THE POWER COMPANY LTD

Asset Management Plan 2015 to 2025

Publicly disclosed in March 2015

Contents

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0. Summary

Reference to the Electricity Distribution Information Disclosure Determination 2012 (EDIDD) is done with the superscript clause number in square brackets. i.e. [A.3.1] refers to "EDIDD Attachment A, clause 3.1"

This section summarises some of the main points from the Asset Management Plan. [A.3.1]

0.1 Background and Objectives

The purpose of the AMP is to provide a governance and management framework that ensures that The Power Company Limited (TPCL):

- Sets service levels for TPCL's electricity network that will meet customer, community and regulatory requirements.
- Understands the network capacity, reliability and security of supply that will be required both now and in the future and the issues that drive these requirements.
- Have robust and transparent processes in place for managing all phases of the network life cycle from commissioning to disposal.
- Has adequately considered the classes of risk TPCL's network business faces and that there are systematic processes in place to mitigate identified risks.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of TPCL's asset locations, ages, conditions and the assets' likely future behaviour as they age and may be required to perform at different levels.

TPCL works to the below strategies at the corporate and asset level:

Corporate Strategies

- Provide its customers with above average levels of service.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Understand and effectively manage appreciable business risk.
- Manage operations in a progressive and commercial manner.
- Strive to be an efficient but effective operation.

Asset Management Strategies

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring & refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
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		✓	✓		✓

This plan covers the period 1 April 2015 to 31 March 2025, and was approved by the TPCL Board on 25 March 2015.

Management of the assets is undertaken by PowerNet Limited which uses a mixture of internal and external contractors to operate, maintain, renew, upsize and expand the network. As some works are tendered, costs of individual projects are not publicly disclosed in this document.

The processes and systems used by PowerNet are described in section 8.

0.2 Details of the assets

TPCL supplies 34,762 customers in Southland and Western Otago, with a population of 61,728. Key industries within TPCL's network area include sheep, beef and dairy farming, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism.

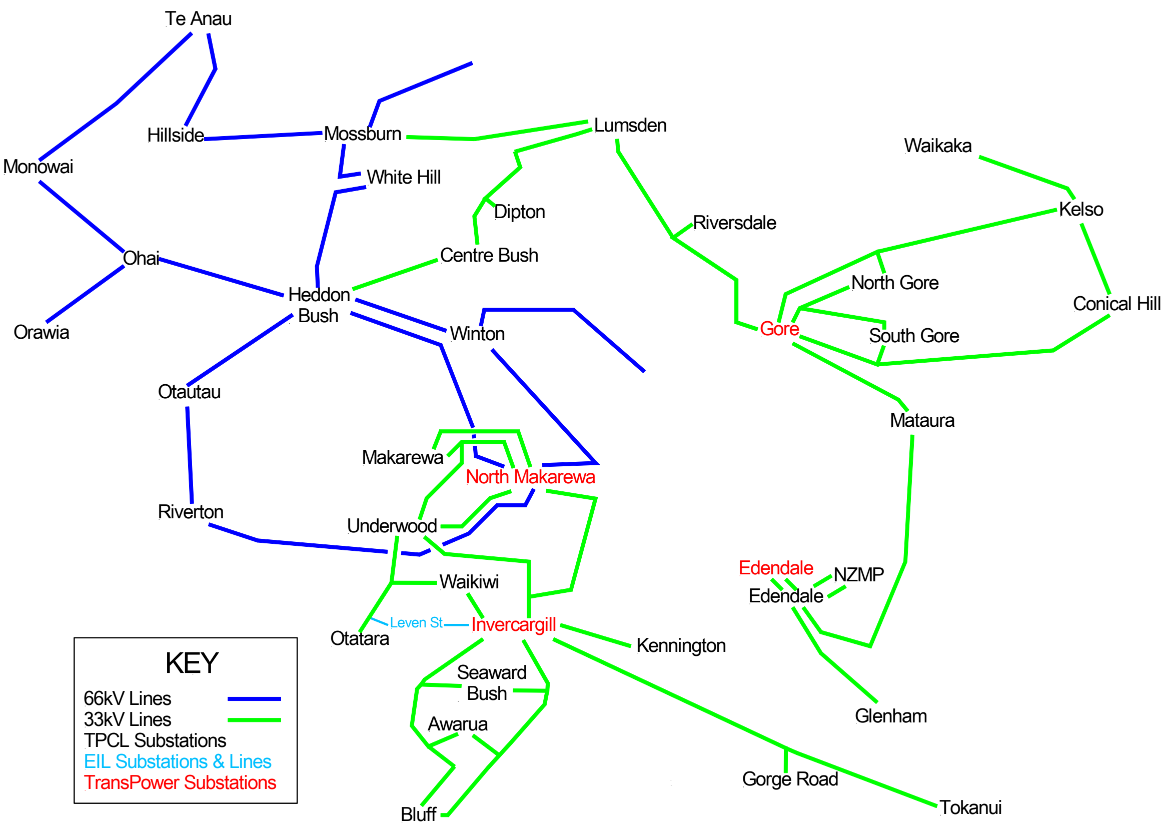


Figure 1 Overview of TPCL Subtransmission Network 1 April 2014

There is:

- 386km of 66kV lines and 466km of 33kV lines and cables.
- 35 zone substations to transform High Voltage (HV) to Medium Voltage (MV).
- Two 11kV feeders supplied from Electricity Invercargill Limited's Racecourse Road Substation.
- 6,753 km of 11kV lines and 126km of 11kV cables.
- 10,895 distribution transformers supplying 34,762 customers.
- 28 Voltage regulator sites, controlling local voltage.
- The low voltage (230V) has 854 km of lines and 215km of cable.

The age of the network is average with approximately 49.7%of its Standard Life (as prescribed in the Commerce Commission ODV Handbook) remaining and most assets are in good condition.

0.3 Proposed Service Levels

Customers are content with the present level of service and no major changes in service levels are proposed. This was the outcome of customer consultation undertaken by telephone survey, one-on-one meetings and public meetings.

The surveyed customers have indicated that they value continuity and then restoration most highly; therefore TPCL's primary service levels are continuity and restoration. To measure performance in this area two internationally accepted indices have been adopted:

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

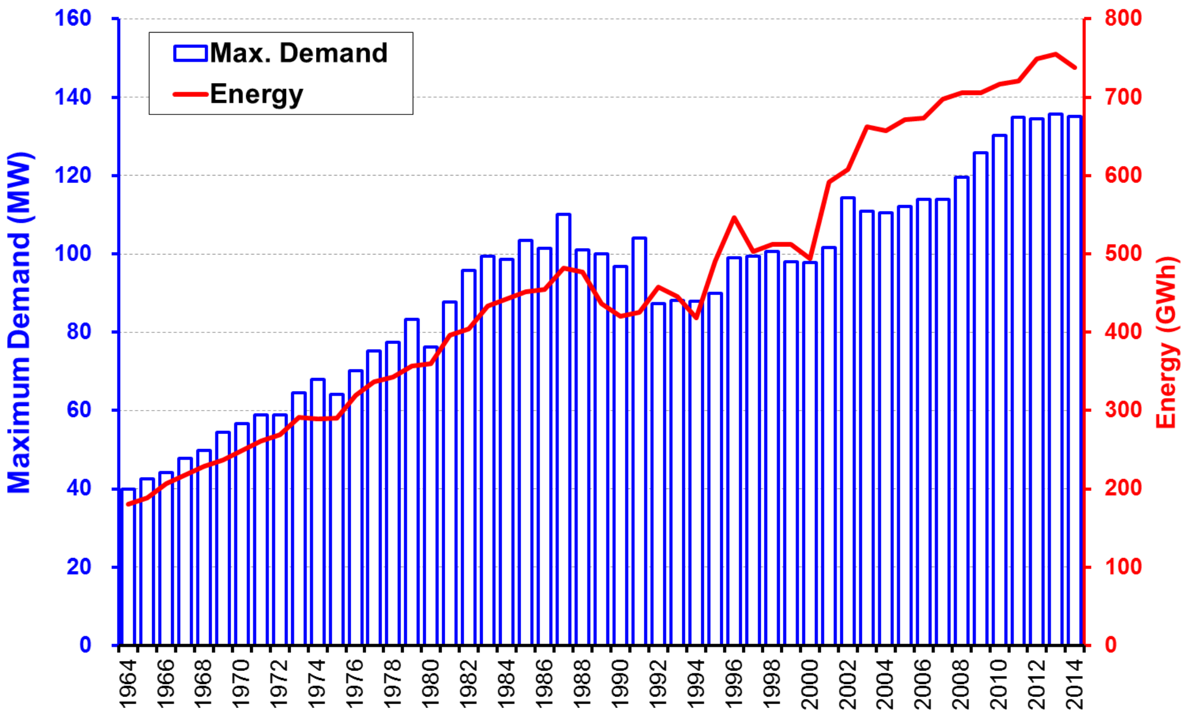
TPCL's targets for these measures for the next ten years are set out below. These reliability projections take into account the new default price path calculation methodology including new extreme event normalising boundaries and a 50% weighting for planned outages.

	Normalised SAIDI			Normalised SAIFI		
	Class B (Planned)	Class C (Unplanned)	Total	Class B (Planned)	Class C (Unplanned)	Total
2015/16	35.74	120.25	155.99	0.178	2.499	2.680
2016/17	35.74	116.40	152.14	0.178	2.443	2.621
2017/18	35.74	113.84	149.58	0.178	2.388	2.566
2018/19	36.74	111.34	148.07	0.178	2.334	2.512
2019/20	36.74	109.67	146.40	0.178	2.322	2.500
2020/21	36.74	108.02	144.76	0.178	2.311	2.489
2021/22	36.74	107.48	144.22	0.178	2.299	2.477
2022/23	36.74	106.94	143.68	0.178	2.288	2.466
2023/24	36.74	106.41	143.15	0.178	2.276	2.454
2024/25	36.74	105.88	142.61	0.178	2.265	2.443

The target for Losses (8.0%) and Load Factor (65%) are not planned to improve over the next ten years with Capacity utilisation improving from 30% to 31%.

0.4 Development Plans

The maximum demand on the network has increased 2.1% per annum over the last 10 years with energy increasing by 1.2% per annum.



The network will be upsized to meet this expected growth with reviews of loadings at zone substations used to trigger actual projects. Large customer or generator connections will require major expansion of the present network and these will be budgeted for when their location and load requirements are known. Work programmed for Northern Southland is part of that required to service large customer growth and allow a suitable backup of supply.

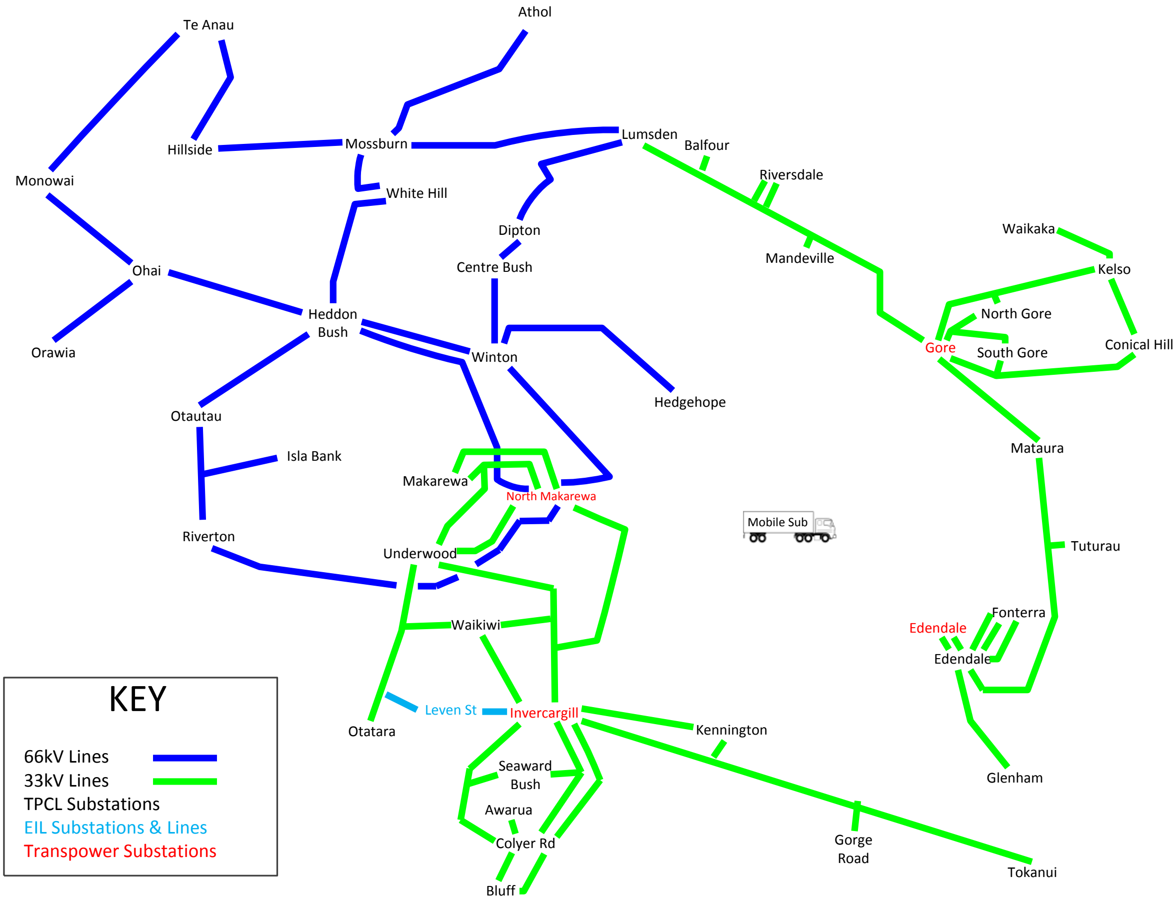
The focus for the next ten years is to maintain service levels by:

- Improving safety at zone substations.
- Upgrading areas to maintain acceptable voltages.
- Renewing unsafe and poorly performing assets.
- Meeting customer and distributed generator requests for new connections.
- Improving efficiency of the network by up-sizing of lines that have high losses and exchanging overloaded distribution transformers with currently installed underutilised units.
- Extending remote monitoring and control to field devices.

Renewals of lines, transformers, air break switches and drop-out fuses are expected to have a significant on-going cost.

Capital expenditure each year varies from $31.1 million in 2015/2016 to $16.3 million in 2024/2025.

Planned subtransmission network for 2025:



0.5 Managing the asset's lifecycle

The asset lifecycle used by TPCL once assets are built, is: Operation, Maintenance, Renewal, Up-sizing, Extensions and Retirement.

Analysis is done to review network operation to check if any trigger is exceeded and actions planned to maintain planned service levels.

Routine and corrective maintenance and inspection of assets is expected to cost $3.3 million p.a.

Asset refurbishment and renewal maintenance is planned to spend $1.1 million p.a.

Tree trimming to comply with the Trees regulations is expected to cost $1.3 million p.a.

Service Interruptions and Emergencies are expected to cost $2.8 million p.a.

0.6 Risk Management

The business is exposed to a wide range of risks. This section examines TPCL's risk exposures, describes what it has done and will do about these exposures and what it will do when disaster strikes.

Risk management is used to bring risk within acceptable levels.

0.7 Funding the business

TPCL's revenue is primarily from retailers who pay for conveying energy over TPCL's lines and from customer contributions for the uneconomic portion of new connections or upgrades.

Customer surveys found that only 10% would like to pay more for an improvement in service, so this is insufficient to warrant a change in the rate of maintaining and renewing the network.

0.8 Processes and systems

TPCL's management company PowerNet uses a system based on ISO9000 quality system but has not maintained certification. Asset information resides in three key locations: Geographical Information System (GIS), Asset Management System (AMS), and Supervisory Control And Data Acquisition (SCADA). Some of this information is excellent but the accuracy of pole ages is poor with 57% having estimated ages.

Condition information is planned to be better collected by use of a scanned form to collect the 20% of the network inspected each year. Planners can then use this data to plan work more efficiently.

0.9 Performance and improvement

Performance targets set in the 2013 - 2023 AMP have generally been achieved.

For the 2013/14 year the network performed well with actual SAIFI of 2.87 within the SAIFI target of 3.21 system interruptions per customer, however actual SAIDI of 177.8 customer-minutes exceeded the target SAIDI of 161.75 customer-minutes.

Capital expenditure was $3.0M over the budgeted $19.5M, but some major projects were not completed due to:

- Contractor disturbance with one alliance contactor closing their business in the region.
- Significant changes in Project Management staff.

Operational expenditure on maintenance was $1.3M over the $7.5M budget.

Some strategies are planned to improve performance and achieve targets.

0.10 Feedback and comments

Comment on this plan is welcome and should be addressed to the Chief Engineer, PowerNet Ltd, PO Box 1642, Invercargill or email amp@powernet.co.nz. The next review of this AMP is planned for publishing in March 2016.

