Asset Management Plan

2025–2035

THEPOWERCOMPANYLTD

Publicly disclosed in March 2025

Enquiries

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This Asset Management Plan (AMP) is available for public disclosure and applies for the period 1 April 2025 to 31 March 2035.

Front cover image: Mitre Peak, Milford Sound

Liability Disclaimer

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 2025).

Due to 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.

Tēnā koe,

This AMP provides for significant investment in network upgrades and security of supply to meet the intense demand for electricity supply in Southland and to connect new renewable energy generation.

Over the past few years, PowerNet and TPCL have worked closely with customers to support conversions from fossil fuels to electrification of production facilities. The GIDI fund accelerated these initiatives and sustainability expectations from export markets are providing further momentum for the continued decarbonisation of process heat in the region.

TPCL has several multi-year upgrade programmes to accommodate these large decarbonisation loads, where lines or zone substations would otherwise be close to exceeding maximum capacity, or where increased resilience is needed as the region becomes increasingly reliant on electricity as its primary energy source.

Load growth from other connections is expected in the form of space heating and electrification of transport. We are collaborating with other South Island EDBs on how to efficiently and effectively convey information on network availability and congestion to EV charging networks, to help them identify optimal charger locations.

As a key stakeholder in SmartCo, TPCL's investment in smart meters and data analytics is now providing the potential to generate substantial network and customer benefits. While uptake of EVs and solar is relatively low in Southland, the ability to closely monitor LV networks prepares us for a future where either EVs or solar become widespread enough to impact on the network. The results of this monitoring could help us identify when to either upgrade network assets or alleviate congestion through demand-side measures.

With so many developments on the TPCL network, this AMP provides a comprehensive plan to deliver the critical infrastructure and reliability that TPCL's customers require.

Jason Franklin
Chief Executive, PowerNet

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This AMP can be found at: https://powernet.co.nz/disclosures/the-power-company/asset-management-plans

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ABBREVIATIONS, ACRONYMS AND DEFINITIONS

ABC	Aerial Bundled Conductor
ABP	Annual Business Plan
ABS	Air Break Switch
ALARP	As Low as Reasonably Practicable
AMIS	Asset Management Information System
AMP	Asset Management Plan
AWP	Annual Works Program
CAPEX	Capital Expenditure
CBD	Central Business District
CCTO	Council Controlled Trading Organisation
CES	Customer Engagement Survey
CIMS	Coordinated Incident Management System
ComCom	Commerce Commission
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DIN	Deutsches Institut für Normung (the German Institute for Standardization)
DPP	Default Price-Quality Path
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association
EIL	Electricity Invercargill Limited
ENA	Electricity Network Aotearoa
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
LNL	Lakeland Network Limited
LSI	Lower South Island
LV	LV
MAR	Maximum Allowable Revenue
MBIE	Ministry of Business, Innovation and Employment
MD	Maximum Demand
MDI	Maximum Demand Indicator
MV	Medium Voltage
NEM	Network Equipment Movement
NER	Neutral Earthing Resistor
O&M	Operations and Maintenance / Operate and Maintain
ODV	Optimised Deprival Valuation
OHL	Overhead Line
OHUG	Overhead to Underground
OJV	OtagoNet Joint Venture (where OJV is used it generally includes the Lakeland network (LNL) unless the context indicates otherwise)
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

ABBREVIATIONS, ACRONYMS AND DEFINITIONS

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.

Flexibility services refer to the ability to adjust power generation or consumption in response to real-time grid conditions. These services include:

- Demand-Side Response (DSR) – Customers reduce or shift their electricity use based on grid needs, often incentivized by financial rewards.
- Distributed Energy Resources (DERs) – Small-scale generation (e.g., solar, batteries, EVs) provides flexibility by injecting power into the grid when needed.
- Energy Storage – Batteries and other storage systems absorb excess electricity and release it during peak demand.
- Generation Flexibility – Power plants adjust their output dynamically to balance supply and demand.
- Network Reconfiguration – Grid operators optimize how electricity flows by switching between different network configurations.


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2025–2035 AMP Summary

Te Anau, Southland

Mores Scenic Reserveal. Photo: Tourism New Zealand

Riverton Heritage Harvest Festival. Photo: Great South

2025–2035 Summary

Cabot Lodge Southland. Photo: Great South

The Power Company Limited (TPCL) is a consumer-owned electricity distribution company that services the Southland region, excluding Invercargill City and the Bluff township.

Our Asset Management Plan (AMP) describes our network and forecasts the capital and operational budget needed to continue to provide high reliability and to support demand growth. The plan also assesses past network performance and infrastructure asset management practices, identifying opportunities for improvements.

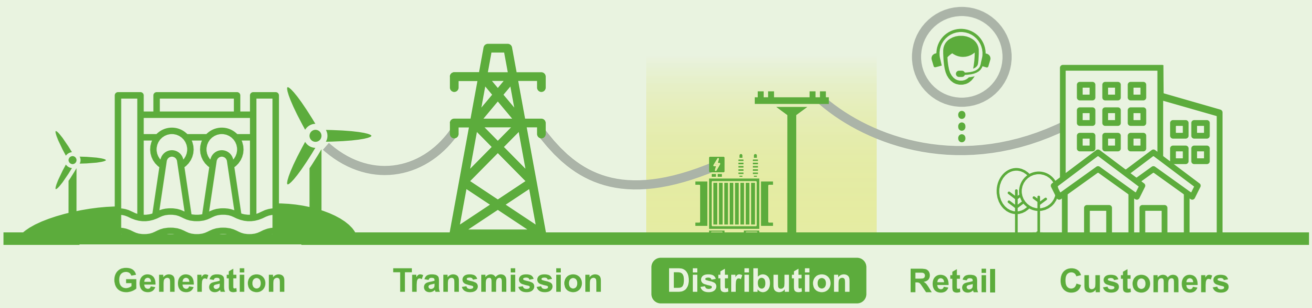
This summary provides key information from our 2025 review of our AMP and identifies steps TPCL is taking to ensure our network is well placed to support changes in electricity usage and increased demand for electricity supply.

8,915 km
Of line and cable

37,850
Consumer Connections

900 GWh
Supplied per year

Where we fit in the electricity industry



Generation

Electricity is generated using a variety of resources – water, geothermal, gas, wind, coal, and solar.

Transmission

Transpower owns and operates the high voltage transmission system that transports electricity from generators to local distribution networks.

Distribution

High voltage electricity is stepped down at substations, then the **TPCL** network distributes it safely to local residential and business consumers using our network of poles, lines, and underground cables. **PowerNet** manages our network for us.

Retail

The retailer measures how much power each customer uses, and sends each customer their power bill. Some of what is paid to retailers comes to us to cover the cost of investing in and maintaining a reliable network.

Customers

Our customers are the households and businesses in Invercargill City and Bluff, who use the electricity provided to power their home or business.

Our network is managed by PowerNet

TPCL has a Network Management Agreement (NMA) with PowerNet. Through this agreement, PowerNet manages our network and carries out all corporate functions of our business.

Our board monitors PowerNet's service delivery against key performance indicators (KPIs), which are regularly reviewed and reset.

With integrated business management systems, significant people capability and capacity, and a core purpose and expertise in asset management, PowerNet is a high-performing asset manager for our network.

PowerNet is an electricity network management company. It was established in 1994 to achieve scale benefits through integrated network management across the Southern region's Electricity Distribution Businesses (EDBs).

PowerNet provides services to over 76,000 customers through more than 14,300 circuit kilometres and manages the fourth-largest suite of EDB assets in New Zealand. With its head office in Invercargill, the company has over 300 staff based at depots in Invercargill, Lumsden, Gore, Balclutha, Te Anau, Frankton and Stewart Island.

Asset management is at the core of PowerNet's business capability. Its network management maturity and capability provide strong and structured asset management practices - 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 has achieved ISO 55001 certification, which is the international standard for asset management. It has also developed and implemented the award-winning health and safety software, RiskMentor.

Ensuring Southland has the electricity network it needs for the future

Electricity networks have an essential role to play in enabling and supporting businesses and households to reduce their use of fossil fuels and lower carbon emissions.

To ensure that we have the required network infrastructure to provide the capacity and reliability that our customers need, we plan to spend **$731 million** over the next 10 years on developing and maintaining the TPCL network.

Our 10-year capital and operating expenditure plan enables a programme of work to mature our asset management capability, support customer growth, and improve our service provision for customers.

$495m

Planned capital expenditure over the next 10 years

$236m

Planned operating expenditure over the next 10 years

Dairy Pryde Southland. Photo: Great South

Photo: Sebastian Katzlese

Investing in capacity to serve ongoing growth

With average annual demand growth on our network of expected to be in excess of 5% over the next few years, our capital expenditure programme has a significant focus on network upgrades. A key driver of the growth that we are experiencing is the electrification of process heat, as large dairy processors and other manufacturers and industrial customers replace their use of coal with electricity. Other sources of demand growth include electrification of space heating, and the development of new subdivisions.

Electrification of transport could lead to large demand growth in future. Ownership of electric vehicles (EVs) is relatively low in Southland. EVs account for around 0.6% of the vehicle fleet in Southland, compared with 2.4% nationally.

While we expect EV uptake to accelerate, the impact on electricity demand is highly uncertain and depends on when and where drivers choose to charge their vehicles. The relatively slower EV uptake in Southland means that we can observe how EV charging demand evolves in other regions and draw on learnings from other EDBs about how to best provide for EV demand on our network.

Dairy Prydē Southland. Photo: Great South

Leading the decarbonisation and electricity of process heat

With a strong agricultural and industrial customer base, TPCL and PowerNet have been at the forefront of decarbonising process heat in New Zealand.

We estimate that around 300 MW of process heat in our network region could be converted to either electricity or biomass. That's approximately 10% of New Zealand's total manufacturing emissions and 1.2% of all greenhouse gasses for the country. Around 110 MW of this process heat has either already been converted to electricity on our network or conversion is underway, with more planned as part of this AMP.

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.

300 MW

Process heat in our network region that could be converted to either electricity or biomass

100 MW

Process heat currently being converted to electric on our network

$35 million capital expenditure on customer connection projects over the past 2 years. We forecast a further $52.5 million over the coming 5 years.

Working with our customers to make new connections and upgrades easier

PowerNet's proactive and collaborative approach to engaging with TPCL's customers has been a catalyst to decarbonisation initiatives in Southland.

In 2021-22 we led the commissioning of a South Island wide process heat stocktake for all industries, which provided a consolidated view of customer plans to decarbonise process heat through conversions to either electricity or biomass. This information has been invaluable to developing our AMP and has led to further customer engagement.

To better work with major customers as they decarbonise, PowerNet modified its internal processes, providing innovative technical and economic solutions tailored to each customer's needs. Our recent work has focussed on how we can facilitate connections for EV chargers.

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Major capital projects for growth, resilience, and safety

Our capital projects for the next 10 years include upgrading assets across the network for the continued security of supply and to cater for growth. Major upcoming projects include:

- **Additional capacity for the Riversdale supply area:** Ongoing load growth has led to constraints in both substation and line capacity. A multi-year project is underway to rebuild the distribution feeders, which will allow future operation at 22kV and provide additional capacity. In parallel, a new 66 kV-rated circuit (initially operated at 33 kV) is being constructed from Nine Mile to the substation, establishing dual supply capability to meet security of supply requirements and support regional growth. Additionally, the substation is being upgraded with the installation of a second transformer to further enhance capacity and reliability. growth from grain farming and drying, irrigation load increases, and to enable new connections.
- **Kingston substation:** Load growth in Kingston village from planned subdivisions and service expansion is expected to surpass the existing line's capability. Ultimately, a new zone substation will be required in Kingston. Based on the pace of subdivision development and housing uptake, this project is expected to begin in 2028/29 and span over three years
- **Awarua 66 kV supply:** TPCL is experiencing significant development in the Awarua region resulted in network constraints. A multiyear program has been developed to provide a new 66kV supply to Awarua region via the new 66 kV connection from Invercargill GXP, triggered by the development in the Awarua region. This work would relieve the capacity constraint on the existing 33kV circuit to the Awarua region.
- **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.
- **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 transformers in 28/29.
- **Customer connections:** Numerous customer connection projects are expected including around $11 million of expenditure (before 50% customer contribution) to enable electrode boilers at the Fonterra Edendale dairy factory.

Network renewals

We have the following ongoing renewal programmes to replace aged assets and improve the efficiency of our network:

- Sub-transmission line replacement
- Continued pole reinforcement
- Distribution transformer and LV pillar box replacements
- Regular mid-life power transformer refurbishments

Operating and maintaining our network

Our fleet plans are fundamental to our expenditure planning process. These plans describe how each asset will be managed over its entire lifecycle, enabling us to plan routine testing and maintenance, determine the resourcing and equipment needed to operate and maintain the assets, and to better estimate both operating and capital expenditure for the next 10 to 20 years.

Our resulting 10-year operating expenditure forecast includes:

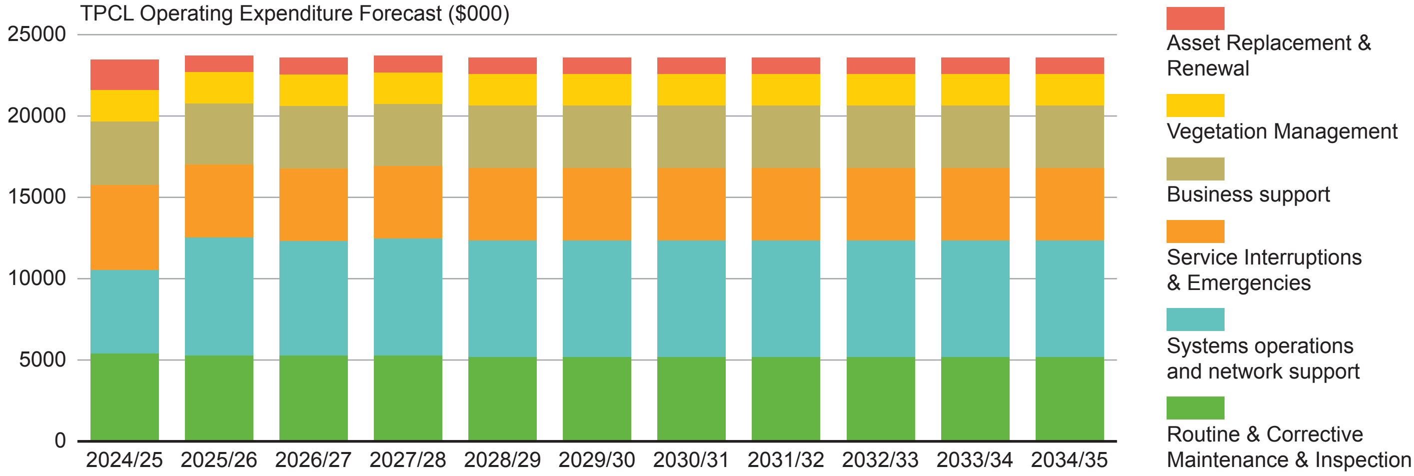
$52m
For routine and corrective maintenance and inspections

$45m
For restoring services when there are outages and emergencies

$19m
For vegetation management, to minimise outages

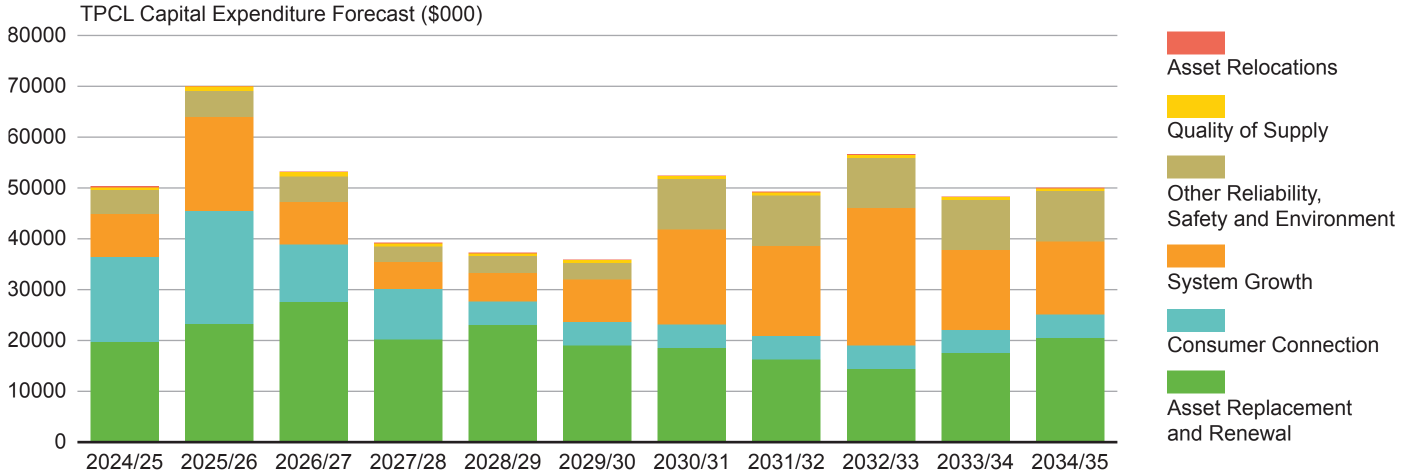
$10m
For operational support of asset replacement and renewal

Our operating expenditure plan



Note: Expenditure is expressed in real terms (FY25 dollars). Inflation must be added for nominal dollars.

Our capital expenditure plan



Note: Expenditure is expressed in real terms (FY25 dollars). Inflation must be added for nominal dollars.

How we are using innovation to deliver better services for our customers

We are a partner in SmartCo, which has developed the Hiko Energy electronic tools that use data from our smart meters to improve network management and customer outcomes.

The Hiko Energy tools provide us with a dashboard highlighting congested LV networks, which provides valuable information for our network planning and management.

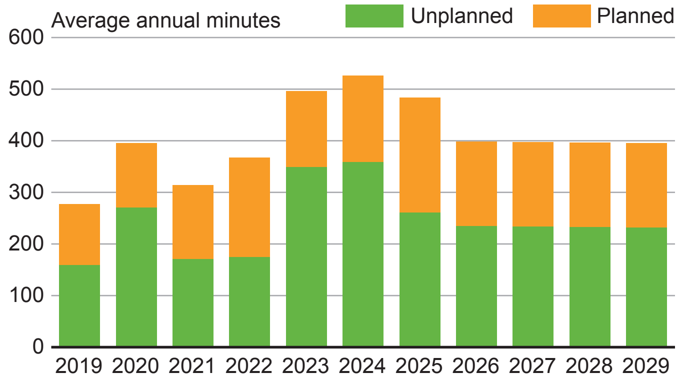
We also use Hiko Energy tools for pre-emptive fault management. For example, we can identify potential neutral faults in LV networks. By identifying these faults promptly, we can improve the safety of our network and reduce the likelihood of damage to customers' electrical equipment.

The Hiko Energy tools also allow us to identify customers who have their own generation installed but are experiencing voltage issues. By identifying these issues, we can help our customers address the problem leading to safe and efficient solar integration.

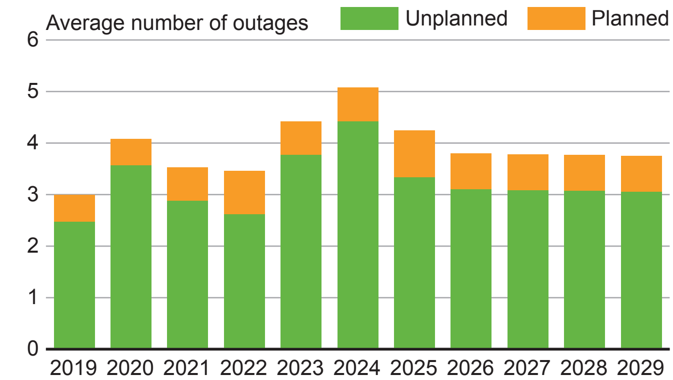
Providing reliable services to our customers

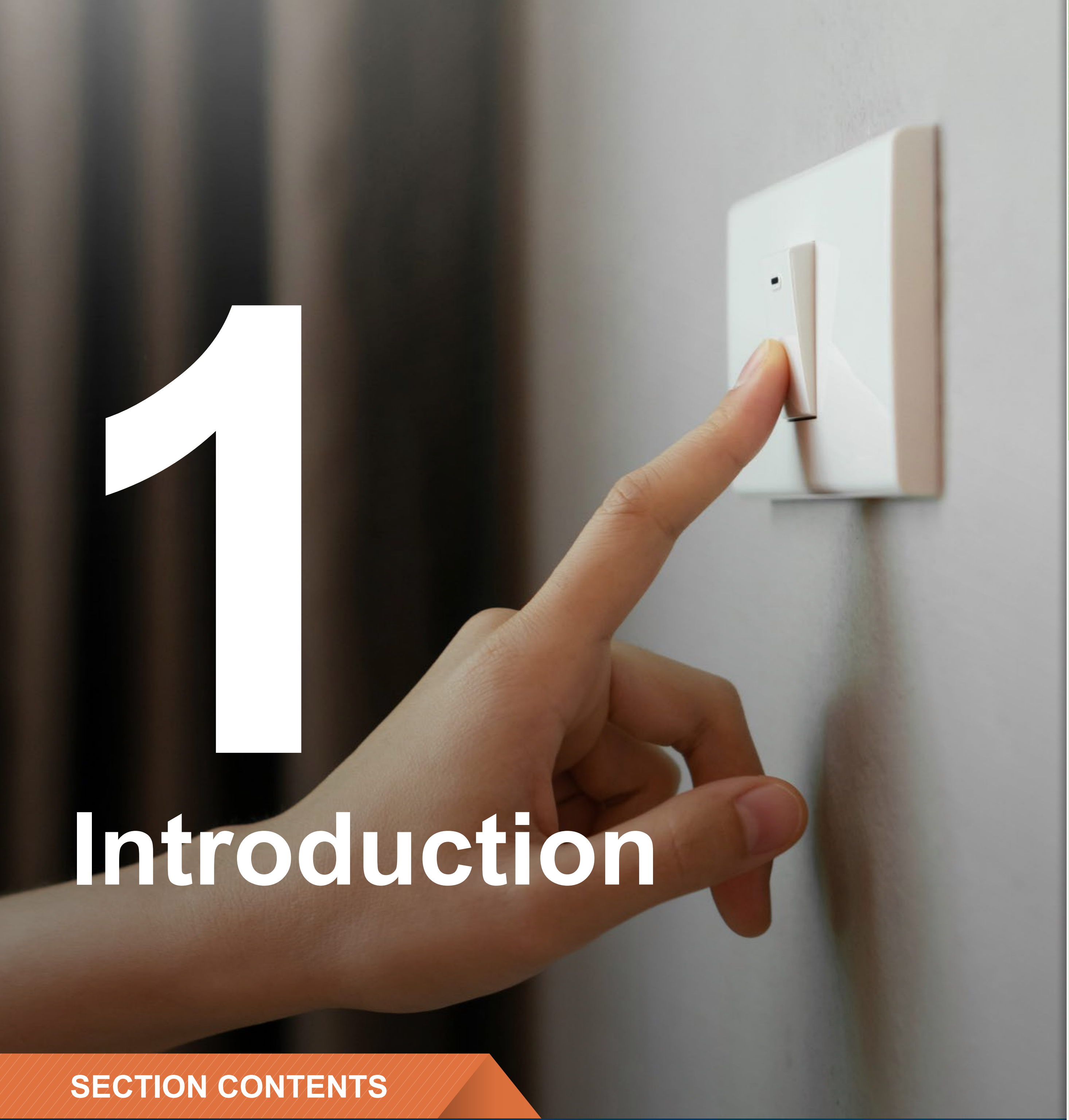
We commission annual customer surveys and use the results to set target service levels. The surveys show that customers most highly value continuity and restoration. We use two internationally accepted indices to measure performance for outage duration and outage frequency.

Average outage duration across the year (SAIDI) – actual and target



Average outage frequency across the year (SAIFI) – actual and target





1 Introduction

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1 INTRODUCTION

The Power Company Limited owns the electricity lines network that conveys electricity to Southland except for Bluff and parts of Invercargill west of Racecourse Road, south and east of Waihopai Stream and north of Elizabeth, Moulson and Brown Streets and Tramway Road. Supplying approximately 37,850 customers.

The Power Company Limited owns the electricity lines network that conveys electricity to Southland except for Bluff and parts of Invercargill, supplying approximately 37,850 customers.

Our Asset Management Plan (AMP) provides an internal governance and asset management framework for the network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination as amended on 25 November 2023 for the ten-year planning period from 1 April 2025 to 31 March 2035.

The purpose of TPCL's Asset Management Plan (AMP) is to:

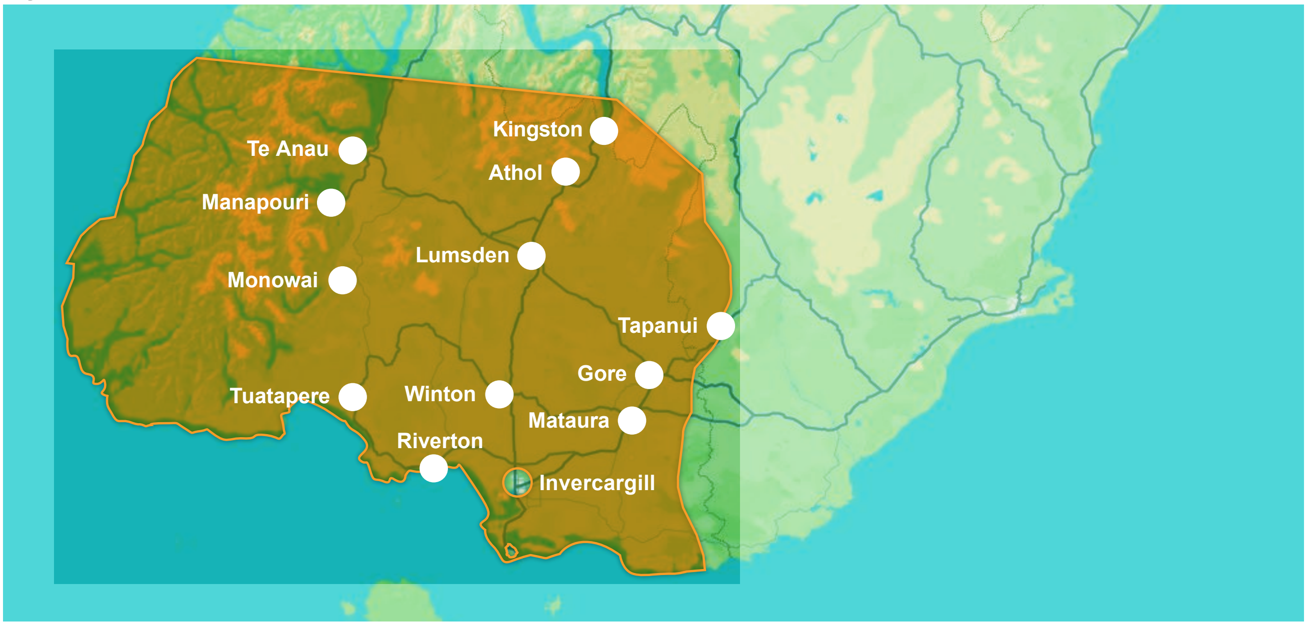
- support TPCL in achieving its vision of being one of the top performing New Zealand electricity distribution businesses through operating in a safe, reliable, efficient and effective manner (section 2),
- document the nature, extent, age, utilisation, condition, performance and value of the infrastructure (section 3),
- describe how we manage exposure to risk (section 4),
- identify existing and proposed levels of service to be achieved over a five-year period, as well as any expected changes in demand (section 5),
- identify the life-cycle management needs (development, renewal, operations and maintenance and any disposal) over the five-year period (section 6),
- assess capital and operational budget needs and funding implications (sections 7 and 8) and the associated capacity and resourcing requirements (section 9), and
- assess the prevailing infrastructure asset management practice and identify further improvements (section 10).

The remainder of this section provides a description of the geographical area and customers that the TPCL network serves, and then discusses how we prepare and communicate our AMP, the key assumptions that we have relied on, and possible variations from those assumptions.

1.1 Our Supply Area and Customers

As shown in the map below, TPCL's distribution area broadly covers all of Southland 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 1: *TPCL Distribution Area*



Our network supplies 37,850 connections. Key industries served by our network include: sheep, beef and dairy farming, dairy processing, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism.

1.2 How we prepare and communicate our AMP

PowerNet's Asset Management team typically creates the first draft of the AMP by November each year and circulates it amongst PowerNet's management for review and comment, before presenting it to the TPCL Board for initial feedback.

Other key asset management documents for TPCL are the Annual Works Programme (AWP) and the Annual Business Plan (ABP). The AWP details the capital and operation expenditure forecasts for the next ten years being produced as part of the development of the AMP. The ABP 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 Board and its shareholders.

The 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 August 2024 survey.

Management and Operations Participation

PowerNet's 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. Progress and variations 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, PowerNet engages contractors. We use “smoothing” of the year-to-year works variation 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

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

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

Post Disclosure Communication

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

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

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

The progress against the AMP objectives is measured as follows:

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

Outcomes of these meetings are presented to the TPCL Board in the monthly reports from PowerNet's Chief Executive and management. This reporting contains information on safety performance, network performance and asset health for specific asset classes identified by the Board.

1.3 Assumptions

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

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

Changes in Traffic Management requirements and the Tree Regulations have been adding additional cost to both Capital and Operational activities. In some instances, the cost of Traffic Management now exceeds 50% of the total project cost. A Beca report "Assessment of Costs of Carrying Out Works in the Road Corridor for Electricity Distribution Businesses" commissioned by ENA indicates a 208% increase in Temporary Traffic Management (TTM) costs incurred by Electricity Distribution Businesses (EDBs) between 2019 and 2024 when working in road corridors throughout New Zealand. The report indicates a further 26% expected increase between 2024 and 2026.

We estimate project costs and timeframes based on previous experience, market analysis and anticipated resourcing. Other than the disclosure schedules included in Appendix 3, all figures are expressed in 2024 dollars and assume an exchange rate of 1 NZ$ to 0.60 US$ (where applicable).

Table 1: *Assumptions and Implications*

Assumption	Discussion & Implications
General demand growth for existing customers tracks close to projected rates.	Prediction of demand growth based on "ground-up" analysis is uncertain, due to the many variables that affect potential growth. The way this is being addressed is through developing scenarios that take the variables into account and choosing the most likely outcome
New housing developments and smaller (<1MW) decarbonisation initiatives are additional to the general growth.	Actual demands may depart significantly from short term forecasts but becomes more predictable in the longer term. This is due to uncertainty in the timing of developments which in turn is due to market conditions and supply chain constraints. Static or declining growth rates in specific areas mean investments to accommodate previously projected growth are deferred and funds are reallocated. The higher growth rate scenario require adjustment in TPCL's resourcing and/or work scheduling to be able to respond to these opportunities.

Assumption	Discussion & Implications
Single large customer driven growth (such as supplies to data centres and electrode boilers) is likely to continue, albeit under different funding mechanisms.	Customers such as Open Country Dairy and Fonterra are making huge investments to replace coal fired thermal processes with electricity-based processes, driven by GIDI funding. Southland is seen as an attractive environment within which to establish data centres. This is due to the colder climate, reducing cooling needs as well as the geographical location relative to Sydney which increases the viability of submarine fibre optic cable. The scenarios that were developed are for load increases of between 20MVA and 150MVA on Invercargill and North Makarewa GXPs with a likely scenario of 100MVA in the area. This will take up the spare capacity at the GXPs and on the subtransmission networks, decreasing the overall resilience of the network. Increased numbers of applications are leading to resource constraints for the analysis and implementation of supply options
Small scale (household) distributed generation is expected to have little coincidence with network peak demand, and therefore will have little impact on network configuration within the ten-year planning horizon. This may however start to change as the increased tariffs envisaged in the DPP4 period start to take effect.	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 compared to buying electricity from a retailer. This will allow usage to be shifted into peak times and reduce peak load on the LV network.
Electric Vehicles (EVs) adoption rate is within the national forecast range. Customers respond well to price signals so that vehicle charging occurs mainly off-peak	EV charging may have a large impact on networks. If customers do not respond well to price signals or if retailers do not send the right price signals, EVs charging may exacerbate peak demand, causing localised constraints on the network and triggering upgrade investment. This effect will be greatest on the LV network where issues are more likely due to lower diversity. Given the cost of EVs, the effect is expected to initially be localised in more affluent areas. The ever-increasing range of EVs, reducing EV prices, a developing market for second hand EVs and fossil fuel taxes may change the vehicle distribution and make it more difficult to predict where issues may arise. Technology and/or pricing mechanisms that will give EDBs a level of control over the time of day when vehicles are being charged need to be developed.
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, criticality and safety for the specific asset. Actual failure rates are utilised to determine the useful life boundaries for each specific asset type. Investment may be deferred if condition analysis provides reasonable certainty of extended asset life.
No material deviation from historical failure rates	Asset reliability deterioration compared to expected failure rates would require accelerated asset replacement (to maintain service levels to customer expectations)
Resourcing is sufficient for projected works programme	Considerable effort has been made to ensure work volumes are deliverable by PowerNet staff and service providers. The local, national and international market demand for skilled resources creates difficulty in staff attraction and retention. Globally decarbonisation projects are increasing so this demand is becoming stronger. These and other unanticipated labour constraints may cause works to be delayed, and/or labour costs to rise.

Assumption	Discussion & Implications
Little change in safety & work practice regulations	Increases in health & safety requirements will have corresponding increases in cost and duration of works.
Inflation for electricity industry input costs track close to expected (CPI forecasts by Treasury where sector specific forecasts are unavailable)	Positive deviation from expected material, labour and overhead input costs will result in increased costs of works programmes. The projected treatment of network constraints may change, depending on the specific changes to each input cost factor.
Future technologies that may impact work methodologies are not priced into cost estimates	Cost savings may occur if technologies develop to a stage where implementation is feasible and economic.
Significant changes in national energy policy	Changes to central government energy policy may affect customer and/or industry behaviour in a way that changes the economic feasibility of EDB investment decisions. .
No significant changes to the shift towards cost-reflective pricing	There is an expectation for electricity distributors to progress towards more service-based and cost-reflective pricing. Challenges from external parties to pricing reform may affect revenue and cause currently proposed investments to be reconsidered.
No significant changes to requirements regarding resource consenting, easements, land access (private, commercial, local, and national authorities)	Increased requirements are likely to result in increased costs, conversely decreased requirements may facilitate more development and reduce costs
No material changes to domestic and small customer expectations of service levels	Changes to domestic and small customer expectations will require adjustment to service levels and subsequent investments. The customer survey shows that these customers are happy with the current price/quality balance and few customers are willing to pay more for increased service levels.
No material changes to large customer expectations of service levels	Changes to large customer expectations will require adjustment to service levels and subsequent investments. Large customers using thermal storage devices are in some instances willing to accept a lower reliability of supply to these facilities.
No significant changes to local and/or national government development policies	Development policies have the potential to affect aggregate and local demand. Investment levels will be adjusted to suit.
Improving industry co-operation	Deterioration in industry co-operation may result in duplicated and uncoordinated efforts and higher costs. Potential areas of improvement are standardisation (this usually leads to decreasing production cost) and coordination of bulk supply upgrades.
Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.	Historic trend expected to continue.
Step changes in underlying growth are possible, should significant investments in the region materialise. Population growth for sizing of equipment is based on the high projection.	Lower than planned population growth may result in some equipment, mainly transformers being oversized. Likely impact on total project cost is minor as the incremental cost of using a larger standard size transformer is minimal while energy losses are reduced. Higher population growth may initiate capacity improvement works earlier.

Assumption	Discussion & Implications
Abnormal price movements caused by major external events (war, terrorism, union action, natural disaster) affecting pricing of equipment or labour substantially are difficult to predict and not allowed for in estimates except for the effects of known events (Covid, Ukraine, Israel, US elections).	These major external events are unable to be predicted with any certainty and TPCL must react accordingly to any changes.
Establishment of Distribution System Operator (DSO) services may enable additional load factor improvements to be achieved, mainly on the Transmission network. This could lead to a decrease in bulk supply costs.	Cost savings may occur if services develop to a stage where implementation is feasible and economic. Managing the maximum load may enable capacity increase projects to be deferred.

1.4 Potential Variation Factors

The information and statements made in this AMP are prepared on assumptions, projections, and forecasts. The AMP represents TPCL's intentions and opinions at the date of issue (31 March 2025).

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

Due to the current global uncertainties caused by events such as Covid-19 and the wars in the Ukraine and Gaza, assumptions and forecasts in the AMP may vary from what actually happens. 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.

The further impact of the war in the Ukraine and the impact of the conflict in Gaza is still uncertain, but an escalation in these conflicts may affect fuel supply and cost. The Trump administration in the USA may also affect supply chains and equipment availability, however the impact of the administration's policies is difficult to predict.

The following table describe specific factors that 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 2: *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. Transport cost and timing is becoming more variable as shipping companies shed uneconomic routes and destinations.
Variation in inflation rates and exchange rates	Higher input costs than forecast, leading to lower work volumes being executed.
High staff turnover and/or inability to recruit required resources	Labour cost increases in order to attract and/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. This also applies to contractors.

Cause of Variation	Implications
Reactive work varying from that estimated	Deferment of capital or planned maintenance work, if those works are dependent on the asset being in-service. Deferment of capital or planned maintenance work may also arise from staff resourcing constraints due to staff utilised on reactive work. One of the key factors that may lead to the increase is climate change, i.e. more frequent storm and high precipitation events.
Equipment failure especially large capital plant	Increased replacement costs and additional costs to maintain supply to customers until replacement. (E.g., generators may have to be deployed) Increased failure rates on specific classes of assets triggers a review of equipment selection and work methodologies.
New safety issues identified, and initiatives created	Higher labour or material costs. Triggers reviews of work methodologies.
Reprioritisation of projects as new work activities are identified	Require revision of the longer-term investment programme and funding requirements.
Obvious short term project options may not be the best long term solutions.	Inefficient investment and potential fruitless expenditure.
Greater demand growth than anticipated levels, especially large new industry, or customers	May cause capital investments to be accelerated, or advanced. May constrain staffing resources.
Lower demand growth than anticipated, 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.

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 Our Business Environment

SECTION CONTENTS

2 OUR BUSINESS ENVIRONMENT

TPCL's vision underpins both its Corporate and Asset Management Strategies. Our corporate drivers from our Strategic Plan are incorporated in the AMP. TPCL has formal accountabilities to its owners for financial and network performance and deliver on these through a network management arrangement with PowerNet.

TPCL has numerous stakeholders and accommodates stakeholder interests in asset management practices. When managing conflicting interests, safety is our top priority.

As well as elaborating on our approach to these issues, this section details our planning processes and related documents, the organisational structure and accountabilities, as well as how our planning takes account of customer requirements, and provides for quality of service.

VISION STATEMENT:

To be recognised as the leading consumer trust owned electricity sector company and an excellent corporate citizen.

2.1 Our 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 various constraints that affect asset management. Managing conflicts between stakeholders and numerous risks to the business are acknowledged.

Corporate Strategy

TPCL's Strategic Plan identifies key corporate drivers to be:

- 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 and 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.

- Use Risk as the fundamental decision-making criterion in all expenditure decisions.
- Safety by design using the ALARP (as low as reasonably practicable) risk principle.
- Minimise long term service delivery cost through condition monitoring and refurbishment.
- Replace assets at their (risk considered) economic end of life.
- No material deterioration in the condition or performance of the networks.
- Facilitate network growth through timely implementation of customer driven projects.
- Maintain supply quality and security with network upgrades to support forecast growth.
- Set performance targets for continuous improvement.
- Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather.
- Utilise overall cost benefit at all investment levels including the "do nothing" option.
- Standardise and optimally resource to provide proficient and efficient service delivery.
- Follow new technology trends and judiciously apply to improve service levels.
- Undertake initiatives to increase existing asset life or capacity.
- Consider alternatives to status quo solutions.
- Improve efficiency of electricity distribution for the net benefit of the customer.
- Achieve 100% regulatory compliance.
- Minimise environmental harm.

Health, Safety and Environmental Strategy

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

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

Interaction of Goals/Strategies

TPCL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 3.

Table 3: *Corporate and Asset Management Strategy Linkages*

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

2.2 Our ownership, governance, and network management

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.

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 Trust (as at 31 March 2025) has five Trustees:

- 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 governance 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 2025) has six directors:
  - Peter Moynihan (Chair);
  - Carmen Blackler;
  - James Carmichael;
  - Wayne Mackey;
  - Karen Sherry; and
  - Murray Wallace.
- The second governance 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.

Network Management

TPCL's uses PowerNet as its contracted asset management company. The PowerNet Chief Executive is accountable to the TPCL Board, with the principal mechanism being the Network Management Agreement (NMA) that specifies a range of strategic and operational outcomes to be achieved. The NMA was entered into in 2022 and has a 10-year term. Under the NMA, PowerNet operates TPCL's network and carries out all asset management functions such as planning, annual maintenance works, fault response, and capital works, including overseeing sub-contracting arrangements. Business functions carried out by PowerNet for TPCL include business planning, accounting services, setting prices and collecting lines charges, administering contracts with Transpower, ensuring regulatory compliance, arranging insurance, and managing new connections to the network.

Associations

TPCL conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff) for approximately 37,850 customer connections. Twenty-one energy retailers on sell this electricity. The TPCL business entity includes the following associations.

- 100% stake in PowerNet, an electricity lines management company. This is an unregulated entity and is therefore not subject to any disclosure requirements.

- 100% stake in Lakeland Network Limited (LNL), which distributes electricity in the Frankton, Wanaka areas of Central Otago.
- 100% stake in OtagoNet. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of EIL, TPCL, and LNL.

