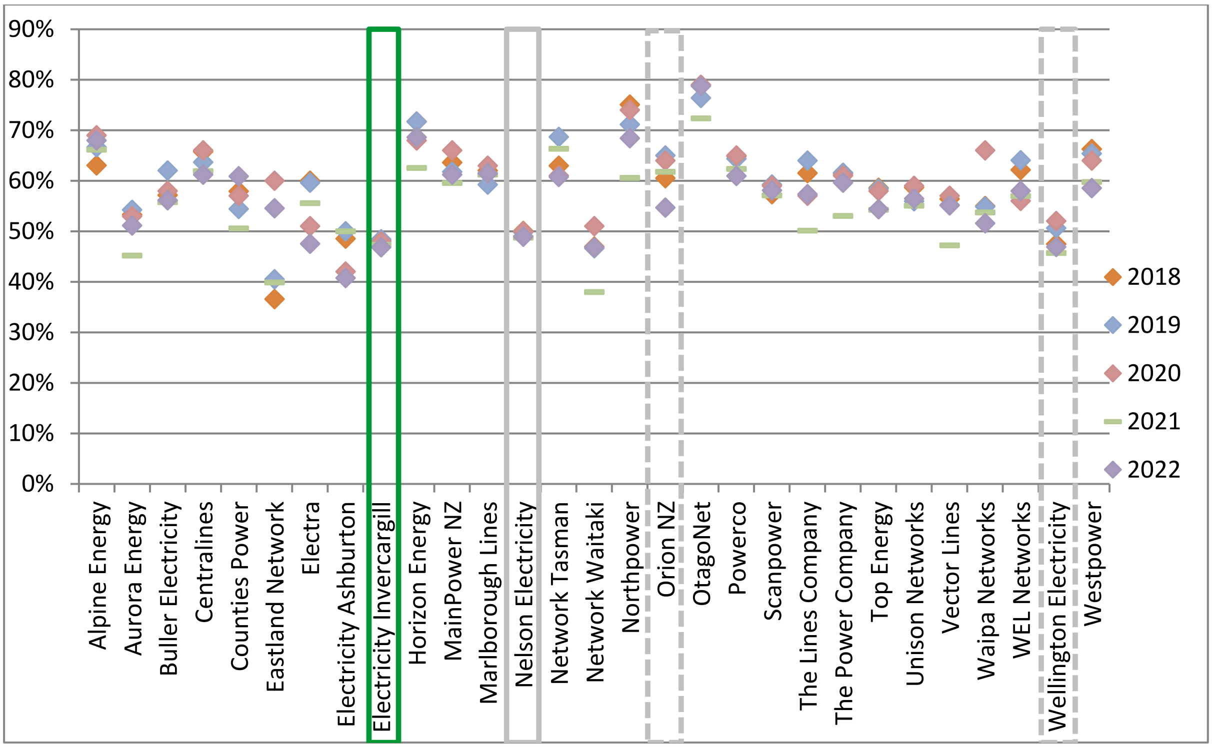
Figure 52: SAIDI Benchmarking



Load Factor

EIL's peak during winter months does not coincide with the LSI peak which tends to be to be late spring. Controlling the peak load was therefore not required in winter, resulting in a higher peak without an increase in energy consumption, thus having an adverse effect on load factor. EIL supplies mostly urban residential customers and the load factor achieved is typical of such a customer mix. None of this will have any adverse effect on the cost to customers.

Figure 53: Load Factor Comparison



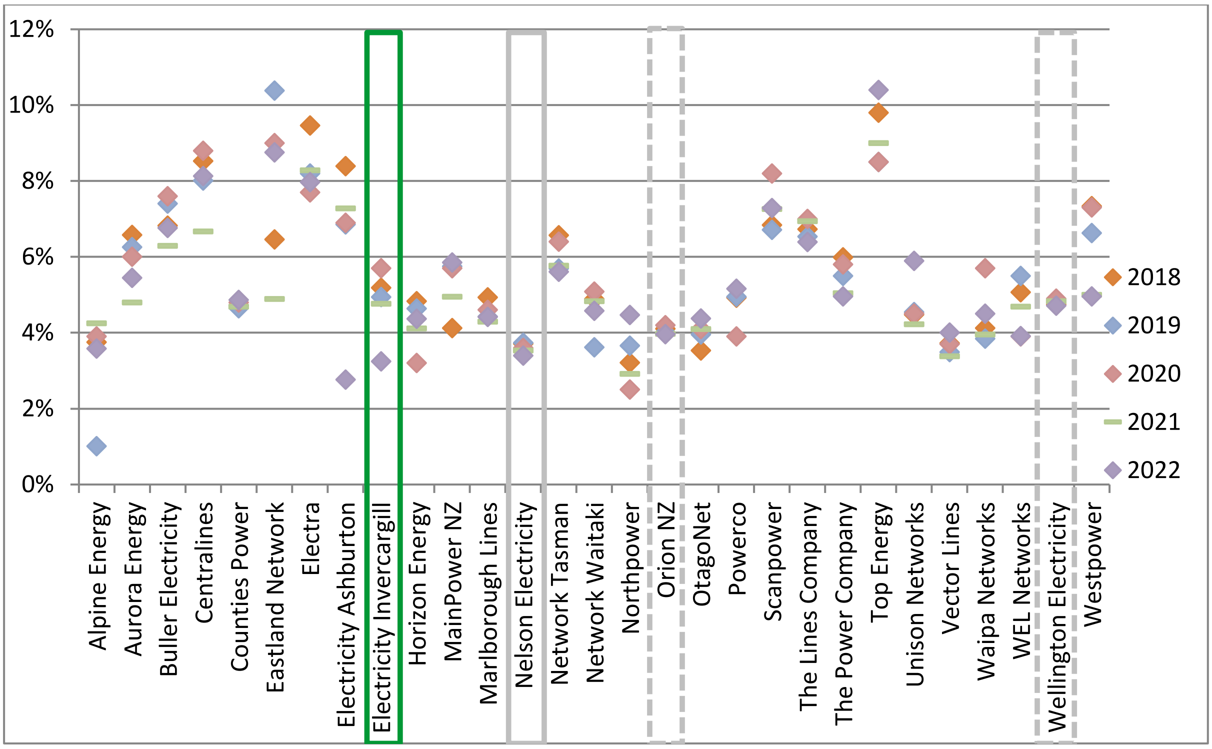
EIL's load factor is expected to remain at current levels in the short term. Improving the load factor would require influencing customer's consumption patterns. This is challenging, as we do not have any direct control over the price to customers. Any line charge incentives offered are repackaged by retailers in their tariffs.

Loss Ratio

Energy efficiency is getting increased attention, but in general it is uneconomical to improve efficiency of primary assets in order to minimise losses. The financial incentive for a network company to reduce losses is minimal, as losses are paid for by retailers. The exception is when the losses lead to other technical issues such as poor voltage or an exceeding the current rating of equipment. Upgrading network equipment as growth occurs will maintain losses at present levels.

In order to determine network losses accurately, accurate consumption data is required. Smart meters are providing improved data and assist with the identification of high loss areas, allowing focussed interventions to address issues.

Figure 54: Loss Ratio Comparison



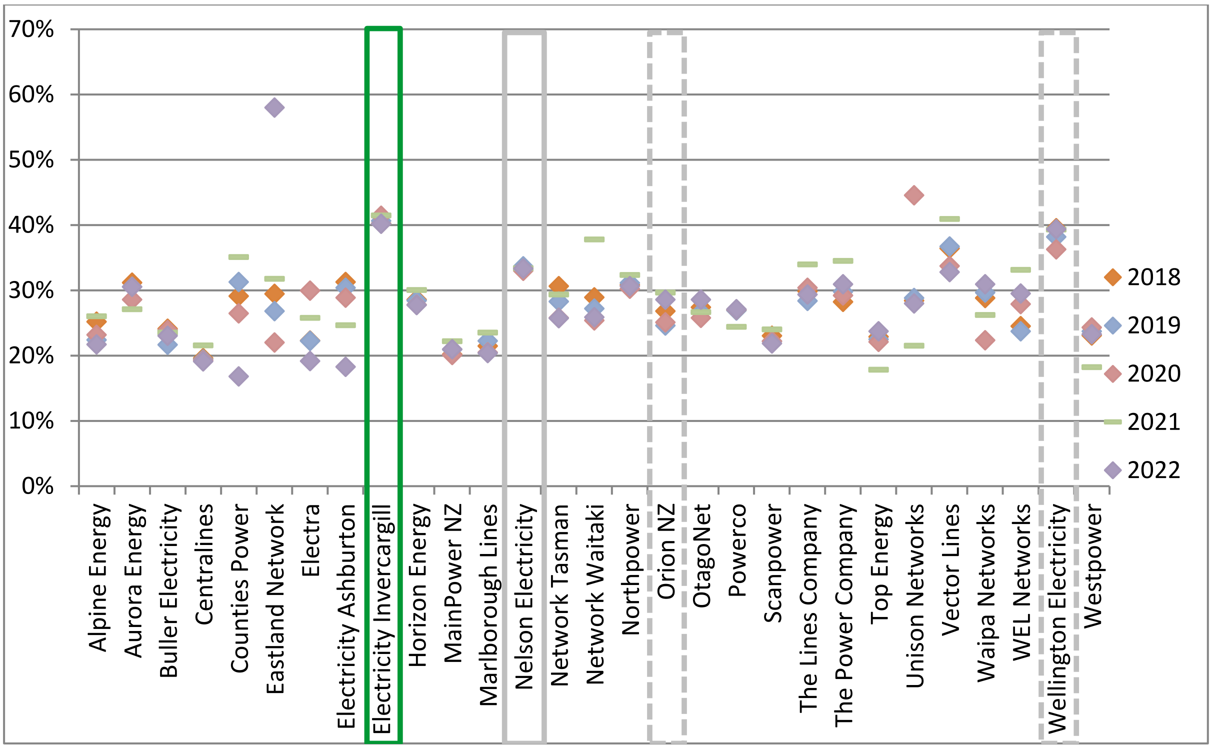
Comparison with other network companies shows EIL's network as moderately efficient. However, not all networks have access to accurate data so comparisons may be misleading.