1. Background and objectives

1.1 Background

The Power Company Limited (TPCL) is the electricity lines business that conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff) to approximately 34,762 customer connections on behalf of eight energy retailers. The wider TPCL entity also includes the following associations:

- A 50% stake in PowerNet, an electricity lines management company jointly owned with Electricity Invercargill. This is an unregulated entity and is therefore not subject to any disclosure requirements.
- A 75.1% stake in Electricity Southland Limited (ESL), which distributes electricity in the Frankton area of Central Otago. ESL is currently below the thresholds for disclosure.
- A 75.1% stake in OtagoNet. The entity for disclosure is OtagoNet JV, and its AMP is prepared and disclosed by PowerNet in Invercargill which manages the OtagoNet assets along with those of Electricity Invercargill and TPCL.
- A 50% stake in Otago Power Services Ltd, an electrical contracting company based in Balclutha.

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

This AMP deals solely with the TPCL electricity network assets and non-network assets as defined by the Electricity Distribution Information Disclosure Determination 2012 (EDIDD).

The TPCL's Asset Management and Planning Processes are based on pervious AMP's, company standards and processes (e.g. PNM-105). These develop an annual works programme (AWP) for the coming two years. [A.3.2.]

The objective for TPCL's Asset Management and Planning Processes is to maintain and develop the TPCL assets to achieve each stakeholder's target service levels. [A.3.2.]

1.2 Purpose of the Asset Management Plan [A.3.3.]

The purpose of the AMP is to provide a governance and management framework that ensures that TPCL [A.3.3.1]:

- Sets service levels for its electricity network that will meet customer, community and regulatory requirements.
- Understands the network capacity, reliability and security of supply that will be required both now and in the future and the issues that drive these requirements.
- Has robust and transparent processes in place for managing all phases of the asset life cycle from commissioning to disposal.
- Has adequately considered the classes of risk TPCL's network business faces and that there are systematic processes in place to mitigate identified risks.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of TPCL's asset locations, ages, conditions and the assets' likely future behaviour as they age and may be required to perform at different levels.

Status of this AMP is 'Embedding' with most processes are in use in PowerNet and the contractors. [A.3.3.1]

Disclosure of TPCL's AMP in this format will also assist in meeting the requirements of Section 2.6 of the Electricity Distribution Information Disclosure Determination 2012.

This AMP is intended to be a general description of TPCL's assets (with details in other parts of the business), and also a description of the thinking, the policies, the strategies, the plans and the resources that TPCL uses and will use to manage the assets.

1.3 Interaction with other goals and drivers

All of the assets exist within a strategic context that is shaped by a wide range of issues including TPCL's vision statement, asset strategy, the prevailing regulatory environment, government policy objectives, commercial and competitive pressures and technology trends. TPCL's assets are also influenced by technical regulations, asset deterioration, the laws of physics and risk exposures independent of the strategic context.

1.3.1 Strategic context

TPCL's strategic context includes many issues that range from the state of the local economy to developing technologies. Issues that TPCL considers include:

- The prevailing regulatory environment which monitors prices and reliability, and requires TPCL to compile and disclose performance and planning information.
- Government policy objectives, such as the promotion of distributed generation (particularly renewables) and efficiency.
- TPCL's commercial goal is primarily to deliver sustainable earnings to TPCL's owners that are the best use of their funds.
- Competitive pressures from other lines companies which might try to supply TPCL customers.
- Pressure from substitute fuels both at end-user level (such as substituting electricity with coal or oil at a facility level) and at bulk generation level (wind farms).
- Advancing technologies such as gas-fired fuel cells that could strand conventional wire utilities.
- Local, national and global economic cycles, in particular the trends in global pastoral commodity prices which can influence the use of land from very passive to very electro-intensive.
- The need for water to irrigate pasture land in Northern Southland, and the associated District and Regional polices.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- The economic climate and 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.

1.3.2 Independence from strategic context

It is also important to recognise that although TPCL's assets must be shaped by the strategic issues identified in section 1.3.1 they will also be influenced (and even constrained) by issues that are independent of the strategic context.

These issues include:

- Technical regulations including such matters as limiting harmonics to specified levels.
- Asset configuration, condition and deterioration. These parameters will significantly limit the rate at which TPCL can re-align 8,600km of lines and 10,500 transformers to fit ever-changing strategic goals.
- The laws of physics which govern such fundamental issues as power flows, insulation failure and faults.
- Physical risk exposures. Exposure to events such as flooding, wind, snow, earthquakes and vehicle impacts are generally independent of the strategic context. Issues in which TPCL's risk exposure might depend on the strategic context could be in regard to natural issues such as climate change (increasing severity and frequency of storms) or regulatory issues (say if Land Transport NZ required all poles to be moved back from the road edge).
- Safety requirements such as earthing of exposed metal and line clearances.

1.3.3 Annual business plan and works plans

Each year, the first two years of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into TPCL's annual business plan. This defines the priorities and actions for the years ahead which will contribute to TPCL's long-term alignment with the strategic context, fully understanding that this alignment process is very much one of "moving goal posts".

An important component of the annual business plan is the annual works program which scopes and costs each individual activity or project that the company expects to undertake in the two years ahead. A critical activity is to firstly ensure that this annual works program accurately reflects the current year's projects in the AMP and secondly ensure that each project is implemented according to the scope prescribed in the works program. [A.3.3.3.]

1.4 Key planning documents

The key planning documents are expanded below and the interactions of the key planning issues, processes and documents are shown in Figure 2:

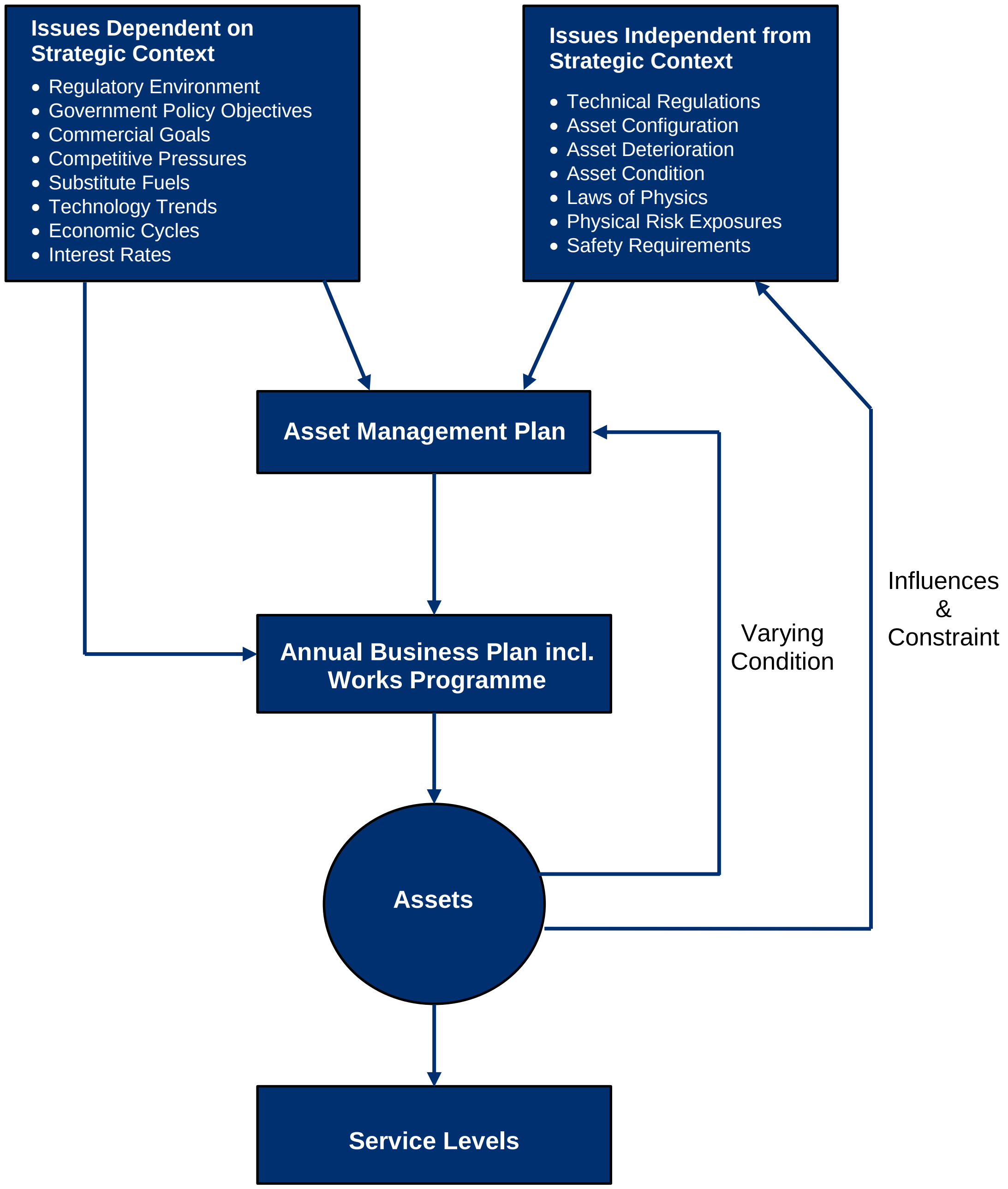


Figure 2 - Interaction of key plans

1.4.1 Statement of intent (SOI)

TPCL's SOI is a requirement under the constitution of the company, and forms the principal accountability mechanism between TPCL's board and the shareholder; the Southland Electric Power Supply Power Consumers Trust (SEPSCT). The SOI includes performance and reliability projections, which form the heart of the asset management activity and implicitly recognise the inherent trade-off between price and supply quality.

The SOI is available at http://www.powernet.co.nz in the Line Owners area under Company Information.

1.4.1.1 2014 Performance targets: Financial

EBIT% - Percentage Group Earnings Before Tax and Interest on Assets Employed

	2015	2016	2017	2018	2019
NPBT	6,951,156	8,492,894	10,066,042	11,458,046	12,931,637
Interest	1,583,932	1,733,908	1,845,840	1,751,748	1,488,463
Net Profit Before Interest & Tax	8,535,088	10,226,803	11,911,882	13,209,794	14,420,100
Total Assets	437,851,671	448,864,293	454,946,462	457,727,185	458,124,187
EBIT %	**1.95%**	**2.28%**	**2.62%**	**2.89%**	**3.15%**
EBIT % (excluding discount)	**3.68%**	**3.88%**	**4.11%**	**4.28%**	**4.45%**

NPAT% - Percentage Group Tax Paid Profit on Equity

	2015	2016	2017	2018	2019
NPAT	5,104,577	6,182,164	7,299,142	8,274,955	9,303,006
Equity	324,484,986	330,801,398	338,270,717	346,775,044	356,294,704
NPAT %	**1.57%**	**1.87%**	**2.16%**	**2.39%**	**2.61%**
NPAT % (excluding discount)	**3.44%**	**3.79%**	**4.12%**	**4.38%**	**4.64%**

Percentage of Consolidated Equity to Total Assets

	2015	2016	2017	2018	2019
Equity	324,484,986	330,801,398	338,270,717	346,775,044	356,294,704
Total Assets	437,851,671	448,864,293	454,496,462	457,727,185	458,124,187
% Equity/ Total Assets	**74.11%**	**73.70%**	**74.43%**	**75.76%**	**77.77%**

1.4.1.2 2014 Performance targets: Quality

SAIFI - System Average Interruption Frequency Index (the average number of times each customer connected to the network is without supply)

2015	2016	2017	2018	2019
2.96	2.875	2.796	2.719	2.692

SAIDI - System Average Interruption Duration Index (the average total time in minutes each customer connected to the network is without supply)

2015	2016	2017	2018	2019
195.19	188.94	182.89	177.04	175.27

1.4.2 Vision statement [A.3.3.2.]

To be recognised as the top performing trust owned rural line company and an excellent corporate citizen.

1.4.3 Strategic plan

Key asset management drivers from TPCL's Strategic Plan are:

1. Manage its operations in a progressive and commercial manner.

2. Undertake new investments, which are:
    - Relevant to the core business.
    - Aimed at yielding a return appropriate for the degree of risk.
    - Undertaken in a manner which will maximise the commercial value of the business.
3. Strive to become an efficient and effective operation within the electricity industry and provide its customers with competitive prices and above average levels of service.

1.4.4 Asset strategy [A.3.10.]

TPCL's asset strategy follows these guiding principles:

- Safety by design using the ALARP (as low as reasonable practicable) risk principle
- Minimise long term service delivery cost through condition monitoring and refurbishment
- Replace assets at their (risk considered) economic end of life
- 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

1.4.5 Prevailing regulatory environment

Because TPCL is consumer controlled, it will not be subject to the Default Price-Quality Path regime under Part 4 of the Commerce Act 1986.

However TPCL will continue to be subject to an information disclosure requirement (including the requirement to publish an AMP) along with other structural regulations such as restrictions on generating and retailing energy, and the requirement to connect embedded generation.

1.4.6 Government objectives

Electricity lines businesses are being increasingly required to give effect to many aspects of government policy, namely:

- Facilitating the connection of distributed generation on a regulated basis.
- Improving the already high levels of public safety around power lines and transformers.
- Offering increasingly variable tariffs to promote demand reduction.

1.4.7 Annual business plan

An Annual Business Plan (ABP) is produced by PowerNet and contains the following:

- Core Business, Vision Statement and Strategies.
- Commercial Objectives, The Nature and Scope of Commercial Activity and Company Polices.
- Two year Works Programme and the Annual Works Plan (AWP) for the following three years.
- Business Plan Financials and Business Unit Reports.

1.4.8 Annual works plan [A.3.3.3.]

The Annual Works Plan (AWP) is produced by PowerNet, as a result of our planning processes, and details the works to be undertaken for each financial year, and is incorporated into the ABP. All of the next five year's works, listed in the AMP, are included in the AWP.

1.5 Interaction of goals / strategies [A.3.3.5.]

The table below shows the linkage between the Corporate and Asset Management Strategies.

Corporate Strategies

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring & refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
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		✓	✓		✓

1.6 Period covered by the Asset Management Plan

This edition of TPCL's AMP covers the period 1 April 2015 to 31 March 2025 [A.3.4.]. This AMP was prepared during November 2014 to March 2015, approved by TPCL's Board 25th March 2015 [A.3.5.] and publicly disclosed at the end of March 2015.

There is a degree of uncertainty in any predictions of the future, and accordingly the AMP is uncertain. Customer demand driven by turbulent commodity markets, public policy trends and possible generation opportunities within TPCL's demand profile means the future is perhaps less certain than many similar infrastructure businesses that have greater scale. Accordingly TPCL has attached the following certainties to the timeframes of the AMP:

Timeframe	Residential and Commercial	Large Industrial	Intending Generators
Year 1 to 2	Very certain	Reasonably certain	Reasonable certainty
Years 3 to 5	Certain	Little if any certainty	Little if any certainty
Years 6 to 10	Little if any certainty	Little if any certainty	Little if any certainty

1.7 Stakeholder interests

1.7.1 Stakeholders [A3.6.1]

A stakeholder is defined as any person or class of persons who may do one or more 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 it is in an 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, District plan requirements).

1.7.2 Stakeholder interests [A.3.6.2.]

The interests of the stakeholders are defined in Table 1 below:

Table 1 - Key stakeholder interests

	Interests				
Stakeholder	**Viability**	**Price**	**Quality**	**Safety**	**Compliance**
Shareholder - SEPSCT	✓	✓	✓	✓	✓
Bankers	✓	✓			✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Energy Retailers	✓	✓	✓		
Mass-market Representative Groups	✓	✓	✓		
Industry Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Suppliers of Goods and Services	✓				
Public (as distinct from customers)				✓	✓
Land owners				✓	✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Ministry of Economic Development		✓	✓	✓	✓
Energy Safety Service				✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Ministry of Consumer Affairs			✓		✓

Table 2 demonstrates how stakeholder's expectations and requirements are identified.