2.3 Our Stakeholders and their Interests

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

- Has a financial interest in TPCL (be it equity or debt).
- Pays money to TPCL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to TPCL's network.
- Uses TPCL's network for conveying electricity.
- Supplies 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 4) and how these interests are identified (Table 5). Table 6 describes how stakeholder's interests are accommodated in TPCL's asset management practices.

Table 4: *Interests of Key Stakeholders*

Interests	Viability	Price	Quality	Safety	Compliance
Southland Electric Power Supply (SEPS) Consumer Trust (Shareholder)	✔	✔	✔	✔	✔
Connected Customers	✔	✔	✔	✔	
Connected Generators	✔	✔	✔	✔	
Contracted Manager (PowerNet)	✔	✔	✔	✔	✔
Ministry of Business, Innovation & Employment		✔	✔	✔	✔
Commerce Commission	✔	✔	✔		✔
Electricity Authority	✔	✔	✔		✔
Utilities Disputes					✔
Councils (as regulators)				✔	✔
Transport Agency				✔	✔
Energy Safety				✔	✔
Industry Representative Groups	✔	✔	✔		
Public (as distinct from customers)				✔	✔
Mass-market Representative Groups	✔	✔	✔		
Staff and Contractors	✔			✔	✔
Energy Retailers	✔	✔	✔		
Flexibility Service Providers	✔	✔	✔		
Suppliers of Goods and Services	✔				
Land owners				✔	✔
Bankers	✔	✔		✔	✔
Transpower	✔	✔	✔		

Table 5: *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 and generators as part of their on-going development needs • Customer contracts • Customer consultation evenings (meetings open to public) • Annual customer surveys • Contact by customers, • Consultants
Potential Customer	• Connection requests • Feasibility study requests • Contact by customers' consultants
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets at least 6 times per year with Chief Executive, Chief Financial Officer and General Manager Asset Management • PNL Staff attend Board meetings when required
Ministry of Business, Innovation & Employment	• Legislation, regulations, and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website • Default Price Path and information disclosure feedback
Electricity Authority	• Weekly updates and briefing sessions • Regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Utilities 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 • Formally to discuss development needs
Transport Agency	• Formally as required
Energy Safety	• Promulgated regulations and codes of practice • Audits of TPCL's activities • Audit reports from other lines businesses

Stakeholder	How Interests are Identified
Industry Representative Groups	• Informal contact with group representatives
Public (as distinct from customers)	• Word of mouth around the city • Feedback from public meetings • Newspapers and social media
Mass-market Representative Groups	• Informal contact with group representatives
Staff & Contractors	• Regular staff briefings • Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Suppliers of Goods & Services	• Regular supply and demand meetings • Contractual arrangements • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet's CE & CFO • TPCL's treasury/borrowing policy • Banking covenants
Transpower	• Regular meetings at various organisational levels • Transpower Customer Services representatives

Table 6: *Accommodating Stakeholders' 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 confidence 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 deliver the returns. Service Level are maximised within those constraints while still keeping the electricity price at affordable levels.
Price	Price influences revenue and signals underlying costs. Getting prices wrong could result in levels of revenue that could not sustain supply reliability to the levels demanded by customers,	TPCL's total revenue roughly follows the regulated price path for EDBs. Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders and affect business customer's viability. Insufficient revenue will compromise the long term sustainability and ability to render services. TPCL's pricing methodology is intended to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.This charge is being phased-out through Government regulatory changes.

Interest	Description	How TPCL Accommodates Interests
Supply Quality	Emphasis on continuity, restoration of supply and voltage wave form management (amplitude, flicker, harmonics) is essential to minimising interruptions to customers' businesses and eliminate the risk of damage to customer equipment.	Stakeholder's needs for supply and service quality are accommodated by having a pool of resources focussed on continuity and restoration of supply. Growth related network upgrades are implemented in time to prevent adverse supply quality. The most recent mass-market survey indicated satisfaction with the present supply quality but also that many customers would be willing to accept a reduction in supply quality in return for lower line charges.
Safety	Staff, contractors, and the public at large must be able to move around in the vicinity of network assets 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. New assets are subjected to the Safety in Design process. Motorists will be kept safe by ensuring that above-ground structures are kept as far as possible from the carriage way within the constraints faced regarding private land and road reserve.
Compliance	Compliance with the many statutory requirements, ranging from safety to disclosing information is compulsory.	All safety issues are documented and available for inspection by authorised agencies. Use the "Comply With" system to keep up to date with changes in legal requirements. Performance information is disclosed in a timely and compliant fashion. Any non-compliances are documented, submitted to and approved by the relevant authority following the approved processes.

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust. This is a primary commercial driver for TPCL, together with the network performance. The Statement of Intent and the NMA formalise these accountabilities to the shareholder.

Connected 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 but 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 and in the ComCom's disclosure requirements.

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

Managing Conflicting Interests

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

1. **Safety.** Safety is always our first priority. The safety of staff, contractors and the public are of paramount importance. These factors are highly ranked in asset management decisions.
2. **Viability.** TPCL's long term financial and technical viability is the second consideration, as TPCL is expected to deliver the electricity distribution function to its customers for the foreseeable future.
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.** Compliance that is not safety and supply quality related is important but ranks lower than the criteria above.

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

2.4 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 are in place 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 gas or biomass at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, which could potentially strand conventional distribution assets.
- Local, national, and global economic cycles which affect growth and development.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- Interest rates which can influence the rate at which new customers connect to the network.
- Ensuring sufficient funds and skilled people are available long term to resource 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.

2.5 Commerce Commission Determination – Financial Impact

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

The determination does not directly affect TPCL, 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'. The 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.

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

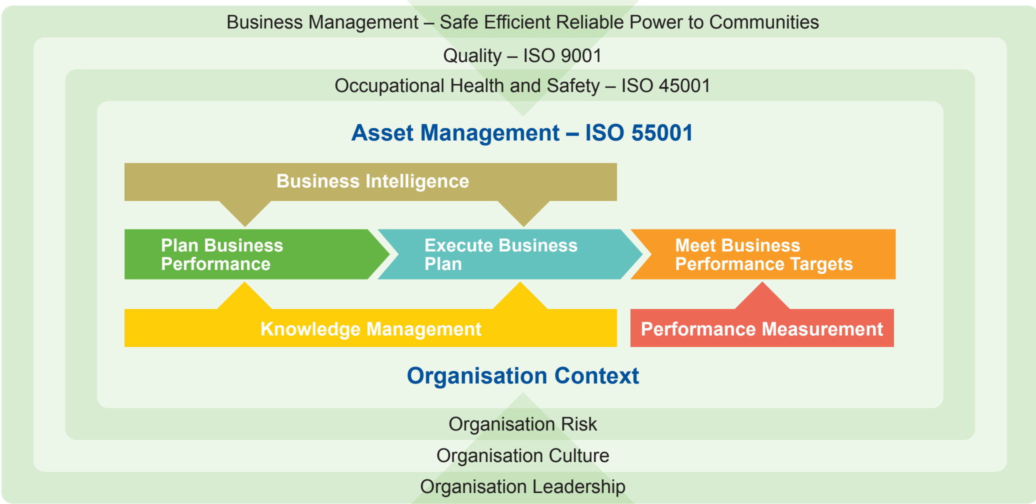
2.6 Planning Processes

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.

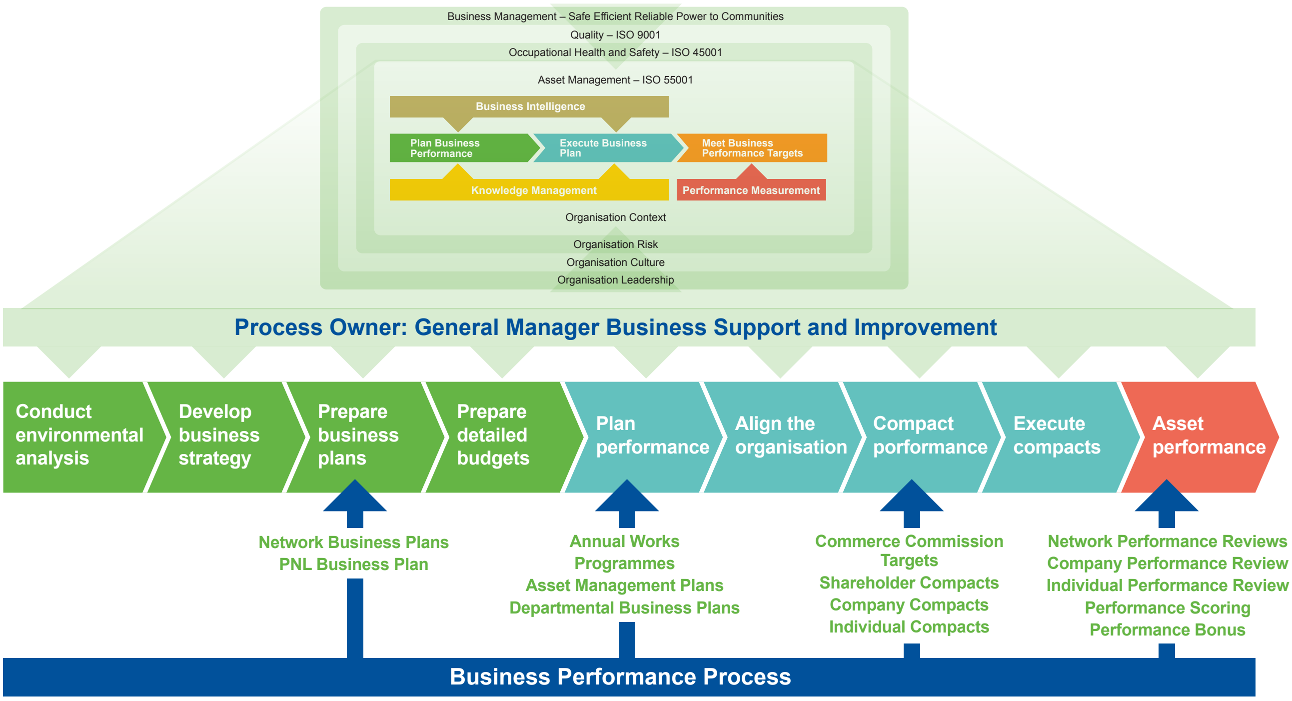
Figure 2: *Business Planning and Execution Processes*



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 must meet. The business plan is executed and the results are measured against the targets to evaluate business performance.

Figure 3 shows the process in more detail and indicates the performance elements from company level through to individual performance compacts. Individuals' performance against the compacts are evaluated for the performance incentive program.

Figure 3: *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. The SOI includes financial performance projections for the following metrics.

- EBIT% (Percentage Group Earnings Before Tax and Interest on Assets Employed).
- NPAT% (Percentage Group Tax Paid Profit on Equity).
- Percentage of Consolidated Equity to Total Assets.
- The quality performance projections for SAIFI and SAIDI are also included. These projections are over a three-year period and form the heart of asset management activities. The inherent trade-off between price and supply quality are acknowledged. The SOI is available at **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 monthly to assist in monitoring of performance and delivery to plan.

Annual Works Programme

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

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

Interaction between Objectives, Drivers, Strategies and Key Documents

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

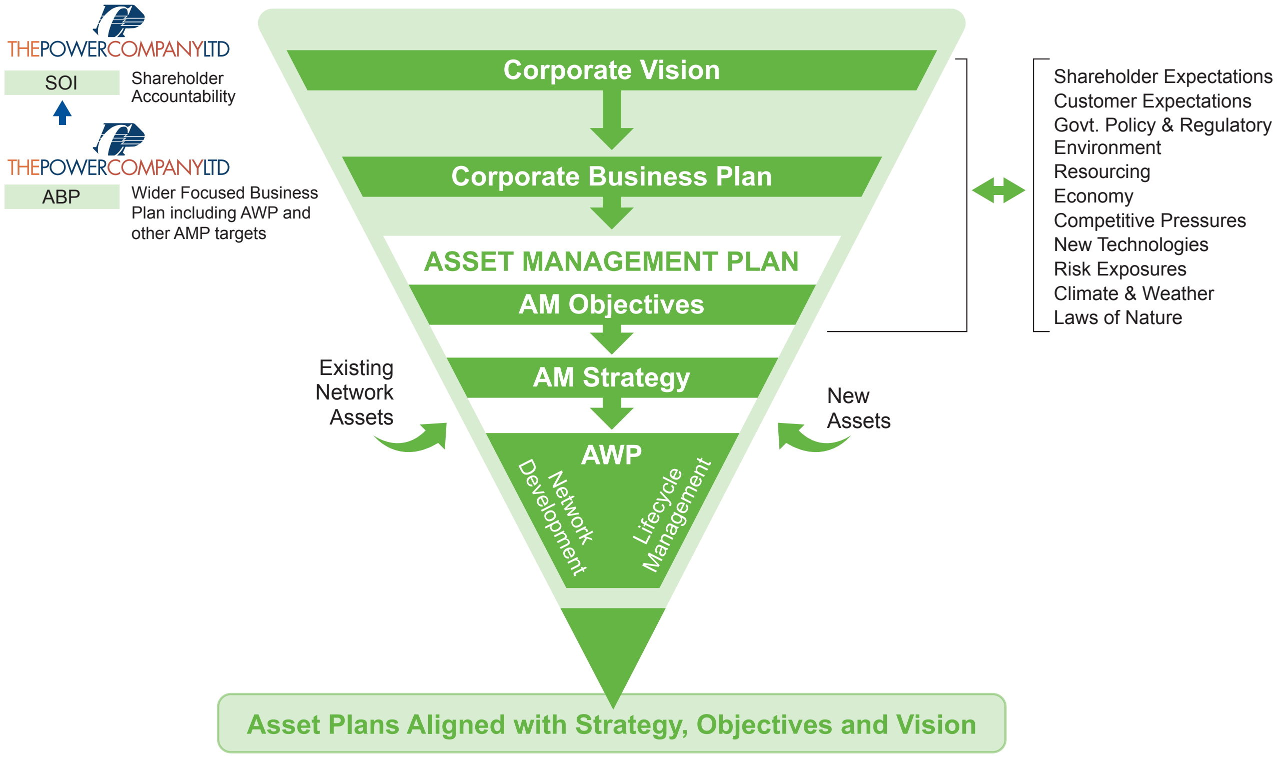
The vision leads to the objectives for TPCL's asset management processes. These asset management processes are documented in the AMP which serves as a guidance and communication mechanism ensuring understanding and consistency within TPCL's asset management company PowerNet and for the TPCL board.

The asset management strategies are designed to provide guidance to achieve 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 drive the strategy development. They also shape the asset management objectives and the corporate vision. However, these tend to remain relatively consistent whereas strategies tend to be more flexible and evolve as the driving factors change with time. The asset management strategies are applied to the existing network assets to meet the asset management objectives including realising development opportunities as they arise. This involves the setting of performance targets which leads the AWP development.

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

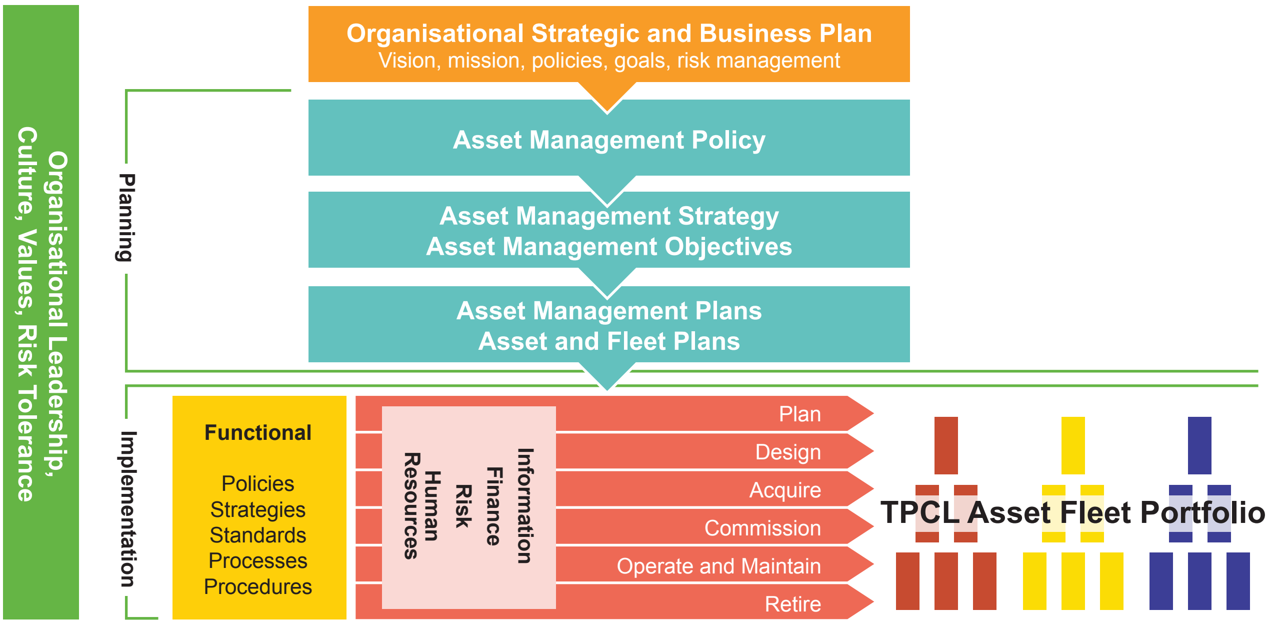
Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP; these together with any wider business issues provide the overall business planning summary used by the wider management team and TPCL Board. The SOI incorporates performance targets (including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

Figure 4: *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 5 shows the framework we use to manage our assets.

Figure 5: *Asset Management Framework*



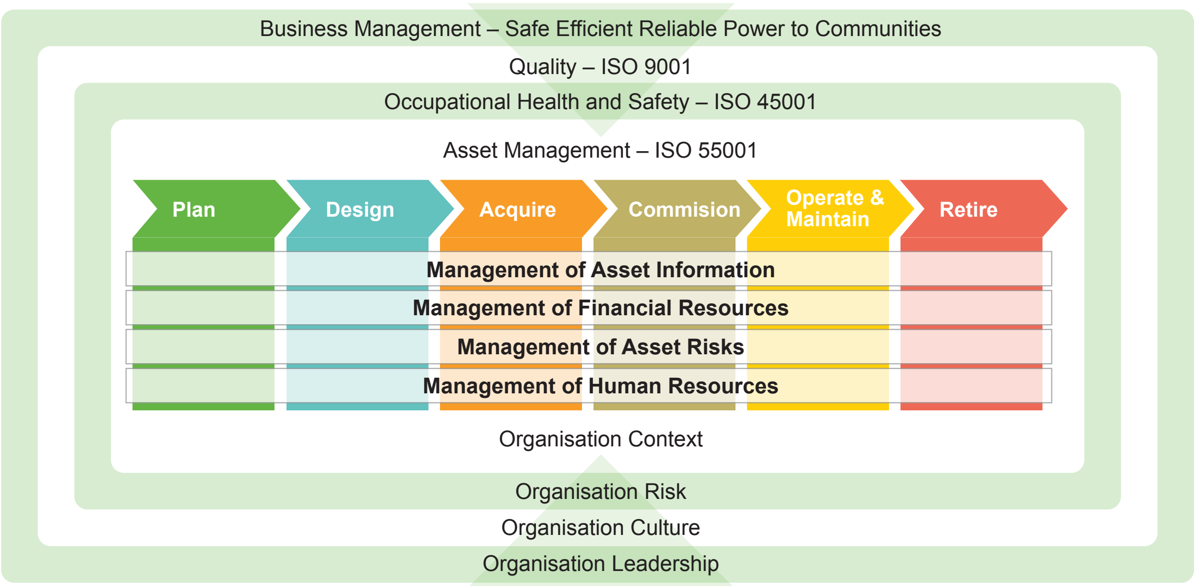
Asset Management Planning

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

- plan;
- design;
- acquire (including construction);
- commission;
- operate and maintain; and
- dispose.

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

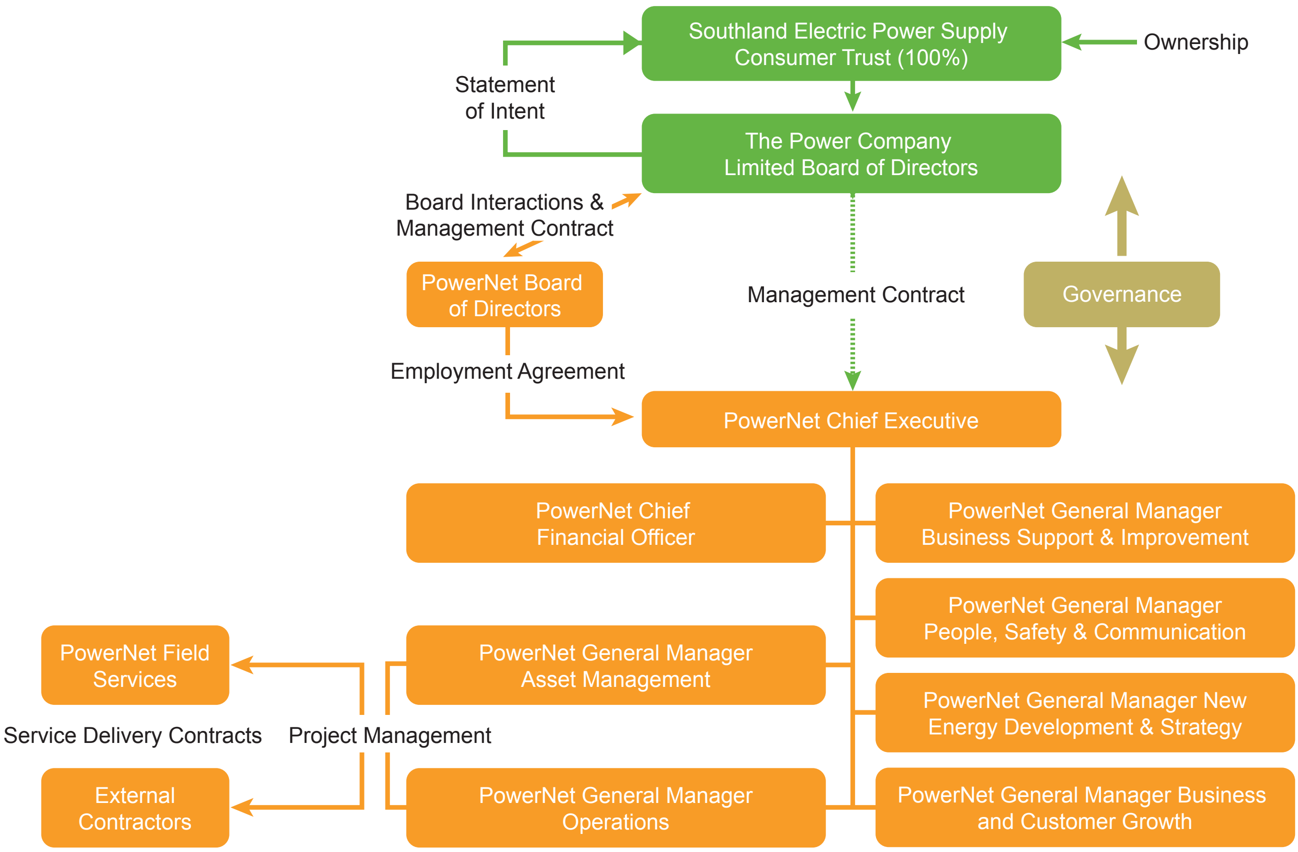
Figure 6: *Asset Management Processes*



2.7 Structure and Accountabilities

TPCL's ownership, governance and management structure is depicted in Figure 7. 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 7:** Governance and Management Accountabilities*



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. Any new project over $100,000 added or variation by more than +10% or -30% (for projects over $100,000) to the approved AWP needs approval from the TPCL 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 seven 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 (non-exhaustive list).

- 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, Electronet, ProTechtion Consulting, Mitchell Daysh, Ergo Consulting, Decom).

2.8 Incorporating customer requirements in our network planning

The topography of TPCL's supply area 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 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 7.

Table 7: *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 during local peak periods. • New capacity required.
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 production. Due to the impact of COVID-19 on general supply chain process, producers have seen a reduction in unit 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.
- Mercury Energy, wind farm at Kaiwera Downs – exclusive 33kV from Gore GXP
- 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.
- 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).
- Pioneer Generation, 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.
- Southern District Health Board, hospitals at Invercargill and Gore – supplied off township feeders with alternatives from other township feeders.
- Te Whatu Ora - Health New Zealand Southern, hospitals at Invercargill and Gore – supplied off township feeders with alternatives from other township feeders.

2.9 Quality of Service (Regulated Service Levels)

Quality of service incentives is a major focus area of the Commerce Commission. The stated intent is that aligning reliability incentives to the value customers place on reliability frees EDBs (within certain bounds) to target the level of reliability and of price that best meets the expectations of their customers. Additionally, normalisation is intended to prevent the effects of severe storms being mistaken for signs of deterioration. The principles embodied within the ComCom quality standards are the following.

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

[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.
[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

SECTION CONTENTS

3 THE NETWORK AND ASSET BASE

The bulk supply points for the TPCL network are at Invercargill, North Makarewa, Gore and Edendale and the embedded generation 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. Embedded generators can supply up to up to 115MW of power.

This section describes the network configuration, load characteristics, and energy and demand characteristics.

The TPCL network is supplied by four Transpower Grid Exit Points (GXP) and embedded generation.

3.1 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 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 and 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 through 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.

TPCL 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 80MVA transformers at Gore at nine 33kV feeders. 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 8: *Bulk Supply Characteristics*

Supply	Voltage	Rating	Firm Rating	Maximum Demand 2023/2024
Invercargill GXP	220/33kV	240MVA	109MVA	106.226MW (9:00 10/08/2023)
TPCL	*(GXP assets shared with EIL)*			51.86MW (8:00 27/10/2023)
North Makarewa GXP	220/33kV	120MVA	67MVA	48.364MW (8:00 03/10/2023)
Gore GXP[1]	110/33kV	160MVA	80MVA	40.882MW (7:30 21/12/2023)
Edendale GXP	110/33kV	60MVA	34MVA	30.806MW (7:30 31/10/2023)
White Hill Generation	66kV	56MVA	0MVA	47.712MW (8:00 20/12/2023)
Monowai Generation	66kV	7.5MVA	5MVA	6.191MW (08:30 09/06/2023)
Flat Hill Generation	11kV	6.8MVA	0MVA	7.19MW (01:30 23/05/2023)
Mataura Generation	11kV	0.9MVA	0MVA	0.916MW (17:00 17/11/2023)
Tararua Wind Power – Kaiwera Downs Generation	33kV	43MVA	0MVA	40.09MW (17:00 28/11/2023)

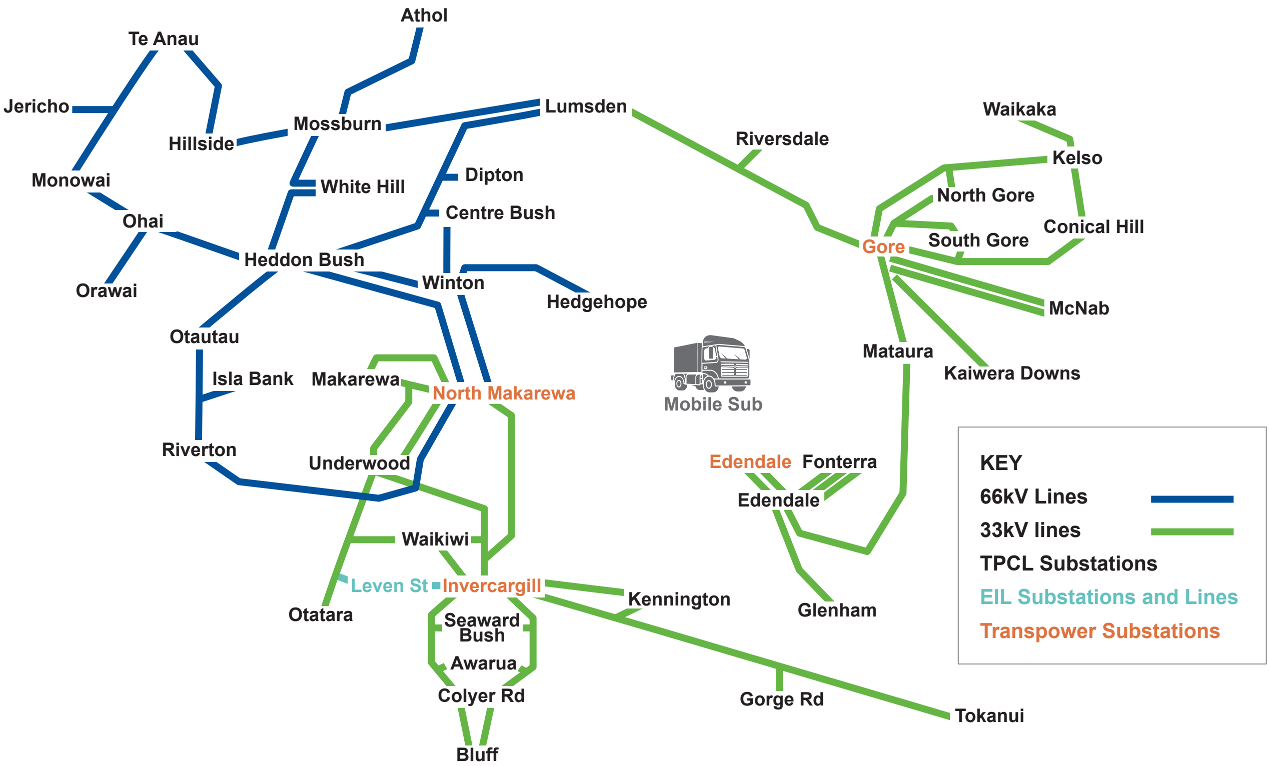
There is significant generation embedded within TPCL's network, as covered in the table above. Several smaller distributed generation connections exist but they are only a few kW each in size. These generators are generally solar installations which, due to their generation profiles tied to sunlight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

[1] 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.

3.2 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 8.

Figure 8: *Subtransmission Network*



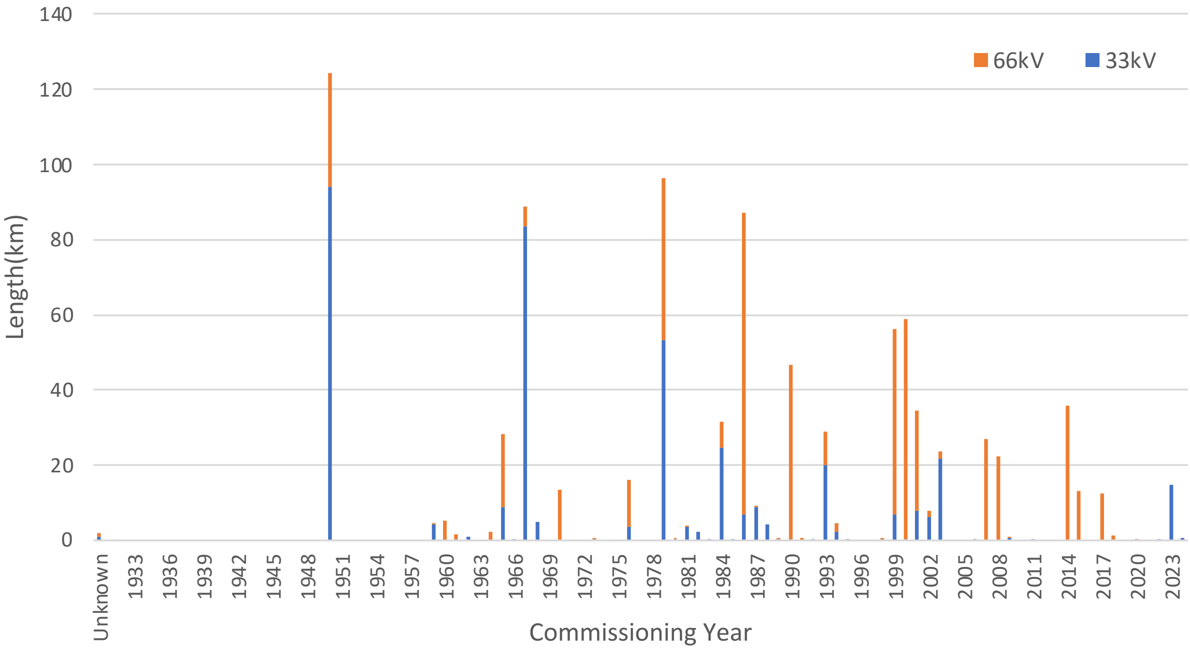
The subtransmission network comprises 531km of 66kV line, 379km of 33kV line, and 35km of 33kV cable and has the following characteristics:

- It is almost totally overhead except for cable runs near GXP's and zone substations. Larger runs of cable include the supply to McNab zone substation, inter-connections to Electricity Invercargill's Leven Street and Southern zone substations, 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 uses 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 of the long distances to loads, putting the loads beyond 11kV reach.

Subtransmission Lines

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. Figure 9 shows the commissioning year and installed length for TPCL's subtransmission lines.

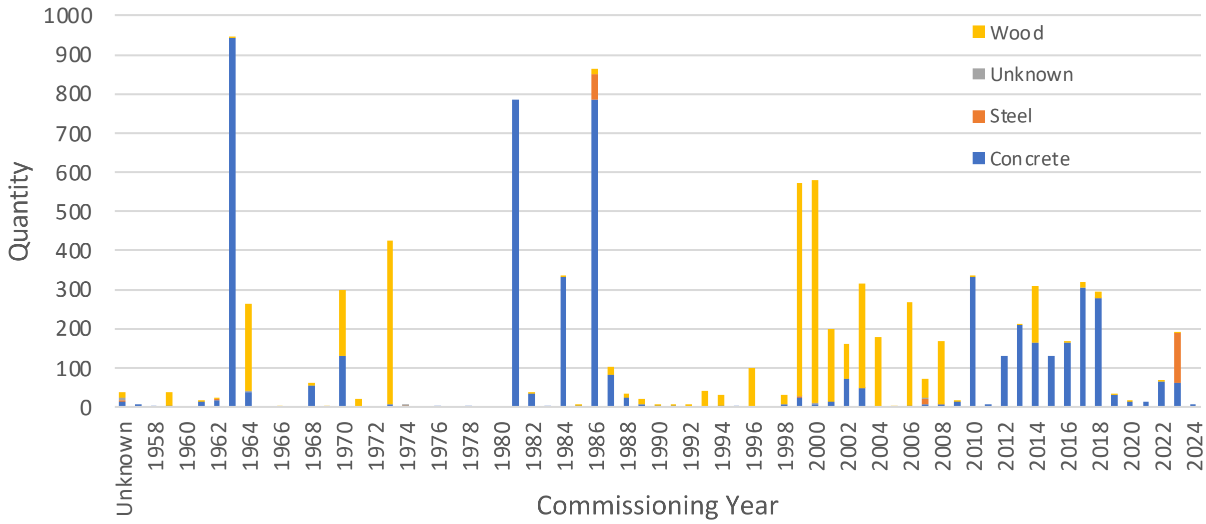
Figure 9: *Subtransmission Line*



Subtransmission Poles

There are a large number of poles that will pass the standard life for wooden poles in the next ten years. Pole replacements are based on condition and condition of subtransmission lines is assessed by annual aerial and five-yearly ground based condition inspections. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection. Figure 10 shows the commissioning year and installed numbers of TPCL's subtransmission poles.

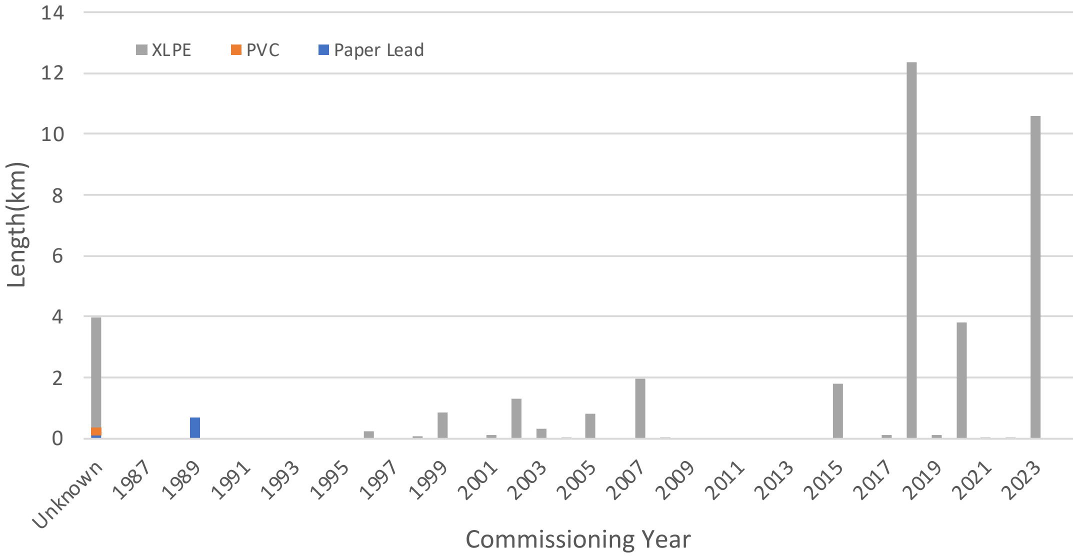
Figure 10: *Subtranmission Pole*



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 11 shows the commissioning year and installed length for TPCL's subtransmission cables.

Figure 11: Subtransmission Cables (33kV Cables)



3.3 Zone Substations

TPCL owns and operates 38 zone substations across Southland which have security levels (see Development Criteria for security level definitions) ranging between 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 9.

***Table 9:** 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 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.

Substation	Nature of load	Description
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 residences, Woodlands village, rural farms.	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.
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.

Substation	Nature of load	Description
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.
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.
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 indoor switchboard 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.
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.

Substation	Nature of load	Description
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 refurbished 33/11kV 6/12MVA 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.

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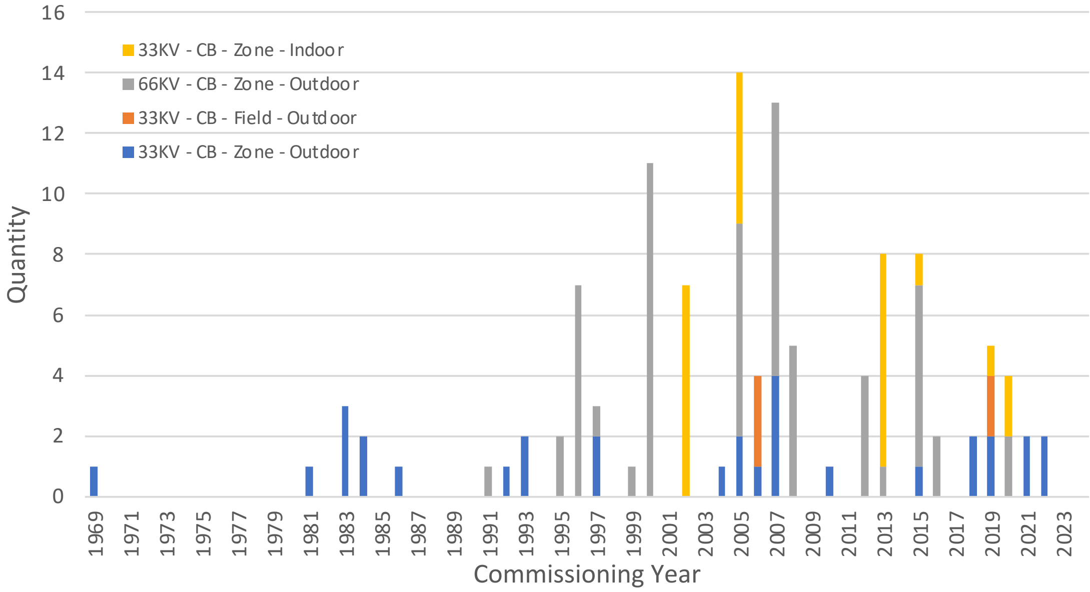
Subtransmission Voltage Switchgear

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 12: *Subtransmission Voltage Circuit Breakers (66kV & 33kV)*

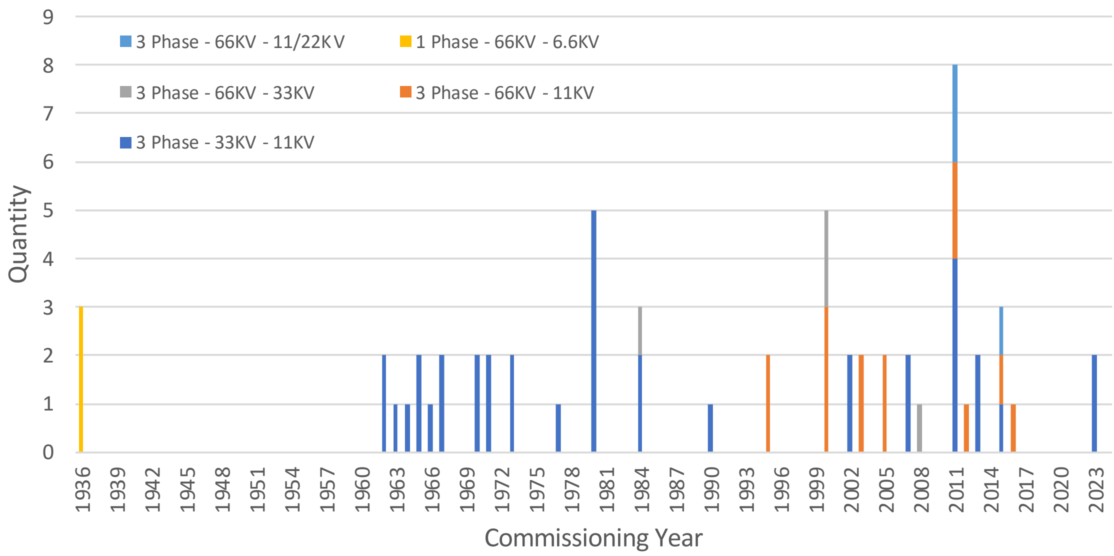


Power Transformers

The Power Transformers on the network are generally in good condition. Twenty four 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 satisfactory 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, Hillside, Kelso, North Gore, Riversdale, Otatara, Edendale and Tokanui substations are being monitored. The age profile of these is shown in Figure 13.