Capacity Utilisation

Capacity utilisation on the network can be improved through optimisation of transformer sizes and numbers. However, there is often a trade-off between utilisation and standardisation. A larger, standard size transformer will in most cases be less expensive that a smaller, non-standard transformer sized to improve utilisation. It is generally more cost effective to replace overloaded transformers with appropriately sized standard units than to build bespoke transformers to increase utilisation.

EIL has the highest capacity utilisation factor of local EDBs and does not require improvement interventions in this regard. Smart meters will provide improved equipment loading profiles which would facilitate planning accuracy and lead to better equipment utilisation.

Figure 55: Capacity Utilisation Comparison



Financial Efficiency

Financial efficiency ratios do not raise any concerns when benchmarked against industry peers. These comparisons are presented in the following figures. These figures show:

- Operational expenditure per ICP is in the low band.
- Operational expenditure per km of network length is relatively high. This mainly due to EIL's high customer density. Similar results are observed from comparable high density distribution networks.
- Operational expenditure per MVA of distribution transformer capacity is good, reflecting the high-capacity utilisation.
- Non-network Operational expenditure measures are comparatively high due to the characteristics of the network. The influence of the network characteristics is clear when these measures are compared with those of OtagoNet and The Power Company Limited which operates under the same financial arrangements.

Figure 56: $OPEX/ICP Benchmarking

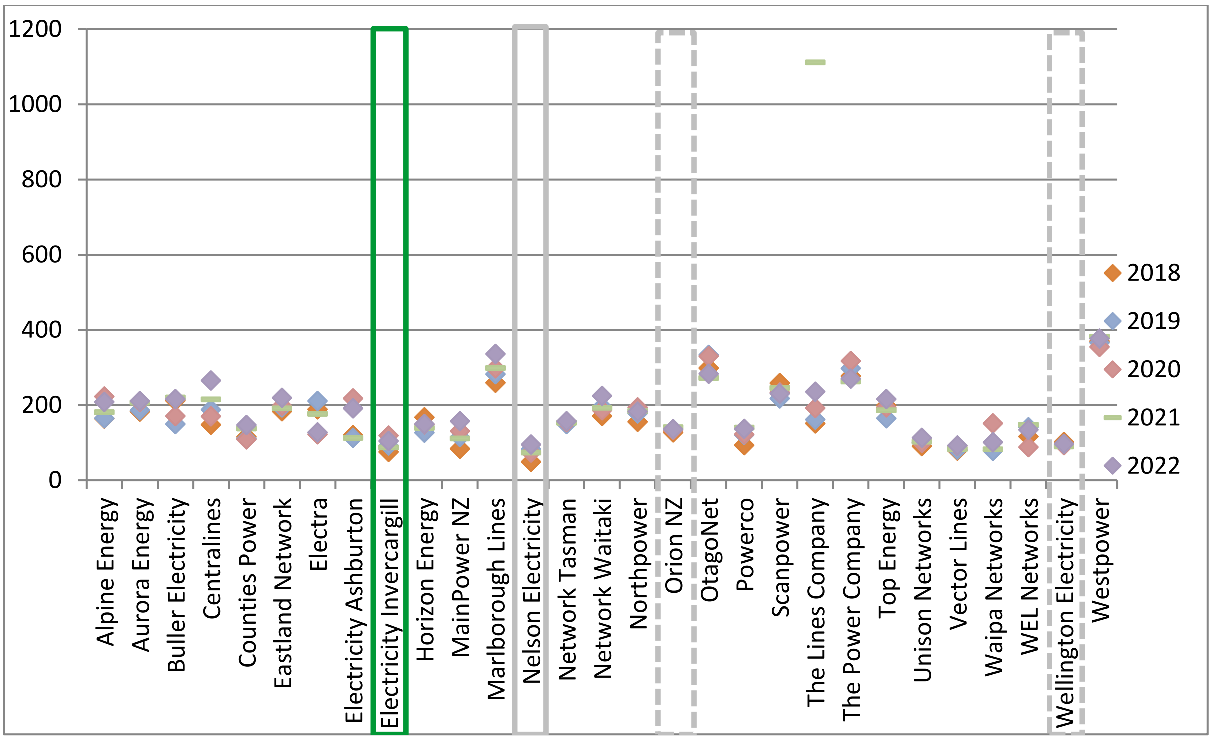


Figure 57: $OPEX/km Benchmarking

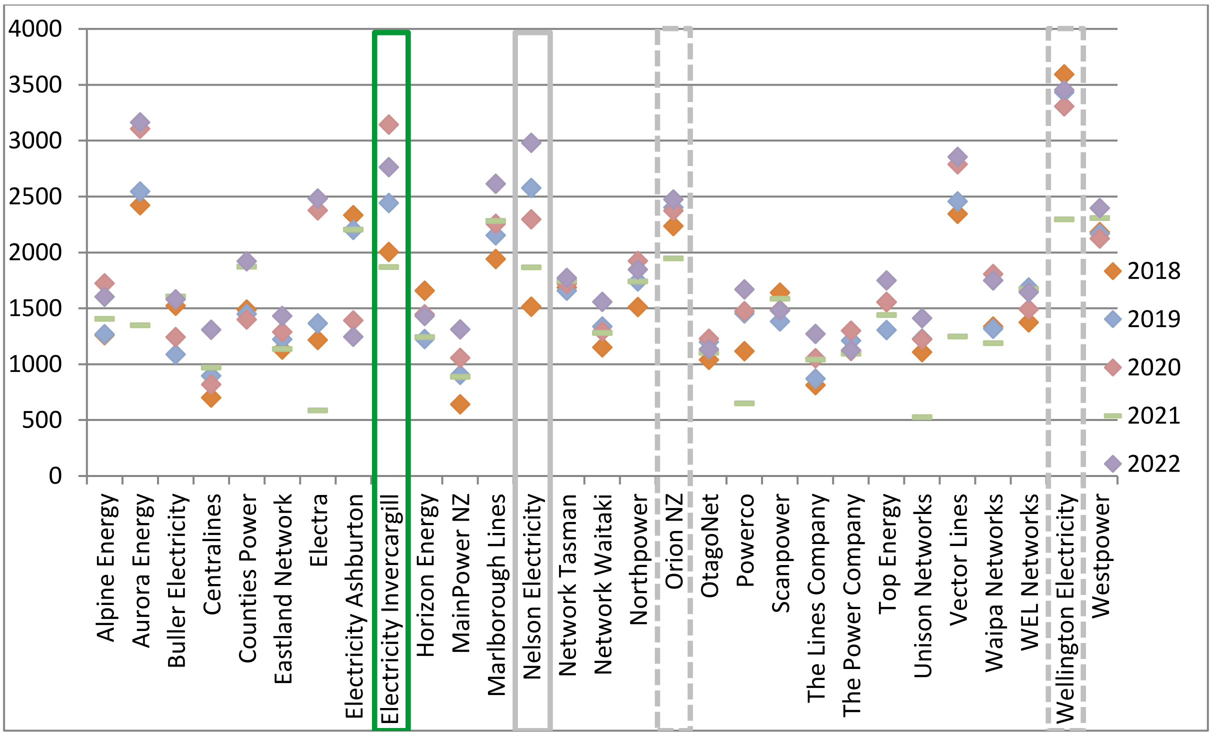


Figure 58: $OPEX/MVA Benchmarking

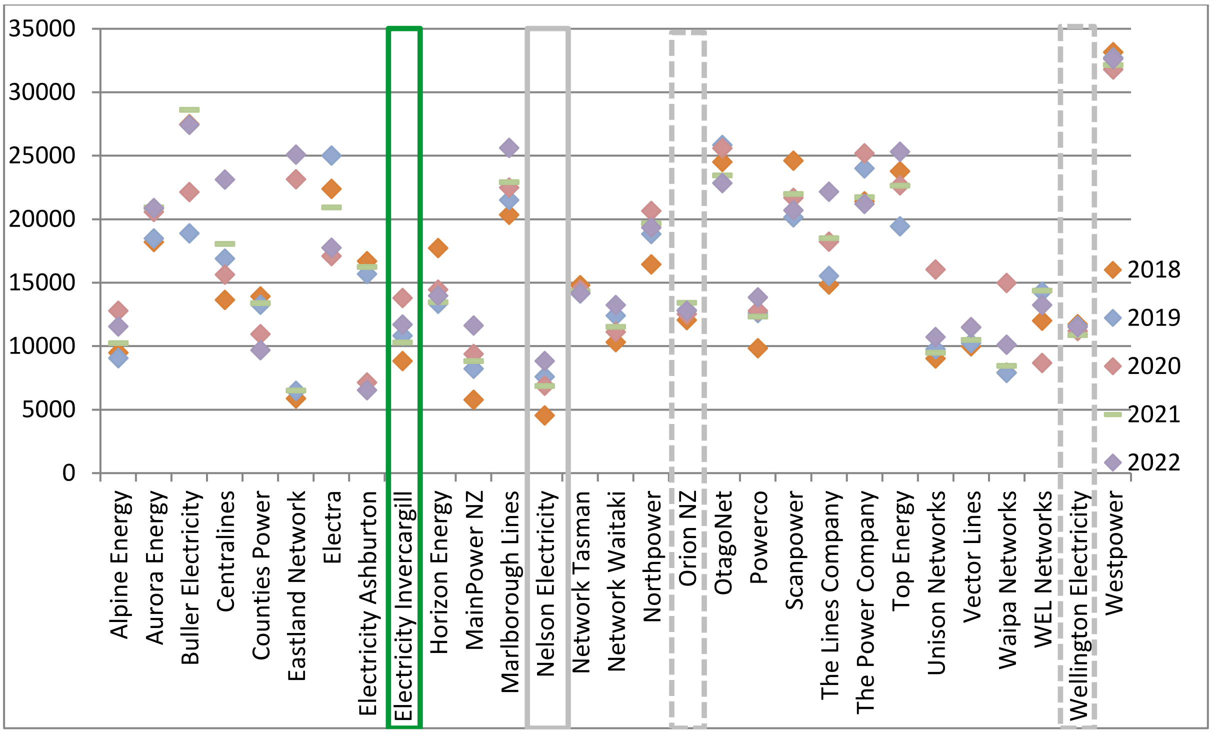


Figure 59: Non-Network $OPEX/ICP Benchmarking

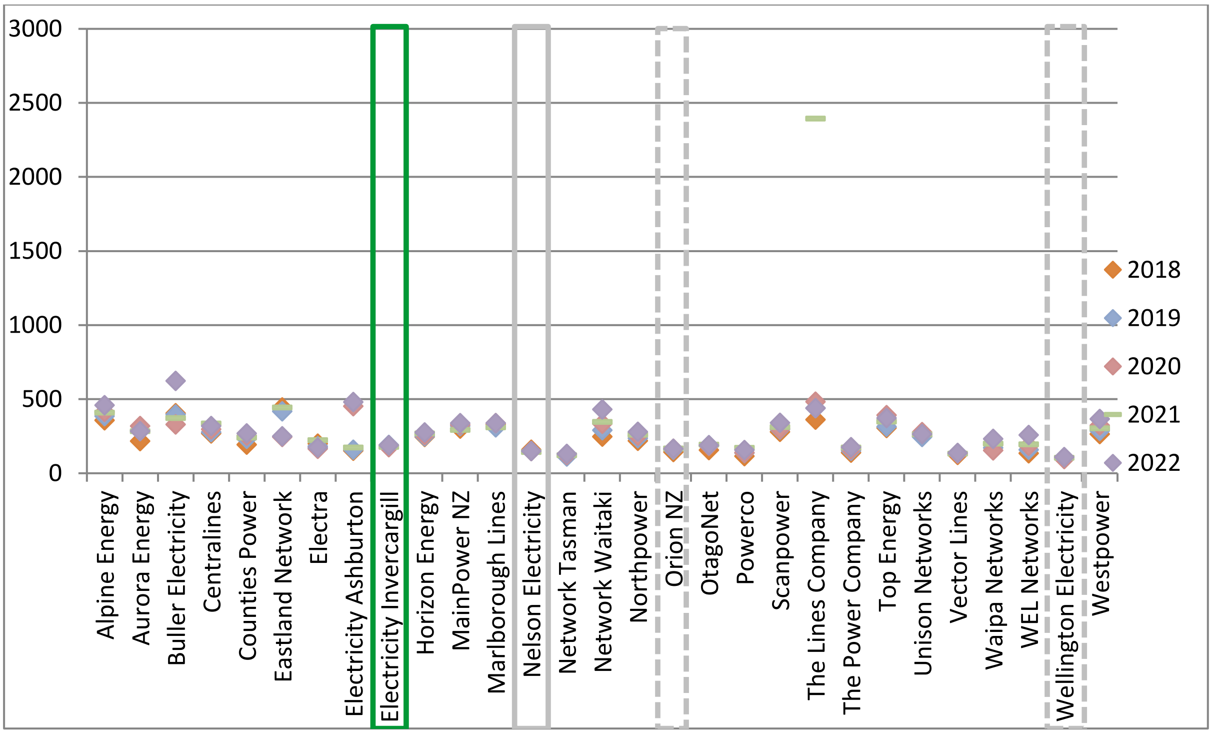


Figure 60: Non-Network $OPEX/km Benchmarking

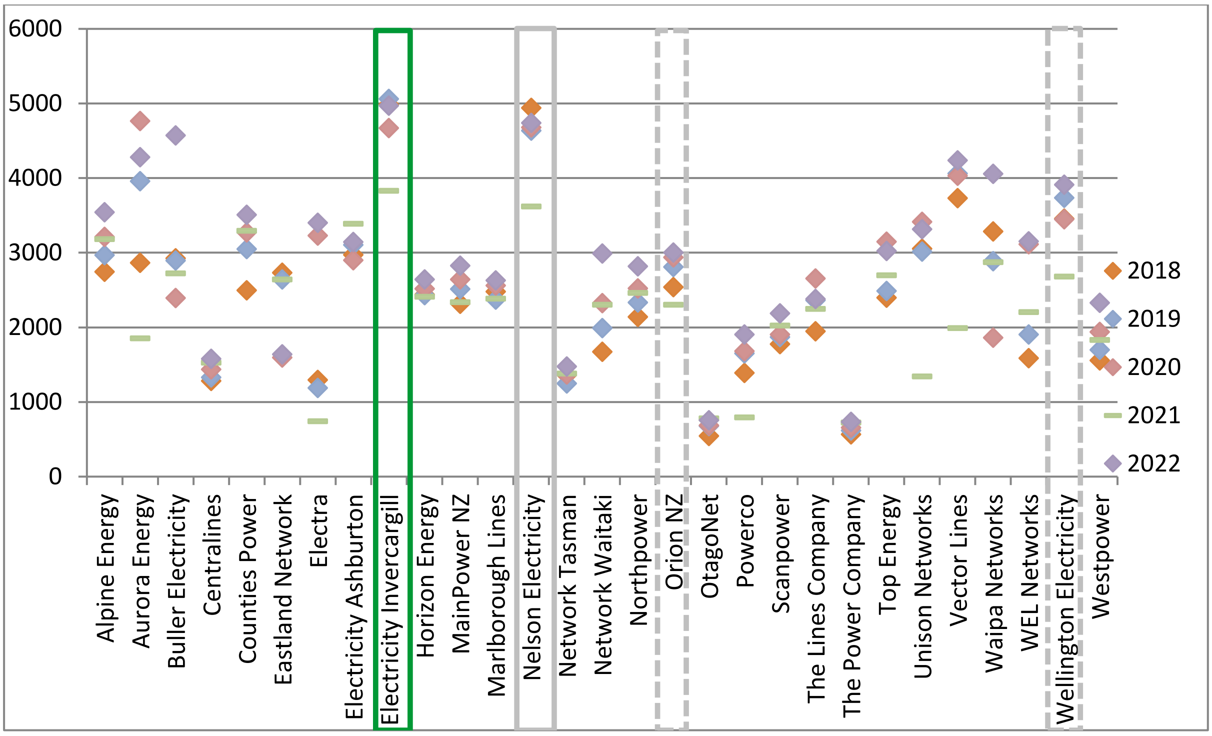
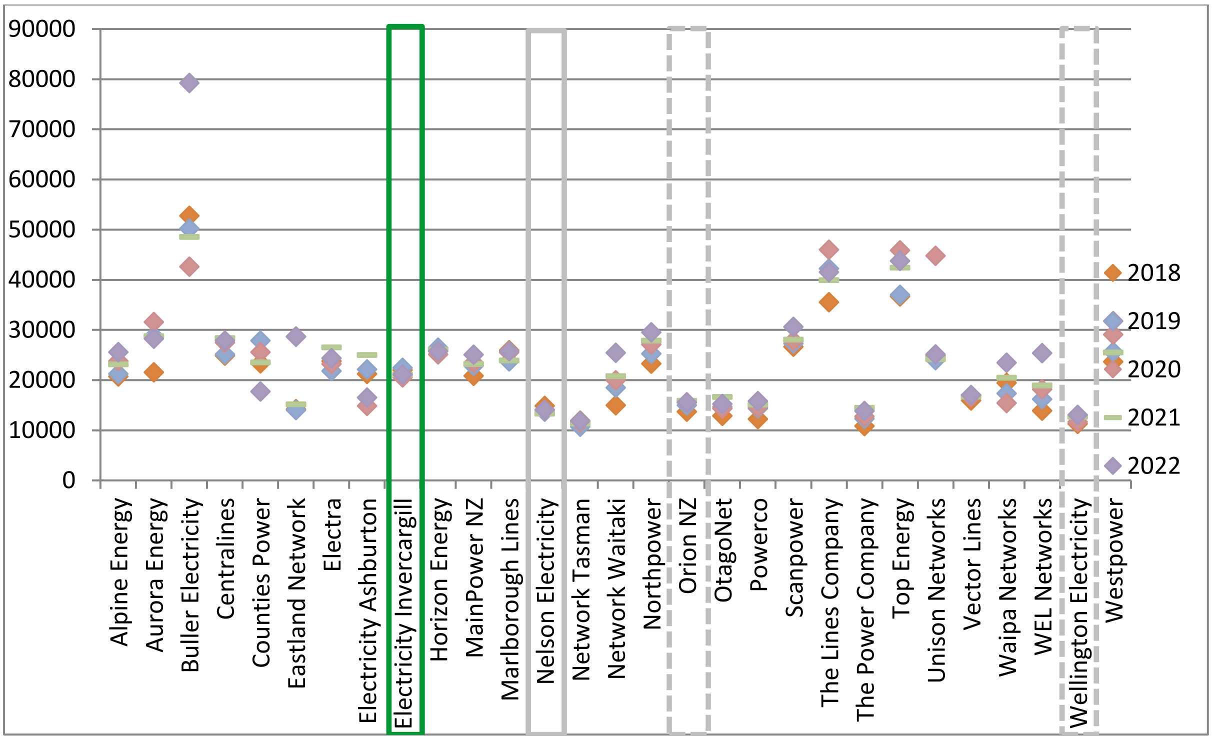


