11 kV Line Rebuild - Calder Road, Centre Bush

Asset Management Plan Update

2024 - 2034

Publicly disclosed in March 2024

Table of Contents

List of Figures

List of Tables

Asset Management Plan Update

The Power Company Limited has chosen to disclose an Asset Management Plan (AMP) update for the 2024/25 regulatory year and not a full AMP. In this document the updates are indicated in black font and the lighter, grey font indicates the information supplied in the 2023/24 AMP. This is done for ease of reference to the previous information.

Section 10 – Evaluation of Performance and Annexure 3 – Disclosure Schedules contain the latest, fully updated information and the 2023/24 information is not included in these sections.

Enquiries

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Liability Disclaimer

2024-25 Updated as indicated.

The information and statements made in this AMP are prepared on assumptions, projections, and forecasts. It represents The Power Company's intentions and opinions at the date of issue (31 March 2023).

~~There is an upsurge of the worldwide Covid-19 pandemic caused by new strains of the coronavirus. This has an impact on TPCL's supply chain and it may influence the resources available to execute this asset management plan. This AMP assumes that the pandemic will be controlled and that it will not have a 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, assumptions and forecasts in the AMP may prove to be wrong, events may occur that were not predicted and The Power Company could decide to take different actions than planned. The Power Company may also change any information in this document at any time. TPCL accepts no liability for any action, inaction, or failure to act based on this AMP.

Foreword

About The Power Company Limited (TPCL)

Established in 1991, The Power Company Limited (TPCL) is one of New Zealand's best-performing, predominantly rural networks, delivering a safe, efficient and reliable power supply to over 37,800 homes and businesses across rural Southland and West Otago.

TPCL are wholly owned by the customers connected to the network through Trust owners, the Southland Electric Power Supply Consumer Trust (Southland Power Trust). The Trust ownership structure ensures TPCL's connected customers remain intrinsic to the company and the decisions made – to ensure customers receive a resilient, reliable and future-ready electricity supply. The company has previously operated as the Southland Electric Power Board and Southland Electric Power Supply.

This Asset Management Plan (AMP) outlines TPCL's approach to managing its electricity distribution assets 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 TPCL and Electricity Invercargill Limited (EIL).

TPCL and EIL 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 exempt EDB of TPCL, the non-exempt EDBs of EIL and OtagoNet Joint Venture Limited (OJV), as well as the non-grid connected Stewart Island Electric Supply Authority (SIESA).

PowerNet manages an asset base and investments in excess of 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 TPCL operating in Southland and West Otago, EIL operates in Invercargill and Bluff, 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 TPCL, EIL,OJV and 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 TPCL. This has been judged by the value and efficiency in managing the TPCL network and the delivery against the key performance indicators (KPIs) regularly reviewed and re-set as part of their 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 provides 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 that TPCL's objectives and our regulatory reporting obligations will be met. 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 are availed. It has a strong focus on the future, particularly as we look towards the impacts of decarbonisation and process heat conversion in our region, the increasing reliance on electrification and the growing uptake of electric transportation, 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 required to deliver against the needs of our customers - today and tomorrow.

AMP Network Development Projects

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

We remained focused on developing our network to provide significant long-term benefits to our local communities. Over the past 5-10 years we have been committed to creating additional network capacity to meet the needs of our growing region and to improve our service levels so we can continue to provide a reliable, efficient and safe supply for our customers.

An increase in electricity demand in the Awarua area resulted in the commissioning of the new Colyer Road substation in 2015, which was built to meet the area's capacity needs and provide greater supply security. In 2017, we upgraded the Waikiwi substation to meet growing demand in the Waikiwi, Lorneville and Otatara areas. In 2019, we finished the Oreti Valley Project, a $27.3 million, five-year project to upgrade and extend our 66kV network to include Centre Bush, Dipton, Lumsden and Mossburn substations.

In addition to our efforts to meet the demand needs and extend capacity across our network, we have been committed to investing in our network to enable process heat electrification for our major customers as part of our support to electrify and decarbonise the New Zealand economy. In 2021-22 we led the commissioning of a South Island wide process heat stocktake for all industries, which provided real clarity for the TPCL network. This provided us with a consolidated view of a number of businesses across our region and their plans to decarbonise their process heat by converting to either electricity or biomass. This information has been invaluable to developing this AMP and has provided the catalyst for engaging with large network connected customers.

TPCL's Asset Management Focus for the Next 5-10 Years

TPCL's AMP future programme focuses on initiatives that will support growth in our region, together with plans to maintain and improve network safety, efficiency, and reliability.

The TPCL network is leading the decarbonisation and electrification of process heat for New Zealand. Within the TPCL network, there is an estimated 300MW of process heat that can be converted to either electric or biomass. This equates to 10% of all New Zealand manufacturing emissions and 1.2% of all greenhouse gasses for the country. There is currently 110MW of this process heat being converted to electric on the TPCL network, with more planned and part of this AMP. TPCL, and with the support of PowerNet, is at the forefront of decarbonising the New Zealand economy and are proud of our achievements to date and excited about our future plans.

For the 10-year period reported in this 2024 AMP, we are forecasting a Total Spend of $689,951,000. Our AMP forecasts still reflect a significant programme of work to mature our asset management capability, support customer growth, and improve our service provision for customers, including:

- Significant investment in eastern Southland and the Invercargill region to meet customer-initiated decarbonisation projects, triggering network upgrades;
- Upgrading assets across the network for the continued security of supply and to cater for growth – the Riversdale substation upgrade (multi-year project to be completed by 2029), a larger transformer at Kelso for growth (which includes moving the existing transformer at Kelso to Waikaka - also for growth), and a new power transformer for Mossburn (with spare transformers relocated to Glenham, Awarua and Seaward Bush);
- The completion of the upgrade of the Athol to Kingston 22kV line;
- Improving the efficiency of our network by replacing and refurbishing assets where needed – including the sub-transmission line replacement, continued pole reinforcement (mainly full replacements), ongoing distribution transformers and LV pillar box replacements, and regular mid-life power transformer refurbishments;
- Ongoing vegetation management;
- Routine inspections, testing and maintenance across all assets;
- Safety, environmental, and other projects.;
- Enabling growth in our region through supporting new subdivisions and continued connections based on historical and future trend analysis.

As outlined, our AMP reflects provisions for the changes to our electricity system, primarily to enable process heat decarbonisation. At TPCL, we predict the emergence of new solutions as people embrace new technologies, take control of their energy use, and demand climate change action. Supporting this evolving environment has been an important strategic lever for TPCL, which is therefore reflected in our 10-year investment plans.

Our Regulatory Environment

TPCL, as an exempt business from the revenue caps and expenditure allowances set by the Commerce Commission, has found it easier 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 TPCL, is in a unique position with its management of three networks (our network being exempt and two being non-exempt), as it can compare the differences this creates and better understand the opportunities it allows for exempt networks like TPCL.

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 and contrast the flexibility and ability to respond to customers' needs on the TPCL 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 our changing customer needs, and TPCL looks forward to this active collaboration with the regulator and other stakeholders.

The regulatory period, from 2020-2025 (DPP3), has been extremely challenging from an asset owner perspective. 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.

In Conclusion

TPCL'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 Southland and West Otago communities over the next 10 years. It sets out planned capital and maintenance expenditure on the network from 2024-2034 and also reflects our continued engagement with customers and developers to better understand their plans to ensure this AMP caters to and supports, the growth projections of our region.

The projects outlined in our AMP acknowledge the different customers that TPCL services, from small residential properties to major industries. TPCL and PowerNet are leading the decarbonisation of the New Zealand economy through the customer-initiated projects both already delivered and planned in this AMP. As outlined in our Executive Summary which follows, our AMP focuses on ensuring our network continues to deliver for our customers through a dedicated investment programme that includes information on our performance and service targets, justification for our planned investments, together with the risks and how those will be mitigated through careful and considered asset management practices over the next ten years.

We are committed to continuing to provide a network that meets the needs of our communities, and we welcome ongoing input with our various stakeholders to ensure our assets and the services we provide are fit for purpose - now and into the future.

Abbreviations, Acronyms and Definitions

2024-25 – No change

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
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	Low Voltage
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.

Executive Summary

2024-25: Minor changes as indicated.

The information and statements made in this AMP are prepared on assumptions, projections, and forecasts. It represents The Power Company's intentions and opinions at the date of issue (~~31 March 2023~~ 31 March 2024).

~~The worldwide Covid-19 pandemic is still ongoing with new infections caused by new strains of the coronavirus. This has an impact on TPCL's supply chain and it influences the 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 wars in the Ukraine and Gaza and the Presidential elections in the USA, assumptions and forecasts in the AMP may prove to be wrong. Further events may occur that were not predicted and TPCL could decide to take different actions than planned. TPCL may also change any information in this document at any time. TPCL accepts no liability for any action, inaction, or failure to act based on this AMP.

Introduction

2024-25: Minor changes.

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 impact of the Covid-19 pandemic and the impact of the wars in Ukraine and Gaza, particularly on fuel prices. There remains a possibility of closure of the Tiwai Point smelter (other variation causes and implications are detailed in the AMP), however this has become more remote due to the upsurge in commodity prices.

The outcome of the Presidential elections in the USA may cause further disruption to world markets.

Most challenges related to Covid-19 have been being addressed, but there are still some remaining cost and project schedule implications.

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.

TPCL 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 TPCL Business Environment

2024-25: No change.

TPCL'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. TPCL'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 TPCL's Strategic Plan are incorporated in the AMP and the guiding principles for TPCL's asset management strategy are described in Section 2. TPCL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 1.

Table 1: 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 above average levels of 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		✓	✓	✓	✓

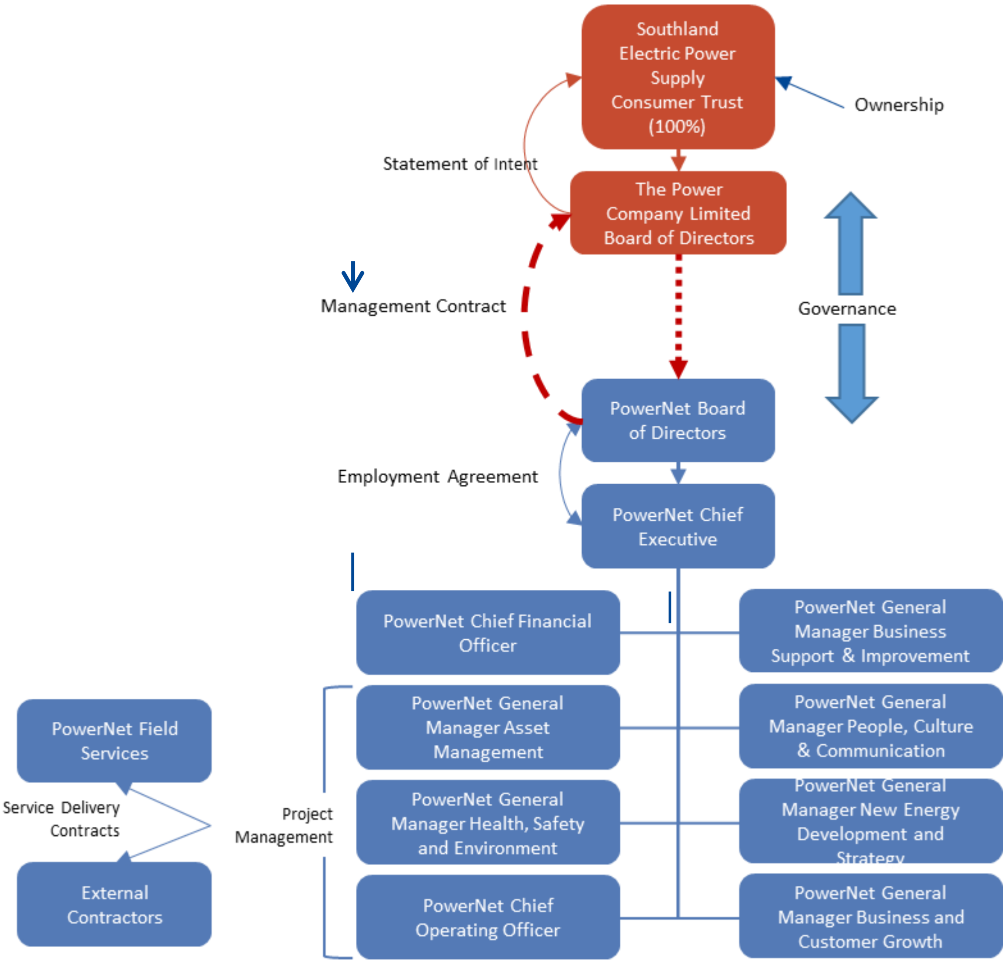
Corporate Strategies

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 above average levels of service.
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		✓	✓		✓

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust. This creates a primary driver for TPCL and formal accountabilities to the shareholder are in place for financial and network performance. However, there are various role-players in TPCL'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

2024-25: The key changes on the network were around the development in the Gore region related to the new 33kV circuit connecting to the Kaiwera Downs Wind Farm and the upgrade related to the McNab substation project. Aside from the abovementioned project, the network and assets are largely unchanged from the 2023-33 AMP.

The TPCL network is supplied by four Transpower Grid Exit Points (GXP) and embedded generation. These bulk supplied points are at the Invercargill, North Makarewa, Gore and Edendale and the embedded generators of up to 72MW are from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station and Southern Generation Limited Partnership's Flat Hill wind farm. The areas supplied by the network as well as the following aspects are described in 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 large new customers are unpredictable so planning tends to be more reactive than proactive to avoid over investment. There are no 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

2024-25: The risks identified on the TPCL network are largely unchanged from the 2023-23 AMP.

Risk is defined as any potential but uncertain occurrence that may impact on TPCL's ability to achieve its objectives and ultimately the value of its business. TPCL 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 TPCL'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.

- COVID-19 pandemic - Loss of key service providers; business operations disrupted; cost and schedule overruns.
- 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

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
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 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 consumers Loss of ability to provide power to customers for extended periods	Treat	Develop improved contingency plans for network events

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
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.

- Oil Filled RMUs.
- Porcelain Insulators Crack on ABS
- Other Systemic Issues.

Service Levels

2024-25: No change in Service Levels.

A broad range of service levels are created for TPCL'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.

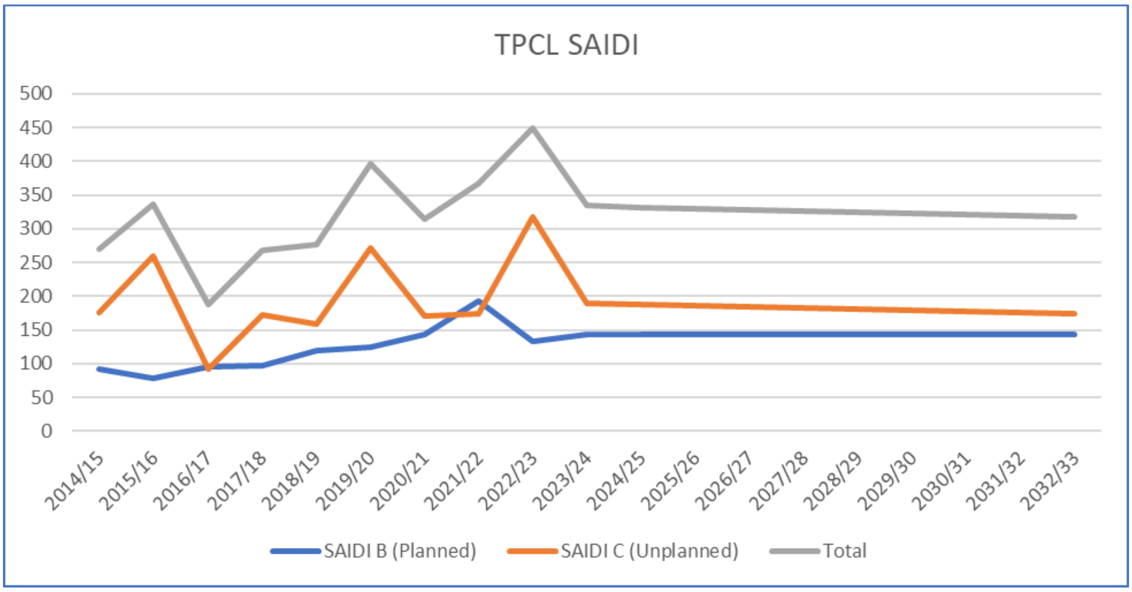
This Section in the AMP describes how TPCL sets its various service levels according to the safety, viability, quality, compliance, and price objectives that are most important to stakeholders. It details how well TPCL is meeting these objectives and what trade-offs exist between differing stakeholders. 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 TPCL'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:

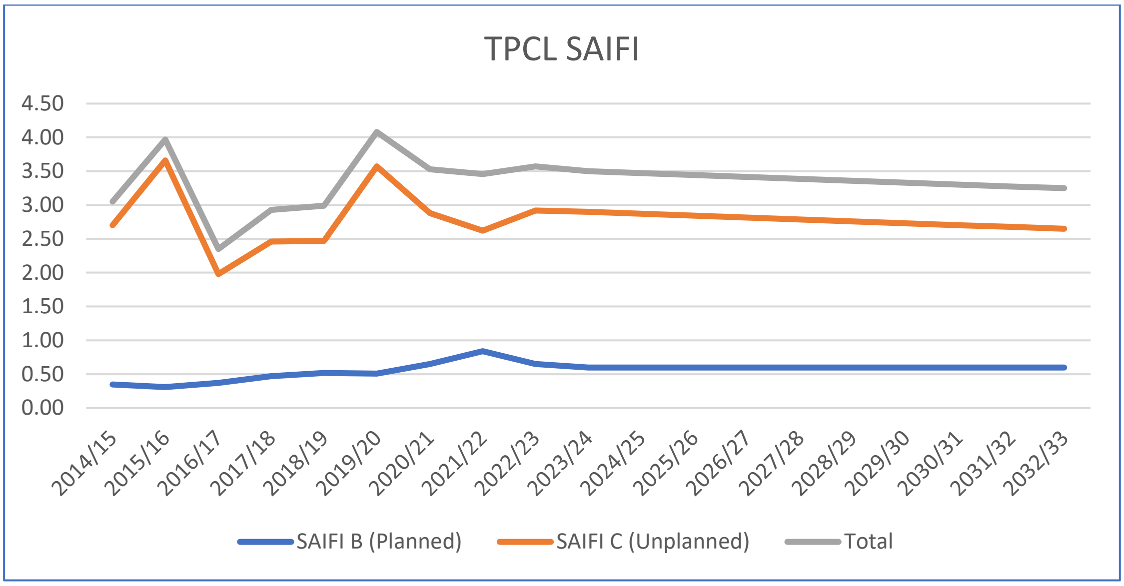
- regulatory service levels;
- service level justification; and
- service level targets.

Figure 2: Historical and predicted SAIDI



Customers on average can expect to be without electricity for around 330 minutes each year.

Figure 3: Historical and predicted SAIFI



Customers will on average experience an interruption 3.5 times each year.

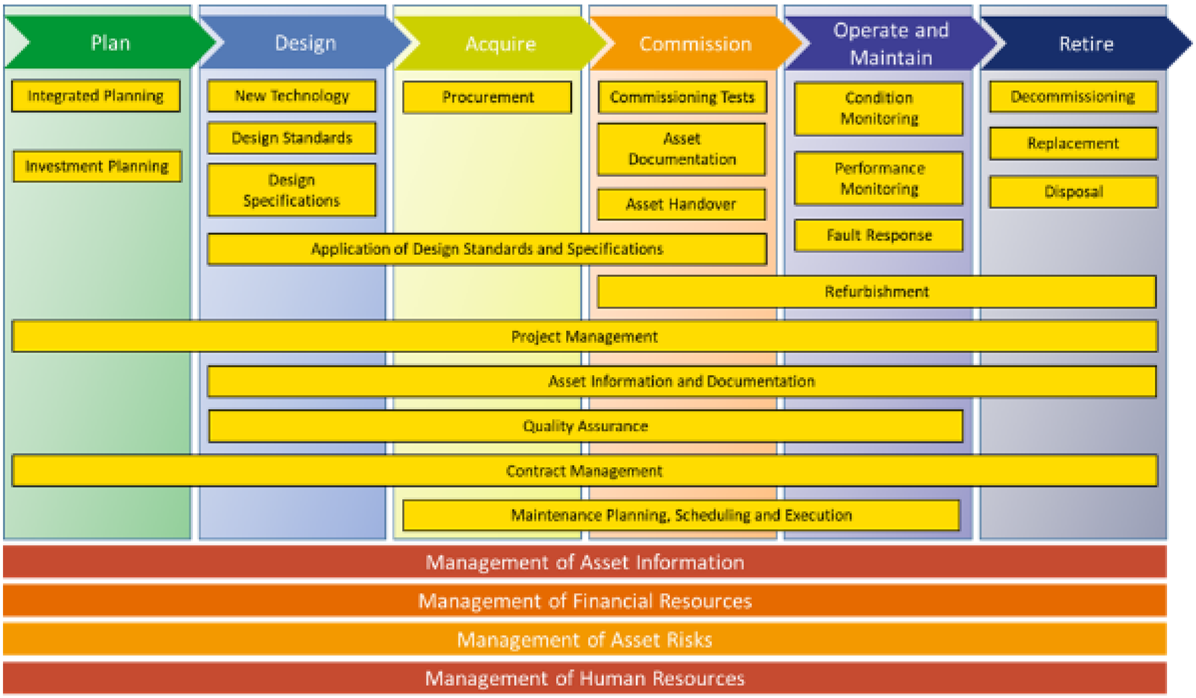
Asset Management Strategy

2024-25: TPCL (through PowerNet) received ISO 55001 – Asset Management System – certification. No change in the Asset Management Strategy. Previous changes are being embedded into the Asset Management System.

TPCL'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 of concern are 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.*

PowerNet is experiencing shortages in critical skills. The pipeline for technical skills is inadequate and skills retention is a challenge.

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

2024-25: The TPCL Capital Expenditure changes as follows:

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.

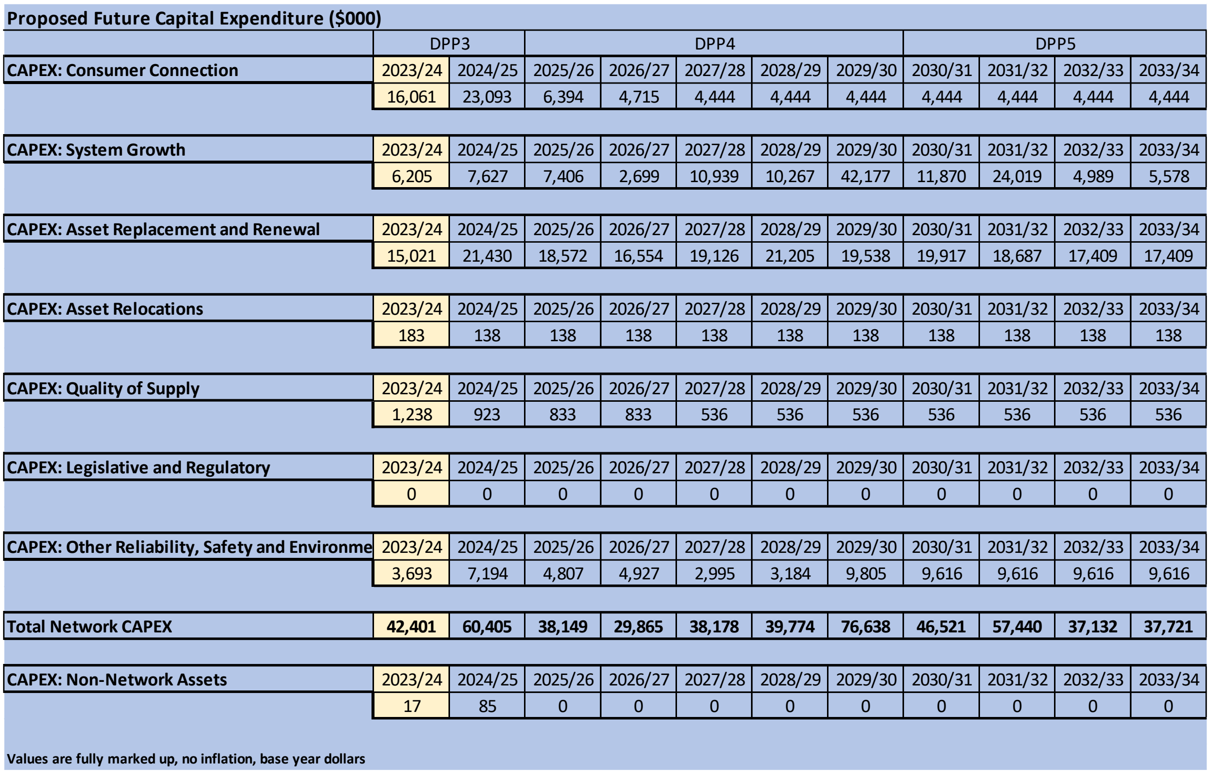
- Consumer Connection.
- System Growth.
- Asset Replacement and Renewal.
- Asset Relocations.
- Reliability, Safety and Environment.

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.

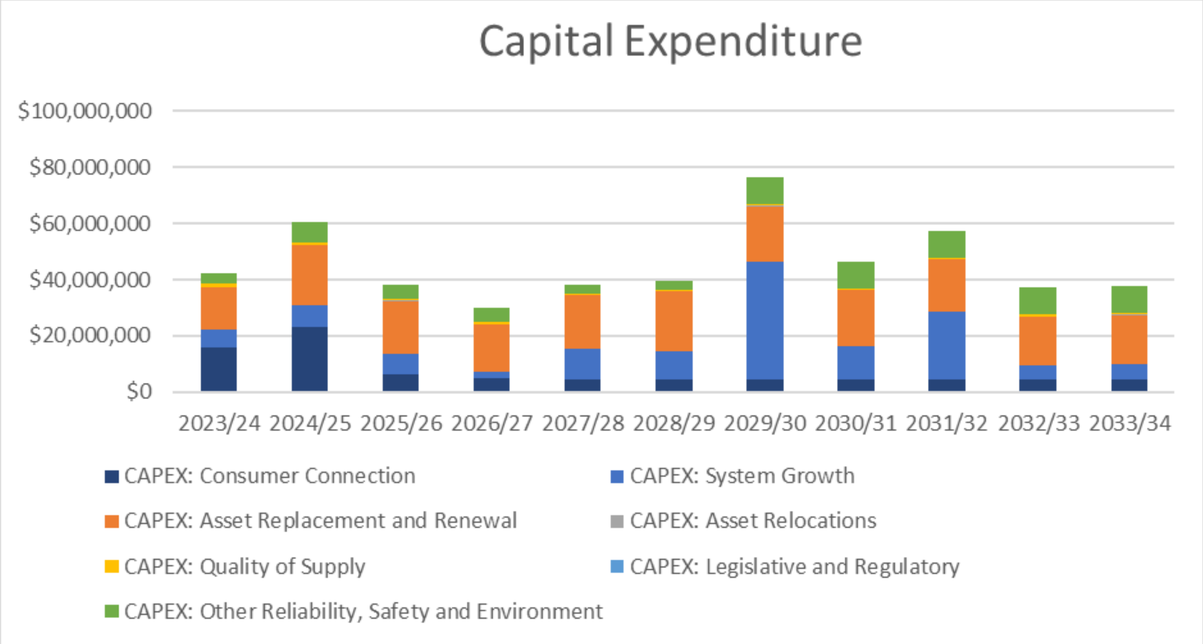
Figure 5: Proposed Capital Expenditure



Proposed Future Capital 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
	16,061	23,093	6,394	4,715	4,444	4,444	4,444	4,444	4,444	4,444	4,444
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
	6,205	7,627	7,406	2,699	10,939	10,267	42,177	11,870	24,019	4,989	5,578
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
	15,021	21,430	18,572	16,554	19,126	21,205	19,538	19,917	18,687	17,409	17,409
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
	183	138	138	138	138	138	138	138	138	138	138
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
	1,238	923	833	833	536	536	536	536	536	536	536
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 Environme	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	3,693	7,194	4,807	4,927	2,995	3,184	9,805	9,616	9,616	9,616	9,616
Total Network CAPEX	**42,401**	**60,405**	**38,149**	**29,865**	**38,178**	**39,774**	**76,638**	**46,521**	**57,440**	**37,132**	**37,721**
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
	17	85	0	0	0	0	0	0	0	0	0

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

Figure 6: Capital Expenditure per ComCom categories.



Operating Expenditure

2024-25: The TPCL Operating Expenditure changes as follows:

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

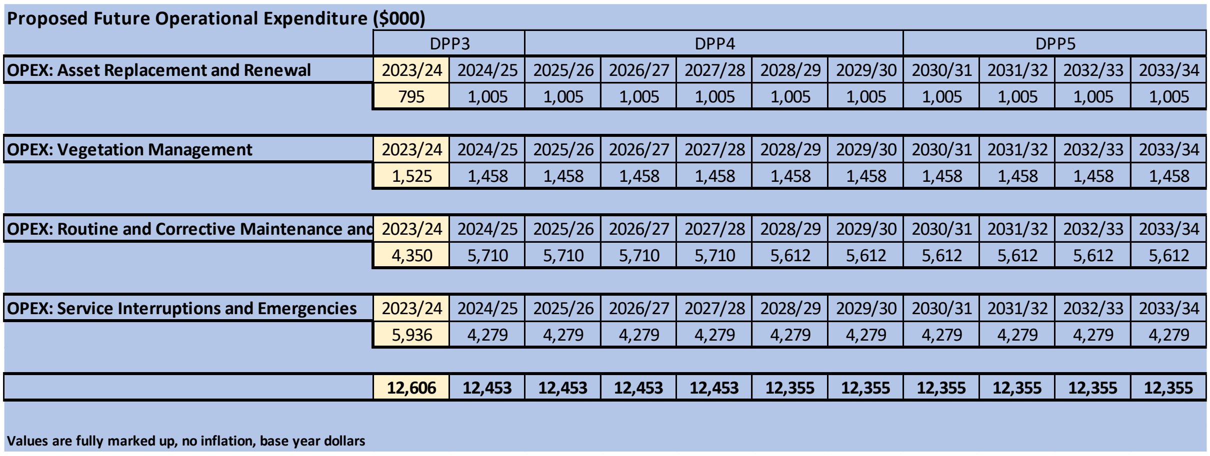
- Asset Replacement and Renewal.
- Vegetation Management.
- Routine and Corrective Maintenance and Inspection.
- Service Interruptions and Emergencies.

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.

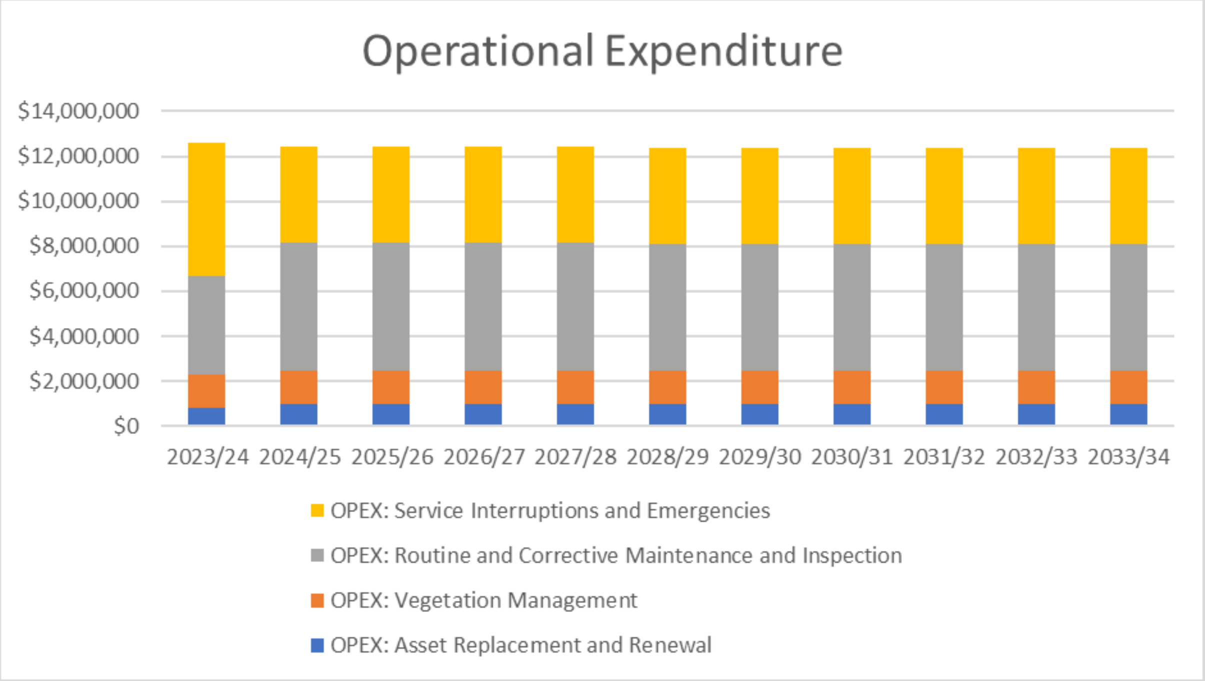
Figure 7: Proposed Operating Expenditure



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
	795	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005
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
	1,525	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458
OPEX: Routine and Corrective Maintenance and	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	4,350	5,710	5,710	5,710	5,710	5,612	5,612	5,612	5,612	5,612	5,612
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
	5,936	4,279	4,279	4,279	4,279	4,279	4,279	4,279	4,279	4,279	4,279
	12,606	**12,453**	**12,453**	**12,453**	**12,453**	**12,355**	**12,355**	**12,355**	**12,355**	**12,355**	**12,355**

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

Figure 8: Operating Expenditure per ComCom categories.



Execution Capacity

Deliverability – 2024/2034 AMP Update

PowerNet, like many others throughout New Zealand, both within the electricity sector and across the infrastructure industry, 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.

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 or procuring the required plant or equipment.

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.

TPCL’s revenue comes primarily from retailers who pay for the conveyance of energy over TPCL’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 fee paid to PowerNet for managing the networks on behalf of TPCL.

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, TPCL 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 – 2024/2034 AMP Update

In 2022/23 capital expenditure was 6% under budget and operating expenditure was 8% higher than planned.

Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased capital and operation expenditure costs.

Network reliability was within the Commerce Commission limits.

Benchmarking service levels against other electricity distribution businesses indicates TPCL is performing well on behalf of its stakeholders.

~~In 2021/22 capital expenditure was 13% lower than expected and operating expenditure was 1% lower. The capital under expenditure related to delays in overseas equipment delivery issues and resulting project delays.~~

~~The small under expenditure of operating funds related to the setting up of the new asset inspection team taking longer than expected to recruit and train staff.~~

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

~~Network reliability showed a lower number of interruptions, but of longer duration, reflecting the complexity of at least one 33 kV subtransmission fault.~~

~~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 or have been completed in the drive towards ISO 55001 certification.~~

1 Introduction

1.1 Assumptions – 2024/2034 AMP Update

The assumptions as per the 2023-33 AMP are still mostly valid. The assumption changes and potential impacts are discussed further in section 0 Risk Management.

1.2 Potential Variation Factors – 2024/2034 AMP Update

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 3: 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
Recruit as required	Higher cost to be able to meet staffing level required to complete works. This may be coupled with deferment of investment programme, or outright cancellation of certain works if issues become ongoing.
Equipment delivery	The wars in Ukraine and Gaza, residual Covid-19 pandemic impact and increased demand for equipment is causing delays in material delivery from overseas suppliers. There are two reasons for this, shipping delays, mainly caused by port congestion due to sea lane constraints as well as demand due to increased renewable generation builds.
Conceivable closure of smelter at Tiwai Point	Potential reduction in the number of residents due to staff relocations may reduce revenue. This would partially be offset by higher load due to decarbonisation initiatives. The specific feeder loading will change and may lead to a requirement for local upgrades.

1.3 Asset Management Plan and Annual Works Program

The Power Company Limited (TPCL) is the disclosing entity for the electricity lines businesses that conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff), supplying approximately 37 000 customers.

TPCL's Asset Management Plan (AMP) provides an internal governance and asset management framework for TPCL's network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination as amended on 21 December 2017 for the ten-year planning period from 1 April 2021 to 31 March 2031.

The purpose of TPCL'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 TPCL 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 TPCL's 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.

1.4 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 TPCL Board supported by a presentation. Any business cases required for large capital projects or other papers covering any novel 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 tend to be more commercially motivated but will also recognise the need to address any identified health and safety related issues as a high 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 TPCL Board for review in January. 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.

Progress Evaluation

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. In addition, the Chief Executive report contains information on safety performance, network performance and asset health for specific asset classes identified by the Board.

1.5 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 scenario considered most likely will eventuate, except for ongoing but sporadic (typically reactive) work, where budgets reflect a longer-term average. This philosophy is used to minimise variation to performance targets (especially financial) over the short to medium term. Exceptions are made where the consequences of an assumption are asymmetric – for example building additional capacity early results in a slight overinvestment, whereas 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. Equipment housed indoors will often exceed ODV life, whereas in the harsh coastal environment assets tend to have a shorter life. Generally the ODV asset life is conservative as borne out by the actual failure rates of equipment.

Since the previous full AMP regulations around Traffic Management have changed significantly. There are also some changes in the way the Tree Regulations are being applied. These changes are adding additional cost to both Capital and Operational activities.

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 2023 dollars and assume an exchange rate of 1 NZ$ to 0.6 US$ (where applicable).

Table 4: Assumptions and Implications+

Assumption	Discussion & Implications
General demand growth for existing customers tracks close to projected rates. New housing developments and decarbonisation initiatives are additional to the general growth.	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 supply chain constraints. Decarbonisation initiatives are driven by government funding, causing additional uncertainty in the timing of these projects. 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

Assumption	Discussion & Implications
	that take the variables into account and choosing the most likely outcome. The unlikely declining growth rate scenario means investments to accommodate previously projected growth are deferred. The more likely higher growth rate scenario require adjustment in TPCL's resourcing and/or work scheduling to be able to respond to these opportunities. Visibility is often limited to the near term, particularly for large commercial developments.
Single large customer driven growth (such as supplies to data centres and electrode boilers) is likely. This may occur on the TPCL network and will affect the bulk supply to TPCL.	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 vehicle adoption rates are within the national forecast range. Consumers respond well to price signals so that vehicle charging occurs mainly off-peak	Potential to have large impact on network demand with sufficient adoption. If consumers do not respond well to price signals or if retailers do not send the right price signals, electric vehicle charging may exacerbate peak demand, triggering greater investment requirements. This effect will be greatest on the LV network where issues are more likely due to lower diversity. Given the cost of electric vehicles, the effect is expected to be localised in more affluent areas. The ever-increasing range of electric vehicles 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.

Assumption	Discussion & Implications
	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	Deterioration of asset reliability 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 service providers. Recurring Covid-19 outbreaks affect availability of resources and the international market demand for skilled resources creates difficulty in staff 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 are utilised where sector specific forecasts are unavailable)	Deviation from expected material, labour, overhead input costs, will result in increased costs to 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 consumer and/or industry behaviour in such a way that TPCL investments decisions become un-economic. Many of these initiatives such as GIDI funding are driven by decarbonisation programmes which are dependent on ruling party policy.
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 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.
No material changes to customer expectations of service levels	Changes to customer expectations will require adjustment to service levels and subsequent investments. The customer survey shows that customers are happy with the current price/quality balance and few customers are willing to pay more for increased service levels.

Assumption	Discussion & Implications
No significant changes to local and/or central 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) 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 considered unlikely based on historical trending over a long period. 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 current events (Covid, Ukraine).	These major external events are unable to be predicted with any certainty and TPCL must react accordingly to any changes.
The line pricing methodology has been updated to reflect more service based and cost reflective pricing, this has been achieved by the introduction of “peak”, “shoulder” and “night” variable pricing periods, which is designed to change customers behaviours and encourage them to use energy in the non-peak times.	Actual future demands may depart significantly from forecasts. Prediction of demand growth is uncertain due to the new line pricing methodology. Declining maximum demands mean that investments to accommodate previously projected growth can be deferred. Should the energy shift not occur, higher growth rates will require adjustment in TPCL’s resourcing and/or work scheduling to be able to respond.
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.

1.6 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 5: 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
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.
Equipment failure (especially large capital plant) which may influence future economic options	Greater replacement costs for unplanned failure. Greater costs to maintain supply to customers, until replacement. Review of equipment selection and work methodologies.
New safety issues identified and initiatives created	Higher labour or material costs. Triggers reviews of work methodologies on existing scheduled works.
Reprioritisation of projects as new work activities are identified	Increased time and costs may arise if changes are not communicated sufficiently ahead of time. Changes also require revision of the longer-term investment programme and funding requirements.
Obvious short term project options may not be the best long term solutions.	Similar implications compared to if new work activities are identified.
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.

This edition of the AMP takes the known actual and potential impacts of the Covid-19 pandemic into account.

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

Impact of the Covid-19 pandemic

The Covid-19 pandemic is affecting the TPCL' supply chain and it has an effect on the execution of this AMP.

Some challenges that have to be overcome are listed below.

- Suppliers and manufacturers of equipment are still experiencing labour shortages at times, causing production facilities to shut down. Combined with utilities internationally trying to source equipment to address pandemic induced backlogs means it is still difficult to obtaining certain equipment and material.
- Offshore equipment delivery is still disrupted, leading to delays in work execution and increased shipping costs.
- Short term resource constraints affect works delivery as Covid infections tend to affect whole teams our offices when it strikes.

Impact of a possible Tiwai Point smelter closure

TPCL 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 affect TPCL revenue.

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 TPCL Business Environment

2024-25: The shareholder representatives, Board members and Business Environment in general remained unchanged.

TPCL'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

TPCL'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 TPCL'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

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

- 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. TPCL’s 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
- Comitted 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

TPCL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 6.

Table 6: Corporate and Asset Management Strategy Linkages

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 above average levels of service.
Asset Management Strategies					
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 TPCL's business and their interests. The paragraphs explain how interests are met and how conflicts between role-players' expectations are managed.

Associations

TPCL conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff) for approximately 37,000 customer connections served by eighteen energy retailers. The TPCL business entity includes the following associations.

- A 50% stake in PowerNet, an electricity lines management company jointly owned with Electricity Invercargill Limited (EIL). This is an unregulated entity and is therefore not subject to any disclosure requirements.
- A 75.1% stake in Lakeland Network Limited (LNL), which distributes electricity in the Frankton, Wanaka areas of Central Otago.
- A 75.1% 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 ESL.
- A 25% stake in Southern Generation Ltd, a generation company with wind and hydro assets in New Zealand jointly owned with EIL and Pioneer Generation Ltd.

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

Ownership

TPCL has a single shareholder – The Southland Electricity Power Supply Consumer Trust (SEPS). The trustees who collectively possess 70,160,000 shares in TPCL on behalf of Trust (as at 31 March 2023) has five directors:

- Carl Findlater (Chair);
- David Rose;
- Stephen Canny;
- Stuart Baird; and
- Wade Devine.

The Trust is subject to the following accountability mechanisms:

- By an election process in which two or three trustees stand for election by connected customers every two years. Trustees stand for a term of four years.
- By the Trust Deed which holds all Trustees collectively accountable to the New Zealand judiciary for compliance with the Deed.

Governance

TPCL's use of PowerNet as their contracted asset management company creates two accountabilities.

- The first governance accountability is between TPCL's Board and shareholder with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes TPCL's Board intimately accountable to TPCL's shareholder for these important asset management outcomes, whilst the inclusion of financial targets in the statement makes

TPCL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI. TPCL (as at 31 March 2023) has four directors:

- Peter Moynihan (Chair);
- James Carmichael;
- Wayne Mackey;
- Wayne McCallum;
- Murray Wallace and
- Karen Sherry.

- The second accountability is between TPCL's Board and PowerNet with the principal mechanism being the management contract 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 TPCL (be it equity or debt).
- Pay money to TPCL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to TPCL's network.
- Use TPCL's network for conveying electricity.
- Supply TPCL 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 TPCL network's existence or operation (such as request disclosure data, regulate prices, investigate accidents or District Plan requirements).

TPCL's identified stakeholders are listed in the following tables - stakeholder's interests (Table 7 and Table 8) and how these interests are identified. Table 9 describes how stakeholder's interests are accommodated in TPCL's asset management practices.

Table 7: Interests of Key Stakeholders

Interests	Viability	Price	Quality	Safety	Compliance
Southland Electric Power Supply (SEPS) Consumer Trust (Shareholder)	✓	✓	✓	✓	✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Ministry of Business, Innovation & Employment		✓	✓	✓	✓

Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Utility Disputes			✓		✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Worksafe				✓	✓
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, equipment suppliers and service providers are also regarded as key stakeholders, however they influence TPCL rather than TPCL having a significant effect on their viability, price, quality, safety or compliance.

Table 8: Identification of Stakeholders’ Interests

Stakeholder	How Interests are Identified
Southland Electric Power Supply (SEPS) Consumer Trust (Shareholder)	• By their approval or required amendment of the SOI • Regular meetings between the directors and executive
Connected Customers	• Regular discussions with large industrial customers as part of their on-going development needs • Customer consultation evenings (meetings open to public) • Annual customer surveys
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets monthly with Chief Executive and PNL Staff
Ministry of Business, Innovation & Employment	• Release of 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
Electricity Authority	• Weekly updates and briefing sessions • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Utility Disputes	• 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
Transport Agency	• Formally as required

Stakeholder	How Interests are Identified
Worksafe	• Promulgated regulations and codes of practice • Audits of TPCL'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
Mass-market Representative Groups	• Informal contact with group representatives
Staff & Contractors	• Regular staff briefings • Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Suppliers of Goods & Services	• Regular supply meetings • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet' s CEO & CFO • By adhering to TPCL's treasury/borrowing policy • By adhering to banking covenants

Table 9: Accommodating Stakeholder's Interests

Interest	Description	How TPCL Accommodates Interests
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in TPCL.	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 that will deliver the returns and Service Level maximised within those constraints accordingly.
Price	Price is a key means of both gathering revenue and signalling underlying costs. Getting prices wrong could result in levels of supply reliability that are less than or greater than what TPCL's customers want.	TPCL's total revenue is managed by self-imposing the regulated price path threshold of similar utilities. Prices will be restrained in line with those of these utilities 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. TPCL's pricing methodology is intended to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this until it is fully phased out.
Supply Quality	Emphasis on continuity, restoration of supply and reducing flicker is essential to minimising interruptions to customers' businesses.	Stakeholder's needs for supply quality will be accommodated by focusing resources on continuity and restoration of supply. The most recent mass-market survey indicated a general satisfaction with the present supply quality but also with many customers indicating a willingness to accept a reduction in supply quality in return for lower line charges.

Interest	Description	How TPCL Accommodates Interests
Safety	Staff, contractors, and the public at large must be able to move around and work on the network in total safety.	The public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, 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. Motorists are kept safe by keeping above-ground structures as far as possible from the carriage way, within the constraints faced regarding private land and road reserves.
Compliance	Compliance with many statutory requirements ranging from safety to disclosing information is compulsory.	All safety issues will be documented and available for inspection by authorised agencies. Performance information will be disclosed in a timely and compliant fashion.

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust. This creates a primary driver for TPCL and formal accountabilities to the shareholder are in place for financial and network performance.

Customers (via electricity retailers) provide TPCL's revenue in return for the services provided by the TPCL network assets. Due to the importance TPCL 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 5 Service Levels for details of these surveys, customer feedback and performance targets.

TPCL is required to compile and publicly disclose performance and planning information (including the requirement to publish an AMP). Although TPCL is not subject to price and quality regulations aims to maintain prices and network reliability in a manner similar to a regulated network. These requirements are listed under Part 4 of the Commerce Act 1986.

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**. Top priority is given to safety. The safety of staff, contractors and the public are of paramount importance. These factors are highly considered in asset management decisions.

2. **Viability**. Viability is a secondary consideration, because without it TPCL would cease to exist, making supply quality and compliance pointless.

3. **Pricing**. TPCL gives third priority to pricing (noting that pricing is only one aspect of viability). TPCL 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 TPCL, successful.

5. **Compliance**. A lower priority is given to compliance that is not safety and supply quality related.

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 TPCL 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 TPCL's asset management practices. Strategies might be developed to effectively manage these concerns.

- Competitive pressures from other lines companies that might try to supply TPCL customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with coal or oil 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 wire utilities.
- 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 TPCL'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 TPCL 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 distributors that are subject to price-quality regulation four months before the end of the current DPP period. As from 1 April 2020, distributors are being subjected to new requirements set out in the DPP determination.

The determination does not directly affect TPC, as it is an unregulated network. We do however subscribe to the intent expressed by the Commerce Commission, namely to provide sufficient flexibility to accommodate increasing uncertainty and change across the distribution sector. Quality of service incentives is a major focus of the determination. The approach followed is one of 'no material deterioration'. TPCL interprets this concept as follows:

- The safety risk to the public from network infrastructure should not increase
- The safety risk to staff working on network assets should not increase
- The quality of electricity supply to customers should not deteriorate
- The average health of network assets should not decrease
- The average age of network assets should not increase.

The Commerce Commission's stated intent is that aligning reliability incentives to the value consumers place on reliability frees distributors (within certain bounds) to target the level of reliability and of price that best meets the expectations of their consumers.

2.5 Planning Processes

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

Business Planning

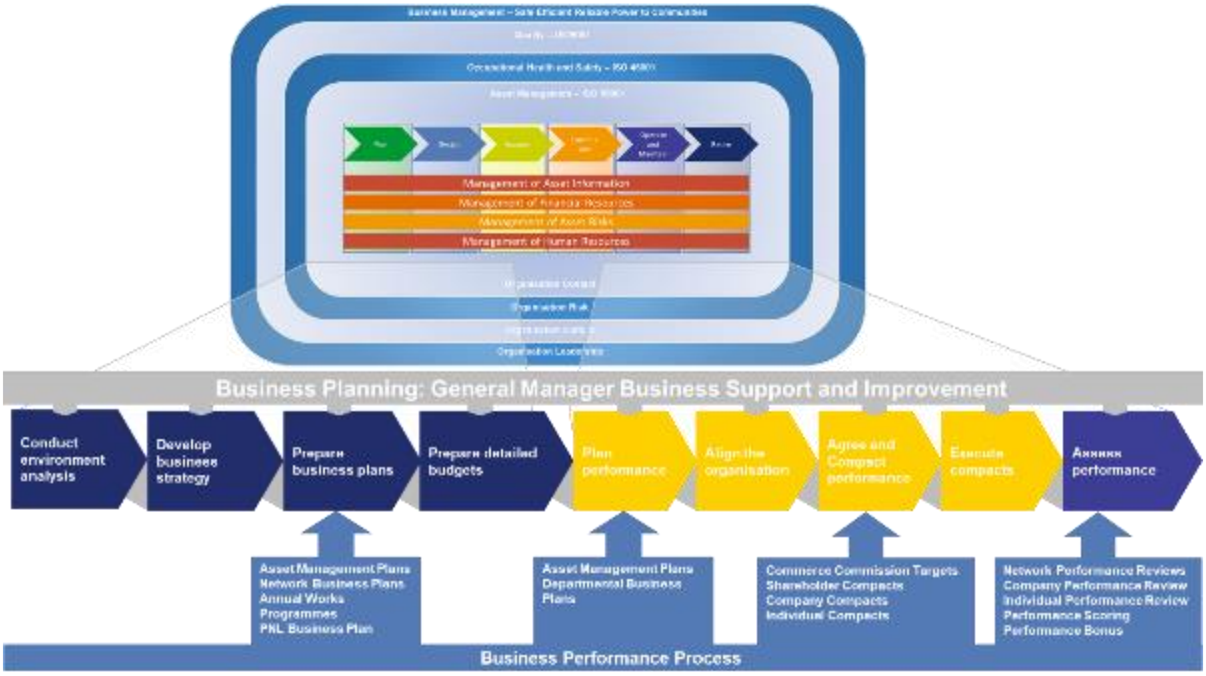
The business planning, execution and performance measurement processes are presented in the next figures.

Figure 9: 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 TPCL has to meet. The business plan is executed and the results are measured against the targets to evaluate business performance.

Figure 10shows 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 10: Business Support and Improvement Processes



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

Statement of Intent

TPCL's Statement of Intent (SOI) is a requirement under the constitution of the company, and forms the principal accountability mechanism between TPCL's board and the shareholder, Southland Electric Power Supply Consumer Trust. TPCL's corporate strategies gain shareholder approval via the SOI.

- 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 The Power Company 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 TPCL'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 TPCL'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 on a monthly base 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 TPCL's corporate vision, asset management objectives, business drivers, strategies and key planning documents is presented in Figure 11.

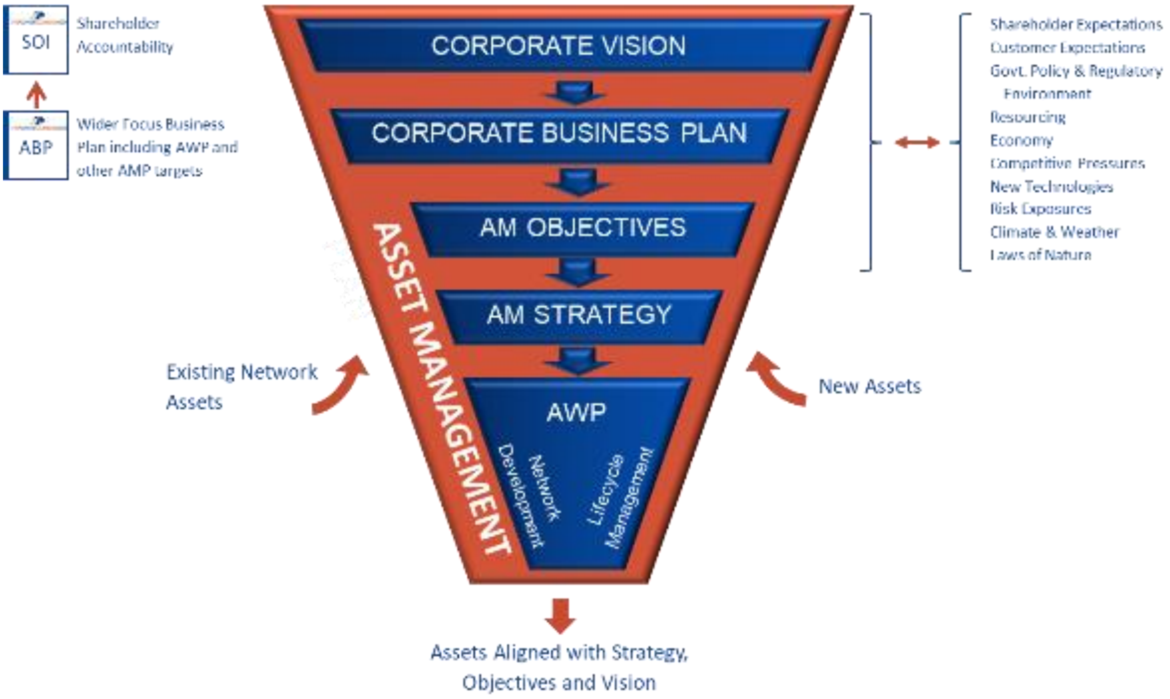
The vision leads to the objectives for TPCL's asset management processes. These asset management processes are documented in the AMP which serves as a guidance and communication mechanism ensuring understanding and consistency within TPCL's asset management company PowerNet and for the TPCL board.