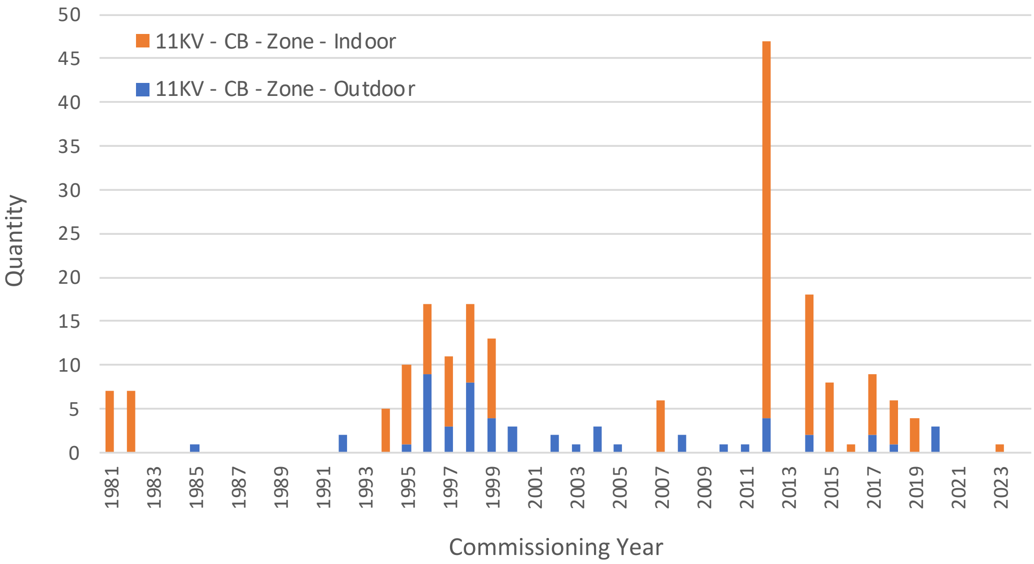
Figure 13: *Power transformers*



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 is shown in Figure 14.

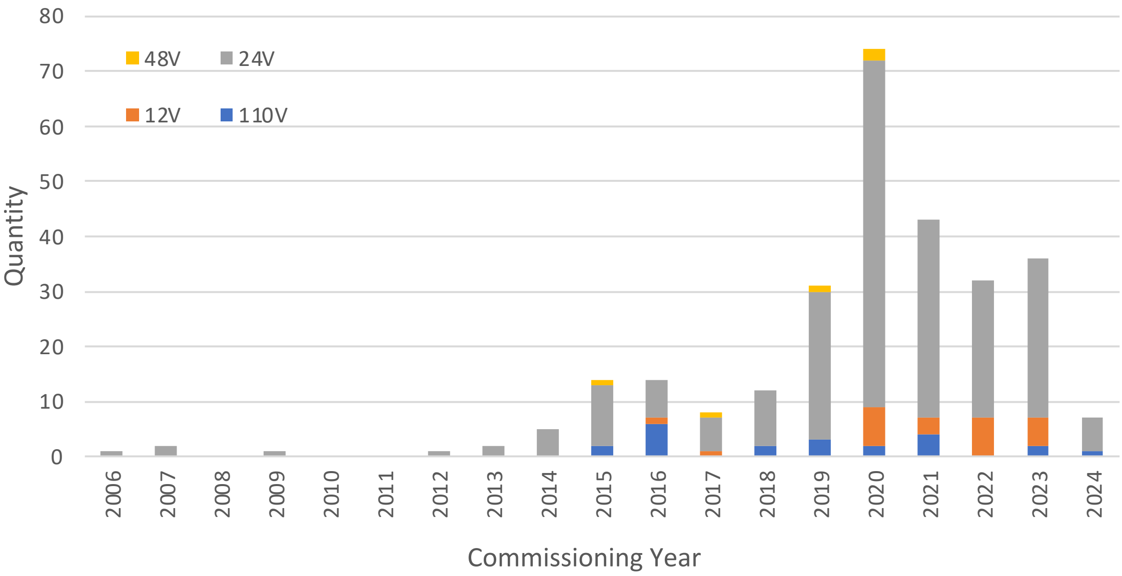
***Figure 14:** Distribution Voltage Switchgear*



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 is shown in Figure 15.

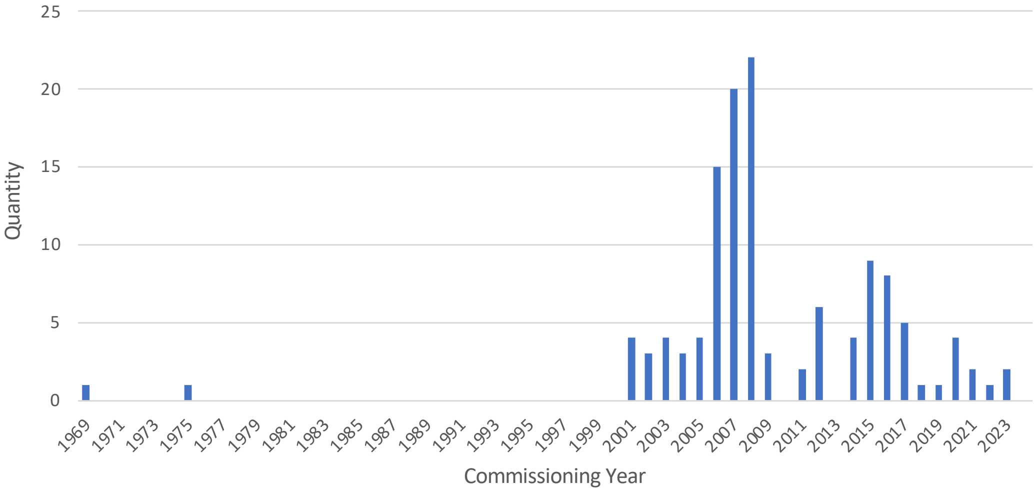
***Figure 15:** DC Batteries*



Tap Changer Controls

There are 125 voltage regulating relays (VRR) in operation, and most have been installed with the associated transformer or voltage regulator. The condition of these is generally good with no major problems. Several regulator sites are equipped with modern Eaton's CL7 voltage regulators, allowing a single VRR per site, while older sites require one VVR per phase. The two oldest VRRs on the network are at Awarua and Riversdale and have been identified for replacement or decommissioning as part of the substation upgrade projects. The age profile of these is shown in Figure 16.

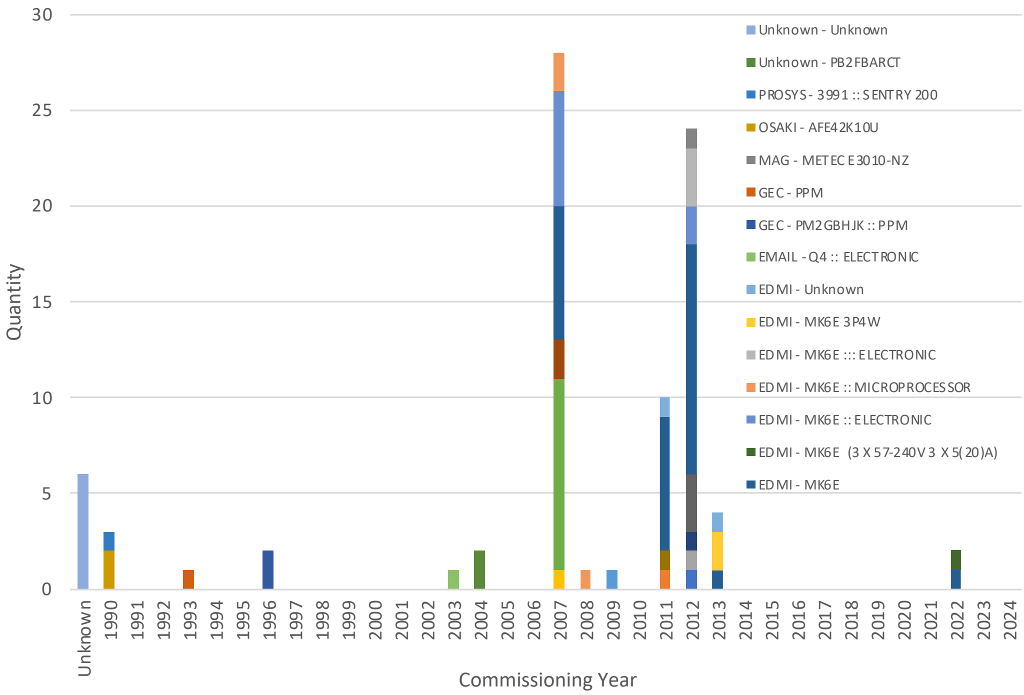
Figure 16: *Voltage Regulating Relay*



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 is shown in Figure 17.

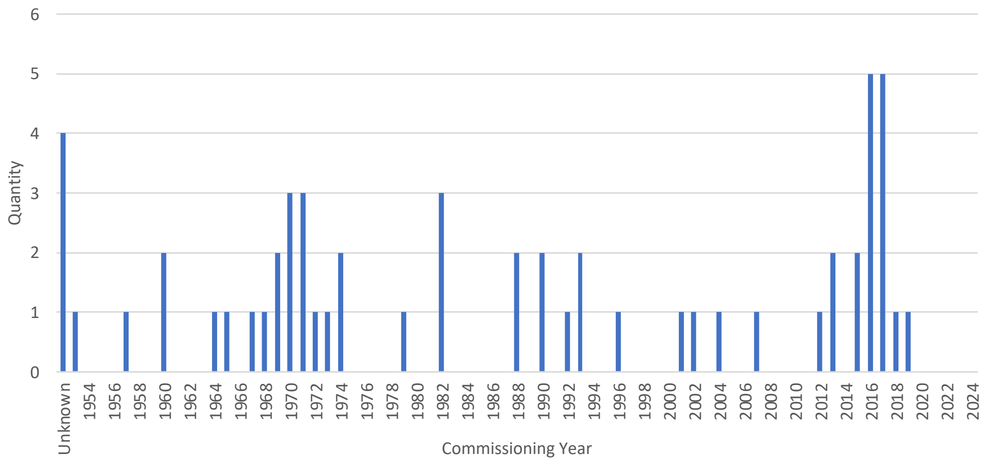
Figure 17: *Metering Assets*



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 57 buildings is shown in Figure 18

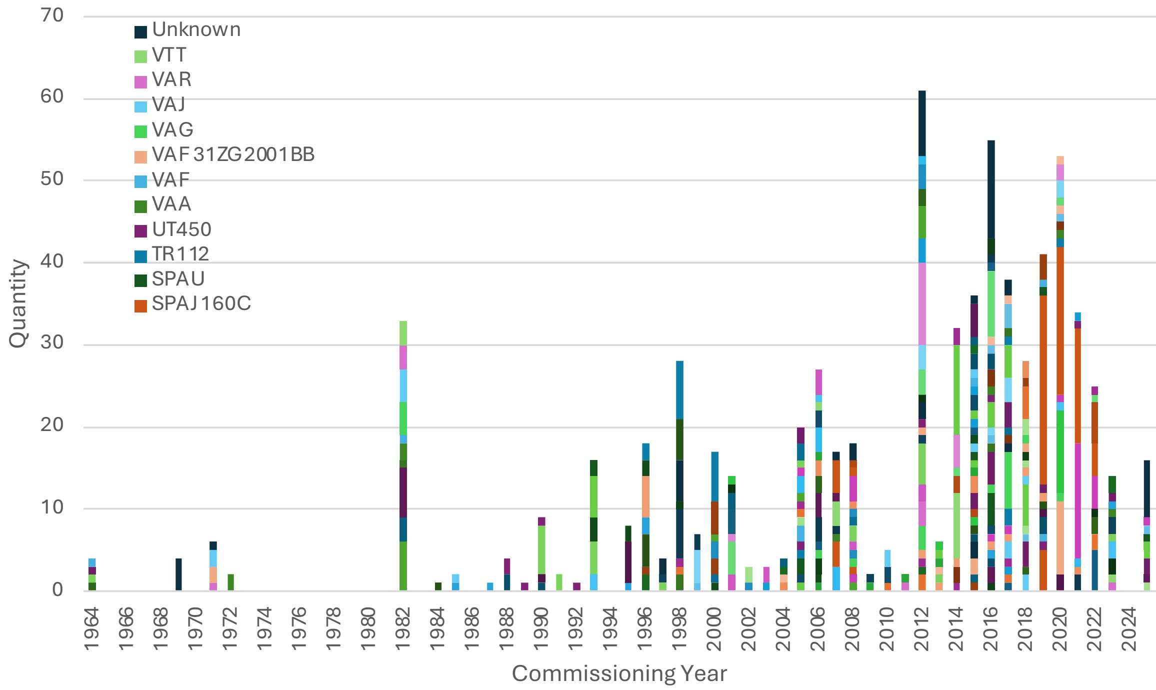
Figure 18: *Substation Buildings*



Protection Equipment

TPCL has some 722 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 722 protection relays is shown in Figure 19.

Figure 19: *Protection Relays*



3.4 Distribution Network

TPCL's distribution network has a total length of 7,065 km to supply its 37,850 customers giving an overall customer density of 5.36 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[2] or XLPE[3] 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 10. 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, improving zone substation transformer capacity utilisation and reliability.

***Table 10:** Distribution network per substation*

Substation	Line Length (km)	Cable Length (km)	Total Length (km)	Customers	Customer density
Athol	119.20	7.81	127.01	559	4.40
Awarua	0.01	0.07	0.07	1	14.29
Bluff (TPCL)	33.71	0.44	34.15	163	4.77
Centre Bush	276.42	0.29	276.71	658	2.38
Colyer Road	13.84	6.52	20.36	45	2.21
Conical Hill	165.18	0.30	165.48	303	1.83
Dipton	161.84	0.27	162.11	320	1.97
Edendale Fonterra	0	0		1	0.00
Edendale	295.94	4.38	300.32	1386	4.62
Glenham	192.59	0	192.59	359	1.86
Gorge Road	165.29	0.26	165.56	397	2.40
Hedgehope	141.32	0.56	141.87	318	2.24
Hillside	226.90	2.18	229.09	370	1.62
Isla Bank	132.78	1.43	134.21	363	2.70
Kelso	442.10	0.29	442.40	1317	2.98
Kennington	176.00	4.22	180.21	799	4.43
Lumsden	331.94	5.90	317.84	845	2.66
Makarewa	246.01	2.55	248.56	1147	4.61
Mataura	235.03	3.51	238.54	1267	5.31
McNab	0	0	0	1	0.00
Monowai	46.91	0.37	47.28	96	2.03
Mossburn	209.91	2.48	212.39	469	2.21
North Gore	284.56	5.37	289.93	2809	9.69
Ohai	212.99	0.51	213.50	787	3.69

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

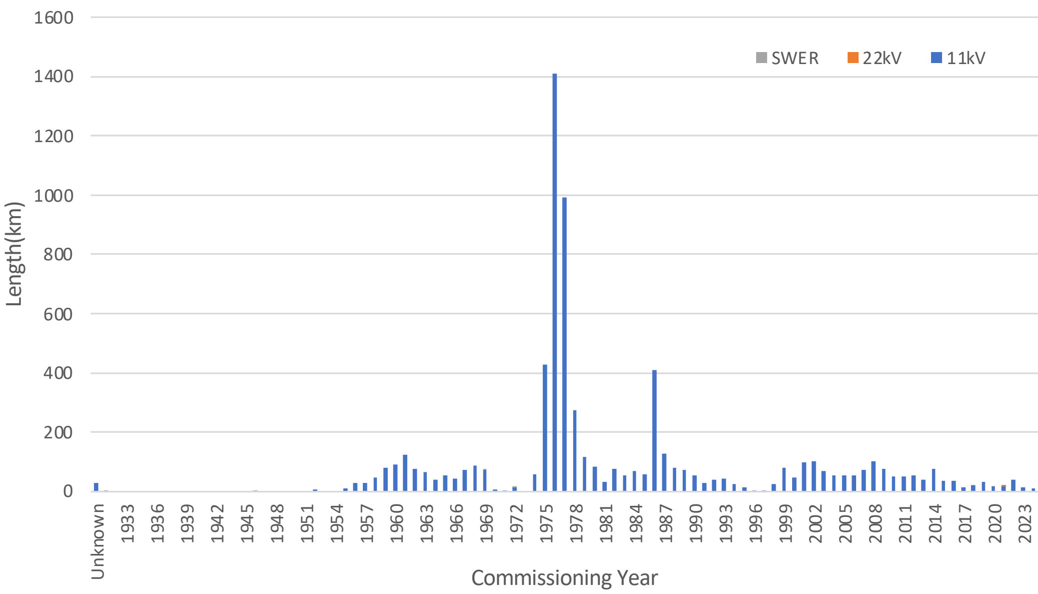
[3] XLPE = Cross-Linked Polyethylene – the modern underground cable construction format.

Substation	Line Length (km)	Cable Length (km)	Total Length (km)	Customers	Customer density
Orawia	313.36	2.56	315.92	945	2.99
Otatara	61.02	6.31	67.33	1432	21.27
Otautau	189.07	1.09	190.15	863	4.54
Racecourse Road (TPCL)	28.63	2.84	31.47	549	17.45
Riversdale	425.59	3.41	429.00	1369	3.19
Riverton	294.99	7.05	302.04	2207	7.31
Seaward Bush	151.02	6.59	157.62	2585	16.40
South Gore	195.55	6.78	202.33	2515	12.43
Te Anau	175.84	41.91	217.75	2919	13.41
Tokanui	230.33	0.72	321.06	586	1.83
Underwood	66.12	2.49	68.61	630	9.18
Waikaka	95.24	0.19	109.00	3622	33.23
Waikiwi	95.24	12.05	107.29	250	2.33
Winton	394.80	8.16	402.96	2587	6.42
Unallocated	1.05	1.37	2.41	11	4.56
Total/average	**6818.61**	**159.54**	**7065.12**	**37,850**	**5.36**

Distribution Lines

The age profile for overhead LV conductors is shown in Figure 20. Overhead LV conductors are replaced based on their condition.

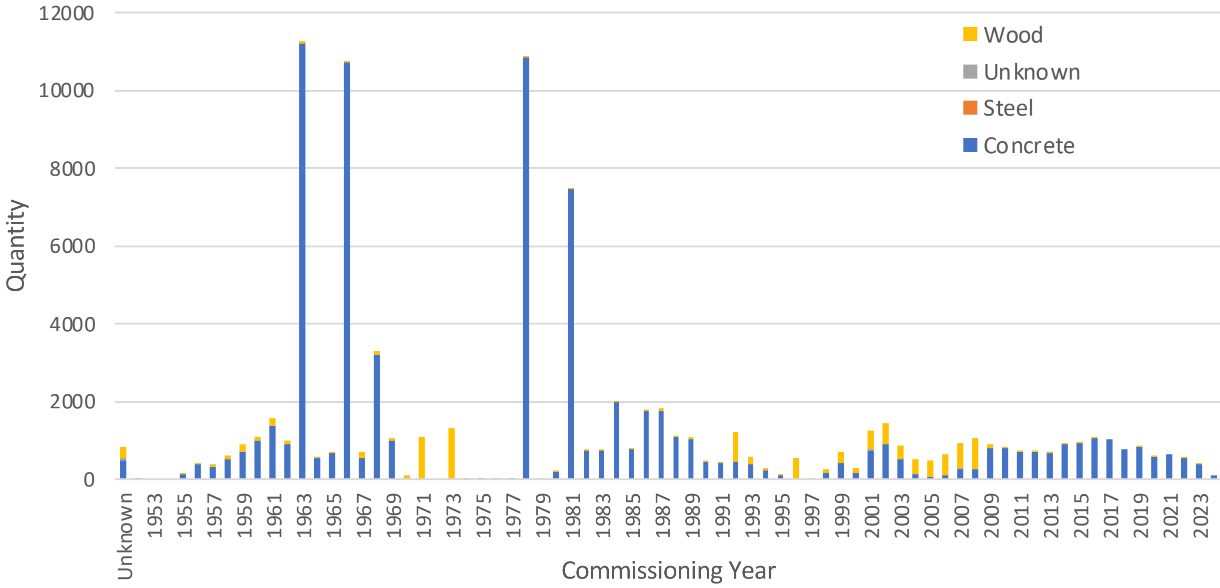
Figure 20: *MV Line Conductors (11kV Overhead)*



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 using 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 21.

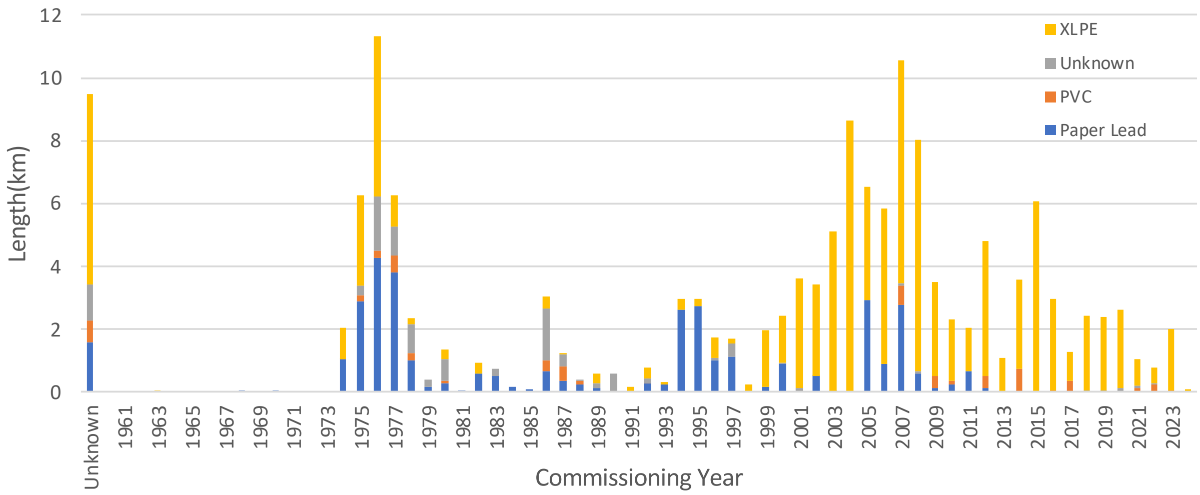
Figure 21: *Distribution Poles*



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 22 shows the lengths of cables on TPCL's distribution network by commissioning year.

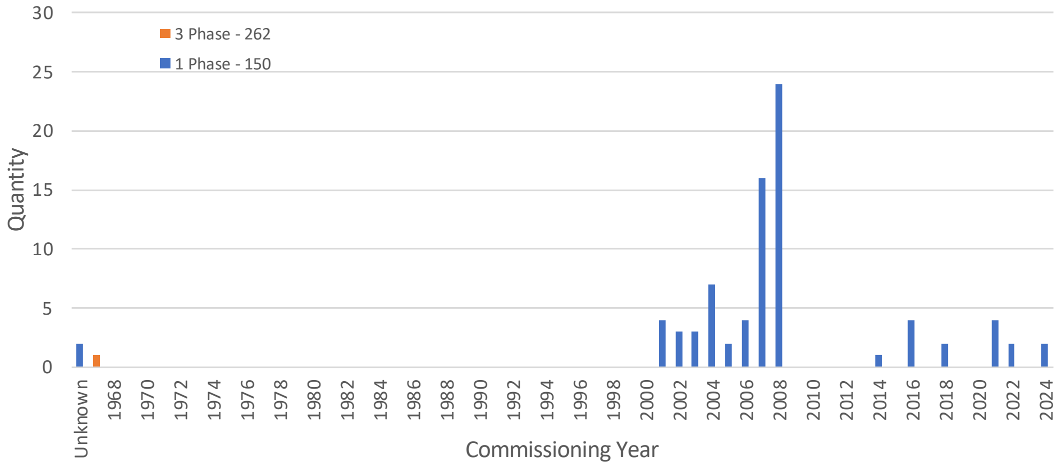
Figure 22: *MV Cables (11kV)*



Voltage Regulators

The age profile for voltage regulators is shown in Figure 23. 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.

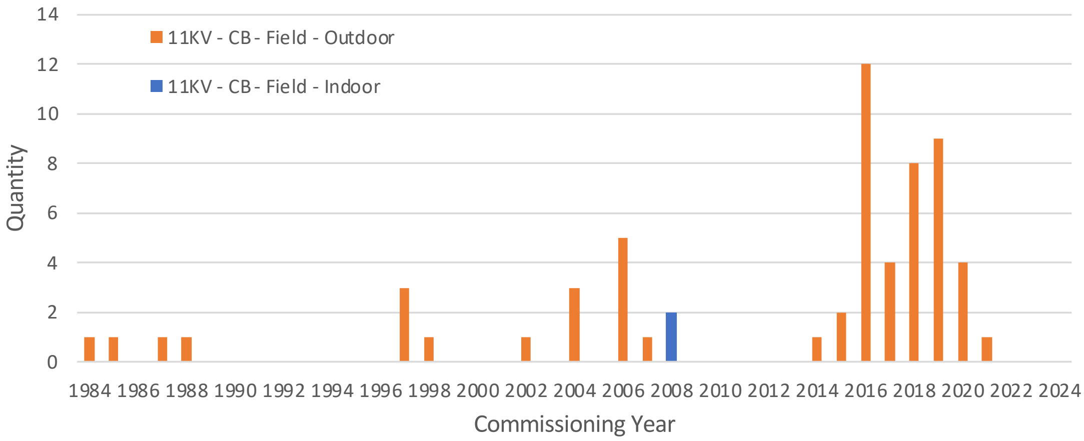
Figure 23: *Voltage Regulators*



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 24 provides an overview of the age profiles of field circuit breakers.

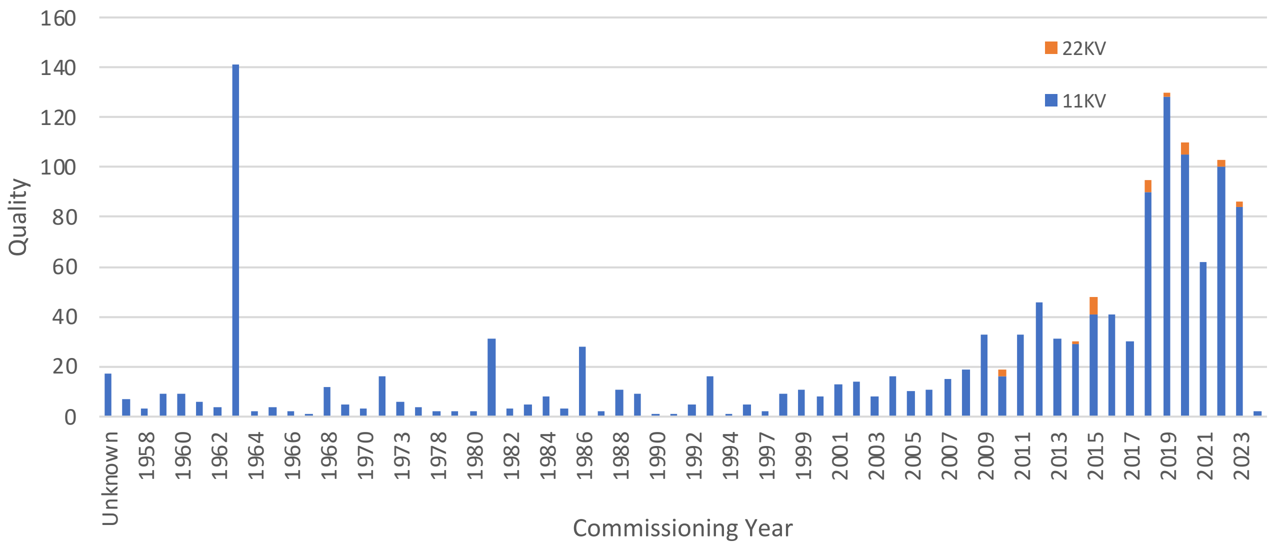
Figure 24: *Field Circuit Breakers at Distribution Voltage (11kV)*



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 therefore an accelerated replacement program has been implemented to replace high risk units. This increases the replacement rate till the end of the 2027/28 financial year. Figure 25 provides an overview of the age profiles of the air break switches.

Figure 25: *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.

3.5 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 0.5kVA 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 South Pacific Meats 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[4] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

Table 11 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 11: *Number of distribution transformers*

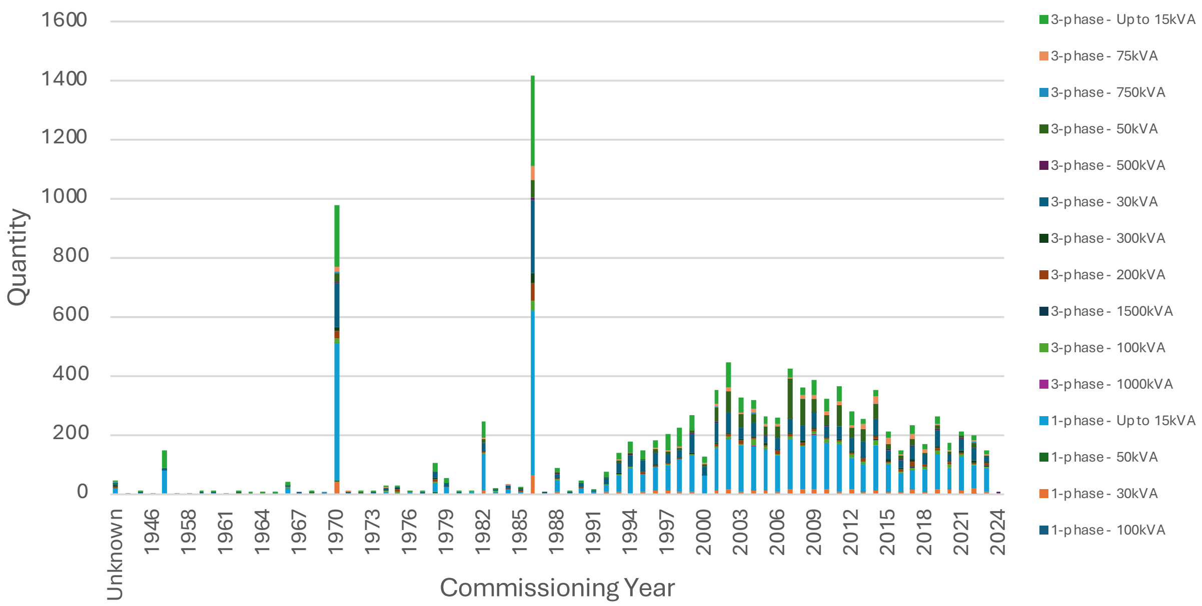
Phases	Rating	Pole Mount	Ground Mount
1 phase	up to 15 kVA	4884	34
	30 kVA	477	13
	50 kVA	13	1

[4] 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
3 phase	up to 15 kVA	1830	4
	30 kVA	1820	52
	50kVA	1044	48
	75 kVA	301	11
	100 kVA	238	80
	200 kVA	93	239
	300 kVA	38	128
	500 kVA	4	52
	750 kVA	5	22
	1,000 kVA	1	13
	1,500 kVA	0	16
Total		**10748**	**713**

Figure 26 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 if the unit has been heavily loaded. 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 26: *Age Profile of Distribution Transformers*

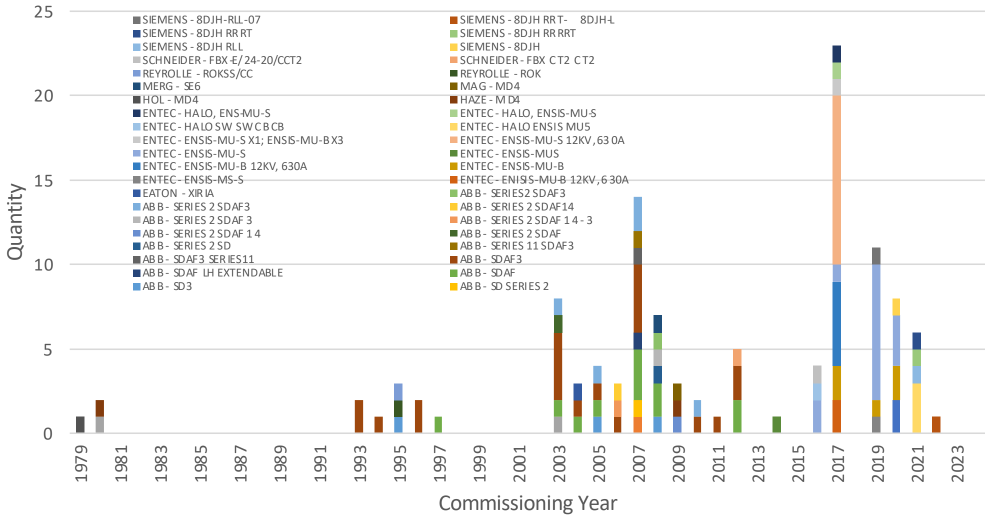


Ring Main Unit

The age profile of ring main units (RMUs) is displayed in Figure 27 which shows several the older (generally indoor) units will be reaching their standard life of 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. However, a programme is being implemented to accelerate the replacement of hazardous units. 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.

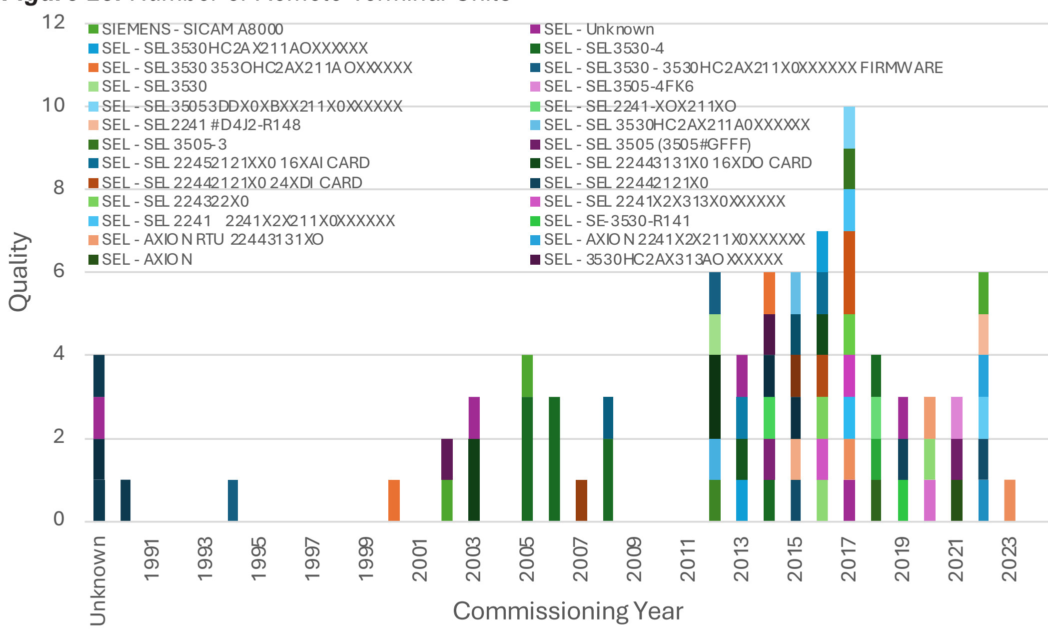
Figure 27: *Age Profile of Ring Main Units*



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 for replacement 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 28.

Figure 28: *Number of Remote Terminal Units*



3.6 Low Voltage Network

TPCL's Low Voltage (LV) network (400/230 V) has a total length of 1088.32km to supply its 37,850 customers giving an overall customer density of 34.78 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 12. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

***Table 12:** LV Network Characteristics per Substation*

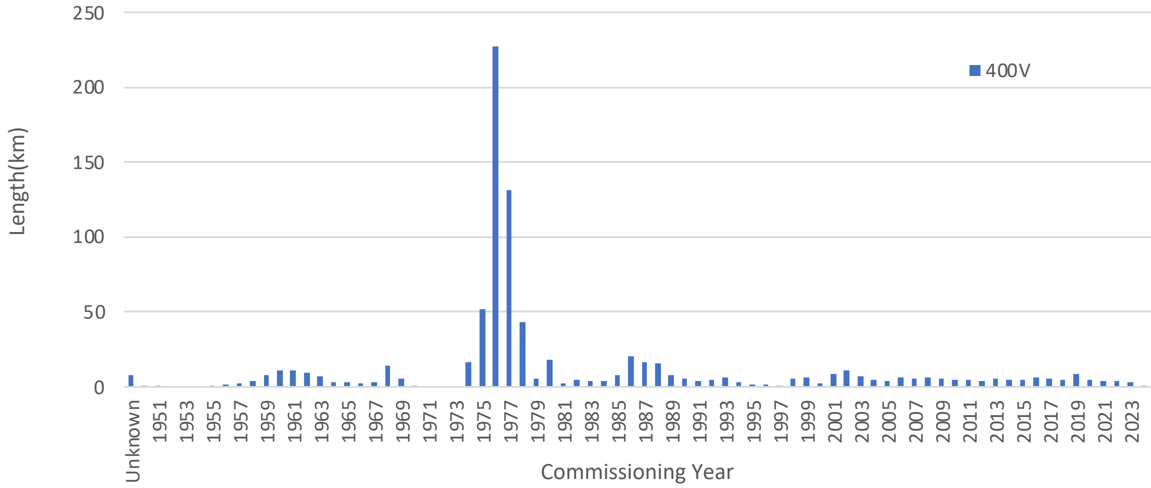
Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	8.56	4.73	559	42.06
Awarua	0	0	1	0.00
Bluff (TPCL)	5.51	0.09	163	29.11
Centre Bush	15.77	0.44	658	40.59
Colyer Road	0.49	0.34	45	54.22
Conical Hill	9.05	0.17	303	32.86
Dipton	7.89	1.18	320	35.28
Edendale Fonterra	0	0	1	0.00
Edendale	47.73	2.14	1386	27.79
Glenham	12.51	0.11	359	28.45
Gorge Road	14.87	0.14	397	26.45
Hedgehope	10.29	1.09	318	27.94
Hillside	3.83	0.38	370	87.89
Isla Bank	11.03	0.29	363	32.07
Kelso	32.23	1.68	1317	38.84
Kennington	31.68	2.45	799	23.41
Lumsden	17.91	2.94	845	40.53
Makarewa	44.19	2.54	1147	24.55

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Mataura	31.73	2.03	1267	37.53
McNab	0	0	1	0.00
Monowai	1.29	0.65	96	49.48
Mossburn	8.16	1.07	469	50.81
North Gore	57.63	12.70	2809	39.94
Ohai	26.28	0.37	787	29.53
Orawia	28.03	3.06	945	30.40
Otatara	30.39	14.20	1432	32.11
Otautau	23.94	3.36	863	31.61
Racecourse Road (TPCL)	9.70	8.79	549	29.69
Riversdale	36.70	1.02	1369	36.29
Riverton	60.93	7.44	2207	32.28
Seaward Bush	42.96	26.16	2585	37.40
South Gore	45.80	15.87	2515	40.78
Te Anau	13.34	65.35	2919	37.09
Tokanui	25.95	1.21	586	21.58
Underwood	16.92	3.03	630	31.58
Waikaka	7.53	0.09	3622	475.33
Waikiwi	57.77	31.17	250	2.81
Winton	50.66	20.12	2587	36.55
Unallocated	0.03	0.64	11	26.19
Total/average	**849.28**	**239.04**	**37,850**	**34.78**

Low Voltage Lines

The age profiles for overhead LV conductors are shown respectively in Figure 29. 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 safety.

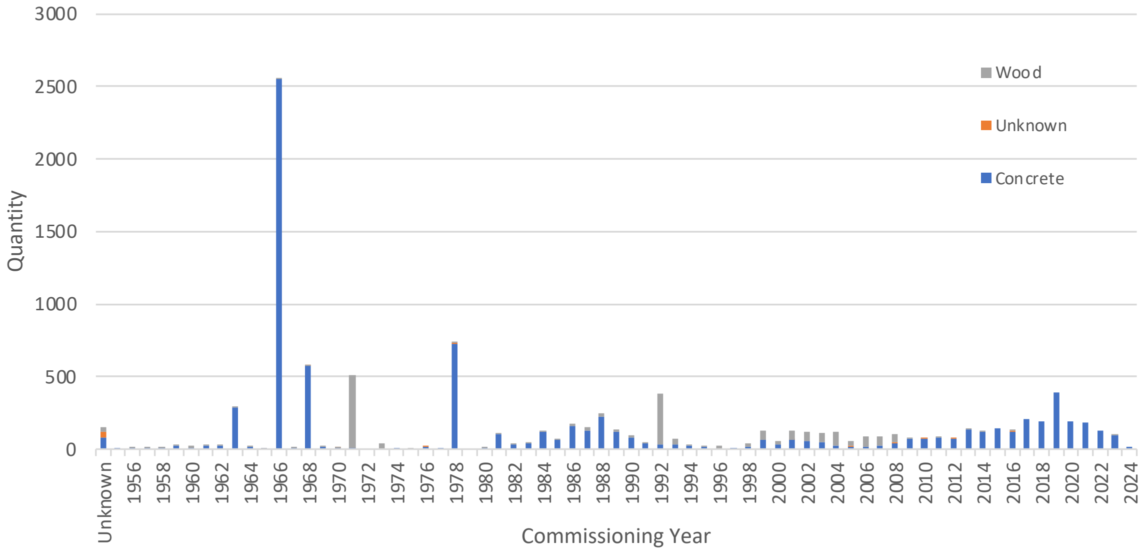
Figure 29: *Overhead LV Conductors*



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 30.