Figure 61: Non-Network $OPEX/MVA Benchmarking



Annexure 1 – Policies, Standards and Procedures

Asset Management and Operating Policies

AM-POL-0001	Sale of Scrap Metal Policy
AM-POL-0002	Earth Safety and Maintenance Policy
AM-POL-0003	Mobile Equipment Policy
AM-POL-0004	Streetlight Connections Policy
AM-POL-0006	Asset Management Policy Statement
AM-POL-0007	Public Safety in Asset Design Policy V1
AM-POL-0008	Power Pole Selection and Disposal Policy
AM-POL-0009	Easement Policy
AM-POL-0011	Approvals Required from Chief Engineer Policy
AM-POL-0012	Asset Management Policy
AM-POL-0013	Safety in Design Framework - Policy
OP-POL-0001	Traffic Management Plans Policy
OP-POL-0002	Live Line Selection and Training Policy
OP-POL-0004	Standby for Faults Response Policy
OP-POL-0006	COVID-19 – Critical and Essential Works Policy
OP-POL-0007	Cable Location Policy

Asset Management and Operating Standards

AM-STD-0001	Distribution Earth Installation Standard
AM-STD-0002	Installation Connection Standard
AM-STD-0003	Maintenance of Zone Transformers Standard
AM-STD-0004	Painting of Power Transformers Standard
AM-STD-0005	Air Break Switch Inspection Standard
AM-STD-0006	Network Design Standard
AM-STD-0008	Maintenance of Mineral Insulating Oil Standard
AM-STD-0009	Overhead Lines Inspection Standard
AM-STD-0010	Site Physical Security - Restricted Areas Standard
AM-STD-0011	Major Overhauls of Zone Transformers Standard
AM-STD-0012	Safety in Design Standard
AM-STD-0013	New Network Asset and Material Approval Standard
AM-STD-0014	Network Constructed by Independent Contractors Standard
AM-STD-0015	EXTERNAL - AMST D1750-13 - International Standard - Standard Test Method for the Determination of Gassing Characteristics of Insulating Liquids Under Thermal Stress
AM-STD-0017	Fencing Standard
AM-STD-0018	EXTERNAL - BS 148:2009 - Reclaimed Mineral Insulating Oil For Transformers And Switchgear - Specification - British Standard
AM-STD-0019	Vegetation Management Standard
AM-STD-0020	Ring Main Unit – Standard Specification
AM-STD-0021	PowerNet Network Lock and Key Standard
AM-STD-0022	Network Fuse Protection Standard
AM-STD-0024	Substation Safety Signage Standard

AM-STD-0025	Protection Design Setting Philosophy Standard
AM-STD-0026	EXTERNAL - EEA Resilience Guide 2022
OP-STD-0001	Network Faults Standard
OP-STD-0003	Security of Supply - Participant Outage Plan Standard
OP-STD-0004	Load Control Standard
OP-STD-0005	Planned Outages and Operating Orders Standard
OP-STD-0006	Major Network Disruptions and Storm Gallery Standard
OP-STD-0007	Fault Response Standard
OP-STD-0008	Radio Telephone Communications Standard
OP-STD-0011	Operating Sequence Standard
OP-STD-0012	SmartCo - PowerNet Installation Requirements and Guidelines

Asset Management and Operating Procedures

AM-PRO-0001	Earth Test Procedure
AM-PRO-0008	Loss Factor Calculation Procedure
AM-PRO-0010	Cable Testing Procedure
AM-PRO-0013	Tendering Procedure
AM-PRO-0014	Commissioning Network Equipment Procedure
AM-PRO-0020	Transformer Maintenance Procedure
AM-PRO-0023	Project Close Out Issue Procedure
AM-PRO-0024	Design and Development Procedure
AM-PRO-0025	Project Control Procedure
AM-PRO-0026	Materials Management Procedure
AM-PRO-0028	Progressing the Project Procedure
AM-PRO-0029	Control of SCADA Computers Procedure
AM-PRO-0033	Setting up the Project Procedure
AM-PRO-0035	Safety In Design Procedure
OP-PRO-0057	Completion and Livening of Customer Connections on PowerNet Networks Procedure
OP-PRO-0002	Customer Service Performance Procedure
OP-PRO-0006	Identification of Cables Procedure
OP-PRO-0010	Ladder Management Procedure
OP-PRO-0013	Second Point of Attachment Procedure
OP-PRO-0017	System Control Station Log Book Procedure
OP-PRO-0023	Network Access Procedure
OP-PRO-0026	Entry to EIL Underground Substations Procedure
OP-PRO-0027	Work on De-energised Overhead Lines Procedure
OP-PRO-0036	Live LV Work - Install a Pole Mounted LV Three Phase Fuse Carrier for Parallel Connection Procedure
OP-PRO-0043	Confined Space Management Procedure
OP-PRO-0045	Operational Requirements for Live Line Work Procedure
OP-PRO-0047	Transpower GXP Building Access Procedure
OP-PRO-0048	Control of Tags Procedure
OP-PRO-0051	Live LV Work - Weekly Testing, Cleaning, Maintenance for Gloves, EWP & Associated Equipment
OP-PRO-0052	Access to Substations and Switchyards Procedure

OP-PRO-0058	H W Richardson Contracting - Hydro Vacuum Truck Procedure
OP-PRO-0059	ABB Series 2 Switchgear Remote Operating Procedure
OP-PRO-0060	ENTEC Halo Switchgear Remote Operating Procedure
OP-PRO-0061	Earthing Upgrade Installation and Final Connection Procedure
OP-PRO-0062	High Voltage Live Work - System Control Procedure
OP-PRO-0064	Long and Crawford Switchgear Remote Opening Procedure
OP-PRO-0065	Spiking of Cables Procedure
OP-PRO-0066	Securing Wooden or Concrete Poles for Travel (Failsafe Method) - Procedure
OP-PRO-0067	Working with Helicopters Procedure
OP-PRO-0068	Manual Reclosing of High Voltage Circuits Following a Fault Procedure

Asset Management and Operating Plans and Specifications

AM-PLN-5002	Asset Fleet Plan - Capacitors
AM-PLN-5003	Asset Fleet Plan - Distribution Transformers
AM-PLN-5004	Asset Fleet Plan - Field CB
AM-PLN-5005	Asset Fleet Plan - Generators and Generator Controllers
AM-PLN-5006	Asset Fleet Plan - LV Outdoor Cubicles
AM-PLN-5007	Asset Fleet Plan - Poles
AM-PLN-5008	Asset Fleet Plan - RMU
AM-PLN-5009	Asset Fleet Plan - StatCom
AM-PLN-5010	Asset Fleet Plan - Switchgear
AM-PLN-5011	Asset Fleet Plan - Trees
AM-PLN-5012	Asset Fleet Plan - Power Transformers
AM-PLN-5013	Asset Fleet Plan - Instrument Transformer
AM-PLN-5014	Asset Fleet Plan - Neutral Earth Resistor
AM-PLN-5015	Asset Fleet Plan - Regulator Transformer
AM-PLN-5016	Asset Fleet Plan - Oil Separator
AM-PLN-5017	Asset Fleet Plan - Distribution Earth
AM-PLN-5018	Asset Fleet Plan - CT-VT Units
AM-PLN-5019	Asset Fleet Plan - Fault Throw Switch
AM-PLN-5020	Asset Fleet Plan - Injection Station
AM-PLN-5021	Asset Fleet Plan - Oil separator
AM-PLN-5022	Asset Fleet Plan - Overhead Lines
AM-PLN-5023	Asset Fleet Plan - Battery Chargers
AM-PLN-5024	Asset Fleet Plan - Fault Indicator
AM-PLN-5025	Asset Fleet Plan - Power Supply
AM-PLN-5026	Asset Fleet Plan - Voltage Regulating Relay
AM-PLN-5028	Asset Fleet Plan - Surge Diverter
AM-PLN-5029	Asset Fleet Plan - Zone Sub
AM-PLN-5030	Asset Fleet Plan - RTU
AM-PLN-5031	Asset Fleet Plan - Cables
AM-PLN-5032	Asset Fleet Plan - Batteries
AM-PLN-5033	Asset Fleet Plan - Protection Relay
AM-SPE-0002	Wiring and Connection of Streetlights Specification
AM-SPE-0003	Standard Construction Specification

Annexure 2 – Customer Engagement Questionnaire

Telephone Survey Questions

I'm $I calling from Research First on behalf of PowerNet.

We are not selling anything or asking you to change anything. We are conducting a survey to help PowerNet deliver the right levels of service to network customers and plan effectively for your future needs.