The asset management strategies are designed to provide guidance in achieving the asset management objectives while aligning with TPCL's vision and corporate strategies. Stakeholder interests and expectations as well as other external influences create business drivers which shape the strategies developed. 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 reshape 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 TPCL's corporate vision whilst meeting stakeholder expectations, in particular those of the shareholder and network customers.

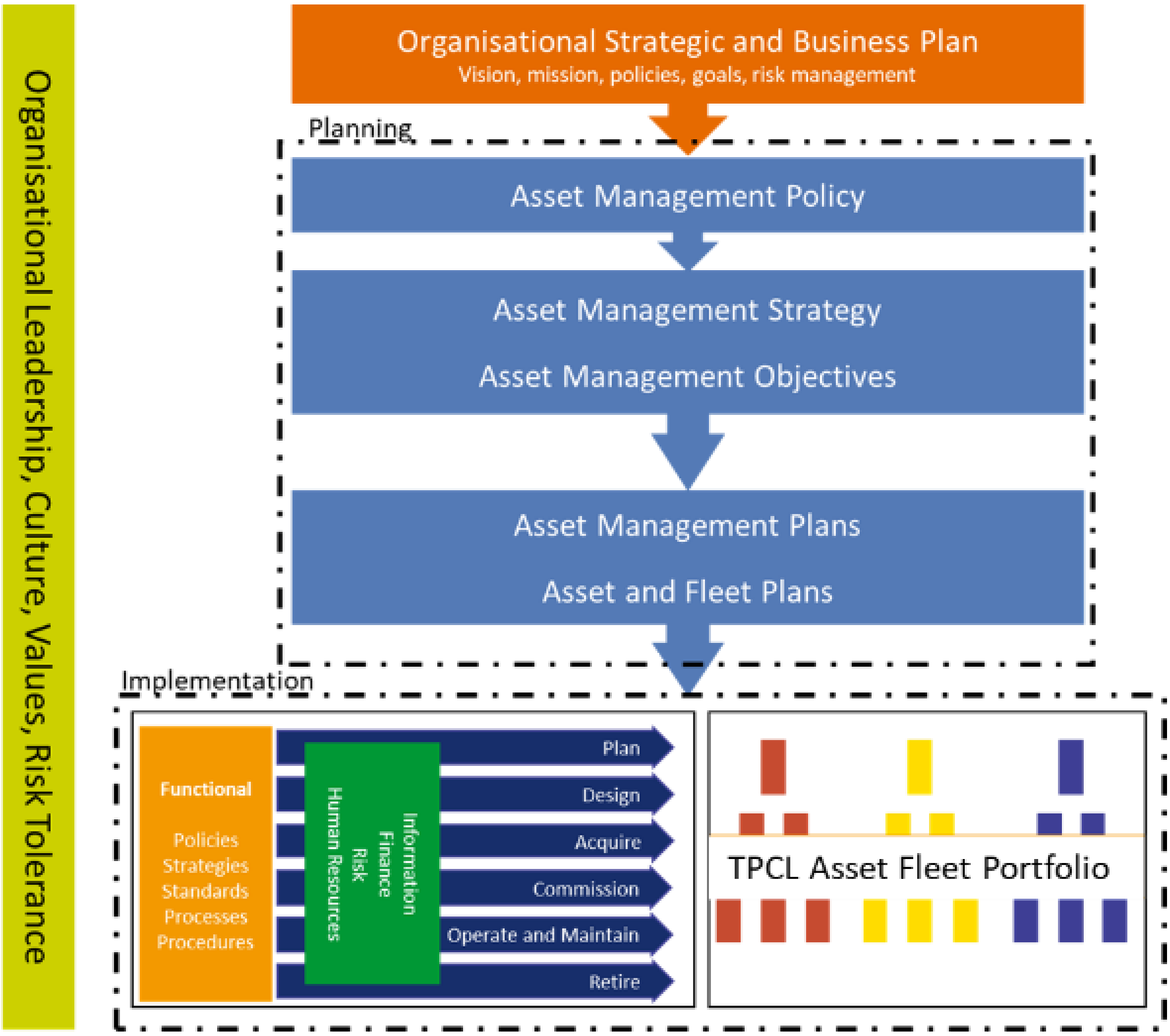
Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP; these together with any wider business issues provide the overall business planning summary used by the wider management team and TPCL Board. The SOI incorporates performance targets (including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

Figure 11: 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 12 shows the framework we use to manage our assets.

Figure 12: Asset Management Framework



Asset Management Planning

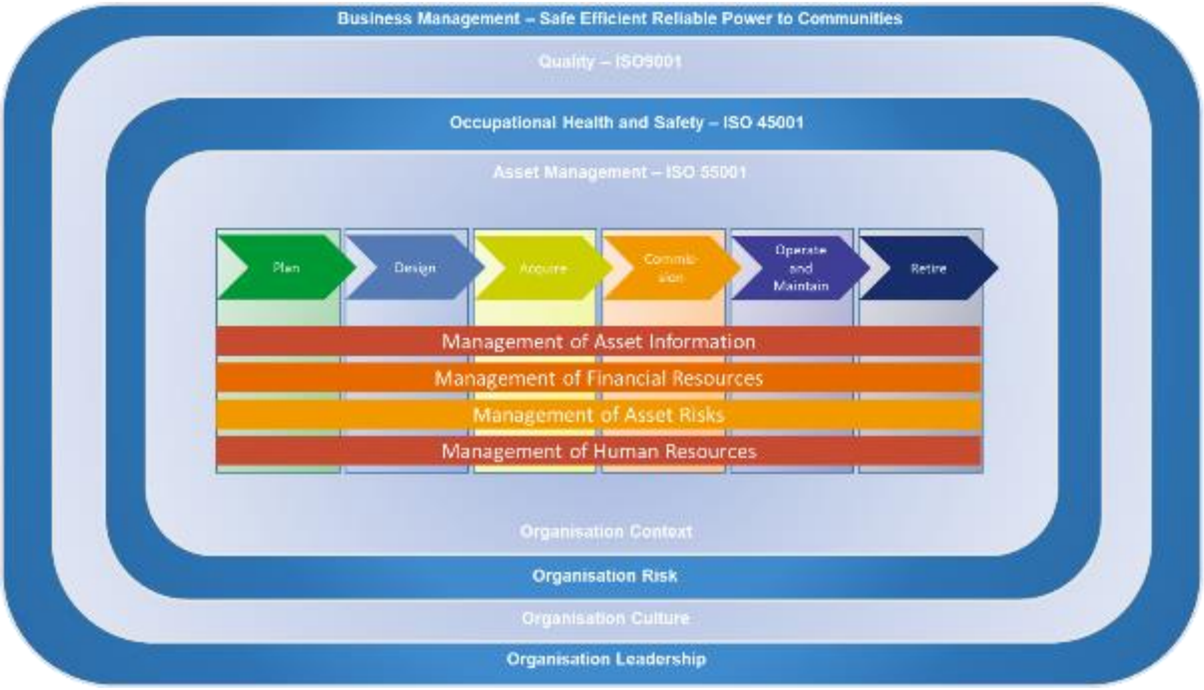
Asset life cycle management processes are demonstrated in Figure 13. The asset life cycle phases are the following:

- 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 section 6 Asset Management Strategy.

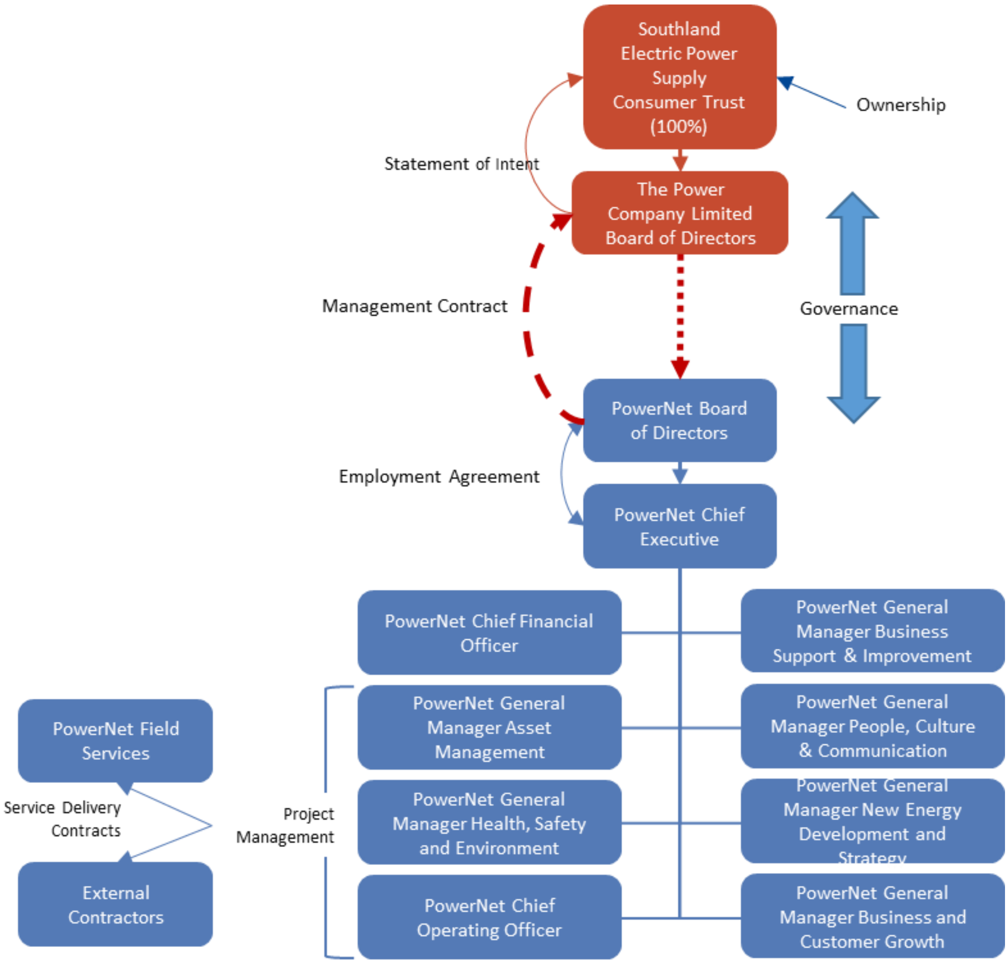
Figure 13: Asset Management Processes



2.6 Structure and Accountabilities

TPCL's ownership, governance and management structure is depicted in Figure 14. 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 TPCL Board as part of ABP process in the previous year.

Figure 14: Governance and Management Accountabilities



TPCL 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 will need to gain approval from the TPCL 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 TPCL 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 TPCL'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, Major Projects Team, Planning (Technical) Team and Planning (Distribution) Team (under the General Manager Asset Management) 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, Energetick, Jacob Consulting, Mitton Electronet, ProTechtion Consulting, Mitchell Daysh, Ergo Consulting, Decom).

2.7 TPCL's Supply Area

TPCL's distribution area broadly covers all of Southland as depicted in Figure 15 except for Bluff and parts of Invercargill that are west of Racecourse Road, south and east of the Waihopai Stream and north of Elizabeth, Moulson and Brown Streets and Tramway Road. TPCL's boundary corresponds with Fiordland National Park to the northwest, Lake Wakatipu to the north and east to the Blue Mountains. This broadly corresponds to the Southland and Gore District Council jurisdictions.

Figure 15: TPCL Distribution Area

Topography varies as follows:

- Flat fertile plains to the immediate east, north and west of Invercargill taking in the towns of Edendale, Wyndham, Mataura, Gore, Winton, Lumsden, Riverton, Otautau and Tuatapere.
- Rolling fertile plains beyond these areas taking in Tapanui, Waipahi, Mossburn, Garston and west towards Te Anau.
- Sparsely populated mountainous areas towards the north-east beyond the rolling fertile plains.
- Uninhabited mountains and bush in the west and north-west of the area.

Key Industries

Key industries within TPCL's network area include sheep, beef and dairy farming, dairy processing, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism. The area's economic fortunes will therefore be strongly influenced by:

- Markets for basic and specialised meats such as beef, mutton and lamb.
- Markets for dairy products.

- Markets for processed timber.
- Markets for black and brown coal.
- Government policies on mining of coal.
- Government policies on forestry and nitrogen-based pastoral farming.
- Access to water for crop and stock irrigation, especially in northern Southland.

The impact of these issues is broadly discussed in Table 10.

Table 10: Impact of key issues

Issue	Visible impact	Impact on TPCL's value drivers
Shifts in market tastes for beef, mutton, and lamb.	May lead to a contraction or expansion of demand by these industries.	Reduces / increases asset utilisation. Possible capacity stranding.
Shifting markets for dairy products.	May lead to a contraction or expansion of demand by these industries.	Reduces / increases asset utilisation. Possible capacity stranding.
Shifting markets for timber.	May lead to a contraction in demand by these industries.	Reduces asset utilisation. Possible capacity stranding.
Shifting markets for coal.	May lead to a contraction in demand by these industries.	Reduces asset utilisation. Possible capacity stranding.
Government CO_2 Policy.	May lead to a contraction or expansion in demand by industries. May create new process requirement for industries.	Reduces asset utilisation. Possible capacity stranding. New capacity required.
Government policy on nitrogen-based farming.	May lead to contraction of dairy shed demand. May lead to contraction of dairy processing demand.	Reduces asset utilisation. Possible capacity stranding.
Access to water.	May lead to increased irrigation demand.	Increases asset utilisation but without corresponding increase in load factor.
Government policy on freshwater quality resulting in restrictions to farming activities	May lead to contraction of dairy processing demand.	Reduce asset utilisation Possible capacity stranding

In the past three years there has been a steady upward trend in dairy product pricing. Due to the impact of COVID-19 on general supply chain process, producers have seen a reduction in price although the quantum of products exported increased year on year.

Major customers that have significant impact on network operations or asset management priorities are:

- Meridian White Hill Wind Farm embedded generation with varying export of up to 58MW.

- Fonterra Co-operative Group Limited dairy plant, Edendale - three 33kV cables each supplying an 11½/23MVA 33/11kV power transformer (N-1 requirement[1]).

- Alliance Group Limited, freezing works at Lorneville and Mataura – generally one or two exclusive 11kV feeders (N-1 requirement).
- Bright Wood NZ Limited, sawmill at Otautau – exclusive 11kV feeder from substation.
- Craigpine Timber Limited, sawmill at Winton – supplied off local feeder.
- Niagara Sawmilling Co Limited sawmill at Kennington – supplied off local feeder for industrial area.
- Lindsay & Dixon Limited, sawmill at Tuatapere – supplied off local feeder.
- Blue Sky Meats Limited, freezing works at Morton Mains – supplied off local feeder but requires regulators at Edendale Hill and Morton Mains on the main supply route and a backup supply from Kennington through one regulator. Has an automatic change-over control of supplying switches at connection point to the network (N-½ requirement[2]).
- Open Country Dairy, at Awarua – supplied off two local feeders (N-1 requirement) at 11kV. The 33kV supply Open Country Dairy being a radial supply with no backup capacity.

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[1] N -1 is defined as a full redundant supply so that full load can be supplied from two separate routes.

[2] N-½ is defined as a change-over scheme to an alternative supply but with a short interruption.

- South Pacific Meats, at Awarua – supplied off local feeder with switched backup (N-½ requirement[3]).
- Balance Agri-Nutrients Limited, at Awarua – supplied off local feeder.
- Silver Fern Farms Limited:
  - Venison abattoir at Kennington – supplied off local feeder.
  - General abattoir at Gore – supplied off local feeder.
- Various Hotels and Motels in Te Anau – supplied off local township feeders with backup capability from other township feeders.
- Pioneer Generation, hydro generator at Monowai – connected onto 66kV ringed network (N-1 requirement).
- Southern Generation Limited Partnership, windfarm at Flat Hill – exclusive 11kV feeder at Bluff.
- South Wood Export Limited, chip mill at Awarua – exclusive 33/11kV 5MVA power transformer due to large synchronous chipper motor.
- Te Whatu Ora - Health New Zealand Southern, hospitals at Invercargill and Gore – supplied off township feeders with alternatives from other township feeders.

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[3] N-½ is defined as a change-over scheme to an alternative supply but with a short interruption.

3 The Network and Asset Base

3.1 Incorporation of Kaiwera Down

The TPCL network is supplied by four Transpower Grid Exit Points (GXP) and embedded generation. These bulk supply points are at the Invercargill, North Makarewa, Gore and Edendale and the embedded generation up to 115MW are from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station, Southern Generation Limited Partnership's Flat Hill wind farm and Mercury's Kaiwera Downs Wind Farm - Stage 1. The network configuration is described in the following paragraphs.

Bulk Supply Points and Embedded Generation

The bulk supply point and embedded generation are largely unchanged from the 2023-33 AMP except at the Gore GXP and the Kaiwera Downs 43MW wind farm.

Gore GXP

Gore GXP is supplied by three 110kV single circuit pole lines, from Roxburgh power station, Invercargill GXP via Edendale and Brydone and interconnected to Berwick and Halfway Bush GXP's. TPCL takes supply from the two 110/33kV 80 MVA transformers at Gore to nine 33kV feeders. Transpower upgraded these transformers from 30 to 80 MVA during 2023. TPCL owns the segments of 33kV line and cable (but not the circuit breakers or bus) within the GXP land area. Gore GXP has a 220kV interconnector between North Makarewa GXP and Three Mile Hill.

The company also owns one 33kV 216⅔Hz ripple injection plant on the south side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Edendale.

Table 11: Bulk Supply Characteristics - Gore

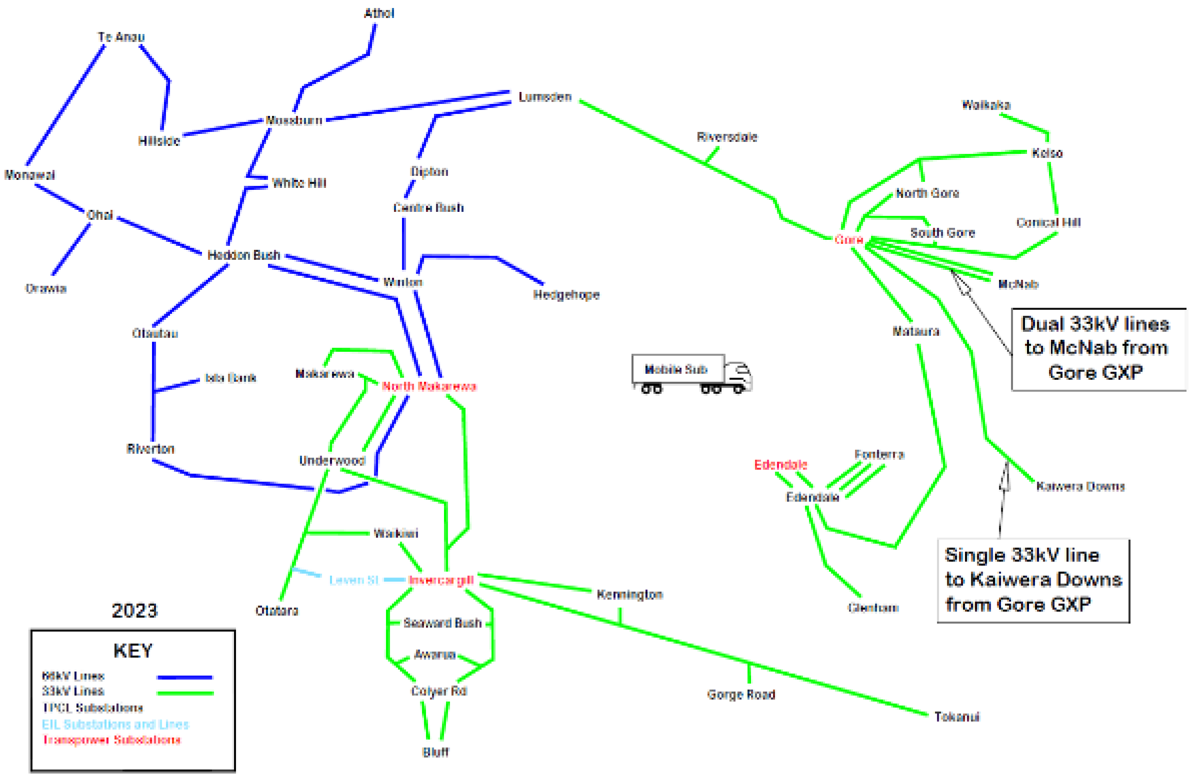
Supply	Voltage	Rating	Firm Rating	Maximum Demand 2023/2024
Gore GXP	110/33kV	160MVA	80MVA	36.754MW (7:30 21/12/2023)

3.2 Network Configuration – 2024/2034 AMP Update

Subtransmission Network

TPCL's sub-transmission network is a meshed electrical network that takes supply from four GXP's at Invercargill, North Makarewa, Edendale and Gore. In 2023 the 33 kV network has been extended from the Gore GXP to the Kaiwera Downs 43 MW wind farm and to the McNab substation, as depicted in Figure 16 below.

Figure 16: Subtransmission Network



Dual 33kV lines to McNab from Gore GXP

Single 33kV line to Kaiwera Downs from Gore GXP

Zone Substations

TPCL owns and operates 37 zone substations across Southland which have security levels (see Development Criteria for security level definitions) ranging from A(i), A(ii), AA and AAA. TPCL also takes an 11kV supply for two feeders supplied from EIL's Racecourse Road substation to supply TPCL customers in areas at the eastern edge of Invercargill. The change from the 2021-31 AMP is the completion of the Substation upgrade projects as provided in Table 12.

Table 12: Zone Substations

Substation	Nature of load	Description
McNab	Single large milk processing factory	A new medium complexity outdoor substation with two 33/11kV 15/25MVA transformers, these supply an indoor 11kV switchboard with three feeders.
Orawia	Town of Tuatapere and village of Orawia, rural farms and sawmills at Tuatapere.	66kV line onto a 66kV circuit breaker and 66/11kV 5/7.5MVA transformer supplying a new indoor switchboard with incomer circuit breaker and four 11kV feeders.
Seaward Bush	South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant, rural Farms.	Medium complexity outdoor substation with two refurbished 33/11kV 6/12MVA transformers, these supply an indoor 11kV switchboard with five feeders.

3.3 Network Configuration

~~The TPCL network is supplied by four Transpower Grid Exit Points (GXP) and embedded generation. These bulk supply points are at the Invercargill, North Makarewa, Gore and Edendale and the embedded generation up to 72MW are from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station and Southern Generation Limited Partnership's Flat Hill wind farm. The network configuration is described in the following paragraphs.~~

The (Network) asset base can be summarised as per Table 13 below.

Table 13: Asset Summary

Asset Class	Group	Total number
Distribution Transformer	OH (Up to 100kVA)	10,456
Distribution Transformer	UG (up to 1MVA) + Platform	803
Power Transformer	1-4MVA	7
Power Transformer	4-8MVA	22
Power Transformer	8-16MVA	20
Power Transformer	> 16MVA	12
Overhead Switch	ABS	1,565
Overhead Switch	LBS (Solid Mould)	3
Protection Relay	G1 - Substation	519
Protection Relay	G2 - Field	88
Battery	G1 - Substation	683
Battery	G2 - Field	270
Distribution Earth	G1	12,712
RMU	Oil + Solid Insulation	113
RMU	Gas Insulation	0
Metalclad Switchgear	All	24
Field CB	Field	39
Field CB	Zone	142
Poles	Wood	17,150
Poles	Concrete/steel	93,006
Cables	HV Cable XLPE	13

Cables	HV Cable Oil Pressurised	0
Cables	MV Cable XLPE / PVC	121
Cables	MV Cable PILC	34
Cables	LV Cable < 1000V	224
Instrument Transformers	VT	159
Instrument Transformers	CT	530
Neutral Earthing Resistor	Zone Subs	40
Regulators	Zone Subs	72
VRR	All	129
PLC	All	14
Injection Station	All	4
Capacitor Banks	All	6
CT-VT Units	Field	14
CT-VT Units	Zone	6
Generators	network-owned, <=600kVA	2
LV Outdoor Cubicles	All	5,129
OHL	km	8,859
Statcom	All	0
Battery Chargers	Zone	103
Battery Chargers	Field	0
Fibre	All	11
Fault Indicator	All	8
Power Supply	All	72
RTU	Zone	85
RTU	Field	0
Earth Mat	Zone	41
Earth Mat	Field (regulator site)	8
Fault Throw Switch	All	4
Oil Separator	All	22

Surge Diverter	Zone	1,588
Surge Diverter	Field	73
Zone Substation	Buildings	58

Bulk Supply Points and Embedded Generation

Invercargill GXP

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 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. TPCL takes supply from six of these feeders in normal operation. Back up supplies are available from other TPCL feeders and are used from time to time.

TPCL owns the segments of 33kV line (but not the circuit breakers or bus) that run within the GXP land area and also accommodates a backup control room for PowerNet's System Control. TPCL 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 Electricity Invercargill Limited (EIL) with each providing backup capability to the other.

North Makarewa GXP

North Makarewa is also a strong point in the 220kV grid which ties to Manapouri power station, Invercargill and Three Mile Hill GXP's and to the Tiwai Point smelter. The company takes supply from North Makarewa at 33kV from two 30/60MVA transformers.

TPCL owns the following assets within the GXP land area:

- Two 33/66kV 30/40MVA step-up transformers.
- One Neutral Earthing Resistor (NER).
- Oil containment and separator system.
- Nine 66kV circuit breakers.
- Four 66kV 5MVAr capacitor banks.
- 66kV bus.
- Six 33kV circuit breakers (but not the incoming 33kV circuit breakers or 33kV bus)
- One 33kV 216⅔Hz ripple injection plant on the southwest side of the GXP site, with backup provided from the 66kV 216⅔Hz ripple injection plant at Winton.

Edendale GXP

Edendale GXP is supplied by two 110kV single-circuit pole lines from Gore GXP via Brydone GXP and from Invercargill GXP. TPCL takes supply to its 33kV bus at Edendale by two incomers from two 30MVA transformers. Seven 33kV feeders, a 33kV bus coupler, 33kV cables and lines within the GXP land area are owned by TPCL.

The company also owns one 33kV 216⅔Hz ripple injection plant on the north side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Gore.

Gore GXP

~~Gore GXP is supplied by three 110kV single circuit pole lines, from Roxburgh power station, Invercargill GXP via Edendale and Brydone and interconnected to Berwick and Halfway Bush GXP's. TPCL takes supply from the two 110/33kV 30MVA transformers at Gore to six 33kV feeders. Transpower will upgrade these transformers from 30 to 80 MVA during 2023. TPCL owns the segments of 33kV line and cable (but not the circuit breakers or bus) within the GXP land area. Gore GXP has a 220kV interconnector between North Makarewa GXP and Three Mile Hill.~~

~~The company also owns one 33kV 216⅔Hz ripple injection plant on the south side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Edendale.~~

Table 14: Bulk Supply Characteristics

Supply	Voltage	Rating	Firm Rating	Maximum Demand 2021/2022	LSI[4] Coincident Demand 2021/2022
Invercargill GXP	220/33kV	240MVA	109MVA	107.671MW (17:30 28/06/2021)	101.728MW (8:00 15/10/2020)
TPCL	*(GXP assets shared with EIL)*			56.744MW (17:30 28/06/2021)	53.49MW (8:00 15/10/2020)
North Makarewa GXP	220/33kV	120MVA	67MVA	50.988MW (8:00 27/10/2021)	42.604MW (8:00 15/10/2020)
Gore GXP[5]	110/33kV	60MVA	37MVA	32.15MW (8:00 15/09/2021)	28.902MW (8:00 15/10/2020)
Edendale GXP	110/33kV	60MVA	34MVA	33.158MW (7:30 27/10/2021)	28.416MW (8:00 15/10/2020)
White Hill Generation	66kV	56MVA	0MVA	44.398MW (8:00 28/04/2021)	2.192MW (8:00 15/10/2020)
Monowai Generation	66kV	7.5MVA	5MVA	6.367MW (16:00 25/09/2021)	6.228MW (8:00 15/10/2020)
Flat Hill Generation	11kV	6.8MVA	0MVA	7.193MW (16:30 21/05/2021)	0.786MW (8:00 15/10/2020)

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[4] LSI = Lower South Island. This is the latest figures from Transpower. The 2020 year is used because of the misalignment between the EDB regulatory year and Transpower's year.

[5] Gore GXP – Transpower are upgrading transformers to 80 MVA each with a total rating of 160 MVA and firm rating of at least 80 MVA.

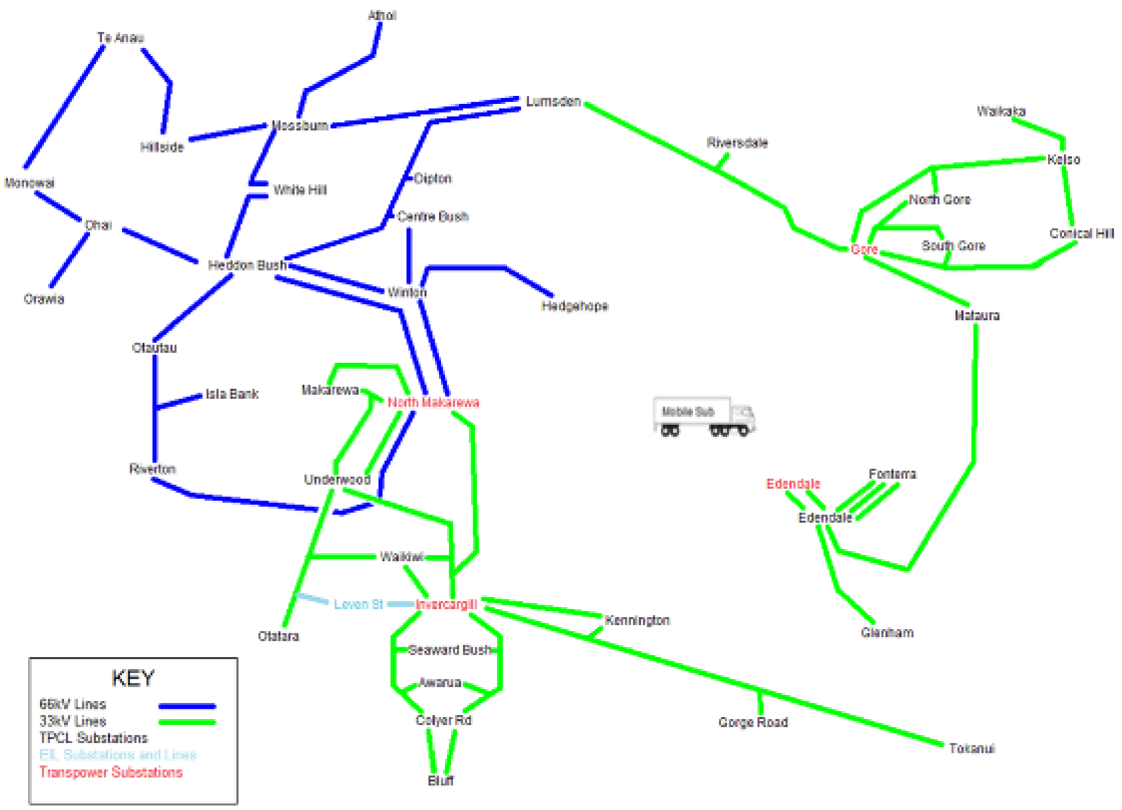
Mataura Generation	11kV	0.9MVA	0MVA	0MW N/A	0MW (8:00 15/10/2020)

There is significant generation embedded within TPCL's network, as covered in the table above. A number of smaller distributed generation connections exist but are only a few kW each in size. These generators are generally installations which due to their generation profiles (tied to sunlight conditions) have negligible effect on GXP loading.

Subtransmission Network

~~TPCL's subtransmission network is a meshed electrical network that takes supply from four GXP's at Invercargill, North Makarewa, Edendale and Gore as depicted in Figure 17.~~

~~Figure 17: Subtransmission Network~~



The subtransmission network comprises 504km of 66kV line, 387km of 33kV line, and 12km of 33kV cable and has the following characteristics:

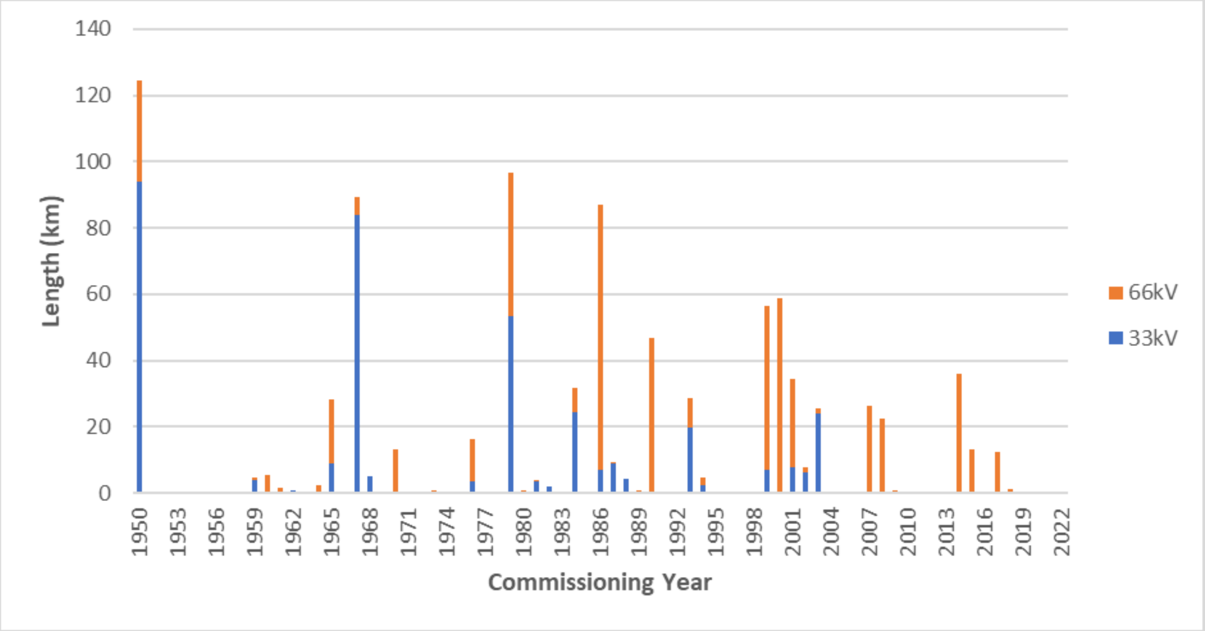
- It is almost totally overhead except for cable runs near GXP's and zone substations. Larger runs of cable include the inter-connects to Electricity Invercargill's Leven Street and Southern zone substations which are cabled from TPCL's Otatara and Seaward Bush lines respectively, short sections of 33kV around corners on the Invercargill to Kennington 33kV circuit, the supply cables to Edendale Fonterra, and connections from the Bluff lines into Colyer Road.

- It includes three different electrical topologies (ring, ladder and spur) as well as an interconnection of 66kV and 33kV at the North Makarewa GXP and at TPCL's Lumsden substation.
- It includes a large number of lightly loaded zone substations because the long distances and loads are beyond the reach of 11kV.

Subtransmission Lines

Pole overhead lines form the majority of subtransmission circuits in the TPCL network. These consist of unregulated 33kV or 66kV circuits of a capacity specifically chosen for the anticipated load. The dominant design parameters are voltage drop and losses. The Monowai to Redcliff 66kV line is over 60 years old but is still in operational condition. Determining the remaining life for multi-component assets is difficult especially as sections are constructed to differing standards and materials. In general, subtransmission cables are short lengths around zone substations or sections through urban areas where the operative District Plan required cables to be installed underground. The 33kV cables are relatively recent additions to the network and these are in good condition. Earlier XLPE cables (pre-1985) are understood to have a slightly shorter life expectancy however the oldest of these cables is still expected to have a remaining life beyond the 10 year planning horizon. Figure 18 shows the commissioning year and installed length for TPCL's subtransmission cables.

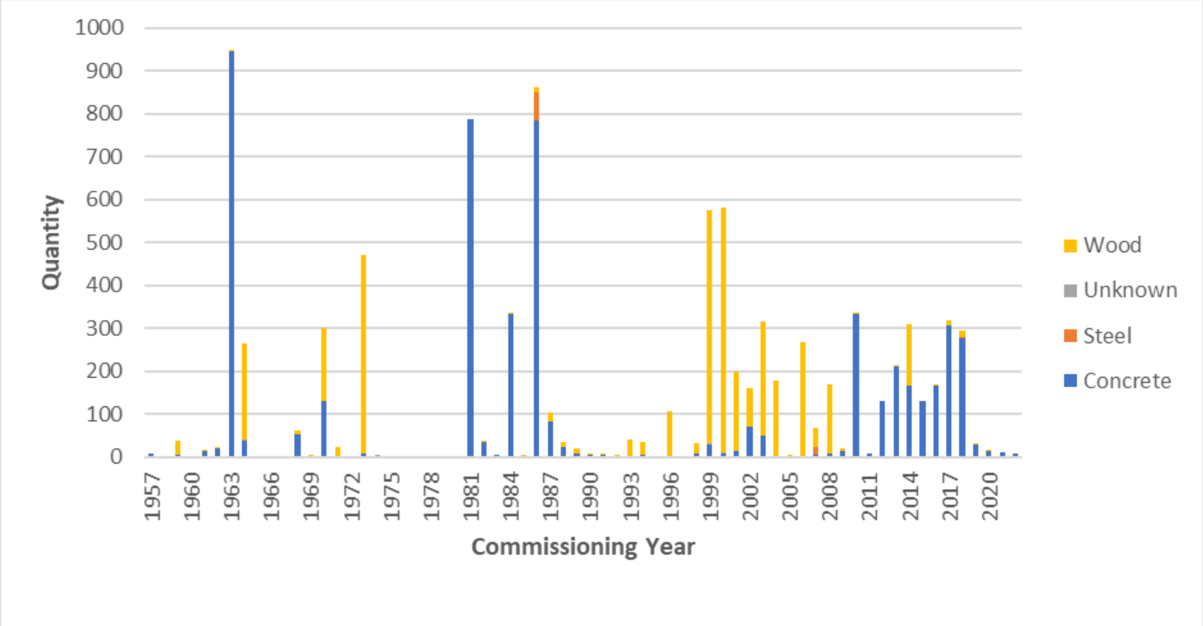
Figure 18: Subtransmission Line



Subtransmission Poles

There are a large number of poles past their standard life for wooden poles in the next ten years. It is noted however, that many poles will exceed the standard lives given above. Pole replacements are based on condition and condition of subtransmission lines is assessed by annual aerial and five-yearly walking condition inspections. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection. Figure 19 shows the commissioning year and installed length for TPCL's subtransmission poles.

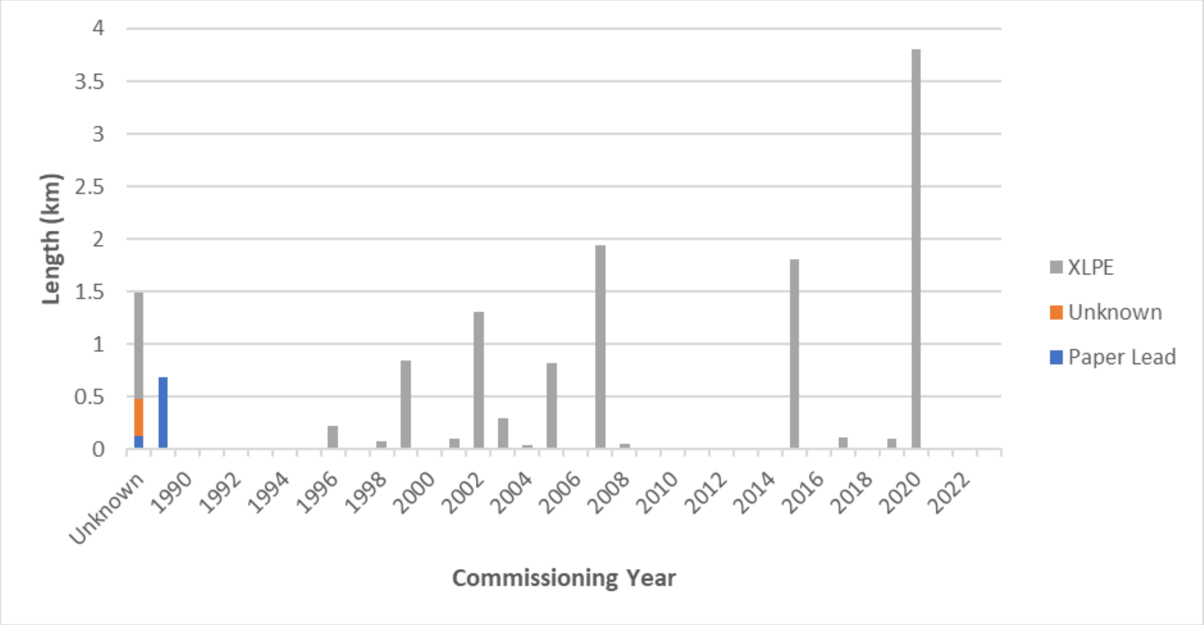
Figure 19: Subtransmission Pole



Subtransmission Cables

In general, subtransmission cables are short lengths around zone substations or sections through urban areas where the operative District Plan required cables to be installed underground. The 33kV cables are relatively recent additions to the network and these are in good condition. Earlier XLPE cables (pre-1985) are understood to have a slightly shorter life expectancy however the oldest of these cables is still expected to have a remaining life beyond the 10 year planning horizon. Figure 20 shows the commissioning year and installed length for TPCL's subtransmission cables.

Figure 20: Subtransmission Cables (33kV Cables)



Zone Substations

TPCL owns and operates 37 zone substations across Southland which have security levels (see Development Criteria for security level definitions) ranging from A(i), A(ii), AA and AAA. TPCL also takes an 11kV supply for two feeders supplied from EIL's Racecourse Road substation to supply TPCL customers in areas at the eastern edge of Invercargill. Descriptions for TPCL's zone substations are provided in Table 15.

Table 15: Zone Substations

Substation	Nature of load	Description
Athol	Villages of Athol and Kingston, rural farms with summer irrigation.	66kV line from Mossburn onto a 66kV circuit breaker and 66/11+11kV 3/5MVA transformer supplying an indoor 22kV rated switchboard with two 11kV feeders.
Awarua	Single large industrial customer.	Simple outdoor site with two 33/11kV 5MVA transformers and associated outdoor 33kV and 11kV circuit breakers.
Bluff	Predominantly urban domestic load in Bluff but including one large and a few medium industrial customers. One large windfarm with exclusive 11kV feeder.	Medium complexity outdoor substation with two 33/11kV 6/12MVA transformers, these supply an indoor 11kV switchboard with four feeders.
Centre Bush	Predominantly rural load in the middle of the Southland Plains.	Simple tee connected 66/11+11kV 5/7.5MVA transformer with four 11kV feeders.
Colyer Road	Predominantly three large industrial customers with some minor rural load to the south-west.	Indoor 33kV switchboard with five feeder circuit breakers, two supply the local 6/12 MVA transformers, two to Bluff and one

Substation	Nature of load	Description
		to the Open Country Dairy Substation. An indoor 11kV switchboard with four feeders.
Conical Hill	Predominantly rural load. Old sawmill next to site, which has been moth-balled.	Large outdoor substation with 33kV circuit breakers on two incoming supplies from Gore via South Gore substation and from Gore via Kelso substation. Two 33/11kV 5MVA transformers supply a full outdoor 11kV structure with incomer circuit breakers and four feeders.
Dipton	Predominantly rural load in the north of the Southland Plains.	Simple tee connected 66/11+11kV 3/5MVA transformer with two 11kV feeders.
Edendale Fonterra	Huge dairy factory with four large milk powder plants and other milk process plants.	Triple 33kV cable and 33/11kV 11.5/23MVA transformers supply to the Fonterra 11kV switchboards.
Edendale	Rural towns of Edendale and Wyndham, small meat works at Morton Mains and rural farms.	Full 33kV switchboard with seven feeder circuit breakers, two supply the local two 33/11kV 6/12MVA transformers, three to Edendale Fonterra, one to Glenham and one to Mataura. An indoor 11kV switchboard with seven feeders.
Glenham	Glenham village, rural farms.	33kV line from Edendale onto a 33kV circuit breaker and 33/11kV 1.5MVA transformer with two outdoor 11kV feeders.
Gorge Road	Gorge Road village, rural farms.	33kV line from Invercargill that continues to supply Tokanui via a 33kV line circuit breaker. Substation has simple tee into single 33kV CB. 33kV bus onto a 33/11kV 5MVA transformers. Indoor 11kV switchboard with three 11kV feeders.
Heddon Bush	Switching station.	Large outdoor 66kV switchyard. Has two 66kV supply routes from North Makarewa, supplies two ends of the North-western 66kV ring and has a 66kV link to Mossburn via White Hill.
Hedgehope	Hedgehope Village, rural farms	66kV line from Winton onto a 66kV circuit breaker and 66/11+11kV 5MVA transformer supplying an indoor 22kV switchboard with three 11kV feeders.
Hillside	The Key village, rural farms.	Medium outdoor substation supplied by two 66kV lines with 66kV circuit breakers, a single 66/11kV 2.25MVA transformer, three single phase voltage regulators, and three outdoor 11kV feeders.
Isla Bank	Villages of Drummond and Isla Bank, rural farms	66kV line teed off the Riverton – Heddon Bush 66kV onto a 66kV circuit breaker and 66/11+11kV 5MVA transformer supplying an indoor 22kV switchboard with three 11kV feeders.
Kelso	Tapanui township, rural farms.	Medium outdoor 33kV structure with two supplying lines from Gore and a 33kV feeder to Waikaka. Single 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Kennington	Industrial area with various manufacturing process and few	Medium outdoor 33kV structure with two 33kV line from Invercargill. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with three 11kV feeders.

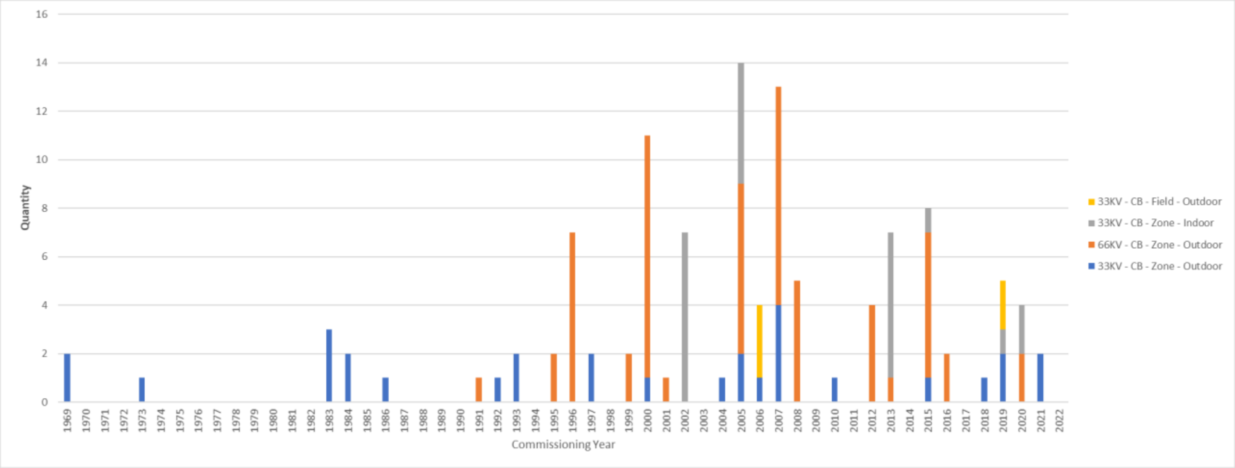
Substation	Nature of load	Description
	residences, Woodlands village, rural farms.	
Lumsden	Lumsden township, rural farms with summer irrigation.	A 66kV substation which forms part of the Northern 66kV ring. There is a normally open link to Riversdale via a 66/33kV transformer. There is a single 66/11+11kV 5MVA transformer supplying four 11kV feeders.
Makarewa	Rural farms with industrial plant.	Medium outdoor 33kV structure with two supplying lines from North Makarewa. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with five 11kV feeders.
Mataura	Township of Mataura, major Meat Processing Plant and rural farms.	Medium outdoor 33kV structure with main supplying line from Gore GXP, with a backup line to Edendale, and four 33kV circuit breakers. Two 33/11kV 10MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders.
Monowai	Remote rural farms.	Medium outdoor 66kV yard with three 66kV circuit breakers. A single 66/11kV 1MVA transformer supplying one 11kV feeder.
Mossburn	Village of Mossburn, small Meat Processing Plant and rural farms.	Large outdoor 66kV yard with five 66kV circuit breakers. A 66/33kV 30/40MVA transformer supplying load via a 3MVA 11kV tertiary winding. (This is a spare for NMK). Outdoor switchboard with incomer circuit breaker and four 11kV feeders. Two 66kV lines as part of North-western 66kV Ring. A 66kV feeder to Athol and a 66kV line to Lumsden.
North Gore	Town of Gore and rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV transformers (10MVA and 10/20MVA) supplying an indoor 11kV switchboard with four 11kV feeders.
Ohai	Town of Ohai and rural farms. Supplies one open-cast coal mine.	Large 66kV structure with lines from North Makarewa GXP, via Winton and Heddon Bush and to Monowai Power Station. Also supplies a 66kV feeder to Orawia. Each circuit is protected by a 66kV circuit breaker. One 66/11kV 5/7.5MVA supplying an indoor 11kV switchboard with four feeders.
Orawia	Town of Tuatapere and village of Orawia, rural farms and sawmills at Tuatapere.	66kV line onto a 66kV circuit breaker and 66/11kV 5/7.5MVA transformer supplying an outdoor 11kV structure with incomer circuit breaker and four 11kV feeders.
Otatara	Town of Otatara and a few farms.	33kV line from Invercargill into simple outdoor substation with single 33/11kV 5MVA transformer supplying an outdoor 11kV structure with incomer circuit breaker and three 11kV feeders. An 11kV alternative supply is available from EIL.
Otautau	Town of Otautau, large sawmill, rural farms.	Medium 66kV structure with lines from North Makarewa GXP via Heddon Bush and Riverton. These lines tee onto a single 66kV circuit breaker supplying one 66/11kV 5/7.5MVA transformer. Outdoor 11kV structure with incomer circuit breaker and five feeders.

Substation	Nature of load	Description
Racecourse Road (EIL)	Eastern area next to Invercargill city, mix of urban, lifestyle blocks and rural. Includes major Hotel/Motel complex.	Two 11kV feeders from the indoor switchboard at Electricity Invercargill Ltd Racecourse Road substation.
Riversdale	Town of Riversdale, village of Waikaia and rural farms, some with summer irrigation.	Small outdoor 33kV structure with main supplying line from Gore, with a back line to Lumsden. Single 33kV circuit breaker and 33/11kV 5MVA transformer. Outdoor 11kV structure with incomer circuit breaker and four 11kV feeders.
Riverton	Town of Riverton, small fish processing, rural farms	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 5/7.5MVA transformers. Part of southern 66kV ring supplied from North Makarewa. Indoor 11kV switchboard with six feeders.
Seaward Bush	South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant, rural Farms.	Medium complexity outdoor substation with two 33/11kV 10MVA transformers, these supply an indoor 11kV switchboard with five feeders.
South Gore	Town of Gore, small meat processing plant, rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders. One 33kV line continues onto Conical Hill substation.
Te Anau	Towns of Te Anau and Manapouri, rural farms.	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 9/12MVA transformers. Part of northern 66kV ring supplied from Heddon Bush. Indoor 11kV switchboard with five feeders.
Tokanui	Villages of Waikawa, Fortrose, Curio Bay and Tokanui, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer. Outdoor 11kV structure incomer circuit breaker and two 11kV feeders. 33kV line from Invercargill via Gorge Road.
Underwood	Major Meat processing plant, town of Wallacetown, rural farms.	Large 33kV structure with three 33kV circuit breakers, supplying two 10/20MVA transformers. An indoor 11kV switchboard with four feeders.
Waikaka	Village of Waikaka, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer, single 33kV circuit breaker with one 11kV feeder. Single 33kV line from Kelso.
Waikiwi	Mix of urban residential and urban light industrial load in northern suburbs of Invercargill.	Substantial two 33/11kV 11.5/23MVA transformer substation with (n-1) supply including possibility of supply from two different GXP’s. Indoor 33kV switchboard with five circuit breakers. Indoor 11kV switchboard has four feeders.
Winton	Town of Winton, Villages of Lochiel and Browns, Large Sawmill, Limeworks, rural farms.	Winton is on the southern 66kV ring supplied from North Makarewa, with two lines from North Makarewa and Heddon Bush. Two 66/11kV 6/12MVA transformers supplying a full indoor 11kV switchboard with seven feeders.

Subtransmission Voltage Switchgear

TPCL has three indoor 33kV switchboards at Waikiwi, Edendale and Colyer Road. All other 33kV circuit breakers are outdoor units. All 66kV circuit breakers are installed outdoors and all units installed after 1992 are SF6 insulated. The single remaining oil 66kV circuit breaker, located at Otautau, is in good condition and is not expected to be decommissioned during the 10-year planning period. The 33kV oil circuit breakers at North Makarewa will or have reached their standard lives during the 10 year planning. Renewals of these will be planned when condition inspections determine that they are no longer fit for service.

Figure 21: Subtransmission Voltage Circuit Breakers (33kV)

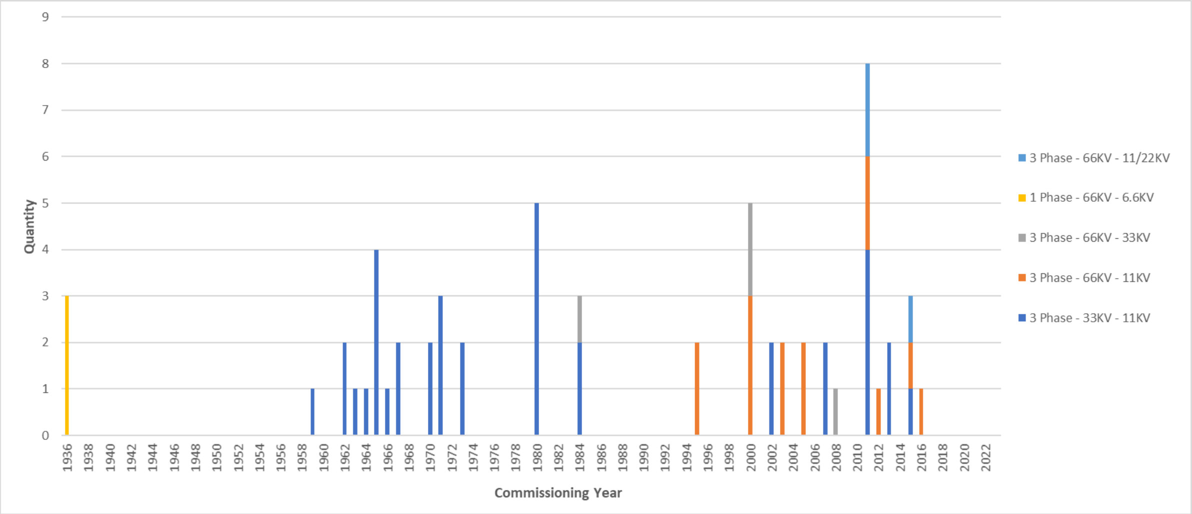


Power Transformers

The Power Transformers on the network are generally in good condition. Twenty two units are expected to exceed the standard service life of 55 years within the 10 year planning period. This standard service life is longer than the theoretical value in the ODV handbook. Condition of these units will continue to be monitored with many of the older units providing reliable service.