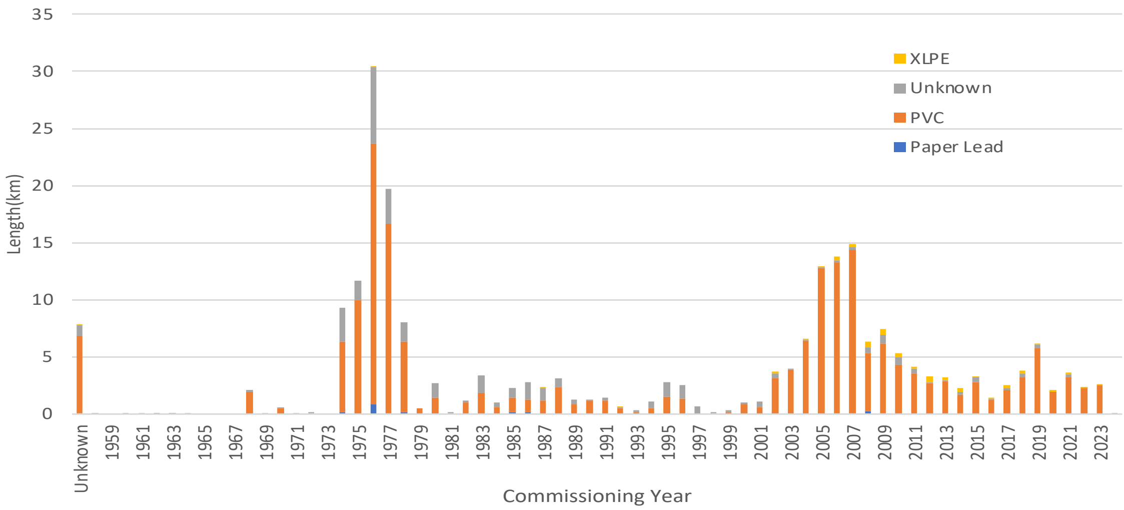
Figure 30: *LV Poles*



Low Voltage Cables

The LV cable commissioning year profile is shown in Figure 31 and shows several assets beyond nominal life. In practice cables are left in service until performance deteriorates and impacts on service levels.

Figure 31: *LV Cables*



3.7 Customer Connections

TPCL has 37,850 customer connections. Revenue is generated by providing a customer connection to the network via the 21 Trader Participants and for one Direct Customer. 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 13. 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.

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Table 13: *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	30 kVA 3ph	50 kVA 3ph	75 kVA 3ph	100kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	
Mar-22	186	1,896	10,142	19,825	2,897	1,570	251	61	61	213	37,102
Mar-23	190	1,927	10,165	20,246	2,888	1,573	254	75	54	218	37,590
Mar-24	192	1,945	9,979	20,680	2,861	1,580	256	83	48	226	37,850

3.8 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 within buildings, providing protection from the elements and extending the life of 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 was 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 14: *List of Injection Plants*

Voltage	Location	Quantity	Manufactured	Condition
66kV	Winton	1	1992 (Remaing Life (RL) = -8yrs)	Average, coupling cell and capacitors are outdoor. Not in operation.
33kV	Invercargill 1	1	1988 (RL = -12yrs)	Average, all gear is indoor
33kV	Gore	1	1990 (RL = -10yrs)	Average, although it requires an interface upgrade between new controller and Invercargill plant. All gear is indoor
33kV	Edendale	1	1988 (RL = -12yrs)	Average, all gear is indoor
33kV	North Makarewa	1	1994 (RL = -6yrs)	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 they can act as a backup for each 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 and Control	
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 also 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. They 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 last software update was implemented with the server upgrades 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 Racecourse Road, Invercargill. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide additional 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.

SCADA and Communications	
Remote Terminal Units (RTUs)	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 owns 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.

Other Assets	
Generation	TPCL owns one 8 kw diesel generator, 12.6 kW of solar generation and 16kW battery at the Blue Cliffs Rowallan Microgrid, but does 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 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.

3.9 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 relatively small variations annually. The main contributing factor to the change in the annual average consumption per residential customer is seasonal changes, resulting in 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 32 and Figure 33 respectively.

Figure 32: *Typical Domestic Feeder Daily Load Profile (July, Waikiwi CB3)*

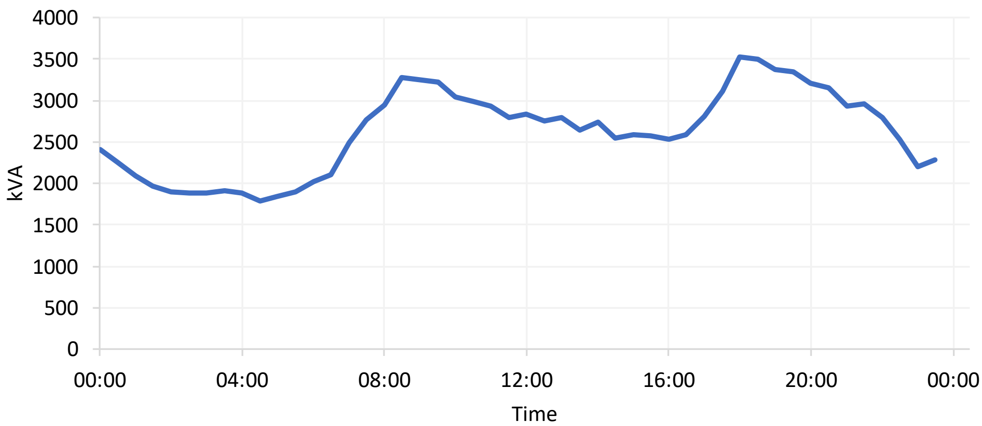
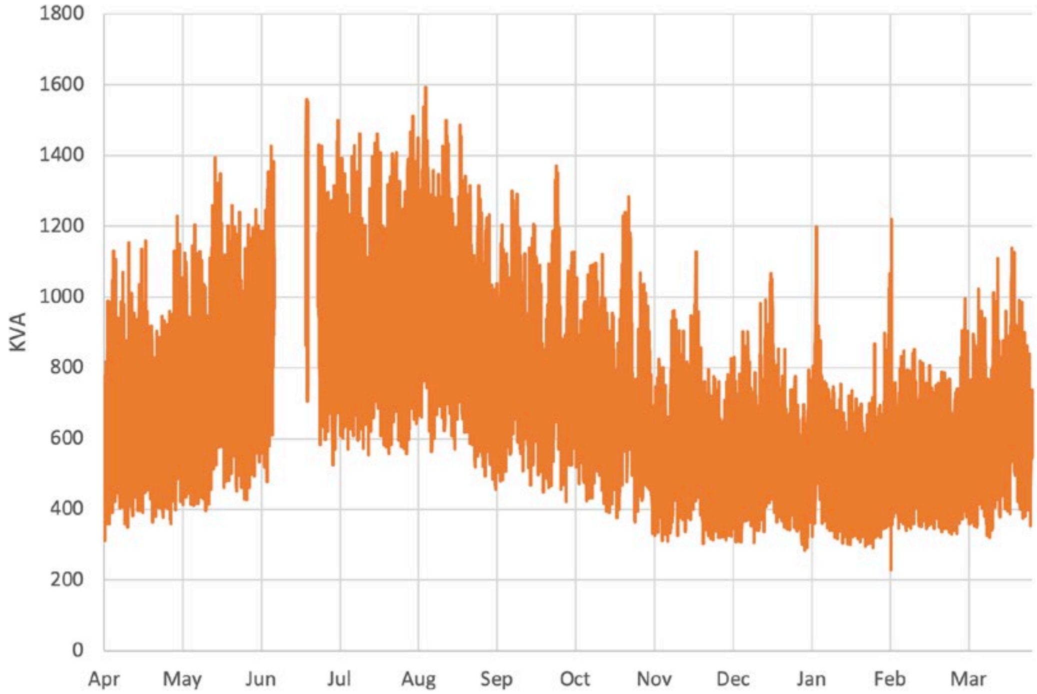


Figure 33: Typical Domestic Feeder Yearly Load Profile (North Gore CB4)



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, although grain farming and drying is increasing. The dairy and grain farming leads to summer peak loads due to irrigation in some areas. The remaining farms normally have low usage loads such as small pumps and electric fences, with peak usage during the few days of shearing or crop harvesting. Typical profiles are shown in Figure 34 and Figure 35.

Figure 34: Typical Farming Feeder Daily Load Profile (October, Centre Bush CB2)

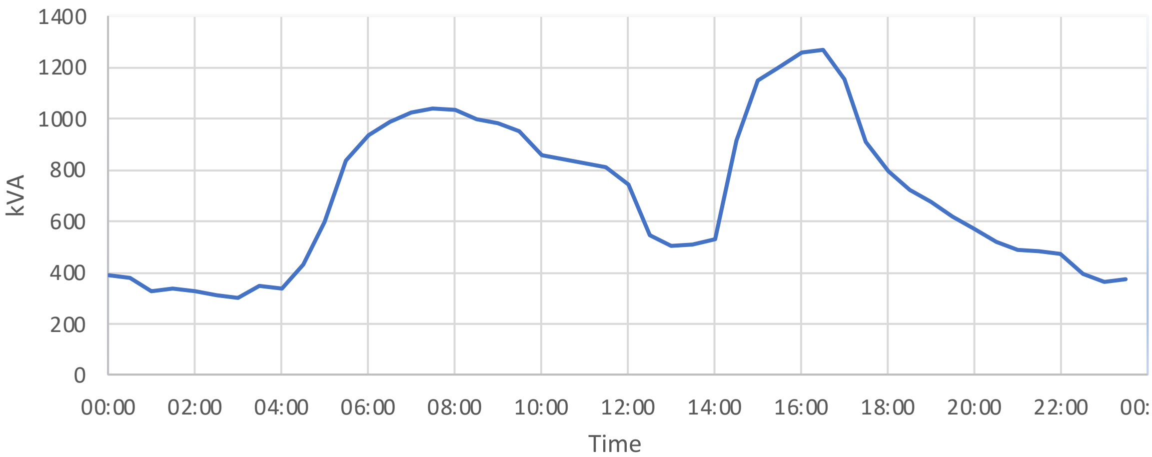
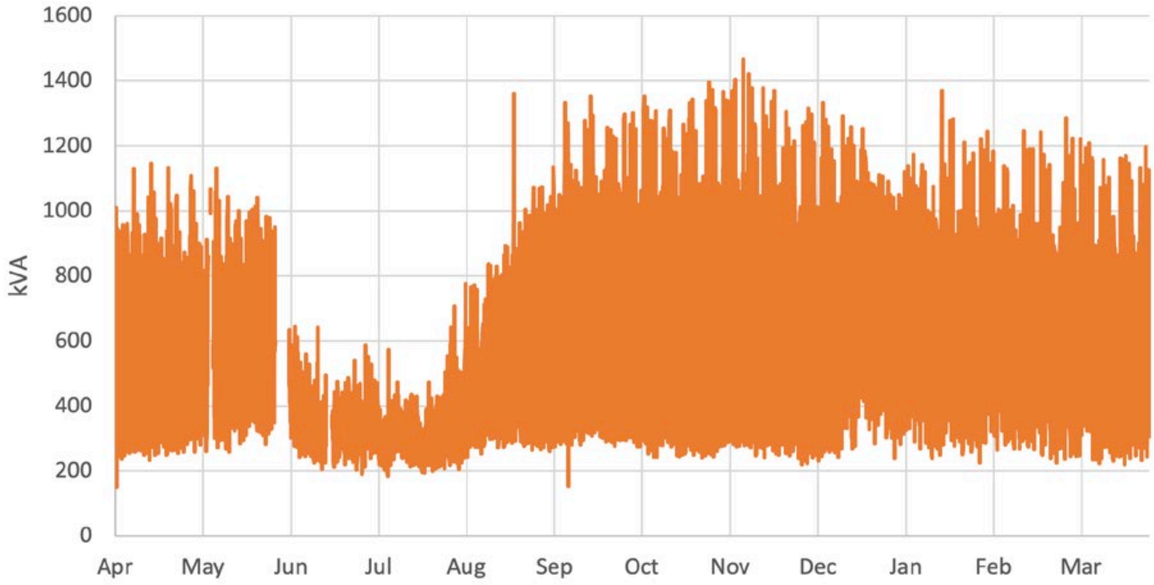


Figure 35: *Typical Farming Feeder Yearly Load Profile (Centre Bush CB2)*

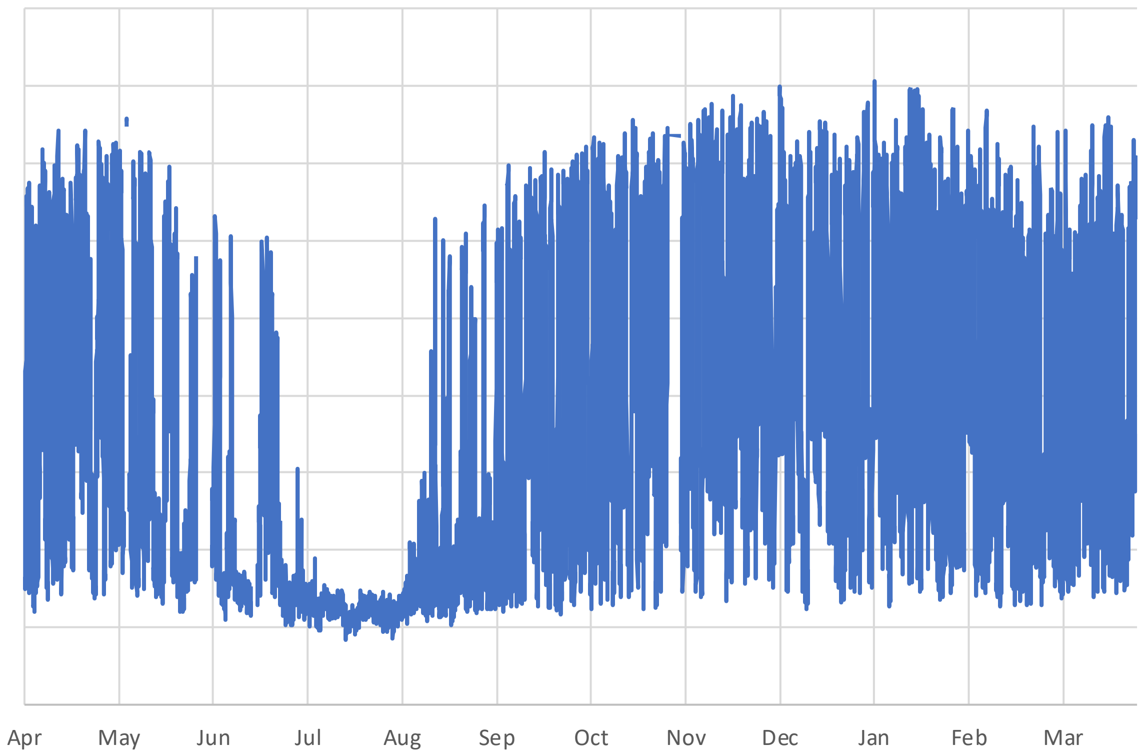


Industrial and Dairy Processing Load Profiles

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 36.

Figure 36: *Typical Dairy Processing Plant Yearly Load Profile*



3.10 Energy and Demand Characteristics

Key energy and demand values for the year ending 31 March 2024 are presented in Table 15.

Table 15: *Energy and Demand Values*

Parameter	Value	Long-term trend
Energy Conveyed	895 GWh	Steady Growth +0.5 - 1.5%
Maximum Demand[5]	164 MW	Steady
Load Factor	63%	Steady
Losses	5.6%	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 account for recent trends. Growth rates are often based on an educated estimate from the planning engineer and confidence in the growth rates shown in Table 15 is low.

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

Cabot Lodge Southland. Photo: Great South

4

Risk Management

SECTION CONTENTS

4 RISK MANAGEMENT

TPCL is exposed to a wide range of risks and uses risk management techniques 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.

This section examines our risk exposures, focussing on the asset management risks. It describes the management of these exposures and activities to reinstate service levels should disaster strike.

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.

4.1 Risk Strategy and Policy

"Understand and Effectively Manage Appreciable Business Risk" is a key corporate strategy and critical business task within TPCL. As a result, 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.

4.2 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.

Risk Identification

Risks need to be identified before they can be mitigated. Many risks might seem obvious, yet the identification of others 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 that review responsibility is 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 required 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 manifest.

These factors are categorised using the terms described 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 16: *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 17: *Event Consequence Categorisation*

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

	Consequence				
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
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 un-derperformance, 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 18: *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 19 indicates how these factors can be combined to present a relative risk level.

Table 19: *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 each cell of 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 20: *Management attention to risk rankings*

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

Risk Treatment and Mitigation

Risks often cannot 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 21 summarises the types of treatment options that are considered for any risk. These options are ordered by effectiveness for the control of risk.

Table 21: *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, however deciding between high cost but effective treatments and low cost, but less effective risk treatment options may be difficult and requires careful evaluation of all factors involved.

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

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

PowerNet has developed and operates an Incident Management and Business Continuity Plan that gets activated in the event of a significant risk materialising. We are now utilising 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 Incident Management Team should any such events occur. Training is continuing to ensure sufficient resources will be available in any high-risk event. The Incident Management and 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.

4.3 Company related risks (general)

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

Cyber Security

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

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

Industry Regulation

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

- Investment – providing business processes that ensure appropriate contracts and guarantees are agreed prior to undertaking large investments.
- Loss of revenue – loss of customers through by-pass or economic downturn could reduce revenue.
- Customer price shock – DPP4 will see significant price increases.
- Management contract – failure of PowerNet as TPCL's asset manager.
- Regulatory – failure to meet regulatory requirements.
- Change in central government policy on any number of industry related issues:
- Decarbonisation
- Industry structure
- Electricity pricing, etc.

International Labour Market

Internationally many economies are still trying to get inflation under control. Interest rates are still higher than anticipated. 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 are being approached and offered sometimes significant increases to move to other utilities in New Zealand but also Australia. This leads to:

- A shortage of of Field Staff required to undertake operation, maintenance, renewal, up-sizing, expansion, and retirement of network assets.
- A shortage of other technical staff such as engineers and project managers that must plan and manage the work issued to the field staff.
- Increased demand for corporate staff such as GIS, IT, analysts and accountants with industry experience
- A shortage of industry knowledge and experience as skills have to be attracted from other sectors.
- Increased emphasis on succession planning for an industry that has an ageing work force and is losing sector knowledge.
- Increased requirement and cost to upskill and train technical and non-technical staff in the industry.

Increases in the cost of equipment

A significant percentage of material and equipment used in the electricity supply is imported. Equipment prices are still rising at higher than CPI, driven by national and international supply and demand. Demand is driven by international and national decarbonisation initiatives.

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.

Conflict in Gaza

The conflict in Gaza has the potential to affect the supply of crude oil, should the conflict escalate.

Table 22: *Industry Regulation Risks and Responses*

Event	Likelihood	Consequence	Responses
Impact of economic factors (on prices to customers and returns to shareholders)	Possible	Major	• Hedge interest rates as per treasury policy and treasury advisor • Monitor interest rate and Commerce Commission WACC changes
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 • Continued regular bi-directional feedback interactions with the relevant stakeholders
Regulatory breaches	Possible	Moderate	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to an Incident Management and Business Continuity Plan.
Inability to attract and retain required skills for PowerNet to meet its core purpose	Almost certain	Moderate	• PowerNet undertakes overseas recruitment, when required, to access skills that are scarce in NZ, and takes steps towards growing local talent • Continued development of attraction strategies and recruitment brand

4.4 Asset Management Risks

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

Table 23: *Asset Management Risks*

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Containment 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; Voltage limits not maintained; Safety compromised; mechanical or electrical failure; ineffective maintenance and operations leading to loss of value; networks cannot supply future loads; environmental issues	Treat	Standardised designs and equipment Inspection and testing of primary and secondary plant Safety in design process Development of asset fleet plans Asset management plans and work plans Implemented AMMAT Improvements Business Management framework
Network Performance	**Operation-al systems failure due to breakdown in telecommuni-cations**	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	Revert to manual operation of substations
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism Reputation	Damage to equipment; Compromise or damage to systems/ data; requirement for change in network configuration; SAIDI/ SAIFI Impacts; Reputational Impacts	Treat	Physical security at substations Inspections Monitored alarms, security beams at some depots Security cameras at some depots and substations based on previous incidents SMS Audits Operational network isolated from Corporate network
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)	Objection of landowner where line is over boundary; Demand for removal of assets and/ or legal action	Tolerate	Move equipment Audit of processes in place Awareness Obtain easements Renegotiate land boundaries where historic issues exist
Operational Performance	**Damage due to high impact low probability 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	Treat	Strengthening of buildings and equipment. Move resources between depots Approach other South Island Lines Companies for assistance (MA) Seismic review of sites. CIMS training and readiness Mobile substation Network planning to avoid high risk sites

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Containment Plan Summary
Operational Performance	**Full sector reputation damage**	Loss of stakeholder confidence due to nationwide issues and concerns with electricity industry or EDB sector specifically DPP4 step change in pricing and distribution may cause political and or consumer reaction	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 and/or distribution price increases as a result on DPPQ reset and higher WACC	Treat	Communication of Shared Vision, specifically focus across Safety, Efficiency and Reliability. Assist stakeholders understand the role PowerNet and managed EDBs play in the electricity supply chain, i.e. education of customers. Changes to sensitive triggers such as pricing considered, and wider impacts understood prior to proceeding. Benefits of local community ownership understood by stakeholders
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	Inspection regime Legal advice Operational management around interacting with private lines Reports to Energy Safety Public education
Operational Performance	**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	Breach of agreement results in loss of ability to continue to provide the service. This results in a significant reduction in value the business	Treat	Contractual obligations well understood and appropriate persons managing key commercial contracts, including training on contractual management. Understanding of key obligations and how these are being met is understood by responsible persons. Legal opinions and review. No recourse clauses in commercial contracts
Operational Performance	**Unavailability of critical spares**	Poor future work planning; High impact low prob; ability events causing high spares usage; Supply chain disruptions	Inability to supply	Treat	Network modelling Project management planning process Detailed critical spares requirements Annual works programme Standardisation of equipment
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	Tendering of capital projects Work planning Providing contractors with clarity of future work Contingency planning Testing alternate suppliers Internalise the resource SLA/Contract management with critical service providers

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Containment Plan Summary
Operational Performance	**Major event causing significant network disruption**	Damage caused by wind, snow, storm events	Delayed or limited provision of power to customers; Loss of ability to provide power to customers for extended periods;	Treat	Moving resources between depots Alternative supply (Mobile Sub & Generators) Use of neighbouring subs - where available New work to current codes/ standards Business Continuity planning Use of satelite phones Implementation of CIMS
Financial	**Change to EDB Environment**	External decision makers trigger industry disruption and change; Regulatory intervention in industry structure and/or economic return framework	Forced amalgamation of EDBs with asset value and sales transaction set/ influenced by third parties with risk of significant shareholder value destruction	Tolerate	Significant input into EDB industry regulatory direction, through presentation in industry bodies at both Board and Working Group level. Advancement of initiatives and shared services to demonstrate PowerNet / managed EDB and wider EDB sector efficiencies (eg Network Waitaki services, SI EDB Forum, etc.). Direct engagement by PowerNet and managed EDBs with key stakeholders, outlining the PowerNet business model and demonstrating scale and efficiency benefits whilst ownership not impacted. Direct relationship building with key government bodies well managed and maintained (eg ComCom, MBIE, EA, MPs, etc.)
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	Understanding of emerging risk areas and motorising and managing the situation directly and/or through industry bodies Ensuring aware of regulatory obligations and where risks of breaches may occur. Appropriate persons managing and monitoring these risk areas

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Containment Plan Summary
Health & Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety. Network System protection is not designed to protect human life, during Incidents involving high resistance, low current faults. These faults do not generate sufficient current to trigger the network protection devices yet produce sufficient current to cause harm.	Serious injury or fatality; Prosecution under H&S Act	Treat	Asset inspections Assets fail to a safe condition (protection systems) Network design specifications External auditing Public safety management system Extensive signage for warning and awareness around all HV and LV assets Road corridor management in liaison with Waka Kotahi to address any dark spots where poles on road reserve are located in high crash rate areas Education campaigns including schools, before you dig, nurseries, field days, vegetation management staff discussing risk with homeowners and commercial entities Close approach process Manual reclose procedures
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Breaches of environmental legislation Cost of rehabilitation	Tolerate	Hazardous good storage, Retrofits, Bunding, Regular inspections, Condition monitoring, Design standards

Asset management specific 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 24.

- **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 24: Risks Associated with Equipment Failures

Event	Likelihood	Consequence	Responses
33 kV & 66 kV Lines and Cables	Possible	Minor	• 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	Minor to Moderate	• 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	Moderate	• Annual testing including PD[1] and IR[2]. • 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	Minor	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by meshed distribution network.
Batteries	Unlikely	Moderate	• Continue monthly check and six-monthly testing. Dual battery banks at critical sites.
Circuit breaker Protection	Unlikely	Moderate	• Continue regular operational checks. • Engineer redundancy/backup into protection schemes. • Regular protection reviews. • Mal-operations investigated.
Circuit Breakers	Unlikely	Minor	• Backup provided by upstream circuit breaker. • Continue regular maintenance and testing.
SCADA RTU	Unlikely	Minor	• 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	Rare	Minor	• Continue to operate as a Dual Redundant configuration, with four operator stations. This requires both Servers to fail before service is lost. • Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.
Load Control	Unlikely	Moderate	• Provide backup between EIL and TPCL ripple injection plants at Invercargill. • Manually operate plant with test set if SCADA controller fails.
Fire	Rare	Major	• Supply customers from neighbouring substations. • Maintain fire alarms in buildings.

[1] PD = Partial Discharge, indication of discharges occurring within insulation.
[2] IR = Infrared, detection of heat of equipment that highlights hot spots.

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 25: *Other Network and Operational Performance Risks*

Event	Likelihood	Consequence	Responses
Animal	Possible	Minor	• Possum guards all poles • Cattle guards, bird spikes as required
Third party accidental	Possible	Major (Safety) Minor (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 26.

- **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.
- **Vehicles crashing into assets** – locate assets away from potential crash sites where feasible.

Table 26: *Health and Safety Risks*

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Possible	Major	• 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

Event	Likelihood	Consequence	Responses
Step & Touch	Unlikely	Major	• Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2019
Arc Flash	Rare	Major	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations • De-energise installation before switching where PPE inadequate
Staff Error	Possible	Major	• Standardised procedures • Training • Worksite audits • Certification required for sub entry, live-line work, etc. • Monitor incidents and investigate root causes
Historical Assets	Possible	Moderate to Major	• Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, check specifications and replace if risk significant
Site Security	Rare	Major	• 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	Major	• 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 27:** High Impact Low Probability Risks*

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

Other Potential Environmental Risks

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

***Table 28:** Other Environmental Risks*

Event	Likelihood	Consequence	Responses
Oil spill (zone sub)	Unlikely	Moderate	• 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	Minor	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Minor	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Minor	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Minor	• 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 29.

- **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 29:** Weather Related Risks*

Event	Likelihood	Consequence	Responses
Wind	Possible	Moderate	• 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.

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

Resilience

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

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, 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 day-to-day 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 consumers switch from using gas and petrol for transportation and heating to using electricity as the primary source of energy for homes. In contrast, by using their batteries to power essential home appliances, EVs can improve the resilience of their households.

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

Climate Change

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

Extreme Weather Events

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

Temperature Extremes

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

Sea Level Rise

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

Renewable Energy Integration

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

Mitigation and Adaptation Strategies

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

a. Infrastructure Resilience: Reinforcing and upgrading existing infrastructure to withstand extreme weather events.
b. Improved Monitoring and Analytics: Investing in advanced monitoring and data analytics to predict and respond to weather-related disruptions and optimize grid operations. To this effect the deployment of an OMS/ADMS system is under investigation and a Business Plan for implementation of a system will be presented to the PowerNet Board in March 2024.
c. Renewable Energy Integration: Expanding and modernizing the electricity distribution networks to accommodate the growing role of renewable energy sources, including smart grids and energy storage systems.
d. Disaster Preparedness: Developing robust disaster recovery and preparedness plans to respond quickly to extreme weather events, minimizing service interruptions and recovery costs. To this end, CIMS has been deployed.
e. Public Awareness: Raising awareness among customers about the importance of energy conservation and grid 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 the weather is generally wet, windy, and partly cloudy year-round. Over the course of the year, the temperature typically varies from 1°C to 17°C and is rarely below -2°C or above 23°C.

The warm season spans from early December to mid-March, with an average daily high temperature above 15°C, and February being the warmest month. The cooler season extends from late May to mid-August, with an average daily high temperature below 10°C and July is typically the coldest month. Cloud cover in Southland varies modestly by season. February is often the clearest month, with clear, mostly clear, or partly cloudy skies around 45% of the time on average. Rain is distributed fairly evenly across the year, with May usually experiencing the highest number of rainy days, and August the least. Day length varies significantly, with long days in summer and shorter days in winter.

The average hourly wind speed in Invercargill experiences mild seasonal variation over the course of the year. Southland experiences an average of 120 days per year with wind gusts exceeding 60 km/hr. The windiest month of the year in Invercargill is October, with an average hourly wind speed of 21.0 km/hr. The calmest month of the year in Invercargill is July, with an average hourly wind speed of 18.2 km/hr.

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

4.5 System Risks

Existing risks to the TPCL 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 to prevent water ingress and consequential failures.

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 programme has been initiated from 2019/20 to mitigate, repair, or replace the affected ABS's. This programme has been accelerated to remove the risk within the next three years.

ENTEC HALO 11kV RMU

The HALO RMU, manufactured by ENTEC Electric & Electronic in Korea, was introduced into the PowerNet managed network in 2014 due to its solid insulation, which does not use SF6, compact design, flexible configuration, readiness for outdoor use, and cost-effectiveness. However, in March 2021, a unit from 2014 that was installed on the EIL network experienced an internal fault, resulting in a significant arc flash event. This incident caused an internal rupture, and the RMU failed to contain the force within the unit.

In response, PowerNet imposed operational restrictions and external restraints on all ENTEC HALO RMUs currently in service. During the investigation, it was found that other EDBs had also experienced similar issues. Appropriate remedial actions have been planned for 2024/25 to replace the affected Generation 1 RMUs manufactured between 2014 and 2019, with priority given to units installed in areas with high exposure risk to the public.

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.

4.6 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.

PowerNet's stated intention is to base all asset related decisions on risk (of which criticality is one component). To give effect to this intention, various systems based on the UK Regulator's (Ofgem) DNO Common Network Asset Indices Methodology (CNAIM) are being investigated. This a comprehensive and common framework of definitions, principles, and calculation methodologies, adopted across all GB Distribution Network Operators, for the assessment, forecasting and regulatory reporting of Asset Risk. PowerNet has developed a spreadsheet-based system to understand the basic principles being utilised in the CNAIM. This has been applied to distribution transformers, ring main units, switchgear, and air-break switches to rank these items according to their Probability of Failure. Location criticality (access to the public) was applied over the Probabilities of Failure to determine the assets that will be replaced.

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

4.7 Price Elasticity of Demand

Price increases over the DPP period will generally be higher than what customers are used to. There are no specific and up to date studies that indicate what the price elasticity for the demand for electricity may be from customers. There are a couple of possible customer responses to these price increases:

- Customers just continue to use electricity as in the past as they regard electricity as an essential service
- Customers initially try to save electricity but after a time return to current usage patterns. This leads to an initial dip in peak demand but returning to the current state after some months
- More customers move on to time of use tariffs, causing the flattening of peak demand on the network and a shift to afterhours energy consumption
- Customers implement energy saving measures leading to an overall reduction in energy usage and peak demand
- The payback period of distributed generation, mainly solar panels and batteries, become shorter and more people move to these systems, reducing demand. This trend is reinforced by the continuing drop in price of distributed generation systems.

The impact on the load of the price increases will be closely monitored. From a network perspective it is envisaged that overall energy flowing through the MV networks may decrease, but that the LV network may become congested in certain areas.

5

Service Levels

Miss Cocoa Coffee. Photo: Great South

SECTION CONTENTS

5 SERVICE LEVELS

This section describes how TPCL sets its broad range of 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 our top priority and is a primary consideration in the AMP. However, safety is and has always been a key consideration in network design and the residual risk that can be additionally addressed through effective management of our assets is extremely low.

5.1 Customer Oriented Service Levels

Customer surveys and how we use them to set service levels are described in the following section.

Customer Surveys

Annual customer engagement surveys measure customer perceptions around a range of service levels. This involves contacting a large sample of customers by telephone 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 on complaints to measure how often customers experience supply quality issues. Issues are dealt with at the time of complaint, but these statistics give an indication of how supply quality and the response services are trending over time. In the last two years, TPCL have received approximately 43 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 high ratings for the current service level performance in areas such as caring for customers, being safety conscious and efficient in-service response. The biggest area of concern was the discrepancies between the communicated planned outage and restoration times and the actual outcomes. This is being improved through the implementation of a more efficient call centre system and the planned implementation of a Customer Relationship Management System.

Service levels such as a limited number of interruptions are most valued by customers. These strongly depend on network assets and require financial expenditure solutions (as opposed to process solutions), with 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 – some customers would still receive a higher level of 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 above, 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 requirements in their regulation of local Electricity Distribution Business (EDBs). TPCL's projections for these measures over the next ten-year period ending 31 March 2035 are shown in Table 30. 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 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 is expected to result in improved reliability for unplanned outages and these projects are taken into account in our 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 30: *Reliability Projections*

Measure	Class	2024/25	2025/26	2026/27	2027/28	2028/29	…	2034/35
SAIDI	B (Planned)	151.4	151.4	151.4	151.4	151.4	–	151.4
	C (Unplanned)	246.9	243.9	240.9	237.9	234.9	–	234.9
	Total	**389.3**	**395.3**	**392.3**	**389.3**	**386.3**	**–**	**386.3**
SAIFI	B (Planned)	0.65	0.65	0.65	0.65	0.65	–	0.65
	C (Unplanned)	3.17	3.13	3.09	3.05	3.01	–	3.01
	Total	**3.82**	**3.78**	**3.74**	**3.70**	**3.66**	–	**3.66**

Table 31: *Reliability History*

Measure	Class	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
SAIDI	B (Planned)	118.7	125.0	143.31	192.1	147.74	167.55
	C (Unplanned)	158.8	270.9	170.73	174.8	348.66	359.12
	Total	**277.5**	**395.90**	**314.04**	**366.9**	**496.4**	**526.67**
SAIFI	B (Planned)	0.52	0.51	0.65	0.84	0.64	0.67
	C (Unplanned)	2.47	3.57	2.88	2.62	3.77	4.42
	Total	**2.99**	**4.08**	**3.53**	**3.46**	**4.41**	**5.08**

The frequency of faults and estimated restoration levels for significant network areas are summarised in Table 32.

Table 32: *Expected fault frequency and restoration time*

General location	Frequency of faults	Estimated restoration[1]
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

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 customers about their willingness to pay extra in line charges to retain the same level of reliability of supply. TPCL customers were willing to incur an increase of 3.85% on their line charge fees on average to maintain the same reliability of power supply.

Table 39 shows the theoretical thresholds that 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 in any one given year. 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

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

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 33: *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 have higher resulting charges. Similarly, in some cases a large customer may 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. The reliability level requested mostly depends on the interruptibility of the customer's load. These are individual contract arrangements with single customers that do 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 34 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 that will equally benefit all customers connected to an asset regardless of whether they pay.

Table 34: *Secondary Service Level Projections*

Attribute	Measure	2025/26	2026/27	2035/36
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 several other services that benefit stakeholders. These include safety, amenity value, absence of electrical interference, and performance data as presented in Table 35. Many of these service levels are imposed on TPCL by statute and are necessary for the proper functioning of a safe and orderly community.

***Table 35:** 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).

Planned outage information is conveyed to customers through the retailers as well as the PowerNet website and social media. Retailers are informed of planned outages 20 days in advance. Key customers and dependent customers are contacted directly telephonically. Key customers are also directly informed where the networks are operating under reduced security.

Communications about new or altered connections are generally done telephonically and confirmed though emails or letters.

5.2 Regulatory Service Levels

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

- Ensure customer satisfaction on pricing and reliability to avoid being placed under a restraining regime.
- Publicly disclose either an AMP or an AMP update 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 6 July 2023) and includes the amendments of 27 November 2024. Previous disclosures were required under Electricity

Distribution (Information Disclosure) Requirements 2008. The complete listing of these measures is included in TPCL disclosure of 31 March 2025 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, therefore 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 36.

Table 36: *Financial Efficiency Targets*

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2025/26	$320	$1,380	$24,800	$215	$877	$15,140
2026/27	$320	$1,380	$24,800	$215	$877	$15,140
2027/28	$320	$1,380	$24,800	$215	$877	$15,140
2028/29	$320	$1,380	$24,800	$215	$877	$15,140
2029/30	$320	$1,380	$24,800	$215	$877	$15,140
2030/31	$320	$1,380	$24,800	$215	$877	$15,140
2031/32	$320	$1,380	$24,800	$215	$877	$15,140
2032/33	$320	$1,380	$24,800	$215	$877	$15,140
2033/34	$320	$1,380	$24,800	$215	$877	$15,140
2034/35	$320	$1,380	$24,800	$215	$877	$15,140

* Dollar values are constant 2025 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 37. Slight improvements are targeted but changes in peak management requirements impact on the load factor. 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 therefore an estimation methodology is utilised.

Table 37: *Energy Efficiency Targets*

Measure	2025/26	2026/27	2027/28	-	2035/36
Load Factor	65%	65%	65%	-	65%
Loss Ratio	7.0%	7.0%	7.0%	-	7.0%
Capacity Utilisation	32%	32%	32%	-	33%

5.3 Service Level Justification

The reasoning behind these service levels is:

- 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. For example, 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 benchmarked against other local distribution networks.

Historical Trends

In setting service level targets, we consider the recent history of service level measures. These measures are slow to change and not easy to influence. We determine trends from historic results and then project forward to forecast future service levels. Projections are adjusted to incorporate CAPEX and OPEX initiatives and other issues that might affect service levels.

Results from the last five years for reliability and energy efficiency targets are listed in Table 38. Customer satisfaction outcomes from past surveys are presented in Table 39.

***Table 38:** Reliability and Energy Efficiency History*

Measure	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
SAIDI	277.5	395.9	314.0	360.9	403.39	461.38
SAIFI	2.99	7.08	3.53	3.46	4.41	5.08
Load Factor	62%	61%	59%	60%	62%	63%
Loss Ratio	5.5%	5.8%	5.0%	5.0%	4.9%	5.6%
Capacity Utilisation	29.4%	29.2%	31.7%	30.9%	31.9%	32.3%
Network OPEX / ICP	298	317	275	270	291	318
Network OPEX / km	1,211	1,300	1,137	1,126	1,221	1,345
Network OPEX / MVA	24,009	25,193	21,739	21,213	22,709	24,778
Non-Network OPEX / ICP	152	160	183	176	188	211
Non-Network OPEX / km	619	655	755	733	790	892
Non-Network OPEX / MVA	12,278	12,697	14,437	13,808	14,698	16,427

DPP3 encouraged EDBs to move towards doing more planned work and in so doing to change the ratio between planned and unplanned work and this philosophy is continued in DPP4. This is done by setting planned work limits and incentivising planned work by allowing deductions on SAIDI minutes for notified planned interruptions.

Table 39: Customer Satisfaction History

Attribute	Measure	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Planned Outages	Provided sufficient information {CES}	99%	99%	-	95%	-	90%
	Satisfaction regarding amount of notice {CES}	99%	98%	-	97%	-	98%
	Acceptance of one planned outage every two years {CES}	-	-	-	98%	97%	97%
	Acceptance of planned outages lasting four hours on average {CES}	89%	-	-	94%	95%	94%
	Acceptance of one planned outage every two years lasting four hours on average {CES}***	91%	64%	-	93%	93%	93%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time {CES}*	-	-	-	58%	64%	65%
	No impact or minor impact of last unplanned outage {CES}***	62%	-	59%	64%	60%	64%
	Information supplied was satisfactory {CES}*	86%	78%	-	55%	72%	74%
	PowerNet first choice to contact for faults {CES}**	6%	17%	-	17%	65%	65%
Supply Complaints	Number of customers who have made supply quality complaints {IK}	3	8	15	20	14	29
	Number of customers having justified supply quality complaints {IK}	0	2	10	14	0	7

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

* As these questions are limited to customers experiencing an unplanned outage in the last six months, the sample size is very small. 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 helps to identify 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 EDBs' performance in Chapter 10.

6 Asset Management Strategy

Manapouri Southland. Photo: Videocopter

SECTION CONTENTS

6 ASSET MANAGEMENT STRATEGY

In 2023, TPCL (through PowerNet) became JASANZ-certified as compliant with ISO 55001 – the international standard for Asset Management Systems.