To thank you for your time and effort, everyone who completes this survey will go into the draw to win 1 of 5 $100 cash prizes,

Can I speak to <NAME>, or the person mainly or jointly responsible for paying the electricity account or making decisions about power supply?

The survey will take about 15 minutes to complete. Are you able to help today?

If necessary: PowerNet is relevant to all electricity users in Southland, West Otago, Queenstown- Lakes, Central Otago and Stewart Island. I will explain further later in the survey.

If required: Please know that Research First is a professional market research company, so we abide by a Code of Practice. This means we treat everything you tell us as totally confidential. You have the right to decline or withdraw from the research at any time.

If required: Phone numbers have been supplied by PowerNet from the customer database. We will not use numbers for any other purpose. You can call PowerNet on (03) 211-1899 with any queries.

S1	I just have to check if you are eligible… Are you a PowerNet staff member, or are any of your immediate family a PowerNet staff member	
	O	No
	O	Yes <survey will end>

Awareness and Perceptions of Performance

1.	Have you heard of PowerNet?	
	O	Yes – Q2
	O	No – Q4

2.	Where have you most recently seen or heard about PowerNet? <do not prompt> <route to 3 except if Facebook mentioned>	
	○	Sponsorship – St John
	○	Sponsorship – Tour of Southland
	○	Sponsorship – other
	○	Website
	○	Facebook page
	○	Logos on vehicles
	○	Newspaper ads
	○	LinkedIn
	○	Other specify
	○	Don't Know

3.	On a scale of 1 to 5 where 1 = 'very poor', 2 = 'poor', 3 = 'neutral', 4 = 'good', and 5 = 'very good', how would you rate PowerNet's performance on the following aspects over the last 12 months? <Don't read out 'Don't know'>							
		Caring for customers	1	2	3	4	5	6
		Supporting the community	1	2	3	4	5	6
		Being safety conscious	1	2	3	4	5	6
		Efficiency in service response	1	2	3	4	5	6
		Reliability of power supply	1	2	3	4	5	6

Section 2: Planned Interruptions to Service

4a	Given the frequency for a planned interruption is one every two years, is this an acceptable frequency for a planned interruption?	
	○	Yes
	○	No

4b	Given the duration for a planned interruption on average is 4 hours, is this an acceptable duration for a planned interruption?	
	○	Yes
	○	No
5	Which of the following options would you prefer?	
	○	Retain the current plan: 1 interruption of 4 hours every 2 years
	○	Have more frequent interruptions but of shorter duration
	○	Have less frequent interruptions but of a longer duration
	○	Don't know <do not prompt>

SECTION 3: Communications – Planned Interruptions

6	It is now your retailer's responsibility to notify you of any planned interuptions. Have you received advice of a planned electricity interruption during the last 6 months?	
	○	Yes – Q7
	○	No – Q11
	○	Don't know – Q11 – DO NOT READ OUT

7	Can you remember how much notice you were given?	
	○	1-2 day -Q8
	○	3-4 days -Q8
	○	5-6 days -Q8
	○	1 week -Q8
	○	2 weeks -Q8
	○	More than 2 weeks -Q8
	○	Don't know – Q11 – DO NOT READ OUT

8	Do you feel that you were given enough notice of this planned interruption?	
	○	Yes

	O	No
	O	Don't know – DO NOT READ OUT

9	Were you satisfied with the amount of information given to you about this planned interruption?	
	O	Yes
	O	No
	O	Don't know– DO NOT READ OUT

10	What additional information on an outage is needed? Probe to clarify.	
	O	Open comment
	O	Don't know
	O	No additional information is needed

SECTION 4: Unplanned Interruptions

11	Who would you telephone in the event your power supply has been unexpectedly interrupted? Do not prompt.	
	O	PowerNet
	O	Retailer/Power company
	O	Local government
	O	Other (specify)
	O	No-one

12	Where would you prefer to receive communication from PowerNet about outages? DO NOT READ OUT, randomise	
	O	PowerNet Facebook Page
	O	PowerNet 0800 faults number (0800 808 587)
	O	The internet (Google, firefox, etc)
	O	PowerNet's Outage Website Page? https://outages.powernet.co.nz/

	O	Text message

13	Can you recall when the last unexpected interruption to your power supply was?	
	O	Yes – In the last week – Q14
	O	In the last month – Q14
	O	2-3 months ago – Q14
	O	3-6 months ago – Q14
	O	More than 6 months ago – Q19
	O	Never had an unexpected interruption to power at this address – Q19
	O	Don't know – Q19 – DO NOT READ OUT
	O	Don't care – Q19 – DO NOT READ OUT

14	Do you recall how long your most recent power cut lasted? Read if necessary	
	O	1-2 hours
	O	2-3 hours
	O	3-4 hours
	O	More than 4 hours
	O	Don't know – DO NOT READ OUT

15	On a scale of 1 to 5 where 1 is no impact at all, 2 is minor impact, 3 is neutral, 4 is moderate impact and 5 is major impact, how much impact did your last power cut have on you?	
	O	No impact
	O	Minor impact
	O	Neutral
	O	Moderate impact
	O	Major impact
	O	Don't know – DO NOT READ OUT

16	Who did you call when the supply was interrupted?	
	O	PowerNet – Q17
	O	Retailer/Power company – Q19

	O	Local government – Q19
	O	No one – Q19
	O	Other (specify)– Q19
	O	Don’t know/can’t remember – Q19 – DO NOT READ OUT

17	On a scale of 1 to 5 where 1 = 'very dissatsfied', 2 = 'dissatisfied', 3 = 'neutral', 4 = 'satisfied', and 5 = 'very satisfied', how satisfied were you with...?							
			Very dissatisfied	Dissatisfied	Neutral	Satisfied	Very satisfied	Don’t know
		The system you had to use to get information	1	2	3	4	5	6
		The information supplied was satisfactory	1	2	3	4	5	6

If coded 1 or 2 at Q17 - go to Q18
If coded 3,4,5 at Q17 - go to Q19

18	<If coded 1 or 2 at Q17> What could be done to improve this process? Probe to clarify.	
	O	Open comment
	O	Don’t know

19	In the event of an unexpected interruption to your electricity supply, what do you consider would be a reasonable amount of time before the electricity supply is restored to your home?	
	O	Under 30 minutes
	O	30min - 1 hour
	O	1-2 hours
	O	2-3 hours

	○	3-4 hours
	○	More than 4 hours
	○	Don't know – DO NOT READ OUT
	○	Don't care – DO NOT READ OUT

20	In the event of an unexpected interruption to your electricity supply, what is the most important information that you wish to receive? Do not prompt, select all that apply.	
	○	Accurate time power will be restored
	○	Reason for fault
	○	That they know the problem and that it is being fixed
	○	Other (specify)
	○	No information required

21	**Costs have gone up significantly due to global supply chain constraints. NZ inflation over the last year has been 6.9% which has increased costs of materials and labour to maintain our networks and service levels. Because of these factors, what percentage increase in line charges are you willing to pay to keep the same quality and reliability of supply?**
○	(Open comment - % textbox)

Section 5: Evolving Technology

22	I am going to read out a list of technologies. For each of these I would like to know if you: Already have it, Would consider purchasing it, Would not consider purchasing, Or, if you have never heard of it before. Read out.

			Already have it	Considering purchasing it	Not Considering it	Never heard of it before
		Solar Panels or Photovoltaic Panels	1	2	3	4
		Wind Turbines	1	2	3	4
		Battery Energy Storage System	1	2	3	4

		EVs	1	2	3	4
		Hot Water Heat Pumps	1	2	3	4
		Space Heating Heat Pumps	1	2	3	4
		Smart Home Technologies (e.g. Smart Controlled Appliances)	1	2	3	4

23	I would like to know which of these technologies you are most interested in. Please tell me which is the 1st, 2nd and 3rd most interesting. Read out. **[Rank 1, 2, and 3]**	
		Solar Panels or Photovoltaic Panels
		Wind Turbines
		Battery Energy Storage System
		EVs
		Hot Water Heat Pumps
		Space Heating Heat Pumps
		Smart Home Technologies (e.g. Smart Controlled Appliances)

Solar Panels

24.	If you were given an opportunity to receive an assessment and you found that installing Solar Panels would be the most economic option for yourself (as opposed to fully purchasing energy from the grid), On a scale from 1 to 5, how likely would you be to install Solar Panels? Where 1 = not at all likely, and 5 = very likely.	
		I am not interested at all
		Not likely at all
		Unlikely
		Neutral
		Likely
		Very likely
		Don't know DO NOT READ OUT

EVs

25.	Which of the following are most important when considering buying an EVs? Please tell me which is the 1st, 2nd and 3rd most important. [Randomise] [Rank 1, 2, and 3]Read out	
		Saving money on fuel
		Reducing emissions
		The distance you can drive on a single charge
		The purchase price
		The size and capability of the vehicle
		The number of charging stations in your area

26	Do you have any comments you would like to make about why you would or would not buy solar panels or an EVs?	
	O	Open comment box
	O	Don't know

Demographics

27	Which of these age groups do you fall into? Read out	
	O	18-24
	O	25-44
	O	45-64
	O	65+
	O	Prefer not to say – DO NOT READ OUT

28	At the property where you are currently living/ working, do you...? Read out	
	O	Own your dwelling outright
	O	Own your dwelling with a mortgage
	O	Rent from a private landlord
	O	Rent from friends/family
	O	Rent from the Council or government

	O	Other (specify) – DO NOT READ OUT

29	How many people are in your household / workplace?	
	O	How many adults are there, including yourself? Aged 18 years and over. Record number
	O	And how many children aged up to 18 are there? Record number
	O	Prefer not to say