Transformers are regularly inspected and oil samples taken periodically over a 12 month cycle. Oil results are captured within the asset management program and units with identified risks are referred for additional analysis. Identified transformers at the Mataura, Seaward Bush, Hillside, Kelso, North Gore, Riversdale, Otatara, and Tokanui substations are being monitored. Due to condition and network growth, the Seaward Bush, Glenham and Awarua transformers will be replaced with network spares in 2023/24. The first Makarewa transformers are scheduled for refurbishment in 2023/24, followed by the second unit in 2024/25. The age profile of these are shown in Figure 22.

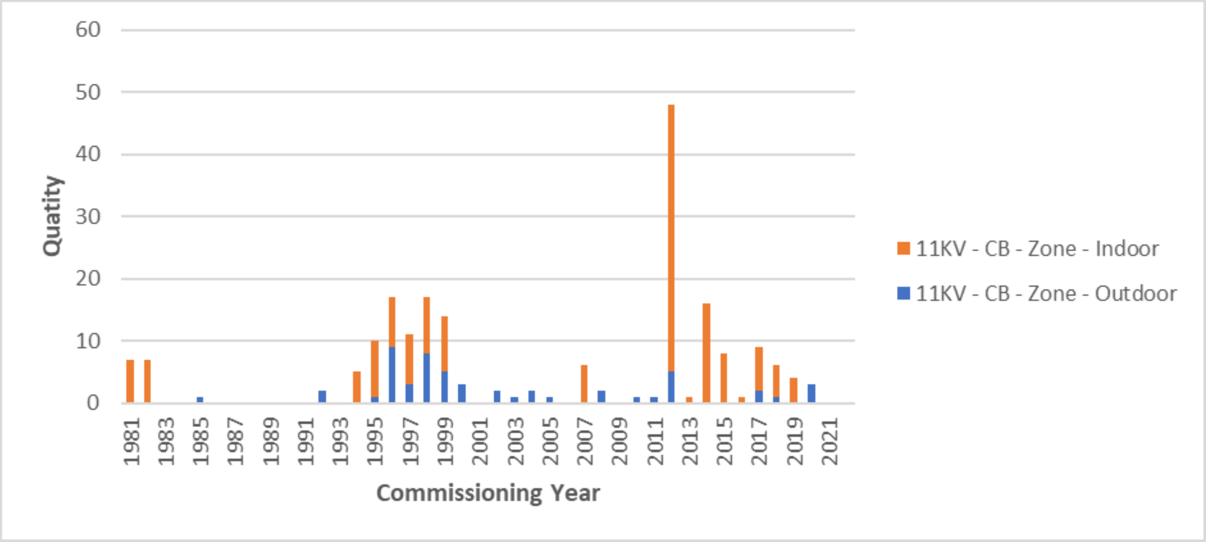
Figure 22: Power Transformer



Distribution Voltage Switchgear

TPCL has a mix of outdoor and indoor distribution circuit breakers. Older circuit breakers are 11kV to match the operating voltage of the network. 22kV circuit breakers have been installed as part of new substation construction as it provides for future voltage conversion and aligns with a long term plan to convert to 22kV within the lifetime of the equipment. The Bluff and Makarewa indoor switchboards are planned for replacement at the end of their standard life, with the project implementation starting in the 2024/25 financial year. The age profile of these are shown in Figure 23.

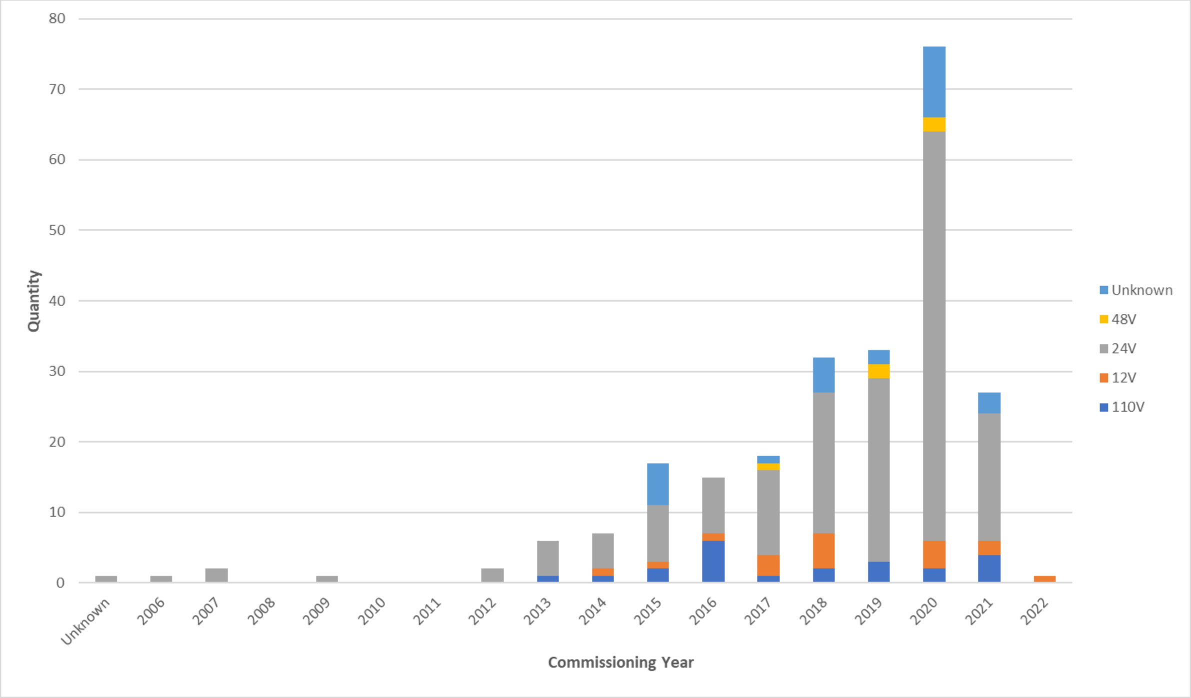
Figure 23: Distribution Voltage Switchgear



DC Power Supplies

DC batteries are essential to the safe operation of protection devices, therefore regular checks are performed and with the majority of battery units below 10 years. The age profile of these are shown in Figure 24.

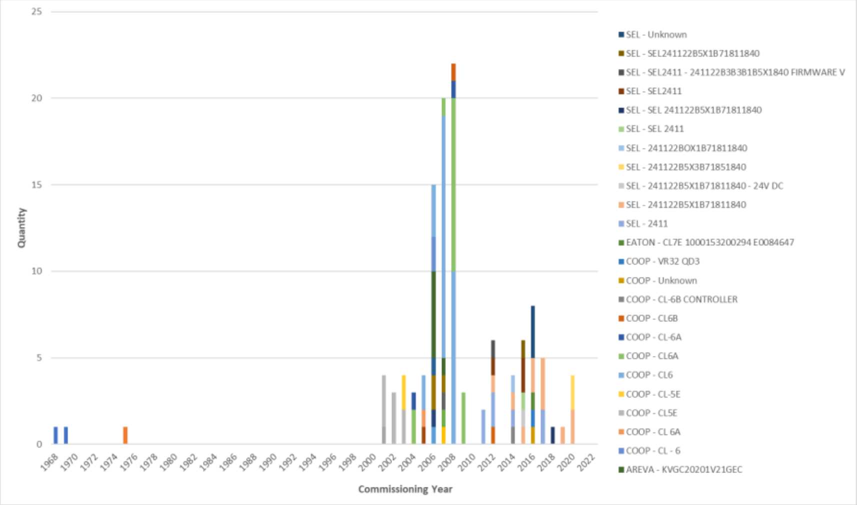
Figure 24: DC Batteries



Tap Changer Controls

118 voltage regulating relays (VRR) are in operation and most have been installed with the associated transformer or voltage regulator. The condition of these is generally good with some recent problems. A number of substation sites utilize single phase voltage regulators, which have a VRR per phase. The two oldest VRRs on the network are at Awarua and Riversdale. The VRR at Riversdale is planned to be replaced within the next 10 years and the VRR at Awarua is on the T2 transformer which is currently energised but not on load following transfer of load. The age profile of these are shown Figure 25.

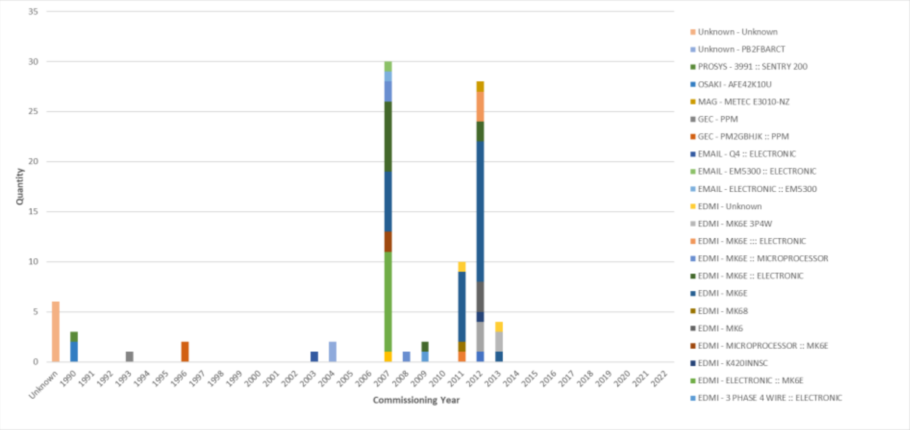
Figure 25: Voltage Regulating Relay



Metering

TPCL has ‘Time Of Use’ (TOU) meters on its incoming circuit breakers to provide accurate loading information on each zone substation. There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these are shown in Figure 26.

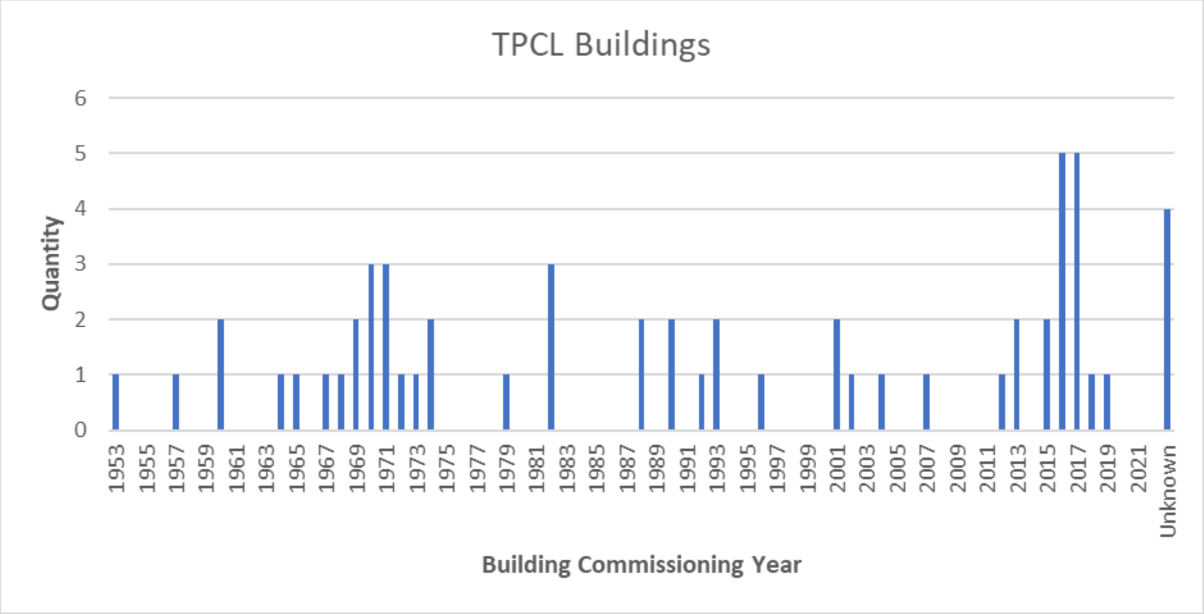
Figure 26: Metering Assets



Substation Buildings

TPCL has buildings at each of its zone substations and others like communications repeater sites. The larger buildings are either concrete block or wooden framed construction with some smaller buildings being made offsite using insulated metal panel construction. The age profile of the 58 buildings are shown in Figure 27.

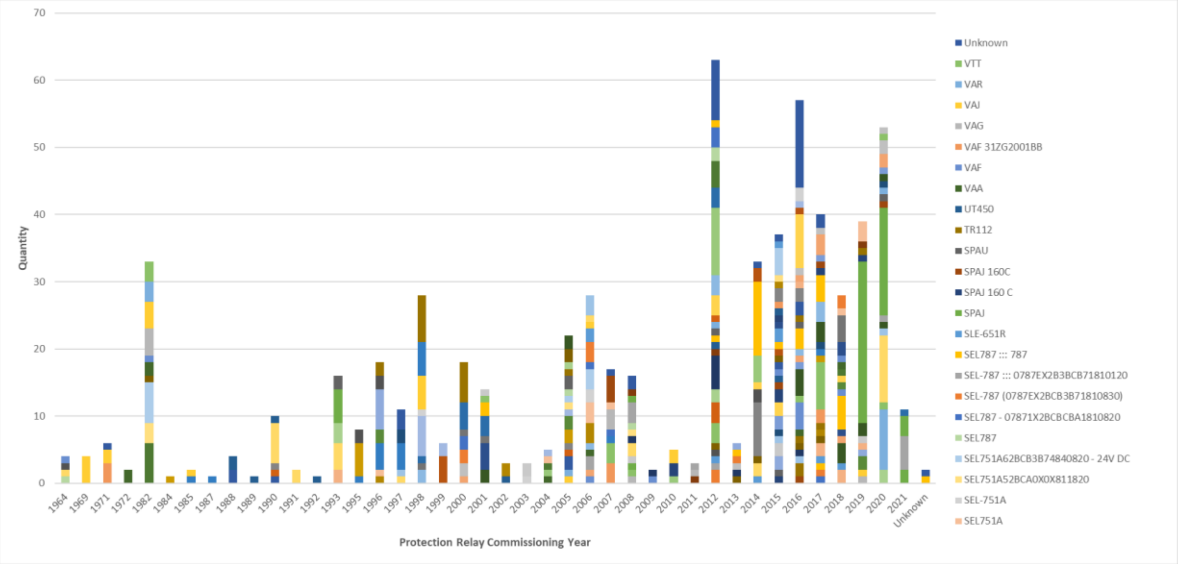
Figure 27: Substation Buildings



Protection Equipment

TPCL has some 724 protection relays of which one third general relays including older electromechanical tripping relays, with the larger two thirds being more modern microprocessor relays. The modern microprocessor relays have been used on the TPCL network since 1998 and a number of these are now recommended for replacement with more capable relays. The older relays are mainly auxiliary and tripping relays, less prone to failure, but are being replaced with whole substation protection upgrades. The age profile of the 724 protection relays are shown in Figure 28.

Figure 28: Protection Relays



Distribution Network

TPCL's distribution network has a total length of 6,978.15 km to supply its 37,102 customers giving an overall customer density of 5.31 customers per kilometre. The rural distribution network is mainly meshed between substations with reasonable backup capability. Distribution off this main distribution feeders is radial with only some meshing. In urban areas a high degree of meshing between 11kV feeders is possible.

- Rural areas are predominantly concrete pole, flat construction with wooden cross-arms and pin insulators.
- Suburban areas are either concrete pole with wooden cross-arms and pin insulators or PILC[6] or XLPE[7] cable.
- CBD areas tend to be PILC cable unless this has been replaced, which will almost always be with XLPE cable.

The split of the distribution network per substation is presented in Table 16. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works. The table incorporates recent MV tie point shifts to allow major work to be completed. Once completed, normal tie points will be restored, improve zone substation transformer capacity utilisation and reliability.

Table 16: Distribution network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	123.65	6.53	530	4.07
Awarua	0.00	0.07	1	14.29
Bluff (TPCL)	33.58	0.44	157	4.61
Centre Bush	276.11	0.21	650	2.35
Colyer Road	13.84	6.51	42	2.06
Conical Hill	165.32	0.30	299	1.81
Dipton	160.49	0.27	318	1.98
Edendale Fonterra	0	0	1	0.00
Edendale	295.78	4.37	1,380	4.60
Glenham	192.54	0	354	1.84
Gorge Road	165.12	0.26	393	2.38
Hedgehope	138.74	0.17	311	2.24
Hillside	226.84	2.18	368	1.61

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[6] PILC = Paper Insulated Lead Covered – a standard underground cable construction format.

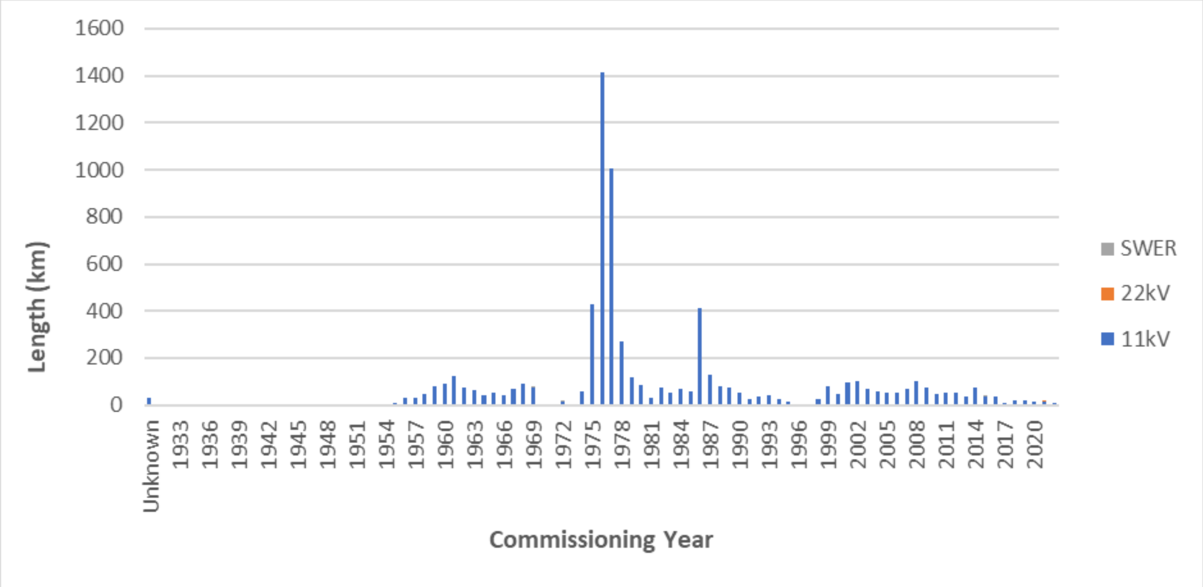
[7] XLPE = Cross-Linked Polyethylene – the modern underground cable construction format.

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Isla Bank	132.81	1.43	355	2.64
Kelso	441.70	0.29	1,306	2.95
Kennington	175.09	3.55	784	4.39
Lumsden	312.23	5.90	830	2.61
Makarewa	246.11	2.20	1,118	4.50
Mataura	234.74	3.51	1,256	5.27
Monowai	46.87	0.37	96	2.03
Mossburn	209.73	2.47	464	2.19
North Gore	284.28	5.06	2,771	9.58
Ohai	212.95	0.56	773	3.62
Orawia	313.42	2.46	944	2.99
Otatara	61.23	5.99	1,392	20.71
Otautau	189.08	1.09	849	4.46
Racecourse Road (TPCL)	28.62	2.84	530	16.85
Riversdale	424.56	3.40	1,354	3.16
Riverton	294.05	7.05	2,166	7.19
Seaward Bush	150.85	6.39	2,510	15.96
South Gore	196.16	20.73	2,512	11.58
Te Anau	175.37	39.36	2,676	12.46
Tokanui	230.33	0.686	580	2.51
Underwood	66.12	2.49	619	9.02
Waikaka	108.80	0.19	252	2.31
Waikiwi	95.39	12.00	3,556	33.11
Winton	394.87	7.94	2,558	6.35
Unallocated	1.16	0.27689	47	1.39
Total/average	6818.61	159.54	37,102	5.31

Distribution Lines

The age profiles for overhead MV conductors are shown respectively in Figure 29. Overhead LV conductors are replaced based on their condition.

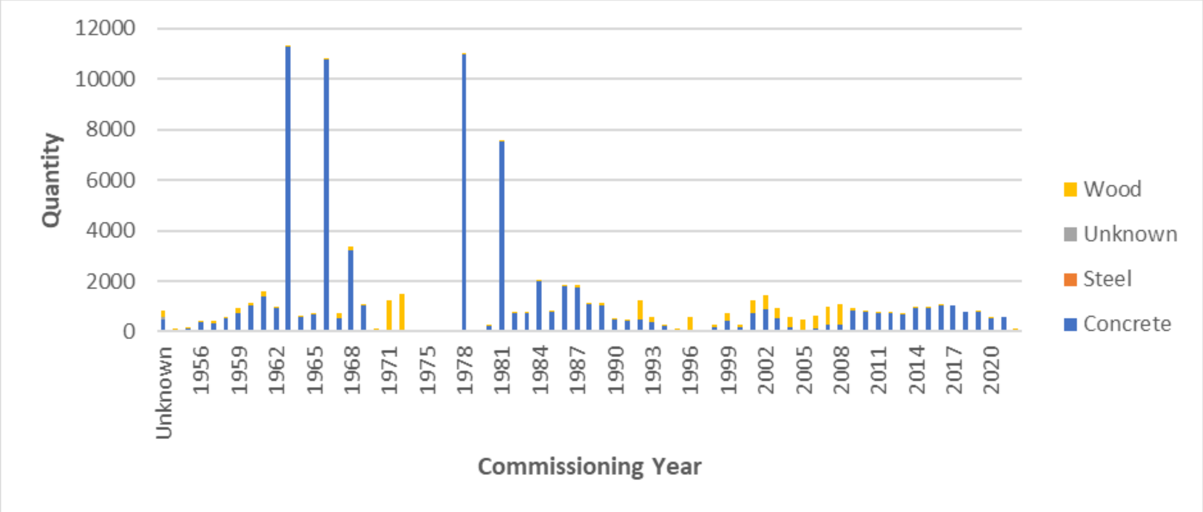
Figure 29: MV Line Conductors (11kV Overhead)



Distribution Poles

Given the age profile of distribution poles (based on large builds over a few years in the early 1960s) expenditure on pole replacements has increased over the last few years and is expected to stay at this level throughout the planning period. It is noted however, that many poles will exceed the standard lives given above. Pole replacements are based on condition and condition of distribution lines is assessed five-yearly walking condition inspections. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection. The age profile of these is shown in Figure 30.

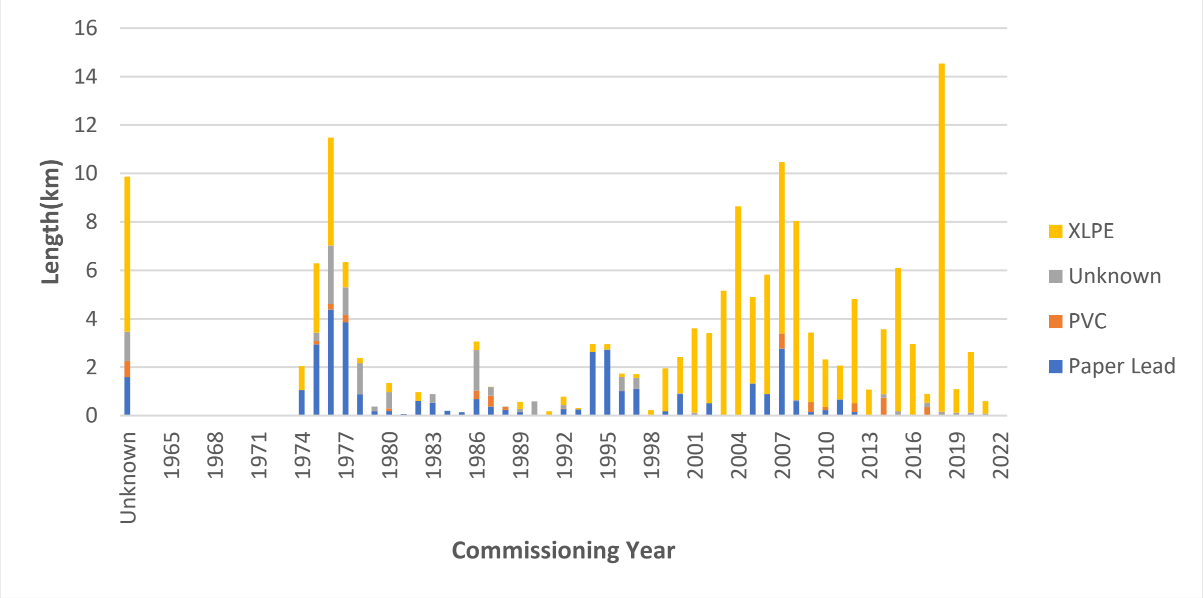
Figure 30: Distribution Poles



Distribution Cables

The age profile of 11kV cables shows that some XLPE cables may need renewal within the planning period (XLPE cables installed before 1985). These will be monitored and replacement done if failures are predicted. Paper lead cables were predominantly used up to about 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 ODV standard life and on-going monitoring of actual performance will be utilised in planning. Most cables are lightly loaded and in sound condition however there have been termination and joint failures. Figure 31 shows the lengths of cables on TPCL's distribution network by commissioning year.

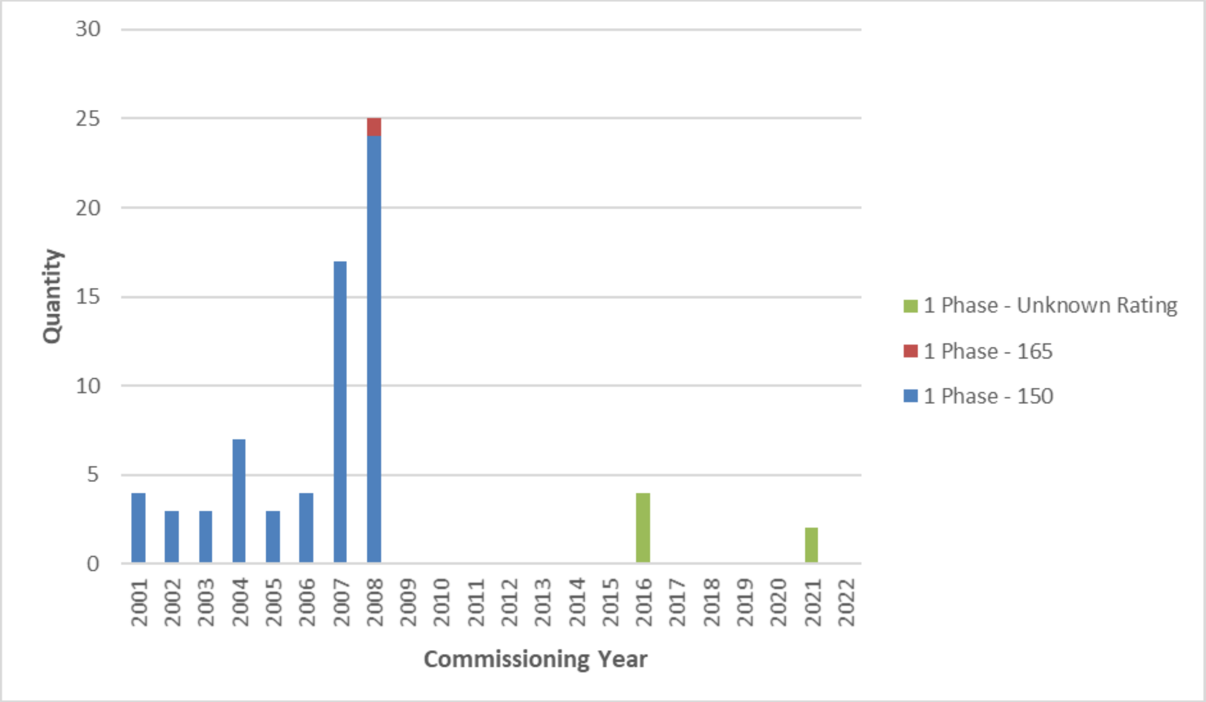
Figure 31: MV Cables (11kV)



Voltage Regulators

The age profile for voltage regulators is shown in Figure 32. Voltage regulators exist on TPCL's network for voltage improvement and to allow for 11kV backups between zone substations. All units are modern single-phase units with the oldest units installed in 2001.

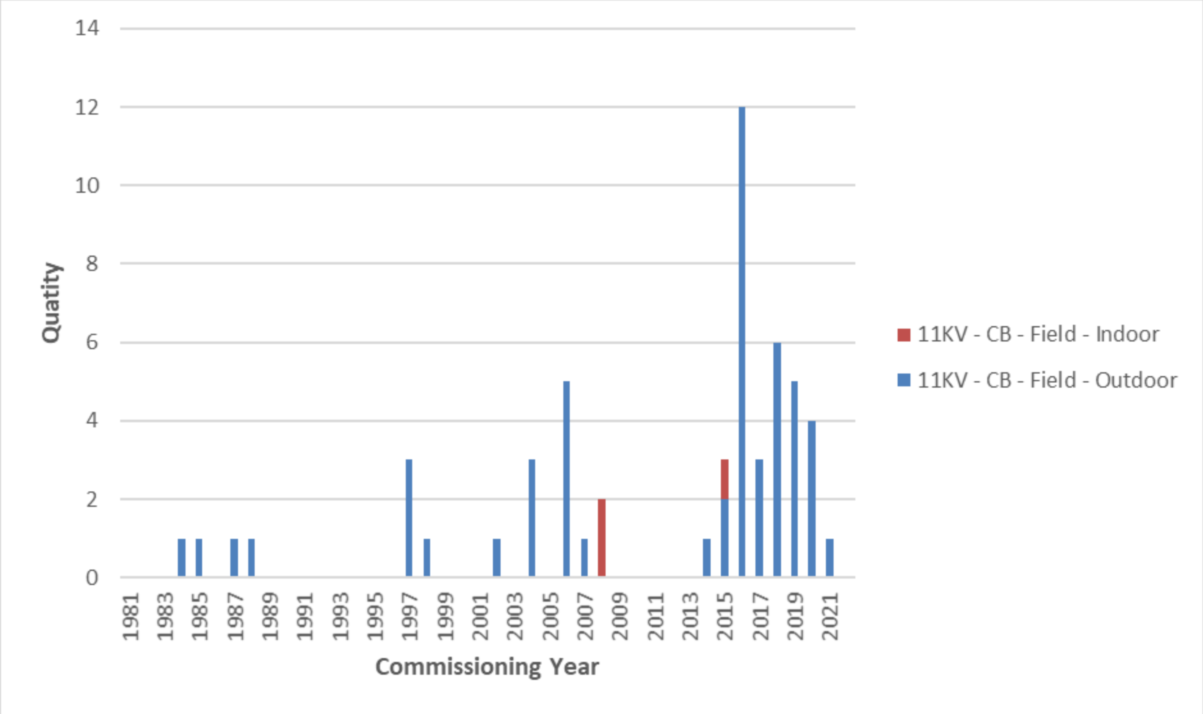
Figure 32: Voltage Regulator at Distribution Voltage (11kV)



Switchgear

TPCL has field circuit breakers installed on the distribution network. These circuit breakers are installed for protection, isolation and connection of transformers and sections of the network. Figure 33 provides an overview of the age profiles of field circuit breakers.

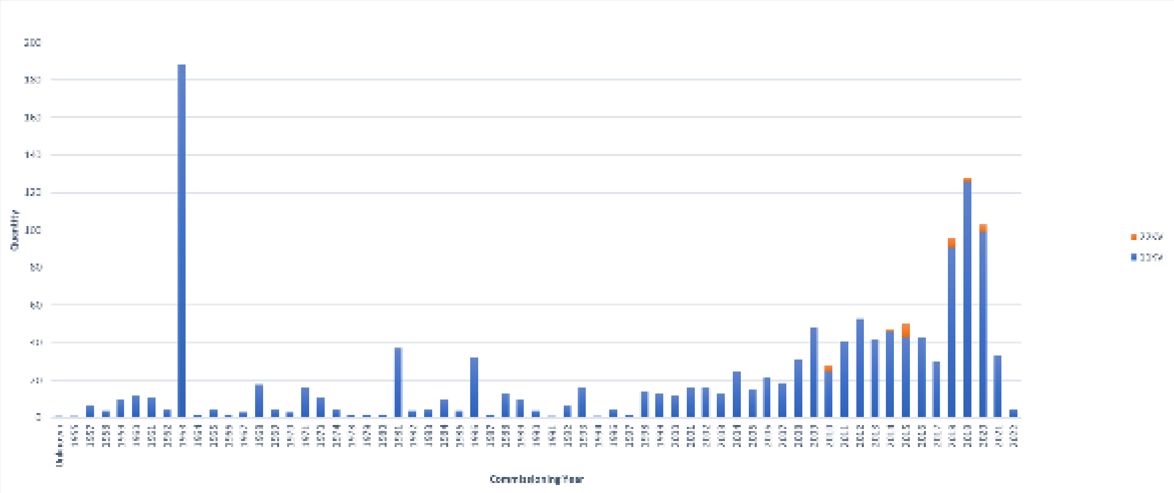
Figure 33: Field Circuit Breakers at Distribution Voltage (11kV)



Air Break Switches

The condition of the air break switches are generally fair with a proportion of older units. However, the 11kV ABS units installed between 1998 and 2014, have a potential failure risk relating to vibration or to any seismic activity due to material defects in the insulators. This causes some insulators to fail prematurely resulting in the breaking of the porcelain bushings. This poses a safety risk to operators and staff and a works program have been implemented to replace all defective units. The program started during the financial year 2019/20 and will continue throughout the DPP period. Figure 34 provides an overview of the age profiles of the air break switches

Figure 34: Air Break Switches



Fuses

There are 10,000+ drop-out fuses on the network protecting transformers and laterals. A limited age profile exists for newer units but the vast majority have no known installation date. These have a relatively low failure rate.

Distribution Substations

Just as zone substation transformers form the interface between the sub-transmission and the 11kV distribution networks, distribution substations form the interface between the 11kV distribution and 400V distribution networks. The distribution substations range from 1-phase 15kVA pole-mounted transformers to 3-phase 1,500kVA ground-mounted transformers supplied via circuit breaker ring main units. These larger substations typically supply special customers, like the Open Country Dairy processing plant at Awarua.

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. Low voltage protection is by the DIN[8] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

Table 17 shows the number of distribution transformers by size on TPCL's network. Most of TPCL's transformers are pole mounted with a much smaller number of ground mounted transformers – generally in larger urban townships or at individual larger customer's premises.

Table 17: Number of distribution transformers

Phases	Rating	Pole Mount	Ground Mount
1 phase	up to 15 kVA	4826	31
	30 kVA	458	11
	50 kVA	9	1
3 phase	up to 15 kVA	1879	3
	30 kVA	1808	48
	50kVA	1024	44
	75 kVA	295	11
	100 kVA	225	78
	200 kVA	97	229
	300 kVA	40	120
	500 kVA	4	46
	750 kVA	4	21

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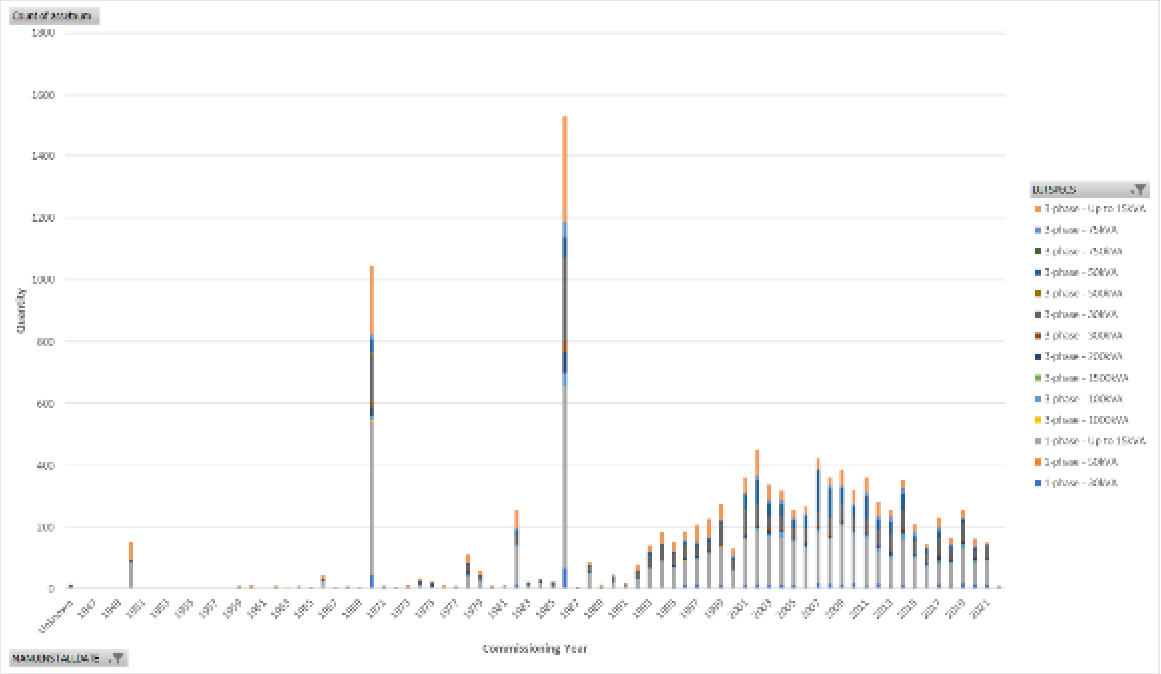
[8] Deutsches Institut für Normung e.V. (DIN; in English, the German Institute for Standardization). This is Germany's national organisation for standardization and an ISO member body.

Phases	Rating	Pole Mount	Ground Mount
	1,000 kVA	1	12
	1,500 kVA	0	15
Total		**10670**	**670**

Figure 35 provides an overview of the age profiles of distribution transformers. Transformers found to be in poor condition after five-yearly inspections will be replaced, sometimes with units removed from service and refurbished for reuse. Condition varies generally due to proximity to the coast and unit load characteristics. Two spikes occur at 1970 and 1986 where estimated ages have been used, as the actual manufacturing year was not able to be found.

Figure 35: Distribution Transformers

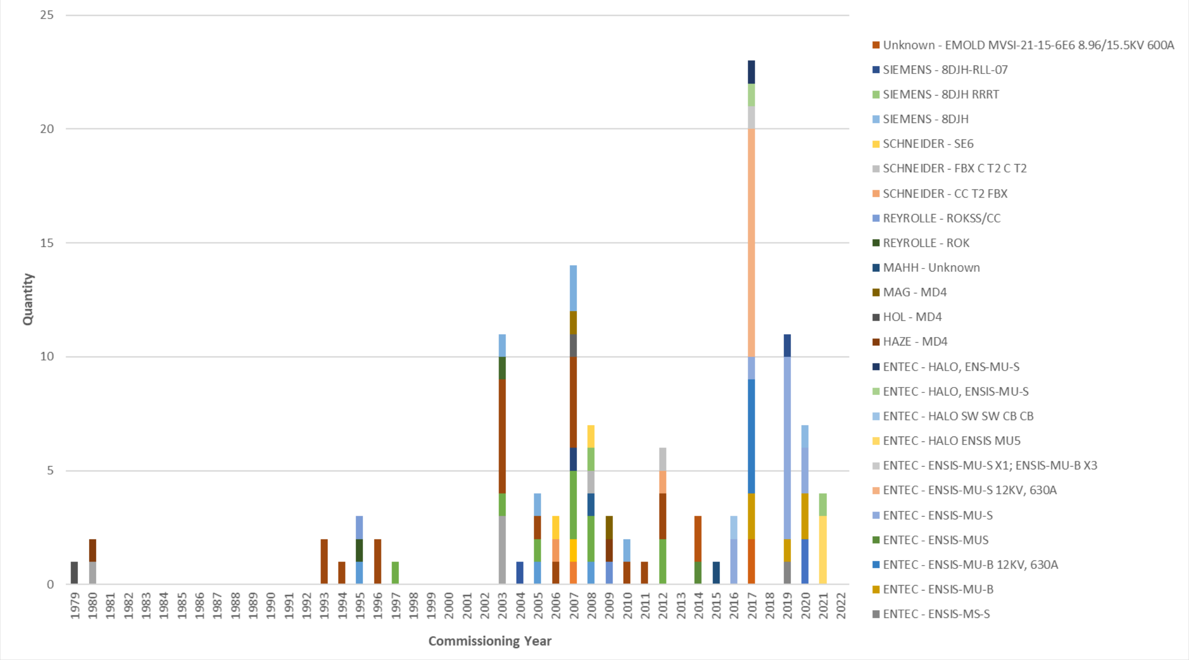


Ring Main Unit

The age profile of ring main units (RMUs) is displayed in Figure 36 which shows several the older (generally indoor) units will be reaching their standard life of 40 years in this planning period (although some ages have been estimated). 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.

Operating restrictions are placed on some RMU equipment. This is to prevent risks and to manage hazards associated with a selection of 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. Some outdoor units have also developed rusting issues that may lead to early replacement of affected switchgear. Generally, these units are replaced as required based on an evaluation of age and condition.

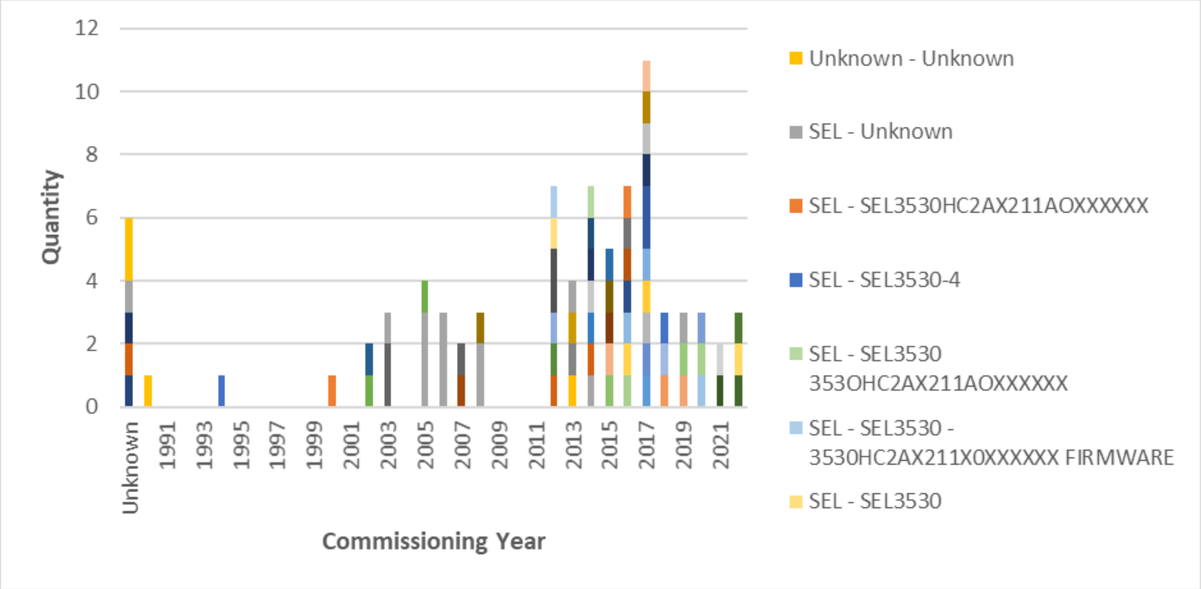
Figure 36: Ring Main Units



Remote Terminal Units

A few units are exceeding the standard age of 15 years and condition is average. The older Kingfisher units starting to become difficult to maintain and are planned to be replaced in future years. In some cases a new SEL 3530 or SEL Axion RTU connected to new equipment is installed in parallel with the existing Kingfisher RTU, which remains connected to older equipment. Over the next 5 years the older equipment will be migrated to the SEL 3530 or SEL Axion RTU's. Age profile of Remote Terminal Units (RTU) are shown in Figure 37.

Figure 37: Remote Terminal Units



Low Voltage Network

TPCL's Low Voltage (LV) network (400/230 V) has a total length of 1072.60km to supply its 37,102 customers giving an overall customer density of 34.59 customers per kilometre.

The 230/400 V Low Voltage (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 is almost solely radial in rural areas but meshed in urban areas which provide some restoration of supply after faults and for planned work. Transformer loading and volt drop tend to be the limiting factors in utilising these backups.

Construction of TPCL's LV network varies considerably and can include the following configurations:

- Overhead LV (including underbuilt on 11kV and underbuilt on 33kV and 66kV) using the following conductors;
  - Open Wire
  - Aerial Bundled Conductor (ABC)
  - Covered
  - Aerial Neutral Screen
- PILC cables only.
- XLPE cable only.
- Conjoint PILC – XLPE cable.

The splits per substation of overhead and underground network, customer count and density are presented in Table 18. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Table 18: LV Network Characteristics per Substation

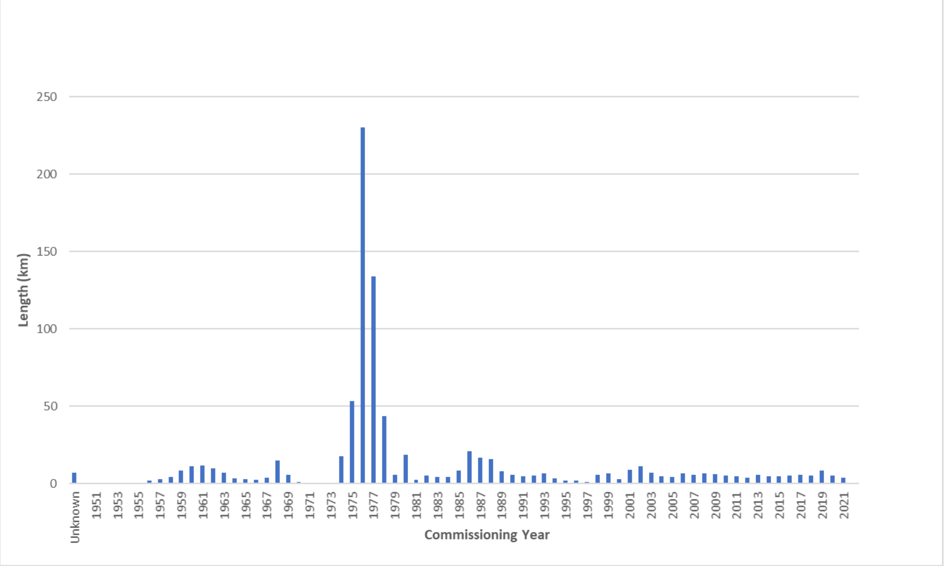
Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	8.53	2.82	530	46.70
Awarua	0	0	1	0.00
Bluff (TPCL)	5.85	0.09	157	26.43
Centre Bush	15.80	0.45	650	40.00
Colyer Road	0.49	0.34	42	50.60
Conical Hill	8.94	0.15	299	32.89
Dipton	7.94	1.12	318	35.10
Edendale Fonterra	0	0	1	0.00
Edendale	47.47	2.02	1,380	27.88
Glenham	12.91	0.11	354	27.19
Gorge Road	14.92	0.14	393	26.10
Hedgehope	10.29	1.05	311	27.43
Hillside	3.82	0.38	368	87.62
Isla Bank	10.94	0.29	355	31.61
Kelso	32.09	1.64	1,306	38.72
Kennington	31.52	2.36	784	23.14
Lumsden	17.69	2.94	830	40.23
Makarewa	44.33	1.90	1,118	24.18
Mataura	31.49	2.11	1,256	37.38
Monowai	1.20	0.65	96	51.89
Mossburn	8.12	1.05	464	50.60
North Gore	57.56	11.77	2,771	39.97
Ohai	26.07	0.33	773	29.28
Orawia	28.60	3.05	944	29.83
Otatara	29.56	13.25	1,392	32.52
Otautau	24.13	3.13	849	31.14

Racecourse Road (TPCL)	9.66	8.69	530	28.88
Riversdale	36.25	1.28	1,354	36.08
Riverton	61.26	7.12	2,166	31.68
Seaward Bush	42.67	25.01	2,510	37.09
South Gore	45.86	15.48	2,512	40.95
Te Anau	13.39	57.81	2,676	37.58
Tokanui	26.20	1.21	580	21.16
Underwood	17.01	2.99	619	30.95
Waikaka	7.42	0.09	252	33.56
Waikiwi	57.43	30.34	3,556	40.51
Winton	49.94	19.86	2,558	36.65
Unallocated	1.41	0.74	47	21.86
Total/average	**848.77**	**223.83**	**37,102**	**34.59**

Overhead LV Conductors

The age profiles for overhead LV conductors are shown respectively in Figure 38. Overhead LV conductors are replaced based on their condition. New overhead lines are ABC (Aerial Bundled Conductors) which does not require cross arms and insulators and has PVC insulation improving line safety.

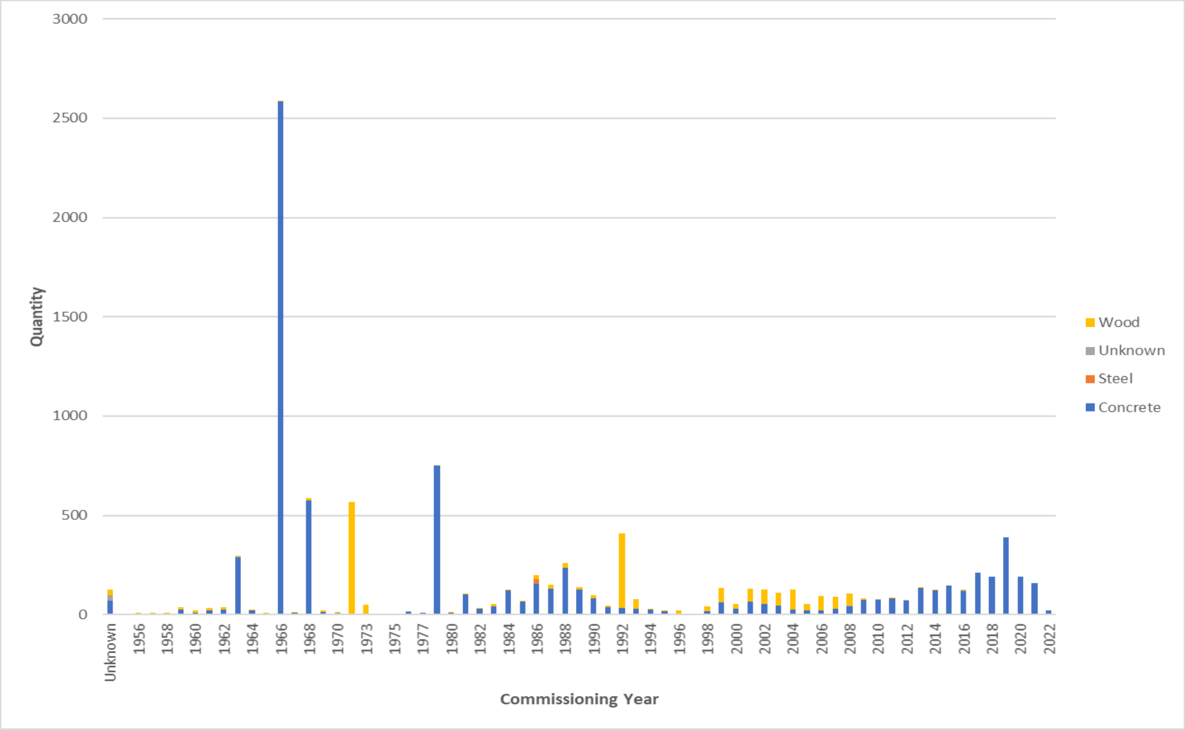
Figure 38: Overhead LV Conductors



Low Voltage Poles

Conditions of these are average, with a large number of poles due for renewal this planning period based on age. Five-yearly walking condition inspections are made of all LV lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection. The number of poles and their commissioning year is presented below in Figure 39.

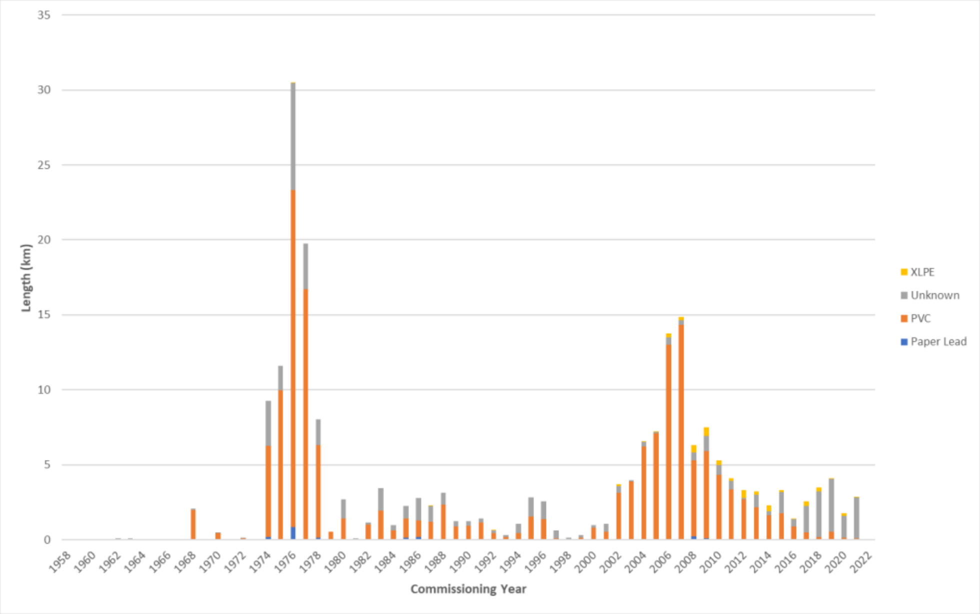
Figure 39: LV Poles



Underground LV Cables

The LV cable commissioning year profile is shown in Figure 40 and shows several assets beyond nominal life. In practice cables are left in service until performance deteriorates and impacts on service levels.

Figure 40: LV Cables



Customer Connections

TPCL has 37,102 customer connections - for which revenue is earned for providing a connection to the network via the 18 retailers which convey electricity over the network. All of the “other assets” convey energy to these customer connections and essentially are a cost to TPCL that has to be matched by the revenue derived from the customer connections. These 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. The number and classes of customer connections are listed in Table 19. In most cases the fuse forms the demarcation point between TPCL’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.

Table 19: 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	
Apr-21	186	1,862	10271	18882	474	2905	1567	249	61	65	206	36,728
May-21	186	1,871	10262	18897	474	2904	1566	246	59	64	206	36,735
Jun-21	186	1,868	10265	18905	475	2899	1561	247	59	62	210	36,737
Jul-21	186	1,874	10257	18957	476	2901	1562	247	59	62	212	36,793
Aug-21	186	1,877	10249	18995	477	2899	1568	248	59	62	212	36,832
Sep-21	186	1,879	10180	19105	476	2900	1566	249	59	62	212	36,874
Oct-21	185	1,887	10157	19158	477	2899	1564	250	59	62	212	36,910
Nov-21	186	1,892	10096	19269	477	2895	1568	251	59	62	212	36,967
Dec-21	186	1,888	10161	19260	479	2894	1567	252	59	61	213	37,020
Jan-22	186	1,891	10109	19303	481	2896	1568	253	60	61	213	37,021
Feb-22	186	1,894	10109	19324	484	2897	1569	251	60	61	213	37,048
Mar-22	186	1,896	10142	19340	485	2897	1570	251	61	61	213	37,102

Assets for Control and Auxiliary Functions

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

Injection Plants

All 33kV plants are enclosed within buildings providing protection from the elements and therefore there is an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply units upgraded in 2005 after failures at other sites. The control equipment at Gore has been replaced in the 2019/20 financial year. The interface plant between Gore and Invercargill injection plants requires an upgrade. These plants are expected to be made redundant with the roll out of smart meters and street light controls in the medium term.