Table 2 How Stakeholder's expectations are identified

Stakeholder	How expectations are identified
SEPS Consumer Trust	By their approval or required amendment of the SOI Regular meetings between the directors, executive and the trustees
Bankers	Regular meetings between the bankers and PowerNet's Chief Executive and Chief Financial Officer. By producing a TPCL's treasury/borrowing policy By agreeing to banking covenants
Connected Customers	Regular discussions with large industrial customers as part of their on-going development needs Annual customer surveys
Contracted Manager (PowerNet)	Board Chairman weekly meeting with the Chief Executive
Energy Retailers	Annual consultation with retailers
Mass-market Representative Groups	Informal contact with group representatives
Industry Representative Groups	Informal contact with group representatives
Staff & Contractors	Regular staff briefings Regular contractor meetings
Suppliers of Goods & Services	Regular supplier meetings Newsletters
Public (as distinct from customers)	Informal talk / gossip around the district Feedback from the Trust's public meetings
Land Owners	Individual discussions as required
Councils (as regulators)	Formally as necessary to discuss issues such as assets on Council land Formally as District Plans are reviewed
Transport Agency	Formally as required
Ministry of Economic Development	Regular bulletins on various matters Release of legislation, regulations and discussion papers Analysis of submissions on discussion papers
Energy Safety Service	Promulgated regulations and codes of practice Audits of TPCL's activities Audit reports from other lines businesses
Commerce Commission	Regular bulletins on various matters Release of discussion papers Analysis of submissions on discussion papers Conferences following submission process
Electricity Authority	Weekly update Release of discussion papers Briefing sessions Analysis of submissions on discussion papers Conferences following submission process General information on their website
Electricity & Gas Complaints Commission	Reviewing their decisions in regard to other lines companies
Ministry of Consumer Affairs	Release of legislation, regulations and discussion papers General information on their website

1.7.3 Meeting stakeholders' interests [A.3.6.3.]

Table 3 provides a broad indication of how stakeholders' interests are accommodated:

Table 3 - Meeting stakeholder interests

Interest	Description	How TPCL meets interests
Safety	Staff, contractors and the public at large must be able to move around and work on the network in total safety.	The public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, all enclosures are kept locked and all exposed metal is earthed. The safety of our staff and contractors is ensured by providing all necessary equipment, improving safe work practices and ensuring that they are stood down in unsafe conditions. Contractors will use all necessary safety equipment, improve their safe work practices and ensure that they stand down in unsafe conditions. 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 in regard to private land and road reserve.
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in TPCL.	Stakeholders' 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 maintain Service Levels within targets and the revenue set to provide the required returns.
Price	Price is a key means of both gathering revenue and signalling underlying costs. Getting prices wrong could result in levels of supply reliability that are less than or greater than TPCL's customers want.	Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders. TPCL's pricing methodology is expected to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.
Supply quality	Emphasis on continuity, restoration of supply and reducing flicker is essential to minimising interruptions to customers' businesses.	Stakeholders' needs for supply quality will be accommodated by focusing resources on continuity and restoration of supply. The most recent mass-market survey indicated a general satisfaction with the present supply quality but also with many customers indicating a willingness to accept a reduction in supply quality in return for lower line charges.
Compliance	Compliance is necessary with many statutory requirements ranging from safety to disclosing information.	All safety issues will be adequately documented and available for inspection by authorised agencies. Performance information will be disclosed in a timely and compliant fashion.

1.7.4 Managing conflicting interests [A.3.6.4.]

The process for handling conflicting stakeholder interests is as follows:

- Conflict identified.
- Analysis of issues and options using the following priority hierarchy:
  - Safety. Top priority is given to safety. The safety of staff, contractors and the public will not be compromised even if budgets are exceeded.
  - Viability. Second priority is viability, because without it TPCL will cease to exist which makes supply quality and compliance pointless.
  - Pricing. TPCL will give third priority to pricing as a follow on from viability (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.
  - Supply quality is the fourth priority. Good supply quality makes customers, and therefore TPCL, successful.
  - Compliance. A lower priority is given to compliance that is not safety and supply quality related.
- Report with recommendation made to management.
- Decision made by Senor Leadership Team, or escalated to TPCL board.

1.7.5 Customer consultation [DD-3.15]

Consultation was undertaken by three methods: First was a phone survey of 400 customers undertaken by external consultants. A copy of the questionnaire used is attached in appendix A. Only 6% willing to pay $10 per month increase in the electricity bill to improve reliability (was 8% in previous survey.) Customer expectations are projected to increase with lesser tolerance to outages and experience of few outages raising the bar.

The second method was a face to face survey by the survey company with eight key clients. The outcome was that all didn't want to pay more for improved reliability and wanted more personal contact from PowerNet's Engineers.

Lastly, individual customers are consulted as they undertake connection to the network. For example, the connection of the distributed generation at White Hill required numerous options and negotiation before the final contract for supply was agreed.

1.8 Accountabilities for asset management [A.3.7]

TPCL's ownership, governance and management structure is depicted in Figure 3:

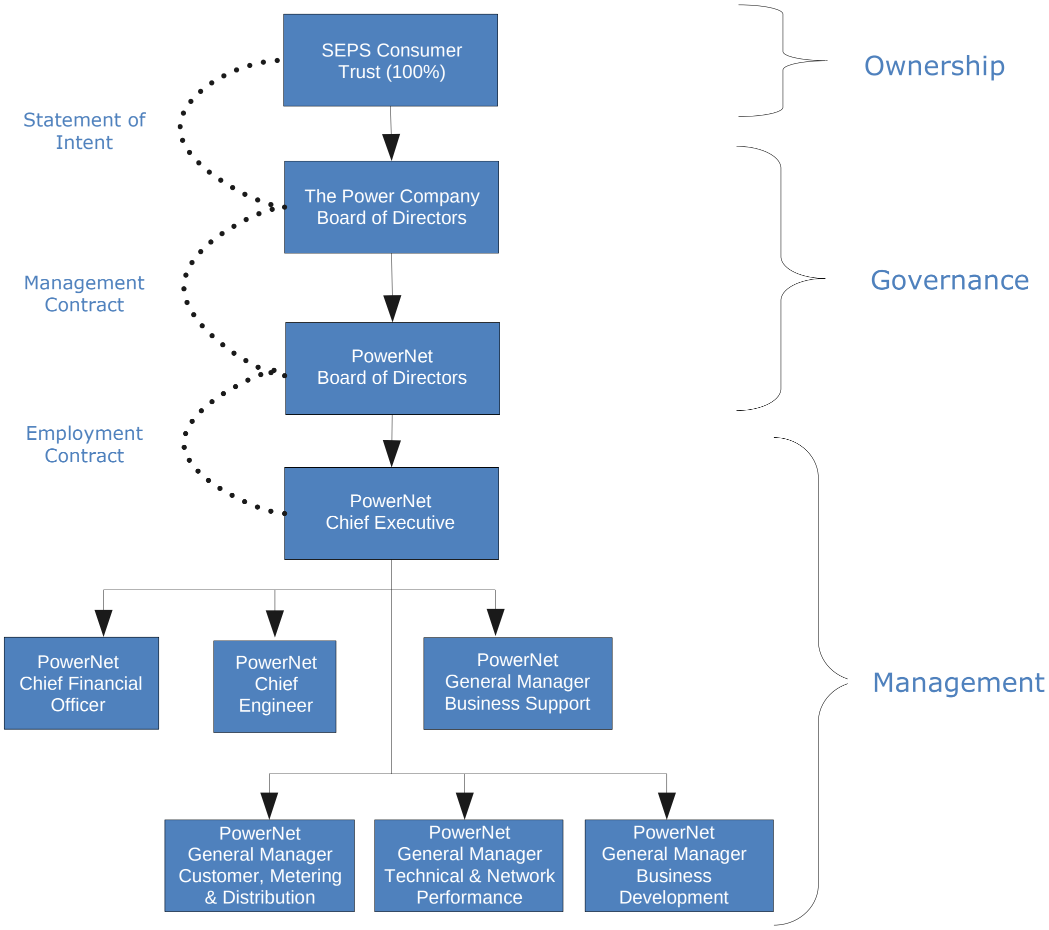


Figure 3 - Governance and management accountabilities

The ultimate accountability is to the connected customers, and it is therefore pleasing to note that the Commerce Amendment Bill has recognised this accountability and removes the price path threshold for such consumer controlled lines businesses.

1.8.1 Accountability at ownership level

TPCL has a single shareholder – the SEPS Consumer Trust. The Trust currently has five trustees who collectively possess 65,751,836 shares in TPCL on behalf of the Trust:

- Jim Hargest (Chairman)
- Wade Devine
- Carl Findlater
- Graham Sycamore
- David Rose

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.

1.8.2 Accountability at governance level [A.3.7.1.]

As TPCL uses a contracted management company (PowerNet Limited) to manage the assets, there is effectively a two-tier governance structure as follows:

The first tier of governance accountability is between TPCL's Board and shareholder with the principal mechanism being the Statement of Intent. Inclusion of reliability 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 reliability.

TPCL currently has four directors:

- Alan Harper (Chairman)
- Duncan Fea
- Douglas Fraser
- Maryann Macpherson

The second tier of governance accountability is between TPCL's Board and the PowerNet Board with the principal mechanism being the management contract that specifies a range of strategic and operational outcomes to be achieved.

1.8.3 Accountability at executive level [A.3.7.2.]

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.

1.8.4 Accountability at management level [A.3.7.2.]

There are six level two managers reporting directly to PowerNet's Chief Executive with the principal accountability mechanisms being their respective employment agreements.

The individual manager who has the most influence over the long-term asset management outcomes will be the Chief Engineer through preparation of the AMP which will guide the nature and direction of the other managers' work.

1.8.5 Accountability at operational level [A.3.7.3.]

PowerNet's Customer Metering and Distribution Services and Technical and Network Performance teams manage the work to achieve the outcomes in the Annual Works Plan. Data and information from inspections and checks are used to plan works for the following years.

Where additional external contractors are required, contracts will be utilised, structured on the following mechanisms:

- Purchase Order – generally only minor work
- Fixed Lump Sum Contract – generally on-going work
- 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.

1.8.6 Accountability at work-face level [A.3.7.3.]

With the recent amalgamation of Power Services with PowerNet (continuing under the name PowerNet) along with the attraction of additional technical staff the majority of field work is now done by internal field staff. The field staff are managed within PowerNet's Customer Metering and Distribution Services and Technical and Network Performance teams. External contractors are used when necessary to supplement workforce capacity or skillsets and include;

- DECOM Limited
- Transfield Services E & T NZ Limited
- Electrix Services Limited
- Otago Power Services Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Total Power Services Limited
- Asplundh Tree Expert (NZ) Limited

- Cory's Limited
- Consultants (Mitton Electronet, Edison, Beca, SKM, S Sinclair, Millpower)

The principal accountability mechanism is through contracts that reflect the outcomes PowerNet must create for TPCL.

1.8.7 Key reporting lines [A.3.10]

The trust receives a monthly report from the Chief Executive and Chief Financial Officer.

The TPCL board receives a monthly report that covers the following items:

- Network reliability – this lists all outages over the last month and trends regarding the SOI reliability targets.
- Network Quality – detail of outstanding voltage complaints and annual statistics on them.
- 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 fees received.
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network.
- Works Programme – monthly and year-to-date (YTD) expenditure on each works programme item and percentage complete, with notes on major variations.

Each level of management has defined financial limits in the PowerNet Financial Authorities Policy. This requires any new project over $100,000 or variation to the approved Annual Works Plan by more than +10% or -30%, to have Board approval with capital projects over $1,000,000 supported by a business case report.

1.9 Systems and processes [A.3.13]

Systems and processes are described in section 8 of this AMP.

2. Details of the assets

This section summarises TPCL's assets and asset configurations, but begins by describing TPCL's geographical coverage, what sort of activities the underlying community uses electricity for, and the issues that are driving key asset parameters such as demand changes.

2.1 Distribution area

2.1.1 Geographical coverage [A.4.1.1.]

TPCL's distribution area broadly covers all of Southland as depicted in Figure 4 except for Bluff and the 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. Broadly corresponds to the Southland and Gore District Council jurisdictions.

Figure 4 - TPCL distribution area

Topography varies as follows:

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

2.1.2 Demographics

The population of TPCL's distribution area is approximately 61,728. Classification of areas within TPCL's distribution area is as follows:

		2013 Census[1]		2026 Projection[2]			
Description	**Includes**	**Count**	**≥ 65**	**Low**	**Medium**	**High**	**≥ 65**
City	Parts of Invercargill not supplied by EIL	9,760	19%	8,320	9,330	10,440	24%
Large Town	Gore	7,560	22%	5890	6770	7750	32%
	Otatara	2.620	11%	2430	2700	2980	18%
	Winton	2,260	26%	1810	2000	2230	35%
	Te Anau	1,950	16%	2010	2160	2330	20%
	Mataura	1,560	15%	1140	1350	1570	23%
	Riverton	1,460	26%	1250	1420	1600	32%
Small Town	Tapanui	740	26%	590	660	740	32%
	Otautau	680	10%	580	650	740	20%
	Wallacetown	680	19%	590	650	720	19%
	Edendale	570	25%	390	440	500	26%
	Tuatapere	570	18%	440	490	550	31%
	Wyndham	550	18%	380	430	480	23%
	Lumsden	420	17%	320	370	420	21%
	Riversdale	380	16%	340	390	450	16%
	Ohai	320	19%	250	280	310	23%
	Nightcaps	300	23%	250	270	300	37%
	Woodlands	270	11%	180	210	230	22%
	Manapouri	230	22%	290	310	340	29%
	Mossburn	210	19%	160	190	210	24%
Rural	Anywhere else	28,638	11%	25076	27833	30806	32%
Total		61,728	15%	52686	58903	65696	22%

It is interesting to note the number of people 65 years and older is projected to increase from 15% in 2013 to 22% in 2026 and that under low and medium projections population is forecast to decrease.

2.1.3 Key industries [A.4.1.2.]

Key industries within TPCL's network area include sheep, beef and dairy farming, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism. Most of the large and small towns listed in section 2.1.2 above are rural service towns. 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 as follows:

[1] 2013 Census Statistics
[2] 2006 Statistics NZ Population Projection, updated December 2012

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

The recent global economic slowdown may well dampen demand growth as the rural sector hesitates to increase dairy shed and irrigation capacity.

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 Ltd dairy plant, Edendale - two 33kV cables each supplying an 11½/23MVA 33/11kV power transformer (N-1 requirement[3]).

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

- Alliance Group Ltd, freezing works at Lorneville, Mataura and Makarewa – generally one or two exclusive 11kV feeders (N-1 requirement).
- Bright Wood NZ Ltd, sawmill at Otautau – exclusive 11kV feeder from substation.
- Craigpine Timber Ltd, sawmill at Winton – supplied off local feeder.
- Niagara Sawmilling Co Ltd sawmill at Kennington – supplied off local feeder for industrial area.
- Lindsay & Dixon Ltd, sawmill at Tuatapere – supplied off local feeder.
- Blue Sky Meats Ltd, 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[4]).
- Open Country Dairy, at Awarua – supplied off local feeder.
- South Pacific Meats, at Awarua – supplied off local feeder.
- Balance Agri-Nutrients Ltd, at Awarua – supplied off local feeder.
- Silver Fern Farms Ltd:
    - Venison abattoir at Mossburn – supplied off local feeder.
    - 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).
- South Wood Export Ltd, 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.

2.1.4 Load Characteristics [A.4.1.3.]

Domestic: Standard household usage with demand peaks in morning (8am) and evening (6:30pm). The use of heat pumps is increasing electricity usage, with no noticeable impact over summer hot period yet. Peaks normally occur in winter.