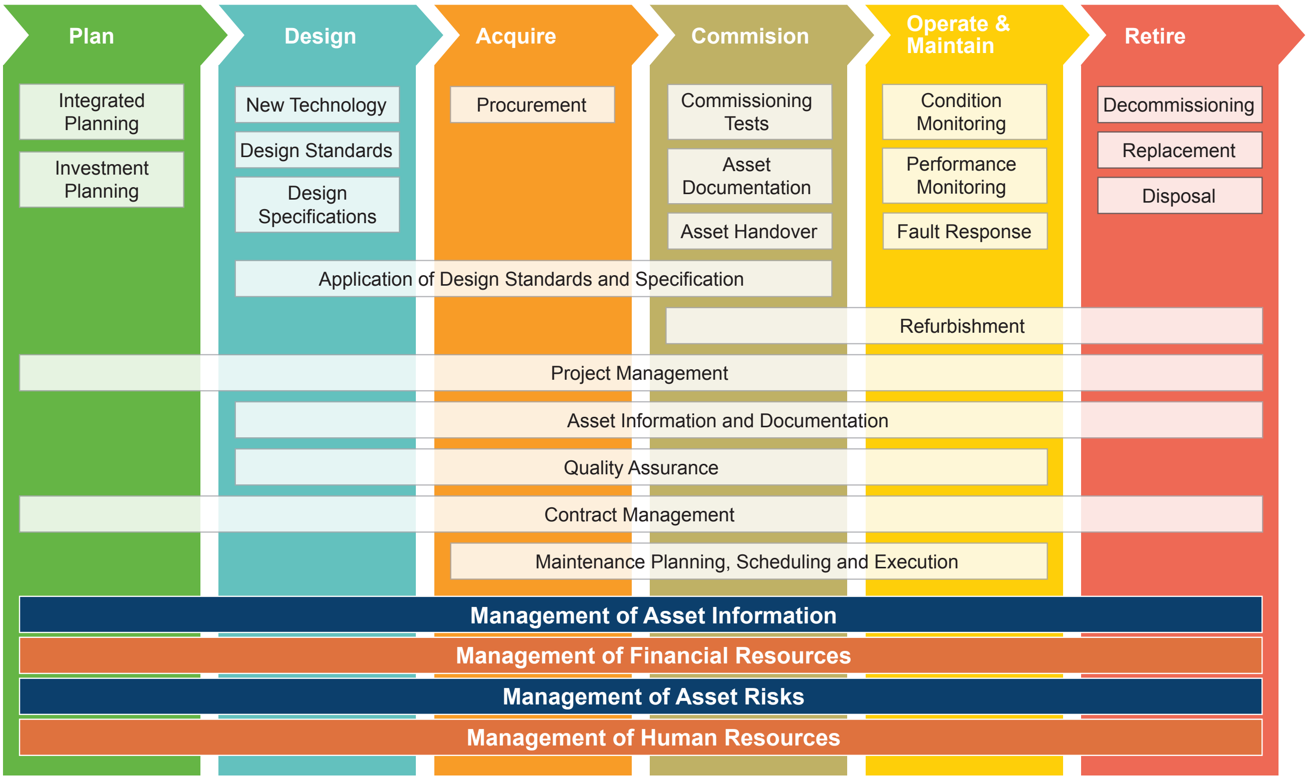
Our Asset Management Strategy is based on PowerNet's asset management model and focuses on a lifecycle management approach. The strategy is structured to address the main activities and challenges faced in each lifecycle stage as well as the support processes. Our strategy identifies clear objectives for each activity and recommends initiatives to achieve those objectives. In each case, responsibilities are defined, and realistic timeframes are suggested.

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

In 2023, TPCL (through PowerNet) became JASANZ-certified as compliant with ISO 55001 – the international standard for Asset Management Systems.

The following chart (Figure 37) shows the various asset lifecycle stages and support processes that cut across the entire value lifecycle.

Figure 37: *Lifecycle Model for Asset Management*



6.1 Lifecycle Stages

The asset lifecycle stages of our asset management approach – planning, designing, acquiring, commissioning, operating and maintaining, and retiring – are described in the following sections.

Planning

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.

Our planning philosophy is to implement the least lifecycle cost option. To do this, we make decisions that 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.

Our major strategic objectives for network planning are:

- 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 network growth and the connection of new customers.
- Capital projects are prioritised based on risk and thereafter economic value.
- Flexibility Services (non-asset solutions) take priority.
- High Impact Low Probability (HILP) event and climate change risks are mitigated to as low a level as possible.

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 cover 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's 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.

Our 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.
- Safety in Design practices are incorporated into every design.
- Potential impact of climate change is considered in designs.
- Flexibility Services are incorporated into designs.

Acquiring

The acquiring 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 premature equipment failures. This makes quality assurance in terms of both equipment and installation of vital importance.

Our major strategic objectives for the acquire lifecycle stage are:

- Procurement policies support lifecycle costing and risk management.
- Construction and installation quality will not compromise the asset life.
- Potential impact on climate change is considered in equipment selection decisions.

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.

Our major strategic objectives for the commissioning lifecycle stage are:

- 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.
- Operating practices mitigate potential risk from network equipment.

Maintenance drivers 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.

Given the resource constraints in terms of skills and money, maintenance for new or relatively new equipment is prioritised, but older equipment are not completely neglected. This approach has shown to deliver the best long-term value to organisations.

Retire

This lifecycle stage includes the following potential activities.

- **Replacement –** The planned replacement of assets for reasons other than system expansion - for example, 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.

Our major strategic objectives for the retire cycle stage are:

- 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 include management of asset risks, asset information, human resources and financial resources.

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 embarked on a journey to upgrade its information systems to make use of the latest technology and to improve cyber security. These upgrades also included enhancing the integration and data flow between the core systems (the Asset Management Information System, the Financial System and the Geographical Information System). In addition, the quality and completeness of asset data was improved through increased field inspections and the use of data capturing technology.

The improved quality of data enhances asset management decision-making and assists in extracting the maximum value from assets.

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 complying 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.

The Electricity Supply Industry as a whole is experiencing shortages in critical skills. These shortages are driven by the massive global development of electricity networks driven by decarbonisation. The pipeline for technical skill development is inadequate and it remains a challenge to obtain and retain appropriately skilled resources. This applies to all categories and levels of staff, but particularly to technical and field staff.

Our 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.

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 in demand for electricity can be 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. In those situations, redesign and development of networks are needed to accommodate these load increases. We accommodate this in the Planning and Design Lifecycle Stages.

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 Fleet Plans

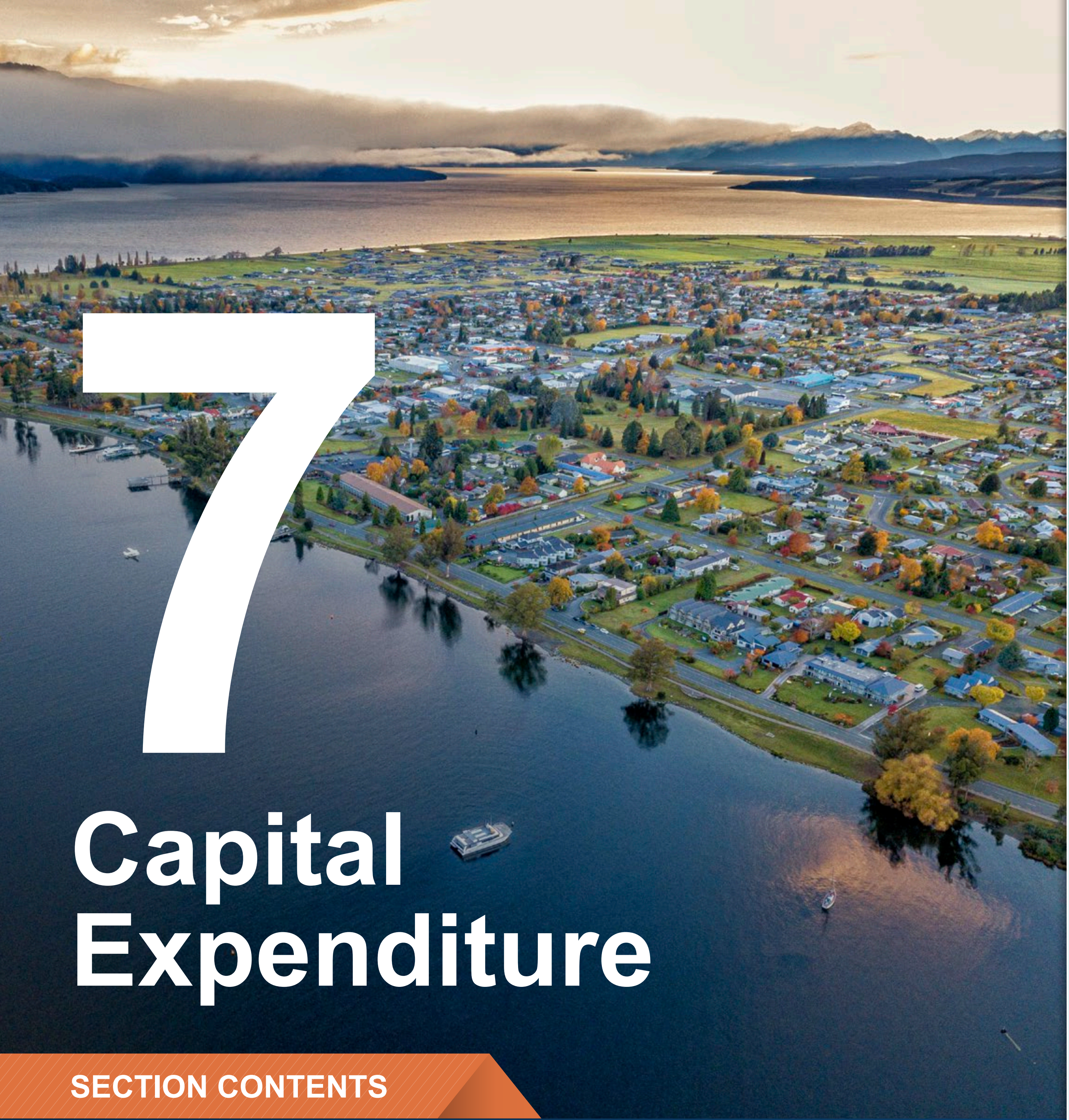
Fleet Plans describe how a specific asset or type of asset will be managed over its entire lifecycle, i.e. how the Asset Management Strategy will be applied to every individual asset. For each asset the material cost and time required to execute the following activities have been determined.

- 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, giving us a “bottom-up” approach to setting budgets.



7

Capital Expenditure

SECTION CONTENTS

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7 CAPITAL EXPENDITURE

Capital Expenditure (CAPEX) is required to increase the capacity of assets or networks, to extend the life of assets, to install new assets for safety or reliability purposes or to replace aging assets, or for a combination of these reasons. This section describes our planned capital expenditure for the next ten years and how we have developed that plan, including our expectations of demand growth and our evaluation of asset-related risk. It applies the plan, design, acquire, commission, and retire lifecycle stages of our asset management model.

Based on our expectations of demand growth and our evaluation of asset-related risk, we expect to make capital investments of $495 million over the next 10 years.

For regulatory disclosure purposes, we categorise each of our planned capital investments into one of the following categories that have been defined by the Commerce Commission.

- 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. We consider the following aspects during this phase.

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

TPCL monitors 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 40:** Planning Phase Risks*

Category	Risk Title	Risk Cause	Risk Treatment
Operational Performance	Damage due to extreme High Impact Low Probability (HILP) Physical Event	Damage caused by force majeure to our infrastructure or equipment (e.g. floods, earthquakes)	Determining areas prone to physical events such-as earthquake (liquefaction), tsunami and flood zones Plan networks to avoid 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 projects to provide further links are underway.
	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

Category	Risk Title	Risk Cause	Risk Treatment
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 discussion describes what we expect to be the most significant sources of demand growth that the TPCL network will experience 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.

Readers should also 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 are still uncertain. We have made an educated assessment of what might be expected on the TPCL network, but there are significant uncertainties and assumptions built into this. The EDB sector is, via Electricity Networks Aotearoa, developing a more rigorous and structured set of demand forecasts and scenarios.

Development demands include the following scenarios:

- 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 considering the various demand drivers that may cause deviation from status quo trends.

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 (DER) and increasing digitisation and smart technology will drive a more distributed electricity system. As the cost of DER, such as residential and commercial solar and batteries decline, their uptake is forecast to increase significantly. Between 2010 and 2020, the cost of a residential solar PV system declined by 65%, with a further decline of 60% predicted in the 2020s, according to the National Renewable Energy Laboratory (NREL). NREL also predicts residential batteries will continue declining in cost, reducing by up to 50% this decade. While purchased primarily for their transport services, EVs can also act as DER across networks.

New smart technologies like automation, AI, Internet of Things (IoT), real-time communication, and network visibility by household will revolutionise the way electricity systems are operated. As technology improves and the cost of IoT sensors decline, it is likely that 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)

Most 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, this 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 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.

Flexibility Services and non-network solutions

As we continue to develop and enhance the electricity networks, our planning approach increasingly considers flexibility services and non-network solutions as viable alternatives to traditional network investments. These solutions provide an opportunity to optimize network performance, defer capital investment, and enhance resilience, particularly as energy demand patterns evolve and distributed energy resources become more prevalent.

Our current practice is to assess flexibility services and non-network options as part of the business case development for network upgrades and expansions. This ensures that all potential solutions—both conventional and innovative—are evaluated on a technical and economic basis to determine the most cost-effective and reliable approach.

Key areas where these solutions may provide value include:

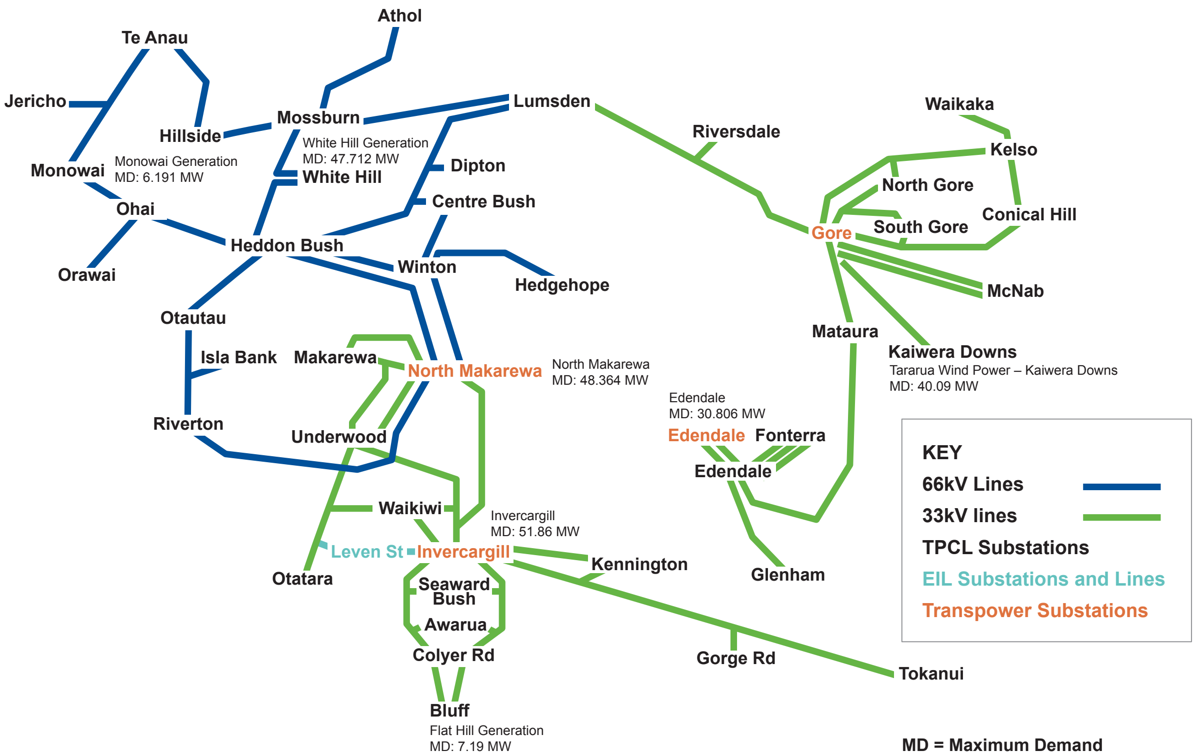
- **Peak Demand Management –** Reducing the need for infrastructure expansion by leveraging demand-side response, battery storage, and distributed generation.
- **Grid Stability and Resilience –** Utilizing flexibility services to support voltage control, frequency response, and contingency planning.
- **Deferring Capital Expenditure –** Optimizing the use of existing assets before investing in new infrastructure, ensuring cost efficiency for both the network and consumers.

As we move forward, we aim to expand the role of flexibility services and non-network solutions, ensuring they are systematically considered in all major network planning processes. Collaboration with market participants, technology providers, and regulators will be essential in unlocking the full potential of these innovative approaches.

Current Demand Profiles

TPCL's maximum demand (MD) of 163.86 MW. All the GXPs which provide supply to TPCL had maximum demands which occurred at a different time to the overall TPCL MD. The individual maximum demands are displayed in Figure 38.

Figure 38: *GXP and Generation Demands*



Demand History

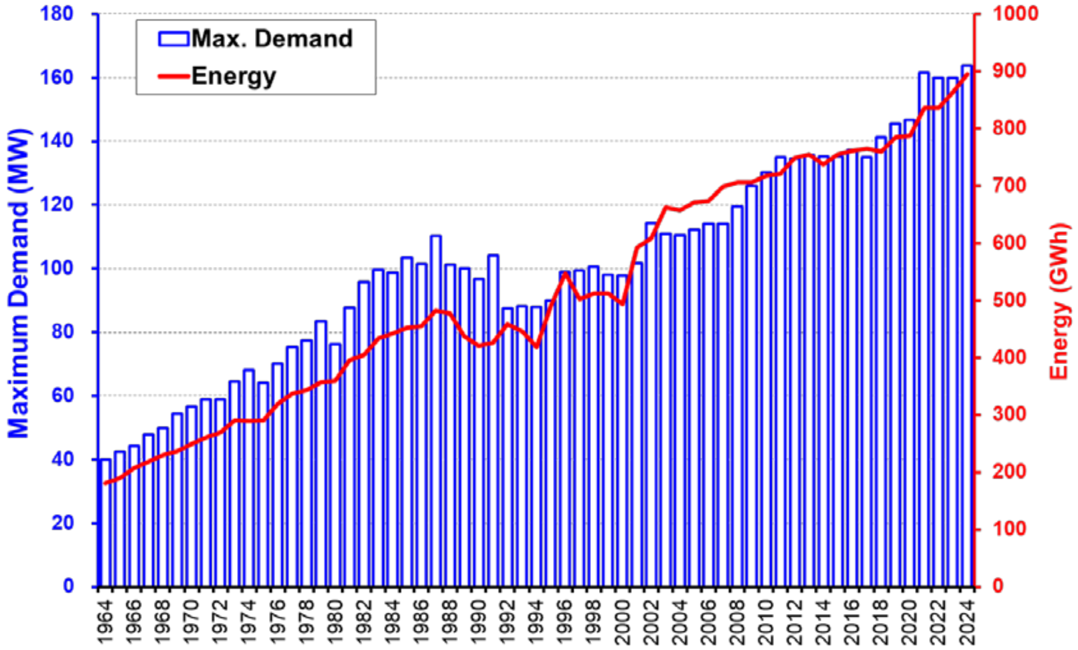
Random variations over and above the main growth patterns impact the accuracy of growth trends. In general, a ten year rolling average will vary substantially between successive years. Longer term trends have a tendency to average out random variations but also obscure recent changes to underlying growth. 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 39 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 39: *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.

Table 41 shows the maximum demand recorded at each zone substation. 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 41: *Zone Substation Demand*

Zone Substation	99.9 Percentile Demand (MVA)							
	2023/24	2022/23	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17
Athol	1.17	1.21	0.94	0.95	0.89	0.9	2.09	2.02
Awarua Chip Mill	0.80	0.79	0.76	0.97	0.84	0.81	0.84	5.38
Bluff	4.34	5.06	5.28	5.11	5.17	5.36	4.7	4.70
Centre Bush	3.73	4.17	3.74	3.73	3.62	3.5	2.93	3.52
Colyer Road	10.25	10.17	9.66	9.55	7.41	7.16	7.08	6.63

Zone Substation	99.9 Percentile Demand (MVA)							
	2023/24	2022/23	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17
Conical Hill	1.70	3.43	3.44	3.39	5.24	1.89	1.51	1.32
Dipton	1.37	1.38	1.41	1.25	1.32	1.54	1.19	1.94
Edendale Fonterra	26.82	27.19	28.59	25.81	24.62	24.64	28.78	26.24
Edendale	6.58	6.11	6.15	5.77	7.43	7.44	6.62	7.16
Glenham	1.28	1.17	1.24	1.31	1.22	1.26	1.24	1.29
Gorge Road	2.53	2.60	2.51	3.41	2.43	2.36	2.76	2.40
Hedgehope	1.57	1.54	1.59	1.54	1.57	1.59	1.50	1.65
Hillside	1.00	0.70	0.75	0.59	0.80	0.8	0.78	0.71
Isla Bank	2.50	1.92	1.88	1.91	1.87	1.99	1.78	1.99
Kelso	4.25	4.29	4.26	4.24	4.26	4.36	4.24	4.40
Kennington	7.83	7.14	6.91	7.11	6.82	6.06	6.06	5.38
Lumsden	4.23	2.93	3.61	3.52	3.24	3.24	3.63	3.72
Makarewa	4.54	4.34	4.05	4.12	4.30	4.19	4.18	4.59
Mataura	7.08	7.88	7.77	5.98	5.46	7.07	5.37	5.98
Monowai	0.17	0.19	0.17	0.15	0.13	0.13	0.16	0.15
Mossburn	1.98	1.96	1.88	1.81	2.11	2.51	2.67	2.27
North Gore	8.17	8.72	8.34	8.85	7.90	10.31	7.81	9.04
North Makarewa	35.44	35.67	33.91	34.94	37.76	43.66	46.05	42.14
Ohai	2.37	2.42	2.55	2.57	2.57	2.55	2.49	2.54
Orawia	3.00	3.02	2.89	3.02	3.06	3.09	3.0	3.40
Otatara	4.12	4.27	4.08	4.01	3.78	3.86	3.74	3.92
Otautau	3.81	3.08	3.56	3.61	3.37	3.32	4.04	4.57
Racecourse Road (EIL)	10.69	11.66	10.97	12.76	9.98	10.24	10.07	10.57
Riversdale	5.48	5.33	5.15	5.42	4.94	4.82	5.02	5.37
Riverton	5.01	4.96	4.89	5.00	4.91	4.73	4.29	4.23
Seaward Bush			6.96	7.38	7.64	7.01	6.51	7.61
South Gore	10.50	10.53	10.33	9.98	10.60	10.01	7.58	8.33
Te Anau	5.82	5.79	5.45	5.57	6.53	6.27	7.46	5.17
Tokanui	1.28	1.18	1.51	1.21	1.22	1.13	1.10	1.22
Underwood	10.33	10.64	10.48	10.74	10.96	11.19	11.89	12.00
Waikaka	0.79	1.44	0.75	0.76	1.48	0.75	0.77	0.78
Waikiwi	11.15	11.81	11.66	12.02	10.96	11.23	8.68	9.93
Winton	9.89	9.22	10.00	10.53	10.01	10.45	11.67	13.13
White Hill (Wind)	-47.71	-38.97	44.40	-52.91	55.54	-46.45	-54.17	-56.74
Monowai (Hydro)	-6.19	-6.13	-6.37	-6.03	-6.23	-7.47	-6.29	-6.47

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. We have identified growth triggers and set corresponding thresholds 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 42.

Table 42: *Development Triggers*

Development	Trigger Point	Typical Network Solution
Extension	New customer requests a connection outside of the existing network footprint; often within the 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 the 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 roll out of smart meters vastly improves our 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

When a trigger point is exceed, TPCL will identify options to bring the asset's operating parameters back within the acceptable range. 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 signals.
- Demand side management.
- Partnerships for non-traditional solutions.

If the extent of changes are 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

A description of demographic and lifestyle drivers of future demand is provided in the next table, followed by population projections in Figure 40.

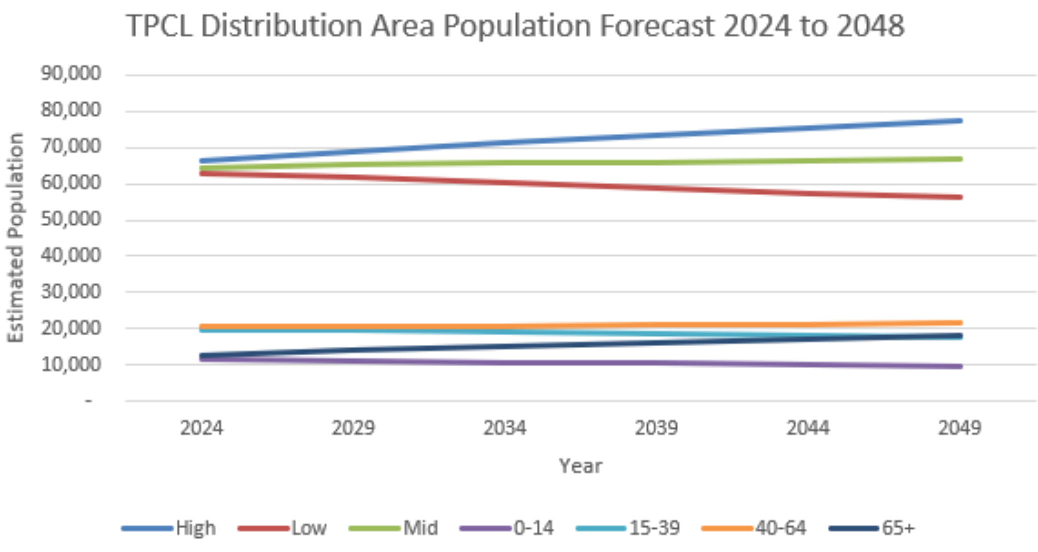
Table 43: *Demographics and Lifestyle Drivers*

Population Growth and Decline	**Effect:** Population projections indicate a relatively slower growth compared to the areas. The distribution area under TPCL is expected to see a 2.0% growth in population from 2024 to 2034. Population projections for age cohorts also indicate that the population is significantly aging.
Description: As of June 2024, the estimated population in TPCL's distribution area is approximately 66,800. TPCL's distribution area has an average population growth estimate of approximately 2.0% by 2034, an upper bound estimate of 7.0% by 2034, and a lower bound estimate of -4.0%. The Southland District expects to see its population grow to 34,000 by 2034. Invercargill City population is projected to be over 59,200 by 2034. 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 approximately 33% of the population in Invecargill city, whose properties are located in the outer regions of the city; and as such expansion of Invercargill for additional housing would therefore often likely fall within TPCL's network boundary. 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.	
Housing Density and Utilisation	**Effect:** Overall support of domestic power demand growth from increasing population as described above. Effects of increased housing density is somewhat offset by increasing housing utilisation as more people share heating and other power requirements.
Description: Housing density and utilisation can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand. 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.	

Rural Migration to Urban Areas	**Effect:** Population growth especially from retirees (baby boomers) is expected to have a limited driver for increased demand. This effect is captured in population growth effect above discussed above.
Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has 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, are 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.	
Increasing Energy use per Customer	**Effect:** Growth minimal and included in existing demand trends.
Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However, this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months. 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.	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for TPCL over the next ten years. Incorporates growth anticipated from council fuel burner constraints.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. Around 8% of energy consumption comes from gas and solid fuel based space heating and has the potential to be replaced by electrical heating. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. 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.	
Electricity Affordability	**Effect:** Minimal change in demand for power supply is expected due to changes in electricity prices. Future change is likely to be a continuation of current demand trends.
Description: Consumption and demand are relatively inelastic to changes in power price as it is seen as an essential service for most people. Improving energy efficiency for heating and appliances and future technology such as smart meters and appliances are expected to counteract effects of increasing electricity prices 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.	
Irrigation & Dairy	**Effect:** Accelerated growth for dairy conversions in pastoral areas of Southland and additional irrigation in the Northern Southland region.
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 2018 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 40: *Figure 46: Population Projections*



Environmental and Climate Drivers

Drivers of future demand based on changes in the environment and climate is discussed in Table 44.

Table 44: *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 45: *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 to continue operations at Tiwai smelter with a long-term electricity contract with a 20-year term from 1 July 2024 to 31 December 2044. It is likely that Tiwai will continue to operate unchanged in the 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 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 46: *Technology Drivers*

Electric Vehicles	**Effect:** It estimated that demand due to Electric Vehicle charging would account for approximately 5-6% of peak demand by the end of the planning period (2034/35).
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 10% and 13% of the light passenger fleet by 2033/34. 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 to grow from 0.7% to 3.5% per annum from this year to 2028/29.).	
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. It is estimated that commercial and residential solar installations will decrease peak demand by less than 2% by the end of the planning period (2034/35). 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 can 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. 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. It is estimated that battery storage will reduce peak demand by less than 2% by 2034/35.
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 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.	
Energy Efficiency	**Effect:** Negative growth driver accounted as part of the energy conservation initiatives. It is estimated that this negative growth driver will reduce peak demand by approximately 2% by 2034/35.
Description: Improving energy efficiency has been a government strategy for several years (energy conservation initiatives). It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.	

On-line shopping	**Effect:** Likely to negatively affect the business sector in TPCL's network area however the overall effect on demand is expected to be relatively insignificant.
Description: Shopping online continues to become more and more popular with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within 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.	
Internet of Things	**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.
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.	
Voltage support	**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
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.	

Demand Forecasts

We estimate that 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 164MW in 2023/24 to about 181MW in 2034/35. 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 0.7% - 3.5% 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 our 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 47 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 47: *Substation Demand Growth Rates*

Substation	MD (MVA) '25/26	MD (MVA) '34/35	Provision for Growth
Athol	1.79	2.46	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 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	NA	Awarua substation has a capacity of 5MVA. The firm rating is not expected to exceed by the end of the planning period. It has been planned to be decommissioned after transferring the existing customer to the Colyer Road Substation. The historical demand of the single customer supplied is historically flat.
Bluff	4.73	5.41	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. However, there are enquiry in the region for step growth in load and generation due to electrification which has not been factored into the demand forecast due to uncertainly but this work would result in substation upgrade.
Centre Bush	3.90	4.26	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	15.46	16.17	Colyer Road substation has a capacity of 24MVA and a firm capacity of 12MVA. 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. To enable the foreseeable decarbonisation activity in the region, a system growth project has been planned for FY26/27 – FY28/29 to increase capacity in the Awarua region.
Conical Hill	2.33	2.55	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.

Substation	MD (MVA) '25/26	MD (MVA) '34/35	Provision for Growth
Dipton	1.53	1.67	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	107.71	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 for the single customer supplied is historically flat, with a new 20MW electrode boiler commissioned in 2024. Although the firm rating has been exceeded, it is managed through a special protection scheme to prevent any overload on the network equipment. To enable the next phase of electrification at the Fonterra Edendale site, a project has been planned for FY2025/26 - FY2027/28, to support decarbonization initiatives at the site.
Edendale	7.19	7.86	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	1.46	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.
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	NA	NA	Switching Station
Hedgehope	2.24	2.34	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	1.08	1.18	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	2.61	2.85	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.

Substation	MD (MVA) '25/26	MD (MVA) '34/35	Provision for Growth
Kelso	4.58	4.79	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	8.50	11.40	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 with the possibility of step growth. The firm rating is not expected to exceed by the end of the planning period but needs monitoring.
Lumsden	4.27	4.67	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	4.80	5.02	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	7.76	8.11	Mataura substation has a capacity of 20MVA and a firm capacity of 10MVA. The load in the supply region are mainly meat processing plant, Mataura township and rural farm. The firm rating is not expected to exceed by the end of the planning period.
McNab	20.00	20.00	McNab substation has a capacity of 50MVA and a firm capacity of 25MVA. The load in the supply region is the Mataura Valley Milk. 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 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	2.37	Monowai 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	8.64	9.44	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.

Substation	MD (MVA) '25/26	MD (MVA) '34/35	Provision for Growth
Ohai	2.54	2.77	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	3.17	3.47	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	4.38	4.79	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 the current levels by the end of the planning period, but it will require ongoing monitoring.
Otautau	4.05	4.43	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)	13.04	13.64	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	5.57	7.01	Riversdale substation has a capacity of 5MVA. The load in the supply region is predominantly rural farming, the township of Riversdale and the 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	5.54	6.34	Riverton substation has a capacity of 7.5MVA and firm capacity of 15MVA. 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.

Substation	MD (MVA) ‘25/26	MD (MVA) ‘34/35	Provision for Growth
Seaward Bush	9.41	9.84	Seaward Bush substation has a capacity of 24MVA and firm capacity of 12MVA. 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 expected to be medium with potential step increase from the decarbonization projects. The firm rating is not expected to exceed by the end of the planning period but need to be monitored.
South Gore	7.90	9.03	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 dropped substantially in 2024/25 due to the electrification of a dairy processing plant, transferring some of the existing load to the McNab Substation. However, new regional decarbonisation projects are expected to fill the gap in this planning period. The firm rating is not likely to exceed by the planning period's end but needs monitoring.
Te Anau	6.25	13.56	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, there are sign of recovery with the New Zealand border reopening to the world. Growth in the region is expect to be high with potential step increase from decarbonisation and could result in exceeding the firm capacity by the end of the planning period but need to be monitored.
Tokanui	1.38	1.51	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. At peak times, the substation's capacity has been exceeded for short periods, and this is anticipated to occur more frequently in the upcoming planning period. As a result of the system growth in the area, an upgrade project for the substation is scheduled for 2032/33. Demand will be monitored to address short-term overloads, and the 11 kV network may transfer to a nearby substation.
Underwood	11.82	11.82	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, with the possibility of step growth due to decarbonisation at the meat processing plant. However, without factoring in the potential step growth, the firm rating is not expected to exceed by the end of the planning period. To enable the foreseeable decarbonisation activity in the region, a system growth project has been planned for FY32/33 - FY34/35 to increase capacity in the Makarewa region.

Substation	MD (MVA) '25/26	MD (MVA) '34/35	Provision for Growth
Waikaka	1.55	1.78	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 this area is anticipated to be modest, although there may be occasional overloads of the substation's capacity due to abnormal network configurations based on historical trends and potential future developments. As part of the Kelso transformer upgrade project, the existing 1.5MVA transformer has been planned for replacement in FY24/25 & FY25/26 with the existing 5MVA at the Kelso substation. The firm rating is not expected to exceed by the end of the planning period.
Waikiwi	12.00	13.72	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	9.93	10.86	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, 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.
Kaiwera Downs (Wind)	40.09	40.09	Kaiwera Downs Wind Farm is owned by Mercury Energy and is embedded generation at the 33kV Gore network with varying export of up to 43MW.
White Hill (Wind)	52.46	52.46	White Hill Wind Farm is owned by Meridian Energy and is embedded generation at the 66kV North Makarewa network with varying export of up to 58MW.
Monowai (hydro)	6.19	6.19	Monowai is owned by Pioneer Generation and is embedded into the 66kV North Makarewa network with varying exports up to 6.3MW
Flat Hill (Wind)	6.29	6.29	Flat Hill Wind is owned by Pioneer Generation and is embedded into the Bluff 11kV network with varying export up to 6.8MW.

Projected annual maximum demands incorporating growth provisions is presented in Table 48. 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 some capacity upgrades being delayed or brought forward.

Table 48: *Substation Maximum Demand (incorporating growth)*

Substation	'25/26	'26/27	'27/28	'28/29	'29/30	'30/31	'31/32	'32/33	'33/34	'34/35
Athol	1.79	2.02	2.07	2.12	2.17	2.23	2.28	2.34	2.40	2.46
Awarua	0.91	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bluff	4.73	4.80	4.87	4.95	5.02	5.10	5.17	5.25	5.33	5.41
Centre Bush	3.90	3.94	3.98	4.02	4.06	4.10	4.14	4.18	4.22	4.26

Substation	'25/26	'26/27	'27/28	'28/29	'29/30	'30/31	'31/32	'32/33	'33/34	'34/35
Colyer Road	15.46	15.54	15.62	15.70	15.77	15.85	15.93	16.01	16.09	16.17
Conical Hill	2.33	2.36	2.38	2.40	2.43	2.45	2.48	2.50	2.53	2.55
Dipton	1.53	1.54	1.56	1.57	1.59	1.60	1.62	1.64	1.65	1.67
Edendale Fonterra	47.71	47.71	97.71	97.71	107.71	107.71	107.71	107.71	107.71	107.71
Edendale	7.19	7.26	7.34	7.41	7.48	7.56	7.63	7.71	7.79	7.86
Glenham	1.46	1.46	1.47	1.48	1.49	1.49	1.50	1.51	1.52	1.52
Gorge Road	2.64	2.66	2.69	2.72	2.74	2.77	2.80	2.83	2.85	2.88
Heddon Bush	0	0	0	0	0	0	0	0	0	0
Hedgehope	2.24	2.25	2.26	2.27	2.29	2.30	2.31	2.32	2.33	2.34
Hillside	1.08	1.09	1.10	1.11	1.12	1.14	1.15	1.16	1.17	1.18
Isla Bank	2.61	2.63	2.66	2.68	2.71	2.74	2.77	2.79	2.82	2.85
Kelso	4.58	4.60	4.62	4.64	4.67	4.69	4.71	4.74	4.76	4.79
Kennington	8.50	10.12	10.27	10.43	10.59	10.74	10.91	11.07	11.23	11.40
Lumsden	4.27	4.32	4.36	4.40	4.45	4.49	4.54	4.58	4.63	4.67
Makarewa	4.80	4.83	4.85	4.88	4.90	4.93	4.95	4.97	5.00	5.02
Mataura	7.76	7.80	7.84	7.88	7.91	7.95	7.99	8.03	8.07	8.11
McNab	22.47	22.47	22.47	22.47	22.47	22.47	22.47	22.47	22.47	22.47
Monowai	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21	0.21
Mossburn	2.26	2.27	2.28	2.30	2.31	2.32	2.33	2.34	2.35	2.37
North Gore	8.64	8.72	8.81	8.90	8.99	9.08	9.17	9.26	9.35	9.44
Ohai	2.54	2.56	2.59	2.61	2.64	2.66	2.69	2.72	2.75	2.77
Orawia	3.17	3.20	3.24	3.27	3.30	3.33	3.37	3.40	3.43	3.47
Otatara	4.38	4.43	4.47	4.52	4.56	4.61	4.65	4.70	4.75	4.79
Otautau	4.05	4.09	4.13	4.17	4.21	4.26	4.30	4.34	4.39	4.43
Racecourse Road (EIL)	13.04	13.11	13.18	13.24	13.31	13.37	13.44	13.51	13.58	13.64
Riversdale	5.57	5.75	5.89	6.04	6.19	6.34	6.50	6.66	6.83	7.01
Riverton	5.54	5.63	5.71	5.80	5.88	5.97	6.06	6.15	6.24	6.34
Seaward Bush	9.41	9.45	9.50	9.55	9.60	9.64	9.69	9.74	9.79	9.84
South Gore	7.90	8.02	8.14	8.26	8.38	8.51	8.63	8.76	8.90	9.03
Te Anau	6.25	6.31	6.88	6.95	7.02	7.39	8.26	8.34	13.43	13.56
Tokanui	1.38	1.40	1.41	1.43	1.44	1.45	1.47	1.48	1.50	1.51
Underwood	12.01	12.01	12.01	12.01	12.01	12.01	12.01	12.01	12.01	12.01
Waikaka	1.55	1.58	1.60	1.62	1.65	1.67	1.70	1.72	1.75	1.78
Waikiwi	12.00	12.18	12.36	12.55	12.73	12.92	13.12	13.32	13.51	13.72
Winton	9.93	10.03	10.13	10.23	10.33	10.43	10.54	10.64	10.75	10.86

Substation	'25/26	'26/27	'27/28	'28/29	'29/30	'30/31	'31/32	'32/33	'33/34	'34/35
Kaiwera Downs (Wind)	40.09	40.09	40.09	40.09	40.09	40.09	40.09	40.09	40.09	40.09
White Hill (Wind)	52.46	52.46	52.46	52.46	52.46	52.46	52.46	52.46	52.46	52.46
Monowai (hydro)	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19
Flat Hill (Wind)	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29

TPCL also manages other general constraints on its network as described in Table 49.

Table 49: *Network Constraints and Intended Remedy*

Constraint	Description	Management Approach
Capacity at Zone Substations	Substations close to (or exceeding) maximum capacity. Colyer Road, Edendale Fonterra, Glenham, Kelso, Kennington, Makarewa, Otatara, Riversdale, Seaward Bush, South Gore, Te Anau, Tokanui, Underwood.	Load are reviewed annually to ensure timing of projects is kept just ahead of load. Upgrades are planned for the following substation: Colyer Road, Edendale Fonterra, Kelso, Makarewa, Otatara, Riversdale, Tokanui, and Underwood.
North Makarewa GXP	Transpower 220/33kV Transformers Capacity	The current capacity of the NMA 220/33kV supply transformer is limited to 67.3 MVA due to the ampacity of the cable. These transformers are rated at 68.3 MVA in summer and 71.2 MVA in winter. The capacity of the Grid Exit Point (GXP) is being closely monitored. If necessary, Transpower may implement the Transformer Overload Protection Scheme (TOPS) for these transformers and upgrade the cable. The expansion of the 66kV network from Invercargill GXP to Underwood and Makarewa substation, which is planned for FY30/31 – FY34/35, is expected to help reduce load at the GXP. However, the increasing number of large-scale generation projects connecting to the western southland region could pose capacity constraints and necessitate an upgrade.
North Makarewa	33/66kV Transformer Capacity	The two 33/66kV transformers at the North Makarewa are 40MVA each; however, due to an increase in generation connection, the capacity of the generation will exceed the capacity of the transformer, and run back scheme will be implemented on a new generation to protect the transformer from overload under abnormal network configuration. An upgrade is planned for the North Makarewa substation, which will involve relocating the existing 40MVA 66/33 kV transformer from Mossburn. This relocation is intended to alleviate the current capacity constraints during FY25/26 and FY26/27, allowing for an installed capacity of 120MVA and a firm capacity of 80MVA. Note: The next constraint will be at the Grid Exit Point (GXP), as discussed in the previous section.