Table 20: List of Injection Plants

Voltage	Location	Quantity	Manufactured	Condition
66kV	Winton	1	1992 (RL = -6yrs)	Average, coupling cell and capacitors are outdoor. Not in operation.
33kV	Invercargill 1	1	1988 (RL = -10yrs)	Average, all gear is indoor
33kV	Gore	1	1990 (RL = -8yrs)	Average, although it requires an interface upgrade between new controller and Invercargill plant. All gear is indoor

33kV	Edendale	1	1988 (RL = -10yrs)	Average, all gear is indoor
33kV	North Makarewa	1	1994 (RL = -4yrs)	Average, all gear is indoor

Load Control Assets

Load Control Assets	
Ripple Injection Plant and Receivers	TPCL currently owns and operates four main 33kV 216⅔Hz 125kVA ripple injection plants at Invercargill, North Makarewa, Gore and Edendale. There is a "backup" 66kV 216⅔Hz 125kVA outdoor ripple injection plant at Winton but this is not operational. At Invercargill, EIL has the same size ripple plant as TPCL and each can act as a backup for the other. 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.

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 charged spring 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. 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. It may also be motorised to provide remote operation for control/isolation. 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 initial SCADA master station was commissioned in 1999 with a further upgrade of the Server PC's in 2005 and most recently in 2017. The software has been developed with the latest version being implemented with the new servers in 2017. A disaster recovery station has been installed in a nearby Transpower substation.

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 TPCL's SCADA is provided as a service by PowerNet Ltd, with the master station located at PowerNet's System Control centre at the Findlay Road GXP, Invercargill. 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	TPCL currently owns and operates a number of different radio systems. These systems transmit protection, SCADA, load control and voice traffic. Most traffic is between zone substations and field devices, and the SCADA master station at System Control. However, in the case of protection traffic, signals are sent directly between the protection devices - generally zone substation to zone substation, or zone substation to field device. The radio system is comprised of • Digital microwave radio links which simultaneously convey multiple types of traffic including protection signals, SCADA, and voice. • UHF radio links which generally convey a single type of traffic, but modern systems may convey multiple types of traffic (although at a lower speed than microwave radio links). These are used for protection signals, SCADA, load control and voice. • Point-to-multipoint UHF channels for SCADA. VHF land mobile channels for voice.
Remote Terminal Units	TPCL owns RTUs at both zone substations and field substations. Field substations generally use the circuit breaker protection relay or regulator controller as the RTU.

Mobile Plant/ Load Correction/ Generation

TPCL own a mobile substation, two power factor correction plants, and Microgrid generation plant but not mobile generation or standby generation plant; however, PowerNet owns three mobile diesel generators rated at 450 kW, 350 kW and 225 kW which TPCL utilises to maintain supply to customers when assets are removed from service for maintenance. Generators are generally used to supply a single transformer's load when the potential interruption would be longer than 6 hours.

Other Assets	
Generation	TPCL own one 8 kw diesel generator, 12.6 kW of solar generation and 16kW battery at the Blue Cliffs Rowallan Microgrid, but 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.
Power Factor Correction	TPCL owns and operates two 2.5MVAr 66kV capacitors at Heddon Bush and four 5MVA 66kV capacitors at North Makarewa. These were installed during the construction of Meridian Energy Limited's White Hill wind farm to cover the VAR requirements of the generators.

Other Assets	
	Other than the above, customers are required to draw load from connection points with sufficiently good power factor so as to avoid the need for network scale power factor correction.
Mobile Substations	TPCL owns a trailer mounted 3 MVA 11kV regulator and circuit breaker with cable connections. TPCL owns a 66-33/22-11kV 5MVA heavy trailer mounted mobile substation with HV and MV circuit breaker with HV overhead line connection and MV cable connections.
Metering	Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

3.4 Load Characteristics

Load profiles for domestic households, Farming and other industrial/ processing plant are described in the following paragraphs.

Domestic Load Profiles

Standard household demand peaks in the morning (8:00am) and evening (6:30pm). The average energy consumption by residential customers is typically flat with relative small variation annually. The main contributing factor to the change in the annual average consumption per residential customer is seasonal changes, resulting on consumption variations due to consumer behaviour. 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 41 and Figure 42 respectively.

Figure 41: Typical Domestic Feeder Daily Load Profile (July, Waikiwi CB3)

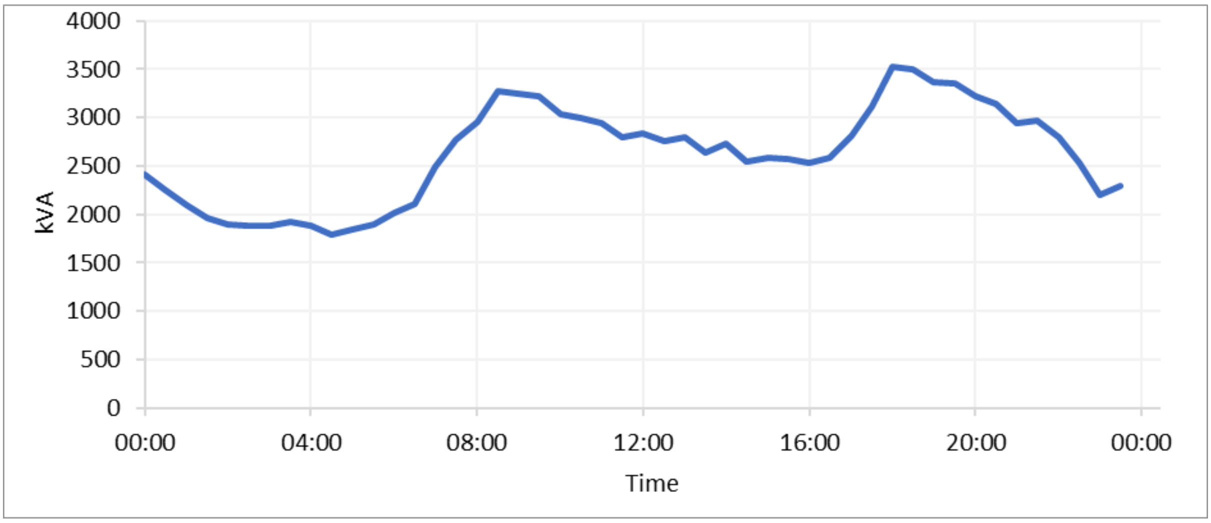
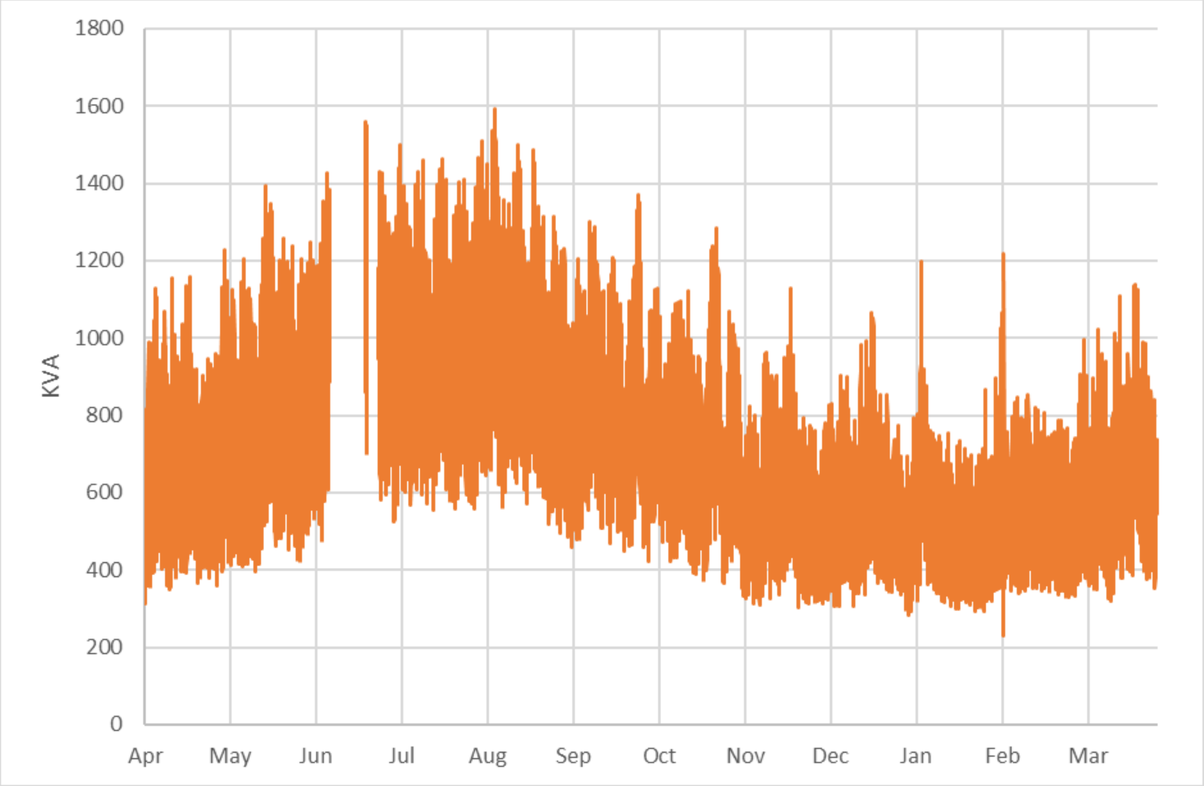


Figure 42: Typical Domestic Feeder Yearly Load Profile (North Gore CB4)



Farming Load Profiles

In Southland the predominant farming load is dairy farming with the milking season between August and May with morning and late afternoon peaks. The remaining farms normally have very low usage by pumps and electric fences, with peak usage during the few days of shearing or crop harvesting. Typical profiles are shown in Figure 43 and Figure 44.

Figure 43: Typical Farming Feeder Daily Load Profile (October, Centre Bush CB2)

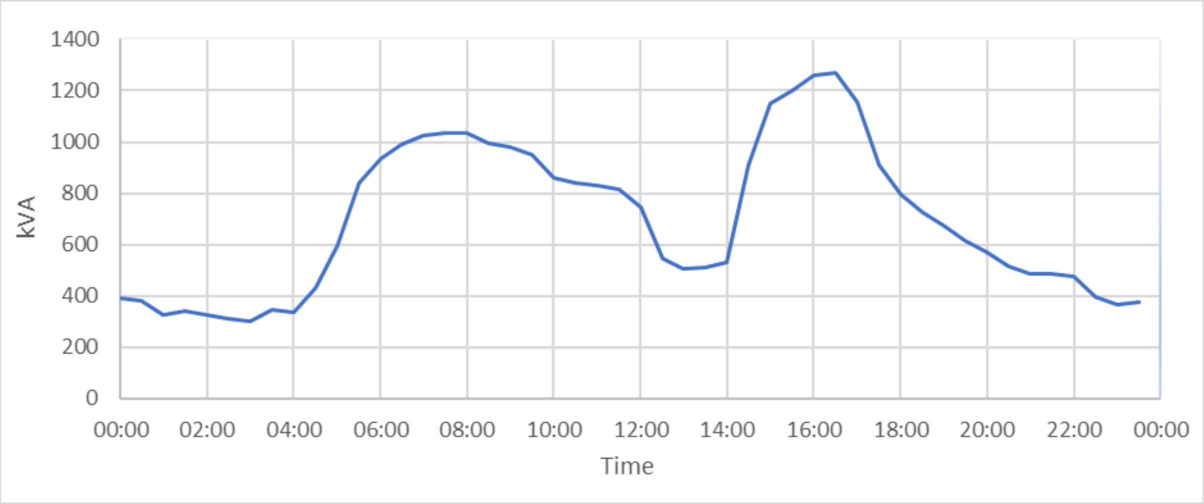
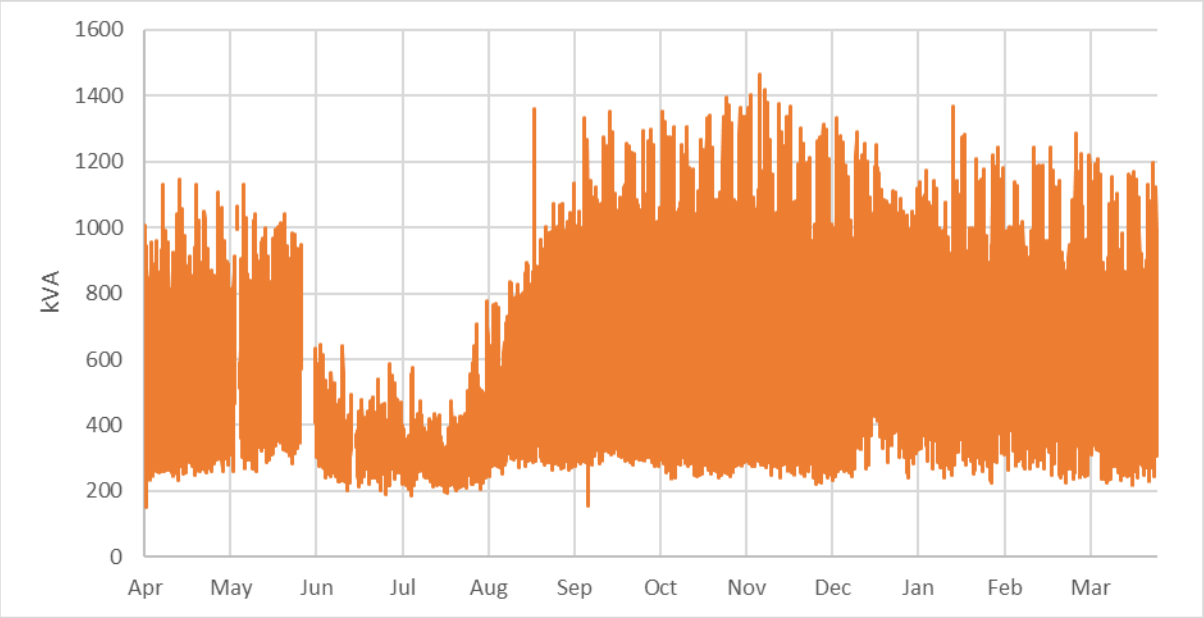


Figure 44: Typical Farming Feeder Yearly Load Profile (Centre Bush CB2)

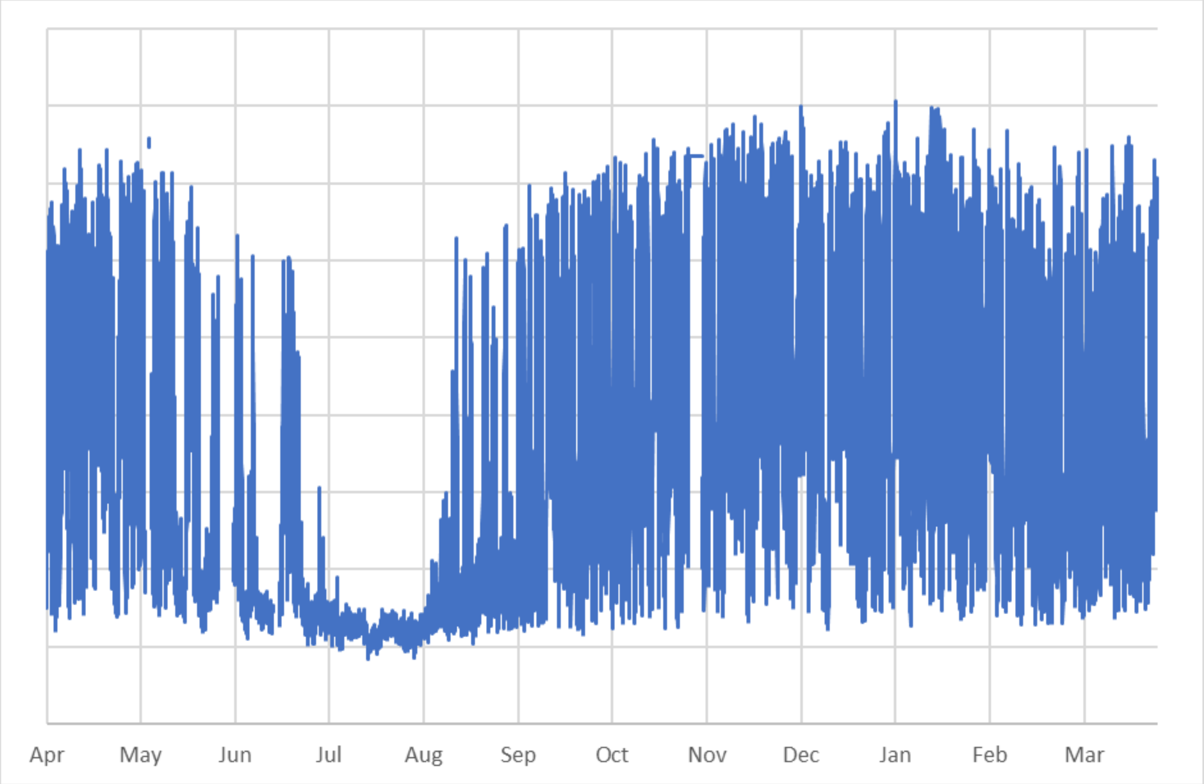


Industrial and Dairy Processing Load Profiles

Sawmills: Usage at sawmills is due to processing and kiln drying of the product. There is also some wood chipping of logs for export, and these have some very large motors with poor starting characteristics.

Dairy Processing: Load characteristic is dependent on milk production with the 'flush' occurring in late October. One plant has 4 MVA of cogeneration, which can create peaks if it is off. A typical annual dairy processing plant profile is shown in Figure 45.

Figure 45: Typical Dairy Processing Plant Yearly Load Profile



Energy and Demand Characteristics

Key energy and demand values for the year ending 31 March 2022 are presented in Table 21.

Table 21: Energy and Demand Values

Parameter	Value	Long-term trend
Energy Conveyed	836 GWh	Steady Growth +0.5 - 1.5%
Maximum Demand[9]	160 MW	Steady
Load Factor	60%	Steady
Losses	5.0%	Steady

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

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

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 Key energy and demand values for the year ending 31 March 2022 are presented in Table 21.

4 Risk Management

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

2024-25 changes in risk profile

TPCL is exposed to a wide range of risks and utilises risk management techniques to keep risk within acceptable levels. This section describes the changes in the risk profile between 2023 and 2024.

4.1 Risk Management Methods

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.

4.2 Company related risks (general)

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

War in the Ukraine?

Although the wars in the Ukraine are not directly affecting TPCL, 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.

4.3 Asset Management Risks – 2024/2034 AMP Update

Reliability and 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 network 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 Network 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 network'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 network'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 networks 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 network 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, network 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 network management more complex. Climate change can exacerbate this intermittency, affecting the consistency of renewable energy generation. This requires better network infrastructure and energy storage systems to manage the fluctuations effectively.

Mitigation and Adaptation Strategies

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

- Infrastructure Resilience: Reinforcing and upgrading existing infrastructure to withstand extreme weather events.
- Improved Monitoring and Analytics: Investing in advanced monitoring and data analytics to predict and respond to weather-related disruptions and optimize network operations. To this effect the deployment of an OMS/ADMS system is under investigation.
- Renewable Energy Integration: Expanding and modernizing the electricity distribution networks to accommodate the growing role of renewable energy sources, including smart networks and energy storage systems.
- 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.
- Public Awareness: Raising awareness among customers about the importance of energy conservation and network reliability and encouraging energy-efficient practices.

In Southland, 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 Southland 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 Southland, 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.

Southland does not experience significant seasonal variation in the frequency of wet days. The month with the most days of rain alone in Southland is May. Rain falls throughout the year in Southland. The month with the least rain in Southland is August. The length of the day in Southland 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 Southland experiences mild seasonal variation over the course of the year. Southland experiences an average of 109 days per year with wind gusts exceeding 61 km/hr. The windiest month of the year in Southland is October, with an average hourly wind speed of 21.0 kilometres per hour. The calmest month of the year in Southland 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.

~~TPCL is exposed to a wide range of risks and utilises risk management techniques to keep risk within acceptable levels. This section examines TPCL'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.~~

4.4 Risk Strategy and Policy

"Understand and Effectively Manage Appreciable Business Risk" is a key corporate strategy and critical business task within TPCL. As such, TPCL'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 TPCL's business faces. The policy was approved by the PowerNet and TPCL 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.

4.5 Risk Management Methods

PowerNet's risk management methods are used to manage TPCL's risk to acceptable levels. Decision making related to TPCL'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.

PowerNet has developed and operates a Business Continuity Plan that gets activated in the event of a significant risk materialising. A number of the Senior Leadership Team has been trained to manage the Business Continuity Team should any such events occur. The Business Continuity Plan is tested on a regular basis using real life scenarios to ensure that it functions effectively. This plan will be activated should a High Impact, Low Probability event occur.

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 TPCL 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 be encountered.

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 22: 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 23: 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

	Consequence				
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
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
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 24: 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 25 indicates how these factors can be combined to present a relative risk level.

Table 25: 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 26: Management attention to risk rankings

Low	**Medium**	**High**	**Critical**
Risk managed through routine	Risk to be reported to relevant manager, may	Risk to be reported to chief executive and senior	Risk to be reported to the board to approve and

management/internal control procedures	require additional risk treatment actions	leadership team to approve and monitor risk treatment actions	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 27 summarises the types of treatment options that are considered for any risk. These options are ordered by effectiveness for the control of risk.

Table 27: 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.
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.

4.6 Company related risks (general)

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

COVID pandemic - Loss of key service providers; business operations disrupted

This risk manifested during 2020 when the COVID-19 virus caused a worldwide pandemic. The probability of this risk occurring was deemed "*Rare*", but it happened. The risk is now a "*Critical*" risk. Although the direct impact of Covid seems to have been reduced, we are still experiencing significant staff absences due to the virus and supply chains are still under pressure. However, in line with Central Government guidelines, Electricity Distribution is an essential service and work needs to continue. The following treatment responses are in place.

- Adhere to government guidelines.
- Work to the PowerNet pandemic plan. This includes measures such as working from home, only critical faults and critical maintenance work and providing emergency kits for offices when the circumstances dictate increased response.
- Supply chain management.
    - Assist in identifying critical suppliers and manufacturers so that the manufacture of critical equipment such as poles can continue.
    - Ensure sufficient stock levels of critical items and consumables, still including safety equipment such as masks disposable gloves and rapid antigen tests.
    - Identify key contractors and negotiate availability agreements.
    - Pre-ordering of equipment well in advance of when it may be utilised.
    - Identify alternative suppliers and equipment and put the equipment through the approval process.
- Contact tracing.

The mitigation measures mostly worked, apart from completing some major projects and some maintenance work. Major projects were delayed by the difficulties in getting imported equipment into New Zealand. Non-critical but nevertheless essential maintenance were postponed, but the resultant backlog has now mostly been cleared. These measures impact on the short-term profitability and cash flow of the company.

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 TPCL's asset manager.
- Regulatory – failure to meet regulatory requirements.

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 TPCL 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

Equipment prices are still rising at higher than CPI, driven by supply and demand market forces as discussed under the labour market. Manufacturers are also operating in an environment where covid 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 TPCL, 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.

Table 28: 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.

4.7 Asset Management Risks

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

Table 29: 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	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	Treat	Implement AMMAT improvements towards ISO 55001 certification; Ensure SiD process is followed; competency framework and resourcing; robust fleet plans; commissioning process; incident

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
		constraints; incorrect disposal of assets.	loads; environmental issues		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
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 access issues;	Treat	Completion of seismic strengthening; Design of networks to avoid

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
	Christchurch earthquake)	equipment (e.g., floods, earthquakes)	safety compromised; SAIDI/SAIFI impact; loss of assets		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: *(currently reviewing situation 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	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

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
			and/or reputational damage		
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 covid or other factors	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)
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 consumers; Loss of ability to provide power to customers for extended periods; safety compromised	Treat	Develop improved contingency plans for network events

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
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
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 30.

- **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 30: 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 [10]and IR[11]. • Replacement at end of life and continue to provide sectionalised boards. • Able to reconfigure network to bypass each switchboard.
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.

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[10] PD = Partial Discharge, indication of discharges occurring within insulation.

[11] IR = Infrared, detection of heat of equipment that highlights hot spots.

Event	Likelihood	Consequence	Responses
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 31: 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. • 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 32.

- **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 32: 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 • 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 2019
Arc Flash	Very Unlikely	High	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations • De-energise installation before switching where PPE inadequate
Underground	Unlikely	High	• De-energise substation before manual switching within substation
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 33: 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.

Other Potential Environmental Risks

- Oil spills from transformers or oil circuit breakers
- Release of SF6 into the atmosphere

Table 34: 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

Event	Likelihood	Consequence	Responses
			• 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 35.

- **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 35: 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.
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.

Climate Change

To try and understand how the global climate change affects the network supply area specifically, hourly weather data for Southland and Otago was analysed to determine if there were any visible trends. The following graphs show some of the findings.

The graphs are interpreted as follows:

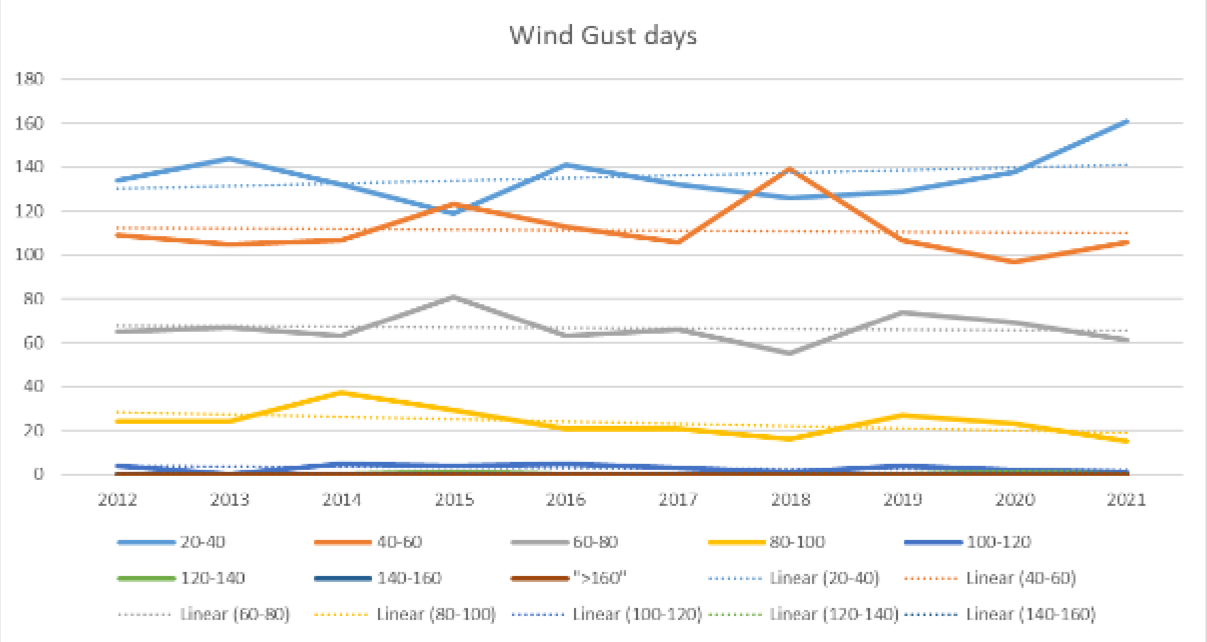
- The horizontal axis show the year
- The vertical axis indicates the number of days where the measurand was within a specific range
- The legend shows the ranges

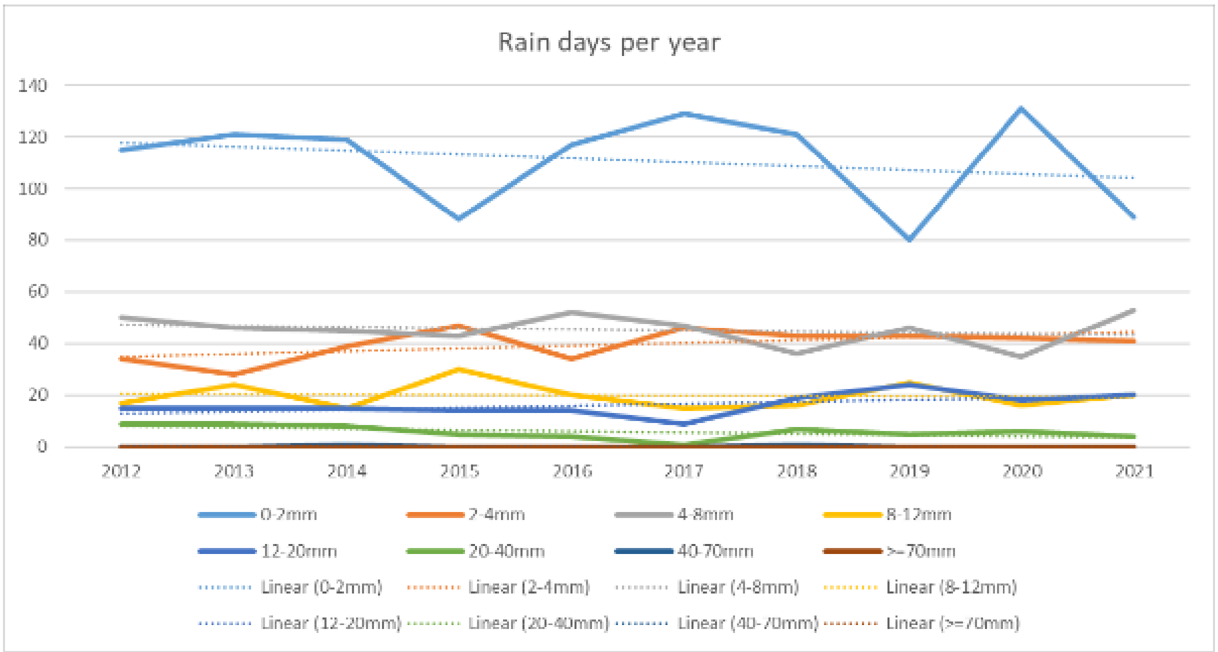
- The solid line shows actual measurements
- The dotted line shows the trendline

As an example – the Wind Gust Days graph for Invercargill shows that in 2021 there was 160 days where the maximum wind gust was between 20 and 40 km/h, 105 days where the maximum wind gust for the day was between 40 and 60 km/h etc. The Rain Days Per Year and Average Wind Speed graphs are interpreted in a similar way.

Graphs were developed for selected areas of supply to see if different locations show different trends.

Invercargill




Rain days per year
140
120
100
80
60
40
20
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2012
2013
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2-4mm
4-8mm
8-12mm
12-20mm
20-40mm
40-70mm
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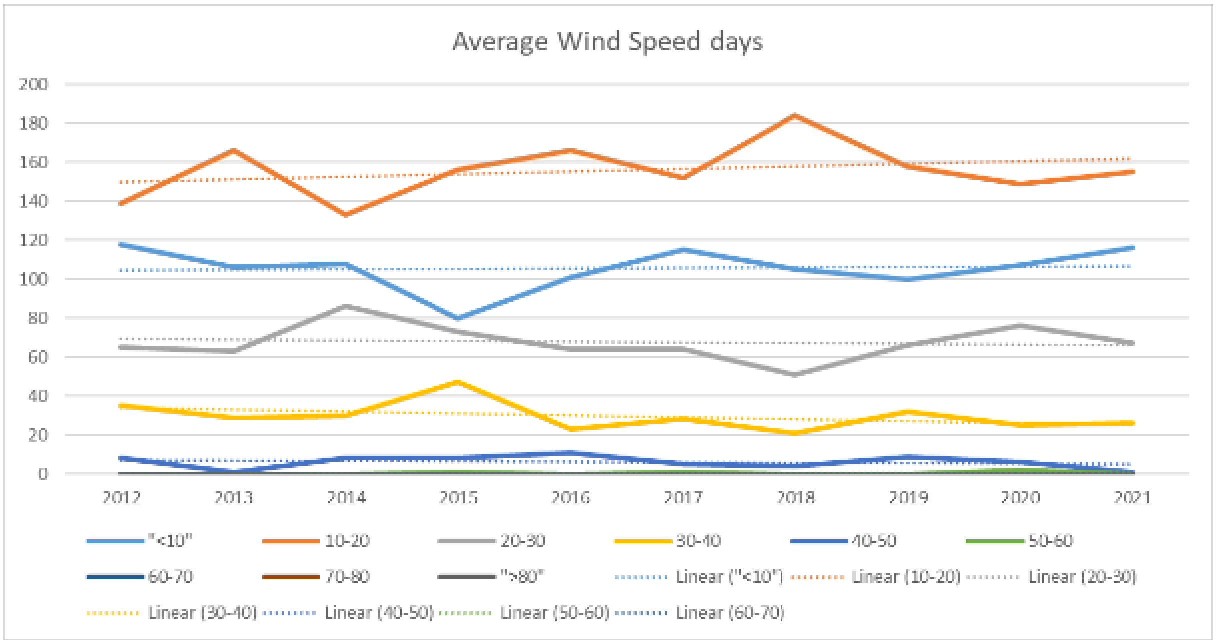
Average Wind Speed days
200
180
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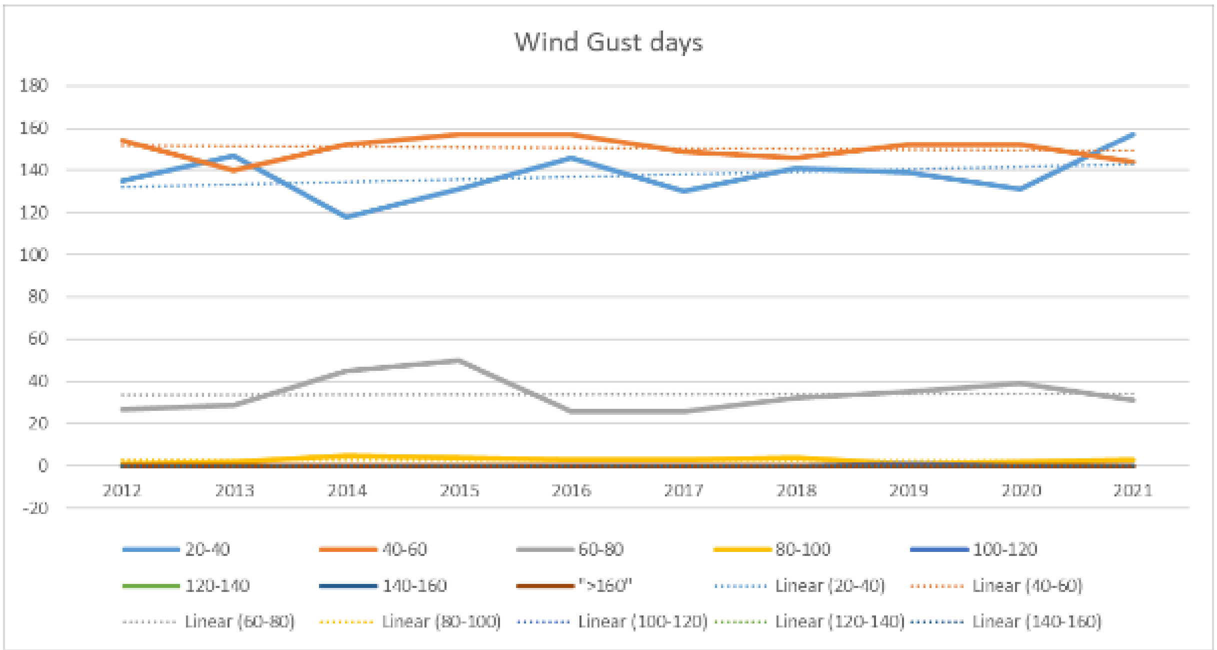
Queenstown


Wind Gust days
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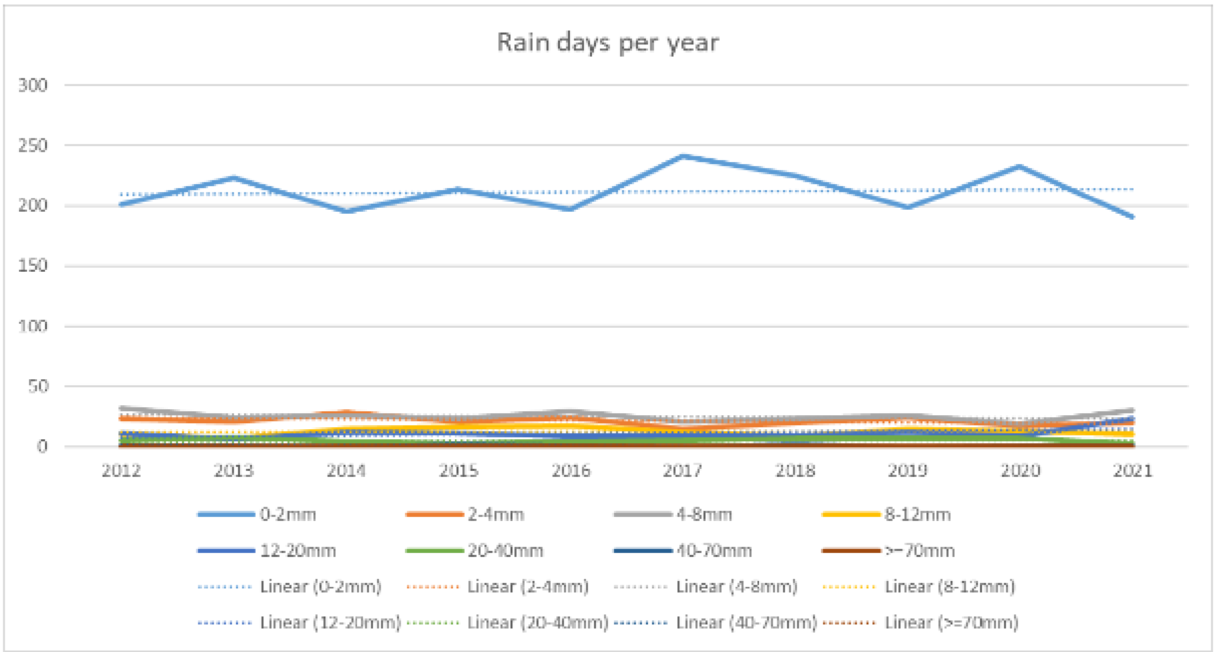
Rain days per year
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8-12mm
12-20mm
20-40mm
40-70mm
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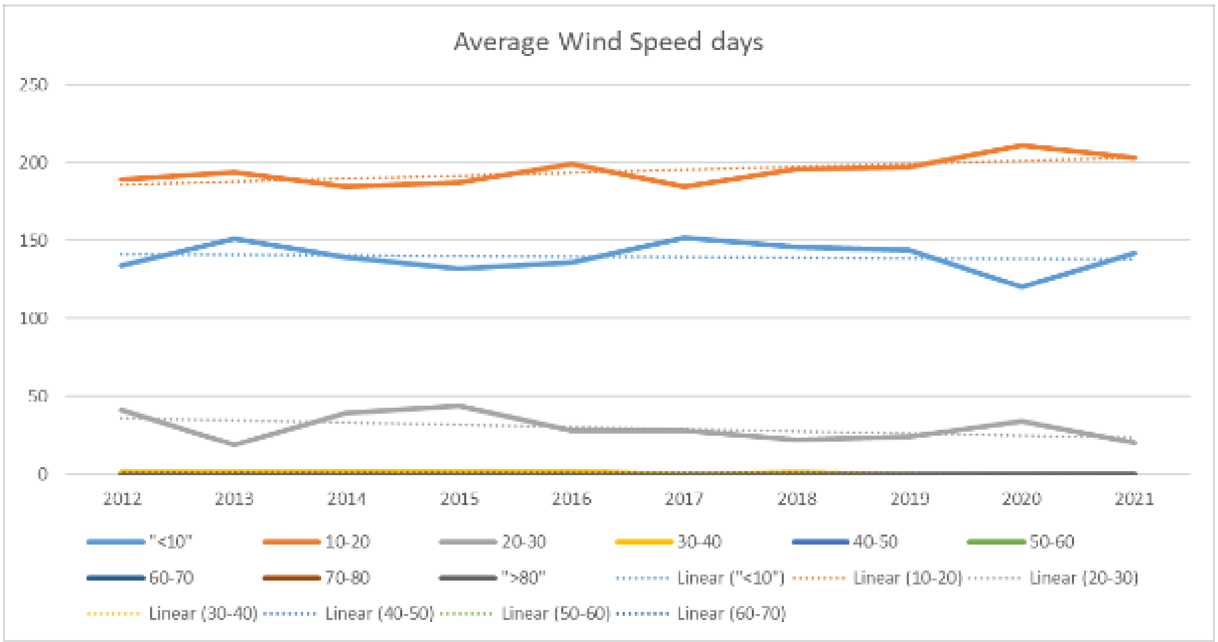
Average Wind Speed days
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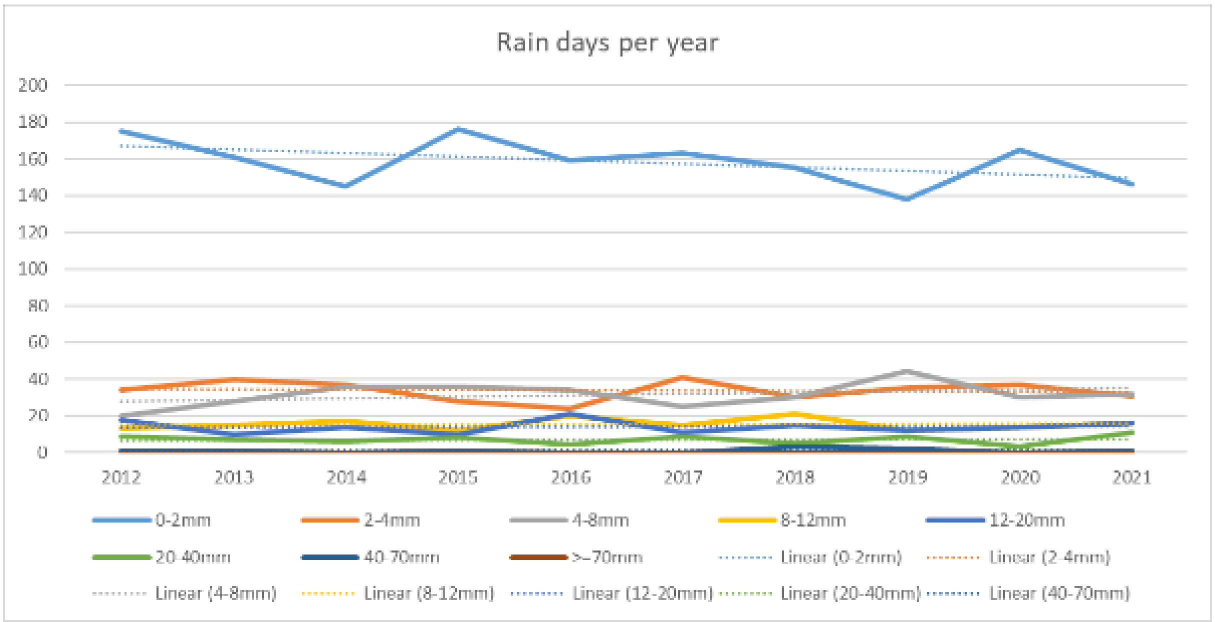
Balclutha


Rain days per year
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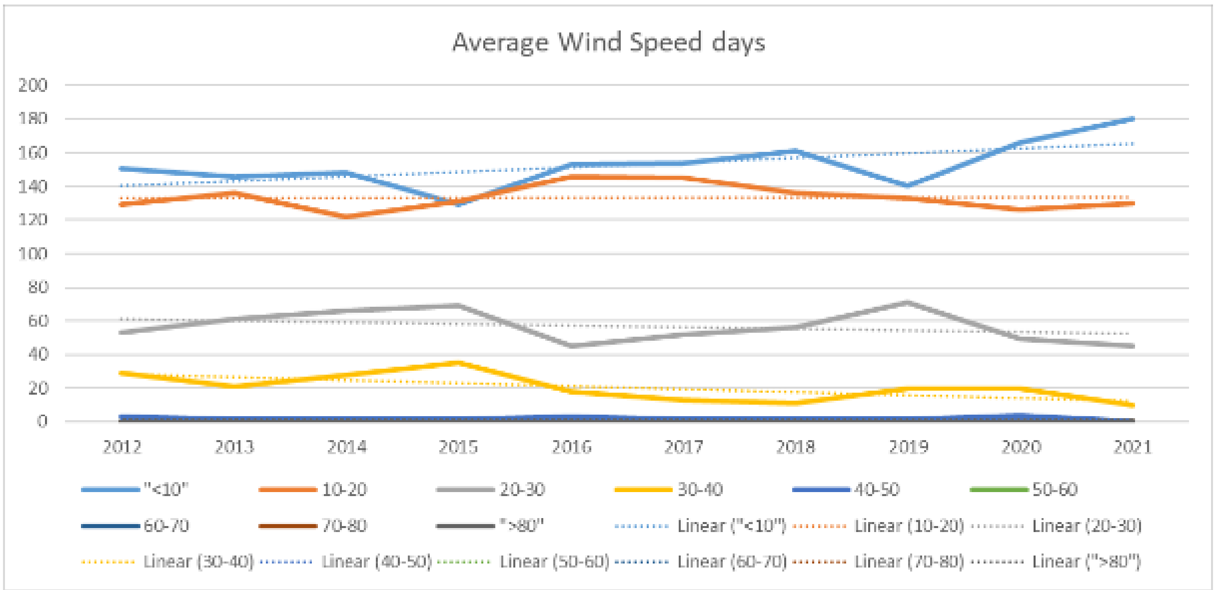
Average Wind Speed days
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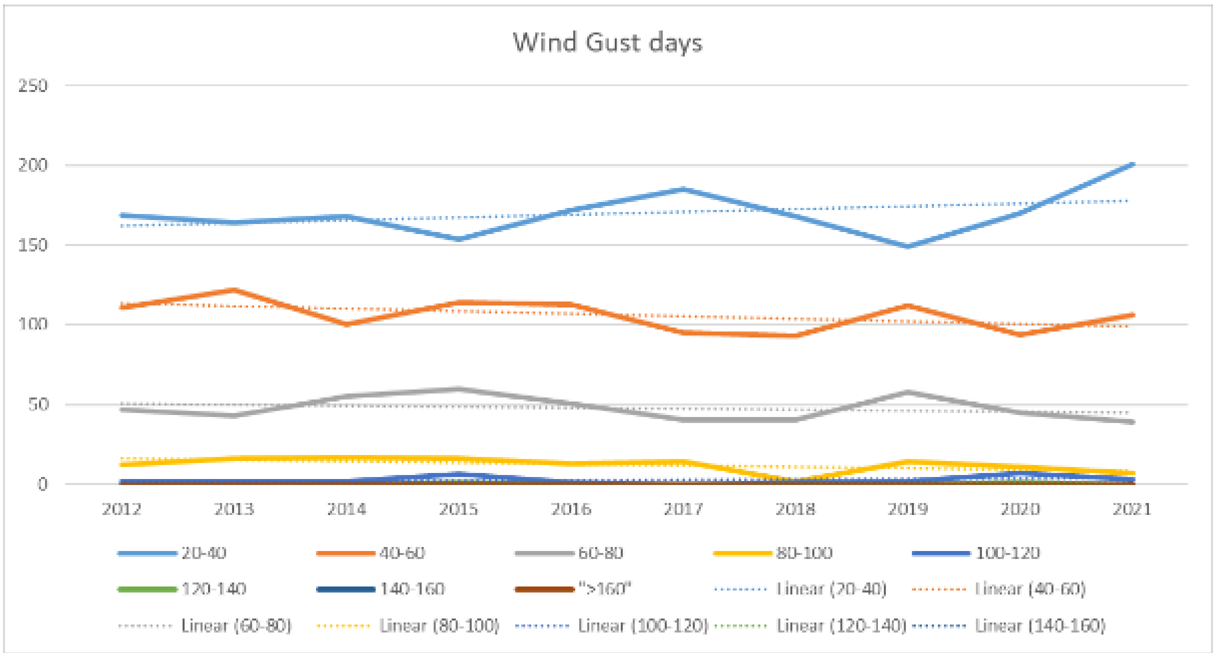
Linear (">80")

Gore


Wind Gust days
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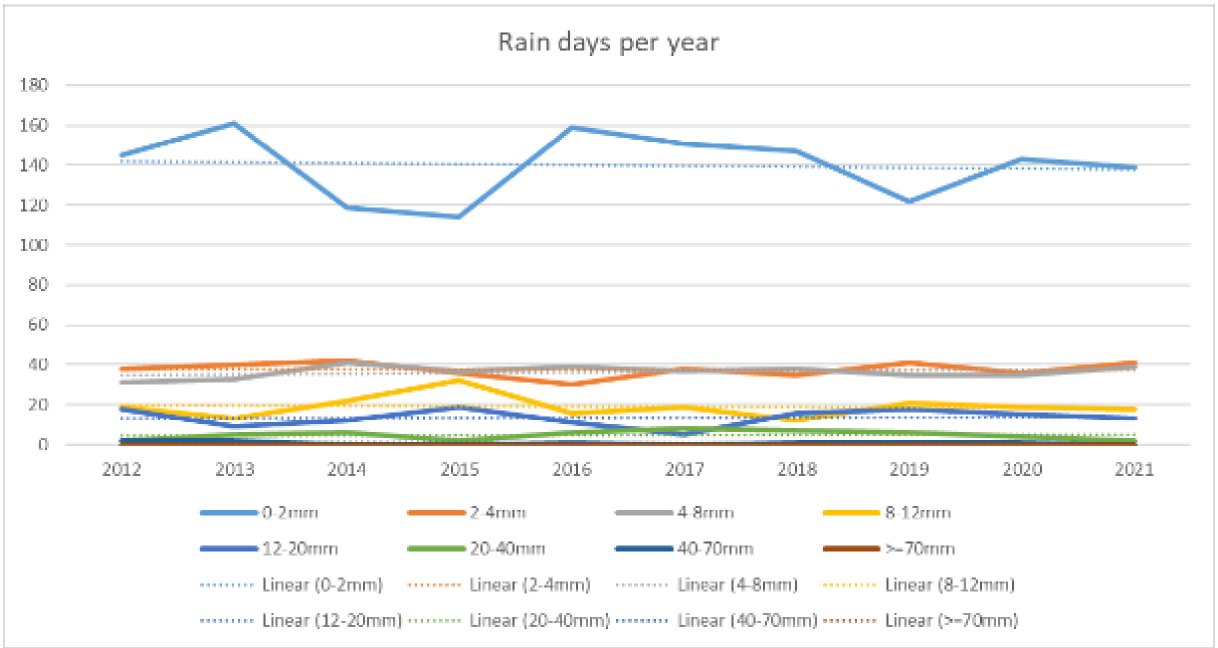
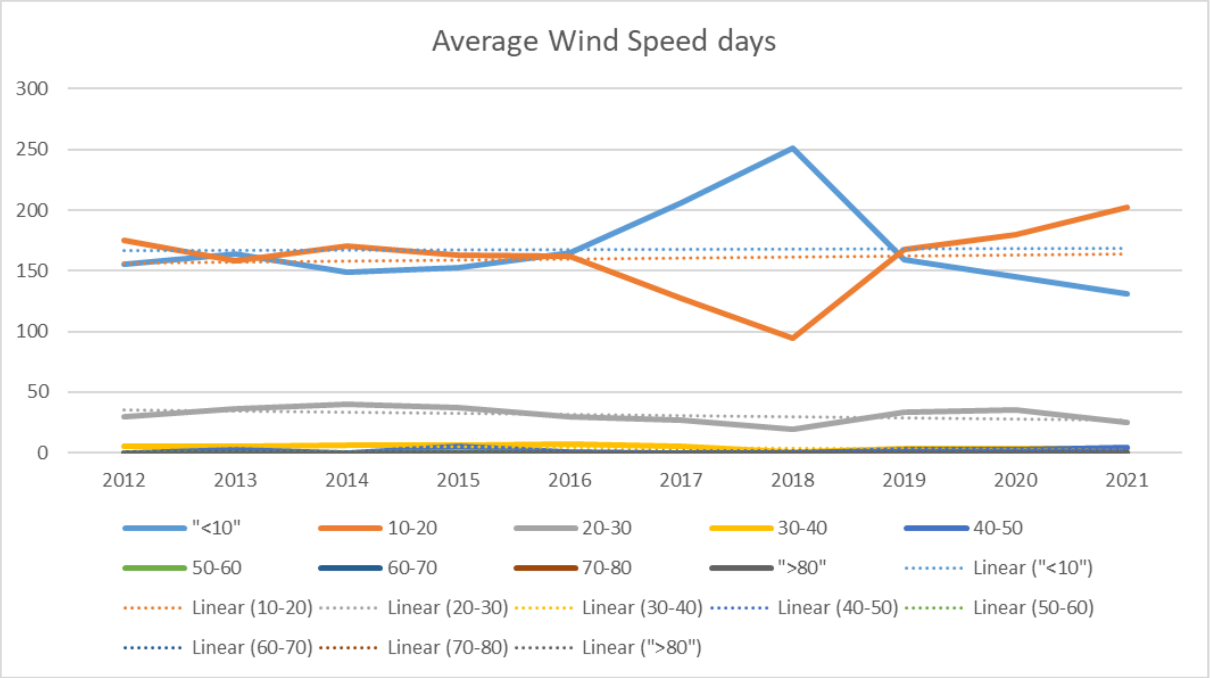
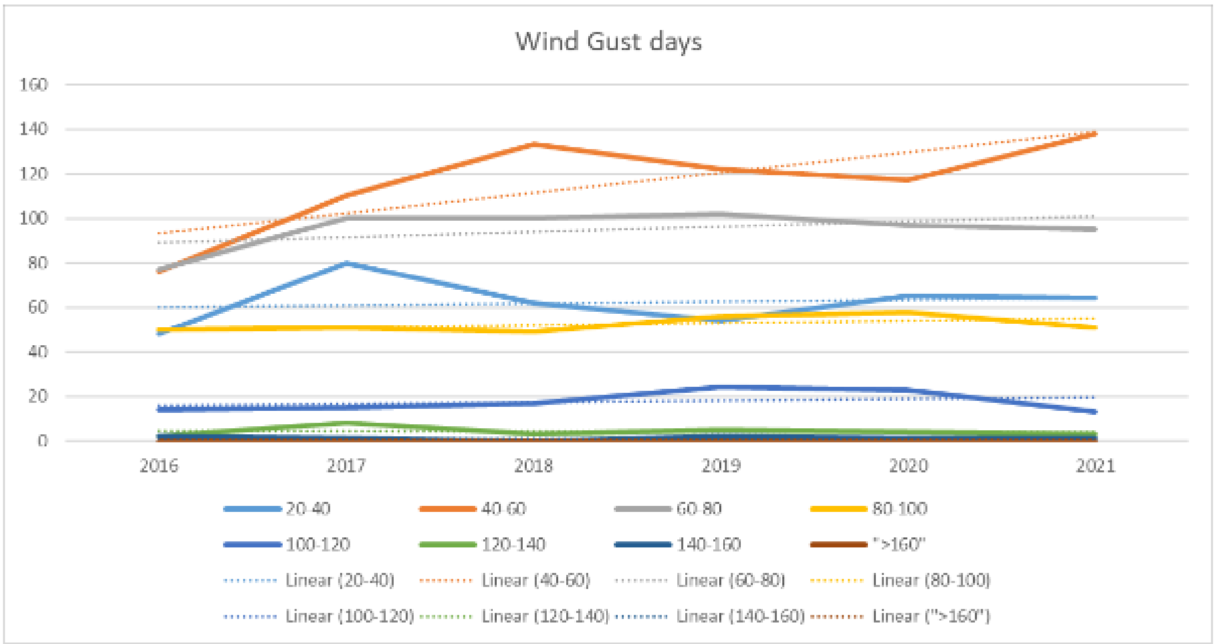
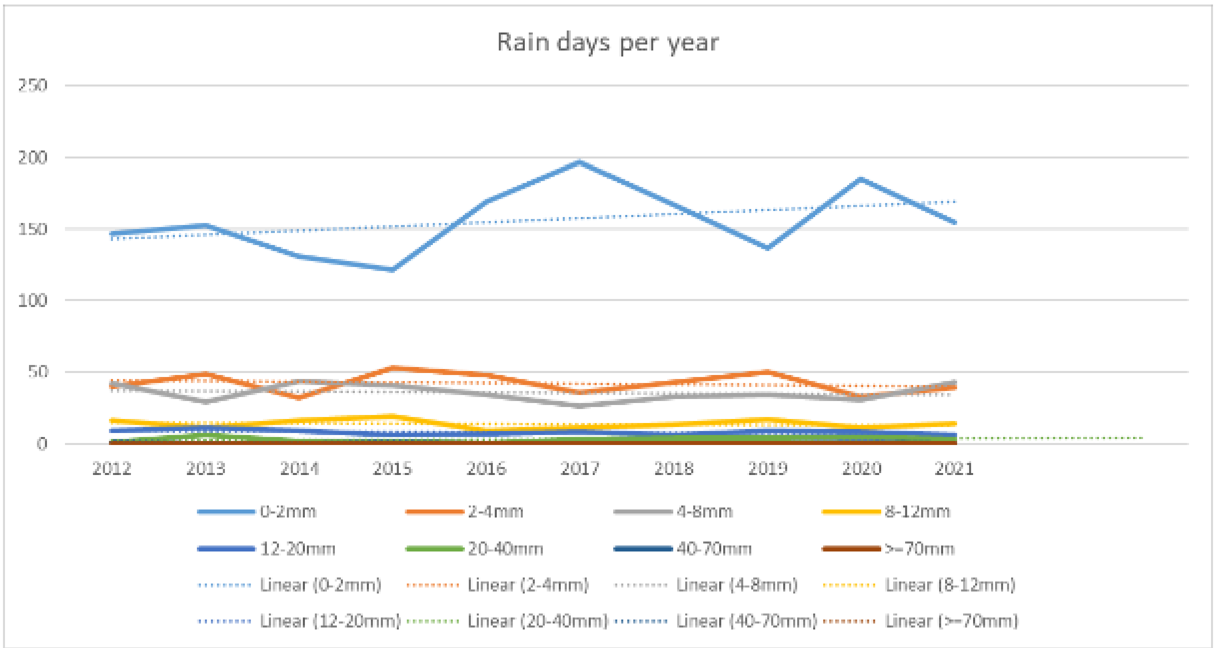
Linear (120-140)
Linear (140-160)

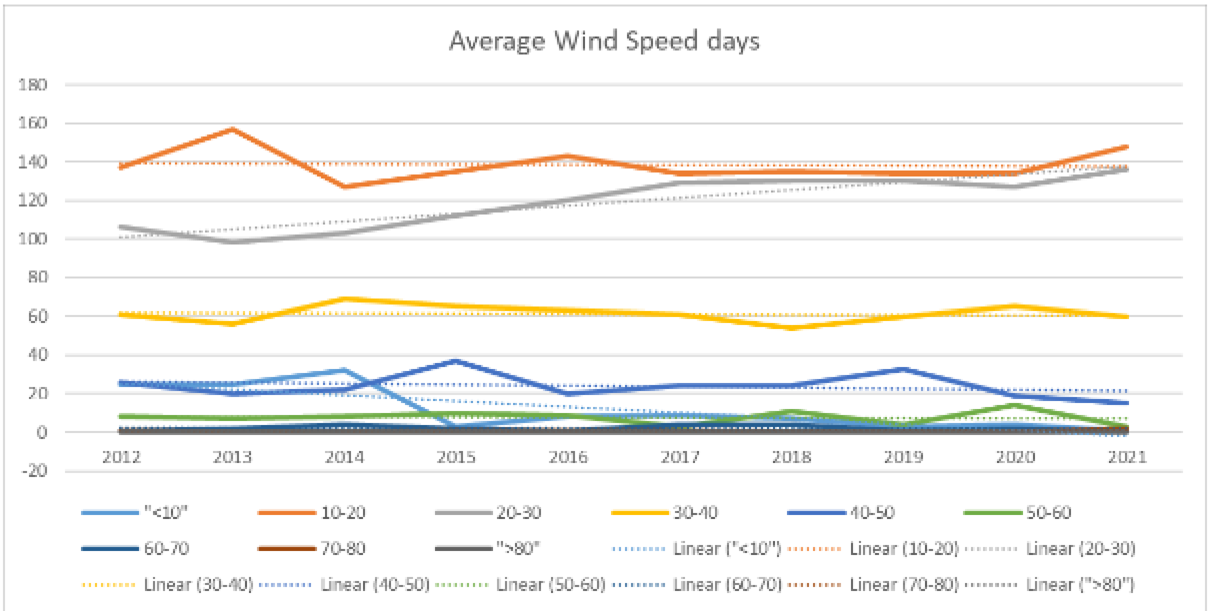

Rain days per year
180
160
140
120
100
80
60
40
20
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
0-2mm
2-4mm
4-8mm
8-12mm
12-20mm
20-40mm
40-70mm
>-70mm
Linear (0-2mm)
Linear (2-4mm)
Linear (4-8mm)
Linear (8-12mm)
Linear (12-20mm)
Linear (20-40mm)
Linear (40-70mm)
Linear (>-70mm)


Average Wind Speed days
300
250
200
150
100
50
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
"<10"
10-20
20-30
30-40
40-50
50-60
60-70
70-80
">80"
Linear ("<10")
Linear (10-20)
Linear (20-30)
Linear (30-40)
Linear (40-50)
Linear (50-60)
Linear (60-70)
Linear (70-80)
Linear (">80")

Nugget Point







The graphs and trendlines indicate that for the Southland and Otago regions the weather has seemingly moderated over the last 10 years. There are fewer days with high wind, fewer rainy days and generally less rain and less extreme event days.