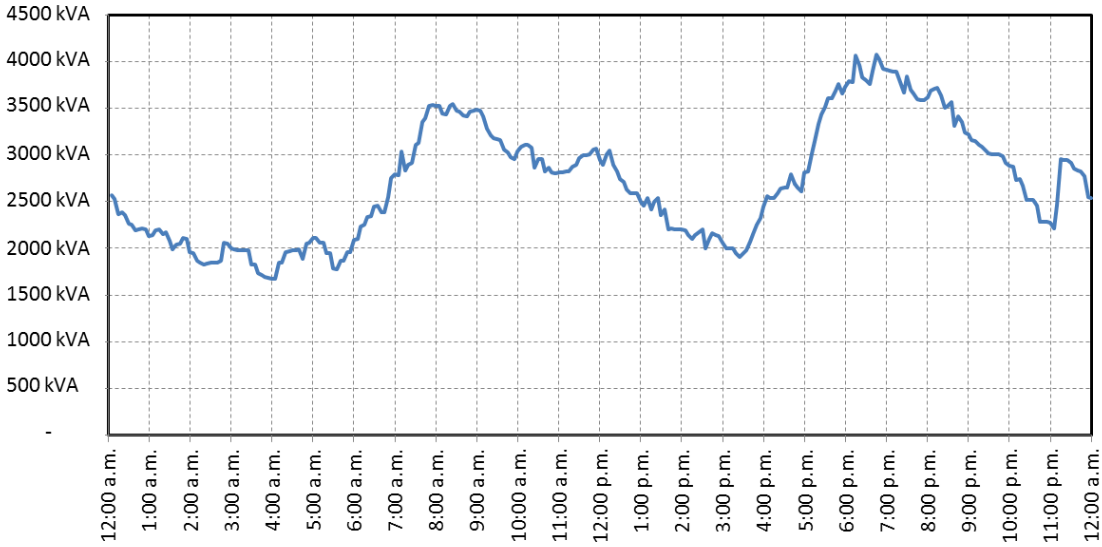


Figure 5 Typical Domestic Daily Load Profile (9 July 2013, Waikiwi CB3)

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

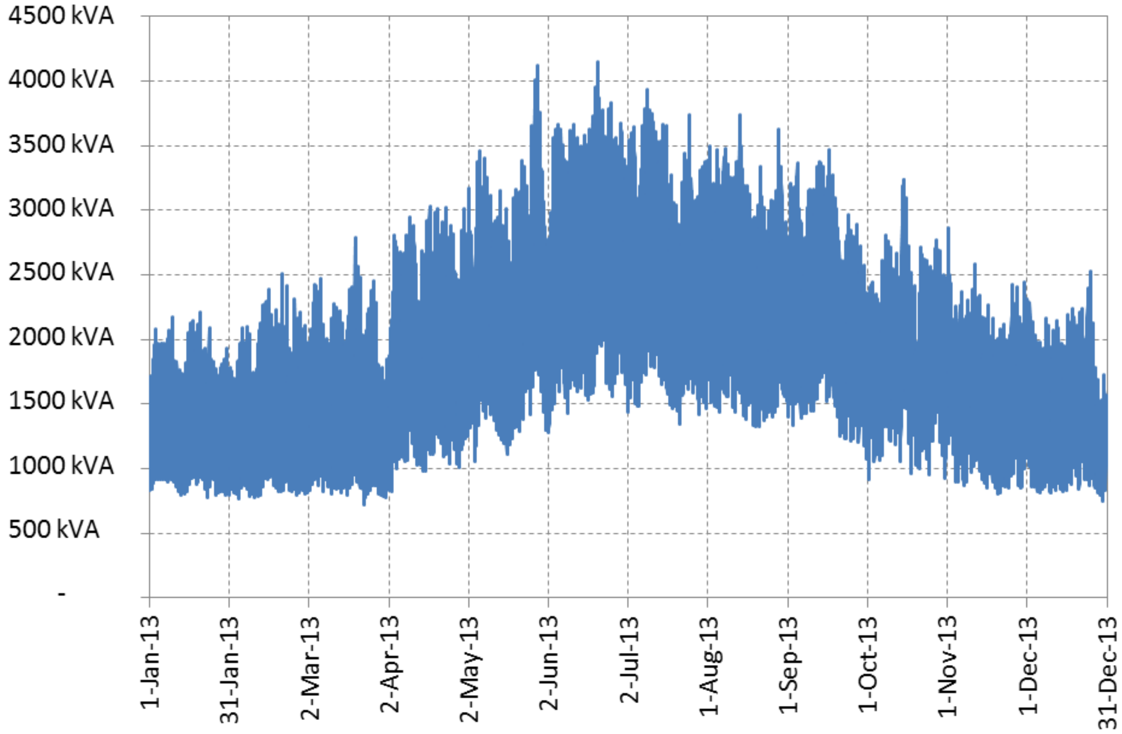


Figure 6 Typical Domestic Feeder Yearly Load Profile (Waikiwi CB3)

Farming: Normally only very low usage with some pumps and electric fences, with peak usage during the few days of shearing or crop harvesting.

Dairy: Milking season between August and May with morning and late afternoon peaks

Sawmills: Usage at sawmills due to processing and kiln drying of product. 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 3.8 MW of cogeneration, which can create peaks if it is off.

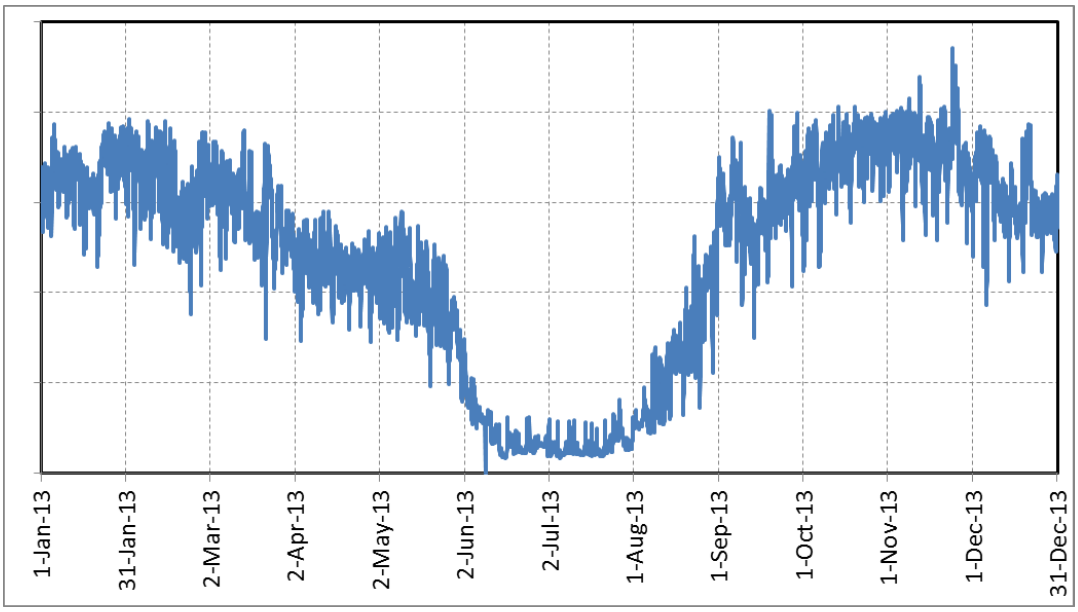


Figure 7 Dairy Processing Plant Yearly Load Profile

Tourism: Mostly over the summer period with steady stream of visitors to or through Fiordland.

2.1.5 Other drivers of electricity use [A.4.1.3.]

Other drivers of electricity use include:

- Low temperatures during winter (-5°C frosts are not uncommon in the area).
- The use of heat pumps as air conditioners in the 25°C summer heat.
- Improving home insulation due to 'Warm Homes' project.
- Increased energy efficiency due to Government campaigns. (Compact Fluorescent light bulbs and LED (Light Emitting Diode) light bulbs.)

2.1.6 Energy and demand characteristics [A.4.1.4.]

Key energy and demand figures for the year end (YE) 31 March 2014 are as follows:

Parameter	Value	Long-term trend (10yr)
Energy entering system for supply to customers	737.79 GWh	Steady growth +1.2%
Maximum demand[5]	135.15 MW	Steady growth +2.1%[6]
Load factor	62%	Steady
Losses	-7.2%	Steady

2.2 Network configuration

To supply TPCL's 34,762 customers the company owns and operates an electrically contiguous network which is supplied by four GXP's at Invercargill, North Makarewa, Edendale and Gore and by up to 66MW of injected generation from Meridian's White Hill wind farm and Pioneer Generation's Monowai hydro station.

2.2.1 Bulk supply assets and embedded generation [A.4.2.1.]

2.2.1.1 Invercargill Grid eXit Point (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 connection point 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 six 33kV feeders each supplied through its own circuit breaker.

TPCL owns the segments of 33kV line (but not the circuit breakers or bus[7]) that run within the GXP land area and also accommodates a control room that oversees the operation of the network. TPCL 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 with each providing backup capability to the other.

2.2.1.2 North Makarewa GXP

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

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[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.

[6] Step change in Maximum Demand occurred due to new Transpower Pricing Methodology, with individual GXP peaks now replaced by Lower South Island peaks across multiple GXP's.

[7] Bus – an electrical term, the point where a number of circuits connect. (Alt: Busbar.)

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.

2.2.1.3 Edendale GXP

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

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

2.2.1.4 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. The company takes supply from the two 110/33kV 30MVA transformers at Gore to five 33kV feeders. TPCL owns the segments of 33kV line (but not the circuit breakers or bus) within the GXP land area.

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.

2.2.1.5 Bulk Supply Characteristics

Supply Point	Voltage	Rating	Firm Rating[8]	MD[9]	CD[10]
Invercargill GXP	220/33kV	2 x 120MVA	104.0MVA	90.2MW	85.8MW
North Makarewa GXP	220/33kV	2 x 60MVA	62.3MVA	47.2MW	31.6MW
Gore GXP	110/33kV	2 x 30MVA	36.6MVA	31.6MW	24.4MW
Edendale GXP	110/33kV	2 x 30MVA	31.6MVA	28.1MW	5.14MW
White Hill Wind Farm	66kV	1 x 65MVA	0MVA	-49.1MW	0MW
Monowai Generation	66kV	2 x 5MVA	5MVA	-6.7MW	-6.1MW

2.2.1.6 White Hill generation

This wind farm consists of twenty-nine 2MW wind turbines connected into the Meridian substation by 22kV cable with a step-up transformer to supply into the Heddon Bush to Hillside 66kV line. The 66kV line being split and brought up the hill to the Meridian substation on a monopole dual circuit 66kV line. TPCL owns this line, the 66kV bus and two circuit breaker bays in the Meridian substation.

[8] Based on 24 hour post Contingency Rating from Transpower's Branch reports
[9] Maximum Demand 1 April 2013 to 31 March 2014
[10] Coincident Demand for Lower South Island (LSI) peak at 0900hrs 10 July 2013.

As part of the installation an American Superconductor's ± 8MVAr Dynamic VAR Compensator (D-VAR) is used to assist in fault capability and a 216⅔Hz blocking filter to reduce ripple frequency absorption.

First generation occurred on 1st June 2007.

2.2.1.7 Monowai generation

TPCL's predecessor, the Southland Electric Power Supply (SEPS), built the original 6.6MW Monowai power station in 1927 as part of the original power development in Southland. As a result of the Electricity Industry Reform Act 1998 Monowai is now owned by Pioneer Generation. Pioneer recently replaced all three 2.2MW generators with modern 2.5 MW units. Monowai currently injects up to 7.5MW into the TPCL 66kV substation.

2.2.1.8 Edendale generation

Fonterra operates a 3.8MW steam turbine generator at its Edendale plant. This generator is embedded within the Edendale plant and as steam is only produced during the milk production season, export of power from the site is rare.

2.2.1.9 Mataura generation

There are two hydro generators on the Mataura Falls connected onto the 11kV feeders out of Mataura substation.

The Alliance Group has an 800kW unit embedded inside its plant with no generation exported.

The Mataura Industrial Estate is operating the 800kW unit at the old Paper Mills on the East bank. The Paper Mills 1875kVA steam turbine generator has been disconnected and is not in service.

2.2.2 Subtransmission network [A.4.2.2.]

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.

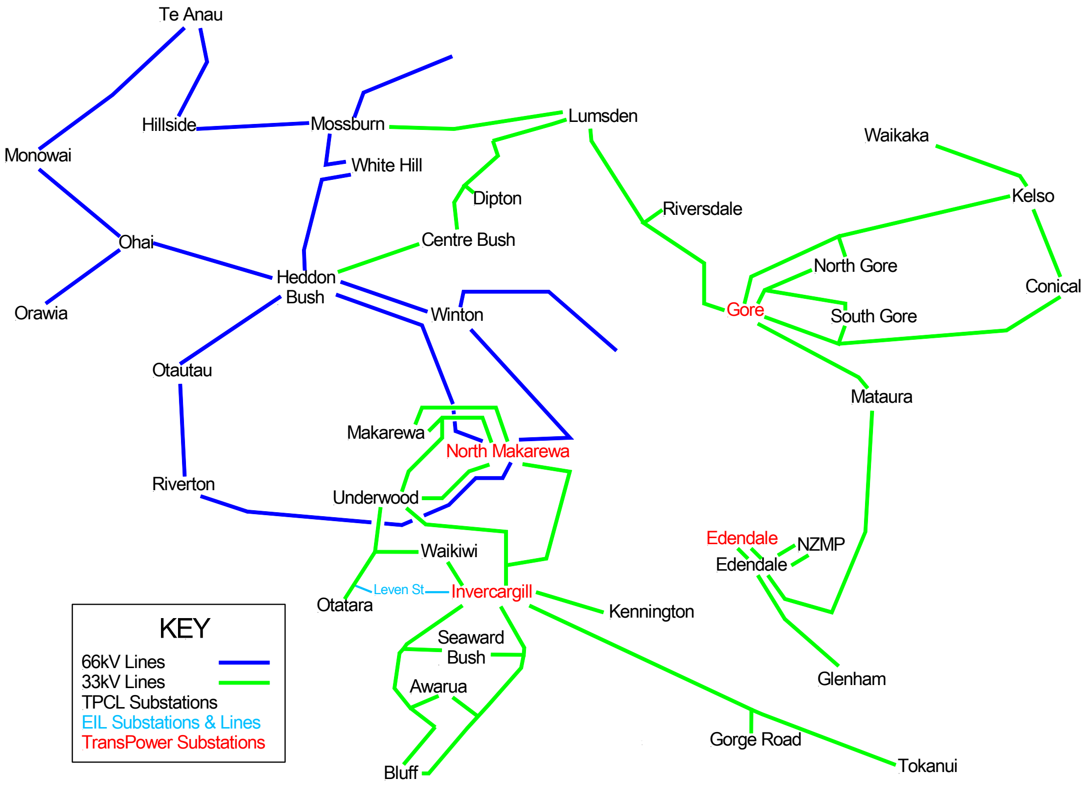

Figure 8 – Subtransmission network

The subtransmission network comprises 386km of 66kV line and 466km of 33kV line and has the following characteristics:

- It is almost totally overhead except for short cable runs at GXP's and zone substations. The notable exceptions are the inter-connects to Electricity Invercargill's Leven Street and Southern zone substations which are cabled from TPCL's Otatara and Seaward Bush lines respectively and some short sections of 33kV around corners on the Invercargill to Kennington 33kV circuit.
- It includes three different electrical topologies (ring, ladder and spur) as well as an interconnection of 66kV and 33kV at the North Makarewa GXP and at TPCL's Heddon Bush substation.
- It includes a large number of lightly-loaded zone substations because the long distances and loads are beyond the reach of 11kV.

2.2.3 Zone substations [A.4.2.2.]

TPCL owns and operates the following 33 zone substations and two feeders supplied from Electricity Invercargill Limited's Racecourse Road substation.

Substation	Nature of load	Description of substation
Awarua	Predominantly three large industrial customers with some minor rural load to the south-west.	Simple outdoor site with two 33/11kV transformers and associated outdoor 33kV and 11kV circuit breakers. Due to a large Synchronous Motor at Southwood Export no other customers are supplied from their feeder.
Bluff	Predominantly urban domestic load in Bluff, but including one large and a few medium industrial customers.	Medium complexity outdoor substation with two 33/11kV 6/12MVA transformers, these supply an indoor 11kV switchboard with three feeders.
Centre Bush	Predominantly rural load in the middle of the Southland Plains.	Simple tee connected 33/11kV 5MVA transformer with three outdoor 11kV feeders. Transformer is able to supply the 33kV with switching of the earthed star point from MV to HV.
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 also from Gore via Kelso substation. Two 33/11kV 5MVA transformers supply a full outdoor 11kV structure with four feeders.
Dipton	Predominantly rural load in the north of the Southland Plains.	Simple tee connected 33/11kV 1.5MVA transformer with two outdoor 11kV feeders.
Edendale Fonterra	Huge dairy factory with four large milk powder plants and other milk process plants.	Dual 33kV cable and 33/11kV 11.5/23MVA transformer supply to the Fonterra 11kV Switchboard.
Edendale	Rural towns of Edendale and Wyndham, small meat works at Morton Mains and rural farms.	Full 33kV switchboard with seven circuit breakers, two supply the local two 33/11kV 6/12MVA transformers, two to Edendale Fonterra, one to Glenham and one to Mataura. An indoor 11kV switchboard with seven feeders.
Glenham	Glenham village, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer with two 11kV feeders. Single 33kV line from Edendale.
Gorge Road	Gorge Road village, rural farms.	Simple outdoor dual 33/11kV 1.5MVA transformers with three 11kV feeders. 33kV line from Invercargill that continues on to supply Tokanui via a 33kV line circuit breaker.

Substation	Nature of load	Description of substation
Heddon Bush	Step down from 66kV to 33kV.	Large outdoor 66kV switchyard with a single 66/33kV 10/15MVA transformer. Has three 66kV supply routes from North Makarewa and supplies two end of the North-western 66kV ring.
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 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 residence.	Medium outdoor 33kV structure with single 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.	Medium outdoor 33kV structure with two supplying lines from Gore and Heddon Bush and a 33kV feeder to Mossburn. Single 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Makarewa	Rural farms with industrial plant.	Medium outdoor 33kV structure with two supplying lines from North Makarewa. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with five 11kV feeders.
Mataura	Township of Mataura, major Meat Processing Plant and rural farms.	Medium outdoor 33kV structure with main supplying line from Gore GXP, with a backup line to Edendale, and four 33kV circuit breakers. Two 33/11kV 10MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders.
Monowai	Remote rural farms.	Medium outdoor 66kV yard with three 66kV circuit breakers. A single 66/11kV 1MVA transformer supplying one 11kV feeder.
Mossburn	Village of Mossburn, small Meat Processing Plant and rural farms.	Large outdoor 66kV yard with six 66kV circuit breakers. A 66/33/11kV 30/3MVA and a 33/11kV 1.5MVA transformer with four 11kV feeders. NER on 66kV and 11kV Neutrals. 66kV lines as part of North-western 66kV Ring. Future 66kV feeders for lines to future subs at Athol and Castlerock. Single 33kV backup line from/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.