SECTION 6: Final Comments

30	Finally, are there any other comments you would like to make about PowerNet services?	
	O	No comment
	O	Happy with service
	O	Other (specify)

Annexure 3 – Disclosure Schedules

Schedule 11a. – Capital Expenditure Forecast

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2024 – 31 March 2034

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	732	1,344	1,107	818	834	851	868	639	895	921	674
11		System growth	-	-	652	117	523	540	784	380	-	-	-
12		Asset replacement and renewal	3,947	4,205	4,359	7,350	7,089	5,963	7,195	6,623	7,604	6,018	6,264
13		Asset relocations	7	7	8	8	8	8	8	8	8	9	9
14		Reliability, safety and environment:											
15		Quality of supply	363	170	174	178	181	185	189	192	196	200	202
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,178	1,397	796	814	1,234	587	598	3,799	5,048	632	632
18		**Total reliability, safety and environment**	1,541	1,567	970	992	1,415	772	787	3,991	5,244	832	834
19		**Expenditure on network assets**	6,227	7,775	6,561	9,691	9,886	8,378	9,238	#REF!	13,751	7,780	7,781
20		Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
21		**Expenditure on assets**	6,227	7,775	6,561	9,691	9,886	8,378	9,238	#REF!	13,751	7,780	7,781
22													
23	*plus*	Cost of financing											
24	*less*	Value of capital contributions	210	403	324	234	234	234	234	234	234	234	234
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	6,017	7,372	6,237	9,457	9,652	8,144	9,004	#REF!	13,517	7,546	7,547
28													
29		Assets commissioned	5,322	7,394	6,633	9,015	9,514	7,784	9,353	11,373	11,723	7,503	7,579

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31												
32		**$000 (in constant prices)**										
33	Consumer connection	733	780	1,080	780	780	780	780	563	774	780	560 #
34	System growth	-	635	111	490	496	#REF!	705	335	-	-	-
35	Asset replacement and renewal	3,416	4,205	4,253	7,017	6,634	5,472	6,472	5,841	6,574	5,101	5,206 #
36	Asset relocations	7	7	7	7	7	7	7	7	7	7	7
37	Reliability, safety and environment:											
38	Quality of supply	363	170	170	170	170	170	170	170	170	170	168
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,178	1,398	777	777	1,156	539	538	3,350	4,364	536	525 #
41	**Total reliability, safety and environment**	1,541	1,568	947	947	1,326	709	708	3,520	4,534	706	693
42	**Expenditure on network assets**	5,697	7,195	6,398	9,242	9,243	#REF!	8,672	10,266	11,889	6,594	6,466
43	Expenditure on non-network assets	-	-	-	-	-	-					
44	**Expenditure on assets**	5,697	7,195	6,398	9,242	9,243	#REF!	8,672	10,266	11,889	6,594	6,466
45												
46	**Subcomponents of expenditure on assets (where known)** **EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
47	Energy efficiency and demand side management, reduction of energy losses	125	125	125	125	125	125	125	125	125	125	125
48	Overhead to underground conversion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Research and development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
51												

Schedule 11a. – Capital Expenditure Forecast (continued)

Difference between nominal and constant price forecasts

$000	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Consumer connection	(1)	564	27	38	54	71	88	76	121	141	114
System growth	-	17	6	33	44	#REF!	(325)	#REF!	-	-	-
Asset replacement and renewal	531	-	106	333	455	491	723	782	1,030	917	1,058
Asset relocations	0	(0)	1	1	1	1	1	1	1	2	2
Reliability, safety and environment:											
Quality of supply	-	0	4	8	11	15	19	22	26	30	34
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	(1)	19	37	78	48	60	449	684	96	107
Total reliability, safety and environment	-	(1)	23	45	89	63	79	471	710	126	141
Expenditure on network assets	530	580	163	449	643	#REF!	566	#REF!	1,862	1,186	1,315
Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
Expenditure on assets	530	580	163	449	643	#REF!	566	#REF!	1,862	1,186	1,315

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

*Consumer types defined by EDB** / $000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Customer Connections (≤ 20kVA)	70	74	74	74	74	74
Customer Connections (21 to 99kVA)	62	66	66	66	66	66
Customer Connections (≥ 100kVA)	140	148	148	148	148	148
Distributed Generation Connection	3	3	3	3	3	3
New Subdivisions	458	489	789	489	489	489
Otatata/Mersey Street	-	-	-	-	-	-
**include additional rows if needed*						
Consumer connection expenditure	733	780	1,080	780	780	780
less Capital contributions funding consumer connection	210	403	324	234	234	234
Consumer connection less capital contributions	523	377	756	546	546	546

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-		-	-	-	-
Zone substations	-		127	22	98	153
Distribution and LV lines	-		-	-	-	-
Distribution and LV cables	-		381	67	294	257
Distribution substations and transformers	-		-	-	-	-
Distribution switchgear	-		127	22	98	86
Other network assets	-		-	-	-	-
System growth expenditure	-	635	111	490	496	#REF!
less Capital contributions funding system growth						
System growth less capital contributions	-	635	111	490	496	#REF!

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	-	-	-	-	-
Zone substations	99	10	10	2,170	1,376	429

Schedule 11a. – Capital Expenditure Forecast (continued)

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
101		Distribution and LV lines	271	288	360	360	360	360
102		Distribution and LV cables	794	791	749	1,101	1,243	1,362
103		Distribution substations and transformers	779	978	1,106	1,106	1,375	1,094
104		Distribution switchgear	1,290	1,943	1,833	2,085	2,085	2,032
105		Other network assets	183	195	195	195	195	195
106		**Asset replacement and renewal expenditure**	3,416	4,205	4,253	7,017	6,634	5,472
107	*less*	Capital contributions funding asset replacement and renewal						
108		**Asset replacement and renewal less capital contributions**	3,416	4,205	4,253	7,017	6,634	5,472
109								
110			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
111								
112		**11a(v): Asset Relocations**						
113		*Project or programme**	**$000 (in constant prices)**					
114		Asset Relocation Projects	7	7	7	7	7	7
115								
116								
117								
118								
119		**include additional rows if needed*						
120		All other project or programmes - asset relocations						
121		**Asset relocations expenditure**	7	7	7	7	7	7
122	*less*	Capital contributions funding asset relocations						
123		**Asset relocations less capital contributions**	7	7	7	7	7	7
124								
125			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
126								
127		**11a(vi): Quality of Supply**						
128		*Project or programme**	**$000 (in constant prices)**					
129		Supply Quality Upgrades - City/Bluff	17	18	18	18	18	18
130		Network Automation Projects	155	38	38	38	38	38
131		Fault Indicator project	191	114	114	114	114	114
132								
133								
134		**include additional rows if needed*						
135		All other projects or programmes - quality of supply						
136		**Quality of supply expenditure**	363	170	170	170	170	170
137	*less*	Capital contributions funding quality of supply						
138		**Quality of supply less capital contributions**	363	170	170	170	170	170
139								
140			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
141								
142		**11a(vii): Legislative and Regulatory**						
143		*Project or programme**	**$000 (in constant prices)**					
144		[Description of material project or programme]						
145		[Description of material project or programme]						
146		[Description of material project or programme]						
147		[Description of material project or programme]						
148		[Description of material project or programme]						
149		**include additional rows if needed*						
150		All other projects or programmes - legislative and regulatory						

Schedule 11a. – Capital Expenditure Forecast (continued)

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
151		**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory						
153		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
154								
155			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
156		**11a(viii): Other Reliability, Safety and Environment**						
157		*Project or programme**	**$000 (in constant prices)**					
158		Earth Upgrades - City/Bluff	297	313	313	313	75	75
159		Pillar Box Lid Upgrade	133	146	146	146	146	146
160		Oil-Filled Cable Work	290	333	-	-	617	-
161		LV Tie Point Disconnectors	140	272	272	272	272	272
162		Fibre Installation	318	334	46	46	46	46
163		**include additional rows if needed*						
164		All other projects or programmes - other reliability, safety and environment						
165		**Other reliability, safety and environment expenditure**	1,178	1,398	777	777	1,156	539
166	*less*	Capital contributions funding other reliability, safety and environment						
167		**Other reliability, safety and environment less capital contributions**	1,178	1,398	777	777	1,156	539
168								
169			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
170								
171		**11a(ix): Non-Network Assets**						
172		**Routine expenditure**						
173		*Project or programme**	**$000 (in constant prices)**					
174		[Description of material project or programme]						
175		[Description of material project or programme]						
176		[Description of material project or programme]						
177		[Description of material project or programme]						
178		[Description of material project or programme]						
179		**include additional rows if needed*						
180		All other projects or programmes - routine expenditure						
181		**Routine expenditure**	-	-	-	-	-	-
182		**Atypical expenditure**						
183		*Project or programme**						
184		[Description of material project or programme]						
185		[Description of material project or programme]						
186		[Description of material project or programme]						
187		[Description of material project or programme]						
188		[Description of material project or programme]						
189		**include additional rows if needed*						
190		All other projects or programmes - atypical expenditure						
191		**Atypical expenditure**	-	-	-	-	-	-
192								
193		**Expenditure on non-network assets**	-	-	-	-	-	-
194								