The general trend across all the analysed weather stations indicates that for the southern part of the South Island the number of moderate days per year is increasing and the number of extreme days per year is decreasing. The area of general concern is the indication of decreasing rainfall which may in the long term affect generation capacity. However, from a network and asset perspective it shows that there is no immediate need to review design parameters to cater for more extreme events.

Network planning still takes areas of potential flooding as well as possible long term sea level rises into effect. These higher risk areas are indicated on the GIS system and are avoided as far as possible. However, as long as developments are allowed in these areas there will always be some assets at risk.

4.8 System Risks

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

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 RMUs affected by severe rust.

After learning that 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 in the TPCL network have had their bus coupling boxes converted to the Guroflex insulating filling compound that succeeded the original HVBT bus coupling kit.

Porcelain Insulators Crack on ABS

The grey porcelain insulators on EDE Air Break Switches manufactured between 1998 and 2014 have a potential defect which can result in water ingress. Over time this can cause the insulator to crack and break into pieces which can fall when the switch is operated. An appropriate remedial action program has been initiated from 2019/20 to mitigate, repair, or replace the affected ABS's.

Other Systemic Issues

Some of these examples represent learnings from issues found on other networks managed by PowerNet but which are common to TPCL network.

- Kidney strain insulators: Replaced with new polymer strains.
- DIN LV fuses: Sourced units that can be used outdoor.
- Parallel-groove clamps: Replaced with compression joints.
- Non-UV stabilised insulation: Exposed LV now has sleeve cover, with new cables UV stabilised.
- Opossum faults: Extended opossum guard length.

4.9 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 TPCL. 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.

5 Service Levels

2024-25: There are no change to Service Levels

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

This section describes how TPCL 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 TPCL 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 TPCL'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.

5.1 Customer Oriented Service Levels

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

Customer Surveys

Customer engagement surveys are annually completed to 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 TPCL customers and collates the results into a customer satisfaction report for presentation. Research First were also engaged to conduct interviews with major customers to help understand service level requirements and satisfaction with current service levels.

TPCL 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, TPCL have received approximately 24 formal justified complaints, with 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 service levels and rated high in PowerNet's performance, such as caring for customers, being safety conscious and efficient in service response. However, targeted improvement initiatives could address some expressed dissatisfaction. Telephonic surveys indicate that customers value accurate time power will be restored and know the problem, and that is being fixed higher than other attributes.

Service levels most valued by customers strongly depend on network assets to be addressed. These require capital expenditure solutions (as opposed to process solutions) and have the following challenges.

- Limited substitutability between service levels – for example, customers prefer TPCL 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 - customers who choose not to pay for improved service levels would still receive 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.

Primary Customer Service Levels

As described in the previous section, customers value continuity and restoration most, therefore, these are TPCL's primary service levels. TPCL 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 align with the Commerce Commission's use of SAIFI and SAIDI (and determines their calculation methodology) in their regulation of local Electricity Distribution Business (EDBs). TPCL's projections for these measures over the next ten-year period ending 31 March 2033 are shown in Table 36. These projections take into account the recently updated default price quality path calculation methodology including new (lower) extreme event normalising boundaries and a 50% weighting for planned outages. TPCL's reliability targets are set equivalent to these projections.

These projections are an average only, given the volatility in reliability statistics due to their dependence on extreme weather events. TPCL's medium-term aim is to reduce this average. It is worth noting the replacement of approximately 10% of Air Break Switches with automated enclosed switches over the next 10 year period are expected to result in improved reliability towards unplanned outages and these projects are taken into account in these forecasts.

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 36: Reliability Projections

Measure	Class	2022/23	2023/24	2024/25	2029/30	2030/31	2031/32
SAIDI	B (Planned)	157.0	144.0	144.0	144.0	144.0	144.0

Measure	Class	2022/23	2023/24	2024/25	2029/30	2030/31	2031/32
	C (Unplanned)	200.0	190.0	188.1	186.2	184.4	182.5
	Total	**557.0**	**334.0**	**332.1**	**330.2**	**328.4**	**326.5**
SAIFI	B (Planned)	0.65	0.60	0.60	0.60	0.60	0.60
	C (Unplanned)	2.92	2.90	2.87	2.84	2.81	2.79
	Total	**4.16**	**3.50**	**3.47**	**3.44**	**3.41**	**3.39**

Table 37: Reliability History

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	B (Planned)	95.5	96.3	118.7	125.0	143.31	192.1
	C (Unplanned)	91.6	171.6	158.8	270.9	170.73	174.8
	Total	**187.0**	**267.9**	**277.5**	**395.90**	**314.04**	**366.9**
SAIFI	B (Planned)	0.37	0.47	0.52	0.51	0.65	0.84
	C (Unplanned)	1.98	2.46	2.47	3.57	2.88	2.62
	Total	**2.35**	**2.93**	**2.99**	**4.08**	**3.53**	**3.46**

The frequency of faults and estimated restoration levels for significant network areas are summarised in Table 38.

Table 38: Expected fault frequency and restoration time

General location	Frequency of faults	Estimated restoration[12]
Parts of Invercargill not supplied by EIL	One outage per year	30 min
Large towns	Two outages per year	45 min
Small towns	Three outages per year	60 min
Village	Four outage per year	120 min
Anywhere else	Five outage per year	240 min

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

Due to global supply chain issues and constraints and with inflation in New Zealand over the last year at 6.9%, we have asked TPCL customer on willingness of paying extra in line charges to retain the same level of reliability of supply. It was found that TPCL customers were willing to increase on average 3.85% of their line charge fees to maintain the same reliability of power supply. Table 39 shows the theoretical thresholds which would apply to TPCL's reliability performance if it were regulated. The boundary values represent the threshold for normalising extreme events where if SAIDI or SAIFI in any day exceeds the respective boundary the contribution to the overall annual SAIDI or SAIFI is capped at that boundary value. The limit represents the upper limits of acceptable reliability for network performance after normalising out extreme events and must not be breached annually. Planned interruption compliance is assessed over the full 5-year DPP period. It is worth noting that whilst TPCL is not regulated, and none of these calculated values apply to TPCL, TPCL calculates its performance in alignment with these measures in order to allow for benchmarking against other EDBs.

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).

Table 39: Theoretical thresholds

	Target	Cap/Limit	Boundary
SAIDI Unplanned	128.66	156.53	9.403
SAIFI Unplanned	2.966	3.564	0.1581
SAIDI Planned	47.271	141.814	
SAIFI Planned	0.221	0.664	

Individual Customer Service Levels

Large individual customers may request different service levels for increased reliability with additional equipment and higher resulting charges or in some cases have requested lower cost options perhaps with single transformer and supply lines or special protection schemes where they are prepared to have a reduced level of supply during certain situations. These are individual contract arrangements with single customers that should not affect the overall service levels for other customers.

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 40 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.

Table 40: 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}	>50%	>50%	>50%
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}	>40%	>40%	>50%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<10	<10	<10
	Number of customers having justified supply quality complaints {IK}	<3	<3	<2

{} 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 41. Many of these service levels are imposed on TPCL by statute and while they are for the public good – i.e., necessary for the proper functioning of a safe and orderly community – TPCL absorbs the associated costs into its overall cost base.

Table 41: Other Service Levels

Service Level	Description
Safety	Various legal requirements require TPCL'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	TPCL 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 TPCL to compile and disclose prescribed information to specified standards.
Electrical Interference	Under certain operational conditions TPCL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or TPCL's own equipment. The following publications are used to prevent issues from interference: • Harmonic levels (NZECP 36:1993). • Single wire earth return limitations (EEA High Voltage SWER Systems Guide). • NZCCPTS: coordination of power and telecommunications (several guides).

5.2 Regulatory Service Levels

Various Acts and Regulations require TPCL 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 each year.
- Publicly disclose prescribed performance measures each year.

In addition to these requirements, TPCL 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 at 9 December 2021). Previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008. The complete listing of these measures is included in TPCL's disclosure of 31 March 2022 and available at:

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

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, therefor TPCL 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.

TPCL has six financial efficiency targets as shown in Table 42.

Table 42: Financial Efficiency Targets

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2023/24	$304	$1,294	$22,350	$206	$877	$15,140
2024/25	$304	$1,294	$22,335	$206	$877	$15,140
2025/26	$304	$1,294	$22,350	$206	$877	$15,140
2026/27	$304	$1,294	$22,335	$206	$877	$15,140
2027/28	$304	$1,294	$22,350	$206	$877	$15,140
2028/29	$304	$1,294	$22,335	$206	$877	$15,140
2029/30	$304	$1,294	$22,350	$206	$877	$15,140
2030/31	$304	$1,294	$22,335	$206	$877	$15,140
2031/32	$304	$1,294	$22,350	$206	$877	$15,140
2032/33	$304	$1,294	$22,335	$206	$877	$15,140

* Dollar values as constant 2023 dollars.

Energy Efficiency

Energy delivery efficiency measures are the following.

- **Load factor** – [kWh entering TPCL's network during the year] / [[max demand for the year] x [hours in the year]].
- **Loss ratio** – [kWh lost in TPCL's network during the year] / [kWh entering TPCL'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 43. 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 43: Energy Efficiency Targets

Measure	2023/24	2024/25	2025/26	…	2033/34
Load Factor	65%	65%	65%	…	65%
Loss Ratio	7.0%	7.0%	7.0%	…	7.0%
Capacity Utilisation	30%	30%	30%	…	31%

5.3 Service Level Justification

TPCL's service levels are justified as we have following conditions.

- 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 five 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 service level called "Safety" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- TPCL'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 44. Customer satisfaction outcomes from past surveys are presented in Table 45.

Table 44: Reliability and Energy Efficiency History

Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	187.0	267.9	277.5	395.9	314.0	366.9
SAIFI	2.35	2.93	2.99	7.08	3.53	3.46
Load Factor	64%	61%	62%	61%	59%	60%
Loss Ratio	6.%	6%	5.5%	5.8%	5.0%	5.0%
Capacity Utilisation	28.6%	27.7%	29.4%	29.2%	31.7%	30.9%
Network OPEX / ICP	275	277	298	317	275	270
Network OPEX / km	1,097	1,120	1,211	1,300	1,137	1,126
Network OPEX / MVA	22,846	21,392	24,009	25,193	21,739	21,213
Non-Network OPEX / ICP	139	140	152	160	183	176
Non-Network OPEX / km	557	567	619	655	755	733
Non-Network OPEX / MVA	11,588	10,834	12,278	12,697	14,437	13,808

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.

Table 45: Customer Satisfaction History

Attribute	Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Planned Outages	Provided sufficient information {CES}	95%	95%	99%	99%	-	95%
	Satisfaction regarding amount of notice {CES}	94%	98%	99%	98%	-	97%
	Acceptance of one planned outage every two years {CES}	97%	-	-	-	-	98%

Attribute	Measure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
	Acceptance of planned outages lasting two hours on average {CES}	95%	91%	89%	-	-	90%
	Acceptance of one planned outage every two years lasting four hours on average {CES}***	-	80%	91%	64%	-	89%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time {CES}*	79%	-	-	-	-	78%
	No impact or minor impact of last unplanned outage {CES}***	-	66%	72%	74%	-	46%
	Information supplied was satisfactory {CES}*	80	79	86	78%	-	55%
	PowerNet first choice to contact for faults {CES}**	50	33	6	17	-	17%
Supply Complaints	Number of customers who have made supply quality complaints {IK}	5	7	3	8	15	20
	Number of customers having justified supply quality complaints {IK}	2	2	0	2	10	14

{} 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 smal. This can lead to substantial year-to-year fluctuations.

**Noting that each year a substantial proportion of responses (72% in 2017/18) 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 TPCL offers. Comparisons with Alpine Energy, Electricity Ashburton, Marlborough Lines, OtagoNet, and The Lines Company, are useful as these networks are like TPCL in terms of density and asset base. Several indicators are benchmarked against other EDB's performance in Chapter 10.

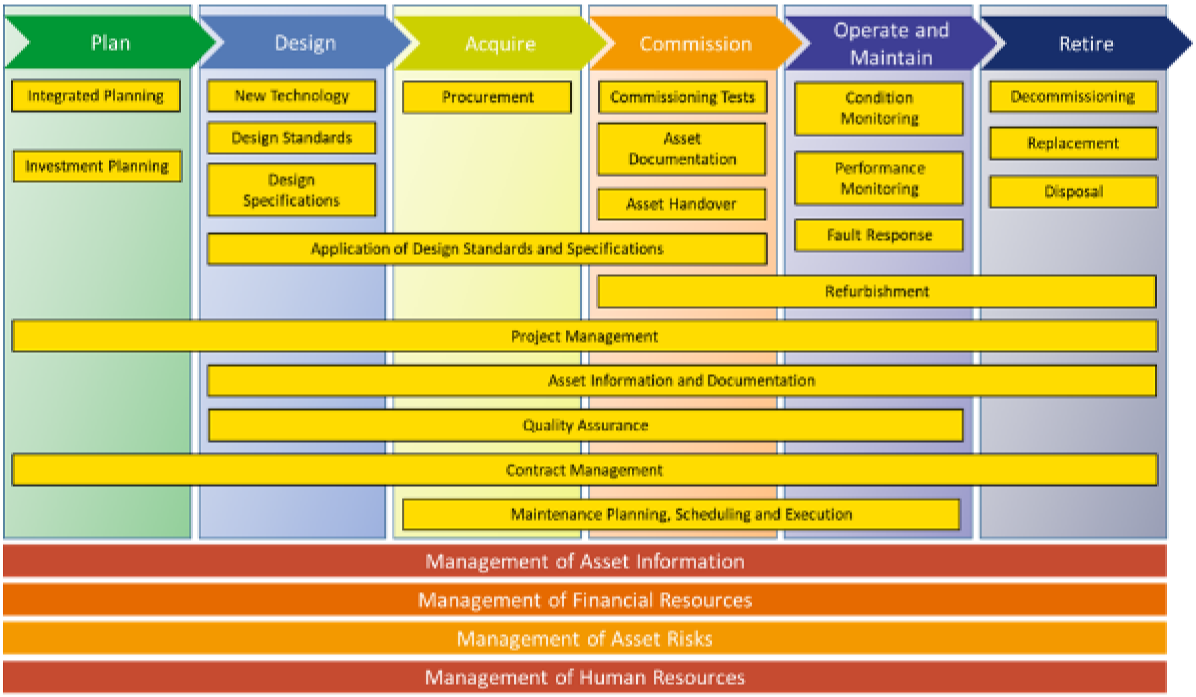
6 Asset Management Strategy

2024-34 AMP Update: TPCL (through PowerNet) has been JASANZ certified as being compliant with the ISO 5001 – Asset Management Systems – standard.

TPCL'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 46 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 46: Lifecycle Model for Asset Management



6.1 Lifecycle Stages

The asset lifecycle stages are described in the following sections.

Planning

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 TPCL'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. TPCL'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.

Acquisitioning

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.

Commissioning

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 TPCL'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 TPCL'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.

TPCL'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.

PowerNet is experiencing shortages in critical skills. 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 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 Growth

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.

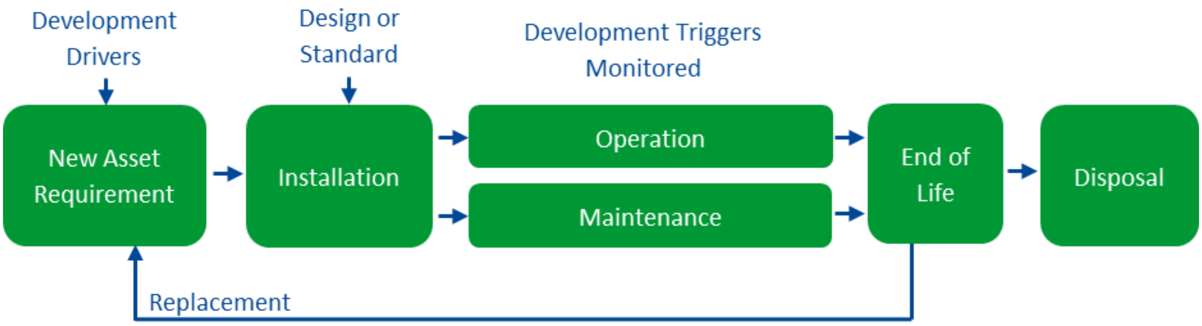
6.4 Lifecycle Management Processes

TPCL 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 47.

Figure 47: 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, TPCL 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

2024-2034 AMP Update:

The proposed Capital Expenditure (CAPEX) is higher than forecast in previous plans due to ongoing requirements 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.

7.1 Asset and Network Load Growth Planning – 2024/2034 AMP Update

Development Programme

Development projects underway or planned for the next 12 months, the following four years and those that are considered for the remaining of the planning period are largely unchanged from the 2023-33 AMP except contents presented in the following tables.

Table 46: Non-routine Development Projects (next 12 months)

Project Description	24/25 CAPEX Cost
Major Customer Connection Projects: TPCL is currently working with three major customers to increase capacity for electrode boilers at two dairy factory and a meat processing plant. The project timing is driven by the customer, The project at Open Country Dairy is due for completion in FY25/26, the “Edendale Process Heat Electrification” and “Underwood substation upgrade for Alliance” is due for completion in FY24/25.	$18,649,297 (Before 50% customer contribution)
System Growth Projects: TPCL is experiencing significant development in the Awarua and Makarewa region resulted in network constraints. A multiyear program has been developed to provide a new 66kV supply to Awarua region and transferring some of the load from the Makarewa region from North Makarewa GXP to the Invercargill GXP via the new 66 kV connection, triggered by the development in the Awarua region. This work would relieve the capacity constraint on the North Makarewa region, improve resilience to western Southland and defer major investments such as the GXP upgrade.	$316,938

Table 47: Non-routine Development Projects (next four years)

Project Description	CAPEX Cost & Timing
System Growth Projects: TPCL is experiencing significant development in the Awarua and Makarewa region resulted in network constraints. A multiyear program has been developed to provide a new 66kV supply to Awarua region and transferring some of the load from the Makarewa region from North Makarewa GXP to the Invercargill GXP via the new 66 kV connection, triggered by the development in the Awarua region. This work would relieve the capacity constraint on the North Makarewa region, improve resilience to western Southland and defer major investments such as the GXP upgrade.	$1,610,980 25/26 $9,382,209 26/27 $7,026,682 27/28

7.2 Asset Acquisitioning – 2024/2024 AMP Update

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 a number of assets of similar age that will be replaced or renewed as part of short- or medium-term programme. The contents covered in the 2023-33 AMP are largely unchanged except contents presented in the following tables.

Table 48: Non-routine Replacement & Renewal Projects (next 12 months)

Project Description	CAPEX Cost & Timing
Gore Link Box Replacement and Undergrounding: The project is to replace all the aged overhead lines and pillar boxes underground on Gore Mains Street. The design was finalised and accepted in 2023 and planned to be completed within FY23/24. However, the local council want to avoid construction throughout the 2023 Christmas period; therefore, the start day of the project got delayed to mid/late January. This project will be broken into three stages. The first stage of the projection involves working on link box 14 to link box 9, which includes two road crossings and has 6 of the 14 link boxes. The project's first stage is expected to be completed within FY23/24, whereas stages two and three are expected to start and be completed in FY24/25.	$704,679
Critical Spares: For 24/25 four items have been identified for addition to the critical spares: 1 x RMU, 1 x 66kV live tank CB and relays/controller. These critical spares provide an option to replace the unit with a tested spare then maintain the removed asset in the workshop and return it to spares for the next job.	$179,640
66kV SF6 CB Refurbishment: Five S1-72.5 F1 live tank circuit breaker has been identified to be refurbished due to the inherent design flaw that made it prone to corrosion around the gasket from the top flange.	$42,066
Substation LS TX: Several substation sites on the network with pole-mounted local service transformers that share the same structure as other equipment and deficient HV protection have been identified and need to be converted to ground mounted.	$188,686
River Crossing Reconstruction: Several river crossings overhead circuits has been washed out or compromised during the latest flood in FY2023. Six sites have been identified to be addressed.	$1,622,847
Distribution Recloser: A number of substation feeders have been identified with insufficient backup sensitivity to detect the end-of-line fault. The work involves installing reclosers on the Waikiwi and Orawia substation feeders to address safety issues.	$606,230
Mossburn to Athol 66kV OHL Hardware Upgrade: The 66kV circuit between the Mossburn and Athol substation needs vibration dampers added along the overhead line to reduce aeolian vibration generated by the wind in conductors.	$ 709,436

Table 49: Non-routine Replacement & Renewal Projects (next four years)

Project Description	CAPEX Cost & Timing
South Gore 33kV Circuit Breaker: Replacing the existing 33kV Fault Throw Switch with CB and associate isolators.	$ 347,132 28/29

7.3 Capital Expenditure Forecast

The capital expenditure forecast is presented in Table 50 and provided in the Information Disclosure Schedule 11a.

Table 50: Capital Expenditure Forecast ($000 - constant 2024/25 terms)

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 (≤ 20kVA)	1,875	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689
Customer Connections (21 to 99kVA)	436	653	653	653	653	653	653	653	653	653	653
Customer Connections (≥ 100kVA)	1,682	917	917	917	917	917	917	917	917	917	917
Distributed Generation Connection	2	7	7	7	7	7	7	7	7	7	7
New Subdivisions	726	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Edendale Process Heat Electrification	0	362	0	0	0	0	0	0	0	0	0
Underwood substation upgrade for Alliance	161	988	0	0	0	0	0	0	0	0	0
McNab Substation upgrade to 33 kV	7,043	0	0	0	0	0	0	0	0	0	0
Kaiwera Downs - Mercury 45MW wind farm	4,135	0	0	0	0	0	0	0	0	0	0
Jericho - Southern Generation 35MW wind farm	0	0	0	271	0	0	0	0	0	0	0
Open Country Dairy 66kV Expansion	0	17,300	1,950	0	0	0	0	0	0	0	0
	16,061	**23,093**	**6,394**	**4,715**	**4,444**	**4,444**	**4,444**	**4,444**	**4,444**	**4,444**	**4,444**

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**
Riversdale Substation Upgrade	0	950	4,775	349	817	2,240	0	0	0	0	0
Kelso Transformer Upgrade	0	2,727	0	0	0	0	0	0	0	0	0
Riversdale 22kV Line Upgrades	480	873	817	706	706	706	2,380	0	0	0	0
22kV Upgrade Athol - Kingston	5,302	2,595	0	0	0	0	0	0	0	0	0
Easements	8	33	33	33	33	33	33	33	33	33	33
Otatara Transformer Replacement	0	0	0	0	0	0	0	0	552	1,449	0
Unspecified Growth Projects	0	0	0	0	0	0	0	0	0	0	4,267
Kingston 66kV Substation	0	0	0	0	0	261	3,787	3,460	0	0	0
Upgrade sections of INV 2742 & 2842 33kV to Colyer Rd	163	0	0	0	0	0	0	0	0	0	0
Upgrade section of Kenington to Woodlands 11kV line	252	0	0	0	0	0	0	0	0	0	0
Upgrade Tokanui TX	0	0	0	0	0	0	0	0	0	413	1,278
Upgrade Riversdale line to 66 kV	0	132	1,781	0	0	0	0	0	0	0	0
Invercargill 66kV Expansion	0	317	0	1,611	9,382	7,027	35,977	8,377	23,435	3,094	0
	6,205	**7,627**	**7,406**	**2,699**	**10,939**	**10,267**	**42,177**	**11,870**	**24,019**	**4,989**	**5,578**

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**
Distribution Transformer Replacements	1,418	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020
Ground Mount Platform Transformers	1,034	1,108	1,108	1,108	1,108	1,108	665	665	665	665	665
Distribution Line Replacement	6,499	7,173	7,173	7,173	7,173	7,173	7,173	7,173	7,173	7,173	7,173
Subtransmission Line Replacement	278	319	875	875	875	875	875	875	875	875	875
Zone Substation Minor Replacement	65	123	123	123	123	123	123	123	123	123	123
RTU Replacement	93	312	312	312	312	312	312	312	312	312	312
Relay Replacements	159	291	290	288	288	288	288	288	288	288	288

Communications Replacement	98	105	105	105	105	105	105	105	105	105	105
General Technical Replacement	76	107	107	107	107	107	107	107	107	107	107
ABS Replacements	1,696	1,820	1,820	1,820	1,820	1,168	1,168	1,168	1,168	1,168	1,168
Power Transformer Refurbishment	175	520	520	520	520	520	520	520	520	520	520
Orawia Substation Upgrade	1,435	353	0	0	0	0	0	0	0	0	0
Makarewa Switchboard Replacement	0	0	0	0	297	2,681	0	0	0	0	0
Bluff Switchboard Replacement	0	297	2,525	0	0	0	0	0	0	0	0
Ripple Plant Upgrade	27	0	0	0	826	826	826	826	0	0	0
Seaward Bush Transformer Change	1,037	0	0	0	0	0	0	0	0	0	0
Glenham Transformer Change	81	0	0	0	0	0	0	0	0	0	0
RMU Renewals	91	736	736	736	736	736	736	1,472	736	736	736
Gore Link Box Replacement and Undergrounding	375	705	0	0	0	0	0	0	0	0	0
Condition Based Asset Replacements	0	0	0	0	0	0	1,560	1,560	2,374	2,374	2,374
LV Pillar Box Replacements and Refurbishments	184	270	270	270	270	270	270	270	270	270	270
Circuit Breaker Replacements	156	545	545	545	545	545	545	674	674	674	674
Awarua Transformer Change	46	415	0	0	0	0	0	0	0	0	0
Hillside Transformer Replacement	0	0	0	0	0	0	0	413	1,278	0	0
Mataura Transformer Replacement	0	0	0	552	2,001	1,449	0	0	0	0	0
North Gore Transformer Replacement	0	0	0	0	0	552	1,899	1,347	0	0	0
Mossburn Transformer Replacement	0	4,169	0	0	0	0	0	0	0	0	0
66kV SF6 CB Refurbishment	0	42	42	0	0	0	0	0	0	0	0
South Gore 33kV Circuit Breaker	0	0	0	0	0	347	0	0	0	0	0

North Gore 33kV Circuit Breaker	0	0	0	0	0	0	347	0	0	0	0
	15,021	**21,430**	**18,572**	**16,554**	**19,126**	**21,205**	**19,538**	**19,917**	**18,687**	**17,409**	**17,409**
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**
Line Relocations	183	138	138	138	138	138	138	138	138	138	138
	183	**138**	**138**	**138**	**138**	**138**	**138**	**138**	**138**	**138**	**138**
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	220	390	390	390	390	390	390	390	390	390	390
Mobile Substation Site Made Ready	48	297	297	297	0	0	0	0	0	0	0
Network Improvement Projects	289	146	146	146	146	146	146	146	146	146	146
Otatara Regulator and Automation	680	91	0	0	0	0	0	0	0	0	0
	1,238	**923**	**833**	**833**	**536**	**536**	**536**	**536**	**536**	**536**	**536**
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	3,417	3,600	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922
Substation Safety	0	0	0	413	0	0	0	0	0	0	0
Remote Area Power Supply	0	0	0	0	0	0	166	166	166	166	166
Hillside Protection Remediation	0	0	0	0	0	0	0	0	0	0	0
Critical Spares	95	180	180	1,382	180	180	0	0	0	0	0
Communications Projects	0	287	287	287	287	287	439	439	439	439	439
Substation LS TX	0	189	189	317	0	189	189	0	0	0	0
River Crossing Reconstruction	0	1,623	1,623	0	0	0	0	0	0	0	0
Distribution Recloser	0	606	606	606	606	606	606	606	606	606	606
Network Resilience Improvement	0	0	0	0	0	0	6,483	6,483	6,483	6,483	6,483
Mossburn to Athol 66kV OHL Hardware Upgrade	0	709	0	0	0	0	0	0	0	0	0
	3,693	**7,194**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Network CAPEX	**42,401**	**60,405**	**38,149**	**29,865**	**38,178**	**39,774**	**76,638**	**46,521**	**57,440**	**37,132**	**37,721**

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
Te Anau Depot	0	85	0	0	0	0	0	0	0	0	0
Racecourse Road Porch	17	0	0	0	0	0	0	0	0	0	0
	17	**85**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Values Fully Marked Up, No Inflation, Base Year dollars

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.

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

7.1 Asset and Network Load Growth 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.

TPCL 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 TPCL's development criteria helps identify the need for network development.

Planning Phase Risks

The following risks are addresses during the planning phase.

Table 51: Planning Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment
Operational Performance	**Damage due to extreme High Impact**	Damage caused by force majeure to our infrastructure or	Determining areas prone to physical events such-as earthquake (liquefaction), tsunami and flood zones

Category	Risk Title	Risk Cause	Risk Treatment
	Low Probability (HILP) Physical Event	equipment (e.g. floods, earthquakes)	Plan networks to avoid high probability HILP event areas
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 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 electric vehicle 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 TPCL 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 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. TPCL 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).
- A connection request from an intending customer requires an increase in network capacity to match their additional load requirements.
- When load growth exceeds 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, electric vehicles 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 electric vehicles 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.43 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 millions of DER will be able to interact in real-time with the electricity system. This provides a significant opportunity to increase consumer participation in markets and more effectively manage complex multi-directional electricity flows that will emerge in future. Energy system changes due to a more distributed electricity system Increased need for system smarts to integrate DER: DER – such as such as rooftop solar, battery storage, EVs, hot water systems, smart appliances, smart meters, and home energy management technologies – will play an important role in New Zealand’s decarbonisation.

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.

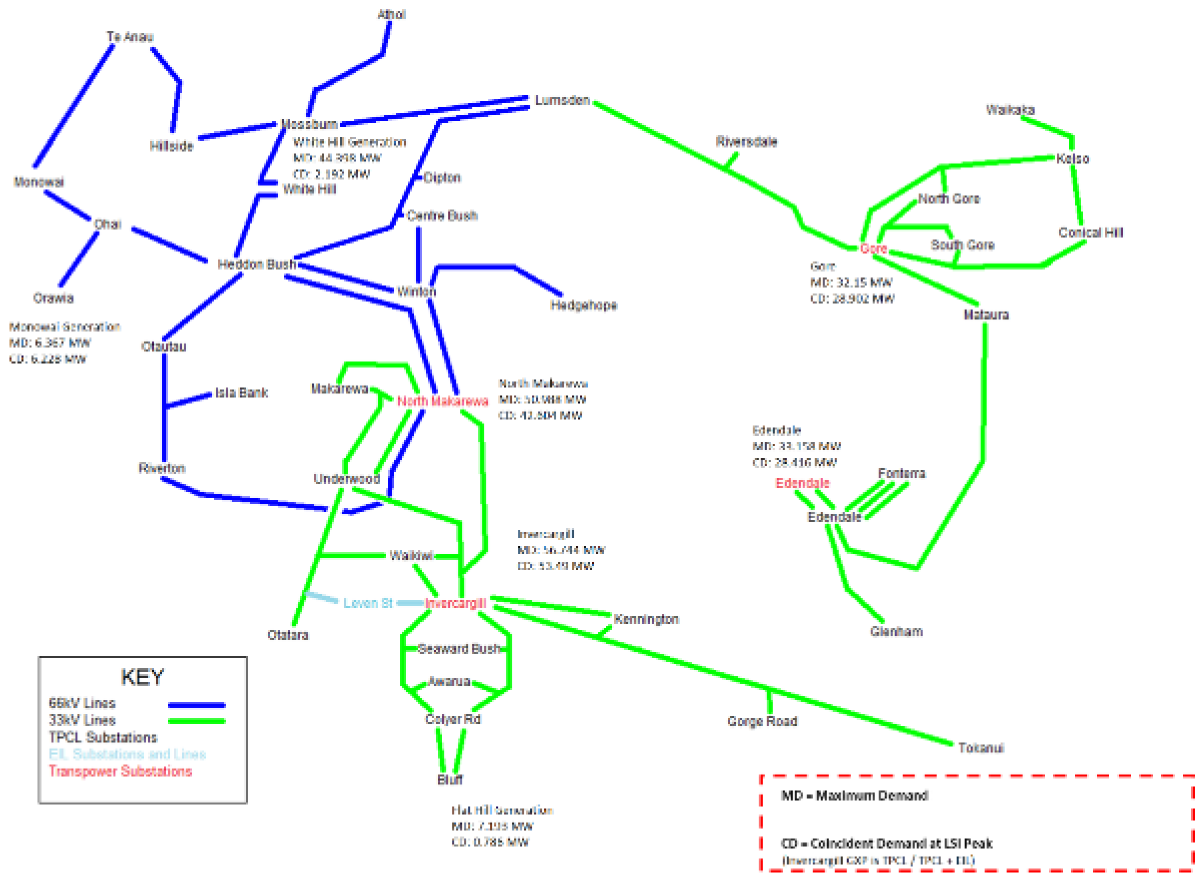
Greater reliance on renewable energy

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

TPCL's maximum demand (MD) of 159.96 MW did not occur at the same time as the Lower South Island (LSI) peak which occurred at 8:00 on the 15th of October 2020. All of the GXPs which provide supply to TPCL had maximum demands which occurred at a different time to both the overall TPCL MD and the LSI peak. TPCL coincident demand at the time of the LSI peak was 161.14 MW. Due to the LSI from does not aligns with TPCL financial years therefore the LSI peak fell into the previous year. The individual maximum demands are displayed in Figure 48.

Figure 48: GXP and Generation Demands



Demand History

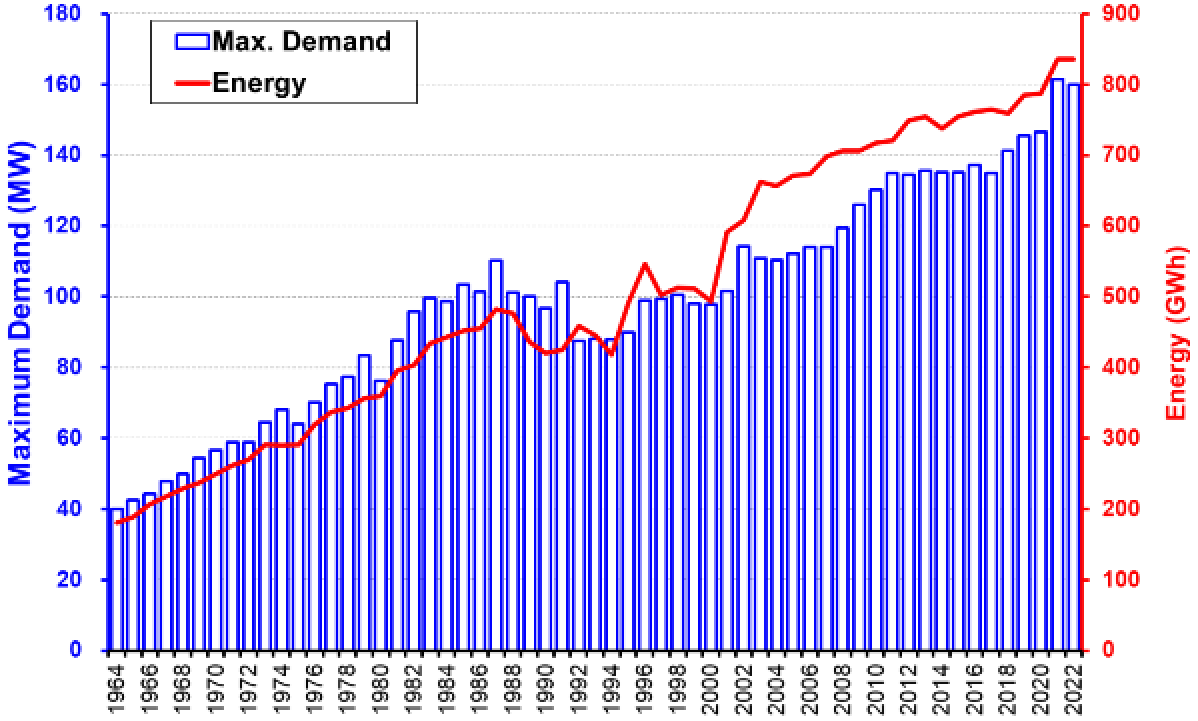
Random variations over and above the main growth patterns impacts the accuracy of growth trends. In general, a ten year rolling average will vary substantially between successive years. Longer term trends have a tendency to average out random variations but also obscures recent changes to underlying 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 and energy consumption has an increasing trend since the start of the decade. Figure 49 shows the overall maximum demand from 1964 and highlights the flattening out of demand in 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 49: 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 52. 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 load transfers. The overall TPCL 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 52: 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
Athol	0.94	0.95	0.89	0.9	2.09	2.02	2.27	0.61
Awarua Chip Mill	0.76	0.97	0.84	0.81	0.84	5.38	5.15	0.72
Bluff	5.28	5.11	5.17	5.36	4.7	4.70	4.69	4.32
Centre Bush	3.74	3.73	3.62	3.5	2.93	3.52	4.30	3.93
Colyer Road	9.66	9.55	7.41	7.16	7.08	6.63	4.66	-
Conical Hill	3.44	3.39	5.24	1.89	1.51	1.32	1.79	1.21
Dipton	1.41	1.25	1.32	1.54	1.19	1.94	1.77	1.74
Edendale Fonterra	28.59	25.81	24.62	24.64	28.78	26.24	21.28	23.35
Edendale	6.15	5.77	7.43	7.44	6.62	7.16	6.93	6.40
Glenham	1.24	1.31	1.22	1.26	1.24	1.29	1.46	1.54
Gorge Road	2.51	3.41	2.43	2.36	2.76	2.40	2.40	2.66
Hedgehope	1.59	1.54	1.57	1.59	1.50	1.65	1.65	-
Hillside	0.75	0.59	0.80	0.8	0.78	0.71	0.75	0.68
Isla Bank	1.88	1.91	1.87	1.99	1.78	1.99	-	-
Kelso	4.26	4.24	4.26	4.36	4.24	4.40	4.30	4.02
Kennington	6.91	7.11	6.82	6.06	6.06	5.38	6.45	5.88
Lumsden	3.61	3.52	3.24	3.24	3.63	3.72	3.38	3.20
Makarewa	4.05	4.12	4.30	4.19	4.18	4.59	5.31	6.30
Mataura	7.77	5.98	5.46	7.07	5.37	5.98	5.82	5.99
Monowai	0.17	0.15	0.13	0.13	0.16	0.15	0.13	0.16
Mossburn	1.88	1.81	2.11	2.51	2.67	2.27	2.37	1.96
North Gore	8.34	8.85	7.90	10.31	7.81	9.04	7.87	7.68
North Makarewa	33.91	34.94	37.76	43.66	46.05	42.14	44.17	45.70
Ohai	2.55	2.57	2.57	2.55	2.49	2.54	2.50	2.49

Orawia	2.89	3.02	3.06	3.09	3.0	3.40	3.11	2.99
Otatara	4.08	4.01	3.78	3.86	3.74	3.92	3.74	3.55
Otautau	3.56	3.61	3.37	3.32	4.04	4.57	4.37	4.11
Racecourse Road (EIL)	10.97	12.76	9.98	10.24	10.07	10.57	9.93	9.42
Riversdale	5.15	5.42	4.94	4.82	5.02	5.37	5.57	5.04
Riverton	4.89	5.00	4.91	4.73	4.29	4.23	4.21	4.55
Seaward Bush	6.96	7.38	7.64	7.01	6.51	7.61	7.98	8.03
South Gore	10.33	9.98	10.60	10.01	7.58	8.33	7.88	8.07
Te Anau	5.45	5.57	6.53	6.27	7.46	5.17	5.38	5.16
Tokanui	1.51	1.21	1.22	1.13	1.10	1.22	1.11	1.06
Underwood	10.20	10.74	10.96	11.19	11.89	12.00	11.80	12.45
Waikaka	0.75	0.76	1.48	0.75	0.77	0.78	1.01	0.75
Waikiwi	11.66	12.02	10.96	11.23	8.68	9.93	10.56	10.03
Winton	10.00	10.53	10.01	10.45	11.67	13.13	11.77	11.80
White Hill (Wind)	-48.56	-52.91	55.54	-46.45	-54.17	-56.74	-56.60	-56.81
Monowai (Hydro)	-6.37	-6.03	-6.23	-7.47	-6.29	-6.47	-6.44	-6.56

The large, embedded generation at the White Hill Wind Farm is not considered in the demand forecast for the North Makarewa GXP and 33/66kV transformers. This is because variable wind resources may generate at different times than the peak. The Monowai hydro generators generally operate a single generator (2.5MVA) as a minimum operation and therefore are considered in demand forecasting for North Makarewa GXP and 33/66kV transformers.

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 53.

Table 53: 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.
Security and Reliability	Load reaches the threshold for increased security as defined by TPCL's security standard. Customers (especially large businesses) may request and be willing to provide a capital contribution for increased security.	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

TPCL 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 endeavours will be made to meet demand by other, less investment-intensive means. The following potential responses and options are considered.

- Pricing reform.
- Demand side management.
- Partnerships for non-traditional solutions.

If the extent of changes is substantive, assets may become underutilised to such an extent that TPCL 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 TPCL 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 TPCL, due to the uneconomic nature of deployment on dense urban networks. This is based on the assumption that markets, regulations, and consumer 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 Figure 50.

Table 54: Demographics and Lifestyle Drivers

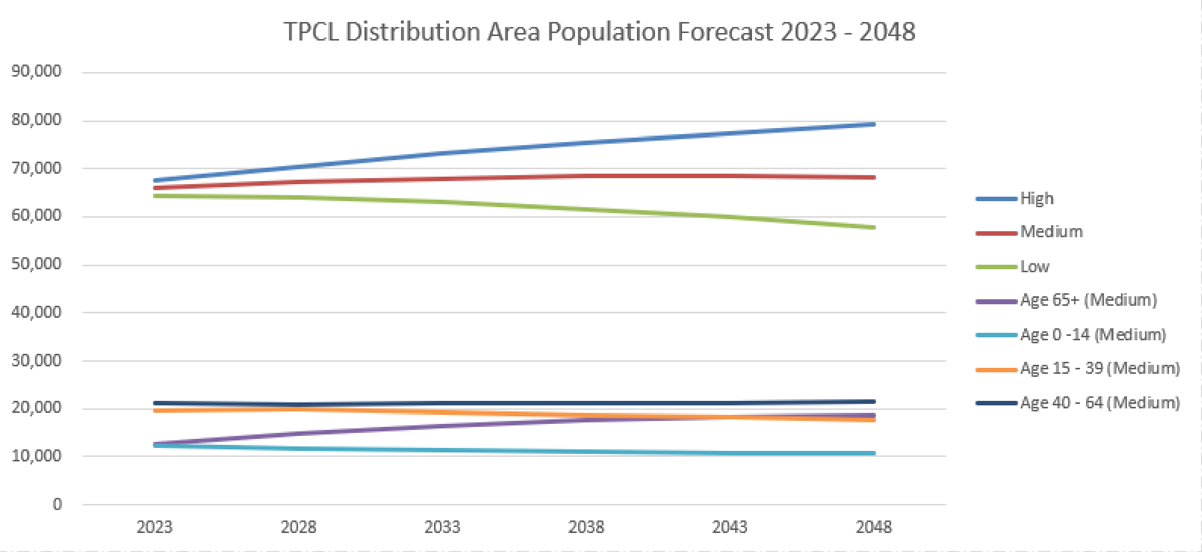
<table>
<tr><td>Population Growth and Decline</td><td>Effect: Population projections indicate a relatively slower growth compared to the areas. The distribution area under TPCL is expected to see a 2.8% growth in population from 2023 to 2033. Population projections for age cohorts also indicate that the population is significantly aging.</td></tr>
<tr><td colspan="2">Description: The population of TPCL's distribution area is approximately 64,134 as per last confirmed Census 2018 data. Census population projections[1] for TPCL's distribution area are shown in Figure 41. It is expected that this number would have grown to 66,125 by 2023. TPCL's distribution area has a mean population growth estimate of approximately 2.8% by 2033, an upper bound estimate of 10.5% by 2033, and a lower bound estimate of -4.6%.
The Southland District expects to see its population grow to 34,300 by 2033. Invercargill City population is projected to be approximately 59,900 by 2033. It is expected that the vast majority of growth would occur in urban areas of which Invercargill is Southland's largest metropolitan area. Further, Southland Institute of Technology as a tertiary education provider is seen as an important attractor for potential migrants located within central Invercargill.
Invercargill would attract the majority of potential migrants however the Invercargill area is supplied by both EIL and TPCL. TPCL supplies some of the population in Invercargill city, whose properties are located in the outer regions of the city; and as such expansion of Invercargill for additional housing would therefore fall within TPCL's network boundary. TPCL 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. The increase in population numbers are more prevalent in areas supplied by North Makarewa and Invercargill GXP's.
Business expansion is also a target for the Southland Regional Development Plan and the majority of industrial expansion would expect to be within TPCL's network area.
Concerns about the closure of the Tiwai smelter and its effects on the local economy have resurfaced. Although TPC does not directly supply the smelter, the potential economic impact of losing the Tiwai employees as customers and the energy consumption of support businesses servicing Tiwai could be significant.</td></tr>
<tr><td>Housing Density and Utilisation</td><td>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.</td></tr>
</table>

<table>
<tr><td colspan="2">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. Expansion into new subdivisions at the edge of Invercargill would see growth on TPCL’s network. The gradual trend toward smaller family size is expected to continue and this may counteract some of the growth caused by increased density.</td></tr>
<tr><td>Rural Migration to Urban Areas</td><td>Effect: Population growth especially from retirees (baby boomers) is expected to have a limited driver for increased demand. Effect is captured in population growth effect above discussed above.</td></tr>
<tr><td colspan="2">Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has been seen in Southland also. 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 growth if the population growth strategy is successful.
the number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2028. The impact of farmers retiring to urban areas increases demand for townhouses in desirable locations. This is not a new effect and therefore there is no increase in growth expected above trending of previous years.</td></tr>
<tr><td>Increasing Energy use per Customer</td><td>Effect: Growth minimal and included in existing demand trends.</td></tr>
<tr><td colspan="2">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. Further work is being done to understand if there is an increasing trend due to heat pumps.
Consumer 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.</td></tr>
<tr><td>Convenience of Electrical Heating</td><td>Effect: The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for TPCL over the next ten years. Incorporates growth anticipated from council fuel burner constraints.</td></tr>
<tr><td colspan="2">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.
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 of time. 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.</td></tr>
<tr><td>Electricity Affordability</td><td>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.</td></tr>
<tr><td colspan="2">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 continuing current trends.
Line charges in the Southland regions reflect TPCL’s high cost of transporting energy over large distances to limited numbers of customers. These costs make alternative technologies such as solar and photovoltaic more attractive to customers. While these alternative technologies are not yet competitive with traditional supply, their gradually declining costs may make them more competitive toward the end of the planning period.</td></tr>
<tr><td>Irrigation & Dairy</td><td>Effect: Accelerated growth for dairy conversions in pastoral areas of Southland and additional irrigation in the Northern Southland region.</td></tr>
</table>

Description: Irrigation is becoming more common in the drier climate of Northern Southland. TPCL substations most likely to be affected are Dipton, Lumsden, Riversdale, Mossburn and Athol. Environment Southland has placed more stringent restrictions on the use of water which encourage the use of spray irrigators; which are both more water-efficient and more electrically demanding than the pre-existing irrigation schemes. The load growth can be very erratic as it depends very much on the effect of climate change and resulting harsh weather conditions outside the norm. The Ministry of Primary Industries has also placed more stringent requirements on the chilling of milk on dairy farms, which is expected to increase load in areas with a substantial dairy population. This affects most of TPCL's rural zone substations.

The current population projections for TPCL's network area are based on estimates from the 2013 Census data from Statistics New Zealand and updated with preliminary 2018 Census projections. Projections for the 65+ age group indicates a significant aging of the population as highlighted in the following figure.

Figure 50: Population Projections



Environmental and Climate Drivers

Drivers of future demand based on changes in the environment and climate is discussed in Table 55.

Table 55: Environment and Climate Drivers

Removal of Coal as Heating	**Effect:** Continuation of existing trends towards electrical space heating.
Description: Regulations within the National Environmental Standards for air quality since 2016. This along with council fuel burner constraints will result in an increase in use of alternative sources of heating including heat pumps with resulting growth expected to affect residential areas. Heat pump usage has naturally continued to increase as a convenient and efficient form of heating and the impact on demand has been less than earlier anticipated, therefore existing growth has been assumed to continue.	
Council Fuel Burner Constraints	**Effect:** Continuation of existing trends towards electrical space heating

Description: Proposed updates to the Regional Air Quality Plan have been advised and include prohibition of open fires from 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.

Burner installation date	Prohibition date
Before 1 January 1997	Invercargill – 1 January 2019 Gore – 1 January 2020 Burn wood only from 1 January 2020
1 January 1997 – 1 January 2001	1 January 2022
1 January 2001 – 1 September 2005	1 January 2025
1 September 2005 – 1 January 2010	1 January 2030
1 January 2010 – 6 September 2014	1 January 2034

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.

Energy Conservation Initiatives	**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.

Description: Energy efficiency in consumer appliances is increasingly popular due the combination of government or local council drivers, marketing and consumer 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).

Increasing Average Ambient Temperature	**Effect:** Small increase in maximum demand on inland rural substations.

Description: Increasing ambient temperature predicted by climate scientists may create increased demand for cooling and irrigation systems. This increased consumption would occur in the warmer months and therefore coincide with the peak demand in inland rural substations. In areas where the winter heating load dominates, increased cooling loads in summer months may improve load factor by a small degree.