Substation	Nature of load	Description of substation
Ohai	Town of Ohai and rural farms. Supplies two open-cast Coal Mines.	Large 66kV structure with lines from North Makarewa GXP, via Winton and Heddon Bush and to Monowai Power Station. Also supplies Orawia 66kV circuit. Each circuit is protected by a 66kV circuit breaker. One 66/11kV 5/7.5MVA and one 66/11kV 5MVA transformer that supplies an indoor 11kV switchboard with four feeders.
Orawia	Town of Tuatapere and village of Orawia, rural farms and sawmills at Tuatapere.	66kV Line onto a 66kV circuit breaker and 66/11kV 5/7.5MVA transformer supplying an outdoor 11kV structure with incomer and four 11kV feeders.
Otatara	Town of Otatara and a few farms.	Simple outdoor single 33/11kV 5MVA transformer with incomer and three 11kV feeders. 33kV line from Invercargill.
Otautau	Town of Otautau, rural farms.	Medium 66kV structure with tee onto a single 66kV circuit breaker supplying one 66/11kV 5/7.5MVA transformer. 66kV line from North Makarewa by the southern 66kV ring. Outdoor 11kV structure with incomer 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 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 Heddon Bush via Lumsden. Single 33kV circuit breaker and 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Riverton	Town of Riverton, small fish processing, rural farms	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 5/7.5MVA transformers. Part of southern 66kV ring supplied from North Makarewa. Indoor 11kV switchboard with six feeders.
Seaward Bush	South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant, rural Farms.	Medium complexity outdoor substation with two 33/11kV 10MVA transformers, these supply an indoor 11kV switchboard with five feeders. Two 33kV lines from Invercargill GXP.
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 with incomer and two 11kV feeders. 33kV line from Invercargill via Gorge Road.

Substation	Nature of load	Description of substation
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. Two 33kV Lines from North Makarewa GXP and two from Invercargill GXP. Provides a backup to the EIL Leven St substation off one of the Invercargill lines so that Leven St can be supplied from North Makarewa GXP.
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 6/12MVA transformer substation with (n-1) supply including possibility of supply from two different GXP's. Indoor 33kV switchboard with five circuit breakers. 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 six feeders.

2.2.4 Distribution network [A.4.2.3.]

2.2.4.1 Configuration

In rural areas the configuration is mainly meshed between substations with reasonable backup capability. Most distribution off this main distribution is radial with only some meshing.

In urban areas a high degree of meshing between 11kV feeders is possible (although transformer loadings rather than distance tends to limit the ability to back-feed on the 11kV).

2.2.4.2 Construction

TPCL's network construction differs between rural and urban as follows:

- 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[11] or XLPE[12] cable.
- CBD areas tend to be PILC cable unless this has been replaced, which will almost always be with XLPE.

2.2.4.3 Per substation basis

TPCL's split of distribution network on a per substation basis is presented below in Table 4. Safety and reliability is TPCL's strongest driver of allocation of resources, with customer density providing an indication of priority of other works.

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

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

Table 4 – Distribution network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Awarua	12.5	1.8	34	2.4
Bluff(TPCL)	34.1	0.5	146	4.2
Centre Bush	237.0	0.0	558	2.4
Conical Hill	164.7	0.3	286	1.7
Dipton	187.3	0.2	364	1.9
Edendale	294.5	4.0	1349	4.5
Edendale Fonterra	0.0	0.0	1	
Glenham	191.6	0.0	347	1.8
Gorge Road	163.1	0.0	382	2.3
Hillside	226.9	2.3	355	1.5
Kelso	436.7	0.4	1269	2.9
Kennington	72.5	2.2	764	10.2
Lumsden	381.9	7.4	1132	2.9
Makarewa	275.5	2.4	1141	4.1
Mataura	294.1	5.2	1335	4.5
Monowai	47.2	0.3	96	2.0
Mossburn	236.9	1.2	500	2.1
North Gore	282.1	3.7	2665	9.3
Ohai	211.1	0.5	754	3.6
Orawia	314.5	3.0	934	2.9
Otatara	61.0	4.7	1237	18.8
Otautau	226.5	1.0	925	4.1
Racecourse Road (TPCL)	28.7	2.7	433	13.8
Riversdale	416.1	1.9	1279	3.1
Riverton	312.9	6.9	2023	6.3
Seaward Bush	149.5	6.0	2404	15.5
South Gore	196.0	5.4	2415	12.0
Te Anau	173.8	37.0	2250	10.7
Tokanui	228.0	0.6	540	2.4
Underwood	67.4	1.6	569	8.3
Waikaka	108.2	0.2	246	2.3
Waikiwi	212.6	14.1	3312	14.6
Winton	514.8	7.4	2718	5.2
Unallocated	0.4	3.7	0	
			Average	**5.0 /km**

2.2.5 Distribution substations [A.4.2.4.]

Just as zone substation transformers form the interface between TPCL's subtransmission and TPCL's distribution networks, distribution transformers form the interface between TPCL's distribution and LV networks. TPCL's distribution substations range from 1-phase 0.5kVA pole-mounted transformers to 3-phase 1,500kVA ground-mounted transformers shown in Table 5.

Table 5 – Number of distribution substations

Rating	Pole	Ground
1-phase up to 15kVA	4378	21
1-phase 30kVA	626	8
1-phase 50kVA	5	1
3-phase up to 15kVA	1593	7

Rating	Pole	Ground
3-phase 30kVA	2213	35
3-phase 50kVA	961	28
3-phase 75kVA	241	9
3-phase 100kVA	155	95
3-phase 200kVA	116	182
3-phase 300kVA	49	96
3-phase 500kVA	4	36
3-phase 750kVA	3	19
3-phase 1,000kVA	1	11
3-phase 1,500kVA	0	2
Total	**10345**	**550**

Each distribution transformer has MV protection by 'Dropout' fuses. This is achieved in two configurations:

- Individual, with a dropout at each site, or,
- Group Fusing, where a single dropout is located at the take-off from the main line, with up to five downstream units. Each individual unit will have MV isolation where the dropout fuse is replaced with a solid link. This is done to speed fault restoration as fault staff can locate the faulty 'group' as the dropout is generally on the main road and check which unit is failed before restoration.

Low voltage protection is by DIN[13] standard HRC[14] fuses sized to protect overload of the distribution transformer.

For management purposes TPCL's 11kV voltage regulators are classified as distribution transformers:

Location	Purpose
Bushy Park	Voltage improvement
Browns	Voltage improvement
Colac Bay	Voltage improvement
Devery's Corner	Enables backup alternative to Orawia
Dunrobin	Voltage improvement
Edendale Hill	Voltage improvement
Elders	Voltage improvement
Fairlight	Voltage improvement
Forest Hill	Voltage improvement
Freshford	Voltage improvement
Five Rivers	Voltage improvement
Hilltop	Voltage improvement
Jacks Hill	Enables backup alternative to Tokanui
Kakapo Road	Voltage improvement
Kelso	Voltage improvement
Kingston Crossing	Voltage improvement
Mobile	Temporary voltage improvement for faults and planned works

[13] Deutsches Institut für Normung e.V. (DIN; in English, the German Institute for Standardization) is the German national organization for standardization and is that country's ISO member body.

[14] High Rupture Capacity.

Location	Purpose
Morton Mains	Voltage improvement
Opio	Voltage improvement
Oreti Hall	Voltage improvement
Otamita	Voltage improvement
Parawa	Voltage improvement
South Hillend	Voltage improvement
The Ridges	Voltage improvement
Tapanui	Voltage improvement
Tuatapere	Voltage improvement
Woodlands	Voltage improvement
Wyndham Ridges	Voltage improvement

2.2.6 LV network [A.4.2.5.]

2.2.6.1 Coverage

TPCL's LV networks are predominantly clustered around each distribution transformer. The coverage of each individual LV network tends to be limited by volt-drop to about a 200m radius from each transformer hence LV coverage is not as extensive as 11kV.

2.2.6.2 Configuration

TPCL's LV networks are almost solely radial in rural areas but meshed in urban areas which provide some restoration of supply after faults and for planned work.

2.2.6.3 Construction

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

- Overhead LV only.
- LV under-built on 11kV.
- LV under-built on 33kV and 66kV.
- PILC cables only.
- XLPE cable only.
- Conjoint PILC – XLPE cable.

2.2.6.4 Per substation basis

On a per substation basis TPCL's split of LV network is shown in Table 6. Similar to the distribution network, safety and reliability is TPCL's strongest driver of allocation of resources, with customer density providing an indication of priority of other works.

Table 6 – LV network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Awarua	0.42	0.01	34	78.1
Bluff(TPCL)	6.19	0.10	146	23.2
Centre Bush	14.64	0.66	558	36.5
Conical Hill	8.93	0.27	286	31.1
Dipton	11.50	0.44	364	30.5
Edendale	46.28	2.58	1349	27.6
Edendale Fonterra	0.00	0.00	1	
Glenham	13.02	0.47	347	25.7
Gorge Road	13.92	0.44	382	26.6
Hillside	3.60	0.60	355	84.7
Kelso	31.73	1.52	1269	38.2
Kennington	3.54	0.12	764	208.8

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Lumsden	25.31	4.76	1132	37.6
Makarewa	44.80	2.43	1141	24.2
Mataura	35.95	1.91	1335	35.3
Monowai	1.07	0.71	96	53.9
Mossburn	9.38	1.26	500	47.0
North Gore	55.37	10.58	2665	40.4
Ohai	25.53	0.33	754	29.2
Orawia	28.58	2.92	934	29.7
Otatara	28.56	10.01	1237	32.1
Otautau	25.42	3.83	925	31.6
Racecourse Road (TPCL)	9.67	7.59	433	25.1
Riversdale	33.29	1.27	1279	37.0
Riverton	65.08	6.74	2023	28.2
Seaward Bush	50.80	24.80	2404	31.8
South Gore	45.38	14.94	2415	40.0
Te Anau	12.71	54.46	2250	33.5
Tokanui	26.16	1.54	540	19.5
Underwood	17.40	2.11	569	29.2
Waikaka	6.95	0.13	246	30.4
Waikiwi	80.84	28.02	3312	34.7
Winton	61.59	19.66	2718	33.4
Unallocated*	10.43	7.64	0	
			Average	**32.52/km**

* Data not allocated to a feeder.

2.2.7 Customer connection assets

TPCL has 34,762 customer connections; all of TPCL's "other assets" convey energy to these customer connections and essentially are a cost 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 changes over the year are shown in Table 7.

Table 7 – Classes of customer connections

	Small (≤ 20kVA)				Medium (21 – 99kVA)			Large (≥ 100kVA)			
	8kVA 1ph	10% Fixed	20kVA 1ph	15kVA 3ph	30kVA 3ph	50kVA 3ph	75kVA 3ph	100kVA 3ph	Non Half-Hour Metered Individual	Half-Hour Metered Individual	Total
Apr 13	1,721	5,928	21,438	388	3,126	1,495	213	50	77	167	34,603
May 13	1,715	6,123	21,280	393	3,130	1,499	212	51	77	167	34,647
Jun 13	1,716	6,134	21,271	396	3,127	1,502	212	51	77	169	34,665
Jul 13	1,724	6,112	21,320	396	3,123	1,508	213	51	77	170	34,690
Aug 13	1,737	6,079	21,368	396	3,122	1,509	213	50	76	167	34,717
Sep 13	1,743	5,994	21,446	391	3,108	1,509	211	49	76	167	34,694
Oct 13	1,736	5,971	21,465	388	3,108	1,509	213	49	78	166	34,683
Nov 13	1,752	5,942	21,469	389	3,103	1,504	215	50	78	166	34,668
Dec 13	1,760	5,952	21,517	391	3,107	1,506	218	50	78	166	34,745
Jan 14	1,757	5,944	21,518	391	3,114	1,509	216	50	79	166	34,744
Feb 14	1,754	6,219	21,259	389	3,108	1,514	219	50	81	166	34,759
Mar 14	1,756	6,242	21,239	388	3,099	1,520	221	50	80	167	34,762

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. However in some cases a single customer is supplied by a length of line or cable (often on public land) configured as a spur off TPCL's network which is referred to as a "service line" (noting that successive revisions of the Electricity Supply Regulations in the late 1970's and early 1980's confused the two definitions). In such cases ownership of the service line has been retained by TPCL but the customer is responsible for funding and maintaining its safety and connectivity to TPCL's network.

2.2.8 Secondary assets and systems [A.4.2.6.]

2.2.8.1 Load control assets

The company currently owns and operates the following load control transmitter facilities for control of ripple relays:

- Four main 33kV 216⅔Hz 125kVA injection plants at Invercargill, North Makarewa, Gore and Edendale.
- One backup 66kV 216⅔Hz 125kVA injection plant at Winton.

2.2.8.2 Protection and control

(a) Key protection systems

TPCL's network protection includes the following broad classifications of systems:

Circuit Breakers

- Circuit breakers provide powered switching (usually charged springs or DC coil) enabling operational control of isolation and interruption of faults.
- Circuit breaker protection relays include over-current, earth-fault and auto-reclose functions. More recent equipment also includes voltage, frequency, directional, distance, arc-flash detection and circuit breaker fail functionality in addition to the basic functions.
- May also be driven by the following to protect downstream devices:
    - Transformer and tap changer temperature sensors.
    - Surge sensors.
    - Explosion vents.
    - Oil level sensors.

Fuses

- Fuses provide fault interruption of some faults and may be utilised by manual operation to provide isolation.
- As fuses are a simple over current device they do not provide a reliable earth fault operation or any other protection function.

Switches (ABS)

- Switches provide no protection function but allow manual operation to provide control and/or isolation.

Switches (AABS)

- Switches provide no protection function but allow remote operation to provide control and/or isolation.

Links

- Links provide no protection function but allow difficult manual operation to provide control/isolation.

(b) DC power supplies

Batteries, battery chargers and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions. This allows continued operation of plant throughout any power outage.

(c) Tap changer controls

Voltage Regulating Relays (VRR) provides automatic control of the 'Tap Change On Load' (TCOL) equipment on power transformers to regulate the outgoing voltage to within set limits.

2.2.8.3 SCADA and communications

SCADA is used for control and monitoring of zone substations and remote switching devices and for activating load control plant.

(a) Master station

TPCL's SCADA master station is located at TPCL's system control centre at the Findlay Road GXP, Invercargill. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide full Power Industry functions.

(b) Communications links

The following communication links are owned and operated by the company:

- Three microwave links.
- Twenty nine UHF links.
- Six Dataradio UHF channels (one shared with EIL).
- One Ripex UHF channel
- One low power unlicensed link.
- Five VHF Land Mobile channels (one shared with EIL).

(c) Remote terminal units

The following remote terminal units (RTU) are owned and operated by TPCL:

Zone substations	RTU	Zone Sub / Field Device	RTU
Awarua	D25	Tokanui	KF
Bluff	KF	Underwood	KF
Centre Bush	C68	Waikaka	SEL
Conical Hill	KF	Waikiwi	D20ME
Dipton	Mini (2)	Winton	3530/D20ME
Edendale	D20C	Winton Injection	C68
Glenham	KF	White Hill	KF
Gore Injection Plant	KF	**Field substations**	**RTU**
Gorge Road	KF	Blue Sky Meats ABS	KF – LP1
Heddon Bush	D20	Crosbies CB	Form 6
Hillside	KF	Dunrobin Reg CB	Nulec
Invercargill Injection Plant	C68	Freshford West CB	SEL
Kelso	3530	Freshford North CB	SEL
Kennington	3530	Freshford West CB	SEL
Lumsden	KF	Gap Road CB	SEL
Makarewa	C68	Haldane CB	KF
Mataura	KF	Holmes Corner CB	Form 5
Monowai	KF	Longwood CB	Nulec
Mossburn	KF	Nine Mile North CB	SEL
North Gore	KF	Nine Mile South CB	SEL
North Makarewa	D20M++	Otama CB	Form 6
Ohai	D20 C	Parawa Regulator	KF
Orawia	KF	Peters CB	SEL
Otatara	KF	Raymonds Gap ABS	KF
Otautau	KF	River Road CB	Nulec
Riversdale	KF	Tapanui Reg	Nulec
Riverton	KF	Twinlaw Repeater	KF

Zone substations	RTU	Zone Sub / Field Device	RTU
Seaward Bush	D20ME	Waikawa CB	KF
South Gore	3530	Woodlands Reg	Mini
Te Anau	KF	Wyndham Ridges Reg	Nulec

- C68 = Siemens rack RTU, HDLC protocol over 300 baud modem.
- Mini = Siemens mini RTU, HDLC protocol over 1200 baud modem.
- D25 = Harris single rack RTU, DNP3.0 protocol over 9600 baud Modem.
- D20 M++, D20ME, D20 = Harris multiple rack RTU, DNP3.0 protocol over 9600 baud Modem.
- SEL = SEL 351 Protection Relay acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- Nulec = Nulec recloser controller acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- Form 5 = Cooper Recloser Controller acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- Form 6 = Cooper Recloser Controller acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- KF = Kingfisher RTU, DNP3.0 protocol over 9600 baud Modem.

2.2.8.4 Other assets

(a) Mobile generation

None, but PowerNet owns 275kW, 350 and 550kW diesel generators which are used for outage restoration, planned work and peak load lopping.