Constraint	Description	Management Approach
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. However, the transferable capacity from the overhead line is minimal. It 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.	The development in the Makarewa region is being closely monitored. Upgrades are planned for FY30/31 to FY34/35 to convert the existing 33kV circuit and substation in the Makarewa region to 66kV, which will be supplied from the Invercargill GXP.
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 supply region. Tactical upgrades have been conducted on the INV 2742 and INV 2842 33kV feeders to increase circuit capacity and temporarily relieve some constraints. Further upgrades are planned for the fiscal years 2026/27 to 2028/29 to enhance the Colyer Road substation to 66kV by introducing a new 66kV circuit from the Invercargill GXP, which is being triggered by the Open Country Dairy Boiler project. This upgrade is expected to relieve approximately 12 MVA from the existing 33kV circuit and provide additional capacity for regional development in the near future.
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.
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) and smart meters are monitored. Transformers will be upgraded or supplemented with additional units as needed. Underutilized transformers may be relocated before purchasing new ones.

Distributed Generation and Demand Management

Distributed Generation (DG) influence on maximum demand is negligible due to the estimated low connection density of DG. It is possible 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 has a minimal influence on projected demand, although historical demand records will include these effects.

Flexibility Services and non-network solutions

As we continue to develop and enhance the electricity networks, our planning approach increasingly considers flexibility services and non-network solutions as viable alternatives to traditional network investments. These solutions provide an opportunity to optimize network performance, defer capital investment, and enhance resilience, particularly as energy demand patterns evolve and distributed energy resources become more prevalent.

Our current practice is to assess flexibility services and non-network options as part of the business case development for network upgrades and expansions. This ensures that all potential solutions—both conventional and innovative—are evaluated on a technical and economic basis to determine the most cost-effective and reliable approach.

Key areas where these solutions may provide value include:

- **Peak Demand Management –** Reducing the need for infrastructure expansion by leveraging demand-side response, battery storage, and distributed generation.
- **Grid Stability and Resilience –** Utilizing flexibility services to support voltage control, frequency response, and contingency planning.
- **Deferring Capital Expenditure –** Optimizing the use of existing assets before investing in new infrastructure, ensuring cost efficiency for both the network and consumers.

As we move forward, we aim to expand the role of flexibility services and non-network solutions, ensuring they are systematically considered in all major network planning processes. Collaboration with market participants, technology providers, and regulators will be essential in unlocking the full potential of these innovative approaches.

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.

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Development Programme

The following tables present TPCL's development projects according to whether they are underway or planned for the next 12 months, planned for the following four years, or are being considered for the remainder of the planning period.

Table 50: *Non-routine Development Projects (next 12 months)*

Project Description	25/26 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.	$4,588,033
Major Customer Connection Projects: TPCL is currently working with two major customers to increase capacity for electrode boilers at a dairy factory. The project timing is driven by the customer, where the Open Country Dairy is due for completion in 2025/26 and Edendale Fonterra is due for completion in 2027/28.	$ 17,616,089 (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. In the Riversdale supply area, ongoing load growth has led to constraints in both substation and line capacity. To address these limitations, a multi-year project is underway to rebuild the distribution feeders, which will allow future operation at 22 kV and provide additional capacity. In parallel, the existing EHV circuits will be running on their current 33kV voltages, installing two new Transformers and bays, installing a new 33kV structure and a new 22kV Indoor switchgear establishing dual supply capability to meet security of supply requirements and support regional growth. The ongoing load increases and recent applications in the Tapanui area are now overloading the 5MVA Kelso zone substation transformer. This two-year project, initiated in 2024/25, includes detailed design work and the purchase of a replacement transformer in first year, with installation planned for 2025/26.	$18,488,884
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.	$143,196
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 economical 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. There is also a mobile substation-ready project that facilitates the deployment of a mobile substation when needed.	$862,499

Table 51: *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. 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.	$4,588,033 from 26/27 ongoing
Major Customer Connection Projects: TPCL is currently working with Edendale Fonterra to enable electrode boilers at a dairy factory. The project timing is driven by the customer, with completion targeted for 2027/28.	$11,674,405 25/26 & 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 3 years to allow the staged installation and change in voltage.	$6,234,045 26/27
System Growth Projects: TPCL is experiencing significant development in the Awarua region resulted in network constraints. A multiyear program has been developed to provide a new 66kV supply to Awarua region via the new 66 kV connection from Invercargill GXP, triggered by the development in the Awarua region. This work would relieve the capacity constraint on the existing 33kV circuit to the Awarua region.	$12,611,208 26/27-28/29
Kingston 66kV Substation: Load growth in Kingston village is projected to exceed the capacity of the newly constructed 22 kV and 66 kV lines built in 2024/25, as planned subdivisions and service expansion will surpass the 22 kV line's capability. Ultimately, a new zone substation will be required in Kingston. Based on the pace of subdivision development and housing uptake, this project is expected to begin in 2028/29 and span over three years.	$272,223 28/29

Table 52: 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.	$ 4,412,284 annually from 33/34

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 53: Table 58: 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. 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.

Category	Risk Title	Risk Cause	Risk Treatment Plan
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 54.

Table 54: *Equipment Standardisation*

Component	Standard	Justification
Underground Cable	Distribution and low voltage network: 35, 95, 185 & 300 mm2 Al	Stocking of common sizes, lower cost
	Cable Cross-linked Polyethylene (XLPE)	Rating, ease of use.
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 mm2 Al (four core).	Safety, lower cost.

Component	Standard	Justification
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 SF6)
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 55 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 55: *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 56: *Security Levels for Zone Substations*

Substation	Current Security Level	Required Security Level	Remarks
Athol	A(i)	A(i)	
Awarua	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	AAA	AA	
Lumsden	A(i)	A(i)	
Makarewa	AAA	AA	
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	AA	A(i)	
Orawia	A(i)	A(i)	

Substation	Current Security Level	Required Security Level	Remarks
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	
Kaiwera Downs (Wind)	A(i)	A(i)	
White Hill (Wind)	A(i)	A(i)	
Monowai (Hydro)	AA	AA	

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 57. Clearly understanding load growth into the future is crucial to making sound investment decisions.

Table 57: 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 58 summarises the decision tools used to evaluate options depending on their cost.

Table 58: 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

Cost & Nature of Option	Decision Tools	Approval Level
$250,000 to $1,000,000: individual projects or programmes of tactical or strategic significance. Timing may or may not be flexible depending on priority.	• Extensive spreadsheet model to calculate NPV that may consider several scenarios. • Risk analysis including environmental and safety considerations with consideration to management cost. • Consultation with stakeholders if necessary.	Chief Executive
Over $1,000,000: occurs maybe once every few years, likely to be strategically significant. May divert resources from routine lower cost projects in the short term.	• Extensive spreadsheet model to calculate NPV, payback that will probably consider several variation scenarios. • Detailed risk analysis including environmental and safety considerations - represented as cost estimates within NPV and Payback calculations. • Resources (financial, workforce, materials, legal) across AWP need to be balanced across many projects and several years managed through planning meetings and spreadsheet models. • Ongoing stakeholder consultation may be required especially large customers. • Business case presented to the Board, highlighting options considered and justification of recommended option.	Board Approval

Prioritisation of Development Projects

Development projects are 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 Acquisition

During asset acquisition, 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 59:** Acquisition 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 60 .

Table 60: *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.

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

Asset Category	Sub Category	Replacement & Renewal Decision Approach
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).
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 61:** Non-routine Replacement & Renewal Projects (next 12 months)*

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.	$2,611,189
Critical Spares: For 25/26 two items have been identified for addition to the critical spares: One Coopers 150 Amp regulator – the original spares have all been used to repair the existing fleet of regulators. This new regulator will allow for timely and simple replacement on site, repair in the workshop, and return to spares. One 1.5MVA 11000/400V transformer - With the increased number of 1.5MVA transformers installed on the network supplying key industrial customers. This unit would allow for a timely and simple replacement on-site due to the long lead time for the ground-mounted distribution transformers.	$184,131
River Crossing Reconstruction: Several river crossings overhead circuits have been washed out or compromised during the latest flood in FY2023. Six sites have been identified to be addressed.	$1,607,932

***Table 62:** Non-routine Replacement & Renewal Projects (next four years)*

Project Description	CAPEX Cost & Timing
Mossburn Transformer Replacement: TPCL has a spare 30/40 MVA 66/33 kV 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 7.5MVA 66/11 kV transformer will be installed at Mossburn allowing the permanent location of the 30/40 MVA transformer at North Makarewa. The work was started in 24/25 to purchase the transformer 25/26 work will involve the design and transformer ordering with completion in the following year 26/27.	$7,549,559 25/26-26/27FY
Awarua Substation Load Reconfiguration: The Awarua substation has reached the end of its operational life, with numerous aging assets in need of replacement. Additionally, the substation is situated in a highly polluted industrial area, increasing the need for decommissioning. This project involves disconnecting and removing all substation assets, addressing environmental considerations, and reconfiguring the network to supply existing customers via the Colyer Road substation, ensuring continued reliability and safety for the community, this work is scheduled to be completed in the 2026/27FY	$4,393,410 25/26-26/27FY
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.	$3,082,360 27/28 & 28/29
Ripple Plant Upgrade: The ripple plants on the network are critical infrastructure for managing load across the network. As the current system components have reached the end of its lifecycle this upgrade aim to improve the reliability of the aging infrastructure.	$ 850,718 annually from 27/28 to 30/31

Project Description	CAPEX Cost & Timing
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 transformers in 28/29.	$4,109,306 26/27 - 28/29
North Gore Transformer Replacement: These two transformers are serviceable but in poor condition and not considered economic or suitable for half-life refurbishment. While condition will be carefully monitored with necessary maintenance and oil leak repairs, but it is expected to replace these transformers in 2028/29/30	$3,898,644 28/29/30
South Gore 33kV Circuit Breaker: The existing South Gore substation currently depends on the fault throw switches to operate the circuit breakers from the Gore GXP. This project involves replacing the fault throw switches with new circuit breakers on the 33kV side of the substation. The upgrade will provide local backup and a faster protection scheme, enhancing the substation's reliability and response time during fault conditions.	$358,142 28/29
North Gore 33kV Circuit Breaker: The existing North Gore substation currently depends on the fault throw switches to operate the circuit breakers from the Gore GXP. This project involves replacing the fault throw switches with new circuit breakers on the 33kV side of the substation. The upgrade will provide local backup and a faster protection scheme, enhancing the substation's reliability and response time during fault conditions.	$358,142 29/30
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.	$43,896 annually from 25/26 – 27/28
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.	$716,751 in total from 25/26 -28/29
Mobile Regulator Replacement: This project aims to replace the existing 3MVA, 11kV trailer mounted voltage regulator with a modern regulator. The upgrade could further enhance network resilience, support network expansion and mobilize around the network.	$752,633 28/29

The non-routine replacement and renewal projects that are under consideration for the remainder of the planning period is described in Table 63.

Table 63: *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.	$1,610,877 30/31 then $2,451,726 annually

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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 64 with the associated capital expenditure estimates.

Table 64: *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.	$2,082,216 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.	$1,131,276 annually till 29/30 $678,987 29/30 & 30/31
Distribution Line Replacement	On-going replacements of distribution line which are generally identified during distribution inspections and targeted inspections based on age.	$ 7,431,190 annually
Subtransmission Line Replacement	On-going replacements of subtransmission line which are generally identified during distribution inspections and targeted inspections based on age.	$ 906,763 annually
Zone Substation Minor Replacement	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	$126,639 annually
RTU Replacements	On-going replacements of RTU which are generally identified during distribution inspections and targeted inspections based on age and obsolescence.	$323,174 annually
Relay Replacements	On-going replacements of relay which are generally identified during distribution inspections and targeted inspections based on age and obsolescence.	$298,180 annually
Communications Replacement	On-going replacements of communication which are generally identified during distribution inspections and targeted inspections based on age.	$108,512 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.	$111,266 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.	$2,000,095 annually

Budget	Description	CAPEX Cost
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	$3,183,123 in 25/26 then $1,659,919 in 26/27 and 27/28 then $986,774 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 Edendale, South Gore, Te Anau, Riverton, Bluff, North Makarewa, Ohai , Orawia and Winton substations.	$1,084,994 annually
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 11kV feeders to address safety issues.	$624,421 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 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 65.

- 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 65: *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
	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 66 and provided in the Information Disclosure Schedule 11a.

Table 66: *Capital Expenditure Forecast ($000 - constant 2025/26 terms)*

Category	DPP3	DPP4					DPP5				
CAPEX: Consumer Connection	**2024/ 25**	**2025/ 26**	**2026/ 27**	**2027/ 28**	**2028/ 29**	**2029/ 30**	**2030/ 31**	**2031/ 32**	**2032/ 32**	**2033/ 34**	**2034/ 35**
Customer Connections (≤ 20kVA)	1,481	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748
Customer Connections (21 to 99kVA)	537	674	674	674	674	674	674	674	674	674	674
Customer Connections (≥ 100kVA)	1,839	944	944	944	944	944	944	944	944	944	944
Distributed Generation Connection	127	8	8	8	8	8	8	8	8	8	8
New Subdivisions	1,409	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
Edendale Process Heat Electrification	362	0	0	0	0	0	0	0	0	0	0
Underwood substation upgrade for Alliance	131	0	0	0	0	0	0	0	0	0	0
McNab Substation upgrade to 33 kV	23	0	0	0	0	0	0	0	0	0	0
Kaiwera Downs - Mercury 45MW wind farm	49	0	0	0	0	0	0	0	0	0	0
Jericho - Southern Generation 35MW wind farm	0	0	280	0	0	0	0	0	0	0	0
Open Country Dairy 66kV Expansion	10,782	9,879	0	0	0	0	0	0	0	0	0
Edendale 110kV Expansion Line	0	7,737	6,421	5,254	0	0	0	0	0	0	0
Edendale 110kV Expansion Substation	0	0	0	0	0	0	0	0	0	0	0
	16,740	**22,204**	**11,289**	**9,842**	**4,588**	**4,588**	**4,588**	**4,588**	**4,588**	**4,588**	**4,588**

CAPEX: System Growth	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30	2030/ 31	2031/ 32	2032/ 32	2033/ 34	2034/ 35
Riversdale Substation Upgrade	536	6,234	6,234	0	0	0	0	0	0	0	0
Kelso Transformer Upgrade	1,460	2,313	0	0	0	0	0	0	0	0	0
Riversdale 22kV Line Upgrades	873	0	0	0	0	2,463	0	0	0	0	0
22kV Upgrade Athol - Kingston	3,891	164	0	0	0	0	0	0	0	0	0
Easements	21	34	34	34	34	34	34	34	34	34	34
Otatara Transformer Replacement	0	0	0	0	0	0	0	566	1,489	0	0
Unspecified Growth Projects	0	0	0	0	0	0	0	0	0	4,412	4,412
Kingston 66kV Substation	0	0	0	0	272	3,893	3,558	0	0	0	0
Upgrade Tokanui TX	0	0	0	0	0	0	0	0	424	1,313	0
Upgrade Riversdale line to 66 kV	132	2,978	0	0	0	0	0	0	0	0	0
Invercargill 66kV Expansion - Stage 1 (Awarua)	1,469	6,766	2,001	5,305	5,305	0	0	0	0	0	0
Invercargill 66kV Expansion - Stage 2 (Makarewa)	0	0	0	0	0	2,007	15,174	15,174	15,174	0	0
Invercargill 66kV Expansion - Stage 1 (Underwood)	0	0	0	0	0	0	0	2,007	9,907	9,907	9,907
	8,383	**18,489**	**8,269**	**5,339**	**5,612**	**8,398**	**18,767**	**17,781**	**27,028**	**15,666**	**14,354**

CAPEX: Asset Replacement and Renewal	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30	2030/ 31	2031/ 32	2032/ 32	2033/ 34	2034/ 35
Distribution Transformer Replacements	2,020	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082
Ground Mount Platform Transformers	1,603	1,131	1,131	1,131	1,131	679	679	0	0	0	0
Distribution Line Replacement	7,173	7,431	7,431	7,431	7,431	7,431	7,431	7,431	7,431	7,431	7,431
Subtransmission Line Replacement	606	907	907	907	907	907	907	907	907	907	907
Zone Substation Minor Replacement	162	127	127	127	127	127	127	127	127	127	127
RTU Replacement	277	323	323	323	323	323	323	323	323	323	323
Relay Replacements	291	298	298	298	298	298	298	298	298	298	298

Communications Replacement	105	109	109	109	109	109	109	109	109	109	109
General Technical Replacement	114	111	111	111	111	111	111	111	111	111	111
ABS Replacements	2,075	3,183	1,660	1,660	987	987	987	987	987	987	987
Power Transformer Refurbishment	843	1,085	1,085	1,085	1,085	1,085	1,085	1,085	542	542	542
Orawia Substation Upgrade	1,170	174	0	0	0	0	0	0	0	0	0
Makarewa Switchboard Replacement	0	0	0	310	2,772	0	0	0	0	0	0
Bluff Switchboard Replacement	548	2,611	0	0	0	0	0	0	0	0	0
Ripple Plant Upgrade	0	0	0	851	851	851	851	0	0	0	0
RMU Renewals	231	850	850	850	850	850	850	638	638	638	638
Gore Link Box Replacement and Undergrounding	981	0	0	0	0	0	0	0	0	0	0
Condition Based Asset Replacements	0	0	0	0	0	0	0	0	0	0	0
LV Pillar Box Replacements and Refurbishments	594	279	279	279	279	279	279	279	279	279	279
Circuit Breaker Replacements	545	564	564	564	564	564	564	564	564	564	564
Hillside Transformer Replacement	0	0	0	0	0	0	424	1,313	0	0	0
Mataura Transformer Replacement	0	0	566	2,055	1,489	0	0	0	0	0	0
North Gore Transformer Replacement	0	0	0	0	566	1,949	1,383	0	0	0	0
Mossburn Transformer Replacement	303	1,711	5,838	0	0	0	0	0	0	0	0
66kV SF6 CB Refurbishment	42	44	44	44	0	0	0	0	0	0	0
South Gore 33kV Circuit Breaker	0	0	0	0	358	0	0	0	0	0	0
North Gore 33kV Circuit Breaker	0	0	0	0	0	358	0	0	0	0	0
Awarua Substation Decomission	0	204	4,190	0	0	0	0	0	0	0	0
Edendale T5 & T6 Replacement	0	0	0	0	0	0	0	0	0	3,075	6,097
Mobile Regulator Replacement	0	0	0	0	753	0	0	0	0	0	0
	19,683	**23,225**	**27,595**	**20,217**	**23,073**	**18,990**	**18,490**	**16,253**	**14,398**	**17,473**	**20,495**

CAPEX: Asset Relocations	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/32	2033/34	2034/35
Line Relocations	352	143	143	143	143	143	143	143	143	143	143
	352	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**

CAPEX: Quality of Supply	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/32	2033/34	2034/35
Supply Quality Upgrades	159	405	405	405	405	405	405	405	405	405	405
Mobile Substation Site Made Ready	125	306	306	0	0	0	0	0	0	0	0
Network Improvement Projects	146	151	151	151	151	151	151	151	151	151	151
Otatara Regulator and Automation	19	0	0	0	0	0	0	0	0	0	0
	449	**862**	**862**	**556**	**556**	**556**	**556**	**556**	**556**	**556**	**556**

CAPEX: Other Reliability, Safety and Environment	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/32	2033/34	2034/35
Earth Upgrades	2,678	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Substation Safety	0	0	427	0	0	0	0	0	0	0	0
Remote Area Power Supply	0	236	0	0	0	0	131	131	131	131	131
Hillside Protection Remediation	0	0	0	0	0	0	0	0	0	0	0
Critical Spares	59	184	1,416	184	184	0	0	0	0	0	0
Communications Projects	0	297	297	297	297	454	454	454	454	454	454
Substation LS TX	189	195	327	0	195	195	0	0	0	0	0
River Crossing Reconstruction	355	1,608	0	0	0	0	0	0	0	0	0
Distribution Recloser	606	624	624	624	624	624	624	624	624	624	624
Network Resilience Improvement	0	0	0	0	0	0	6,706	6,706	6,706	6,706	6,706
Mossburn to Athol 66kV OHL Hardware Upgrade	709	0	0	0	0	0	0	0	0	0	0
	4,777	**5,145**	**5,091**	**3,105**	**3,300**	**3,273**	**9,916**	**9,916**	**9,916**	**9,916**	**9,916**

Total Network CAPEX	**53,674**	**78,108**	**44,660**	**46,764**	**36,207**	**36,196**	**47,048**	**74,003**	**44,821**	**67,209**	**47,938**

CAPEX: Non-Network Assets	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/32	2033/34	2034/35
	0	**2,142**	**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 67: *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.
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

SECTION CONTENTS

8 OPERATING EXPENDITURE

Our OPEX programme supports risk management, maintenance and inspection processes, and operations aspects of O&M such as control room functions and service restoration.

Operating Expenditure (OPEX) is required to operate and maintain TPCL's networks. This section describes our planned operating expenditure for the next ten years and applies the Operate & Maintain (O&M) lifecycle stage of our asset management model.

When identifying operating expenditure initiatives we pursue the following objectives.

- 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 a way that meets the requirements of customers, internal stakeholders and relevant legal authorities, at minimum life cycle cost.

8.1 The Operation and Maintenance Lifecycle Phase

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

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

O&M Phase Risks

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

Table 68: *Operation & Maintenance Phase Risks*

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

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	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 • Employment legislation • Metering recertification	Utilise the Planned Interruption SAIDI and SAIFI allocations optimally by planning work more effectively

8.2 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 $ 1,750,978 from 2025/26 onward.

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 $ 188,161 from FY25/26 onwards.

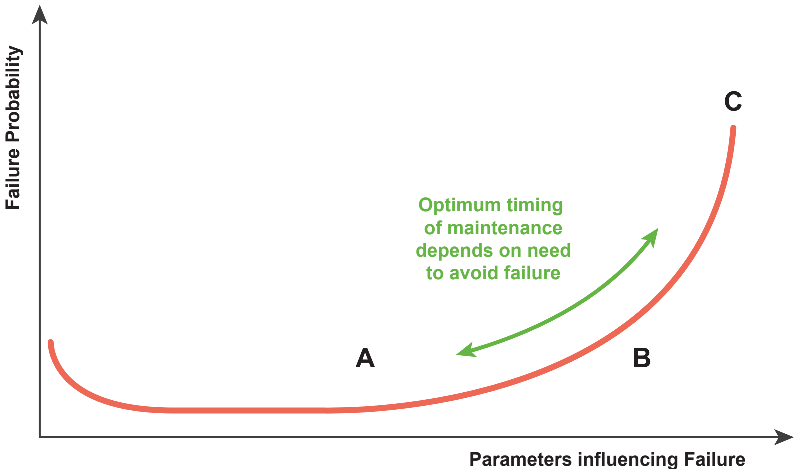
8.3 Asset Maintenance

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 41. 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 41:** 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.

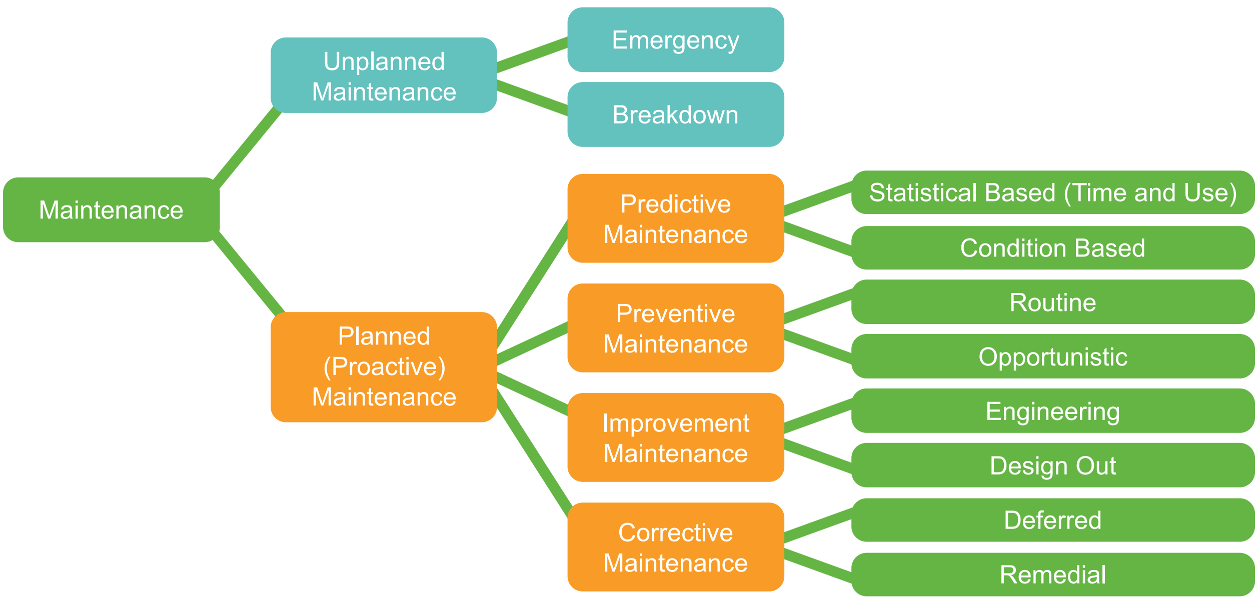
TPCL's maintenance decisions are made on cost-benefit criteria with the principal benefit being avoidance of supply interruption. Increasing maintenance costs (labour and consumables) over the asset's lifecycle, taken together with the cost of discarding unused component life, must be traded off against 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 41 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 next figure.

***Figure 42:** 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.

Cables are underground, which means 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 69 summarises the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 69: *Maintenance Approach by Asset Category*

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	**O/H**	Condition assessment through periodic visual inspection.	2-5 yearly
		Tightening, repair, or replacement of loose, damaged, deteriorated or missing components.	Ad-hoc based
	U/G	Generally, run to failure and repair.	Part of monthly substation inspections
		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.	
		Sheath test, Link box & Sheath arrestors inspection and oil condition (RGP) along with planned maintenance schedule.	5 yearly
		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.	3 yearly
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Exercise switch and lubrication of moving parts.	6 yearly

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Asset Category	Sub Category	Maintenance Approach	Frequency
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 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 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

Asset Category	Sub Category	Maintenance Approach	Frequency
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 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.	1 - 6 years
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

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 that could lead to failure or deteriorate beyond economic repair within the period until the next inspection. Observed deterioration 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.

We set out budget descriptions for routine corrective maintenance and inspection activities in Table 70. 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 70: *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.	$658,098 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.	$1,277,754 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.	438,403 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.	$272,225 p.a.
Communications Routine Inspection and Checks	Ventia undertakes routine maintenance inspections on the communications equipment.	$94,010 p.a.
Distribution Earthing Mtce	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed five yearly.	$151,812 p.a.

Partial Discharge Survey	Partial discharge condition monitoring of equipment to identify abnormal discharge levels before failure occurs.	$57,983 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.	$27,136 p.a.
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	$23,194 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.	$21,330 p.a.
Connections Minor Maintenance	Operational portion of expenditure for the customer connections process is captured in this budget.	$162,187 p.a.
RAPS maintenance	A budget for the maintenance of remote area power supplies.	$ 19,896p.a.
Routine Distribution Inspection – Additional helicopter survey	A budget to perform aerial inspections of the network	$132,845 p.a.
LV Network Conductor Inspections	A budget for the inspecting the LV network assets	$102,704 p.a. 25/26 to 27/28

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 71.

Table 71: *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.	$465,243 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.	$103,822 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.	$76,742 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.	$261,635p.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.	$137,186 p.a.

8.4 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 and the optimal balance between reliability and cost.

Well-planned and executed operations allow 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 using the nationally deployed Coordinated Incident Management System (CIMS) which has the following principal objectives:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- Planning alternate facilities.

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

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

PowerNet Pandemic Action Plan

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

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

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 EIL 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.

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 $5,021,664 per annum.

8.5 Operational Expenditure Forecast

Table 72 presents our forecasts of TPCL's operational expenditure for the next 10 years. This information is also provided in the Information Disclosure Schedule 11b.

Table 72: *Operating Expenditure Forecast ($000 - constant 2025/26 terms)*

Category	DPP3	DPP4					DPP5				
OPEX: Asset Replacement and Renewal	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/35**
General Distribution Replacement and Renewal	747	465	465	465	465	465	465	465	465	465	465
Subtransmission Replacement and Renewal	126	104	104	104	104	104	104	104	104	104	104
Zone Substation Replacement and Renewal	22	77	77	77	77	77	77	77	77	77	77
Power Transformer Replacement and Renewal	794	262	262	262	262	262	262	262	262	262	262
Distribution Transformer Replacement and Renewal	132	137	137	137	137	137	137	137	137	137	137
Locks and Security	65	0	0	0	0	0	0	0	0	0	0
	1,886	**1,045**	**1,045**	**1,045**	**1,045**	**1,045**	**1,045**	**1,045**	**1,045**	**1,045**	**1,045**
OPEX: Vegetation Management	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/35**
Vegetation Management	1,758	1,751	1,751	1,751	1,751	1,751	1,751	1,751	1,751	1,751	1,751
Line Access Maintenance	180	188	188	188	188	188	188	188	188	188	188
	1,938	**1,939**	**1,939**	**1,939**	**1,939**	**1,939**	**1,939**	**1,939**	**1,939**	**1,939**	**1,939**
OPEX: Routine and Corrective Maintenance and Inspection	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/35**
Routine Distribution Inspections	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321
Distribution Routine Maintenance	383	658	658	658	658	658	658	658	658	658	658
Distribution Earthing Mtce	100	152	152	152	152	152	152	152	152	152	152
Distribution Corrective Maintenance	502	438	438	438	438	438	438	438	438	438	438
Communications Routine Inspection and Checks	90	94	94	94	94	94	94	94	94	94	94
Technical Routine Inspections & Checks	511	511	511	511	511	511	511	511	511	511	511

Technical Routine Maintenance	1,229	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278
Technical Corrective Maintenance	764	272	272	272	272	272	272	272	272	272	272
Infrared Survey	26	27	27	27	27	27	27	27	27	27	27
Partial Discharge Survey	34	58	58	58	58	58	58	58	58	58	58
Supply Quality Checks	22	23	23	23	23	23	23	23	23	23	23
Spares Checks and Minor Maintenance	21	21	21	21	21	21	21	21	21	21	21
Connections Minor Maintenance	266	162	162	162	162	162	162	162	162	162	162
RAPS maintenance	21	20	20	20	20	20	20	20	20	20	20
Routine Distribution Inspections - Additional helicopter survey	0	133	133	133	133	133	133	133	133	133	133
LV Network Conductor Inspections	94	103	103	103	0	0	0	0	0	0	0
	5,384	**5,271**	**5,271**	**5,271**	**5,169**	**5,169**	**5,169**	**5,169**	**5,169**	**5,169**	**5,169**

OPEX: Service Interruptions and Emergencies	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/35**
Depot Location Recovery Fixed Fee	384	370	370	370	370	370	370	370	370	370	370
Incident Response - Distribution - Unplanned	4,521	3,757	3,757	3,757	3,757	3,757	3,757	3,757	3,757	3,757	3,757
Incident Response - Communications - Unplanned	67	70	70	70	70	70	70	70	70	70	70
Incident Response - Technical - Unplanned	262	262	262	262	262	262	262	262	262	262	262
	5,234	**4,458**	**4,458**	**4,458**	**4,458**	**4,458**	**4,458**	**4,458**	**4,458**	**4,458**	**4,458**

Operational Expenditure Total	**14,443**	**13,984**	**13,981**	**13,981**	**13,878**	**13,878**	**13,878**	**13,878**	**13,878**	**13,879**	**13,879**
System Operations and Network Support	5,142	7,264	7,042	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175
Business Support	3,894	3,756	3,829	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825
AMP Total Operational Expenditure	**23,478**	**23,733**	**23,584**	**23,714**	**23,611**	**23,611**	**23,611**	**23,611**	**23,611**	**23,611**	**23,611**

Grand Total Capital and Operational Expenditure	**73,861**	**95,964**	**76,834**	**62,916**	**60,883**	**59,560**	**76,071**	**72,848**	**80,240**	**71,953**	**73,662**

Values Fully Marked Up, No Inflation, Base Year dollars

9

Execution Capacity

Hokonui Fashion Awards. Photo: Great South

SECTION CONTENTS

9 EXECUTION CAPACITY

The core of TPCL's asset management activities lies within the detailed processes and systems that reflect our thinking, manifest in our 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. 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.

Figure 43: *TPCL's Business Management System*

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.

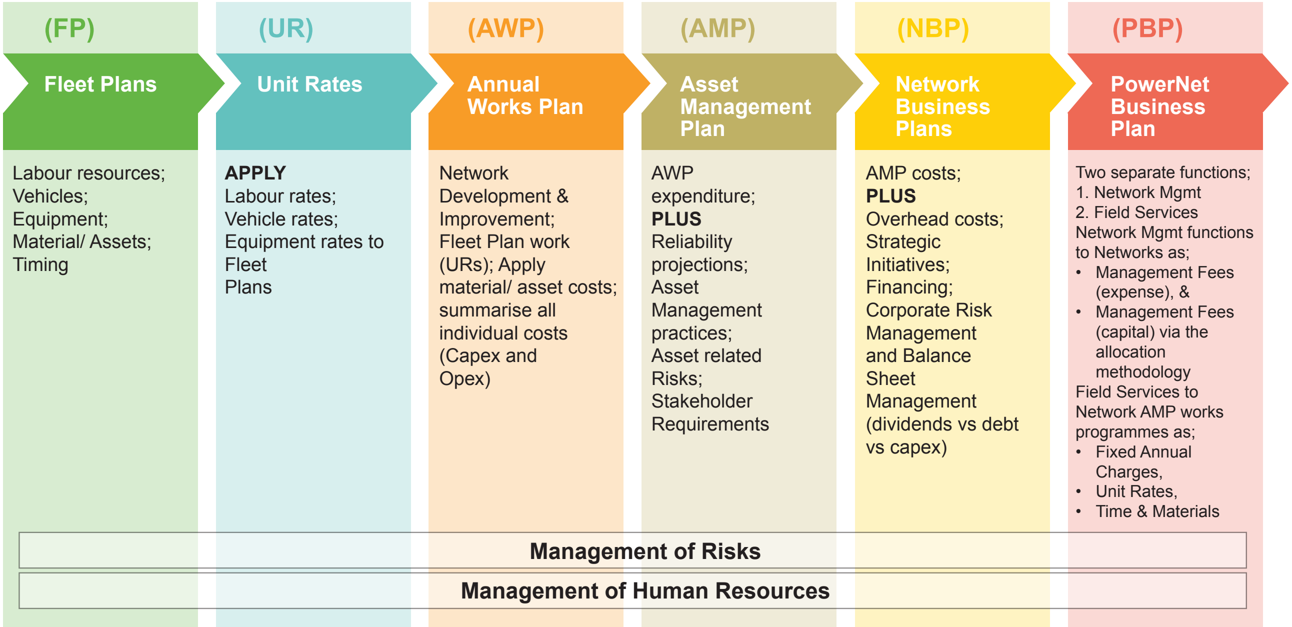
The foundation for managing the assets and determining the required resources and funding is our Fleet Plans. Our Fleet Plans

- 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)
  - Taking 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 44: TPCL's Value Chain



9.1 People, Culture and Leadership

TPCL's work must be planned, managed and executed by people. Organisational leadership and the 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 to ensure that the value generated from these assets are optimised. PowerNet also manages its 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 be delaying work until resources become available, using contractors or, if there is a long-term resource requirement, appointing additional staff or procuring the required plant or equipment. The year-to-year work volumes in the AWP is smoothed out to prevent peaks and troughs in resources required (to the extent possible acknowledging appropriate risk controls) in order to provide a relatively constant work stream.

Utilising PowerNet's works management and field services staff has great benefit in ensuring a longer-term approach may be taken to resourcing. Staff numbers can be increased with added confidence that they will be fully utilised in future years given the long-term plans developed, as these resources can be utilised on all the PowerNet managed networks. The smoothing out of resource requirements can be done over a larger base load of work.

Working closely with 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 13 vacancies for field and technical staff. Many of these vacancies are filled using overseas recruitment.

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 on 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 (90%) are not willing to pay more in order to reduce interruptions
- A small minority (2%) are willing to pay more in order to reduce interruptions
- A small minority (8%) 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 73 below:

Table 73: *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

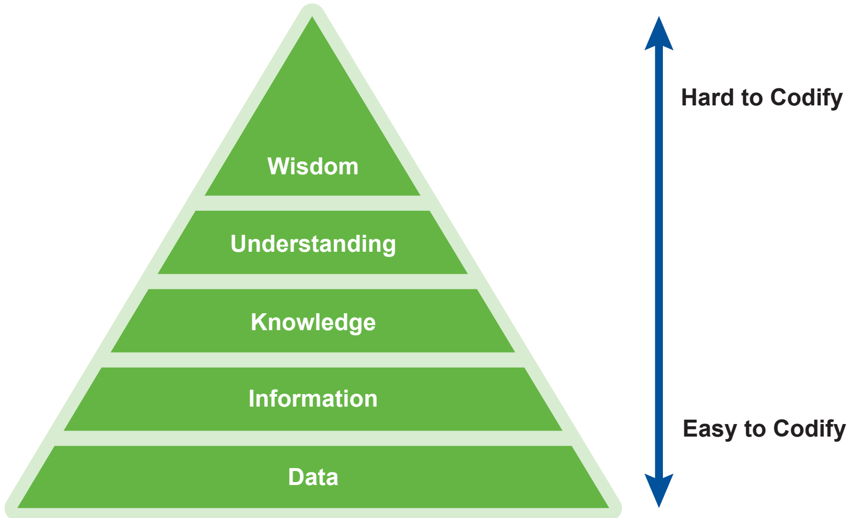
Assets are depreciated using straight line depreciation over the asset expected life. This doesn't strictly model the decline in service potential of an asset. An asset mostly remains serviceable until it has rusted, rotted, acidified, or eroded substantially and then fails quickly. Straight-line depreciation 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 45 shows the typical information and knowledge residing within TPCL's business (including employees from PowerNet).

***Figure 45:** 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. Developments in the field of Artificial Intelligence (AI) are closely monitored to see if AI will become of use in this regard.

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.

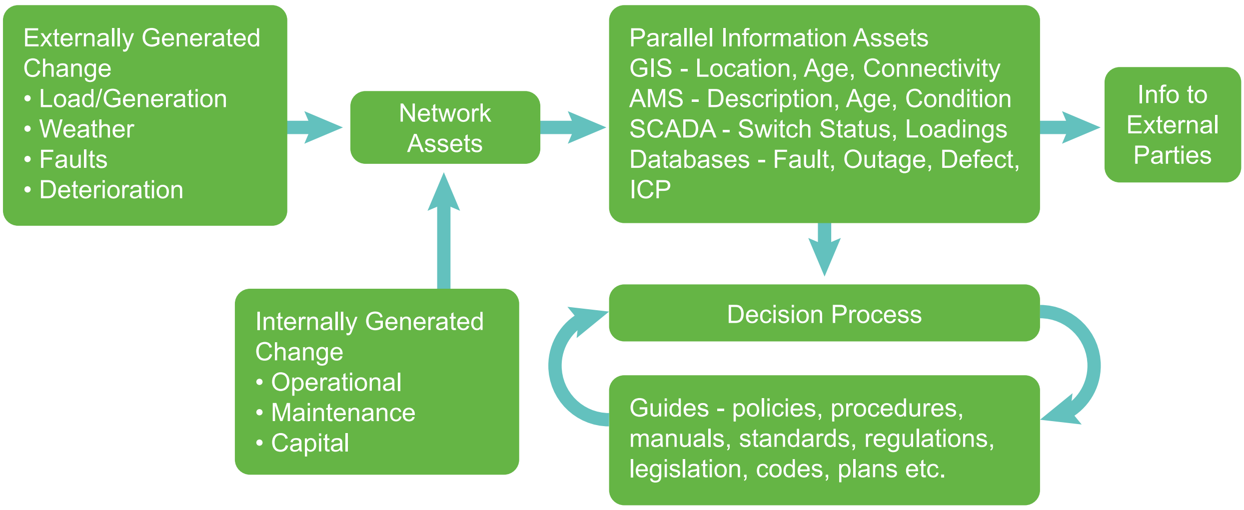
Interfacing with DER resources on the LV network - Developing methods to provide network relevant data to DER resources (and their management interface) and obtain data from these sources. This will include developing methods of exchanging information with local generation, storage and discretionary 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 46 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 45) are incorporated.

Figure 46: *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 74.

Table 74: *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 the next table.

Table 75: *Data Completeness within Information Systems*

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion and GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion and GIS update
GIS	Age	Reasonable	Equipment ages include some estimate by type (era of manufacture)
Condition Assessment Database	Condition	Acceptable	Regular inspections but some subjectivity and condition data not updated with repair
AMIS	Description	Acceptable	Some delays between job completion and Maximo update
AMIS	Details	Acceptable	Some delays between job completion and Maximo update
AMIS	Age	Acceptable	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMIS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

Data Control, Improvement and Limitations

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 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 which were historically captured in spreadsheets to be captured in the AMIS; 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 (Asset related)

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, age 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. (This system is currently being replaced with Microsoft BC with the same functionality).
- **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 complies with the ISO55001 Asset Management System and the AS/NZS9001 Quality Management System standards. TPCL, through PowerNet, i audited and is certified to both systems. 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 Annexure 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.

- Asset Management System (ISO 55001 compliance)
- 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).
- Asset Management Maturity Assessment Tool (AMMAT) review.
- AMP format and compliance review.
- Spend forecast assessment.
- Spend approval process review.

10

Evaluation of Performance

Southland A&P Show. Photo: Great South

SECTION CONTENTS

10 EVALUATION OF PERFORMANCE

This section reviews TPCL's performance on expenditure measures, service level performance, and network efficiency. It also examines asset management maturity using the AMMAT tool and identifies initiative for continued improvement. Finally, TPCL's performance relative to other EDBs is considered, using data from regulatory information disclosures.

10.1 Progress against Plan

The performance between estimated expenditure and actual expenditure for CAPEX and OPEX is described below.

Capital Expenditure

The variation of estimated expenditure versus actual capital spending is presented in the following table.