Wider Range in Weather Variations	**Effect:** Potential impact on maximum demand, and worsening load factor. Some impact on network reliability.

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.

Economic Drivers

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

Table 56: Economic Drivers

Major Industry Continuance or Growth	**Effect:** Assumption that existing industries will continue and major new industries will eventuate.
Description: Tiwai aluminium smelter takes supply directly from the transmission grid; it helps support many businesses and individuals directly and indirectly. The loss of this business could significantly impact the local economy and the growth of TPCL's network, particularly in the Invercargill area. Negotiations between Rio Tinto and other stakeholders have resulted in an agreement resulting in the continuation of operations at Tiwai smelter and exploring potential pathways with electricity generators for the smelter's future beyond the end of the current contract in December 2024. It is considered most likely Tiwai will continue to operate unchanged in short to medium term; therefore, no change to growth forecasts has been made. A medium to long-term view is more difficult to predict and will be assessed as future developments unfold.	
$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. The recent coronavirus may result in an economic downturn, and stall recovery. 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 57: Technology Drivers

Electric Vehicles	**Effect:** Negligible over planning period.
Description: With significant penetration into the transport sector, electric vehicles have the potential to have a large impact on network demand. Some demand increase is expected in the second half of the planning period as electric vehicle adoption rates increase between 2% and 4% of the light passenger fleet by 2031. It is expected that the majority of this load should be able to be managed so that it is consumed at off-peak times (especially overnight) and therefore would have much less impact on peak demand and even improve load factor. There is likely to be some low peak demand growth but the impact will largely be felt in sub-urban LV networks in built up urban and semi-urban areas. The upstream MV network generally has sufficient capacity to support the expected growth from electric vehicles (estimated at 0.2% to 0.3% per annum from 2025/26). PowerNet is working towards a methodology to cluster smart meter profiles and some typical profiles that represents various customer segments on the network. 86% of the customers in TPCL have smart meters. PowerNet is currently simulating all ICPs without smart meters, to provide typical profiles. ICP's can then be grouped accordingly and future load projection can be simulated, incorporating other distributed energy resources (DER) such as photovoltaics (PV) and electric vehicle supply equipment (EVSE) or more commonly known as electric vehicle charging stations.	

Autonomous Vehicles

Effect: Potential for residential customer density to spread. Potential clustering of electric vehicle 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 lowers the costs of commuting, and may make living further from centres of business more viable for consumers. 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 electric vehicles, as the technology is often packaged into newer electric vehicles. 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.

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

Distributed Generation

Effect: Generation system tends not to coincide with network peak demand therefore the effect on network peak demand is expected to be negligible. However injection of generation during the period of low load around the midday could potentially create voltage issues toward the end of the ten year planning period.

Description: The vast majority of the distributed generation seen so far has been solar installations and this trend is expected to continue for the foreseeable future. Relatively low numbers of new solar connections have been seen on TPCL's network to date. Although reducing costs are increasing the number of households for which a solar installation is cost-neutral, the majority of such customers either cannot afford a solar installation, are unable to install solar (e.g. rental), or prefer to dispose of their income elsewhere.

Public awareness of the environmental advantages of solar power is gradually increasing. Recent customer surveys indicate that more customers are considering purchasing solar in the medium term than any of the other disruptive technologies, most likely due to the influence of solar marketing efforts in recent years; but with energy cost reduction options such as home insulation and electric vehicles now also receiving increased marketing and generally offering a superior return, solar penetration is not expected to be widespread by the end of the planning period.

The LV network can however be vulnerable to solar installations; solar tends to depress 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 sufficient solar generation is connected. In weaker areas of the network a relatively small cluster of solar may be sufficient to cause issues.

The impact of solar installations on the network can be significantly reduced when the solar inverters employ volt-VAr compensation. The standard for new solar installations do require the usage of approved inverters capable of volt-VAr compensation. Similarly to electric vehicles, the concentration of effects on the LV network makes the location of future voltage problems difficult to predict. Individual ICP smart meter data will better enable TPCL to identify and address vulnerable points on the network.

Currently most customers installing solar systems do so without battery storage. The cost of battery systems is decreasing and when it reaches the level where it becomes economic to install, it will start influencing the evening peak. This will decrease the maximum load on the LV network and will alleviate some the problems identified above. In the long term this could lead to lower investment requirements for LV network installation and upgrades.

Total energy consumption is likely to be reduced to some extent by solar installations within the planning period, however energy does not tend effect planning which focuses on providing capacity for peak demand periods.

Energy Storage

Effect: Not expected to have a significant presence within the ten year planning horizon and therefore negligible effect on network demand.

Description: Energy storage is one technology that could have a large impact on network demand especially if used in combination with distributed generation installations. Storage gives customers some control over their demand without impacting on their consumption, and could make it feasible for customers to go "off-grid" with a sufficiently sized solar system or other generation source. However there is significant uncertainty in this area around the viability of alternative

<table>
<tr><td colspan="2">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 TPCL 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.</td></tr>
<tr><td>Energy Efficiency</td><td>Effect: Negative growth driver accounted a part of the energy conservation initiatives.</td></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>On-line shopping</td><td>Effect: Likely to negatively affect the business sector in TPCL's network area however the overall effect on demand is expected to be relatively insignificant.</td></tr>
<tr><td colspan="2">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 TPCL'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 TPCL's area.</td></tr>
<tr><td>Internet of Things</td><td>Effect: It is not considered likely that this technology will be extensively used in the near future and has 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 plans would be able to react sufficiently quickly.</td></tr>
<tr><td colspan="2">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 dwelling's 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.</td></tr>
<tr><td>Voltage support</td><td>Effect: Where there is a low voltage issue at the end of a feeder, an alternative approach to a traditional conductor upgrade, regulator installation or the supply voltage being increased, is the installation of capacitors or a Static VAr Generator</td></tr>
<tr><td colspan="2">Description: In cases where the load will increase on a feeder to the extent that the voltage will fall below the required levels there may be very significant costs associated with the implementation of a conductor upgrade, regulator installation or voltage upgrade. If this is the case and where the additional load is seen to be a one off or where there is seen to be a period of time where the load is not likely to increase significantly over the following few years, then the installation of voltage support may be the solution.
They essentially defer the need for a more expensive solution.
One strong factor in favour of technologies such as this is that if capacitors or a static VAr generator were to be installed, they could be redeployed to some other site if and when the load continues to increase. So they will never become a stranded asset.</td></tr>
</table>

Demand Forecasts

The overall impact of the drivers explained above is a slow growth rate for maximum demand on TPCL's network of 0.5-1.5% per annum. TPCL's total maximum demand is forecast to increase from approximately 160MW in 2021/22 to about 166MW in 2032/33. TPCL's demand (at a zone substation level) is expected to increase over the planning period by the following factors.

- Standard natural growth of 1.0%, with some decline of small rural communities.
- Irrigation growth in Northern Southland of 1.5%.
- Continued Dairy conversions across pastoral Southland of 0.5%
- Electric vehicle related growth of 0.3% from 2025.

The projected substation demands indicate the expected growth forecast. This is the most likely outlook and these projections are the basis for TPCL's network development planning. TPCL 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 consumer 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.

With declining growth rates, project schedules (to address capacity constraints) are postponed to minimise over-investment risks. TPCL endeavours to realise growth opportunities as they arise, which means developing the network to alleviate constraints as required within the parameters of acceptable risk. 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 growth rates are a possibility and present a risk of missed opportunity for growth for both TPCL and TPCL'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, TPCL 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

Table 58 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 58: Substation Demand Growth Rates

Substation	MD (MVA) '23/24	MD (MVA) '32/33	Provision for Growth
Athol	1.24	2.36	Athol substation has a capacity of 5MVA. The supply region's load is predominantly Athol and Kingston villages, rural farms with summer irrigation. Growth in the region is expected to be due to the development

Substation	MD (MVA) ‘23/24	MD (MVA) ‘32/33	Provision for Growth
			of Kingston. The firm rating is unlikely to be exceeded within the planning period based on the region's historical trend of subdivision development.
Awarua	0.91	0.91	Awarua substation has a capacity of 5MVA. The firm rating is not expected to exceed by the end of the planning period. The historical demand of the single customer supplied is historically flat.
Bluff	6.17	7.06	Bluff substation has a capacity of 26MVA and a firm capacity of 13 MVA. The supply region’s load is predominantly the urban domestic load at Bluff, a few large to medium industrial customers and a wind farm connection on a deliciated 11kV feeder. The growth is expected to be modest based on the historical trend and due to the predominantly rural load in the region. The firm rating is not expected to exceed by the end of the planning period.
Centre Bush	4.01	4.39	Centre Bush substation has a capacity of 5MVA. The growth is expected to be modest based on the historical trend and due to the predominantly rural load in the region. The firm rating is not expected to exceed by the end of the planning period.
Colyer Road	10.25	12.59	Colyer Road substation has a capacity of 24MVA and a firm capacity of 24MVA. The load in the supply region is predominantly three large industrial customers with some minor rural load to the south-west. Growth in the region is expected to be high with step increase from the potential decarbonization projects. The firm rating is expected to exceed within the planning period, and it needs to be monitored.
Conical Hill	3.70	4.04	Conical Hill substation has a capacity of 10MVA and a firm capacity of 5MVA. The growth is expected to be modest based on the historical trend and due to the predominantly rural load in the region. The firm rating is not expected to exceed by the end of the planning period.
Dipton	1.61	1.71	Dipton substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Edendale Fonterra	29.21	29.21	Edendale Fonterra substation has a capacity of 69MVA and a firm capacity of 46MVA. The load in the supply region is the Edendale Fonterra Plant. The historical demand of the single customer supplied is historically flat. The firm rating is not expected to exceed by the end of the planning period.
Edendale	6.92	7.57	Edendale substation has a capacity of 24MVA and a firm capacity of 12MVA. The load in the supply region is predominantly Edendale, Wyndham town, small meat at Moron Mains and rural farming. The historical demand of the single customer supplied is historically flat. The firm rating is not expected to exceed by the end of the planning period.
Glenham	1.39	1.52	Glenham substation has a capacity of 1.5MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is expected to exceed by the end of the planning period.

Substation	MD (MVA) '23/24	MD (MVA) '32/33	Provision for Growth
Gorge Road	2.64	2.88	Gorge Road substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Heddon Bush	0	0	Switching Station
Hedgehope	1.76	1.84	Hedgehope substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Hillside	1.00	1.09	Hillside substation has a capacity of 3MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Isla Bank	1.96	2.14	Isla Bank substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Kelso	4.52	4.73	Kelso substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Kennington	9.80	11.21	Kennington substation has a capacity of 24MVA and a firm capacity of 12MVA. The load in the supply region are mainly industrial area with various manufacturing processing, a few residences, village and rural farm. Growth in the region is expected to be high from industrial electrification and expansion. The firm rating is not expected to exceed by the end of the planning period, but it needs to be monitored.
Lumsden	3.92	4.69	Lumsden substation has a capacity of 5MVA. The load in the supply region is predominantly the township and rural farming. Growth in the region is expected to be medium based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Makarewa	4.07	4.26	Makarewa substation has a capacity of 24MVA and a firm capacity of 12MVA. The load in the supply region are mainly industrial area and rural farm. Growth in the region is expected to be rapid from industrial electrification and expansion. The potential step growth in the region is likely to exceed the firm rating in the planning period and needs to be monitored. Due to the lack of certainties and commercial sensitivity, it is not reflected in the MD forecast.
Mataura	7.97	8.34	Mataura substation has a capacity of 20MVA and a firm capacity of 10MVA. The load in the supply region are mainly meat processing plant,

Substation	MD (MVA) ‘23/24	MD (MVA) ‘32/33	Provision for Growth
			Mataura township and rural farm. The firm rating is not expected to exceed by the end of the planning period.
Monowai	0.20	0.21	Monowai substation has a capacity of 1MVA (the smallest readily available 66kV transformer size). The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Mossburn	2.26	2.36	Mossburn substation has a capacity of 3MVA. The load in the supply region is predominantly rural farming and village. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
North Gore	8.89	9.72	North Gore substation has a capacity of 30MVA and firm capacity of 10MVA. The load in the supply region is predominantly rural farming and the Gore Township. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Ohai	2.71	2.96	Ohai substation has a capacity of 7.5MVA. The load in the supply region is predominantly rural farming and the Ohai Township. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Orawia	3.02	3.30	Orawia substation has a capacity of 7.5MVA. The load in the supply region is predominantly rural farming, village of Orawia and sawmill at Tuatapere. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Otatara	3.99	4.36	Otatara substation has a capacity of 5MVA. The load in the supply region is predominantly the township of Otatara and a few farms. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Otautau	3.99	4.36	Otautau substation has a capacity of 7.5MVA. The load in the supply region is predominantly rural farming, township of Otautau and a sawmill plant. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Racecourse Road (EIL)	10.2	11.4	Racecourse Road substation has a capacity of 23MVA. The load in the supply region Eastern area next to Invercargill city, mix of urban, lifestyle blocks and rural. Includes major Hotel/Motel complex. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Riversdale	5.47	6.83	Riversdale substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming, the township of Riversdale and the

Substation	MD (MVA) '23/24	MD (MVA) '32/33	Provision for Growth
			village of Waikaia. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. However, demand in the region has been exceeding the transformer nameplate capacity in the past few years for short periods at peak times. A set of fan cooling systems has been installed to accommodate the short-time overload and temporary 11kV transfer to shift load to the nearby substations. The system growth in the region has triggered a multiyear upgrade project at the substation from 2024/25 onward.
Riverton	5.30	6.06	Riverton substation has a capacity of 15MVA and firm capacity of 7.5MVA. The load in the supply region is predominantly the township of Riverton, small fish processing and rural farming. Growth in the region is expected to be medium based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Seaward Bush	7.83	11.41	Seaward Bush substation has a capacity of 20MVA and firm capacity of 10MVA. The load in the supply region is predominantly South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant and rural farms. Growth in the region is expect to be high with step increase from the potential decarbonization projects. The power transformer has been planned to be replace in the 2023/24 due to age and condition therefore the capacity of the substation is going to increase to 24MVA and firm capacity of 12MVA after the completion of the work. The firm rating is not expected to exceed by the end of the planning period but need to be monitored.
South Gore	7.90	10.16	South Gore substation has a capacity of 24MVA and a firm capacity of 12MVA. The load in the supply region is predominately the town of Gore, meat processing plants and rural farming. The substation's load is expected to drop substantially in 2024/25 due to the electrification of a dairy processing plant resulting in transferring some of the existing load to the McNab Substation. However, it expects that new regional decarbonisation projects would fill in the gap in this planning period. The firm rating is not expected to exceed by the end of the planning period but need to be monitored.
Te Anau	6.24	6.53	Te Anau substation has a capacity of 24MVA and a firm capacity of 12MVA. The load in the supply region is predominately the town of Te Anau, Manapouri and rural farming. The substation demand has dropped significant since the start of the COVID-19 pandemic due to a decline in tourists. However, it is expected the situation will be able to recover slowly with the New Zealand border reopening to the world. The firm rating is not expected to exceed by the end of the planning period.
Tokanui	1.75	1.91	Tokanui substation has a capacity of 1.5MVA. The load in the supply region is predominately the villages of Waikawa, Fortrose, Curio Bay, Tokanui and rural farming. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating has been exceeded in the past years at peak times for short periods and is expected to be more frequent in the coming planning period. The system growth in the region has triggered an upgrade project

Substation	MD (MVA) '23/24	MD (MVA) '32/33	Provision for Growth
			at the substation in 2032/33. The demand will be monitored, possibly 11kV network transfer to the nearby substation to accommodate the short-time overload.
Underwood	10.37	14.86	Underwood substation has a capacity of 31MVA and a firm capacity of 15.5MVA. The load in the supply region is predominately a large meat processing plant, Wallacetown and rural farming. Growth in the region is expected to be modest after the step growth due to decarbonisation in 2023/24. The firm rating is not expected to exceed by the end of the planning period.
Waikaka	0.94	1.08	Waikaka substation has a capacity of 1.5MVA. The load in the supply region is predominately the village of Waikaka and rural farms. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Waikiwi	12.60	14.40	Waikiwi substation has a capacity of 46MVA and a firm capacity of 23MVA. The load in the supply region is a mix of urban residential and urban light industrial load in the northern suburbs of Invercargill. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
Winton	10.68	11.68	Winton substation has a capacity of 24MVA and a firm capacity of 12MVA. The supply region's load is predominately Winton's town, Lochiel and Browns' villages, Large Sawmill, Limeworks and rural farms. Growth in the region is expected to be modest based on the historical trend and possible foreseeable development. The firm rating is not expected to exceed by the end of the planning period.
White Hill (Wind)	54.76	54.76	White Hill Wind Farm is owned by Meridian Energy embedded generation at the 66kV North Makarewa network with varying export of up to 58MW.
Monowai (hydro)	6.37	6.37	Monowai is owned by Pioneer Generation and is embedded into the 66kV North Makarewa network with varying exports up to
Flat Hill (Wind)	7.23	7.23	Flat Hill Wind is owned by Southern Generation Limited Partnership embedded generation at Bluff 11kV network with varying export up to 6.8MW.
McNab		20	McNab substation is currently supplied from the South Gore Substation via 11kV. The load in the supply region is the Mataura Valley Milk Plant, and historical demand is flat. It is presently being upgraded to have a firm capacity of 23.8 MVA to meet the growth of a customer-driven project. The firm rating is not expected to exceed by the end of the planning period.
Kaiwera Downs (Wind)	-	45	The Kaiwera Downs wind farm is being constructed by Mercury Energy and will be connected during 2023 and has a capacity of 45MW exporting into TPCLs 33 kV connection at the Gore GXP.

Projected annual maximum demands incorporating growth provisions is presented in Table 59. 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 59: 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
Athol	1.24	1.28	1.81	2.03	2.08	2.14	2.19	2.24	2.30	2.36
Awarua	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Bluff	6.17	6.26	6.36	6.45	6.55	6.65	6.75	6.85	6.95	7.06
Centre Bush	4.01	4.06	4.10	4.14	4.18	4.22	4.26	4.30	4.35	4.39
Colyer Road	10.25	12.10	12.16	12.22	12.28	12.34	12.40	12.46	12.53	12.59
Conical Hill	3.70	3.73	3.77	3.81	3.85	3.88	3.92	3.96	4.00	4.04
Dipton	1.61	1.62	1.64	1.65	1.67	1.69	1.71	1.72	1.74	1.76
Edendale Fonterra	29.36	29.50	29.65	29.80	29.95	30.10	30.25	30.40	30.55	30.71
Edendale	6.92	6.99	7.06	7.13	7.20	7.28	7.35	7.42	7.50	7.57
Glenham	1.39	1.40	1.41	1.43	1.44	1.46	1.47	1.49	1.50	1.52
Gorge Road	2.64	2.66	2.69	2.71	2.74	2.77	2.80	2.83	2.85	2.88
Heddon Bush	-	-	-	-	-	-	-	-	-	-
Hedgehope	1.76	1.77	1.78	1.79	1.79	1.80	1.81	1.82	1.83	1.84
Hillside	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09
Isla Bank	1.96	1.98	2.00	2.01	2.04	2.06	2.08	2.10	2.12	2.14
Kelso	4.52	4.55	4.57	4.59	4.61	4.64	4.66	4.68	4.71	4.73
Kennington	9.62	9.77	9.91	10.06	10.21	10.37	10.52	10.68	10.84	11.00
Lumsden	3.92	4.00	4.08	4.16	4.25	4.33	4.42	4.51	4.60	4.69
Makarewa	4.07	4.09	4.11	4.13	4.15	4.17	4.19	4.21	4.24	4.26
Mataura	7.97	8.01	8.05	8.09	8.13	8.17	8.21	8.25	8.29	8.34
Monowai	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.21
Mossburn	2.26	2.27	2.28	2.29	2.30	2.32	2.33	2.34	2.35	2.36
North Gore	8.89	8.98	9.07	9.16	9.25	9.34	9.44	9.53	9.63	9.72
Ohai	2.71	2.74	2.76	2.79	2.82	2.85	2.88	2.90	2.93	2.96
Orawia	3.02	3.05	3.08	3.11	3.14	3.17	3.20	3.24	3.27	3.30
Otatara	3.99	4.03	4.07	4.11	4.15	4.19	4.23	4.27	4.32	4.36
Otautau	3.99	4.03	4.07	4.11	4.15	4.19	4.23	4.27	4.32	4.36
Racecourse Road (EIL)	10.2	10.3	10.3	10.4	10.6	10.7	10.9	11.1	11.4	11.4
Riversdale	5.47	5.61	5.75	5.89	6.04	6.19	6.34	6.50	6.67	6.83
Riverton	5.30	5.38	5.46	5.54	5.62	5.71	5.79	5.88	5.97	6.06
Seaward Bush	7.83	10.97	11.02	11.08	11.13	11.19	11.24	11.30	11.36	11.41
South Gore	7.90	9.02	9.15	9.29	9.43	9.57	9.71	9.86	10.01	10.16
Te Anau	6.24	6.28	6.31	6.34	6.37	6.40	6.43	6.47	6.50	6.53

Tokanui	1.75	1.77	1.78	1.80	1.82	1.84	1.86	1.87	1.89	1.91
Underwood	14.86	14.86	14.86	14.86	14.86	14.86	14.86	14.86	14.86	14.86
Waikaka	0.94	0.96	0.97	0.98	1.00	1.01	1.03	1.05	1.06	1.08
Waikiwi	12.60	12.79	12.98	13.17	13.37	13.57	13.77	13.98	14.19	14.40
Winton	10.68	10.79	10.90	11.01	11.12	11.23	11.34	11.45	11.57	11.68
White Hill (Wind)	54.76	54.76	54.76	54.76	54.76	54.76	54.76	54.76	54.76	54.76
Monowai (hydro)	-6.37	-6.37	-6.37	-6.37	-6.37	-6.37	-6.37	-6.37	-6.37	-6.37
Flat Hill (Wind)	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19
McNab	6.51	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Kairewa (Wind)	-45.0	-45.0	-45.0	-45.0	-45.0	-45.0	-45.0	-45.0	-45.0	-45.0

TPCL also manages other general constraints on its network as described in Table 60.

Table 60: Network Constraints and Intended Remedy

Constraint	Description	Management Approach
Capacity at Zone Substations	Substations close to (or exceeding) maximum capacity. Glenham, Kelso, North Gore, Tokanui, Riversdale, South Gore and Winton	Loadings are reviewed annually to ensure timing of projects is kept just ahead of load. Upgrades planned for, Glenham, Kelso, and Riversdale during the planning period. Load transfers will be used to keep, North & South Gore, Tokanui plus Winton under their respective capacity.
Gore GXP	Substation demand close to firm capacity of 38 MVA	Transpower has been engaged in the 2021 to upgrade the Gore GXP transformers to 80MVA triggered by the process heat electrification project at the Mataura Valley Milk and the 45MW Kairewa Downs Mercury Energy wind farm. The work is expected to be completed in mid-2023 with both extra load and generation in 2023/24.
North Makarewa GXP	Transpower 220/33kV Transformers Capacity	The existing NMA 220/33kV supply transformer capacity cannot exceed 67 MVA due to restrictions from the circuit breaker and current transformer (67 MVA), 33kV incomer (68 MVA) and disconnector (71 MVA). Although, these transformers are rated for 76/79 MVA (summer/winter). Transpower is intended to replace the circuit breaker and remove the current transformer limit by 2024-2026. However, the 33 kV incomer cables and disconnectors are not due for replacement and will still be limiting the transformer branch to approximately 68 MVA and 71 MVA, respectively. Up-size when load control cannot keep load under this limit. Close monitoring of the 66kV load within firm capacity.
Limited Transfer Capacity between Gore and North Makarewa	Limited integration between Gore and North Makarewa GXP.	The 33/66kV transformer at Lumsden intends to provide an N-1 supply for Riversdale Substation, allowing transferable between Gore and North Makarewa. Therefore, the transferable capacity from the overhead line is minimal and can only cover load on Riversdale from North Makarewa or part of Lumsden from Gore, even though the transformer is rated for 15MVA.

		Investigate network upgrades to improve network reliability during contingency conditions
Capacity available on the 33kV circuit to Makarewa and Underwood substation	The capacity available on the Makarewa and Underwood circuit is expected to reach its design limitation by mid-2023.	Close monitoring the development at the Makarewa and Underwood substation region.
Capacity available on the 33kV circuits to Colyer Road substation	The capacity available on the 33kV lines to the Coloyer Road is close to its design limitation.	Closely monitoring the development at the Seaward Bush, Coloyer Road and Bluff substation region. Sections of the line have been planned to be upgraded in the 2022-23 years to relieve some of the constraints. Investigate network upgrades to improve network capacity.
Subdivisions	Possible large developments in Athol and Kingston	Upgrade MV distribution network from the Athol substation and extend the 66kV subtransmission to Kingston if further growth occurs.
Voltage constrains on the Rural distribution network	Conversion of farms to dairying may cause feeder voltage to drop below network planning limit.	Install 11kV regulators to improve voltage. Install new substations or convert lines and supply to 22kV if growth continues.
Voltage constrains on the Rural distribution network	Abnormal and dry weather conditions will impact demand on inland areas causing voltage drop below network planning limit.	Install 11kV regulators to improve voltage. Install new substations or convert lines and supply to 22kV if growth continues.
Environmental – Oil	Expectation that no significant oil spills from substations	Install oil bunding, blocking and separation systems.
Coastal marine	Increased corrosion of overhead lines Salt pollution reducing insulation effectiveness	Use high-spec (corrosion resistant) equipment near coast Over-insulate lines near coast
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. Underutilised transformers may be relocated before purchasing new.

Distributed Generation and Demand Management

Distributed Generation (DG) influence on maximum demand is negligible due to the estimated low connection density of DG. 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 61: Non-routine Development Projects (next 12 months)

Project Description	23/24 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 TPCL. Expenditure and timing may differ from that published as customer developments progress. There have been increased demand for new connections over the last few years and this is expected to continue based on enquiries and early subdivision requests.	$4,150,080
Major Customer Connection Projects: TPCL is currently working with three major customers to increase capacity for electrode boilers at a dairy factory and a meat processing plant and also providing a new 33 kV connection to a wind farm. The project timing is driven by the customer, but all three multi year projects are due for completion in 2023/24.	$7,607,495 (before 50% customer contribution)
System Growth Projects: Many smaller new connections and existing customer growth may overload the existing capacity of the 11 kV lines or zone substation transformers, requiring network reconfigurations, rebuilding and increased transformer capacity. TPCL presently has a requirement to upgrade the 11 kV lines in the Riversdale area as the new connections and growth are currently limited by the line capacity and voltage levels. For the	$4,564,806

Project Description	23/24 CAPEX Cost
Riversdale project the lines are being rebuilt with additional capacity and insulation at 22 kV for a later increase in voltage and step change in capacity. The ongoing load increases and recent applications in the Tapanui area are now overloading the 5MVA Kelso zone substation transformer. This two-year project will start in 2023 with the detailed design and replacement transformer ordering. The Athol to Kingston 11 kV line is subject of a multi year project to upgrade the capacity into Kingston, provide for 22 kV line insulation and provide for future subtransmission capacity. The current Kingston load requires the current line upgrade work and the second stage of the large subdivision at Kingston will require the second line to be completed from Athol. The final stages of the 1,000+ section subdivision will require a new 66 kV zone substation at Kingston to supply the load and the current line design will allow for that future eventuality.	
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.	$130,096
Quality of Supply Projects: On the LV network, operation beyond capacity typically manifests as low voltage 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. The quality of supply to Otatara will be improved by installing a new regulator on the 11 kV feeder from Waikiwi substation and circuit breaker connections to the Otatara feeders	$1,039,330

Table 62: Non-routine Development Projects (next four years)

Project Description	CAPEX Cost & Timing
Customer Connections: 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. 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 generally 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.	$4,150,080 from 24/25 ongoing

Project Description	CAPEX Cost & Timing
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. Connection activity is increased in recent years and the ongoing budgets reflect the current rate to provide the required supporting electrical infrastructure. Budgets for subdivisions and distributed generation are separated from other connections to support trending analysis.	
Major Customer Connection Projects: TPCL has an application to connect a new wind farm in the Black Mount area with a simple 66 kV connection. This is planned for 24/25 but will require confirmation of the design requirements and timing from the customer. The Government Investment in Decarbonising Industry (GIDI) fund is expected to involve a number of customer requests for increased capacity, mainly from electrode boilers to replace fossil fuse boilers. TPCL has had a number of enquiries from large customers and has provided high level costing for some options involving increasing subtransmission voltage from 33 to 66 kV and increased GXP capacity. While projects are yet to receive approval or GIDI funding, an allowance has been made in this plan for their development. TPCL has also received enquiries to connect large data centres, again involving increased subtransmission voltages and increased GXP capacity. High level pricing has been provided to a number of potential customers and again is included in this plan as an allowance over the next 4 years.	$10,000,000 24/25 $5,000,000 25/26 $5,253,791 26/27 $3,500,000 27/28 (before 50% customer contribution)
Riversdale Substation Upgrade: The 11 kV lines are currently being prepared for increased capacity and conversion to 22 kV. The Riversdale zone substation has a single 5 MVA 33/11 kV transformer that is now being regularly overloaded. This increasing load and the security standard now require a second transformer to provide the required AA security level. The need to increase the voltage to 22 kV means new dual voltage transformers and a new indoor 22 kV switchboard. This project will run over 5 years to allow the staged installation and change in voltage.	$988,046 24/25 $1,650,000 25/26 $2,250,000 26/27 $250,000 27/28
Athol to Kingston Line Upgrade: The load growth in Kingston village will exceed the current 11 kV line capacity in 2023, requiring a line upgrade and voltage regulators to take power from the Athol substation. The line will be at for 22 kV and 66 kV as the proposed subdivision and services growth will exceed the capability of 22 kV line and it will ultimately require a 66 kV extension from Athol and a new zone substation to be established at Kingston. This is planned for over the next 4 years but will be dependant on the subdivision and housing uptake.	$2.119,771 24/25 $1,505,970 25/26 $2,308,682 26/27

Table 63: Non-routine Development Projects (under consideration)

Project Description	CAPEX Cost & Timing
Unspecified Projects: This budget is an estimate of costs for projects that are as yet unknown, but are considered likely to arise in the longer term. Certainty for these estimates is obviously low. These projects and this expenditure will eventuate based on customer driven developments and engineering evaluation of network capacity.	$No provision

Non-network Development

IT and management services support are provided through the services contract with PowerNet. TPCL 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 64: Design Phase Risks

Category	Risk Title	Risk Cause	Risk 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)	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.

Category	Risk Title	Risk Cause	Risk Treatment Plan
			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 Unexpected inability of contractor to complete work Major health event/pandemic	Standardised design do not lead to single supplier dependencies. A limited number of asset options are available Designs can be implemented by any of a number of competent contractors.
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 coming into contact with 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, TPCL 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. In reality, 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 TPCL. 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. TPCL 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 which increases 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 TPCL 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 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 TPCL’s network. TPCL 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 of time. Though these opportunities do not arise often on TPCL’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 of the TPCL 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 65.

Table 65: Equipment Standardisation

Component	Standard	Justification
Underground Cable	Distribution and low voltage network: 35, 95, 185 & 300 mm^2 Al	Stocking of common sizes, lower cost
	Cable Cross-linked Polyethylene (XLPE)	Rating, ease of use.

Component	Standard	Justification
Overhead Conductor	Subtransmission and distribution: All aluminium alloy conductor (AAAC) - Fluorine, Helium, Iodine, Neon	Low corrosion, low resistance, cost, stocking of common sizes
	Aluminium conductor steel reinforced (ACSR) – Flounder, Wolf	Higher strength (longer spans, snow load)
	Low Voltage 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. TPCL'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. 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 load 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 assets.
- **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 subtransmission assets with any available back-feed on the 11 kV providing a third tier of security. Table 66 summarises the security standards adopted by TPCL. 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 66: 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 67: Security Levels for Zone Substations

Substation	Current Security Level	Required Security Level	Remarks
Athol	A(i)	A(i)	
Awarua Chip Mill	A(ii)	A(ii)	
Bluff	AAA	AA	
Centre Bush	A(i)	A(i)	
Colyer Road	AAA	AAA	
Conical Hill	AAA	A(i)	Sawmill closed
Dipton	A(i)	A(i)	
Edendale Fonterra	AAA	AAA	
Edendale	AAA	AA	Fonterra down-stream plant supplied off this substation
Glenham	A(i)	A(i)	
Gorge Road	A(i)	A(i)	
Heddon Bush	AA	AA	Switching Station
Hedgehope	A(i)	A(i)	
Hillside	A(ii)	A(ii)	
Isla Bank	A(i)	A(i)	
Kelso	A(i)	A(i)	
Kennington	AA	AA	
Lumsden	A(i)	A(i)	
Makarewa	AAA	AA	Major customer closed
Mataura	AA	AA	Can switch over to Edendale GXP
Monowai	A(ii)	A(ii)	
Mossburn	A(i)	A(i)	
North Gore	AAA	AAA	Gore Hospital supplied off this substation
North Makarewa	AAA	AAA	Spare supply transformer at Mossburn
Ohai	A(i)	A(i)	
Orawia	A(i)	A(i)	
Otatara	A(i)	A(i)	
Otautau	A(i)	A(i)	
Racecourse Road (EIL)	A(i)	A(i)	
Riversdale	A(i)	AA	Tee off 33kV supply has no alternative
Riverton	AAA	AA	Spare 66/11kV 5/7.5MVA transformer in service at this site.
Seaward Bush	AAA	AAA	Southland hospital supplied off this substation.

South Gore	AAA	AAA	Supplies Gore CBD.
Te Anau	AAA	AAA	Main tourism centre.
Tokanui	A(i)	A(i)	
Underwood	AAA	AAA	
Waikaka	A(i)	A(ii)	
Waikiwi	AA	AAA	Need to switch-over to alternate 33kV if supplying 33kV faults.
Winton	AAA	AAA	
White Hill (Wind)	A(i)	A(i)	
Monowai (Hydro)	AAA	AAA	

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 TPCL'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 underutilised if not done correctly. While sizing a particular asset for the present time is relatively straight forward, 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 standardisation will limit the options available to assist in the selection of capacity. In general, this will mean the balancing of over-investment and under-investment will result in a small amount of over-investment (i.e. increased capacity). However, this is considered to be optimal, due to the often marginal cost of increased capacity versus significant cost of re-work should the investment prove to 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 of the existing network footprint is required as the assets are less likely to be reutilised 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 68. Clearly understanding load growth into the future is crucial to making sound investment decisions.

Table 68: Capacity Selection Criteria

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

Best Option Identification

Of the many possible development options that may be identified for meeting demand and service levels, the option which best meets TPCL's investment criteria is determined using a range of analytical approaches. Each of the possible approaches to meeting demand will contribute to strategic objectives in different ways. Increasingly detailed and comprehensive analytical methods are used for evaluating more expensive options. Table 69 summarises the decision tools used to evaluate options depending on their cost.

Table 69: 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.	• TPCL standards. • Industry rules of thumb. • Manufacturer's tables and recommendations. • Simple spreadsheet model based on a few parameters.	Project Manager
$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 $500,000: 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
$500,000 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, payback that will probably consider several variation scenarios. • Risk analysis including environmental and safety considerations - represented as cost estimates. • Resource (financial, workforce, materials, legal) requirements. • Ongoing stakeholder consultation may be required especially large customers. • Short form business case presented to the Board, justifying recommended option.	
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 prioritised when competition for resources exists in the management of conflicting stakeholder Interests. Safety, viability, pricing, supply quality and compliance is the order of priority for managing the conflicts. These factors cannot be applied generally, as each project will have its own combination of these factors presenting in various degrees. Instead, a weighting approach is used recognising the relative severity of these factors between projects and their importance relative to each other. Each factor also implicitly recognises risk however this may need to be rationalised as it affects the AWP as a whole. The resulting prioritised AWP is presented to the TPCL Board for approval with supporting justification in the updated AMP.

Electrification and Energy Efficiency

TPCL 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 TPCL will use these solutions, e.g. specifying low loss cores used in the magnetic circuits of transformers.

Power consumed by TPCL 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. Southland Power Trust (TPCL's shareholder) formed the Southland Warm Homes Trust (SWHT) in 2008 with the Electricity Invercargill Limited (EIL). 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 make a contribution. 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 TPCL is actively encouraged. Currently there are no distributed generators within TPCL's network that 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 TPCL'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 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 any and all safety requirements promulgated by TPCL.
- TPCL 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 TPCL. Such metering may need to be half-hourly.
- TPCL 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 TPCL's own prevailing standards.

Use of Non-Network Solutions

TPCL 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. 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. 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 consumer behaviour create opportunities, but also complexities and risks for TPCL. 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 70: 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 need to 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, but complex assets (such as a zone substation) will require substantial design work before installation. Equipment and materials are procured (as per the relevant design or standard) and these are implemented according to TPCL's standardisation requirements.

Post-installation, the commissioning process follows. This process is either specified in the design or (for standardised 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 have the objective 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 delivery of desired service levels over the long term.

Inspection and testing programmes identify assets that are 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 a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole-of-life cost analysis, there are several other replacement drivers including operational/public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology. Some of these may be diminished through cost analysis. Asset replacement requirements might also be impacted by the network development driver.

Innovations That Defer Asset Replacement

Although asset age is taken into account in any replacement decision, asset condition is the main driver. There are a number of 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 71.

Table 71: Replacement and Renewal Decisions per Asset Category

Asset Category	Sub Category	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.
	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.

Asset Category	Sub Category	Replacement & Renewal Decision Approach
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 yrs 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. 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).

Asset Category	Sub Category	Replacement & Renewal Decision Approach
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 a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

Table 72: Non-routine Replacement & Renewal Projects (next 12 months)

Project Description	CAPEX Cost & Timing
Asset Replacement and Renewal Projects: TPCL has kept a number of spare zone substation transformers, displaced from previous upgrade works. These transformers have been maintained and kept available to use for use in the TPCL network. There are three zone substations where the existing transformers are in need of retirement or refurbishment, depending on condition. During the 23/24 year there are three transformer moves planned: At Seaward Bush the old badly leaking 10 MVA transformers will be changed with the ex Waikiwi 6/12 MVA transformers and the old transformers scrapped as being at the end of their economic life. At Glenham the old leaking 1.5 MVA transformer will be replaced with the best of the two spare 1.5 MVA transformers and the ex-Glenham transformer evaluated for refurbishment and returning to spares. At Awarua the existing 5MVA transformer is badly rusting and in need of a mid life refurbishment. The current spare 5MVA transformer will be installed and the ex Awarua transformer will be refurbished and returned to spares. TPCL has a spare 30/40 MVA 66/33 kV spare transformer for the two units at North Makarewa which supply the whole 66 kV network. The spare transformer has a small tertiary 11 kV winding and it has been in service at Mossburn to supply the local area. Recent concerns over the North Makarewa bushings have highlighted the time it would take to move this large transformer from Mossburn to Makarewa and get it into service on failure of one of the existing North Makarewa transformers. To provide the required security to the 66 kV system and continue to service the Mossburn customers, a new small 5MVA 66/11 kV transformer will be installed at Mossburn allowing the permanent location of the 30/40 MVA transformer at North Makarewa. The 23/24 work will involve the design and transformer ordering with completion in the following year. The Orawia substation upgrade project will be completed in 23/24 with new switchgear, protection, control building and the removal of the earthquake prone structures,	$4,408,626

Project Description	CAPEX Cost & Timing
The remaining old link boxes on the 400m North West, 3 block section, of the Gore main street will be replaced along with removing the remaining overhead lines and poles. The replacement link boxes will connect to the existing underground cable network that already supplies the South East side and much of the existing commercial area of Gore.	
Critical Spares: For 23/24 two items have been identified for addition to the critical spares: One complete Coopers 150 Amp regulator and controller – the original spares have all been used to repair the existing fleet of 72 regulators. Complete regulators will allow for timely and simple replacements on site and repairs in the workshop and return to spares. One Nova circuit breaker – these circuit breakers in the field have been subject to planned maintenance and testing, but difficult to achieve up a pole on the side of the road, a safer and quicker option is to replace the unit with a tested spare then maintain the removed circuit breaker in the workshop and return it to spares for the next job.	$130,096

Table 73: Non-routine Replacement & Renewal Projects (next four years)

Project Description	CAPEX Cost & Timing
Bluff Switchboard Replacement: The Bluff 11 kV switchboard with oil filled circuit breakers will reach its expected 45 year life in 2026. The design and ordering will be completed in 24/25 with installation and change over in 25/26.	$1,809,576 24/25/26
Mataura Transformer Replacement: These two transformers are serviceable but in poor condition and now at 57 years old and without any half-life refurbishment are the next transformers to be replaced. While condition will be carefully monitored over the next years, it is expected to replace these from design in 2026 with completion by 2029.	$3,688,000. 26/27/28/29
Makarewa Switchboard Replacement: The Makarewa 11 kV switchboard with oil filled circuit breakers will reach its expected 45 year life in 2027. The design and ordering will be completed in 27/28 with installation and change over in 28/29.	$2,066,086 27/28/29
North Gore Transformer Replacement: These two transformers are serviceable but in poor condition and now at 56 and 51 years old are not considered economic or suitable for half-life refurbishment. While condition will be carefully monitored over the next years with necessary maintenance and oil leak repairs, but it is expected to replace these transformers by 2031	$3,497,838 28/29/30/31
Hillside Transformer Replacement: This transformer bank is made up of 4 single phase transformers dating from 1936. These are now the oldest and most at risk units on the TPCL network, but with 4 transformers (3 in service and 1 spare) a single failed transformer can be replaced within a day to restore power. While their condition will continue to be monitored over the years it is expected to replace the original bank with a new single 5 MVA 66/11 kV transformer by 2032.	$1,558,756 30/31/32

The non-routine replacement and renewal projects that are under consideration for the remainder of the planning period is described in Table 74.

Table 74: 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 as 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 TPCL'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 75 with the associated capital expenditure estimates.

Table 75: Ongoing Replacement & Renewal Programmes

Budget	Description	CAPEX Cost
Distribution Transformer Replacements	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.	$1,878,745 annually
Ground Mount Platform Transformers	On-going replacements of large platform distribution transformers with ground mount. The selection are generally prioritise during distribution inspections and targeted inspections based on age. Some removed units are refurbished for use as spares.	$1,034,139 in 23/24/25/26/27 then $620,704 annually
Distribution Line Replacement	On-going replacements of distribution line which are generally identified during distribution inspections and targeted inspections based on age.	$6,498,839 23/24 $6,670,561 24/25 then$ 6,754,694 annually
Subtransmission Line Replacement	On-going replacements of subtransmission line which are generally identified during distribution inspections and targeted inspections based on age.	$ 162,632
Zone Substation Minor Replacement	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	$114,519 annually
RTU Replacements	On-going replacements of RTU which are generally identified during distribution inspections and targeted inspections based on age.	$173,667 annually
Relay Replacements	On-going replacements of relay which are generally identified during distribution inspections and targeted inspections based on age.	$273,949 in 23/24, $271,645 in 24/25, $270,723 in 25/26

Budget	Description	CAPEX Cost
		then $270,924 annually
RMU Replacements	On-going ring main unit replacements based on condition, age and serviceability as identified during routine and targeted inspections	$321,784 23/24 then $461,277 annually
LV Pillar Box Replacements	On-going repairs and replacements based on condition and serviceability as identified during routine and targeted inspections	$253,287 annually
Communications Replacement	On-going replacements of communication which are generally identified during distribution inspections and targeted inspections based on age.	$98,075 annually
General Technical Replacement	On-going replacement of assets other than transformer, relay, RTU and communications as they reach end of life and risk of failure increases at distribution substations to maintain reliability of supply and safety in the vicinity of the substation.	$144,845 in 23/24 then $101,564 annually
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. Upgrade works may include additional earthing rods or banks, replacement of surface material (asphalt or gravel) to reduce risk, and installation of insulating fences or fence sections to reduce the risk of transfer of voltage to adjacent conductive fences. Routine testing is completed five yearly with the above ground inspect in yearly. Ongoing maintenance and low priority refurbishment work is expected from 2025 onward.	$3,416,872 in 23/24 & 24/25 then $1,829,186 annually
ABS Replacement	The grey porcelain insulators on EDE Air Break Switches manufactured between 1998 and 2014 have a potential defect which can result in water ingress. Over time this can cause the insulator to crack and break into pieces which can fall when the switch is operated. An appropriate remedial action program have been initiated from 2019/20 to mitigate, repair, or replace the affected ABS's	$1,696,696 in 23/24/25/26/27/28 then $1,087,753 annually
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 TPCL's customers. The identified transformers for refurbishment are at the Makarewa, Edendale, South Gore, Te Anau, North Makarewa and Ohai substations.	$497,880 annually

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 stopbank, 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.

7.4 Commissioning of Assets

The commissioning life cycle phase addresses the following aspects and risks are presented in Table 76.

- 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 76: 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 Capital Expenditure Forecast

The capital expenditure forecast is presented in ~~Table 77~~ and provided in the Information Disclosure Schedule 11a.

~~Table 77: Capital Expenditure Forecast ($000 - constant 2023/24 terms)~~

~~Category~~	~~DPP3~~			~~DPP4~~					~~DPP5~~		
~~CAPEX: Consumer Connection~~	~~2022/23~~	~~2023/24~~	~~2024/25~~	~~2025/26~~	~~2026/27~~	~~2027/28~~	~~2028/29~~	~~2029/30~~	~~2030/31~~	~~2031/32~~	~~2032/33~~
~~Customer Connections (≤ 20 kVA)~~	~~1,515~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~	~~1,587~~
~~Customer Connections (21 to 99 kVA)~~	~~462~~	~~609~~	~~609~~	~~609~~	~~609~~	~~609~~	~~609~~	~~609~~	~~609~~	~~609~~	~~609~~
~~Customer Connections (≥ 100 kVA)~~	~~705~~	~~852~~	~~852~~	~~852~~	~~852~~	~~852~~	~~852~~	~~852~~	~~852~~	~~852~~	~~852~~
~~Distributed Generation Connection~~	~~0~~	~~7~~	~~7~~	~~7~~	~~7~~	~~7~~	~~7~~	~~7~~	~~7~~	~~7~~	~~7~~
~~New Subdivisions~~	~~1,515~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~	~~1,095~~
~~Underwood substation upgrade for Alliance~~	~~115~~	~~1,123~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~McNab Substation upgrade to 33 kV~~	~~2,716~~	~~5,908~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Kaiwera Downs - Mercury 45MW wind farm~~	~~9,350~~	~~576~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Jericho - Southern Generation 35MW wind farm~~	~~0~~	~~0~~	~~0~~	~~0~~	~~254~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Government Decarbonising (GIDI) Funded Projects~~	~~0~~	~~0~~	~~10,000~~	~~5,000~~	~~5,000~~	~~3,500~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
-	~~16,059~~	~~11,758~~	~~14,150~~	~~9,150~~	~~9,404~~	~~7,650~~	~~4,150~~	~~4,150~~	~~4,150~~	~~4,150~~	~~4,150~~
-	-	-	-	-	-	-	-	-	-	-	-
~~CAPEX: System Growth~~	~~2022/23~~	~~2023/24~~	~~2024/25~~	~~2025/26~~	~~2026/27~~	~~2027/28~~	~~2028/29~~	~~2029/30~~	~~2030/31~~	~~2031/32~~	~~2032/33~~

~~Riversdale Substation Upgrade~~	~~0~~	~~100~~	~~500~~	~~1,200~~	~~1,800~~	~~0~~	~~1,200~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Kelso Transformer Upgrade~~	~~0~~	~~507~~	~~1,573~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Riversdale 22kV Line Upgrades~~	~~635~~	~~480~~	~~488~~	~~450~~	~~450~~	~~250~~	~~2,000~~	~~0~~	~~0~~	~~0~~	~~0~~
~~22kV Upgrade Athol - Kingston~~	~~682~~	~~3,106~~	~~2,476~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Easements~~	~~18~~	~~31~~	~~31~~	~~31~~	~~31~~	~~31~~	~~31~~	~~31~~	~~31~~	~~31~~	~~31~~
~~Otatara Transformer Replacement~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~507~~	~~1,337~~
~~Unspecified Growth Projects~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~2,000~~	~~2,000~~	~~4,000~~	~~4,000~~
~~Upgrade Tokanui TX~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~380~~
~~Upgrade Riversdale line to 66 kV~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~1,100~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
-	~~**1,969**~~	~~**4,565**~~	~~**5,069**~~	~~**1,681**~~	~~**2,281**~~	~~**1,381**~~	~~**3,481**~~	~~**5,531**~~	~~**5,231**~~	~~**4,538**~~	~~**5,749**~~
-	-	-	-	-	-	-	-	-	-	-	-
~~**CAPEX: Asset Replacement and Renewal**~~	~~**2022/23**~~	~~**2023/24**~~	~~**2024/25**~~	~~**2025/26**~~	~~**2026/27**~~	~~**2027/28**~~	~~**2028/29**~~	~~**2029/30**~~	~~**2030/31**~~	~~**2031/32**~~	~~**2032/33**~~
~~Distribution Transformer Replacements~~	~~977~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~	~~1,879~~
~~Ground Mount Platform Transformers~~	~~92~~	~~1,034~~	~~1,034~~	~~1,034~~	~~1,034~~	~~621~~	~~621~~	~~621~~	~~621~~	~~621~~	~~621~~
~~Distribution Line Replacement~~	~~6,375~~	~~6,499~~	~~6,671~~	~~6,755~~	~~6,755~~	~~6,755~~	~~6,755~~	~~6,755~~	~~6,755~~	~~6,755~~	~~6,755~~
~~Subtransmission Line Replacement~~	~~154~~	~~163~~	~~163~~	~~163~~	~~163~~	~~163~~	~~163~~	~~163~~	~~163~~	~~163~~	~~163~~
~~Zone Substation Minor Replacement~~	~~108~~	~~115~~	~~115~~	~~115~~	~~115~~	~~115~~	~~115~~	~~115~~	~~115~~	~~115~~	~~115~~
~~RTU Replacement~~	~~164~~	~~174~~	~~174~~	~~174~~	~~174~~	~~174~~	~~174~~	~~174~~	~~174~~	~~174~~	~~174~~
~~Relay Replacements~~	~~65~~	~~274~~	~~272~~	~~271~~	~~271~~	~~271~~	~~271~~	~~271~~	~~271~~	~~271~~	~~271~~
~~Communications Replacement~~	~~93~~	~~98~~	~~98~~	~~98~~	~~98~~	~~98~~	~~98~~	~~98~~	~~98~~	~~98~~	~~98~~
~~General Technical Replacement~~	~~41~~	~~145~~	~~102~~	~~102~~	~~102~~	~~102~~	~~102~~	~~102~~	~~102~~	~~102~~	~~102~~
~~ABS Replacements~~	~~1,625~~	~~1,696~~	~~1,696~~	~~1,696~~	~~1,696~~	~~1,696~~	~~1,088~~	~~1,088~~	~~1,088~~	~~1,088~~	~~1,088~~
~~Power Transformer Refurbishment~~	~~425~~	~~498~~	~~498~~	~~498~~	~~498~~	~~498~~	~~498~~	~~498~~	~~498~~	~~498~~	~~498~~
~~Orawia Substation Upgrade~~	~~701~~	~~2,037~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Makarewa Switchboard Replacement~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~262~~	~~1,806~~	~~0~~	~~0~~	~~0~~	~~0~~

~~Bluff Switchboard Replacement~~	~~0~~	~~0~~	~~229~~	~~1,580~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Ripple Plant Upgrade~~	~~118~~	~~27~~	~~0~~	~~0~~	~~0~~	~~766~~	~~766~~	~~766~~	~~766~~	~~0~~	~~0~~
~~Seaward Bush Transformer Change~~	~~0~~	~~657~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Glenham Transformer Change~~	~~0~~	~~323~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~RMU Renewals~~	~~244~~	~~322~~	~~461~~	~~461~~	~~461~~	~~461~~	~~461~~	~~461~~	~~923~~	~~461~~	~~461~~
~~Gore Link Box Replacement and Undergrounding~~	~~0~~	~~620~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Condition Based Asset Replacements~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~1,458~~	~~1,458~~	~~1,458~~	~~1,458~~	~~2,219~~	~~2,219~~
~~LV Pillar Box Replacements and Refurbishments~~	~~247~~	~~253~~	~~253~~	~~253~~	~~253~~	~~253~~	~~253~~	~~253~~	~~253~~	~~253~~	~~253~~
~~Circuit Breaker Replacements~~	~~462~~	~~433~~	~~489~~	~~489~~	~~489~~	~~489~~	~~489~~	~~489~~	~~607~~	~~607~~	~~607~~
~~Awarua Transformer Change~~	~~0~~	~~392~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Hillside Transformer Replacement~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~380~~	~~1,178~~	~~0~~
~~Mataura Transformer Replacement~~	~~0~~	~~0~~	~~0~~	~~0~~	~~507~~	~~1,844~~	~~1,337~~	~~0~~	~~0~~	~~0~~	~~0~~
~~North Gore Transformer Replacement~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~507~~	~~1,749~~	~~1,242~~	~~0~~	~~0~~
~~Mossburn Transformer Replacement~~	~~0~~	~~380~~	~~1,277~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
-	**~~11,891~~**	**~~18,016~~**	**~~15,409~~**	**~~15,566~~**	**~~14,493~~**	**~~17,903~~**	**~~18,839~~**	**~~16,938~~**	**~~17,390~~**	**~~16,479~~**	**~~15,301~~**
-	-	-	-	-	-	-	-	-	-	-	-
~~CAPEX: Asset Relocations~~	**~~2022/23~~**	**~~2023/24~~**	**~~2024/25~~**	**~~2025/26~~**	**~~2026/27~~**	**~~2027/28~~**	**~~2028/29~~**	**~~2029/30~~**	**~~2030/31~~**	**~~2031/32~~**	**~~2032/33~~**
~~Line Relocations~~	~~187~~	~~130~~	~~130~~	~~130~~	~~130~~	~~130~~	~~130~~	~~130~~	~~130~~	~~130~~	~~130~~
-	**~~187~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**	**~~130~~**
-	-	-	-	-	-	-	-	-	-	-	-
~~CAPEX: Quality of Supply~~	**~~2022/23~~**	**~~2023/24~~**	**~~2024/25~~**	**~~2025/26~~**	**~~2026/27~~**	**~~2027/28~~**	**~~2028/29~~**	**~~2029/30~~**	**~~2030/31~~**	**~~2031/32~~**	**~~2032/33~~**
~~Supply Quality Upgrades~~	~~348~~	~~370~~	~~370~~	~~370~~	~~370~~	~~370~~	~~370~~	~~370~~	~~370~~	~~370~~	~~370~~
~~Mobile Substation Site Made Ready~~	~~152~~	~~63~~	~~277~~	~~277~~	~~277~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Network Improvement Projects~~	~~129~~	~~219~~	~~137~~	~~137~~	~~137~~	~~137~~	~~137~~	~~137~~	~~137~~	~~137~~	~~137~~
~~Otatara Regulator and Automation~~	~~0~~	~~387~~	~~84~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
-	**~~630~~**	**~~1,039~~**	**~~868~~**	**~~784~~**	**~~784~~**	**~~507~~**	**~~507~~**	**~~507~~**	**~~507~~**	**~~507~~**	**~~507~~**
-	-	-	-	-	-	-	-	-	-	-	-

~~CAPEX: Other Reliability, Safety and Environment~~	~~2022/23~~	~~2023/24~~	~~2024/25~~	~~2025/26~~	~~2026/27~~	~~2027/28~~	~~2028/29~~	~~2029/30~~	~~2030/31~~	~~2031/32~~	~~2032/33~~
~~Earth Upgrades~~	~~2,420~~	~~3,417~~	~~3,417~~	~~1,829~~	~~1,829~~	~~1,829~~	~~1,829~~	~~1,829~~	~~1,829~~	~~1,829~~	~~1,829~~
~~Substation Safety~~	~~267~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Remote Area Power Supply~~	~~0~~	~~0~~	~~0~~	~~0~~	~~155~~	~~310~~	~~310~~	~~310~~	~~310~~	~~310~~	~~310~~
~~Hillside Protection Remediation~~	~~66~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Critical Spares~~	~~0~~	~~138~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Communications Projects~~	~~0~~	~~209~~	~~207~~	~~207~~	~~207~~	~~239~~	~~411~~	~~411~~	~~411~~	~~411~~	~~411~~
~~North Gore Move OH structure away from Road Fence~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Kennington Fibre install from Racecourse Rd~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
-	~~3,700~~	~~3,765~~	~~3,624~~	~~2,036~~	~~2,191~~	~~2,379~~	~~2,551~~	~~2,551~~	~~2,551~~	~~2,551~~	~~2,551~~
-	-	-	-	-	-	-	-	-	-	-	-
~~Total Network CAPEX~~	~~34,436~~	~~39,272~~	~~39,249~~	~~29,347~~	~~29,283~~	~~29,950~~	~~29,658~~	~~29,807~~	~~29,959~~	~~28,355~~	~~28,387~~
-	-	-	-	-	-	-	-	-	-	-	-
~~CAPEX: Non-Network Assets~~	~~2022/23~~	~~2023/24~~	~~2024/25~~	~~2025/26~~	~~2026/27~~	~~2027/28~~	~~2028/29~~	~~2029/30~~	~~2030/31~~	~~2031/32~~	~~2032/33~~
~~Racecourse Road Porch~~	~~0~~	~~15~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~

Values Fully Marked Up, No Inflation, Base Year dollars

7.6 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 78: 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 particular locations (e.g. Aerial trespass, subdivision)	Historical land use rights are formalised should the land be required for the installation of new assets.