(b) Stand-by generators

None.

(c) Power factor correction

None.

(d) Mobile substations

One trailer mounted 3MVA 11kV regulator and circuit breaker with cable connections.

(e) Metering

Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

2.3 Age and condition of TPCL's assets by category [A.4.4.]

A general overview of all assets managed by PowerNet is provided in appendix B.

2.3.1 Bulk supply assets and embedded generation [A.4.5.9.]

The company owns the following assets within the GXP's:

Transformers

Voltage	Location	Quantity	Manufactured	Condition
33/66kV	North Makarewa	Two 30/40MVA	2000 (RL[15] = 41yrs)	Good.
33/11kV	Edendale	Two 6/12MVA	2002 (RL = 43rs)	Good.

15 RL = Remaining Life based on ODV handbook standard life, as at 31 March 2014.

Circuit breakers

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	5	2007 (RL = 38yrs)	Good.
66kV	North Makarewa	4	2000 (RL = 31yrs)	Good.
33kV	North Makarewa	1	1971 (RL = 2yrs)	Average.
33kV	North Makarewa	1	1981 (RL = 12yrs)	Average.
33kV	North Makarewa	2	1983 (RL = 14yrs)	Average.
33kV	North Makarewa	2	1984 (RL = 15yrs)	Average.
33kV	Edendale	7	2002 (RL = 44yrs)	Good.
11kV	Edendale	5	1994 (RL = 25yrs)	Good.
11kV	Edendale	1	1995 (RL = 26yrs)	Good.
11kV	Edendale	1	1996 (RL = 27yrs)	Good.
11kV	Edendale	1	1998 (RL = 39yrs)	Good.
11kV	Edendale	2	1999 (RL = 30yrs)	Good.

Bus

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	1	2000 (RL = 31yrs)	Good.
33kV	Edendale	1	2002 (RL = 44yrs)	Good, Indoor switchboard.

Capacitor Banks

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	4	2007 (RL = 38yrs)	Good.

Neutral Earthing Resistor

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	1	2000 (RL = 31yrs)	Good.

Injection Plants

Voltage	Location	Quantity	Manufactured	Condition
66kV	Winton	1	1992 (RL = -2yrs)	Average, coupling cell and capacitors are outdoor.
33kV	Invercargill 1	1	1988 (RL = -6yrs)	Good, all gear is indoor.
33kV	Gore	1	1990 (RL = -4yrs)	Good, all gear is indoor.
33kV	Edendale	1	1988 (RL = -6yrs)	Good, all gear is indoor.
33kV	North Makarewa	1	1994 (RL = 0yrs)	Good, all gear is indoor.

There are a number of significant embedded generation plants (i.e. About 1MW or greater) but these are not owned by the company.

2.3.2 Subtransmission network [A.4.5.1.]

The chart below summarises the subtransmission lines constructed each year:

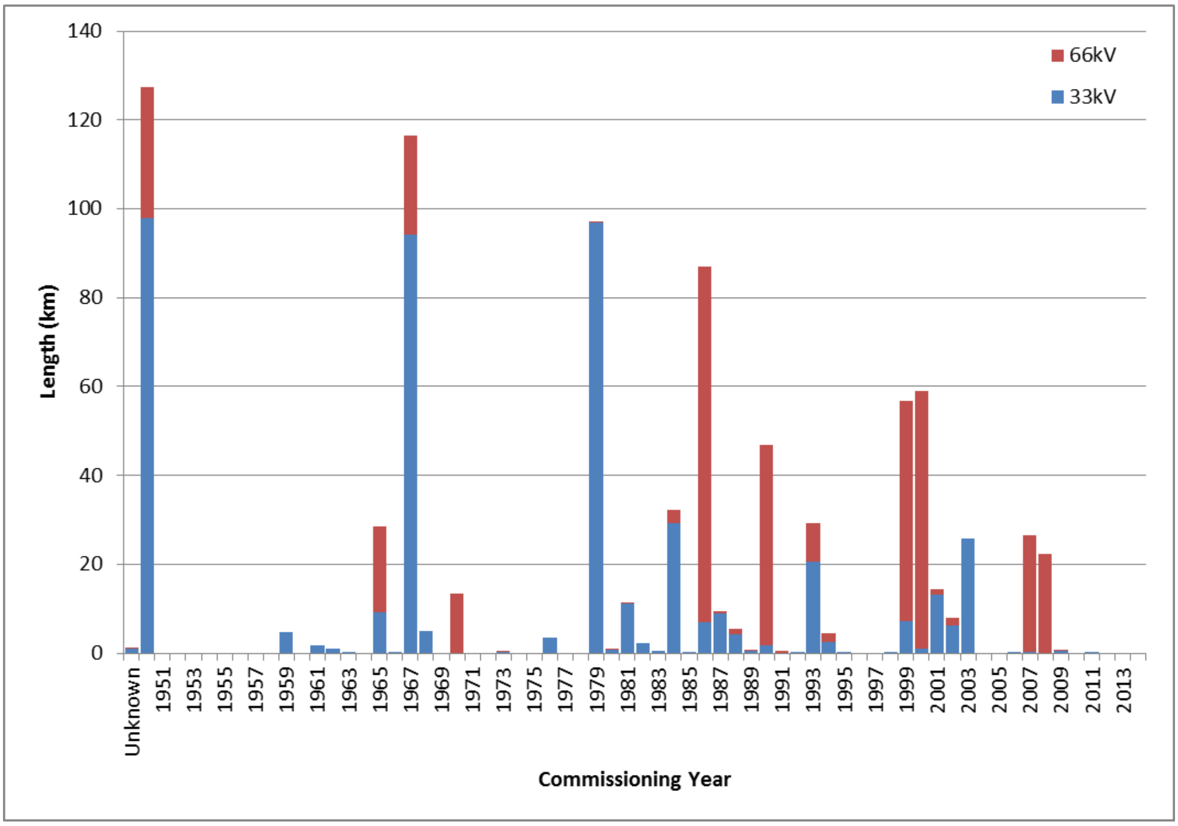

Figure 9 - Subtransmission line construction

The Monowai to Redcliff 66kV line is over 60 years old but is still in operational condition. Determining the remaining life for multi-componented assets is difficult especially as sections are constructed to differing standards and materials. The chart following shows the remaining life based on poles on the subtransmission network:

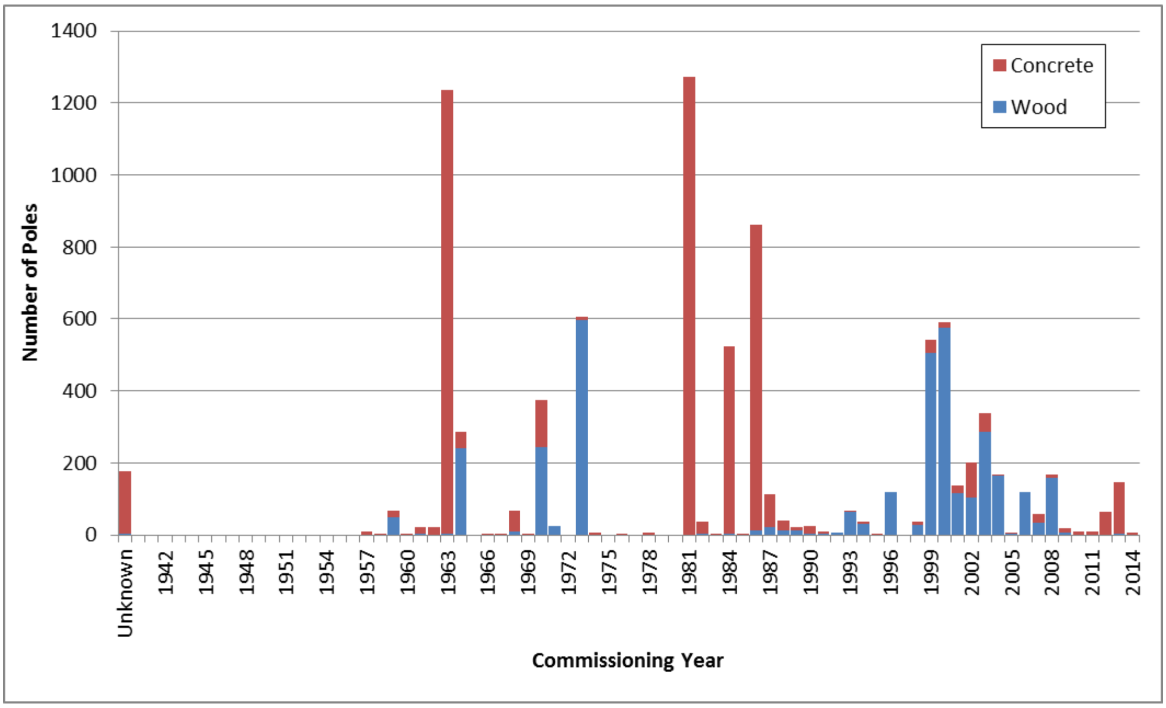

Figure 10 - Subtransmission Poles Type

In theory, for wooden poles all lines built prior to 1980 should be replaced before the end of 2025. Five yearly checks are made of all subtransmission lines with remedial repairs or renewal planned based on information obtained. Due to the criticality of this asset to supply reliability, complete circuits are renewed to modern standards verses piece-meal replacements.

This chart shows for concrete poles that a few lines segments with concrete poles will need to be renewed during the planning period.

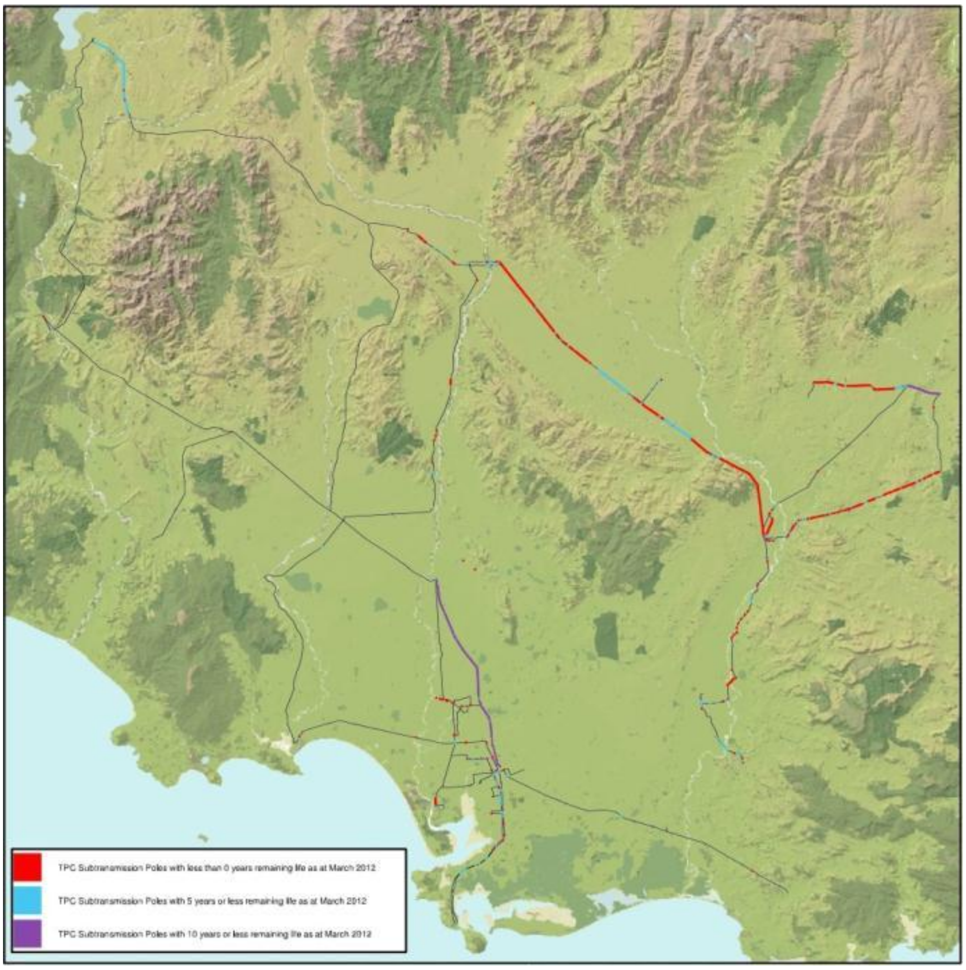

Figure 11 Subtransmission Pole with 10 year or less of life remaining

The 33kV cables are recent additions to the network and these are in good condition.

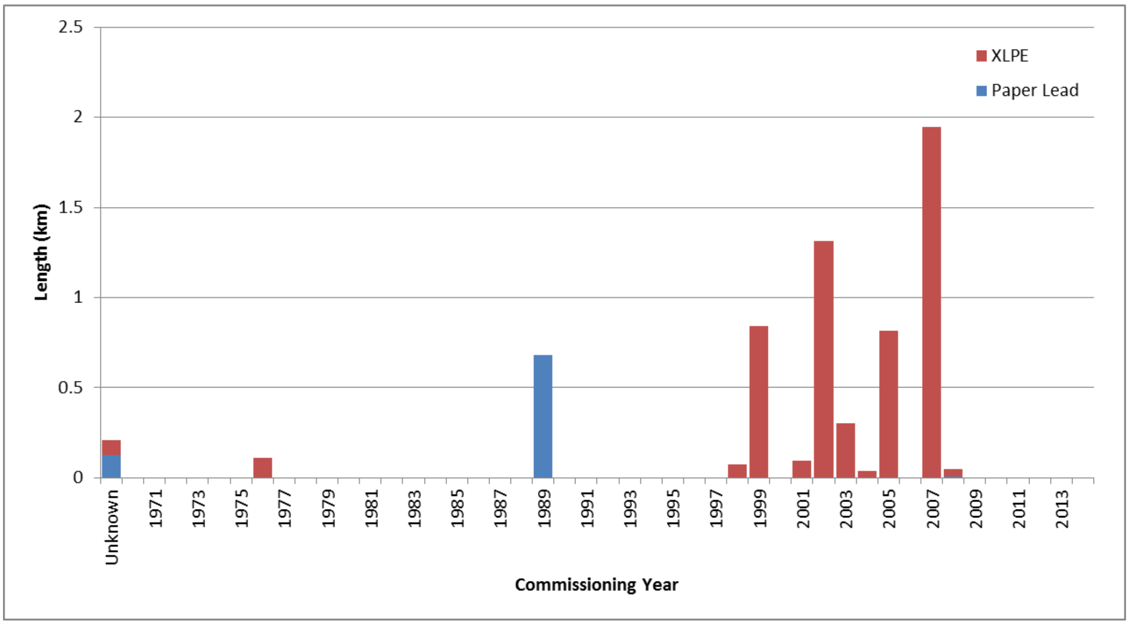

Figure 12 - Subtransmission Cables

2.3.3 Zone substations [A.4.5.2.]

2.3.3.1 HV Switchgear

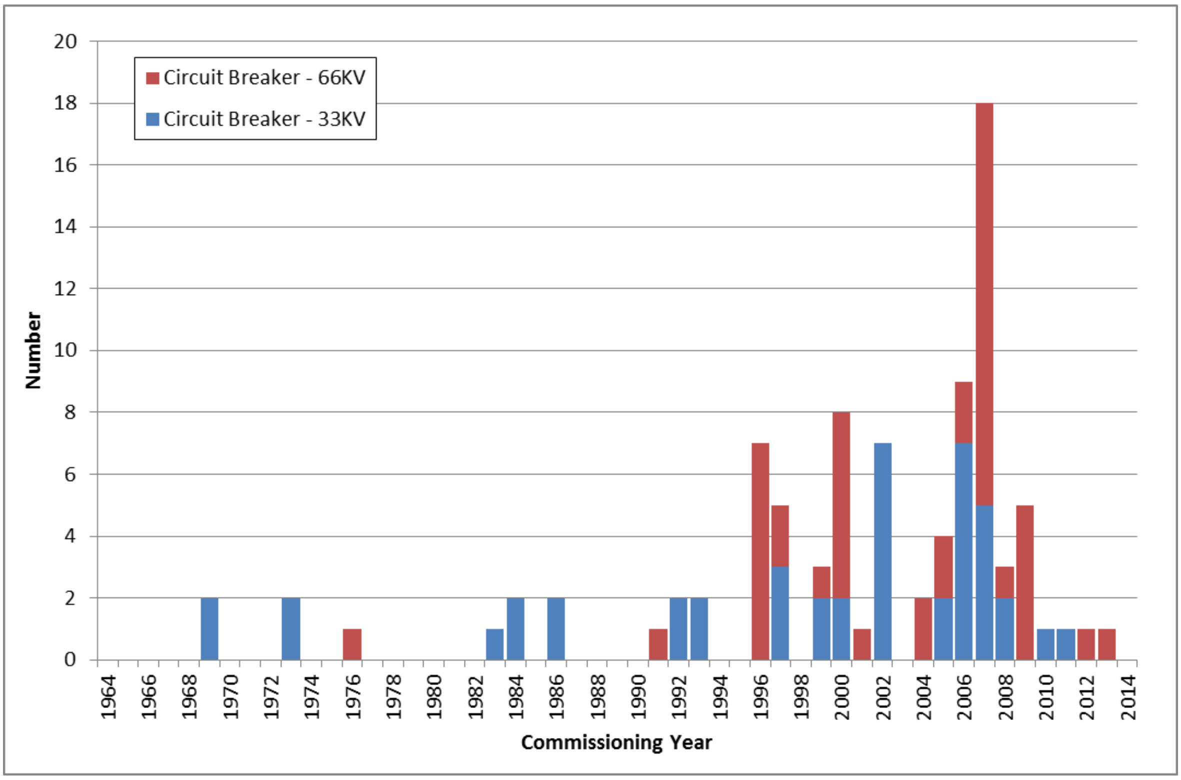

Figure 13 - High Voltage Switchgear

The age profile is shown for high voltage circuit breakers. Five circuit breakers (CB's) will exceed the standard life of 45 years over the next ten years. Condition is generally good, with failed inspections and testing triggering replacements.