Table 76: *Variance between Capital Expenditure Forecast and Actual Expenditure*

Capital Expenditure	Forecast 2023/24 ($k)	Actual 2023/24 ($k)	Variance
Consumer Connection	11,758	15,669	33%
System Growth	4,565	6,748	48%
Asset Replacement and Renewal	18,016	14,768	(18%)
Asset Relocations	130	242	86%
Quality of Supply	1,039	1,256	21%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	3,765	3,246	(14%)
Capital Expenditure on Network Assets	39,273	41,930	7%

The overall actual capex expenditure on network assets was 7% over budget.

Customer Connections:

- 33% over budget
- Customer-initiated work primarily influences this budget, and we are seeing greater than expected growth in "Customer Connections (≥100kVA)." Additionally, the spending for the multi-year project "Kaiwera Downs – Mercury Energy 45MW Wind Farm" was deferred from FY22/23 to FY23/24 compared to the forecast. However, this deferral does not significantly affect the total project cost.

System Growth:

- 48% over budget
- Some of the work that has been scheduled in FY24/25 on the 22kV Athol-Kingston project was brought forward to ensure there is sufficient workforce to conduct the customer driven work for the FY24/25.
- Unplanned work at the Edendale Substation driven by customer growth.

Asset Replacement and Renewal:

- 18% under budget.
- Completion of the Orawia Substation project has been delayed due to unavailability of the mobile substation and getting the construction contact sign with contractors.
- RMU replacement has been delayed due to availability of suitable RMUs in the market.
- Power Transformer refurbishment has been delayed due to the tap changers failure at Te Anau substation which require delivery of the tap changer from overseas.
- Link box replacement project has been delayed on request of the Gore District Council.
- Circuit Breaker replacement has been delayed due to late delivery of circuit breakers caused by ongoing international logistics challenges.

Asset Relocations:

- 86% over budget.
- Work mainly driven by customer requests and Territorial Local Authority work programmes with the opportunity taken to move lines to the roadside where it is economical.

Quality of Supply:

- 21% over budget.
- Asbestos was found during the installation of the communication masts at the Transpower GXP resulting in unexpected cost in the projects.
- During the Otatara Regulator project execiution the budget had to be reviewed due a number of variations, including a change in the site's location due to an easement issue.

Other Reliability, Safety and Environment:

- 14% under budget.
- The delivery timeline of critical spare equipment such as regulator and controller had to be extended, resulting in the financial spend in the FY24/25 instead of FY23/24

Operational Expenditure

The variation of estimated expenditure versus actual operational spending is presented in Table 77.

Table 77: *Variance between Operational Expenditure Forecast and Actual Expenditure*

Operational Expenditure	Forecast 2023/24 ($k)	Actual 2023/24 ($k)	Variance
Asset Replacement and Renewal	1,018	562	(45%)
Vegetation Management	1,225	1,529	25%
Routine and Corrective Maintenance and Inspection	4,808	4,118	(14%)
Service Interruptions and Emergencies	4,085	5,780	41%
Operational Expenditure on Network Assets	11,136	11,989	8%

The overall actual operational expenditure on network assets was 5% over budget.

Service Interruptions and Emergencies:

- 41% over budget
- Higher unplanned distribution and technical fault response costs due to faults from weather conditions and some increased material costs.
- Mobile Substation has been deployed to Te Anau Substation to maintain the security of supply in the region due to tap changer failure in the zone substation transformers.

Vegetation Management:

- 25% over budget
- The amount of work completed by Asplundh was higher than budgeted, with more trees being identified and cut. In addition, traffic management costs increased.

Routine and Corrective Maintenance:

- 14% under budget.
- Corrective maintenance higher due to increased number of follow up repairs, linked to incident response spend.
- Connections maintenance incurred an additional cost from smart meter data providers.
- Routine maintenance work below budget due to resource constraints.

Asset replacement and renewal maintenance:

- 45% under budget
- Work is largely driven from the inspection program and aligned to the refurbishment work identified during the year.

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

Table 78 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 78:** Performance against Primary Service Targets*

Measure	Class	2023/24 Target	2023/24 Limit	2023/24 Actual
SAIDI	Planned	47.3	144	97.66
	Unplanned	128.7	190	201.35
SAIFI	Planned	-	0.6	0.660
	Unplanned	-	2.9	3.152

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 2024 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 79 shows the 2023/24 results for the service level targets.

***Table 79:** Performance against Secondary Service Targets*

Attribute	Measure	Target 2023/24	Actual 2023/24
Customer Satisfaction on Faults	No impact or minor impact of last unplanned outage {CES}	>80%	64%
	Information supplied was satisfactory {CES}	>80%	74%
	PowerNet first choice to contact for faults {CES}	>40%	65%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	<10	29
	Number of customers having justified supply quality complaints {IK}	<3	7
Planned Outages	Provide sufficient information {CES}	>80%	90%
	Satisfaction regarding amount of notice {CES}	>80%	98%
	Acceptance of one planned outage every two years lasting four hours on average {CES}	>50%	94%

{ } 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

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

Table 80: *Performance against Efficiency Targets*

Measure	2023/24 Target	2023/24 Actual
Load factor	> 65%	63%
Loss ratio	< 7.0%	5.6%
Capacity utilisation	> 30%	32.3%

Financial Efficiency

TPCL's network financial efficiency results were marginally higher than planned for 2023/24.

Table 81: *Performance against Financial Targets*

Measure	2023/24 Target	2023/24 Actual
Network OPEX/ICP	$304	$318
Network OPEX/km	$1,294	$1,345
Network OPEX/MVA	$22,350	$24,778
Non-Network OPEX/ICP	$206	$211
Non-Network OPEX/km	$877	$892
Non-Network OPEX/MVA	$15,140	$16,427

10.3 AMMAT Performance

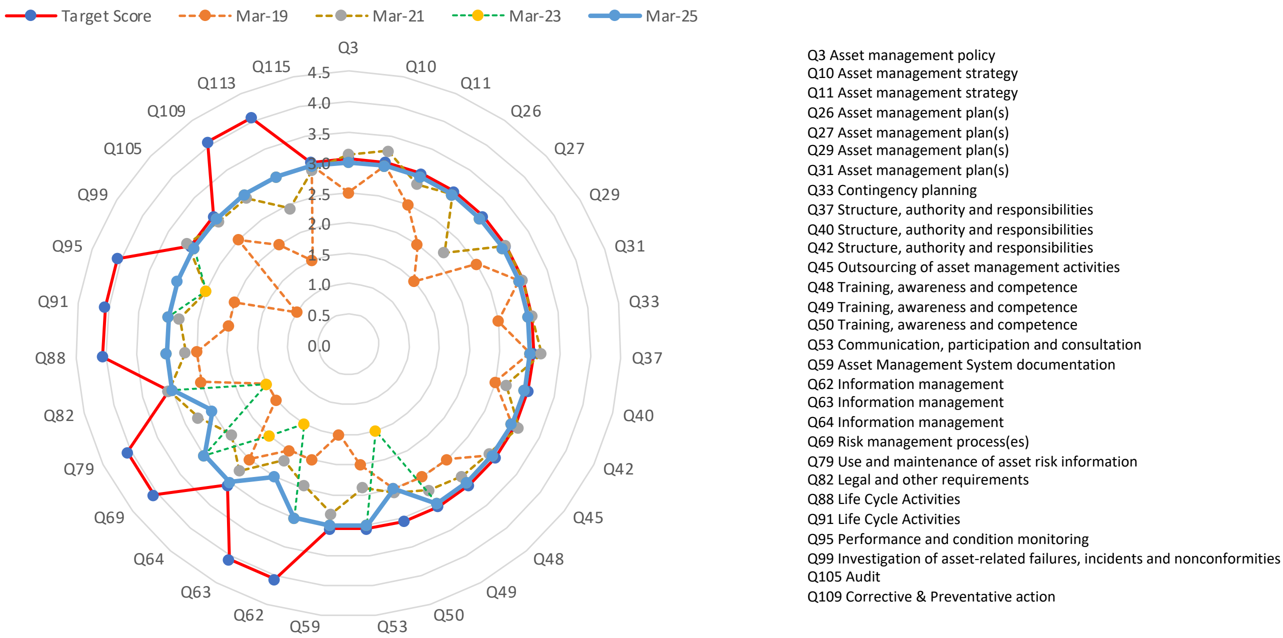
PowerNet understands the foundations of good asset management practice and endeavours to comply with international best practice as embodied in the ISO5500X suite of standards (a management system for Asset Management). In addition, the original PAS 55 principles are adopted (as this is the measurement 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 2023 assessment. In scoring TPCL’s asset management practice against the maturity tool, scores from ‘2.5’ to ‘3.0’ with an average score of ‘2.95’ were achieved as shown in Figure 47. 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 red curve.

The green curve shows the result of this assessment.

***Figure 47:** 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, TPCL believes that some improvements are realisable and appropriate. The 2023 audit showed that TPCL had maturity improvement in all of the previously weaker areas:

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?

Other initiatives for improvement that have been completed or are in progress are:

- A new drawing management system that allows access to drawings from the field.
- A system to keep everybody abreast of legal, regulatory, and statutory requirements.
- 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:
  - Developing more compatible units and unit rates to allow standardisation of 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.
- Still to be fully implemented 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.

ISO 55001 Asset Management System implementation

PowerNet's Asset Management System has been certified to ISO 55001.

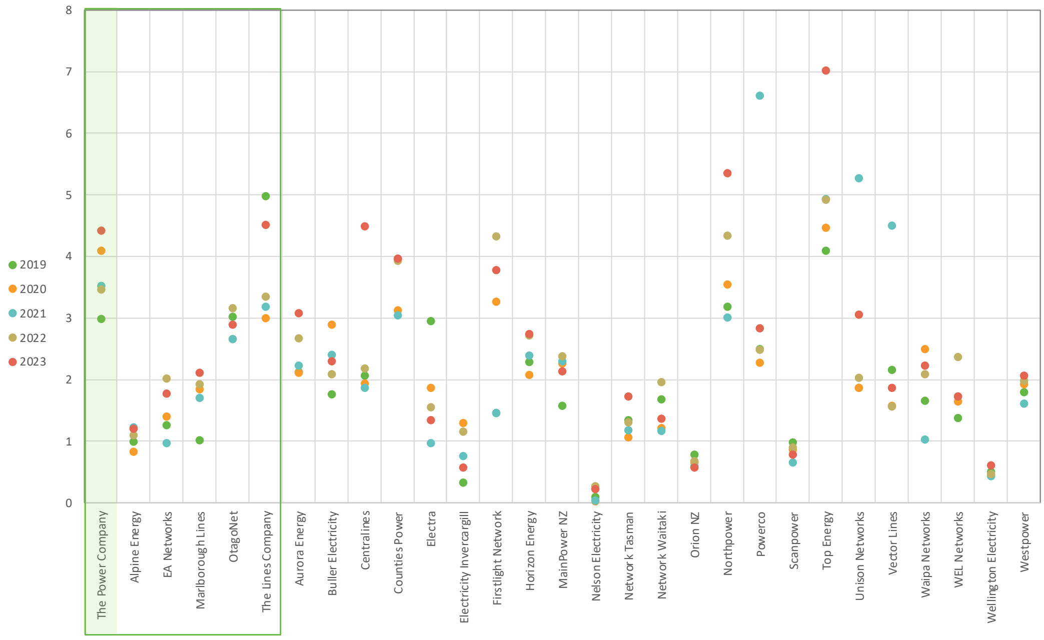
10.5 Benchmarking

Benchmarking against other local distribution networks assists 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 figures 48 through to 58.

SAIFI

TPCL is increasing vegetation management and network inspections to limit outage frequency across the network related to vegetation and defective equipment faults.

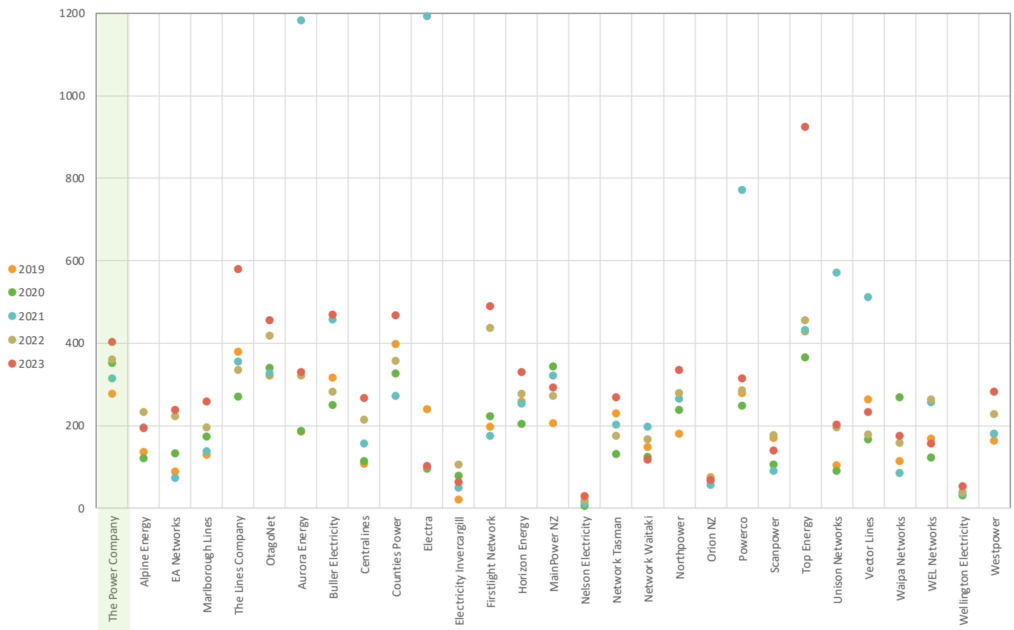
Figure 48: *SAIFI Benchmarking*



SAIDI

TPCL is installing SCADA enabled switches within the network and strategic locations to limit outage duration by improving restoration times.

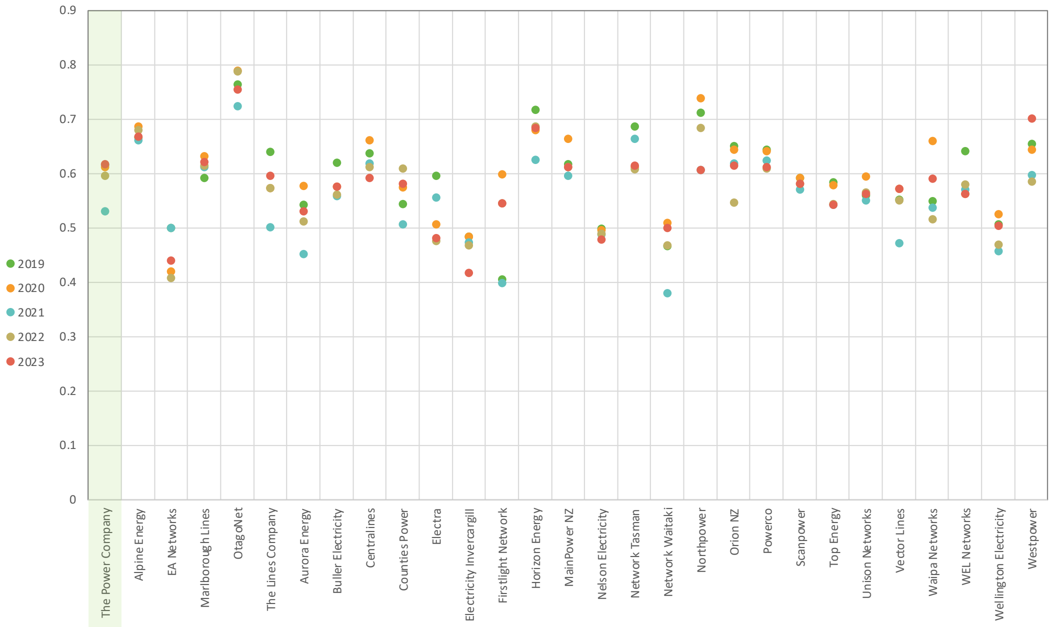
Figure 49: *SAIDI Benchmarking*



Load Factor

Comparison with other networks shows that TPCL's load factor is around the 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 50.

***Figure 50:** Load Factor Comparison*

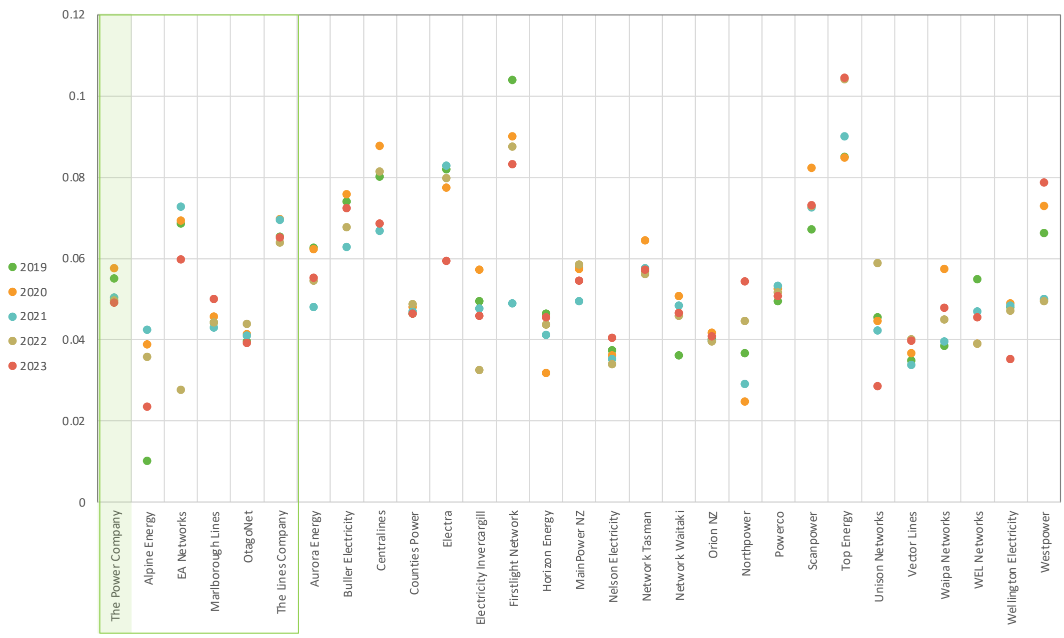


Loss Ratio

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. The exception is when the losses lead to other technical issues such as poor voltage or 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 loss ratio sits around the 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 51:** Loss Ratio Comparison*

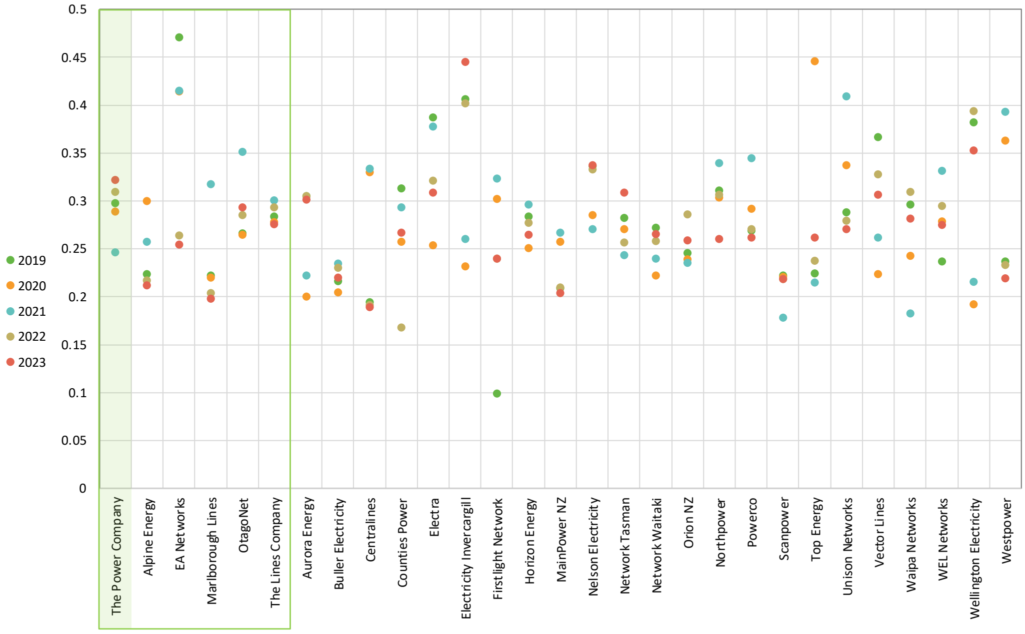


Capacity Utilisation

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 than 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 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.

Figure 52: *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 53:** $OPEX/ICP Benchmarking*

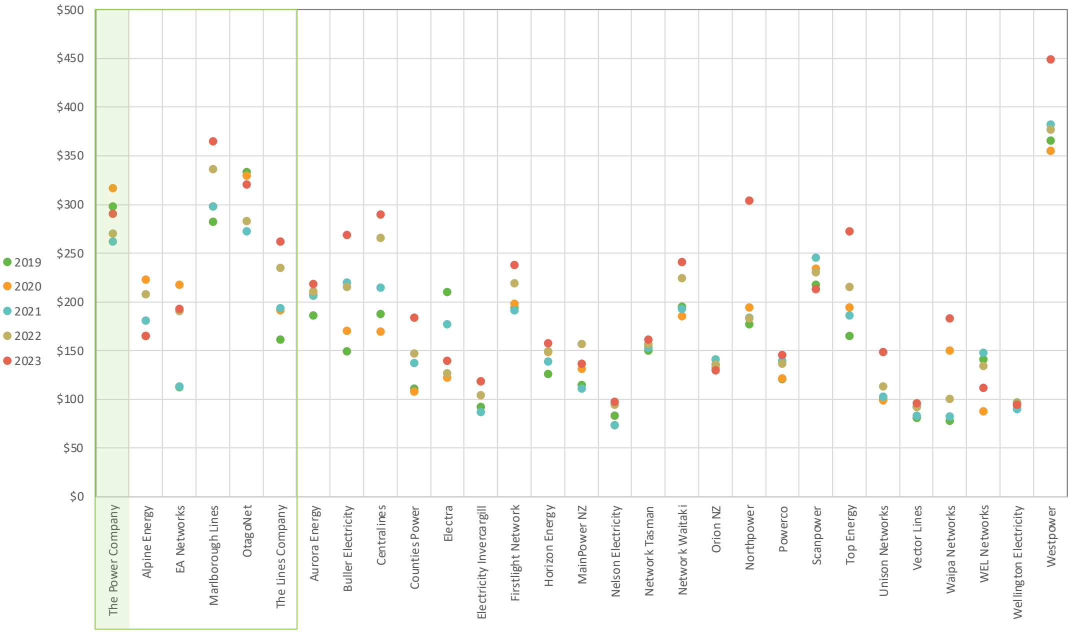


***Figure 54:** $OPEX/km Benchmarking*

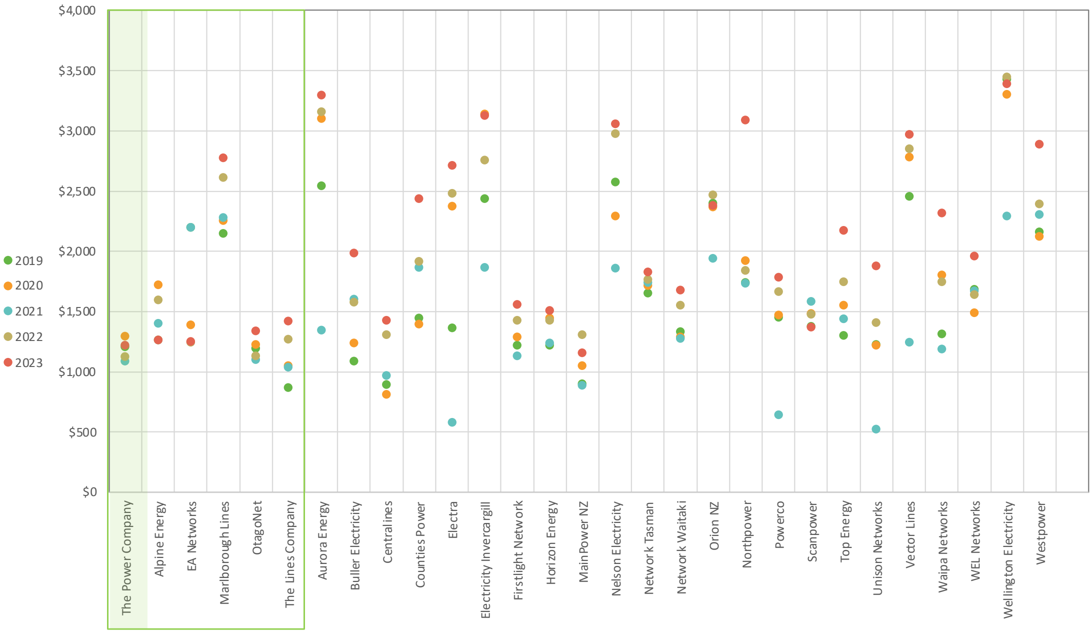


Figure 55: *$OPEX/MVA Benchmarking*

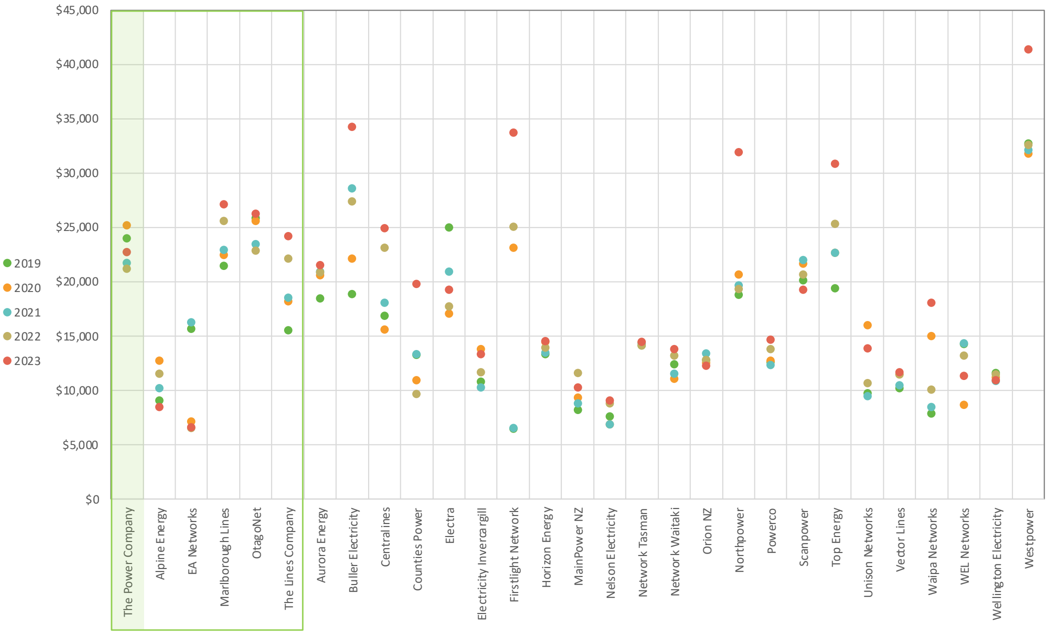


Figure 56: *Non-Network $OPEX/ICP Benchmarking*

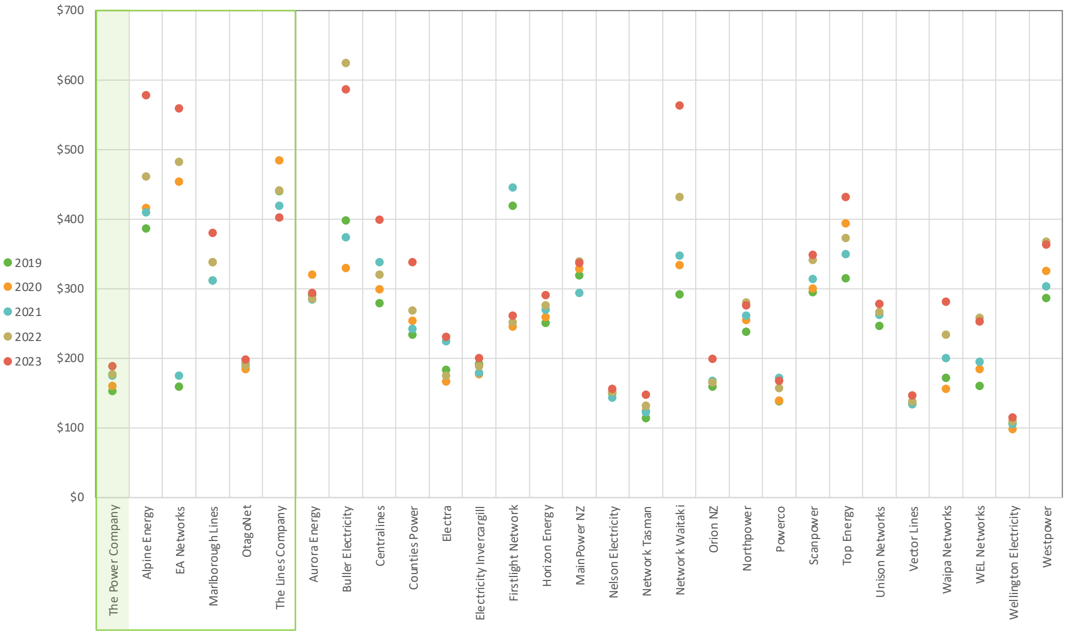


Figure 57: *Non-Network $OPEX/km Benchmarking*

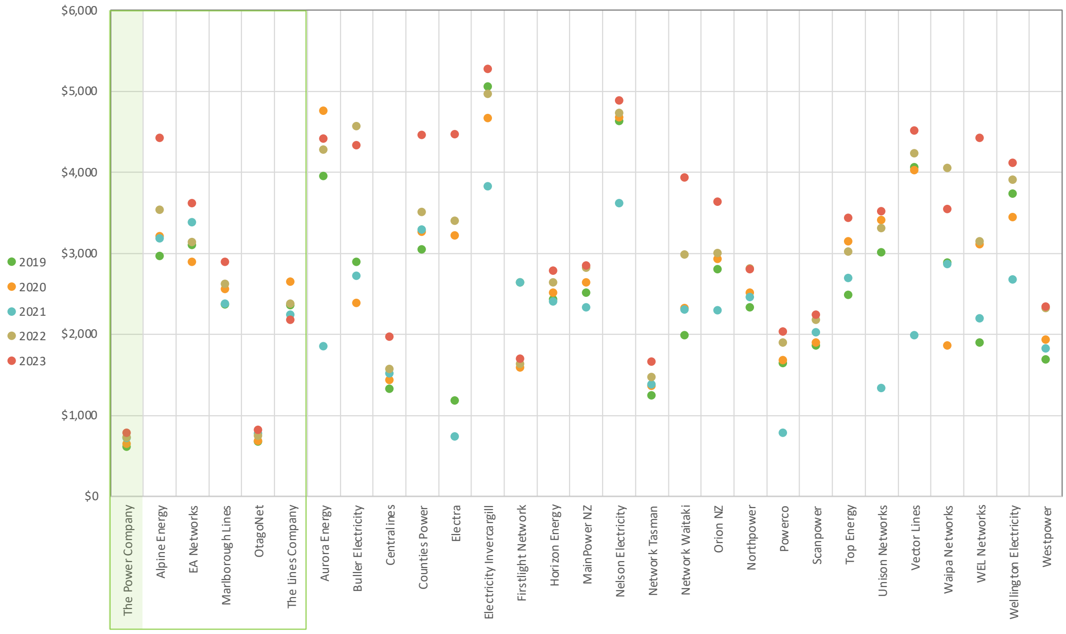
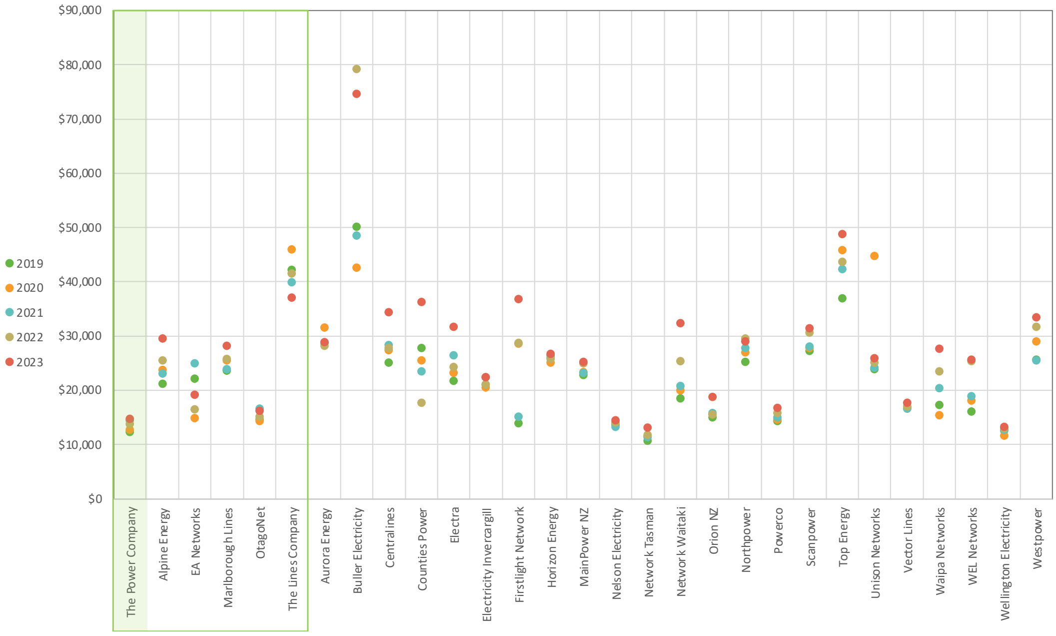
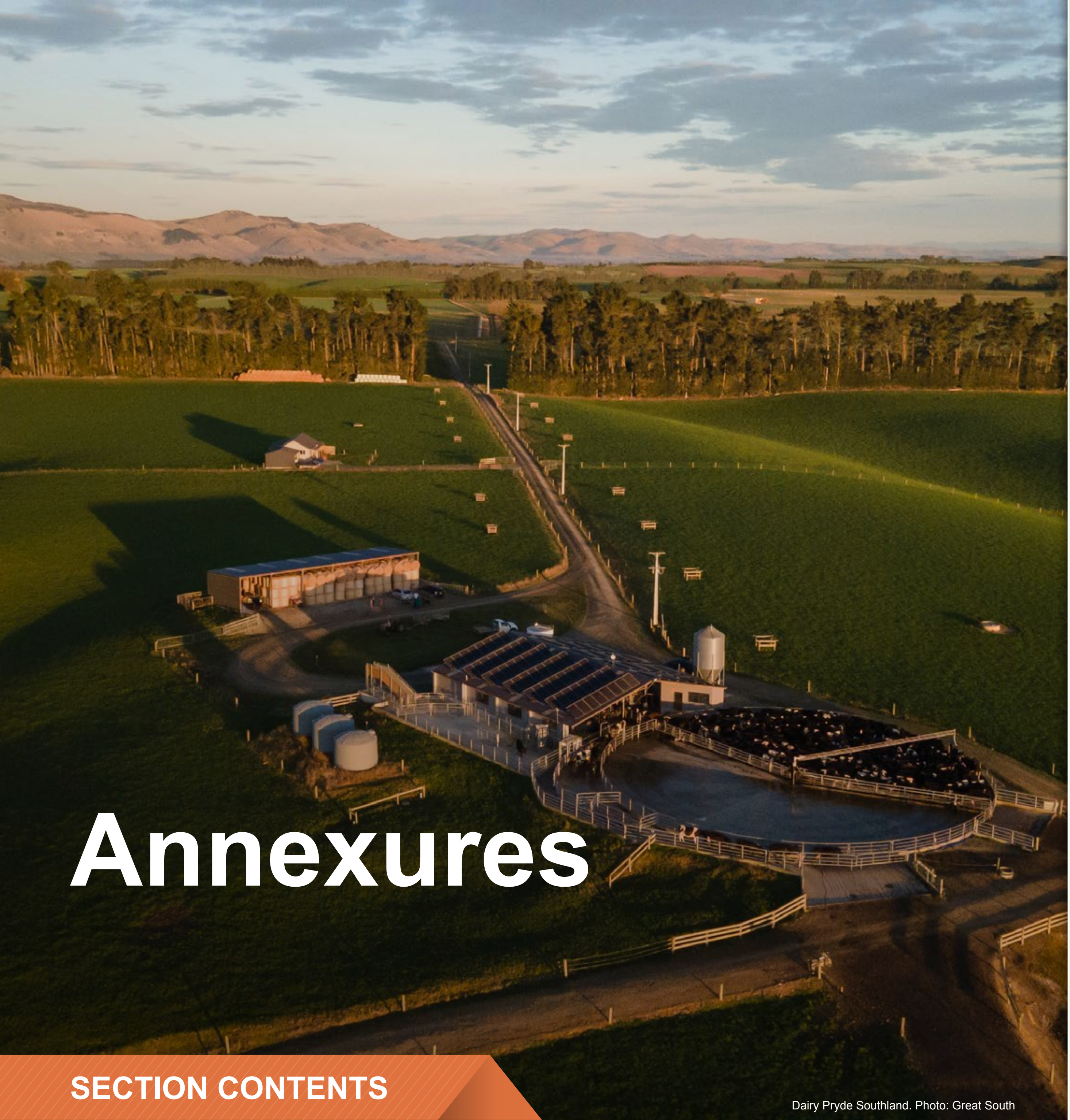


Figure 58: *Non-Network $OPEX/MVA Benchmarking*





Annexures

Dairy Pryde Southland. Photo: Great South

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AM-POL-0003	Mobile Equipment Policy
AM-POL-0004	Streetlight Connections Policy
AM-POL-0006	Asset Management Policy Statement
AM-POL-0007	Public Safety in Asset Design Policy V1
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AM-POL-0009	Easement Policy
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AM-STD-0012	Safety in Design Standard
AM-STD-0013	New Network Asset and Material Approval Standard
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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
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AM-PLN-5025	Asset Fleet Plan - Power Supply
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AM-SPE-0003	Standard Construction Specification

ANNEXURE 2 – CUSTOMER ENGAGEMENT QUESTIONNAIRE

Telephone Survey Questions

I'm $I calling from Research First on behalf of PowerNet.

We are not selling anything or asking you to change anything. We are conducting a survey to help PowerNet deliver the right levels of service to network customers and plan effectively for your future needs.

To thank you for your time and effort, everyone who completes this survey will go into the draw to win 1 of 5 $100 cash prizes,

Can I speak to <NAME>, or the person mainly or jointly responsible for paying the electricity account or making decisions about power supply?

The survey will take about 15 minutes to complete. Are you able to help today?

If necessary: PowerNet is relevant to all electricity users in Southland, West Otago, Queenstown- Lakes, Central Otago and Stewart Island. I will explain further later in the survey.

If required: Please know that Research First is a professional market research company, so we abide by a Code of Practice. This means we treat everything you tell us as totally confidential. You have the right to decline or withdraw from the research at any time.

If required: Phone numbers have been supplied by PowerNet from the customer database. We will not use numbers for any other purpose. You can call PowerNet on (03) 211-1899 with any queries.

S1	I just have to check if you are eligible... Are you a PowerNet staff member, or are any of your immediate family a PowerNet staff member?	
	O	No
	O	Yes <survey will end>

Awareness and Perceptions of Performance

1.	Have you heard of PowerNet?	
	O	Yes – Q2
	O	No – Q4

2.	Where have you most recently seen or heard about PowerNet? <do not prompt> <route to 3 except if Facebook mentioned>	
	O	Sponsorship – St John
	O	Sponsorship – Tour of Southland
	O	Sponsorship – other
	O	Website
	O	Facebook page
	O	Logos on vehicles
	O	Newspaper ads
	O	LinkedIn
	O	Other specify
	O	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?	
	O	Yes
	O	No

4b	Given the duration for a planned interruption on average is 4 hours, is this an acceptable duration for a planned interruption?	
	O	Yes
	O	No
5	Which of the following options would you prefer?	
	O	Retain the current plan: 1 interruption of 4 hours every 2 years
	O	Have more frequent interruptions but of shorter duration
	O	Have less frequent interruptions but of a longer duration
	O	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?	
	O	Yes – Q7
	O	No – Q11
	O	Don't know – Q11 – DO NOT READ OUT

7	Can you remember how much notice you were given?	
	O	1-2 day -Q8
	O	3-4 days -Q8
	O	5-6 days -Q8
	O	1 week -Q8
	O	2 weeks -Q8
	O	More than 2 weeks -Q8
	O	Don’t know – Q11 – DO NOT READ OUT

8	Do you feel that you were given enough notice of this planned interruption?	
	O	Yes
	O	No
	O	Don’t know – DO NOT READ OUT

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

10	What additional information on an outage is needed? Probe to clarify.	
	O	Open comment
	O	Don’t know
	O	No additional information is needed

SECTION 4: Unplanned Interruptions

11	Who would you telephone in the event your power supply has been unexpectedly interrupted? Do not prompt.	
	O	PowerNet
	O	Retailer/Power company
	O	Local government
	O	Other (specify)
	O	No-one

12	Where would you prefer to receive communication from PowerNet about outages? DO NOT READ OUT, randomise	
	O	PowerNet Facebook Page
	O	PowerNet 0800 faults number (0800 808 587)
	O	The internet (Google, firefox, etc)
	O	PowerNet's Outage Website Page? https://outages.powernet.co.nz/
	O	Text message

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

14	Do you recall how long your most recent power cut lasted? Read if necessary	
	O	1-2 hours
	O	2-3 hours
	O	3-4 hours
	O	More than 4 hours
	O	Don't know – DO NOT READ OUT

15	On a scale of 1 to 5 where 1 is no impact at all, 2 is minor impact, 3 is neutral, 4 is moderate impact and 5 is major impact, how much impact did your last power cut have on you?	
	O	No impact
	O	Minor impact
	O	Neutral
	O	Moderate impact
	O	Major impact
	O	Don't know – DO NOT READ OUT

16		Who did you call when the supply was interrupted?
	O	PowerNet – Q17
	O	Retailer/Power company – Q19
	O	Local government – Q19
	O	No one – Q19
	O	Other (specify) – Q19
	O	Don't know/can't remember – Q19 – DO NOT READ OUT

17 On a scale of 1 to 5 where 1 = 'very dissatsfied', 2 = 'dissatisfied', 3 = 'neutral', 4 = 'satisfied', and 5 = 'very satisfied', how satisfied were you with…?