Category	Risk Title	Risk Cause	Treatment Plan
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 to be 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.

8 Operating Expenditure

2024-25: Changes as indicated.

Operating Expenditure (OPEX) is required to operate and maintain TPCL's networks.

8.1 The Operation and Maintenance Lifecycle Phase – 2024/2034 AMP Update

The 2023-33 AMP is largely unchanged.

Line Access Maintenance

These works (to be outsourced to external contractors) are addressing the vegetation at ground level that prevent access to assets for day-to-day operations such as inspection, maintenance and addressing network faults. The OPEX for Line Access Maintenance is budgeted at $ 165,290 from FY24/25 onwards.

8.2 Asset Operation – 2024/2034 AMP Update

Operational Expenditure Forecast

The operational expenditure forecast is presented in Table 79 and provided in the Information Disclosure Schedule 11b.

Table 79: 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**
General Distribution Replacement and Renewal	362	447	447	447	447	447	447	447	447	447	447
Subtransmission Replacement and Renewal	65	100	100	100	100	100	100	100	100	100	100
Zone Substation Replacement and Renewal	70	74	74	74	74	74	74	74	74	74	74
Power Transformer Replacement and Renewal	138	252	252	252	252	252	252	252	252	252	252
Distribution Transformer Replacement and Renewal	95	132	132	132	132	132	132	132	132	132	132
Locks and Security	65	0	0	0	0	0	0	0	0	0	0
	795	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**	**1,005**
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	1,525	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278

Line Access Maintenance	0	180	180	180	180	180	180	180	180	180	180
	1,525	**1,458**	**1,458**	**1,458**	**1,458**	**1,458**	**1,458**	**1,458**	**1,458**	**1,458**	**1,458**

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**
Routine Distribution Inspections	1,321	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869
Distribution Routine Maintenance	361	633	633	633	633	633	633	633	633	633	633
Distribution Earthing Mtce	38	146	146	146	146	146	146	146	146	146	146
Distribution Corrective Maintenance	353	422	422	422	422	422	422	422	422	422	422
Communications Routine Inspection and Checks	84	90	90	90	90	90	90	90	90	90	90
Technical Routine Inspections & Checks	511	534	534	534	534	534	534	534	534	534	534
Technical Routine Maintenance	768	1,229	1,229	1,229	1,229	1,229	1,229	1,229	1,229	1,229	1,229
Technical Corrective Maintenance	510	262	262	262	262	262	262	262	262	262	262
Infrared Survey	25	26	26	26	26	26	26	26	26	26	26
Partial Discharge Survey	53	56	56	56	56	56	56	56	56	56	56
Supply Quality Checks	6	22	22	22	22	22	22	22	22	22	22
Spares Checks and Minor Maintenance	11	21	21	21	21	21	21	21	21	21	21
Connections Minor Maintenance	185	156	156	156	156	156	156	156	156	156	156
RAPS maintenance	29	19	19	19	19	19	19	19	19	19	19
Routine Distribution Inspections - Additional helicopter survey	94	127	127	127	127	127	127	127	127	127	127
LV Network Conductor Inspections	0	98	98	98	98	0	0	0	0	0	0
	4,350	**5,710**	**5,710**	**5,710**	**5,710**	**5,612**	**5,612**	**5,612**	**5,612**	**5,612**	**5,612**

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**
Depot Location Recovery Fixed Fee	339	354	354	354	354	354	354	354	354	354	354

Incident Response - Distribution - Unplanned	5,233	3,607	3,607	3,607	3,607	3,607	3,607	3,607	3,607	3,607	3,607
Incident Response - Communications - Unplanned	64	67	67	67	67	67	67	67	67	67	67
Incident Response - Technical - Unplanned	299	251	251	251	251	251	251	251	251	251	251
	5,936	**4,279**	**4,279**	**4,279**	**4,279**	**4,279**	**4,279**	**4,279**	**4,279**	**4,279**	**4,279**
Operational Expenditure Total	**12,606**	**12,453**	**12,453**	**12,453**	**12,453**	**12,355**	**12,355**	**12,355**	**12,355**	**12,355**	**12,355**
System Operations and Network Support	2,972	5,142	6,380	6,627	6,627	6,627	6,627	6,627	6,627	6,627	6,627
Business Support	4,404	3,894	3,846	3,977	3,977	3,977	3,977	3,977	3,977	3,977	3,977
AMP Total Operational Expenditure	**19,982**	**21,489**	**22,679**	**23,058**	**23,058**	**22,960**	**22,960**	**22,960**	**22,960**	**22,960**	**22,960**
Grand Total Capital and Operational Expenditure	**62,400**	**81,979**	**60,828**	**52,923**	**61,236**	**62,733**	**99,598**	**69,481**	**80,400**	**60,092**	**60,681**

Values Fully Marked Up, No Inflation, Base Year dollars

8.3 Asset Operation – 2024/2034 AMP Update

The operations aspect of the O&M lifecycle phase refers to the day-to-day activities required to provide service delivery to TPCL's customers. Operation of the network is effectively the service that TPCL'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. The contents covered in the 2023-33 AMP are largely unchanged except for the PowerNet Business Continuity Plan.

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.

Operating Expenditure (OPEX) is required to operate and maintain TPCL'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.

8.4 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 80: Operation & Maintenance Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Operational Performance	**Damage due to extreme Physical Event (i.e.**	Damage caused by force majeure to our infrastructure or equipment (e.g. floods, earthquakes)	Structures are inspected and maintained to retain structural functionality

Category	Risk Title	Risk Cause	Treatment Plan
	Christchurch earthquake)		
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 asset are operated correctly
	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 being implemented
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 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	Utilise the Planned Interruption SAIDI and SAIFI allocations optimally by planning work more effectively

Category	Risk Title	Risk Cause	Treatment Plan
		- Employment legislation - Metering recertification	

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 TPCL'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. The OPEX for vegetation management is budgeted at $ 1,224,711 from 2023/24 onward. Vegetation management has been fully outsourced to Asplundh.

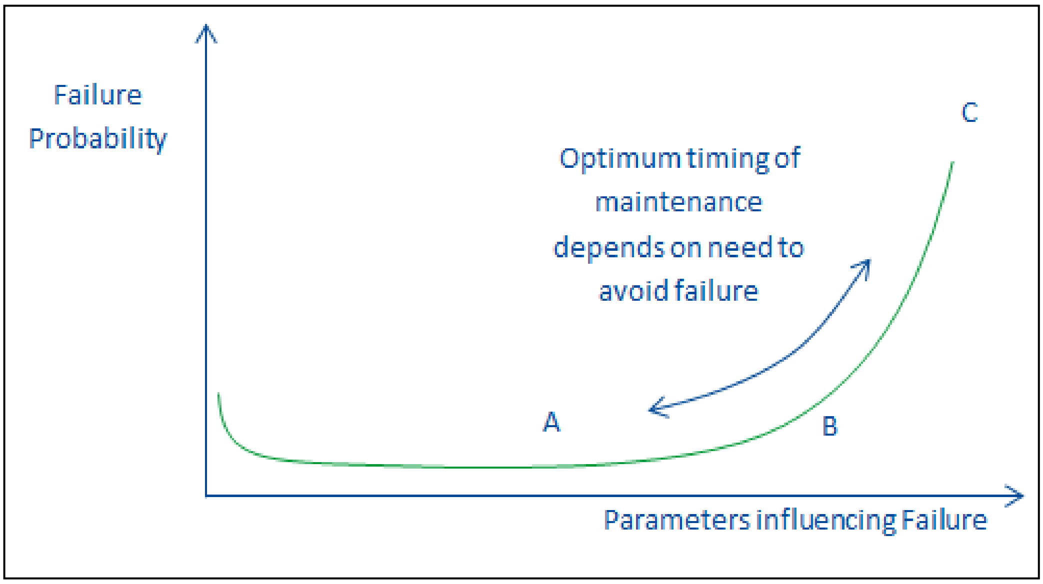
Asset Maintenance

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 be designed to "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 51. 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 51: 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.

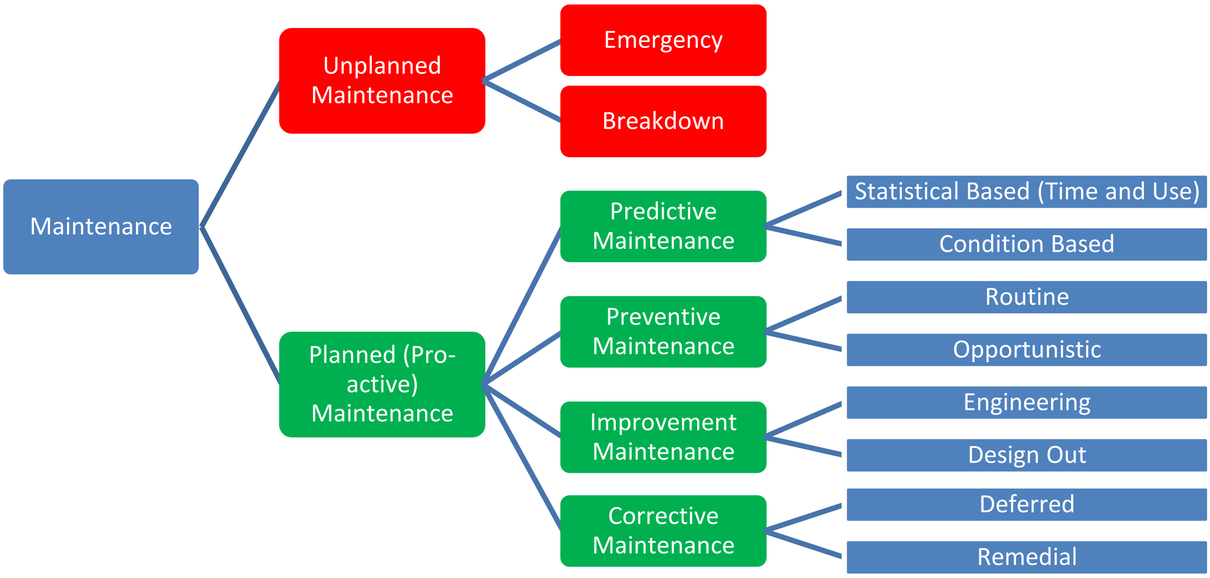
TPCL's maintenance decisions are made on cost-benefit criteria with the principal benefit being avoidance of supply interruption. Increasing maintenance costs (labour and consumables) over the asset's lifecycle, taken together with the cost of discarding unused component life, must be traded off against 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 TPCL'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 51 and condition will be extensively monitored to minimise the likelihood of supply interruption. Meanwhile assets supplying merely a small customers, 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 Figure 52.

Figure 52: 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 age. Condition assessment allows deferral of maintenance cost for assets that are in good condition, and permits maintenance to be focused on the 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.

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 81 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 81: 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.	2-5 yearly Ad-hoc based
	U/G	Generally, run to failure and repair. Inspection of visible terminations as part of zone substation checks, opportunistic inspection if covers removed for other work, sheath insulation IR test. Inspect oil pressure gauge.	Part of monthly substation inspections 5 yearly

		Sheath test, Link box & Sheath arrestors inspection and oil condition (RGP) along with planned maintenance schedule. 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.	
	Distributed Subtransmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Exercise switch and lubrication of moving parts.	3 yearly 6 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. Oil CB's after 3 faults in-between planned service intervals
	Power Transformers	Condition monitoring through periodic inspections. Replacement of breathers when saturated. Function checks on auxiliaries (Buchholz, pressure relief, thermometers). Predictive maintenance - oil analysis (moisture, dissolved gases) 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 and routine electrical testing. 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 3-7yrs aligned with Tap Changer schedule Non-periodic
	Distribution Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas	Monthly

		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.	5 Yearly Oil CB's after 3 faults in-between planned service intervals Non-Periodic
	Other (Buildings, Structures, 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. Battery testing 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. Earth mat testing	Monthly 3 monthly 5 yearly Non-Periodic 5-10 y ears
Distribution Network	O/H	Condition assessment through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	3-5 years
	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.	Cable inspection & testing in conjunction with distribution equipment program
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. PD & IR on selected equipment	1 - 6 years

		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. Batteries & relays planned inspection & maintenance at same intervals.	
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.	yearly or (5-yearly if <100 kVA O/H) 15 Years (>100kVA platform & ground mount) 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. In selected RMU's Batteries & relays planned inspection & maintenance at same intervals.	1 yearly 5 year (Oil) 10 year (Gas)
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. Overhead structures included in distribution network inspections.	Annual
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

	Dist. Earths	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.	Visual 2 years Testing 5 years
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Planned maintenance & remedial actions.	Annual 2 yearly
	Vegetation	Inspection of networks using timeframes of 1, 2.5 and 5 years based on feeder criticality Planned maintenance & remedial actions.	

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. Testing may be destructive or non-destructive; for example insulation resistance (IR) testing simply gives an ohmic value for insulation under test, while very low frequency (VLF) 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 82 . 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.

Table 82: 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.	$1,320,807 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.	$511,050 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.	$601,360 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.	$1,167,718 p.a.
Distribution Corrective Maintenance	Permanent repairs carried out on faulted Distribution assets that had temporarily been made safe/functional during the initial incident response.	$ 400,504 p.a.
Technical Corrective Maintenance	Permanent repairs carried out on faulted technical assets that had temporarily been made safe/functional during the initial incident response.	$248,495 p.a.
Communications Routine Inspection and Checks	Ventia undertakes routine maintenance inspections on the communications equipment.	$84,397 '23/24/25 then $86,397 p.a.
Distribution Earthing Maintenance	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed five yearly.	$138,183 p.a.
Partial Discharge Survey	Partial discharge condition monitoring of equipment to identify abnormal discharge levels before failure occurs.	$53,250 p.a.
Infra-Red Survey	Routine Infra-Red condition monitoring survey of bus-work, connections, contacts etc. for abnormal heating as indication of poor electrical contact between current carrying components which may lead to voltage quality issues and/or failure of equipment.	$24,921 p.a.
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	$21,300 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.	$10,626 '23/24-24/25 $19,490 p.a. thereafter
Connections Minor Maintenance	Operational portion of expenditure for the customer connections process is captured in this budget.	$113,208 p.a.

Budget	Description	OPEX Cost
RAPS maintenance	A budget for the maintenance of remote area power supplies.	$18,100 p.a. '23/24-25/26 $33,450 p.a. '26/27-28/29 $54,800 p.a. '29/30-32/33
LV Network Conductor Inspections	A budget for the inspecting and data gathering on the LV network assets	$94,320 p.a. 23/24 to 26/27

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 83.

Table 83: 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.	$425,063 p.a.
Subtransmission Refurbishment	A budget to allow refurbishment work that doesn't impact on the valuation of the subtransmission assets. This covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	$95,183 p.a.

Budget	Description	OPEX Cost
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.	$69,545 p.a.
Power Transformer Replacement and Renewal	A budget to allow refurbishment works that won't impact on the valuation of the power transformers. Covers items like painting.	$238,227 p.a.
Distribution Transformer Replacement & Renewal	Refurbishment of distribution transformers such as rust repairs, paint touch-up, oil renewal, replacement of minor parts such as bushings, seals etc.	$125,384 p.a.
Locks and Security	Upgrading the locks and security of all assets to minimise the risk of unauthorised access.	$64,929 p.a. 23/24-24/25 & $20,128 in 25/26

8.5 Asset Operation

The operations aspect of the O&M lifecycle phase refers to the day-to-day activities required to provide service delivery to TPCL's customers. Operation of the network is effectively the service that TPCL'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 TPCL 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 TPCL'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, TPCL 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 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.

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.

- This plan was activated in 2020-21 due to COVID-19 and may need to be activated again should another outbreak of COVID-19 occurs. The plan is available as a separate document.

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 zone substation.

Network Operating Plans

As contingency for major outages on the TPCL 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

TPCL 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 $3,984,618 per annum.

Operational Expenditure Forecast

The operational expenditure forecast is presented in ~~Table 84~~ and provided in the Information Disclosure Schedule 11b.

~~Table 84: Operating Expenditure Forecast ($000 - constant 2023/24 terms)~~

~~**Category**~~	~~**DPP3**~~			~~**DPP4**~~					~~**DPP5**~~		
~~**OPEX: Asset Replacement and Renewal**~~	~~**2022/23**~~	~~**2023/24**~~	~~**2024/25**~~	~~**2025/26**~~	~~**2026/27**~~	~~**2027/28**~~	~~**2028/29**~~	~~**2029/30**~~	~~**2030/31**~~	~~**2031/32**~~	~~**2032/33**~~
~~General Distribution Replacement and Renewal~~	~~400~~	~~425~~	~~425~~	~~425~~	~~425~~	~~425~~	~~425~~	~~425~~	~~425~~	~~425~~	~~425~~
~~Subtransmission Replacement and Renewal~~	~~89~~	~~95~~	~~95~~	~~95~~	~~95~~	~~95~~	~~95~~	~~95~~	~~95~~	~~95~~	~~95~~
~~Zone Substation Replacement and Renewal~~	~~66~~	~~70~~	~~70~~	~~70~~	~~70~~	~~70~~	~~70~~	~~70~~	~~70~~	~~70~~	~~70~~
~~Power Transformer Replacement and Renewal~~	~~71~~	~~238~~	~~238~~	~~238~~	~~238~~	~~238~~	~~238~~	~~238~~	~~238~~	~~238~~	~~238~~
~~Distribution Transformer Replacement and Renewal~~	~~32~~	~~125~~	~~125~~	~~125~~	~~125~~	~~125~~	~~125~~	~~125~~	~~125~~	~~125~~	~~125~~
~~Locks and Security~~	~~96~~	~~65~~	~~65~~	~~20~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
-	~~**755**~~	~~**755**~~	~~**1,018**~~	~~**1,018**~~	~~**974**~~	~~**953**~~	~~**953**~~	~~**953**~~	~~**953**~~	~~**953**~~	~~**953**~~
-	-	-	-	-	-	-	-	-	-	-	-
~~**OPEX: Vegetation Management**~~	~~**2022/23**~~	~~**2023/24**~~	~~**2024/25**~~	~~**2025/26**~~	~~**2026/27**~~	~~**2027/28**~~	~~**2028/29**~~	~~**2029/30**~~	~~**2030/31**~~	~~**2031/32**~~	~~**2032/33**~~
~~Vegetation Management~~	~~1,339~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~	~~1,225~~
-	~~**1,339**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~	~~**1,225**~~
-	-	-	-	-	-	-	-	-	-	-	-
~~**OPEX: Routine and Corrective Maintenance and Inspection**~~	~~**2022/23**~~	~~**2023/24**~~	~~**2024/25**~~	~~**2025/26**~~	~~**2026/27**~~	~~**2027/28**~~	~~**2028/29**~~	~~**2029/30**~~	~~**2030/31**~~	~~**2031/32**~~	~~**2032/33**~~
~~Routine Distribution Inspections~~	~~1,229~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~	~~1,321~~
~~Distribution Routine Maintenance~~	~~465~~	~~601~~	~~601~~	~~601~~	~~601~~	~~601~~	~~601~~	~~601~~	~~601~~	~~601~~	~~601~~
~~Distribution Earthing Mtce~~	~~100~~	~~138~~	~~138~~	~~138~~	~~138~~	~~138~~	~~138~~	~~138~~	~~138~~	~~138~~	~~138~~
~~Distribution Corrective Maintenance~~	~~377~~	~~401~~	~~401~~	~~401~~	~~401~~	~~401~~	~~401~~	~~401~~	~~401~~	~~401~~	~~401~~
~~Communications Routine Inspection and Checks~~	~~60~~	~~84~~	~~84~~	~~87~~	~~87~~	~~87~~	~~87~~	~~87~~	~~87~~	~~87~~	~~87~~
~~Technical Routine Inspections & Checks~~	~~525~~	~~511~~	~~511~~	~~511~~	~~511~~	~~511~~	~~511~~	~~511~~	~~511~~	~~511~~	~~511~~
~~Technical Routine Maintenance~~	~~1,066~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~	~~1,168~~
~~Technical Corrective Maintenance~~	~~225~~	~~248~~	~~248~~	~~248~~	~~248~~	~~248~~	~~248~~	~~248~~	~~248~~	~~248~~	~~248~~
~~Infrared Survey~~	~~23~~	~~25~~	~~25~~	~~25~~	~~25~~	~~25~~	~~25~~	~~25~~	~~25~~	~~25~~	~~25~~
~~Partial Discharge Survey~~	~~40~~	~~53~~	~~53~~	~~53~~	~~53~~	~~53~~	~~53~~	~~53~~	~~53~~	~~53~~	~~53~~
~~Supply Quality Checks~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~
~~Spares Checks and Minor Maintenance~~	~~10~~	~~11~~	~~11~~	~~19~~	~~19~~	~~19~~	~~19~~	~~19~~	~~19~~	~~19~~	~~19~~
~~Connections Minor Maintenance~~	~~117~~	~~113~~	~~113~~	~~113~~	~~113~~	~~113~~	~~113~~	~~113~~	~~113~~	~~113~~	~~113~~
~~RAPS maintenance~~	~~105~~	~~18~~	~~18~~	~~18~~	~~33~~	~~33~~	~~33~~	~~55~~	~~55~~	~~55~~	~~55~~

~~LV Network Conductor Inspections~~	~~0~~	~~94~~	~~94~~	~~94~~	~~94~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~TOTAL~~	**~~4,364~~**	**~~4,808~~**	**~~4,808~~**	**~~4,819~~**	**~~4,835~~**	**~~4,740~~**	**~~4,740~~**	**~~4,762~~**	**~~4,762~~**	**~~4,762~~**	**~~4,762~~**
-	-	-	-	-	-	-	-	-	-	-	-
~~OPEX: Service Interruptions and Emergencies~~	**~~2022/23~~**	**~~2023/24~~**	**~~2024/25~~**	**~~2025/26~~**	**~~2026/27~~**	**~~2027/28~~**	**~~2028/29~~**	**~~2029/30~~**	**~~2030/31~~**	**~~2031/32~~**	**~~2032/33~~**
~~Depot Location Recovery Fixed Fee~~	~~225~~	~~339~~	~~339~~	~~339~~	~~339~~	~~339~~	~~339~~	~~339~~	~~339~~	~~339~~	~~339~~
~~Incident Response - Distribution - Unplanned~~	~~3,325~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~	~~3,441~~
~~Incident Response - Communications - Unplanned~~	~~66~~	~~64~~	~~64~~	~~64~~	~~64~~	~~64~~	~~64~~	~~64~~	~~64~~	~~64~~	~~64~~
~~Incident Response - Technical - Unplanned~~	~~209~~	~~240~~	~~240~~	~~240~~	~~240~~	~~240~~	~~240~~	~~240~~	~~240~~	~~240~~	~~240~~
~~TOTAL~~	**~~3,825~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**	**~~4,085~~**
-	-	-	-	-	-	-	-	-	-	-	-
~~Operational Expenditure Total~~	**~~10,282~~**	**~~11,136~~**	**~~11,136~~**	**~~11,102~~**	**~~11,097~~**	**~~11,003~~**	**~~11,003~~**	**~~11,024~~**	**~~11,024~~**	**~~11,024~~**	**~~11,024~~**
~~System Operations and Network Support~~	~~2,916~~	~~3,541~~	~~3,674~~	~~3,763~~	~~3,763~~	~~3,763~~	~~3,763~~	~~3,763~~	~~3,763~~	~~3,763~~	~~3,763~~
~~Business Support~~	~~3,997~~	~~4,286~~	~~4,242~~	~~4,413~~	~~4,413~~	~~4,413~~	~~4,413~~	~~4,413~~	~~4,413~~	~~4,413~~	~~4,413~~
~~AMP Total Operational Expenditure~~	**~~17,195~~**	**~~18,963~~**	**~~19,052~~**	**~~19,278~~**	**~~19,274~~**	**~~19,179~~**	**~~19,179~~**	**~~19,201~~**	**~~19,201~~**	**~~19,201~~**	**~~19,201~~**
-	-	-	-	-	-	-	-	-	-	-	-
~~Grand Total Capital and Operational Expenditure~~	**~~51,631~~**	**~~58,251~~**	**~~58,301~~**	**~~48,626~~**	**~~48,557~~**	**~~49,129~~**	**~~48,837~~**	**~~49,007~~**	**~~49,160~~**	**~~47,556~~**	**~~47,588~~**
-	-	-	-	-	-	-	-	-	-	-	-

Values Fully Marked Up, No Inflation, Base Year dollars

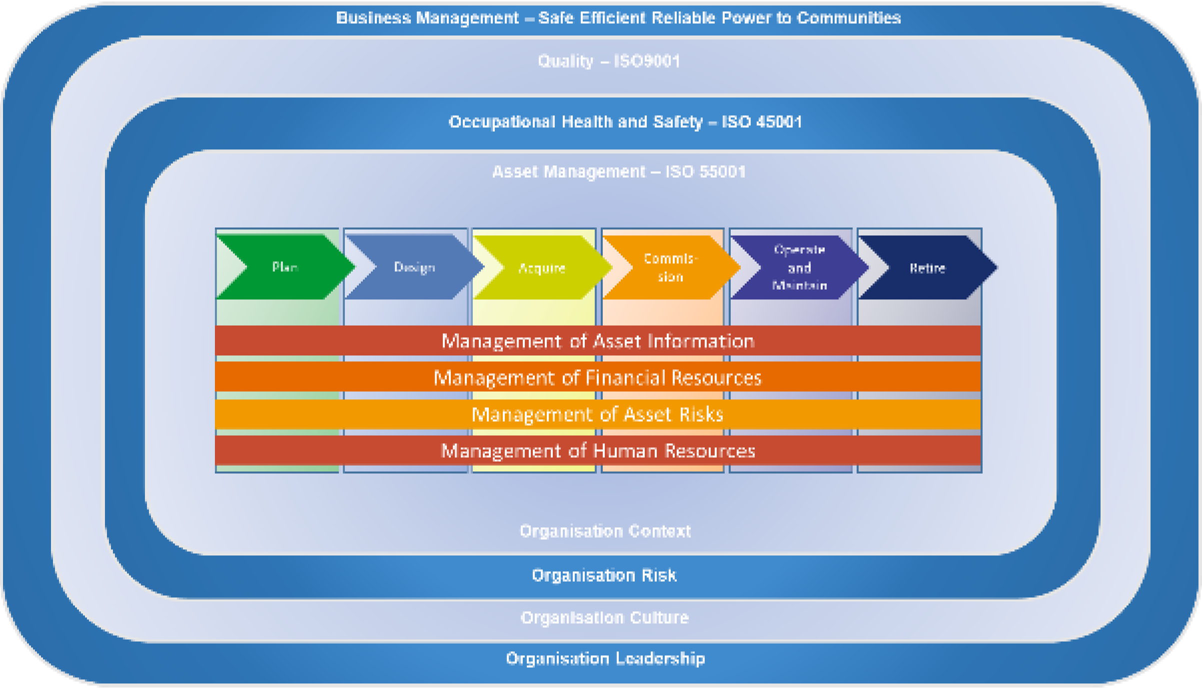
9 Execution Capacity

2024-25: No change

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

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

Figure 53: TPCL's Business Management System



This figure illustrates the asset lifecycle approach that we use in managing the assets of TPCL. 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.

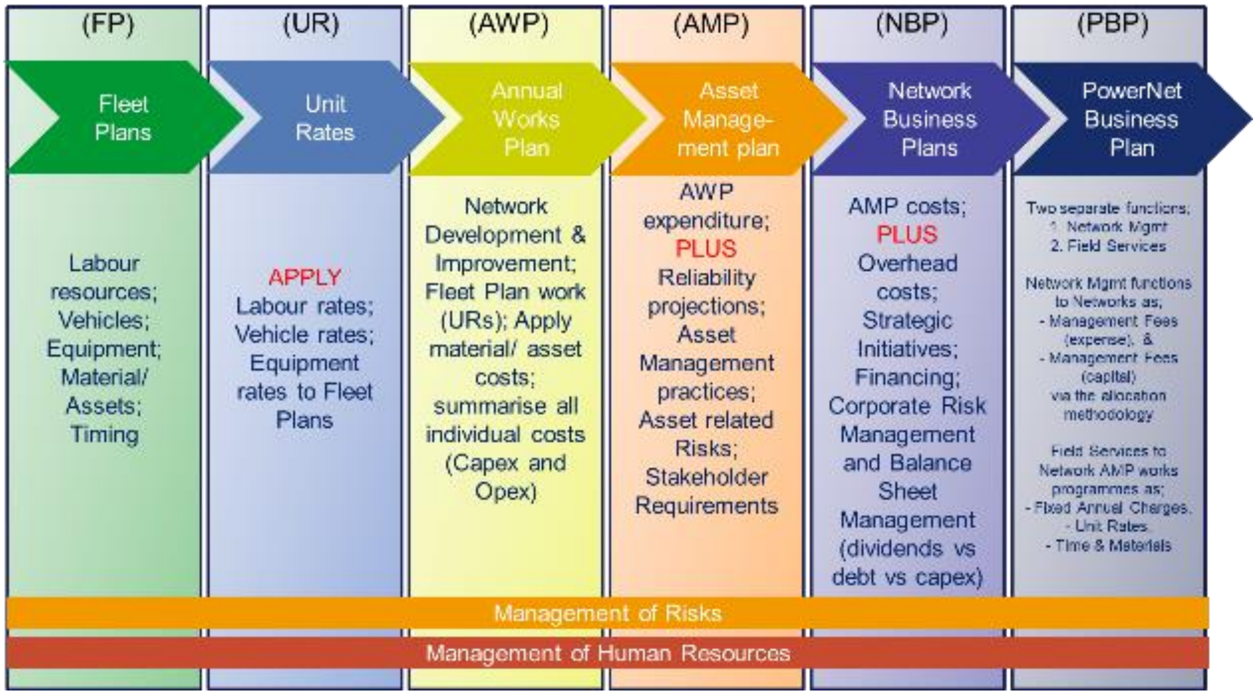
The foundation for managing the assets and determining the required resources and funding is our Fleet Plans. The Fleet Plans

- 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 (Capital Expenditure) and (Operating Expenditure) in the AMP. This value chain is depicted in the following diagram.

Figure 54: TPCL's Value Chain



9.1 People, Culture and Leadership

TPCL's work must be planned, managed and executed by people. Organisational leadership and culture are key determinants in the efficacy of work execution by people.

The TPCL leadership consists of the TPCL and PowerNet Boards and the PowerNet SLT. The TPCL Board sets and monitors the network performance objectives, evaluates, and addresses network and TPCL 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 TPCL Board is met.

The PowerNet SLT manages the assets of TPCL 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 TPCL and PowerNet and does the medium to 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. These adjustments may delay work until resources become available, or use contractors or, if there is a long-term resource requirement, appoint additional staff or procure 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 TPCL'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 TPCL'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. We generally have around 20 vacancies for field and technical staff. PowerNet has appointed 15 trainee linesmen to try and alleviate the shortage, but it will take time to get them to the required level of competency to be fully productive.

9.2 Funding the Business

Revenue

TPCL's revenue comes primarily from retailers who pay for the conveyance of energy over TPCL's network and 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 TPCL to avoid new capital on its balance sheet, but perhaps more importantly also allows TPCL 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 TPCL.

Influences the Value of Assets

An annual independent telephone survey is undertaken each year and consistently indicates TPCL'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, TPCL'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 TPCL with the dilemma of responding to customers wishes for lower cost supply in the face of a "no material decline in SAIDI" requirement and revenue incentives to improve reliability. Factors that will influence TPCL's asset value are shown in Table 85 below:

Table 85: Factors influencing TPCL's asset value

Factors that increase TPCL's asset value	Factors that decrease TPCL'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, TPCL'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

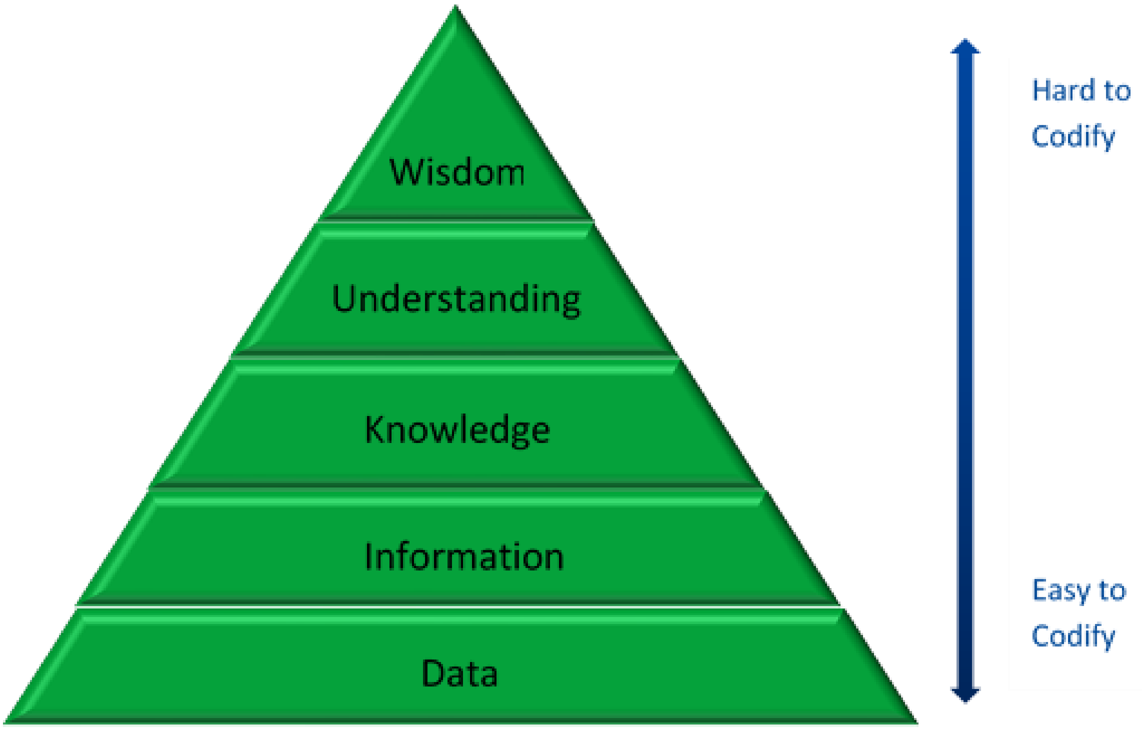
Assets are depreciated using straight line depreciation over the asset expected life. This doesn't strictly model the decline in service potential of an asset. An asset mostly remains serviceable until it has rusted, rotted, acidified, or eroded substantially and then fails quickly. Straight-line depreciation does, however, provide a smooth and reasonably painless means of gathering funds to renew assets reaching the end of their life. This will be particularly important as the potential "bow wave" of asset renewals approaches.

9.3 Information Management

Information Management Model

The data hierarchy model in Figure 55 shows the typical information and knowledge residing within TPCL’s business (including employees from PowerNet).

Figure 55: TPCL's Data Hierarchy Model



The bottom two layers of the hierarchy, ‘*Data’* and ‘*Information’* strongly relate to TPCL’s asset and operational data, and the summaries thereof impacts TPCL’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 quite 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.

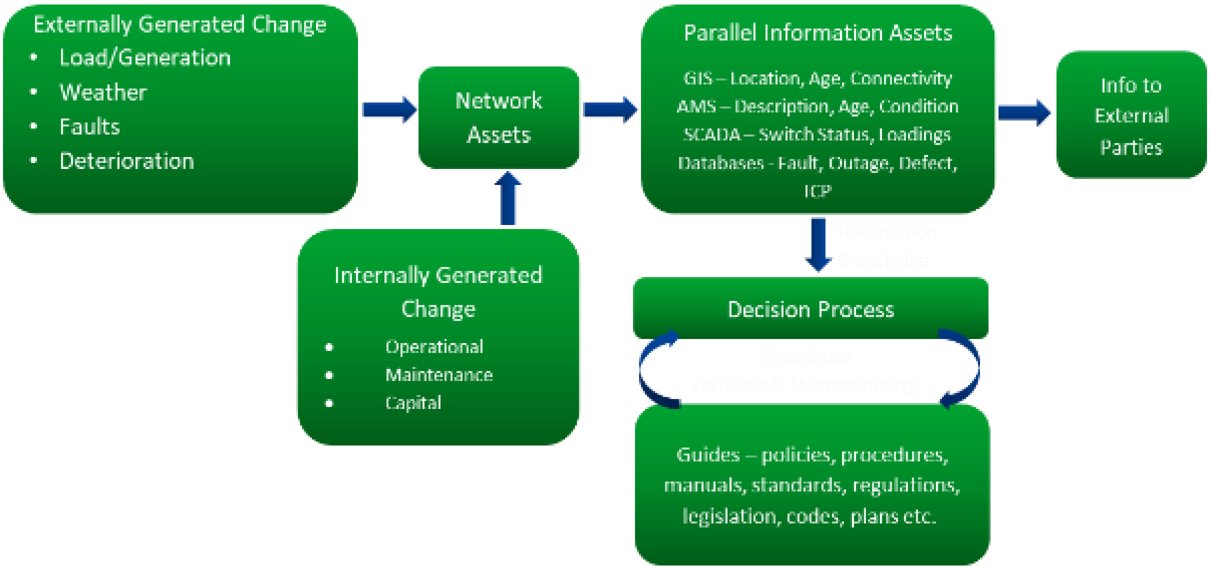
Interfacing with DER resources on the LV network – developing methods to provide network relevant data to DER resources (and their management interface) and obtain data from these sources. This will include developing methods of exchanging information with local generation, storage and discretionary 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.

TPCL's Asset Management Information Systems

Figure 56 provides a high-level summary of TPCL's asset management processes and systems. The role and interaction of each component of the data hierarchy model (Figure 56) are incorporated.

Figure 56: 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, TPCL has sufficient knowledge about almost all the assets; their location, what they are made of, how old they are in general and their performance. This knowledge will be used for either making decisions within TPCL's own business or assisting external entities with resolutions. A summary of the key data repositories is listed in Table 86.

Table 86: 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 and a summary with noted limitations is provided in Table 87.

Table 87: 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	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMIS	Description	Okay	Some delays between job completion and Maximo update

AMIS	Details	Okay	Some delays between job completion and Maximo update
AMIS	Age	Okay	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

TPCL'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 overhead lines, had limited supporting information. Old overhead lines 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 lines, 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 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% 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 allow additional asset details to be captured 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 as it 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 TPCL's network assets efficiently and effectively. These are described below.

- **Asset Management Information System (AMIS)**

  This system stores TPCL'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 intricately 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. TPCL 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 TPCL.

- **Supervisory Control and Data Acquisition (SCADA) System**

  The SCADA system provides real time operational data such as loads, voltages, temperature, 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 TPCL 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 Databases**

  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 TPCL 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 low conductor spans are also marked for a heightened priority. 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 class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history resides in this database system. 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

TPCL's key asset management processes and systems are based around the asset lifecycle activities and the AS/NZS9001 Quality Management System. The processes are not intended to be bureaucratic or burdensome but are intended to guide TPCL'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.

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 processes are documented in Promapp. This is process mapping software that 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 – 2024/2034 AMP Update

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 88.

Table 88: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2022/23 ($k)	Actual 2022/23 ($k)	Variance
Consumer Connection	13,045	13,101	0%
System Growth	3,330	3,278	(2%)
Asset Replacement and Renewal	12,403	11,263	(9%)
Asset Relocations	123	285	132%
Quality of Supply	418	576	38%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	4,996	3,735	(25%)
Capital Expenditure on Network Assets	**34,315**	**32,239**	**(6%)**

Capital works variances were due to:

- System Growth – 2% under budget due to the following.
    - Two planned line reinforcement were delayed beyond the financial year end due to the loading requiring work to be completed in the dairy off season.
- Asset Replacement and Renewal – 9% under budget due to the following.
    - Late delivery of switchgear and building material for the two-year Orawia substation upgrade.
    - ABS replacement work did not achieve budget due to equipment delivery delays.
    - LV pillar box replacements largely reactive inspection driven work with some supply issues.
- Asset Relocations – 132% over budget due to the following.
    - Work mainly driven by customer request and Territorial Local Authority work program with the opportunity taken to move lines to the roadside where it is economical.
- Quality of Supply – 38% over budget due to the following.
    - Additional work for mobile substation connection.
    - Completion work on communication network improvement projects.
- Other Reliability, Safety and Environmental – 25% over due to the following.

  - Earth upgrades had a delayed start due to labour and plant constraints earlier in the year.
  - Radio equipment delivery delays affected the completion of communications project.

Operational Expenditure

The variation of estimated expenditure versus actual operational spending is presented in Table 89.

Table 89: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2022/23 ($k)	Actual 2022/23 ($k)	Variance
Asset Replacement and Renewal	842	642	(24%)
Vegetation Management	1,150	1,380	20%
Routine and Corrective Maintenance and Inspection	4,208	4,456	6%
Service Interruptions and Emergencies	3,825	4,367	14%
Operational Expenditure on Network Assets	**10,025**	**10,845**	**8%**

Operational works variances were due to:

- Asset Replacement and Renewal – 24% under budget due to the following.
  - Work is largely driven from the inspection program with less distribution refurbishment work identified during the year.
- Vegetation Management – 20% over budget due to the following.
  - New Asplundh contract rates and amount of work completed was higher than budgeted, with more trees being identified and cut.
- Routine and Corrective Maintenance and Inspection - 6% over budget due to the following.
  - Corrective maintenance higher due to cable fault repairs and 66kV bushing replacement.
  - Distribution routine maintenance higher due to reactive maintenance requirements from the inspection program.
  - Connections maintenance incurred an additional cost from smart meter data providers.
- Service interruptions and emergencies – 14% over budget due to the following.
  - Higher unplanned distribution fault response costs due to faults from weather conditions and some increased material costs.

10.2 Service Level Performance

Customer Consultation

Key customers are surveyed annually by external consultants. PowerNet, as the de facto service provider, is used as a proxy for the network companies. The main survey findings were:

- Communication – there was a 50/50 split between participants that felt communication was one of PowerNet's strengths, and those who believed it was an area for improvement.
- Transformer information - participants expressed their desire to have a better understanding about the maintenance needs of transformers, servicing information and how regularly they need to be upgraded.
- Major projects - A few participants confirmed that they would be pursuing major projects in the future. Many have an interest in upgrading their power supply to operate in a more environmentally conscious way, including upgrading to electric boilers and electric machinery due to internal targets and the carbon tax.
- Participants would like to see PowerNet take the initiative and time to fully understand each business and their needs. Ideally, most participants would like to see a PowerNet representative annually to discuss the future needs of the customer's organisation.

Reliability – 2024/2034 AMP Update

Table 90 displays the target versus actual reliability performance on the network. Totals displayed for SAIDI and SAIFI are a sum of planned (Class B) and unplanned (Class C).

Table 90: Performance against Primary Service Targets

	2022/23 Target	2022/23 Actual
SAIFI	4.16	4.4134
SAIDI	557.0	403.39

The target projections consider the updated default price quality path calculation methodology including new (lower) extreme event normalising boundaries and a 50% weighting for planned outages. TPCL's reliability targets are set equivalent to these projections and the Current asset application of no material deterioration in conjunction will keep the reliable performance at neutral.

The information was prepared consistently with previous disclosures, successive interruptions originating from the same cause were recorded as single interruptions.

Customer Satisfaction

In June-July 2022 PowerNet conducted customer engagement surveys of the mass market customers and major customers. The objective of both these surveys were to understand the customers' perception of PowerNet, how we are performing in terms of planned and unplanned outages, interest in new energy technologies and general feedback. Statistics are also recorded for any customer complaints received. Table 91 shows the 2021/22 results for the service level targets.

Table 91: 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}	>80%	57%
	Information supplied was satisfactory {CES}	>80%	78%
	PowerNet first choice to contact for faults {CES}	>40%	43%
Supply Complaints	Number of customers who have made supply quality complaints {IK}	<10	20
	Number of customers having justified supply quality complaints {IK}	<3	14
Planned Outages	Provide sufficient information {CES}	>80%	92%
	Satisfaction regarding amount of notice {CES}	>80%	97%
	Acceptance of one planned outage every two years lasting four hours on average {CES}	>50%	90%

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

Additionally, our major customers express interest in more interactions, representation, and understanding of their business from PowerNet, especially on issues regarding timing of unplanned outages.

Overall survey results for planned outages were positive while there is still room for improvement in unplanned fault response.

Network Efficiency

Table 92: Performance against Efficiency Targets

Measure	2021/22 Target	2021/22 Actual
Load factor	> 65%	60%
Loss ratio	< 7.0%	5.0%
Capacity utilisation	> 30%	32%

Capacity utilisation and loss ratio were better than target while load factor did not achieve target.

Load factor reflects the ratio of TPCL’s average demand to peak demand and averages around 60%. Transpower’s Transmission Pricing Methodology does not drive the control of peak demand, thus having a negative impact on load factor.

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. TPCL’s capacity utilisation compares very well with other distribution businesses.

Financial Efficiency

Table 93: Performance against Financial Targets

Measure	2021/22 Target	2021/22 Actual
Network OPEX/ICP	$300	$270
Network OPEX/km	$1,213	$1,126
Network OPEX/MVA	$24,274	$21,213
Non-Network OPEX/ICP	$146	$176
Non-Network OPEX/km	$591	$733
Non-Network OPEX/MVA	$11,812	$13,808

TPCL's network financial efficiency results were better than planned for 2021/22. As discussed under SAIDI and SAIFI, additional work was required to address the following aspects.

The non-network OPEX financial efficiency results were marginally higher than planned.

10.3 AMMAT Performance

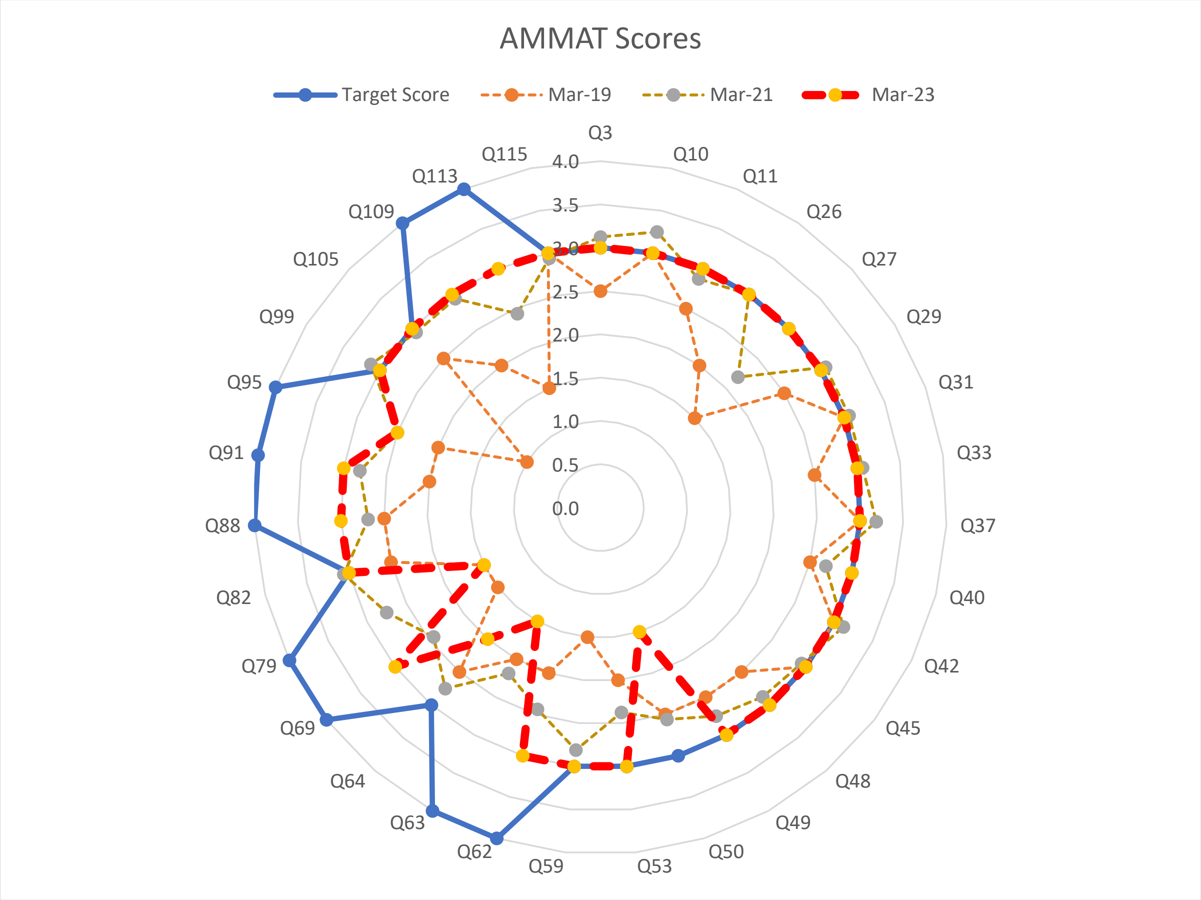
PowerNet understands the foundations of good asset management practice and endeavours to comply with international best practice as embodied in the ISO5500X suite of standards (a management system for Asset Management). In addition, the original PAS 55 principles are adopted (as this is the measurement standard still utilised by ComCom). These foundations are applied in TPCL.

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 TPCL'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 57. 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 57: Asset Management Maturity Assessment Scores



10.4 Gap Analysis and Planned Improvements

Asset Management Maturity

For a distribution company of TPCL's size a score of between '2' and '3' for many of the asset management functions is considered appropriate. However as PowerNet provides TPCL's asset management services as well as providing this service across other networks, TPC believes that some improvements are realisable and appropriate. The audit shows that TPCL 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 the 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 TPCL 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 TPCL'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 is in the process of certification to ISO 5001. Indications after the two round of audits are that our system is compliant and that we will be certified in April.

10.5 Benchmarking

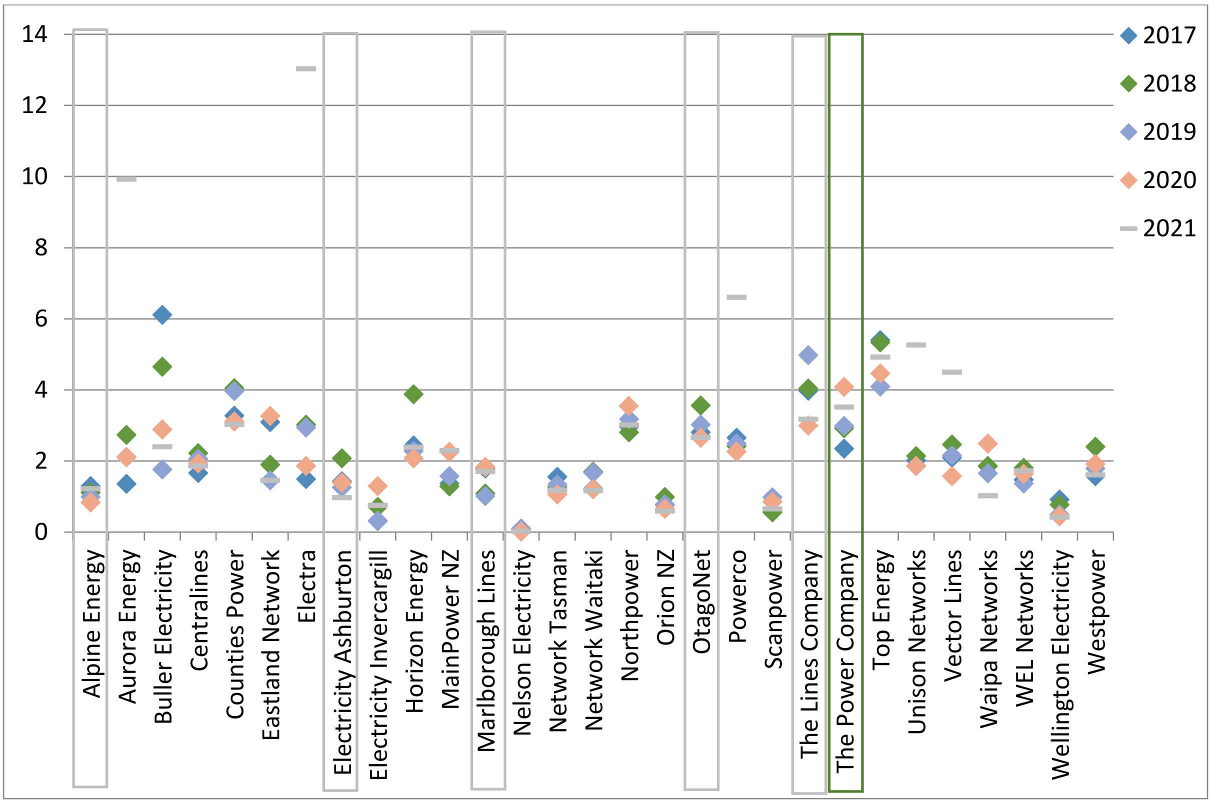
Benchmarking against other local distribution networks assist with the identification of potential improvements in the current service levels that TPCL offers. Comparisons with Alpine Energy, Electricity Ashburton, Marlborough Lines, OtagoNet, and The Lines Company are useful as these networks are similar to TPCL in terms of customer density and types of assets. These comparisons are shown in Figure 58 through to Figure 62.

SAIFI

EDB reliability results as published by ComCom since 2013 show TPCL performance have been quite variable in the last couple of years, but due to the significant influence of storms, low customer density and region covered, the performance is considered acceptable. Generally specific actions to improve SAIFI are not required.