2.3.3.2 Power Transformers

Age profile shows the present profile of ages for Power Transformers and Regulators.

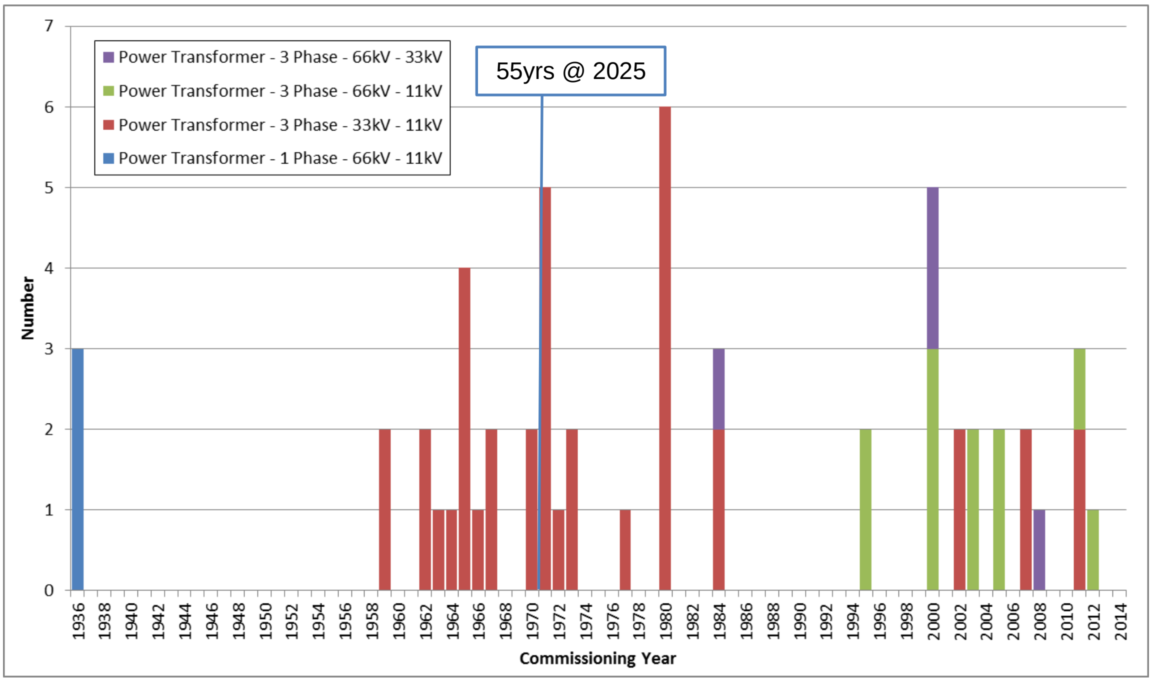

Figure 14 - Power Transformers

The three single phase units at Hillside are not showing signs of failure no replacement is planned within the next ten years. A recent inspection revealed the need for bushing replacement due to oil seepage which is planned for 2015-16. Fifteen other units will exceed 55 years of service with replacements triggered due to poor condition (DGA Test and inspection) or load growth. Six transformers are planned to be replaced in the next five years.

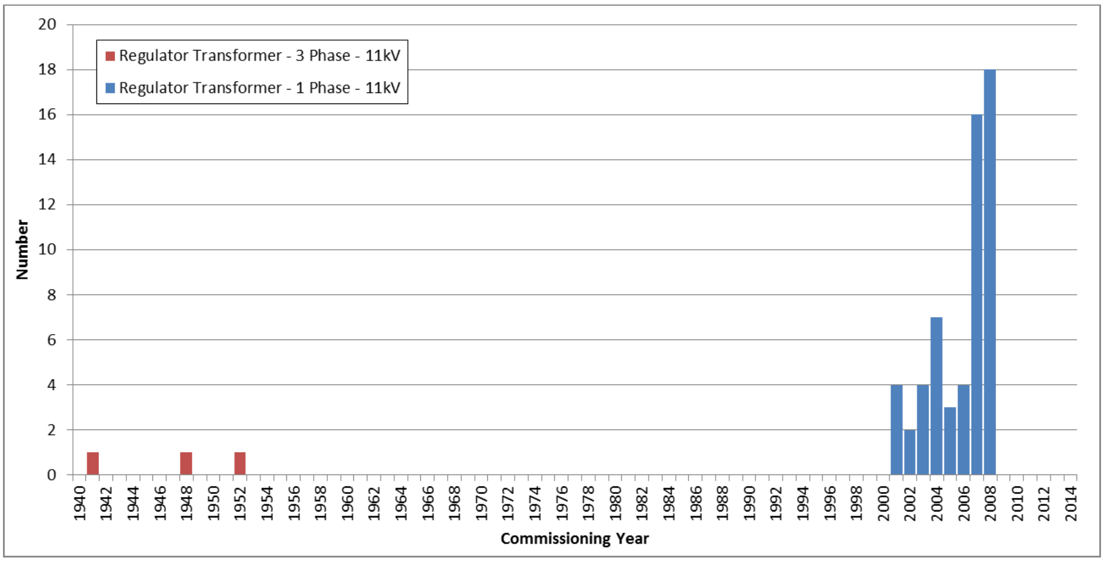

Figure 15 - Regulators

On-going renewal of old Regulators is planned with one unit replaced every two years. This will result in no Regulators older than 24 years by 2025.

2.3.3.3 MV Switchgear

11kV circuit breakers in zone substations are either installed indoor or outdoor with the indoor units having an extra 5 years standard life. Therefore outdoor units older than 1985 and indoor older than 1980, should be refurbished or replaced by 2025.

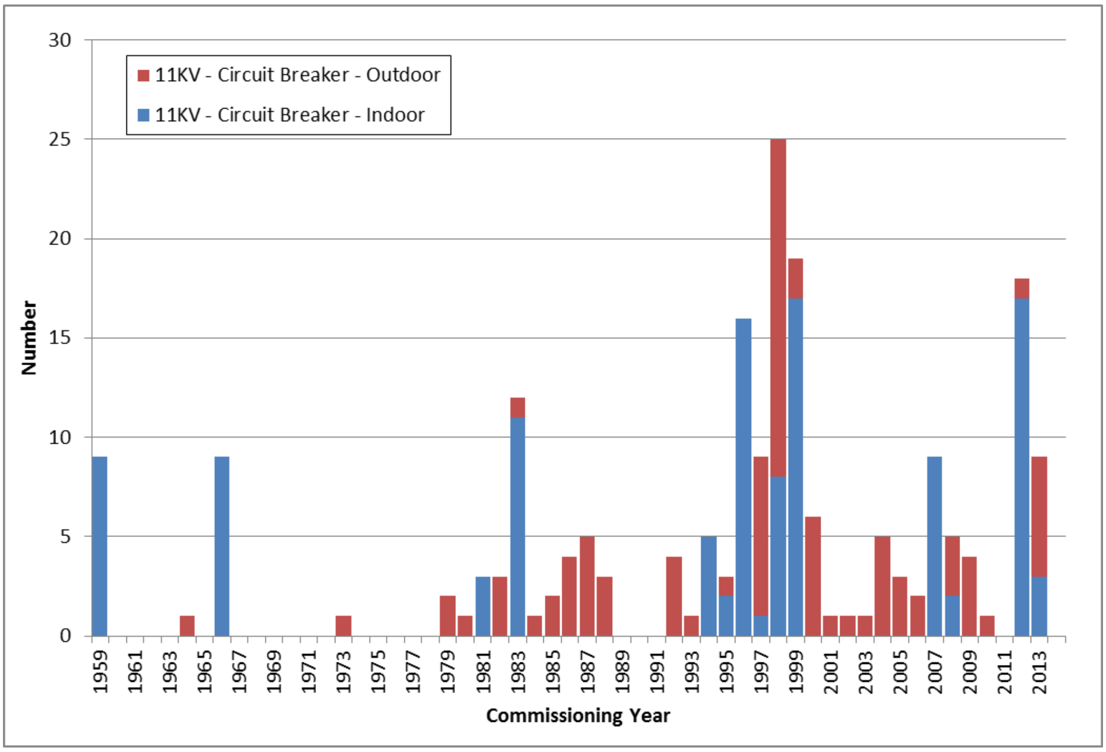

Figure 16 - Medium Voltage Switchgear

18 indoor circuit breakers, and 11 outdoor, will be due for replacement before 2025. Indoor boards at Winton is planned for 2014/15 and Riverton in 2015/16.

2.3.3.4 DC power supplies

As DC batteries are essential to the safe operation of protection devices, regular checks are carried out and each battery is replaced prior to the manufacturer's recommended life.

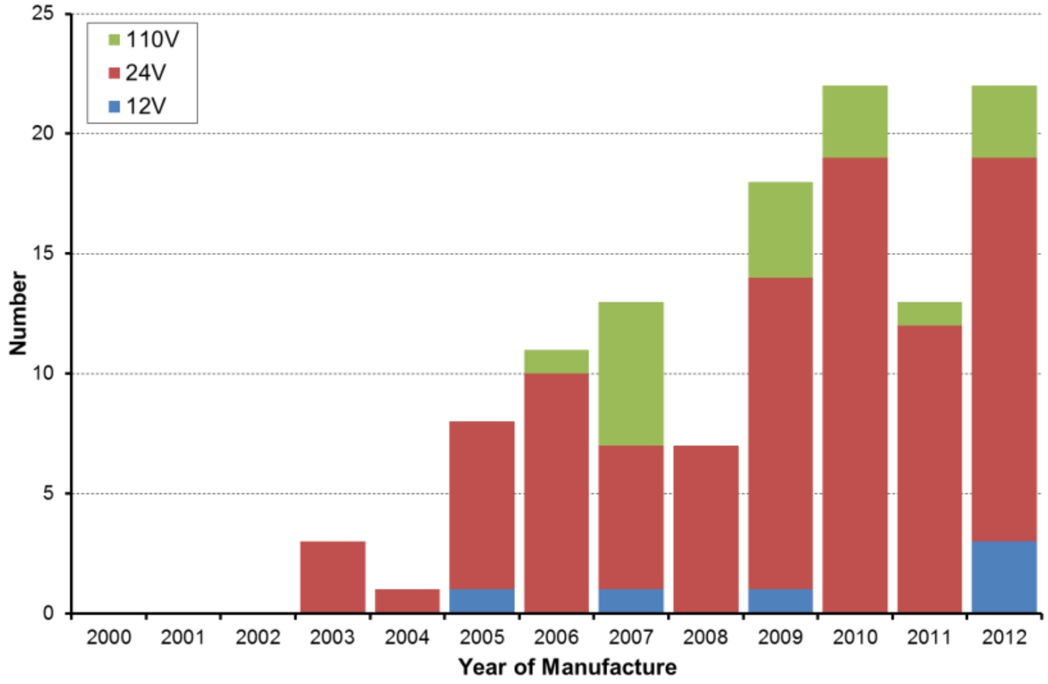

Figure 17 – Battery Banks

2.3.3.5 Tap changer controls

96 voltage regulating relays (VRR) are in service and most have been installed with the associated transformer. The condition of these is average with some recent problems. The recent significant jump in numbers is due to the installation of single phase voltage regulators, which have a VRR per phase.

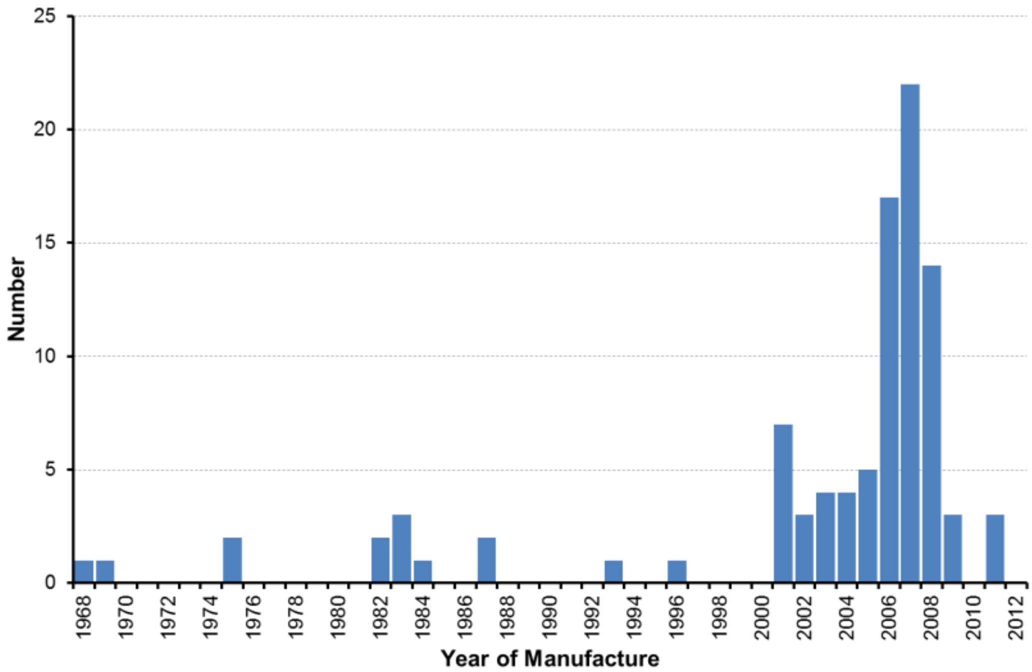

Figure 18 – Voltage Control Devices

2.3.3.6 Remote terminal units

Age profile of Remote Terminal Units (RTU) is shown in Figure 19. Standard age is 15 years and condition is average: with older Siemens units starting to become difficult to maintain.

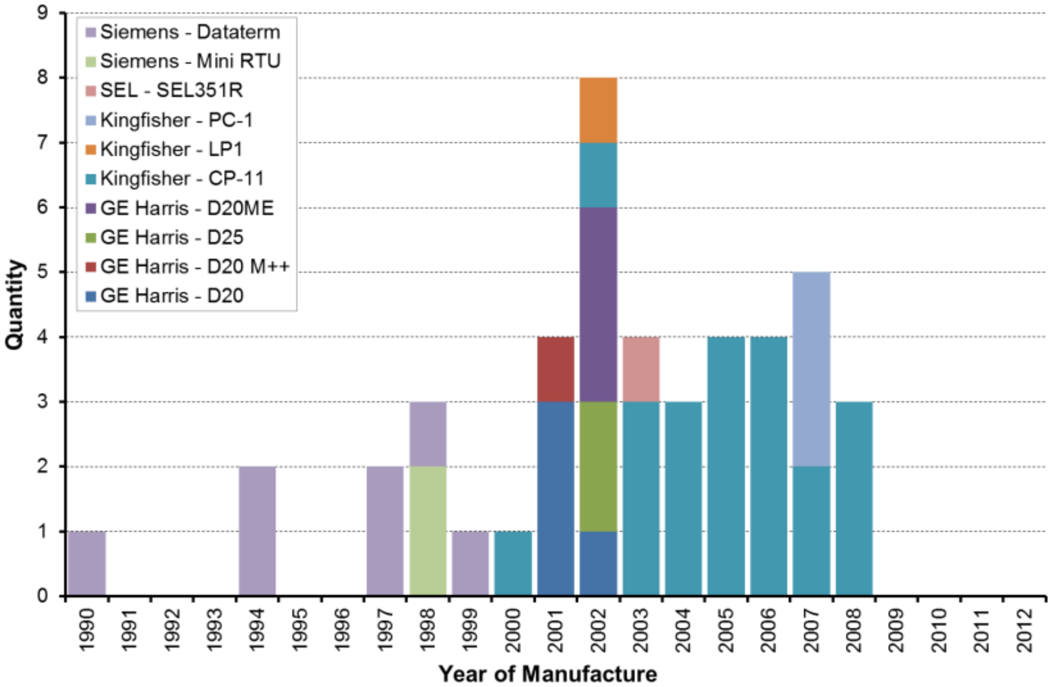

Figure 19 – Remote Terminal Units

2.3.3.7 Metering

TPCL has 'Time Of Use' (TOU) meters on its Incoming Circuit Breakers to provide accurate loading information on each zone substation.