Schedule 11b. – Operational Expenditure Forecast

AMP Planning Period **1 April 2024 – 31 March 2034**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	550	615	628	641	654	668	683	698	713	721	737
11	Vegetation management	2	3	3	3	3	3	3	3	3	2	2
12	Routine and corrective maintenance and inspection	1,518	1,791	1,805	1,841	1,878	1,920	1,962	2,005	2,049	1,971	1,669
13	Asset replacement and renewal	228	189	193	197	201	205	210	214	219	186	190
14	**Network Opex**	2,298	2,598	2,629	2,682	2,736	2,796	2,858	2,920	2,984	2,880	2,598
15	System operations and network support	1,506	1,809	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959
16	Business support	2,370	2,441	2,473	2,444	2,444	2,444	2,444	2,444	2,444	2,444	2,444
17	**Non-network opex**	3,876	4,250	4,432	4,403	4,403	4,403	4,403	4,403	4,403	4,403	4,403
18	**Operational expenditure**	6,174	6,848	7,061	7,085	7,139	7,199	7,261	7,323	7,387	7,283	7,001
19		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20												
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	550	576	576	576	576	576	576	576	576	570	570
23	Vegetation management	2	2	2	2	2	2	2	2	2	2	1
24	Routine and corrective maintenance and inspection	1,518	1,679	1,656	1,656	1,656	1,656	1,656	1,656	1,656	1,558	1,291
25	Asset replacement and renewal	228	177	177	177	177	177	177	177	177	147	147
26	**Network Opex**	2,298	2,434	2,411	2,411	2,411	2,411	2,411	2,411	2,411	2,277	2,009
27	System operations and network support	1,506	1,809	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959
28	Business support	2,370	2,441	2,473	2,444	2,444	2,444	2,444	2,444	2,444	2,444	2,444
29	**Non-network opex**	3,876	4,250	4,432	4,403	4,403	4,403	4,403	4,403	4,403	4,403	4,403
30	**Operational expenditure**	6,174	6,684	6,843	6,814	6,814	6,814	6,814	6,814	6,814	6,680	6,412
31	**Subcomponents of operational expenditure (where known)**											
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
32–33	Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	181	501	501	501	501	501	501	501	501	501	501
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
39												
40		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
41												
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	39	52	65	78	92	107	122	137	151	167
44	Vegetation management	(0)	1	1	1	1	1	1	1	1	(0)	1
45	Routine and corrective maintenance and inspection	-	112	149	185	222	264	306	349	393	413	378
46	Asset replacement and renewal	-	12	16	20	24	28	33	37	42	39	43
47	**Network Opex**	(0)	164	218	271	325	385	447	509	573	603	589
48	System operations and network support	-	-	-	-	-	-	-	-	-	-	-
49	Business support	-	-	-	-	-	-	-	-	-	-	-
50	**Non-network opex**	-	-	-	-	-	-	-	-	-	-	-
51	**Operational expenditure**	(0)	164	218	271	325	385	447	509	573	603	589
52												
53	**Commentary on options and considerations made in the assessment of forecast expenditure**											
54	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*											
55												

Schedule 12a. – Asset Condition

Company Name: **Electricity Invercargill Limited**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)							
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	-	44.30%	54.93%	0.77%	3	0.76%
11	All	Overhead Line	Wood poles	No.	20.10%	54.07%	24.40%	0.48%	-	0.96%	3	-
12	All	Overhead Line	Other pole types	No.	N/A	N/A	N/A	N/A	N/A	N/A	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	20.96%	46.10%	8.38%	24.56%	3	12.50%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	23.68%	36.84%	39.47%	-	3	0
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	75.00%	21.43%	3.57%	-	-	2	16.67%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	20.00%	20.00%	60.00%	-	-	4	20.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%	-	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	66.67%	-	33.33%	3	33.33%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	1.79%	-	83.93%	-	14.29%	3	44.64%

Schedule 12a. – Asset Condition (Continued)

	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35												
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	28.57%	71.43%	-	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.52%	27.08%	44.62%	23.09%	4.51%	0.17%	2	-
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.97%	0.83%	29.24%	63.72%	5.24%	2	3.03%
44	HV	Distribution Cable	Distribution UG PILC	km	-	0.11%	4.10%	81.45%	14.24%	0.11%	2	1.06%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	100.00%	-	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3.23%	3.23%	12.90%	25.81%	3.23%	51.61%	3	6.45%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	19.66%	19.94%	21.35%	23.03%	16.01%	-	2	12.62%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	-	45.45%	9.09%	45.45%	3	-
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0.46%	6.18%	87.19%	1.60%	4.58%	3	0.46%
53	HV	Distribution Transformer	Voltage regulators	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	100.00%	1	-
55	LV	LV Line	LV OH Conductor	km	-	3.28%	9.55%	59.11%	27.00%	1.06%	2	6.67%
56	LV	LV Cable	LV UG Cable	km	0.38%	13.31%	29.71%	43.79%	12.36%	0.45%	2	11.76%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.99%	3.18%	4.85%	76.69%	12.76%	1.54%	2	5.81%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	22.22%	-	44.44%	33.33%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	41.38%	0.57%	-	58.05%	-	-	4	48.85%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	100.00%	-	-	-	-	1	-
61	All	Capacitor Banks	Capacitors including controls	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
62	All	Load Control	Centralised plant	Lot	-	100.00%	-	-	-	-	4	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Schedule 12b. – Capacity Forecast

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2024 – 31 March 2034

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*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
8										
9	Spey Street	28	36	N-1	40	78%	36	70%	No constraint within +5 years	
10	Leven Street	15	23	N-1	25	65%	21	65%	No constraint within +5 years	Short interruption for changeover (Normally Open supply from alternate GXP, via TPCL owned subtransmission circuits). Growth in surrounding areas will erode subtransmission backfeed capability.
11	Racecourse Road	10	-	N	12	-	-	-	No constraint within +5 years	No firm capacity
12	Southern	12	23	N-1	9	52%	23	53%	No constraint within +5 years	limited transfer capacity for extended periods. Further transfer of load will result in poorer network reliability. Utilisation projected to increase with planned feeder tie-point shifts from Racecourse Rd to Southern substation in post substation upgrade
13						-				
14						-				
15						-				
16						-				
17						-				
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c. – Demand Forecast

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2024 – 31 March 2034

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected during year by consumer type*			**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10								
11		*Consumer types defined by EDB**						
12		Customer Connections (≤ 20kVA)	118	118	118	118	118	118
13		Customer Connections (21 to 99kVA)	15	15	15	15	15	15
14		Customer Connections (≥ 100kVA)	3	3	3	3	3	3
15								
16								
17		**Connections total**	136	136	136	136	136	136
18		**include additional rows if needed*						
19								
20								
21								
22		**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23		Number of connections made in year	6	10	10	10	10	10
24		Capacity of distributed generation installed in year (MVA)	0.035	0.080	0.080	0.080	0.080	0.080
25		**12c(ii) System Demand**						
26			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27		**Maximum coincident system demand (MW)**						
28		GXP demand	64	64	64	64	64	64
29	*plus*	Distributed generation output at HV and above	-	-	-	-	-	-
30		**Maximum coincident system demand**	64	64	64	64	64	64
31	*less*	Net transfers to (from) other EDBs at HV and above	1	1	1	1	1	1
32		**Demand on system for supply to consumers' connection points**	63	63	63	63	63	63
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	248	248	248	248	248	248
35	*less*	Electricity exports to GXPs	-	-	-	-	-	-
36	*plus*	Electricity supplied from distributed generation	0	0	0	1	1	1
37	*less*	Net electricity supplied to (from) other EDBs	(11)	(11)	(11)	(11)	(11)	(11)
38		**Electricity entering system for supply to ICPs**	259	259	259	260	260	260
39	*less*	Total energy delivered to ICPs	249	249	249	249	249	249
40		**Losses**	10	10	10	11	11	11
41								
42		**Load factor**	47%	47%	47%	47%	47%	47%
43		**Loss ratio**	4.0%	4.0%	4.0%	4.2%	4.2%	4.2%
44								

Schedule 12d. – Reliability Forecast

	Company Name	Electricity Invercargill Limited
	AMP Planning Period	1 April 2024 – 31 March 2034
	Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	32.0	32.0	32.0	32.0	32.0	32.0
12	Class C (unplanned interruptions on the network)	41.0	39.0	38.6	38.2	37.8	37.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.15	0.15	0.15	0.15	0.15	0.15
15	Class C (unplanned interruptions on the network)	0.70	0.69	0.69	0.68	0.67	0.67

Schedule 13. – Asset Management Maturity Assessment Tool

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY				
This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices.				
Question No.	**Function**	**Question**	**Score March 2023**	**Maturity Level Description**
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.

29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.

45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	1.5	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.

59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	1.5	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	1.5	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.

82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.5	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.

105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

Schedule 14a - Mandatory Explanatory Notes on Forecast Information

Company Name Electricity Invercargill Limited

For Year Ended 31 March 2024

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 9 December 2021.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

1. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

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

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

Inflationary assumptions were used to calculate the nominal prices in the forecast. Nominal Prices are based on NZ Treasury's economic forecasts, as published in the Half Year Economic and Fiscal Update released December 2022.

	2023/24	2024/25	2025/26	2026/27	2027/28
Inflator CAPEX	6.900%	4.500%	2.800%	2.200%	2.000%

In addition to the general inflation, material costs have increased by a weighted average of 5.2% in 2022 and labour and external services costs have increased by 6.5%. These increases are included in the CAPEX forecasts for 2023 onwards.

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan

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

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

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

Nominal Prices are based on NZ Treasury's economic forecasts, as published in the Half Year Economic and Fiscal Update released December 2022.