TPCL plans to normalise extreme events using the Commerce Commission DPP methodology. Forecast projections are calculated on historical rolling average performance.

Figure 58: SAIFI Benchmarking

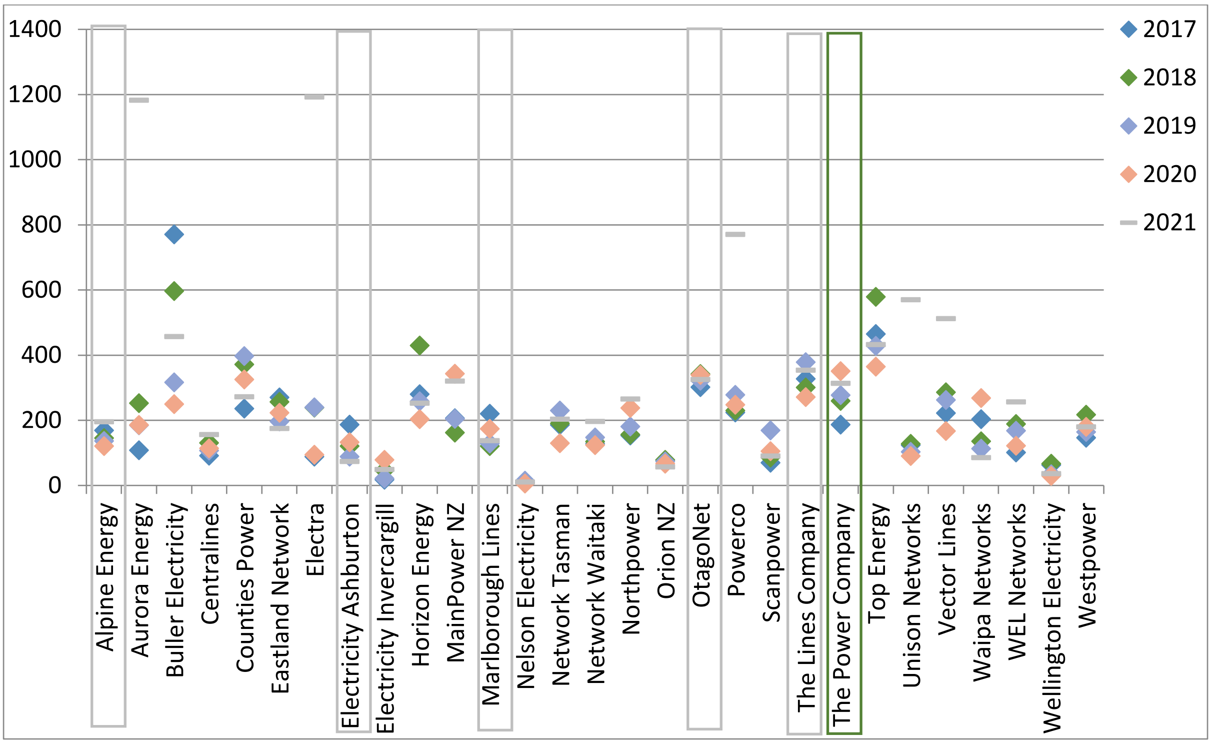


SAIDI

SAIDI reliability results for 2021/22 shows an improvement from the 2019/20 results.

TPCL plans to normalise extreme events using the Commerce Commission DPP methodology. TPCL is installing SCADA enabled switches within the network and strategic locations to limit outage duration by improving restoration times.

Figure 59: SAIDI Benchmarking

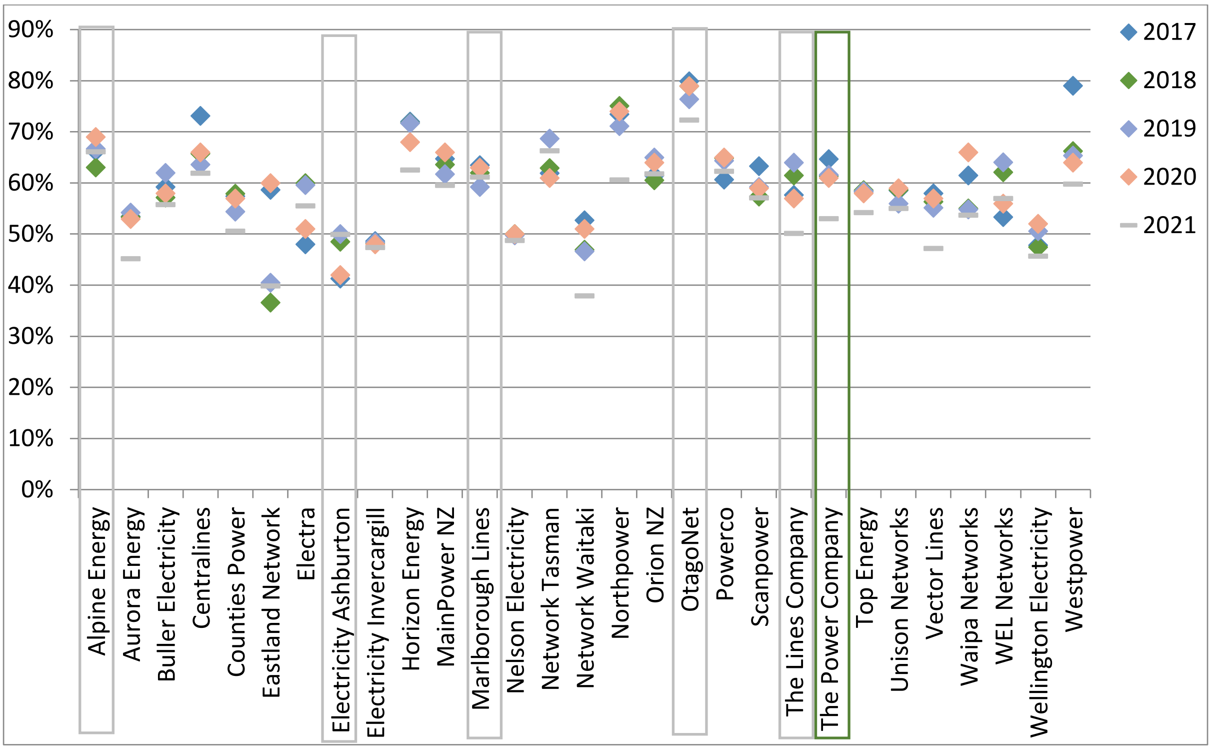


Load Factor

LSI peak is due to New Zealand Aluminium Smelter (NZAS) and other network companies, with the most recent LSI peak occurring during winter.

Comparison with other networks shows that TPCL's load factor is average. Since the 2019/20 results, TPCL forecasted slight improvement due to transformer rationalisations. This is reflected in the improved result for 2021/22 as shown in Figure 60.

Figure 60: Load Factor Comparison

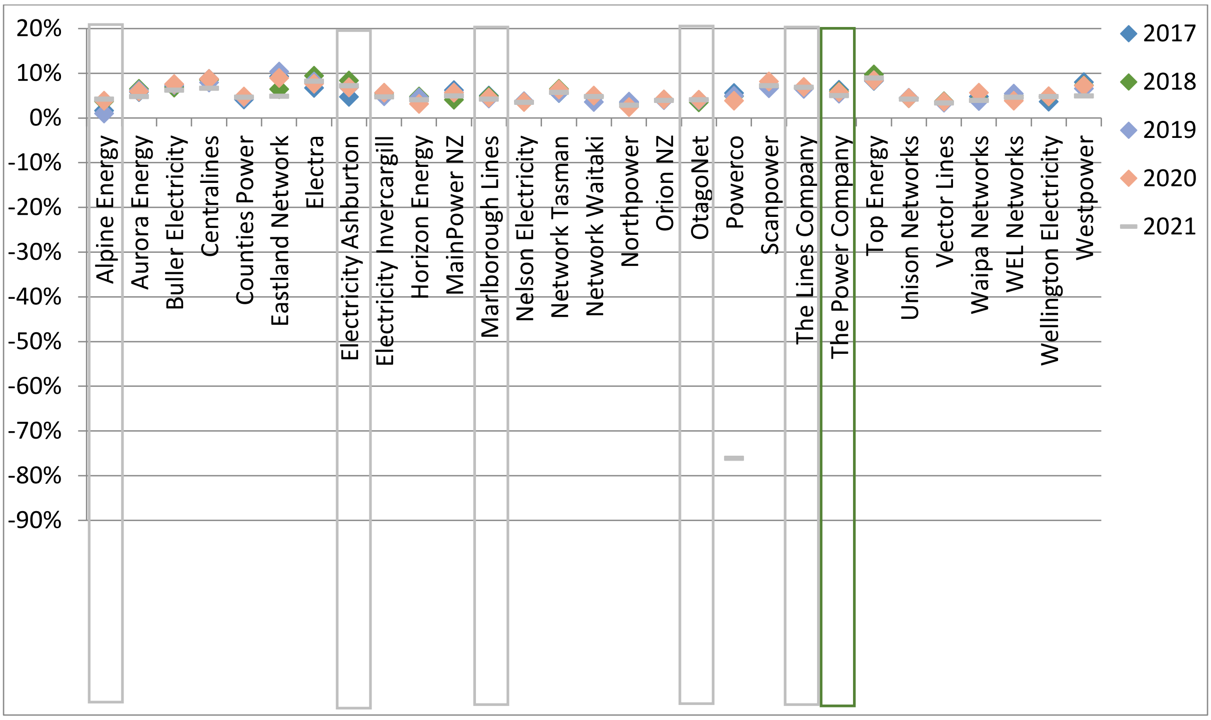


Loss Ratio

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.

Comparison with other network companies shows TPCL's network is average. Trending over a five-year period shows network losses are flat. TPCL can expect a long-term average of less than 7% to be maintained. Year to year results can vary due to retailer estimations, but variation is expected to reduce over time as the number of smart meter installations increase. The result is reduced need for retailer estimation.

Figure 61: Loss Ratio Comparison



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.

The expanding dairy industry is likely to impact with a large number of larger capacity transformers being installed to supply new farms. The load profile on these is very peaky with no rationalisation[13] of transformers since dairy sheds are normally distant from existing farmhouses. Only minor improvements can be expected. Compared to other EDBs, TPCL is average. Therefore, no change in strategy is planned.

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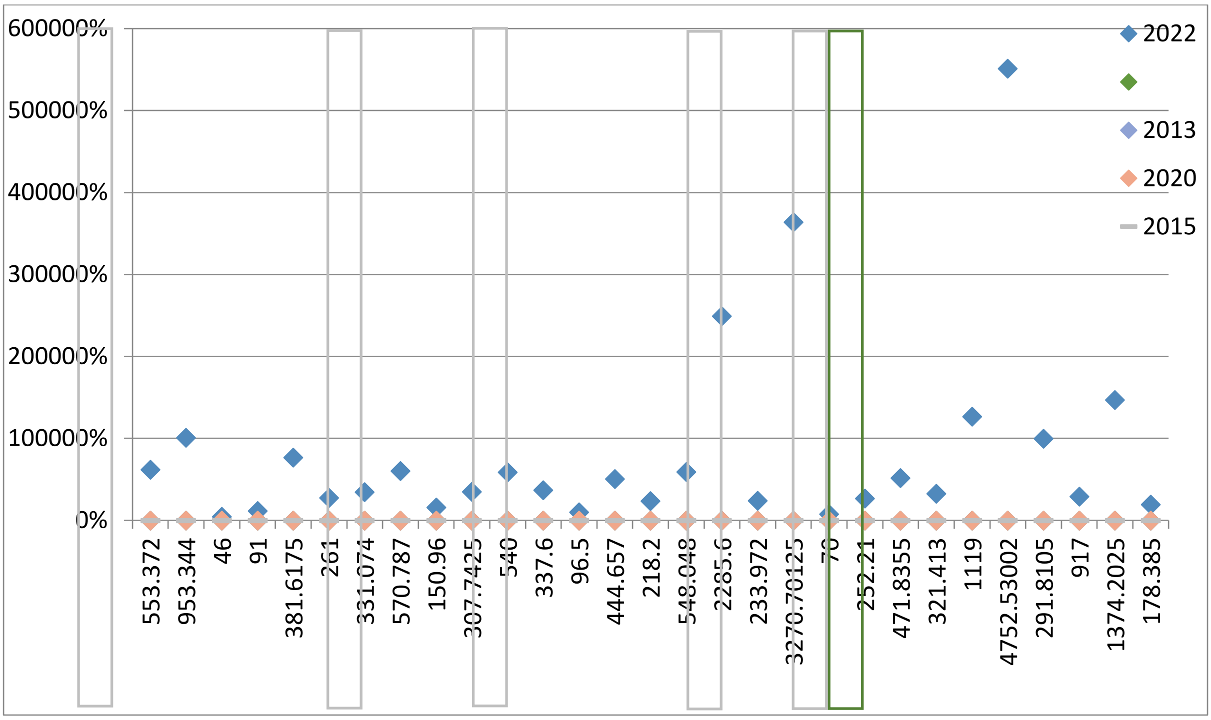
[13] Rationalisation is where one transformer is used to supply multiple customers. With peaks occurring at different periods, a smaller installed capacity usually results. e.g. dairy shed transformer of 50kVA can normally supply the farmhouse, but due to distances usually requires its own 15kVA transformer.

Figure 62: 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 comparable to peers.
- Operational expenditure per km of network length is relatively low.
- Operational expenditure per MVA of distribution transformer capacity slightly above average, reflecting the high-capacity utilisation.
- Non-network Operational expenditure measures are comparatively low.

Initiatives to improve scheduling and efficiency of PowerNet’s workforce are developed and it is anticipated that these will have a positive impact on future results.

Figure 63: $OPEX/ICP Benchmarking

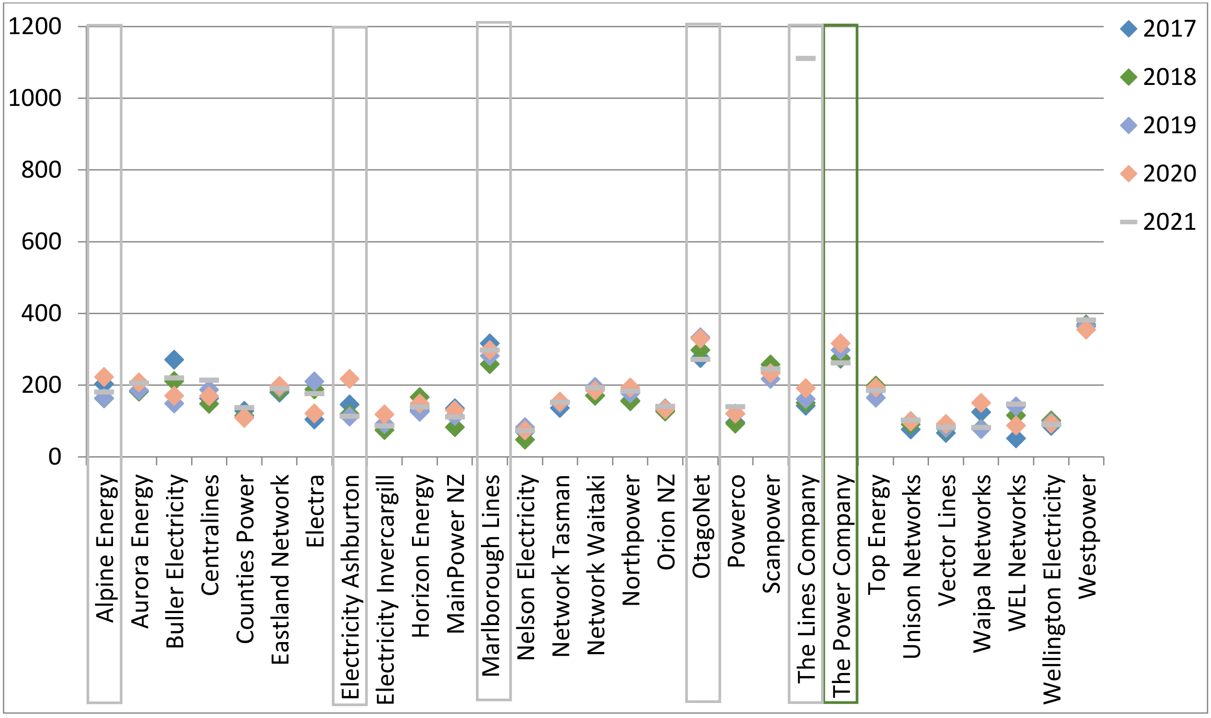


Figure 64: $OPEX/km Benchmarking

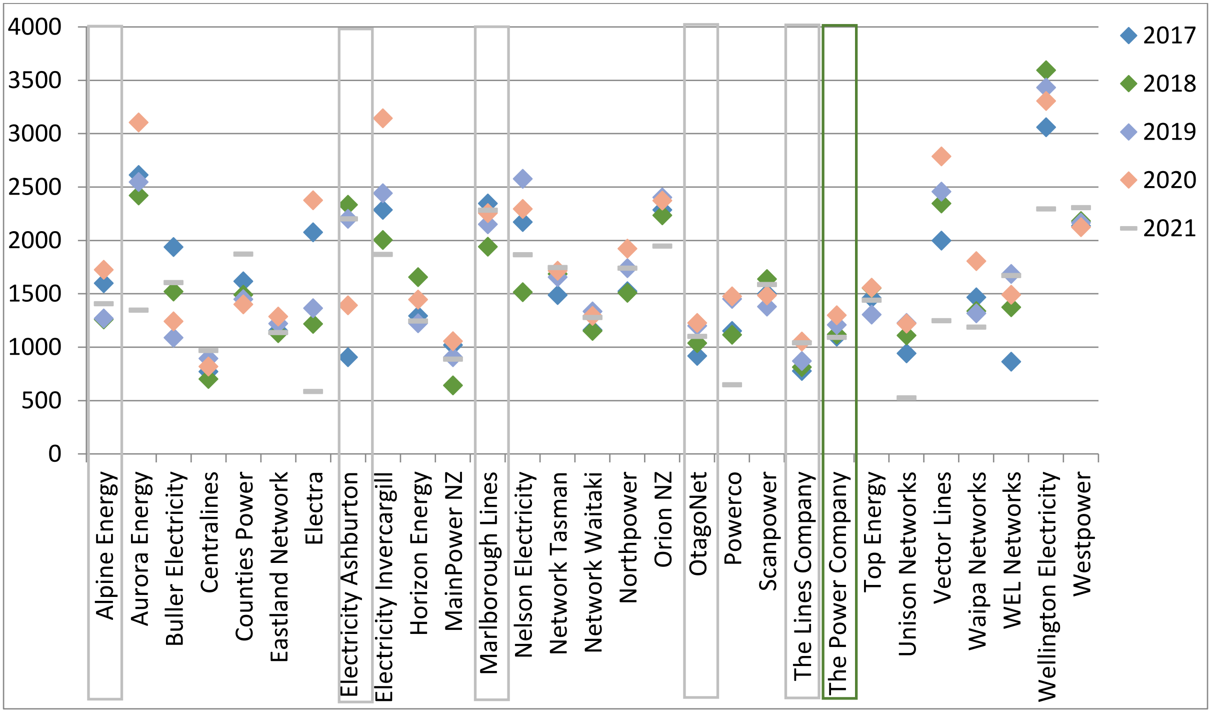


Figure 65: $OPEX/MVA Benchmarking

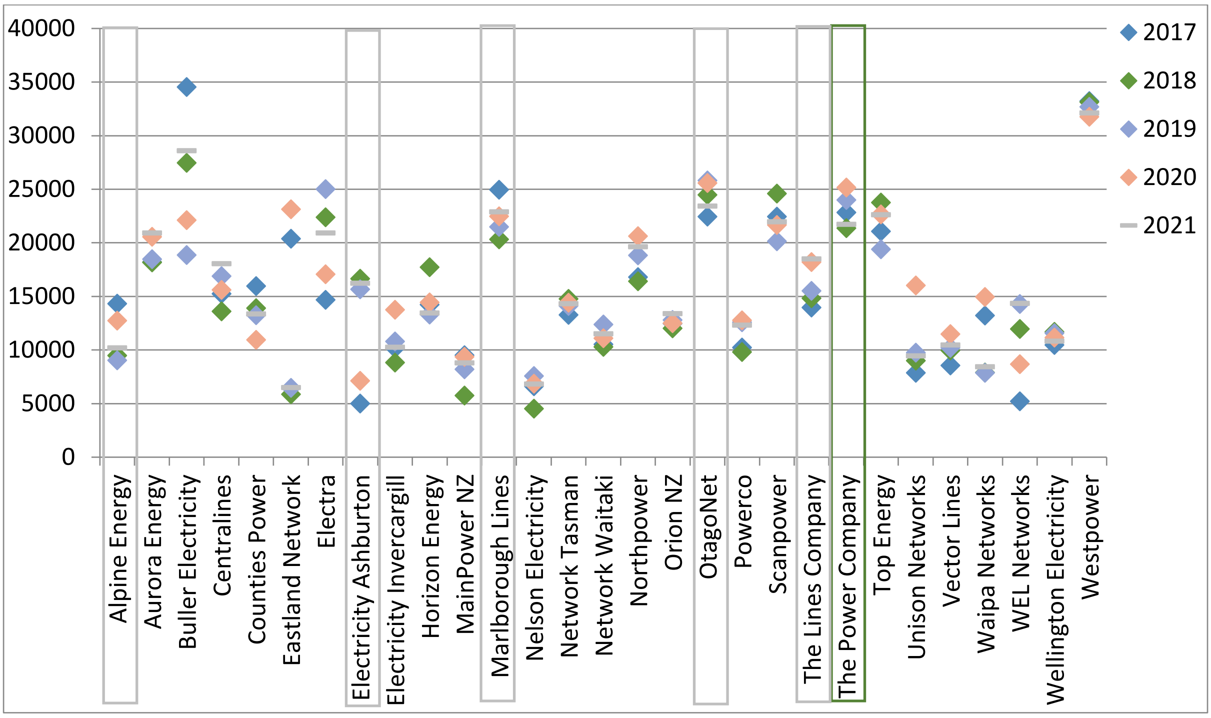


Figure 66: Non-Network $OPEX/ICP Benchmarking

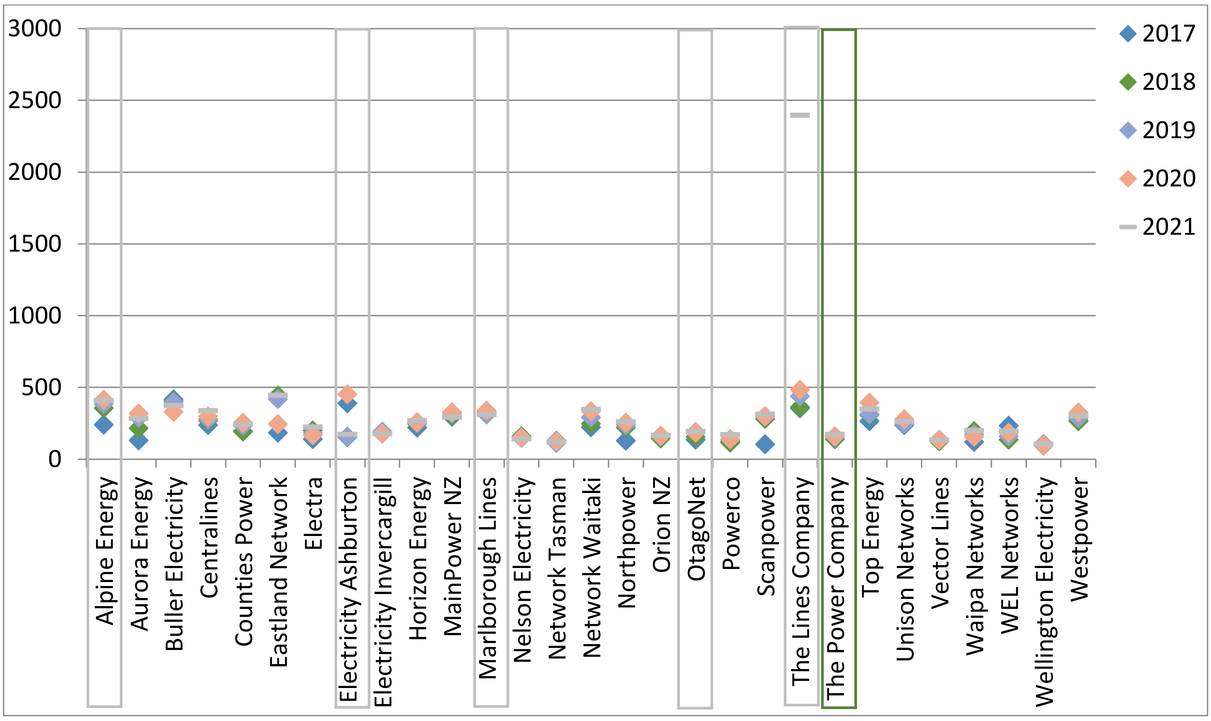


Figure 67: Non-Network $OPEX/km Benchmarking

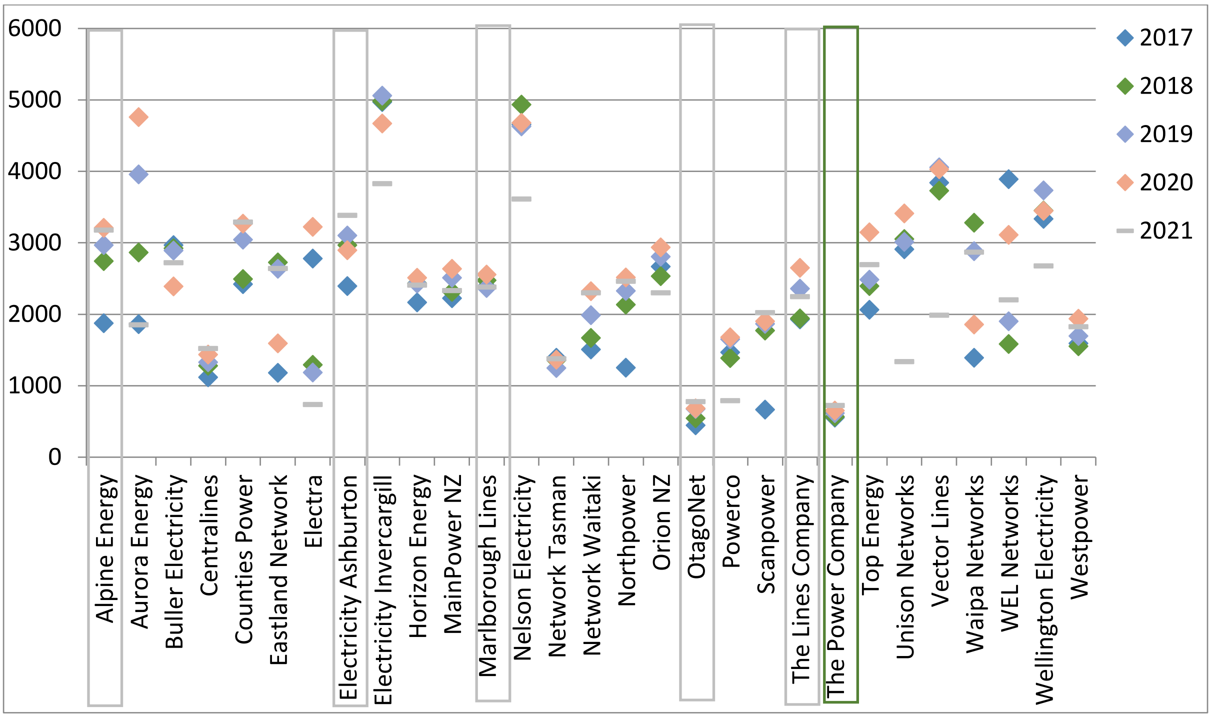
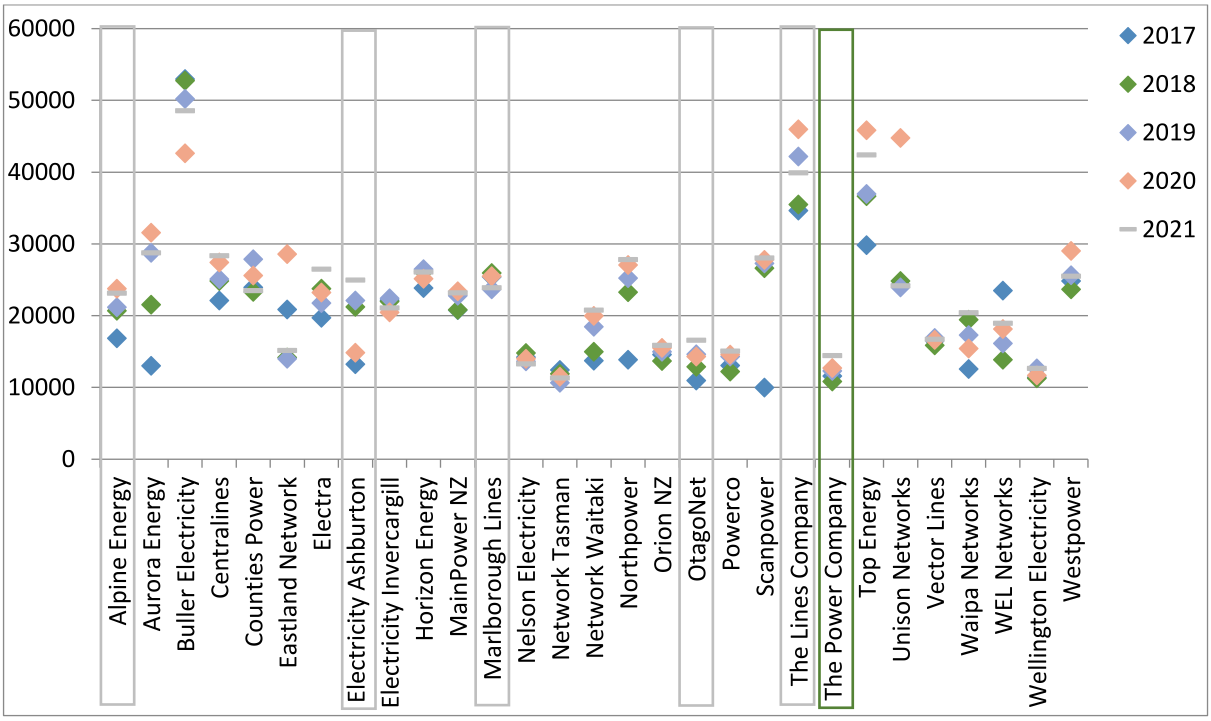


Figure 68: Non-Network $OPEX/MVA Benchmarking



Annexure 1 – Policies, Standards, Procedures and Plans

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 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	
	○	No
	○	Yes <survey will end>

SECTION 1: Awareness and Perceptions of Performance

1.	Have you heard of PowerNet?	
	○	Yes – Q2
	○	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
	○	No
	○	Don't know – DO NOT READ OUT

9	Were you satisfied with the amount of information given to you about this planned interruption?	
	○	Yes
	○	No
	○	Don't know– DO NOT READ OUT

10	What additional information on an outage is needed? Probe to clarify.	
	○	Open comment
	○	Don't know
	○	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.	
	○	PowerNet
	○	Retailer/Power company
	○	Local government
	○	Other (specify)
	○	No-one

12	Where would you prefer to receive communication from PowerNet about outages? DO NOT READ OUT, randomise	
	○	PowerNet Facebook Page
	○	PowerNet 0800 faults number (0800 808 587)

	○	The internet (Google, firefox, etc)
	○	PowerNet's Outage Website Page? https://outages.powernet.co.nz/#/Index
	○	Text message

13	Can you recall when the last unexpected interruption to your power supply was?	
	○	Yes – In the last week – Q14
	○	In the last month – Q14
	○	2-3 months ago – Q14
	○	3-6 months ago – Q14
	○	More than 6 months ago – Q19
	○	Never had an unexpected interruption to power at this address – Q19
	○	Don't know – Q19 – DO NOT READ OUT
	○	Don't care – Q19 – DO NOT READ OUT

14	Do you recall how long your most recent power cut lasted? Read if necessary	
	○	1-2 hours
	○	2-3 hours
	○	3-4 hours
	○	More than 4 hours
	○	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?	
	○	No impact
	○	Minor impact
	○	Neutral
	○	Moderate impact
	○	Major impact
	○	Don't know – DO NOT READ OUT

16	Who did you call when the supply was interrupted?

	○	PowerNet – Q17
	○	Retailer/Power company – Q19
	○	Local government – Q19
	○	No one – Q19
	○	Other (specify)– Q19
	○	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.	
	○	Open comment
	○	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?	
	○	Under 30 minutes
	○	30min - 1 hour

	○	1-2 hours
	○	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
		Electric Vehicles	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
		Electric Vehicles
		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

Electric Vehicles

25.	Which of the following are most important when considering buying an electric vehicle? 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 electric vehicle?	
	○	Open comment box
	○	Don't know

Demographics

27	Which of these age groups do you fall into? Read out	
	○	18-24
	○	25-44
	○	45-64
	○	65+
	○	Prefer not to say – DO NOT READ OUT

28	At the property where you are currently living/ working, do you...? Read out	
	○	Own your dwelling outright
	○	Own your dwelling with a mortgage
	○	Rent from a private landlord

	○	Rent from friends/family
	○	Rent from the Council or government
	○	Other (specify) – DO NOT READ OUT

29	How many people are in your household / workplace?	
	○	How many adults are there, including yourself? Aged 18 years and over. Record number
	○	And how many children aged up to 18 are there? Record number
	○	Prefer not to say

SECTION 6: Final Comments

30	Finally, are there any other comments you would like to make about PowerNet services?	
	○	No comment
	○	Happy with service
	○	Other (specify)

Annexure 3 – Disclosure Schedules

Schedule 11a: Report on Forecast Expenditure

Company Name	**The Power Company 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*
7												
8												
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	16,061	23,093	6,554	4,939	4,748	4,843	4,940	5,039	5,140	5,242	5,347
11	System growth	6,205	7,627	7,591	2,827	11,688	11,190	46,887	13,459	27,780	5,886	6,712
12	Asset replacement and renewal	15,021	21,430	19,036	17,341	20,437	23,110	21,720	22,584	21,613	20,538	20,948
13	Asset relocations	183	138	142	145	148	151	154	157	160	163	166
14	Reliability, safety and environment:											
15	Quality of supply	1,238	923	854	872	572	584	596	607	620	632	645
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	3,693	7,194	4,927	5,162	3,201	3,470	10,900	10,904	11,122	11,345	11,572
18	**Total reliability, safety and environment**	4,931	8,117	5,781	6,034	3,773	4,054	11,496	11,512	11,742	11,977	12,216
19	**Expenditure on network assets**	42,401	60,405	39,103	31,285	40,794	43,348	85,196	52,750	66,434	43,805	45,390
20	Expenditure on non-network assets	17	85	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	42,418	60,490	39,103	31,285	40,794	43,348	85,196	52,750	66,434	43,805	45,390
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	8,503	11,991	3,732	2,935	2,849	2,906	2,964	3,023	3,084	3,145	3,208
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	33,915	48,499	35,370	28,350	37,945	40,442	82,232	49,727	63,351	40,660	42,182
28												
29	Assets commissioned	66,988	43,628	45,997	26,348	27,031	66,154	31,345	137,901	28,916	66,096	35,218
30		*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	4,722	4,444	4,444	4,444	4,444	4,444	4,444	4,444	4,444	4,444	4,444
34	System growth	6,205	7,627	7,406	2,699	10,939	10,267	42,177	11,870	24,019	4,989	5,578
35	Asset replacement and renewal	15,021	21,430	18,572	16,554	19,126	21,205	19,538	19,917	18,687	17,409	17,409
36	Asset relocations	183	138	138	138	138	138	138	138	138	138	138
37	Reliability, safety and environment:											
38	Quality of supply	1,238	923	833	833	536	536	536	536	536	536	536
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	3,693	7,194	4,807	4,927	2,995	3,184	9,805	9,616	9,616	9,616	9,616
41	**Total reliability, safety and environment**	4,931	8,117	5,640	5,760	3,531	3,720	10,341	10,152	10,152	10,152	10,152
42	**Expenditure on network assets**	31,061	41,756	36,199	29,595	38,178	39,774	76,638	46,521	57,440	37,132	37,721
43	Expenditure on non-network assets	17,288	85,000	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	48,349	126,756	36,199	29,595	38,178	39,774	76,638	46,521	57,440	37,132	37,721
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											
48	Overhead to underground conversion											
49	Research and development											
50	Cybersecurity (Commission only)											
51												

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Difference between nominal and constant price forecasts	$000										
Consumer connection	11,340	18,649	2,110	495	304	399	496	595	696	799	903
System growth	-	-	185	128	749	923	4,710	1,589	3,761	897	1,134
Asset replacement and renewal	-	-	464	787	1,310	1,906	2,182	2,667	2,926	3,129	3,539
Asset relocations	-	-	3	7	9	12	15	19	22	25	28
Reliability, safety and environment:											
Quality of supply	-	-	21	40	37	48	60	72	84	96	109
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	120	234	205	286	1,095	1,288	1,506	1,728	1,955
Total reliability, safety and environment	-	-	141	274	242	334	1,155	1,359	1,590	1,824	2,064
Expenditure on network assets	11,340	18,649	2,904	1,691	2,615	3,575	8,558	6,229	8,994	6,673	7,669
Expenditure on non-network assets	(17,270)	(84,915)	-	-	-	-	-	-	-	-	-
Expenditure on assets	(5,930)	(66,266)	2,904	1,691	2,615	3,575	8,558	6,229	8,994	6,673	7,669

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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
*Consumer types defined by EDB**	$000 (in constant prices)					
Customer Connections (≤ 20kVA)	1,875	1,689	1,689	1,689	1,689	1,689
Customer Connections (21 to 99kVA)	436	653	653	653	653	653
Customer Connections (≥ 100kVA)	1,682	917	917	917	917	917
Distributed Generation Connection	2	7	7	7	7	7
New Subdivisions	726	1,178	1,178	1,178	1,178	1,178
Edendale Process Heat Electrification	-	362	-	-	-	-
Underwood substation upgrade for Alliance	161	988	-	-	-	-
McNab Substation upgrade to 33 kV	7,043	-	-	-	-	-
Kaiwera Downs - Mercury 45MW wind farm	4,135	-	-	-	-	-
Jericho - Southern Generation 35MW wind farm	-	-	-	271	-	-
Open Country Dairy 66kV Expansion	-	17,300	1,950	-	-	-
**include additional rows if needed*						
Consumer connection expenditure	4,722	4,444	4,444	4,444	4,444	4,444
less Capital contributions funding consumer connection	8,503	11,991	3,641	2,802	2,666	2,666
Consumer connection less capital contributions	(3,781)	(7,547)	802	1,642	1,778	1,778

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	163	143	-	725	4,222	3,423
Zone substations	586	4,877	7,373	1,780	5,746	6,109
Distribution and LV lines	1,586	713	33	194	971	735
Distribution and LV cables	1,060	519	-	-	-	-
Distribution substations and transformers	1,749	856	-	-	-	-
Distribution switchgear	1,060	519	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	6,205	7,627	7,406	2,699	10,939	10,267
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	6,205	7,627	7,406	2,699	10,939	10,267

96			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
97								
98		**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
99		Subtransmission	278	319	875	875	875	875
100		Zone substations	3,349	7,173	4,464	2,446	5,018	7,749
101		Distribution and LV lines	4,874	5,380	5,380	5,380	5,380	5,380
102		Distribution and LV cables	112	195	54	54	54	54
103		Distribution substations and transformers	2,452	3,128	3,128	3,128	3,128	3,128
104		Distribution switchgear	3,859	5,129	4,565	4,565	4,565	3,913
105		Other network assets	98	105	105	105	105	105
106		**Asset replacement and renewal expenditure**	15,021	21,430	18,572	16,554	19,126	21,205
107	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
108		**Asset replacement and renewal less capital contributions**	15,021	21,430	18,572	16,554	19,126	21,205
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		Line Relocations	183	138	138	138	138	138
115								
116								
117								
118								
119		**include additional rows if needed*						
120		All other project or programmes - asset relocations	-	-	-	-	-	-
121		**Asset relocations expenditure**	183	138	138	138	138	138
122	*less*	Capital contributions funding asset relocations	-	-	-	-	-	-
123		**Asset relocations less capital contributions**	183	138	138	138	138	138
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	220	390	390	390	390	390
130		Mobile Substation Site Made Ready	48	297	297	297	-	-
131		Network Improvement Projects	289	146	146	146	146	146
132		Otatara Regulator and Automation	680	91	-	-	-	-
133								
134		**include additional rows if needed*						
135		All other projects or programmes - quality of supply	-	-	-	-	-	-
136		**Quality of supply expenditure**	1,238	923	833	833	536	536
137	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
138		**Quality of supply less capital contributions**	1,238	923	833	833	536	536
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									
145									
146									
147									
148									
149			**include additional rows if needed*						
150			All other projects or programmes - legislative and regulatory						
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	3,417	3,600	1,922	1,922	1,922	1,922
159			Substation Safety	-	-	-	413	-	-
160			Critical Spares	95	180	180	1,382	180	180
161			Communications Projects	182	287	287	287	287	287
162			Substation LS TX	-	189	189	317	-	189
161			River Crossing Reconstruction	-	1,623	1,623	-	-	-
162			Distribution Recloser	-	606	606	606	606	606
162			Mossburn to Athol 66kV OHL Hardware Upgrade	-	709	-	-	-	-
163			**include additional rows if needed*						
164			All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
165		**Other reliability, safety and environment expenditure**		3,693	7,194	4,807	4,927	2,995	3,184
166	*less*		Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
167		**Other reliability, safety and environment less capital contributions**		3,693	7,194	4,807	4,927	2,995	3,184
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			Te Anau Depot	-	85,000	-	-	-	-
175			Racecourse Road Porch	17,288	-	-	-	-	-
176									
177									
178									
179									
180			All other projects or programmes - routine expenditure						
181		**Routine expenditure**		17,288	85,000	-	-	-	-
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**		17,288	85,000	-	-	-	-
194									

Schedule 11b: Report on forecast Operational Expenditure

Company Name	**The Power Company Limited**
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												
8												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	5,936	4,279	4,386	4,483	4,573	4,664	4,757	4,852	4,950	5,049	5,150
11	Vegetation management	1,525	1,458	1,495	1,528	1,558	1,589	1,621	1,654	1,687	1,720	1,755
12	Routine and corrective maintenance and inspection	4,350	5,710	5,853	5,982	6,101	6,116	6,238	6,363	6,490	6,620	6,753
13	Asset replacement and renewal	795	1,005	1,031	1,053	1,074	1,096	1,118	1,140	1,163	1,186	1,210
14	**Network Opex**	12,606	12,453	12,765	13,046	13,306	13,465	13,735	14,009	14,290	14,575	14,867
15	System operations and network support	2,972	5,142	6,539	6,942	7,081	7,223	7,367	7,515	7,665	7,818	7,975
16	Business support	4,404	3,894	3,942	4,166	4,250	4,335	4,421	4,510	4,600	4,692	4,786
17	**Non-network opex**	7,376	9,035	10,481	11,109	11,331	11,558	11,789	12,024	12,265	12,510	12,760
18	**Operational expenditure**	19,982	21,489	23,246	24,154	24,637	25,023	25,523	26,034	26,555	27,086	27,627

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
19												
20												
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	5,936	4,279	4,279	4,279	4,279	4,279	4,279	4,279	4,279	4,279	4,279
23	Vegetation management	1,525	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458
24	Routine and corrective maintenance and inspection	4,350	5,710	5,710	5,710	5,710	5,612	5,612	5,612	5,612	5,612	5,612
25	Asset replacement and renewal	795	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005
26	**Network Opex**	12,606	12,453	12,453	12,453	12,453	12,355	12,355	12,355	12,355	12,355	12,355
27	System operations and network support	2,972	5,142	6,380	6,627	6,627	6,627	6,627	6,627	6,627	6,627	6,627
28	Business support	4,404	3,894	3,846	3,977	3,977	3,977	3,977	3,977	3,977	3,977	3,977
29	**Non-network opex**	7,376	9,035	10,226	10,605	10,605	10,605	10,605	10,605	10,605	10,605	10,605
30	**Operational expenditure**	19,982	21,489	22,679	23,058	23,058	22,960	22,960	22,960	22,960	22,960	22,960

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	150	150	150	150	150	150	150	150	150	150	150
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	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000

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

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
39												
40												
41												
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	-	107	203	293	385	478	573	670	769	870
44	Vegetation management	-	-	36	69	100	131	163	195	228	262	296
45	Routine and corrective maintenance and inspection	-	-	143	272	391	504	627	751	879	1,008	1,141
46	Asset replacement and renewal	-	-	25	48	69	90	112	135	157	181	204
47	**Network Opex**	-	-	311	592	853	1,110	1,380	1,654	1,935	2,220	2,512
48	System operations and network support	-	-	159	315	454	596	740	887	1,038	1,191	1,347
49	Business support	-	-	96	189	272	357	444	533	623	715	809
50	**Non-network opex**	-	-	256	504	726	953	1,184	1,420	1,660	1,906	2,156
51	**Operational expenditure**	-	-	567	1,096	1,579	2,063	2,564	3,074	3,595	4,126	4,668
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 **The Power Company 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												
7					Asset condition at start of planning period (percentage of units by grade)							
8												
	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**
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	0.05%	75.44%	23.86%	0.65%	3	0.20%
11	All	Overhead Line	Wood poles	No.	7.02%	26.61%	62.64%	1.25%	0.33%	2.15%	3	16.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	12.72%	15.71%	21.32%	32.67%	15.57%	2.01%	2	1.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	20.00%	62.35%	17.65%	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
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	-	-	-	100.00%	-	-	2	-
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.	-	10.00%	60.00%	30.00%	-	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	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.	-	-	5.71%	80.00%	5.71%	8.57%	3	15.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	100.00%	1	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	0.80%	5.60%	61.60%	0.80%	31.20%	3	7.20%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	100.00%	-	4	-
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.	-	5.00%	5.00%	90.00%	-	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	96.34%	0.61%	3.05%	3	9.20%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	2.27%	97.73%	-	-	4	11.36%
35												

Schedule 12a. – Asset Condition (Continued)

					Asset condition at start of planning period (percentage of units by grade)							
36												
37	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
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	1.56%	23.44%	70.31%	3.13%	1.56%	3	7.80%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.04%	5.84%	56.53%	22.10%	14.99%	0.51%	3	3.00%
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	-	-	100.00%	-	-	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.12%	1.04%	5.67%	18.63%	64.47%	10.07%	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	64.54%	31.47%	3.98%	3	-
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.	-	-	-	95.12%	-	4.88%	4	8.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2.18%	5.80%	11.31%	24.51%	12.76%	43.44%	3	21.75%
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.	-	3.49%	18.60%	41.86%	32.56%	3.49%	3	18.75%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.06%	0.51%	3.47%	22.41%	9.63%	63.92%	3	9.30%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.14%	1.94%	9.71%	75.73%	2.36%	10.12%	3	6.24%
53	HV	Distribution Transformer	Voltage regulators	No.	-	3.90%	6.49%	85.71%	3.90%	-	4	2.90%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	14.29%	-	-	-	85.71%	1	14.29%
55	LV	LV Line	LV OH Conductor	km	-	3.83%	60.04%	18.06%	16.98%	1.08%	2	1.60%
56	LV	LV Cable	LV UG Cable	km	-	1.36%	42.71%	16.05%	33.73%	6.15%	1	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	1.05%	67.59%	15.94%	11.02%	4.40%	1	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	20.00%	17.14%	14.29%	48.57%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	23.87%	6.36%	12.57%	43.93%	2.82%	10.31%	3	9.89%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.00%	-	-	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	-	4	-
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 **The Power Company 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**

8	*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
9	Athol	1	-	N	2	-	-	-	No constraint within +5 years	The new and existing customer in the Kingston region will be supplied from the future Kingston substation with the substation project starting in FY28/29
10	Awarua	1	-	N	1	-	-	-	No constraint within +5 years	
11	Bluff	4	13	N-1	2	33%	13	69%	No constraint within +5 years	
12	Centre Bush	4	-	N	1	-	-	-	No constraint within +5 years	
13	Colyer Road	10	12	N-1	1	85%	12	100%	Subtransmission circuit	Extending the 66kV network to Colyer Road Substation from Invercargill GXP in FY26/27 and purchasing land for expansion in FY24/25
14	Conical Hill	2	5	N-1	2	34%	-	75%	No constraint within +5 years	
15	Dipton	1	-	N	2	-	-	-	No constraint within +5 years	
16	Edendale Fonterra	27	46	N-1	-	58%	46	102%	Transpower	Additional 20MW unfirm connection will be connected to the substation in FY24/25. Peak load managed by special protection scheme with Transpower
17	Edendale	7	12	N-1	3	55%	12	61%	No constraint within +5 years	
18	Glenham	1	-	N	1	-	-	-	No constraint within +5 years	
19	Gorge Road	3	-	N	2	-	-	-	No constraint within +5 years	
20	Hedgehope	2	-	N	2	-	-	-	No constraint within +5 years	
21	Hillside	1	-	N	1	-	-	-	No constraint within +5 years	
22	Isla Bank	3	-	N	2	-	-	-	No constraint within +5 years	
23	Kelso	5	-	N	2	-	-	-	Transformer	It is anticipated that the substation load will exceed the capacity of the current 5MVA transformer, with a projected load of 5.2 MVA in FY25/26. To accommodate the increasing demand in the network, the current 5MVA transformer will be replaced with a 12MVA transformer in FY24/25.
24	Kennington	8	12	N-1	3	70%	12	85%	No constraint within +5 years	
25	Lumsden	4	-	N	2	-	-	-	No constraint within +5 years	
26	Makarewa	5	12	N-1	2	38%	12	39%	No constraint within +5 years	
27	Mataura	7	10	N-1	2	71%	10	82%	No constraint within +5 years	The Mataura substation will starts it transformer replacement project in FY26/27 with new 23MVA units
	McNab	20	25	N-1	-	80%	25	80%	Subtransmission circuit	The 33kV cables between Transpower Gore GXP and McNab are rated for 18.4MVA when only one cable is in service. A run-back system has been agreed upon and implemented to prevent overloading on network equipment.
	Monowai	0	-	N	-	-		-	No constraint within +5 years	
	Mossburn	2	-	N	2	-		-	No constraint within +5 years	
	North Gore	8	10	N-1	4	82%	10	93%	No constraint within +5 years	The North Gore substation will starts it transformer replacement project in FY28/29 with new 23MVA units
	North Makarewa	35	40	N-1	-	89%	40	100%	Transpower	The North Makarewa GXP and the 33/66kV step-up transformer are expected to reach their firm capacity. A multi-year program has been developed with Transpower to transfer some of the load to the new Invercargill 66kV connection under the project "Invercargill 66kV Expansion", which would relieve the capacity constraint in the region. Embedded generation available at Monowai, White Hill and the future 35MW Jericco Wind Farm.
	Ohai	2	-	N	1	-		-	No constraint within +5 years	
	Orawia	3	-	N	2	-		-	No constraint within +5 years	
	Otatara	4	-	N	3	-		-	No constraint within +5 years	
	Otautau	4	-	N	2	-		-	No constraint within +5 years	
	Riversdale	6	-	N	2	-		-	Transformer	A multi year substation upgrade project has been triggered including a new 12MVA transformer in FY24/25 and the remainding substation upgraded work will be completed in the FY28/29
	Riverton	5	8	N-1	3	67%	8	70%	No constraint within +5 years	
	Seaward Bush	8	12	N-1	4	67%	12	80%	No constraint within +5 years	Supplying Hydrogen Refill Station commission in FY24/25 and further development expected within +5 years
	South Gore	11	12	N-1	5	88%	12	69%	No constraint within +5 years	Load has been transferred to McNab substation as part of the McNab Substation upgrade project in FY22/23 & FY23/24
	Te Anau	6	12	N-1	1	49%	12	53%	No constraint within +5 years	
	Tokanui	1		N	1	-		-	No constraint within +5 years	
	Underwood	10	16	N-1	2	67%	16	90%	Subtransmission circuit	Extending the 66kV network to Underwood Substation from Invercargill GXP in FY30/31
	Waikaka	1	-	N	0	-		-	No constraint within +5 years	The existing 5MVA transformer at Kelso will be relocated to Waikaka substation in FY24/25 to replace the existing 1.5MVA transformer
	Waikiwi	11	23	N-1	4	48%		58%	No constraint within +5 years	
	Winton	9	12	N-1	3	77%	12	93%	No constraint within +5 years	
						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c. – Demand Forecast

Company Name	**The Power Company 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								
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)	365	360	360	360	360	360
13		Customer Connections (21 to 99kVA)	27	30	30	30	30	30
14		Customer Connections (≥ 100kVA)	7	6	6	6	6	6
15								
16								
17		**Connections total**	399	396	396	396	396	396
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	44	50	50	50	50	50
24		Capacity of distributed generation installed in year (MVA)	43.23	0.25	0.25	35.25	0.25	0.25
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	102	102	104	126	127	129
29	*plus*	Distributed generation output at HV and above	60	60	60	60	75	75
30		**Maximum coincident system demand**	162	162	164	186	202	204
31	*less*	Net transfers to (from) other EDBs at HV and above	(2)	(2)	(2)	(2)	(2)	(2)
32		**Demand on system for supply to consumers' connection points**	164	164	166	188	204	206
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	664	680	698	782	840	845
35	*less*	Electricity exports to GXPs	219	369	369	369	380	400
36	*plus*	Electricity supplied from distributed generation	450	600	600	600	650	700
37	*less*	Net electricity supplied to (from) other EDBs	3	13	13	13	13	13
38		**Electricity entering system for supply to ICPs**	892	898	916	1,000	1,097	1,132
39	*less*	Total energy delivered to ICPs	848	853	870	950	1,041	1,075
40		**Losses**	44	45	46	50	56	57
41								
42		**Load factor**	62%	62%	63%	61%	61%	63%
43		**Loss ratio**	4.9%	5.0%	5.0%	5.0%	5.1%	5.0%
44								

Schedule 12d. – Reliability Forecast

Company Name	**The Power Company 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							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	148.9	151.4	151.4	151.4	151.4	151.4
12	Class C (unplanned interruptions on the network)	329.3	246.9	243.9	240.9	237.9	234.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.60	0.65	0.65	0.65	0.65	0.65
15	Class C (unplanned interruptions on the network)	3.45	3.17	3.13	3.09	3.05	3.01

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?	**1.5**	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	The Power Company 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 2023.

	2024/25	2025/26	2026/27	2027/28	2028/29
Inflator CAPEX	4.100%	2.500%	2.500%	2.200%	2.000%

In addition to the general inflation, material costs have increased by a weighted average of 9.0% in 2023 and labour and external services costs have increased by 4.35%. These increases are included in the CAPEX forecasts for 2024 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 2023.

	2024/25	2025/26	2026/27	2027/28	2028/29
Inflator OPEX	4.100%	2.500%	2.500%	2.200%	2.000%

In addition to the general inflation, material costs have increased by a weighted average of 9.0% in 2023 and labour and external services costs have increased by 4.35%. These increases are included in the CAPEX forecasts for 2024 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	TPCL'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 2019
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

TPCL - Directors Approval

Certification for Year-beginning Disclosures

We, Peter William Moynihan and, James Albert Carmichael being directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of The Power Company Limited prepared for the purposes of clause 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 The Power Company Limited' corporate vision and strategy and are documented in retained records.

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Peter William Moynihan

Carmichael

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James Albert Carmichael

Date: 28-03-2024