	Very dissatisfied	Dissatisfied	Neutral	Satisfied	Very satisfied	Don' t know
The system you had to use to get information	1	2	3	4	5	6
The information supplied was satisfactory	1	2	3	4	5	6

If coded 1 or 2 at Q17 – go to Q18

If coded 3,4,5 at Q17 – go to Q19

18		<If coded 1 or 2 at Q17> What could be done to improve this process? Probe to clarify.
	O	Open comment
	O	Don't know

19		In the event of an unexpected interruption to your electricity supply, what do you consider would be a reasonable amount of time before the electricity supply is restored to your home?
	O	Under 30 minutes
	O	30min - 1 hour
	O	1-2 hours
	O	2-3 hours
	O	3-4 hours
	O	More than 4 hours
	O	Don't know – DO NOT READ OUT
	O	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.	
	O	Accurate time power will be restored
	O	Reason for fault
	O	That they know the problem and that it is being fixed
	O	Other (specify)
	O	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?
O	(Open comment - % textbox)

SECTION 5: Evolving Technology

22 I am going to read out a list of technologies. For each of these I would like to know if you: Already have it, Would consider purchasing it, Would not consider purchasing, Or, if you have never heard of it before. Read out.

	Already have it	Considering purchasing it	Not Considering it	Never heard of it before
Solar Panels or Photovoltaic Panels	1	2	3	4
Wind Turbines	1	2	3	4
Battery Energy Storage System	1	2	3	4
EVs	1	2	3	4
Hot Water Heat Pumps	1	2	3	4
Space Heating Heat Pumps	1	2	3	4
Smart Home Technologies (e.g. Smart Controlled Appliances)	1	2	3	4

23 I would like to know which of these technologies you are most interested in. Please tell me which is the 1st, 2nd and 3rd most interesting. Read out. [Rank 1, 2, and 3]

	Solar Panels or Photovoltaic Panels
	Wind Turbines
	Battery Energy Storage System
	EVs
	Hot Water Heat Pumps
	Space Heating Heat Pumps
	Smart Home Technologies (e.g. Smart Controlled Appliances)

Solar Panels

24.	If you were given an opportunity to receive an assessment and you found that installing Solar Panels would be the most economic option for yourself (as opposed to fully purchasing energy from the grid), On a scale from 1 to 5, how likely would you be to install Solar Panels? Where 1 = not at all likely, and 5 = very likely.	
		I am not interested at all
		Not likely at all
		Unlikely
		Neutral
		Likely
		Very likely
		Don't know DO NOT READ OUT

EVs

25.	Which of the following are most important when considering buying an EVs? Please tell me which is the 1st, 2nd and 3rd most important. [Randomise] [Rank 1, 2, and 3] Read out	
		Saving money on fuel
		Reducing emissions
		The distance you can drive on a single charge
		The purchase price
		The size and capability of the vehicle
		The number of charging stations in your area

26	Do you have any comments you would like to make about why you would or would not buy solar panels or an EVs?	
	O	Open comment box
	O	Don't know

Demographics

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

28	At the property where you are currently living/ working, do you…? Read out	
	O	Own your dwelling outright
	O	Own your dwelling with a mortgage
	O	Rent from a private landlord
	O	Rent from friends/family
	O	Rent from the Council or government
	O	Other (specify) – DO NOT READ OUT

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

SECTION 6: Final Comments

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

THEPOWERCOMPANYLTD

Company Name: **The Power Company Limited**
AMP Planning Period: **01 April 2025 - 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	16,740	22,204	11,526	10,249	4,873	4,971	5,071	5,172	5,275	5,381	5,489
11		System growth	8,383	18,489	8,443	5,561	5,961	9,099	20,740	20,044	31,078	18,374	17,171
12		Asset replacement and renewal	19,683	23,225	28,175	21,054	24,509	20,576	20,435	18,322	16,555	20,493	24,517
13		Asset relocations	352	143	146	149	152	155	158	161	165	168	171
14		Reliability, safety and environment:											
15		Quality of supply	449	862	881	579	591	602	615	627	639	652	665
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	4,777	5,145	5,198	3,234	3,506	3,547	10,958	11,178	11,401	11,629	11,862
18		**Total reliability, safety and environment**	5,226	6,007	6,079	3,813	4,097	4,149	11,573	11,804	12,041	12,281	12,527
19		**Expenditure on network assets**	50,384	70,068	54,369	40,826	39,592	38,951	57,977	55,504	65,113	56,697	59,875
20		**Expenditure on non-network assets**	-	2,162,000	-	-	-	-	-	-	-	-	-
21		**Expenditure on assets**	50,384	2,232,068	54,369	40,826	39,592	38,951	57,977	55,504	65,113	56,697	59,875
22													
23	*plus*	Cost of financing											
24	*less*	Value of capital contributions	8,909	11,561	6,231	5,603	2,924	2,983	3,042	3,103	3,165	3,229	3,293
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	41,475	2,220,507	48,138	35,223	36,668	35,968	54,935	52,401	61,948	53,468	56,582
28													
29		Assets commissioned	36,613	77,942	80,453	44,020	118,594	26,997	28,442	24,530	213,820	30,142	156,453
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	16,739	22,204	11,288	9,841	4,588	4,588	4,588	4,588	4,588	4,588	4,588
34		System growth	8,382	18,490	8,268	5,339	5,612	8,397	18,767	17,781	27,028	15,666	14,354
35		Asset replacement and renewal	19,683	23,225	27,594	20,215	23,072	18,989	18,490	16,253	14,398	17,473	20,495
36		Asset relocations	352	143	143	143	143	143	143	143	143	143	143
37		Reliability, safety and environment:											
38		Quality of supply	449	862	862	556	556	556	556	556	556	556	556
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	4,778	5,144	5,091	3,105	3,300	3,273	9,916	9,916	9,916	9,916	9,916
41		**Total reliability, safety and environment**	5,227	6,006	5,954	3,661	3,856	3,830	10,472	10,472	10,472	10,472	10,472
42		**Expenditure on network assets**	50,383	70,068	53,247	39,200	37,271	35,947	52,460	49,237	56,629	48,342	50,052
43		Expenditure on non-network assets	-	2,162	-	-	-	-	-	-	-	-	-
44		**Expenditure on assets**	50,383	72,230	53,247	39,200	37,271	35,947	52,460	49,237	56,629	48,342	50,052
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses											
49		Overhead to underground conversion											
50		Research and development											
52													

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Company Name	**The Power Company Limited**
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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
54												
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	1	0	238	408	285	383	483	584	687	793	901
57	System growth	1	(1)	175	222	349	702	1,973	2,263	4,050	2,708	2,817
58	Asset replacement and renewal	(0)	(0)	581	839	1,437	1,587	1,945	2,069	2,157	3,020	4,022
59	Asset relocations	0	-	3	6	9	12	15	18	21	25	28
60	Reliability, safety and environment:											
61	Quality of supply	-	(0)	18	23	35	46	58	71	83	96	109
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	(0)	1	107	129	206	274	1,043	1,262	1,485	1,714	1,946
64	**Total reliability, safety and environment**	(0)	1	125	152	240	320	1,101	1,333	1,569	1,810	2,055
65	**Expenditure on network assets**	1	0	1,122	1,626	2,320	3,004	5,517	6,267	8,484	8,355	9,823
66	Expenditure on non-network assets	-	2,159,838	-	-	-	-	-	-	-	-	-
67	**Expenditure on assets**	1	2,159,838	1,122	1,626	2,320	3,004	5,517	6,267	8,484	8,355	9,823

68

69 **Commentary on options and considerations made in the assessment of forecast expenditure**

70 *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*

71

72

73		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
74	**11a(ii): Consumer Connection**						
75	*Consumer types defined by EDB**	**$000 (in constant prices)**					
76	Customer Connections (≤ 20kVA)	1,481	1,748	1,748	1,748	1,748	1,748
77	Customer Connections (21 to 99kVA)	537	674	674	674	674	674
	Customer Connections (≥ 100kVA)	1,839	944	944	944	944	944
	Distributed Generation Connection	127	8	8	8	8	8
	New Subdivisions	1,409	1,214	1,214	1,214	1,214	1,214
	Edendale Process Heat Electrification	362					
	Underwood substation upgrade for Alliance	131					
	McNab Substation upgrade to 33 kV	23					
	Kaiwera Downs - Mercury 45MW wind farm	49					
	Jericho - Southern Generation 35MW wind farm			280			
	Government Decarbonising (GIDI) Funded Projects	-	-	-	-	-	-
	Open Country Dairy 66kV Expansion	10,782	9,879				
	Edendale 110kV Expansion Line		7,737	6,421	5,254		
	Edendale 110kV Expansion Substation						
78							
79							
80							
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	16,739	22,204	11,288	9,841	4,588	4,588
83	*less* Capital contributions funding consumer connection	8,909	11,561	6,103	5,379	2,753	2,753
84	**Consumer connection less capital contributions**	7,830	10,643	5,185	4,462	1,835	1,835
85	**11a(iii): System Growth**						
86	Subtransmission	661	3,045	900	2,387	2,660	4,796
87	Zone substations	3,739	14,573	7,134	2,387	2,387	3,366
88	Distribution and LV lines	1,141	752	234	565	565	235
89	Distribution and LV cables	778	33				
90	Distribution substations and transformers	1,284	54				
91	Distribution switchgear	778	33				
92	Other network assets	-					
93	**System growth expenditure**	8,382	18,490	8,268	5,339	5,612	8,397
94	*less* Capital contributions funding system growth	-	-	-	-	-	-
95	**System growth less capital contributions**	8,382	18,490	8,268	5,339	5,612	8,397
96							

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Company Name	The Power Company Limited
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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
98								
99	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
100		Subtransmission	606	907	907	907	907	907
101		Zone substations	4,294	7,232	12,727	5,767	8,544	5,666
102		Distribution and LV lines	5,380	5,594	5,992	5,573	5,573	5,573
103		Distribution and LV cables	315	56	56	56	56	56
104		Distribution substations and transformers	3,623	3,213	3,213	3,213	3,966	2,761
105		Distribution switchgear	5,360	6,115	4,591	4,591	3,918	3,918
106		Other network assets	105	109	109	109	109	109
107		**Asset replacement and renewal expenditure**	19,683	23,225	27,594	20,215	23,072	18,989
108	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
109		**Asset replacement and renewal less capital contributions**	19,683	23,225	27,594	20,215	23,072	18,989
110								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
112								
113	**11a(v): Asset Relocations**							
114		*Project or programme**	**$000 (in constant prices)**					
115		Line Relocations	352	143	143	143	143	143
116								
117								
118								
119								
120		**include additional rows if needed*						
121		All other project or programmes - asset relocations	-	-	-	-	-	-
122		**Asset relocations expenditure**	352	143	143	143	143	143
123	*less*	Capital contributions funding asset relocations	-	-	-	-	-	-
124		**Asset relocations less capital contributions**	352	143	143	143	143	143
125								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
127								
128	**11a(vi): Quality of Supply**							
129		*Project or programme**	**$000 (in constant prices)**					
130		Supply Quality Upgrades	159	405	405	405	405	405
131		Mobile Substation Site Made Ready	125	306	306			
132		Network Improvement Projects	146	151	151	151	151	151
133		Otatara Regulator and Automation	19					
134								
135		**include additional rows if needed*						
136		All other projects or programmes - quality of supply	-	-	-	-	-	-
137		**Quality of supply expenditure**	449	862	862	556	556	556
138	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
139		**Quality of supply less capital contributions**	449	862	862	556	556	556
140								

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Company Name	The Power Company Limited
AMP Planning Period	01 April 2025 - 31 March 2035

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).

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sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
142								
143	**11a(vii): Legislative and Regulatory**							
144		*Project or programme**	**$000 (in constant prices)**					
145								
146								
147								
148								
149								
150		**include additional rows if needed*						
151		All other projects or programmes - legislative and regulatory						
152		**Legislative and regulatory expenditure**	-	-	-	-	-	-
153	*less*	Capital contributions funding legislative and regulatory						
154		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
155								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
157	**11a(viii): Other Reliability, Safety and Environment**							
158		*Project or programme**	**$000 (in constant prices)**					
159		Earth Upgrades	2,678	2,000	2,000	2,000	2,000	2,000
160		Substation Safety	-	-	427	-	-	-
		Remote Area Power Supply	-	236	-	-	-	-
		Critical Spares	59	184	1,416	184	184	-
		Communications Projects	182	297	297	297	297	454
		Substation LS TX	189	195	327		195	195
		River Crossing Reconstruction	355	1,608				
		Distribution Recloser	606	624	624	624	624	624
161		Network Resilience Improvement						
162		Mossburn to Athol 66kV OHL Hardware Upgrade	709					
163								
164		**include additional rows if needed*						
165		All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
166		**Other reliability, safety and environment expenditure**	4,778	5,144	5,091	3,105	3,300	3,273
167	*less*	Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
168		**Other reliability, safety and environment less capital contributions**	4,778	5,144	5,091	3,105	3,300	3,273
169								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
171								
172	**11a(ix): Non-Network Assets**							
173	**Routine expenditure**							
174		*Project or programme**	**$000 (in constant prices)**					
175		Racecourse Road Rental Fence		17				
176		Racecourse Road Office Extension		2,125				
177		Green Shed Laydown		20				
178		[Description of material project or programme]						
179		[Description of material project or programme]						
180		**include additional rows if needed*						
181		All other projects or programmes - routine expenditure						
182		**Routine expenditure**	-	2,162	-	-	-	-
183	**Atypical expenditure**							
184		*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		[Description of material project or programme]						

Company Name	**The Power Company Limited**
AMP Planning Period	**01 April 2025 - 31 March 2035**

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).

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sch ref							
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure						
192	**Atypical expenditure**	-	-	-	-	-	-
193							
194	**Expenditure on non-network assets**	-	2,162	-	-	-	-

Company Name	The Power Company Limited
AMP Planning Period	01 April 2025 - 31 March 2035

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.

sch ref													
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8													
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		5,234	4,458	4,552	4,643	4,736	4,830	4,927	5,026	5,126	5,229	5,333
11	Vegetation management		1,938	1,939	1,980	2,019	2,060	2,101	2,143	2,186	2,230	2,274	2,320
12	Routine and corrective maintenance and inspection		5,384	5,271	5,382	5,490	5,490	5,600	5,712	5,827	5,943	6,062	6,183
13	Asset replacement and renewal		1,886	1,045	1,067	1,088	1,110	1,132	1,154	1,178	1,201	1,225	1,250
14	**Network Opex**		14,443	12,713	12,981	13,240	13,396	13,663	13,936	14,217	14,500	14,790	15,086
15	System operations and network support		5,142	7,264	7,190	7,472	7,621	7,774	7,929	8,088	8,250	8,415	8,583
16	Business support		3,894	3,756	3,909	3,984	4,064	4,145	4,228	4,312	4,398	4,486	4,576
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	21	20	20	21	21	22	22	22	23	23	24
18	**Non-network opex**		9,057	11,040	11,119	11,477	11,706	11,941	12,179	12,422	12,671	12,924	13,183
19	**Operational expenditure**		23,499	23,753	24,100	24,717	25,102	25,604	26,115	26,639	27,171	27,714	28,269
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21													
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		5,234	4,458	4,458	4,458	4,458	4,458	4,458	4,458	4,458	4,458	4,458
24	Vegetation management		1,938	1,939	1,939	1,939	1,939	1,939	1,939	1,939	1,939	1,939	1,939
25	Routine and corrective maintenance and inspection		5,384	5,271	5,271	5,271	5,169	5,169	5,169	5,169	5,169	5,169	5,169
26	Asset replacement and renewal		1,886	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045	1,045
27	**Network Opex**		14,443	12,713	12,713	12,713	12,611	12,611	12,611	12,611	12,611	12,611	12,611
28	System operations and network support		5,142	7,264	7,042	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175
29	Business support		3,894	3,756	3,829	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	21	20	20	20	20	20	20	20	20	20	20
31	**Non-network opex**		9,056	11,040	10,891	11,020	11,020	11,020	11,020	11,020	11,020	11,020	11,020
32	**Operational expenditure**		23,499	23,753	23,604	23,733	23,631	23,631	23,631	23,631	23,631	23,631	23,631
33	**Subcomponents of operational expenditure (where known)**												
35													
36	Energy efficiency and demand side management, reduction of energy losses												
37	Direct billing*												
38	Research and Development												
39	Insurance												
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
42													
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
44													
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		(0)	-	94	185	278	372	469	568	668	771	875
47	Vegetation management		-	-	41	80	121	162	204	247	291	335	381
48	Routine and corrective maintenance and inspection		-	-	111	219	321	431	543	658	774	893	1,014
49	Asset replacement and renewal		-	-	22	43	65	87	109	133	156	180	205
50	**Network Opex**		(0)	-	268	527	785	1,052	1,325	1,606	1,889	2,179	2,475
51	System operations and network support		-	-	148	297	446	599	754	913	1,075	1,240	1,408
52	Business support		-	-	80	159	239	320	403	487	573	661	751
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	0	-	-	1	1	2	2	2	3	3	4
54	**Non-network opex**		0	-	228	457	686	921	1,159	1,402	1,651	1,904	2,163
55	**Operational expenditure**		0	-	496	984	1,471	1,973	2,484	3,008	3,540	4,083	4,638
56													
57	**Commentary on options and considerations made in the assessment of forecast expenditure**												
58	*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.*												

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Company Name	The Power Company Limited
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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)							
9	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
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	-	75.66%	23.70%	0.64%	3	-
11	All	Overhead Line	Wood poles	No.	0.00%	0.01%	32.62%	46.35%	18.24%	2.78%	3	0.01%
12	All	Overhead Line	Other pole types	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	12.72%	17.18%	19.77%	32.66%	15.66%	2.01%	2	13.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	20.34%	62.71%	16.95%	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.	-	5.40%	64.60%	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.	-	-	-	98.85%	1.15%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	1.42%	96.45%	0.70%	1.42%	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	100.00%	1	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	1.15%	8.00%	85.00%	3.45%	2.30%	3	1.15%
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.	-	-	-	100.00%	-	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	98.73%	0.63%	0.63%	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	4.17%	93.75%	2.08%	-	4	-
35												

Company Name	**The Power Company Limited**
AMP Planning Period	**01 April 2025 - 31 March 2035**

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

36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	20.59%	72.06%	2.94%	-	4	7.80%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.04%	6.93%	56.65%	22.23%	13.65%	0.50%	3	0.05%
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	0.11%	3.27%	9.80%	22.97%	53.53%	10.33%	3	3.38%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	70.37%	25.51%	4.12%	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.	-	-	-	97.22%	-	2.78%	4	-
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.	1.79%	5.26%	11.00%	35.05%	11.82%	35.05%	2	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.	-	1.33%	10.67%	80.00%	1.33%	6.67%	3	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.03%	0.88%	46.25%	35.19%	10.52%	7.14%	3	0.91%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.14%	1.82%	12.71%	74.86%	2.79%	7.68%	3	1.96%
53	HV	Distribution Transformer	Voltage regulators	No.	-	3.90%	4.76%	83.33%	11.90%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	14.29%	-	-	-	85.71%	1	14.29%
55	LV	LV Line	LV OH Conductor	km	-	4.89%	61.31%	16.72%	15.97%	1.10%	2	-
56	LV	LV Cable	LV UG Cable	km	-	1.70%	45.11%	19.82%	30.22%	3.14%	1	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	1.42%	67.93%	16.10%	10.71%	3.83%	1	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	20.59%	-	55.88%	23.53%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	32.00%	61.91%	2.42%	3.67%	3	-
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%	-	-	-	-	3	-
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

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Company Name	**The Power Company Limited**
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Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	223.8	163.0	163.0	163.0	163.0	163.0
12	Class C (unplanned interruptions on the network)	260.5	235.0	234.0	233.0	232.0	230.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.91	0.70	0.70	0.70	0.70	0.70
15	Class C (unplanned interruptions on the network)	3.34	3.10	3.08	3.07	3.05	3.03

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Company Name	**The Power Company Limited**
AMP Planning Period	**01 April 2025 - 31 March 2035**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	Existing Zone Substations	Current peak load (MVA)	Installed firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
8			*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*before DY2025*	*before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	
10	Athol	1.21				-			[Select one]	Winter	5.0	N	No constraint	3.79	Winter	2.83	N	Winter	2.82	2.92	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
11	Awarua Chip Mill	0.79				-			[Select one]	Winter	5.0	N	No constraint	4.21	[Select one]	-	[Select one]	[Select one]	-	-	[Select one]	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	Substation to be decommissioned in FY25/26. Network to be reconfigured to supply existing customers from Coyler Road substation
12	Bluff	5.06				-			[Select one]	Winter	26.0	N-1	No constraint	20.94	Winter	20.98	N-1	Winter	20.82	21.14	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
13	Centre Bush	4.17				-			[Select one]	Summer	5.0	N	No constraint	0.83	Summer	0.94	N	Summer	0.31	0.71	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
14	Colyer Road	10.17				-			[Select one]	Summer	24.0	N-1	No constraint	13.83	Summer	8.23	N-1	Summer	8.72	9.39	N-1	Security	1	Zone substation transformer	Network upgrade	Solution confirmed	> 3 years	Planned substation upgrade. New 66kV circuit from Invercargill from FY26/27 to FY 28/29 expected to relieve 12MVA from existing 33kV
15	Conical Hill	3.43				-			[Select one]	Spring	10.0	N-1	No constraint	6.57	Spring	7.57	N-1	Spring	7.07	7.31	N-1	[Select one]	None	Not applicable	Not required	Not applicable	Not applicable	
16	Dipton	1.38				-			[Select one]	Summer	5.0	N	No constraint	3.62	Summer	3.41	N	Summer	3.08	3.24	N	[Select one]	None	Not applicable	Not required	Not applicable	Not applicable	
17	Edendale (Fonterra)	27.19				-			[Select one]	Spring	69.0	N	Security	41.81	Spring	-38.71	N	Spring	-38.71	-38.71	N	Security	1	Zone substation transformer	Demand response	Implementation stage	Not applicable	New 20MW electrode boiler commissioned in 2024. Security managed by special protection scheme Working with Transpower and Fonterra to implement a long term solution.
18	Edendale	6.11				-			[Select one]	Summer	24.0	N-1	No constraint	17.89	Summer	16.52	N-1	Summer	15.95	16.53	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
19	Glenham	1.17				-			[Select one]	Spring	1.5	N	No constraint	0.33	Spring	0.01	N	Spring	-0.25	-0.10	N	Capacity	6	Zone substation transformer	Divert load to alternative substation	Solution confirmed	> 3 years	The load growth is uncertian and loading can be transferred to other stations
20	Gorge Road	2.60				-			[Select one]	Spring	5.0	N	No constraint	2.40	Spring	2.26	N	Spring	1.66	1.96	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
21	Hedgehope	1.54				-			[Select one]	Spring	5.0	N	No constraint	3.46	Spring	2.71	N	Spring	2.21	2.45	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
22	Hillside	0.70				-			[Select one]	Winter	3.0	N	No constraint	2.30	Winter	1.88	N	Winter	1.66	1.78	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
23	Isla Bank	1.92				-			[Select one]	Spring	5.0	N	No constraint	3.08	Spring	2.29	N	Spring	2.00	2.26	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
24	Kelso	4.29				-			[Select one]	Spring	5.0	N	No constraint	0.71	Spring	0.33	N	Spring	-0.47	-0.04	N	Capacity	8	Zone substation transformer	Network upgrade	Solution confirmed	1 - 3 years	Transformer upgrade planned for FY24/25 to FY25/26
25	Kennington	7.14				-			[Select one]	Spring	24.0	N-1	No constraint	16.86	Spring	13.41	N	Spring	12.73	13.48	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
26	Lumsden	2.93				-			[Select one]	Summer	5.0	N	No constraint	2.07	Summer	0.55	N	Summer	-0.05	0.37	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
27	Makarewa	4.34				-			[Select one]	Spring	24.0	N-1	No constraint	19.66	Spring	19.1	N-1	Spring	18.48	18.90	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	Potential step change in load, project will be initiated by customers
28	Mataura	7.88				-			[Select one]	Winter	20.0	N-1	No constraint	12.12	Winter	12.09	N-1	Winter	11.45	12.02	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
29	McNab	22.47				-				Summer	50.0	N-1	Capacity	27.53	Summer	27.53	N-1	Summer	27.53	27.53	N-1	Capacity	1	Subtransmission circuit	Demand response	Solution confirmed	Not applicable	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
30	Monowai	0.19				-				Winter	1.0	N	No constraint	0.81	Winter	0.79	N	Winter	0.78	0.79	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
31	Mossburn	1.96				-				Summer	3.0	N	No constraint	1.04	Summer	0.69	N	Summer	0.28	0.50	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
32	North Gore	8.72				-				Winter	30.0	N-1	No constraint	21.28	Winter	21.01	N-1	Winter	20.40	21.04	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
33	Ohai	2.42				-				Spring	7.5	N	No constraint	5.08	Spring	4.86	N	Spring	4.69	4.90	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
34	Orawai	3.02				-				Spring	7.5	N	No constraint	4.48	Spring	4.2	N	Spring	3.79	4.07	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
35	Otatara	4.27				-				Winter	5.0	N	No constraint	0.73	Winter	0.44	N	Winter	0.04	0.38	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
36	Otautau	3.08				-				Spring	7.5	N	No constraint	4.42	Spring	3.29	N	Spring	2.92	3.28	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
37	Riversdale	5.33				-				Summer	5.0	N	No constraint	-0.33	Summer	-1.19	N-1	Summer	0.55	0.92	N-1	Capacity	1	Zone substation transformer	Network upgrade	Implementation stage	< 1 year	Fans installed and 11kV transfer to shift load for short term solution. Multiyear upgrade project from FY24/25, including feeder refurbishment and parallel incomers
38	Riverton	4.96				-				Spring	7.5	N-1	No constraint	2.54	Spring	1.62	N-1	Spring	1.33	1.76	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
39	Seaward Bush	-				-				Winter	24.0	N-1	No constraint	24.00	Winter	14.4	N-1	Winter	15.57	16.11	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
40	South Gore	10.53				-				Winter	24.0	N-1	No constraint	13.47	Winter	15.62	N-1	Winter	15.40	15.94	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
41	Te Anau	5.79				-				Winter	24.0	N-1	No constraint	18.21	Winter	16.98	N-1	Winter	10.05	10.50	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
42	Tokanui	1.18				-				Spring	1.5	N	No constraint	0.32	Spring	0.06	N	Spring	-0.15	-0.02	N	Capacity	1	Zone substation transformer	Network upgrade	Solution confirmed	< 1 year	Upgrade project for the substation is scheduled for 2032/33. Demand will be monitored to address short-term overloads, and the 11 kV network may transfer to a nearby substation.
43	Underwood	10.64				-				Autumn	31.0	N-1	No constraint	20.36	Autumn	18.99	N-1	Autumn	17.62	18.53	N-1	No constraint	None	Not applicable	Network upgrade	Planning stage	> 3 years	A system growth project has been planned for FY32/33 - FY34/35 to increase capacity in the Makarewa region.
44	Waikaka	1.44				-				Spring	1.5	N	No constraint	0.06	Spring	-0.15	N	Spring	-0.51	-0.35	N	Capacity	3	Zone substation transformer	Network upgrade	Solution confirmed	1 - 3 years	The existing 1.5MVA transformer has been planned for replacement in FY24/25 & FY25/26 with the existing 5MVA at the Kelso
45	Waikiwi	11.81				-				Winter	46.0	N-1	No constraint	34.19	Winter	33.27	N-1	Winter	32.87	33.71	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
46	Winton	9.22				-				Spring	24.0	N-1	No constraint	14.78	Spring	13.67	N-1	Spring	12.75	13.58	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	

[1] Extend table as necessary to disclose all capacity and constraint information by each zone substation

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Company Name	The Power Company Limited
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SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected during year by consumer type*			**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10								
11		*Consumer types defined by EDB**						
12		Customer Connections (≤ 20kVA)	332	335	335	335	335	335
13		Customer Connections (21 to 99kVA)	11	12	12	12	13	13
14		Customer Connections (≥ 100kVA)	4	5	5	5	5	5
15								
16								
17		**Connections total**	347	352	352	352	353	353
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	42	43	43	43	43	43
24		Capacity of distributed generation installed in year (MVA)	1	1	36	1	1	1
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	104	126	127	129	131
29	*plus*	Distributed generation output at HV and above	90	90	90	105	105	105
30		**Maximum coincident system demand**	192	194	216	232	234	236
31	*less*	Net transfers to (from) other EDBs at HV and above	(1)	(1)	(1)	(1)	(1)	(1)
32		**Demand on system for supply to consumers' connection points**	193	195	217	233	235	237
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	688	698	782	840	845	850
35	*less*	Electricity exports to GXPs	283	300	300	369	369	380
36	*plus*	Electricity supplied from distributed generation	591	600	600	650	700	700
37	*less*	Net electricity supplied to (from) other EDBs	11	13	13	13	13	13
38		**Electricity entering system for supply to ICPs**	986	985	1,069	1,108	1,163	1,157
39	*less*	Total energy delivered to ICPs	936	936	1,016	1,053	1,105	1,099
40		**Losses**	49	49	53	55	58	58
41								
42		**Load factor**	58%	58%	56%	54%	56%	56%
43		**Loss ratio**	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

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	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3			Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3			In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
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			Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3			The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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			Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3			The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3			It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
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			Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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			In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
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			Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3			Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
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			Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	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	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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			There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3			Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
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?	2.5			A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	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).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	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.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
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Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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			Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
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			Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
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			Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
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?	2.5			The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	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.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3			Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
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			Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.5			Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
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			In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	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.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	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.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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			Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3			Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3			Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
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			Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have process(es) 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.	The organisation is aware of the need to have process(es) and procedure(s) 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 but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting 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 for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	The Power Company Limited
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3			This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3			Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
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			Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

Schedule 14a - Mandatory Explanatory Notes on Forecast Information

Company Name: **The Power Company Limited**
For Year Ended: **31 March 2025**

(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 2024.

	2025/26	2026/27	2027/28	2028/29	2029/30
Inflator CAPEX	1.800%	2.100%	2.000%	2.000%	2.000%

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 2024.

	2025/26	2026/27	2027/28	2028/29	2029/30
Inflator OPEX	1.800%	2.100%	2.000%	2.000%	2.000%

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan

ANNEXURE 4 – REFERENCES

Ref #	Description
1	Electricity Distribution Information Disclosure Determination 2012 (consolidated as at 9 December 2021), ISBN 978-1-869459-59-8, Project no. 44933, Publication date: 9 December 2021, Commerce Commission, Wellington, New Zealand
2	EIL's Strategic Plan.
3	ISO 31000:2009 Standard: Risk Management - Principles and Guidelines.
4	Health and Safety at Work Act 2015.
5	Electricity (Safety) Regulations 2010
6	Electricity (Hazards from Trees) Regulations 2003.
7	Maintaining safe clearances from live conductors (NZECP34 or AS2067).
8	EEA Guide to Power System Earthing Practice 2009
9	https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors
10	https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/trends-in-local-lines-company-performance

ANNEXURE 5 – AMP DISCLOSURE TABLE

Electricity Distribution Information Disclosure Determination 2012 (consolidated December 2021)				
Attachment A; Asset Management Plans - Mandatory disclosure requirements				
AMP design				**Where in the AMP?** (Chapter/ paragraph)
1			**The core elements of asset management—**	
	1.1		A focus on measuring network performance, and managing the assets to achieve service targets;	2.2; 5; 10.2
	1.2		Monitoring and continuously improving asset management practices;	10.3; 10.4
	1.3		Close alignment with corporate vision and strategy;	2.1; 2.5
	1.4		That asset management is driven by clearly defined strategies, business objectives and service level targets;	2; 5; 6
	1.5		That responsibilities and accountabilities for asset management are clearly assigned	2.2; 2.6
	1.6		An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets;	3
	1.7		An emphasis on optimising asset utilisation and performance;	6
	1.8		That a total life cycle approach should be taken to asset management;	6
	1.9		That the use of ‘non-network’ solutions and demand management techniques as alternatives to asset acquisition is considered.	2.1; 7.1; 7.2; 7.3; 7.6
2			**The disclosure requirements are designed to produce AMPs that—**	
	2.1		Are based on, but are not limited to, the core elements of asset management identified in clause 1;	Overall
	2.2		Are clearly documented and made available to all stakeholders;	Website
	2.3		Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB’s asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets;	2.5
	2.4		Specifically support the achievement of disclosed service level targets;	5; 10.2
	2.5		Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment;	4
	2.6		Consider the mechanics of delivery including resourcing;	2.5; 9.1; 9.2
	2.7		Consider the organisational structure and capability necessary to deliver the AMP;	2.6
	2.8		Consider the organisational and contractor competencies and any training requirements;	6.2; Schedule 13
	2.9		Consider the systems, integration and information management necessary to deliver the plans;	9
	2.10		To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and	Overall
	2.11		Promote continual improvements to asset management practices.	10.4

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Contents of the AMP				
3			**The AMP must include the following:**	
	3.1		A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Exec Summary
	3.2		Details of the background and objectives of the EDB's asset management and planning processes;	2.1; 6
	3.3		A purpose statement which -	
		3.3.1	makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	1; 2.5; 6
		3.3.2	states the corporate mission or vision as it relates to asset management;	2.1
		3.3.3	identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	2.5
		3.3.4	states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	2.5
		3.3.5	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	2.5
			The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.	
	3.4		Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed;	1.1
			Good asset management practice recognises the greater accuracy of short-tomedium term planning, and will allow for this in the AMP. The asset management planning information for the second 5 years of the AMP planning period need not be presented in the same detail as the first 5 years.	
	3.5		The date that it was approved by the directors;	Annexure
	3.6		A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	2.2
		3.6.1	how the interests of stakeholders are identified	2.2
		3.6.2	what these interests are;	2.2
		3.6.3	how these interests are accommodated in asset management practices; and	2.2
		3.6.4	how conflicting interests are managed;	2.2
	3.7		A description of the accountabilities and responsibilities for asset management on at least 3 levels, including	2.2; 2.6
		3.7.1	governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors;	2.6
		3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured; and	2.6

		3.7.3	field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	2.6
	3.8		All significant assumptions	1.3
		3.8.1	quantified where possible;	1.3
		3.8.2	clearly identified in a manner that makes their significance understandable to interested persons, including	1.3
		3.8.3	a description of changes proposed where the information is not based on the EDB's existing business;	N/A
		3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.3
		3.8.5	the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	Annexure 3
	3.9		A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	1.4
	3.10		An overview of asset management strategy and delivery;	2.1; 2.5
			To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify- • *how the asset management strategy is consistent with the EDB's other strategy and policies;* • *how the asset strategy takes into account the life cycle of the assets;* • *the link between the asset management strategy and the AMP; and* • *processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*	
	3.11		An overview of systems and information management data;	9.3
			To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- • the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; • the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; • the systems and controls to ensure the quality and accuracy of asset management information; and • the extent to which these systems, processes and controls are integrated.	
	3.12		A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	9.3
			Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.	
	3.13		A description of the processes used within the EDB for:	

		3.13.1	managing routine asset inspections and network maintenance;	8.1
		3.13.2	planning and implementing network development projects; and	7.1
		3.13.3	measuring network performance;	10.2
	3.14		An overview of asset management documentation, controls and review processes.	2.5; 6
			To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should- *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system;* *(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system.*	
	3.15		An overview of communication and participation processes;	1.2; 2.1; 6.1
			To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should- *(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and* *(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	
	3.16		The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	1.3
	3.17		The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Overall
Assets covered				
4			The AMP must provide details of the assets covered, including	
	4.1		a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including	2.7; 3.1
		4.1.1	the region(s) covered;	2.7
		4.1.2	identification of large consumers that have a significant impact on network operations or asset management priorities;	2.7
		4.1.3	description of the load characteristics for different parts of the network;	3.1
		4.1.4	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	3.1

	4.2		a description of the network configuration, including-	
		4.2.1	identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	3.1
		4.2.2	a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	3.1; 7.2
		4.2.3	a description of the distribution system, including the extent to which it is underground;	3.1
		4.2.4	a brief description of the network's distribution substation arrangements;	3.1
		4.2.5	a description of the low voltage network including the extent to which it is underground; and	3.1
		4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	3.1
			To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.	3.1
	4.3		If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	N/A
Network assets by category				
	4.4		The AMP must describe the network assets by providing the following information for each asset category	3.1
		4.4.1	voltage levels;	3.1
		4.4.2	description and quantity of assets;	3.1
		4.4.3	age profiles; and	3.1
		4.4.4	a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	3.1
	4.5		The asset categories discussed in clause 4.4 should include at least the following	
		4.5.1	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	3.1
		4.5.2	assets owned by the EDB but installed at bulk electricity supply points owned by others;	N/A
		4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	3.1

		4.5.4	other generation plant owned by the EDB.	3.1
Service Levels				
5			The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	5.1; 5.2
6			Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	5.1
7			Performance indicators for which targets have been defined in clause 5 should also include	
		7.1	Consumer oriented indicators that preferably differentiate between different consumer types; and	5.1
		7.2	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	10.2; 10.4
8			The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	5.1
9			Targets should be compared to historic values where available to provide context and scale to the reader.	5.1
10			Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	
			Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.	
Network Development Planning				
11			AMPs must provide a detailed description of network development plans, including—	
	11.1		A description of the planning criteria and assumptions for network development;	7.1
	11.2		Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	7.1
	11.3		A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	6.1; 7.2
	11.4		The use of standardised designs may lead to improved cost efficiencies. This section should discuss	
		11.4.1	the categories of assets and designs that are standardised; and	7.2
		11.4.2	the approach used to identify standard designs;	7.2

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	11.5		A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	
			The energy efficient operation of the network could be promoted, for example, though network design strategies, demand side management strategies and asset purchasing strategies.	
	11.6		A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;	7.1; 7.2
			The criteria described should relate to the EDB's philosophy in managing planning risks.	
	11.7		A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	2.1; 2.2; 7.2
	11.8		Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	7.1
		11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	7.1
		11.8.2	provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	7.1
		11.8.3	identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	7.1
		11.8.4	discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	7.1
	11.9		Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including	
		11.9.1	the reasons for choosing a selected option for projects where decisions have been made;	7.1
		11.9.2	the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	7.1
		11.9.3	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	7.2
	11.10		A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include	7.1
		11.10.1	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	7.1
		11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	7.1

		11.10.3	an overview of the material projects being considered for the remainder of the AMP planning period;	7.1; 7.2; 7.3; 7.5
			For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.	
	11.11		A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	7.2
	11.12		A description of the EDB's policies on non-network solutions, including	
		11.12.1	economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	7.2
		11.12.2	the potential for non-network solutions to address network problems or constraints.	7.2
Lifecycle Asset Management Planning (Maintenance and Renewal)				
12			The AMP must provide a detailed description of the lifecycle asset management processes, including—	6.1
	12.1		The key drivers for maintenance planning and assumptions;	8
	12.2		Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include	8
		12.2.1	the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	8.2
		12.2.2	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	
		12.2.3	budgets for maintenance activities broken down by asset category for the AMP planning period;	8.4
	12.3		Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include	7.3
		12.3.1	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	7.3
		12.3.2	a description of innovations that have deferred asset replacements;	7.3
		12.3.3	a description of the projects currently underway or planned for the next 12 months;	7.3
		12.3.4	a summary of the projects planned for the following four years (where known); and	7.3
		12.3.5	an overview of other work being considered for the remainder of the AMP planning period; and	7.3

	12.4		The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	
Non-Network Development, Maintenance and Renewal				
13			AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	
	13.1		a description of non-network assets;	N/A
	13.2		development, maintenance and renewal policies that cover them;	N/A
	13.3		a description of material capital expenditure projects (where known) planned for the next five years; and	N/A
	13.4		a description of material maintenance and renewal projects (where known) planned for the next five years.	N/A
Risk Management				
14			AMPs must provide details of risk policies, assessment, and mitigation, including—	4
	14.1		Methods, details and conclusions of risk analysis;	4.2
	14.2		Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	4.3; 4.4
	14.3		A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	4.4
	14.4		Details of emergency response and contingency plans.	4.4
			Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.	
Evaluation of performance				
15			AMPs must provide details of performance measurement, evaluation, and improvement, including—	
	15.1		A review of progress against plan, both physical and financial;	10.1; 10.2
			• *referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;* • *commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and* • *commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.*	
	15.2		An evaluation and comparison of actual service level performance against targeted performance;	10.2

			• *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.*	
	15.3		An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	10.4; Schedule 13
	15.4		An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	10.4
Capability to deliver				
16			AMPs must describe the processes used by the EDB to ensure that-	
	16.1		The AMP is realistic and the objectives set out in the plan can be achieved; and	1.3; 9.1
	16.2		The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	1.2; 2.6

Annexure 6 – Directors Approval

We, Peter William Moynihan (Chair) and Murray John Wallace, being directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a. The attached information of The Power Company Limited prepared for the purposes of clauses 2.6.1 and 2.6.6 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b. The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c. The forecasts in Schedules 11a, 11b, 12a, 12b, 12c, 12d and 14a are based on objective and reasonable assumptions which both align with The Power Company Limited corporate vision and strategy and are documented in retained records.

Peter William Moynihan (Chair)

Murray John Wallace

26 March 2025

Date