	2023/24	2024/25	2025/26	2026/27	2027/28
Inflator OPEX	6.900%	4.500%	2.800%	2.200%	2.000%

In addition to the general inflation, material costs have increased by a weighted average of 5.2% in 2022 and labour and external services costs have increased by 6.5%. These increases are included in the CAPEX forecasts for 2023 onwards.

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan

Annexure 4 - References

Ref #	Description
1	Electricity Distribution Information Disclosure Determination 2012 (consolidated as at 9 December 2021), ISBN 978-1-869459-59-8, Project no. 44933, Publication date: 9 December 2021, Commerce Commission, Wellington, New Zealand
2	EIL's Strategic Plan.
3	ISO 31000:2009 Standard: Risk Management - Principles and Guidelines.
4	Health and Safety at Work Act 2015.
5	Electricity (Safety) Regulations 2010
6	Electricity (Hazards from Trees) Regulations 2003.
7	Maintaining safe clearances from live conductors (NZECP34 or AS2067).
8	EEA Guide to Power System Earthing Practice 2009
9	https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors
10	https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/trends-in-local-lines-company-performance

Annexure 5 - AMP Compliance Table

Electricity Distribution Information Disclosure Determination 2012 (consolidated December 2021)				
Attachment A; Asset Management Plans - Mandatory disclosure requirements				
AMP design				**Where in the AMP? (Chapter/ paragraph)**
1			**The core elements of asset management—**	
	1.1		A focus on measuring network performance, and managing the assets to achieve service targets;	2.2; 5; 10.2
	1.2		Monitoring and continuously improving asset management practices;	10.3; 10.4
	1.3		Close alignment with corporate vision and strategy;	2.1; 2.5
	1.4		That asset management is driven by clearly defined strategies, business objectives and service level targets;	2; 5; 6
	1.5		That responsibilities and accountabilities for asset management are clearly assigned	2.2; 2.6
	1.6		An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets;	3
	1.7		An emphasis on optimising asset utilisation and performance;	6
	1.8		That a total life cycle approach should be taken to asset management;	6
	1.9		That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	2.1; 7.1; 7.2; 7.3; 7.6
2			**The disclosure requirements are designed to produce AMPs that—**	
	2.1		Are based on, but are not limited to, the core elements of asset management identified in clause 1;	Overall
	2.2		Are clearly documented and made available to all stakeholders;	Website
	2.3		Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets;	2.5
	2.4		Specifically support the achievement of disclosed service level targets;	5; 10.2
	2.5		Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment;	4

	2.6		Consider the mechanics of delivery including resourcing;	2.5; 9.1; 9.2
	2.7		Consider the organisational structure and capability necessary to deliver the AMP;	2.6
	2.8		Consider the organisational and contractor competencies and any training requirements;	6.2; Schedule 13
	2.9		Consider the systems, integration and information management necessary to deliver the plans;	9
	2.10		To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and	Overall
	2.11		Promote continual improvements to asset management practices.	10.4
Contents of the AMP				
3			**The AMP must include the following:**	
	3.1		A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Exec Summary
	3.2		Details of the background and objectives of the EDB's asset management and planning processes;	2.1; 6
	3.3		A purpose statement which -	
		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;	1; 2.5; 6
		3.3.2	states the corporate mission or vision as it relates to asset management;	2.1
		3.3.3	identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	2.5
		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	2.5
		3.3.5	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	2.5
			The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.	
	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;	1.1

			Good asset management practice recognises the greater accuracy of short-tomedium 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.	
	3.5		The date that it was approved by the directors;	Annexure
	3.6		A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	2.2
		3.6.1	how the interests of stakeholders are identified	2.2
		3.6.2	what these interests are;	2.2
		3.6.3	how these interests are accommodated in asset management practices; and	2.2
		3.6.4	how conflicting interests are managed;	2.2
	3.7		A description of the accountabilities and responsibilities for asset management on at least 3 levels, including	2.2; 2.6
		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;	2.6
		3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured; and	2.6
		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;	2.6
	3.8		All significant assumptions	1.3
		3.8.1	quantified where possible;	1.3
		3.8.2	clearly identified in a manner that makes their significance understandable to interested persons, including	1.3
		3.8.3	a description of changes proposed where the information is not based on the EDB's existing business;	N/A
		3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.3
		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;	Annexure 3
	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;	1.4
	3.10		An overview of asset management strategy and delivery;	2.1; 2.5

			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.*	
	3.11		An overview of systems and information management data;	9.3
			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.*	
	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;	9.3
			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.	
	3.13		A description of the processes used within the EDB for:	
		3.13.1	managing routine asset inspections and network maintenance;	8.1
		3.13.2	planning and implementing network development projects; and	7.1
		3.13.3	measuring network performance;	10.2
	3.14		An overview of asset management documentation, controls and review processes.	2.5; 6

			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.*	
	3.15		An overview of communication and participation processes;	1.2; 2.1; 6.1
			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) 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	1.3
	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 clause 2.6.2 of the determination.	Overall
Assets covered				
4			The AMP must provide details of the assets covered, including	
	4.1		a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including	2.7; 3.1
		4.1.1	the region(s) covered;	2.7

		4.1.2	identification of large consumers that have a significant impact on network operations or asset management priorities;	2.7
		4.1.3	description of the load characteristics for different parts of the network;	3.1
		4.1.4	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	3.1
	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;	3.1
		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;	3.1; 7.2
		4.2.3	a description of the distribution system, including the extent to which it is underground;	3.1
		4.2.4	a brief description of the network's distribution substation arrangements;	3.1
		4.2.5	a description of the low voltage network including the extent to which it is underground; and	3.1
		4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	3.1
			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.	3.1
	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
Network assets by category				
	4.4		The AMP must describe the network assets by providing the following information for each asset category	3.1
		4.4.1	voltage levels;	3.1
		4.4.2	description and quantity of assets;	3.1
		4.4.3	age profiles; and	3.1

		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.	3.1
	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);	3.1
		4.5.2	assets owned by the EDB but installed at bulk electricity supply points owned by others;	N/A
		4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	3.1
		4.5.4	other generation plant owned by the EDB.	3.1
Service Levels				
5			The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	5.1; 5.2
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.	5.1
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	5.1
		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.	10.2; 10.4
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.	5.1
9			Targets should be compared to historic values where available to provide context and scale to the reader.	5.1

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.	
			Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.	
Network Development Planning				
11			AMPs must provide a detailed description of network development plans, including—	
	11.1		A description of the planning criteria and assumptions for network development;	7.1
	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;	7.1
	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;	6.1; 7.2
	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	7.2
		11.4.2	the approach used to identify standard designs;	7.2
	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.	
	11.6		A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;	7.1; 7.2
			The criteria described should relate to the EDB's philosophy in managing planning risks.	
	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;	2.1; 2.2; 7.2
	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;	7.1
		11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	7.1

		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;	7.1
		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	7.1
		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;	7.1
	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;	7.1
		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	7.1
		11.9.3	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	7.2
	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	7.1
		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;	7.1
		11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	7.1
		11.10.3	an overview of the material projects being considered for the remainder of the AMP planning period;	7.1; 7.2; 7.3; 7.5
			For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.	

	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	7.2
	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	7.2
		11.12.2	the potential for non-network solutions to address network problems or constraints.	7.2
Lifecycle Asset Management Planning (Maintenance and Renewal)				
12			The AMP must provide a detailed description of the lifecycle asset management processes, including—	6.1
	12.1		The key drivers for maintenance planning and assumptions;	8
	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	8
		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;	8.2
		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;	8.4
	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	7.3
		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;	7.3
		12.3.2	a description of innovations that have deferred asset replacements;	7.3
		12.3.3	a description of the projects currently underway or planned for the next 12 months;	7.3
		12.3.4	a summary of the projects planned for the following four years (where known); and	7.3

		12.3.5	an overview of other work being considered for the remainder of the AMP planning period; and	7.3
	12.4		The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	
Non-Network Development, Maintenance and Renewal				
13			AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	
	13.1		a description of non-network assets;	N/A
	13.2		development, maintenance and renewal policies that cover them;	N/A
	13.3		a description of material capital expenditure projects (where known) planned for the next five years; and	N/A
	13.4		a description of material maintenance and renewal projects (where known) planned for the next five years.	N/A
Risk Management				
14			AMPs must provide details of risk policies, assessment, and mitigation, including—	4
	14.1		Methods, details and conclusions of risk analysis;	4.2
	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;	4.3; 4.4
	14.3		A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	4.4
	14.4		Details of emergency response and contingency plans.	4.4
			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.	
Evaluation of performance				
15			AMPs must provide details of performance measurement, evaluation, and improvement, including—	
	15.1		A review of progress against plan, both physical and financial;	10.1; 10.2

			• 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.*	
	15.2		An evaluation and comparison of actual service level performance against targeted performance;	10.2
			• 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.	
	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.	10.4; Schedule 13
	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.	10.4
Capability to deliver				
16			AMPs must describe the processes used by the EDB to ensure that-	
	16.1		The AMP is realistic and the objectives set out in the plan can be achieved; and	1.3; 9.1
	16.2		The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	1.2; 2.6

Annexure 6 - Directors Approval

We, Robert Datema Jamieson and Emma Jane Ihaia, being directors of Electricity Invercargill Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The attached information of Electricity Invercargill Limited prepared for the purposes of clauses 2.6.1 and 2.6.6 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c, 12d and 14a are based on objective and reasonable assumptions which both align with Electricity Invercargill Limited corporate vision and strategy and are documented in retained records.

Robert Datema Jamieson

Emma Jane Ihaia

Date: 28th March 2024