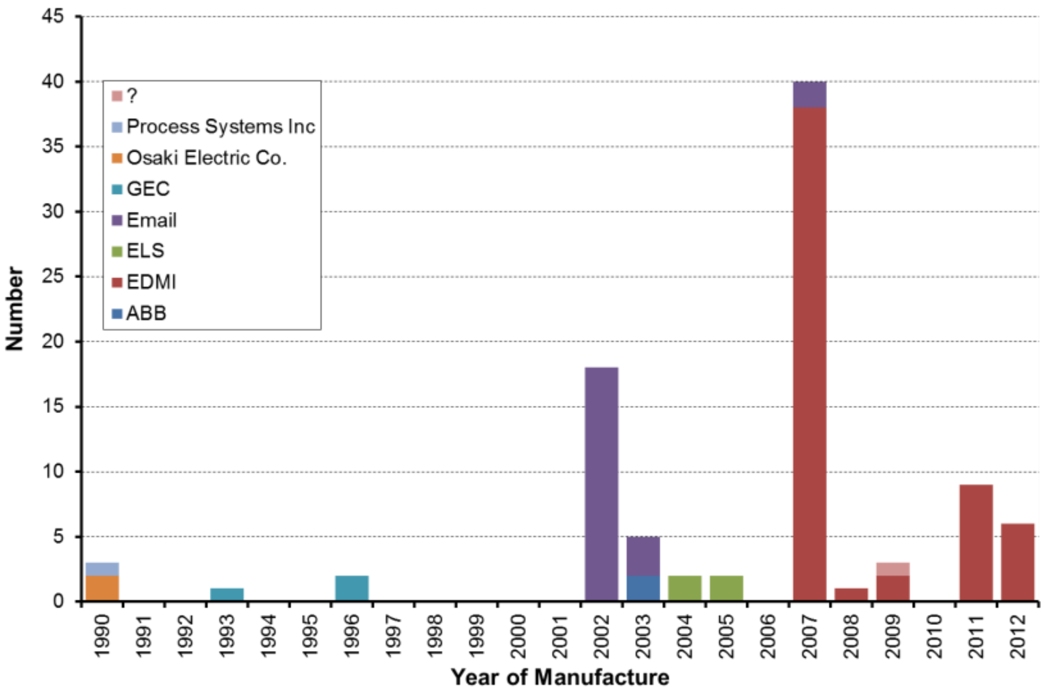

Figure 20 – TOU Meters

There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these meters is given in Figure 20.

2.3.4 Distribution lines [A.4.5.3.]

Medium voltage lines have an age profile as shown in Figure 21. In theory 6,811 wooden poles and 18,867 concrete poles should be renewed by 2025. Over the following ten year period the renewal values for concrete poled lines drops to 16,263 and wooden drops to 5,275. This shows the 'wave of wire' that would require an average of over 2,300 poles per year to be renewed. Good pole lives proven by inspection and non-destructive testing (NDT) will hopefully allow 25% to remain in service for an additional ten years.

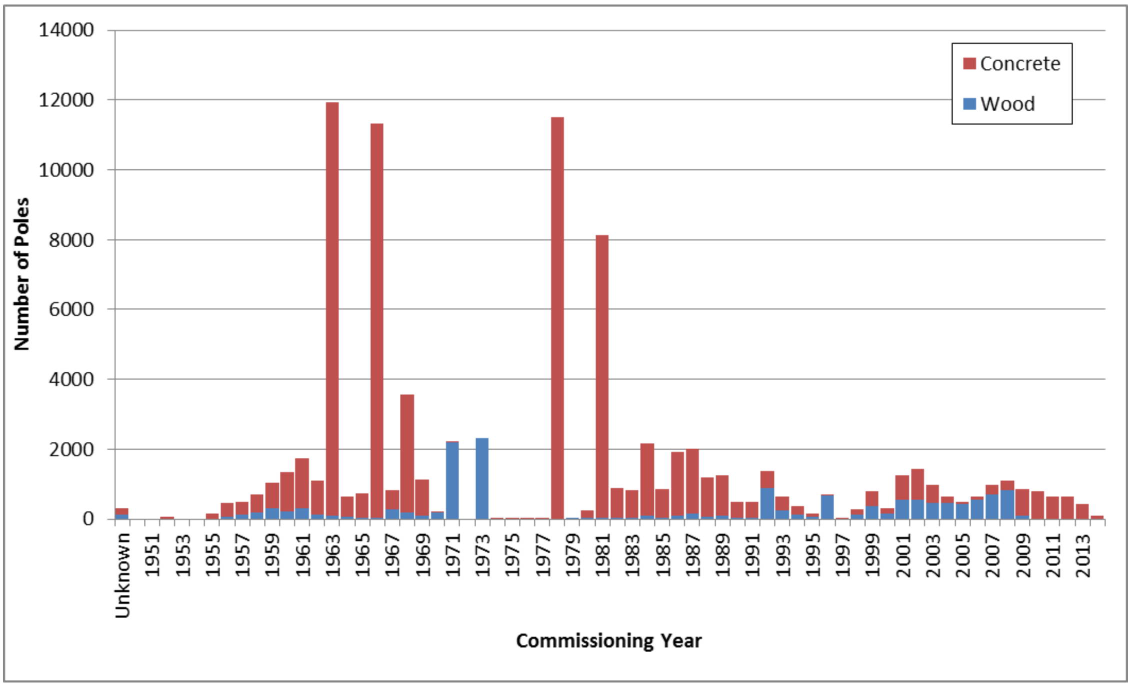

Figure 21 - Distribution Poles

To smooth this wave the company is proposing to increase the renewal for the next ten years from the average required of 750 poles (60km) per year, to 1,500 (120km) per year. The actual replacement rate will depend on available resources, the amount of new connections requiring upgrades, the five yearly inspection, NDT and fault incidences.

The figure 22 shows the location of distribution poles that 'in theory' should be replaced over the next ten years.

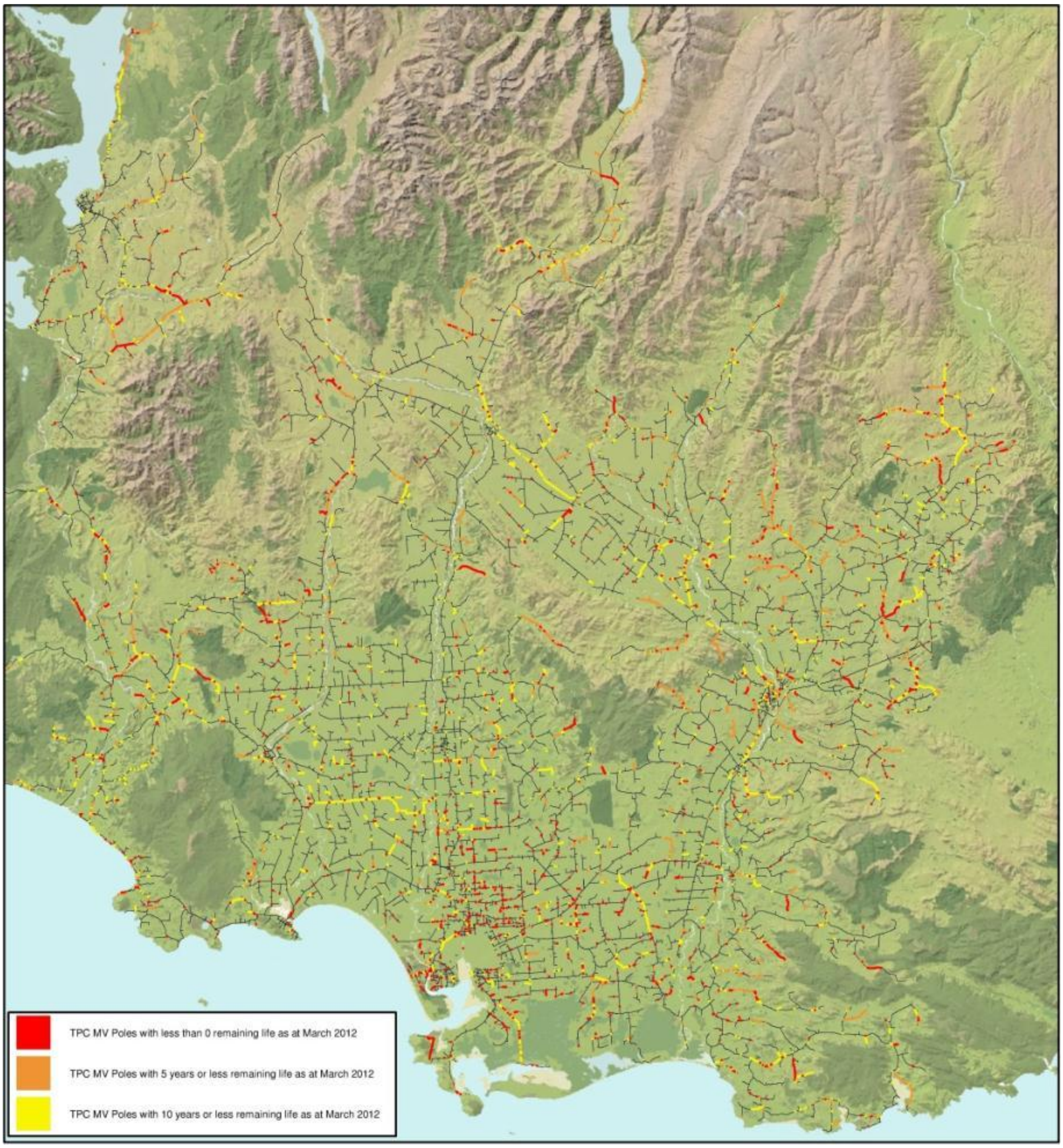

Figure 22 MV Poles with less than 10 year remaining life

2.3.5 Distribution cables [A.4.5.4.]

The age profile of 11kV cables shows that some XLPE cables may need renewal within the planning period (XLPE cables installed before 1980) These will be monitored and replacement done if failures are predicted.

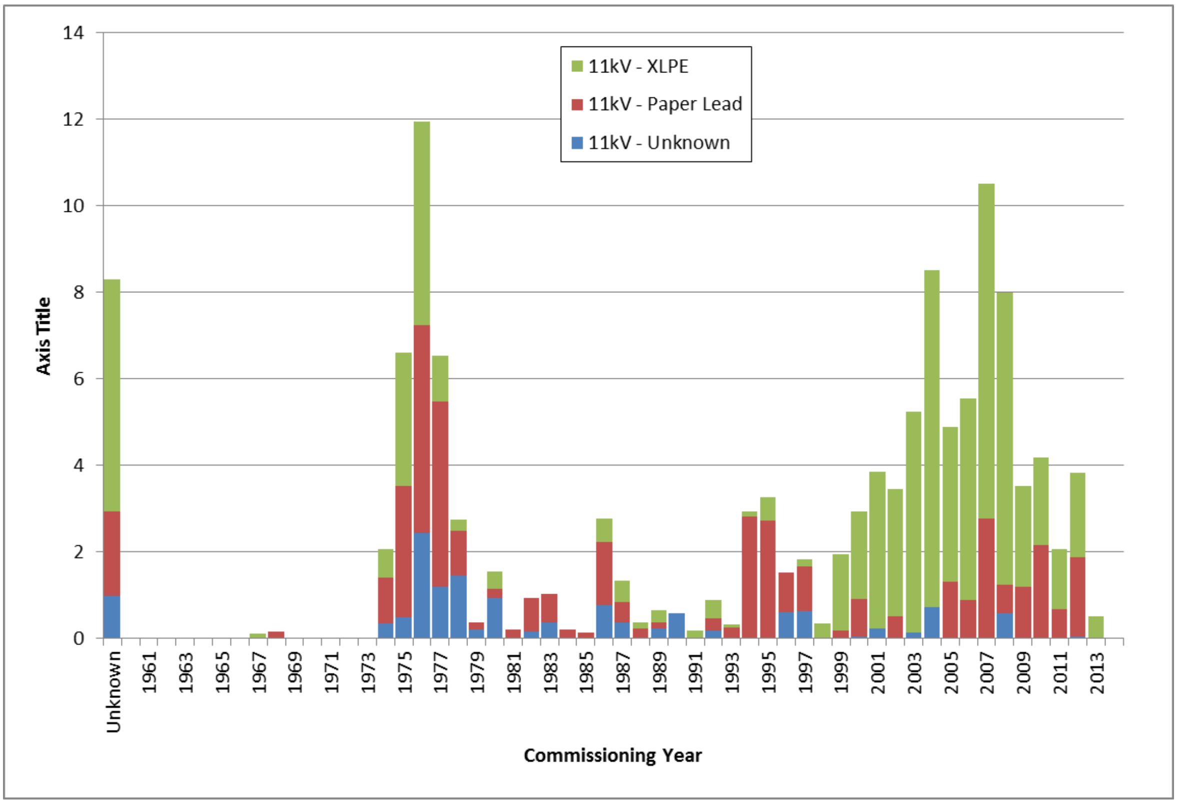

Figure 23 - Distribution Cables

2.3.6 Distribution substations and transformers [A.4.5.5.]

The age profile of distribution transformers is shown below. Condition of these varies generally due to proximity to the coast and if the unit has been heavily loaded.

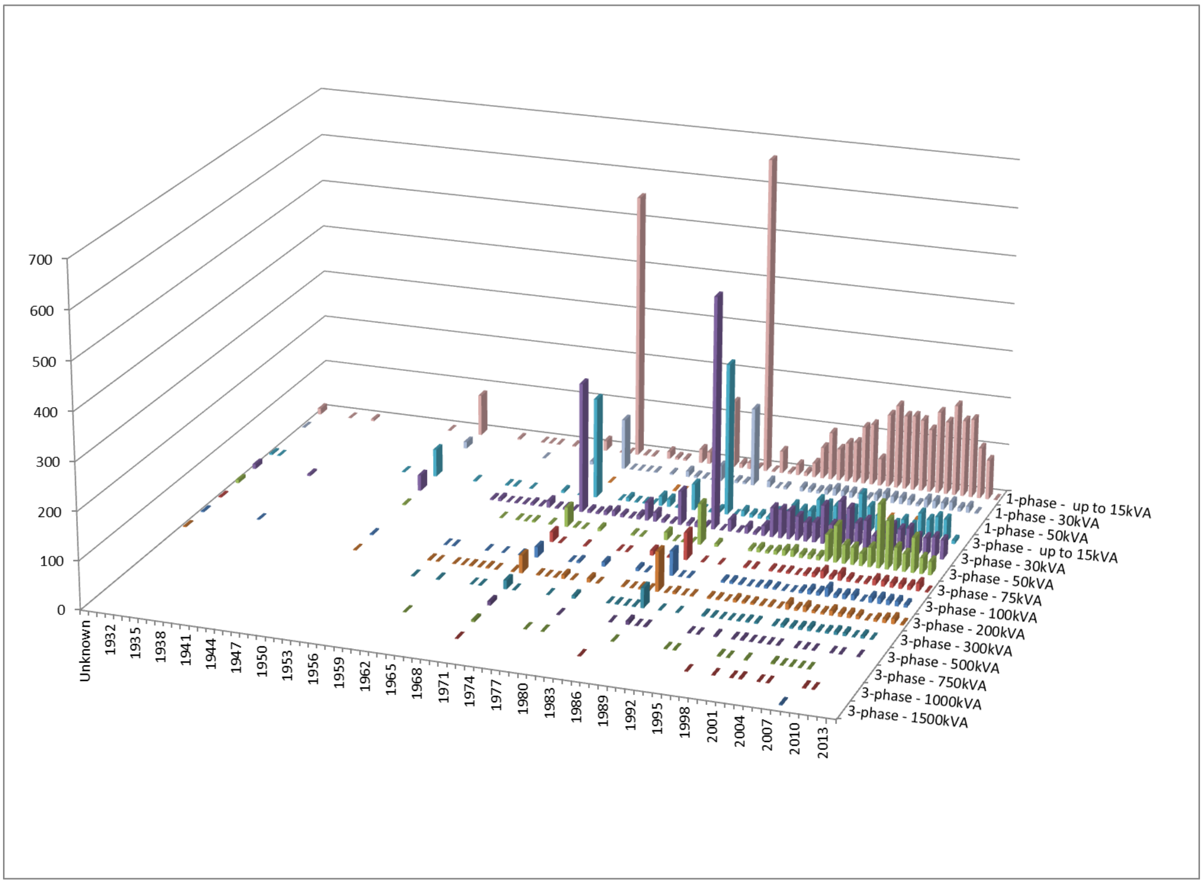

Figure 24 - Distribution Transformers

Two spikes occur at 1970 and 1986 where estimated ages have been used, as the actual manufacturing year was not able to be found.

2.3.7 LV lines [A.4.5.3.]

The age profile of the 400 volt lines is displayed following. Conditions of these are average, with 1,911 poles due for renewal this planning period. The next planning period should renew 4,177 poles.

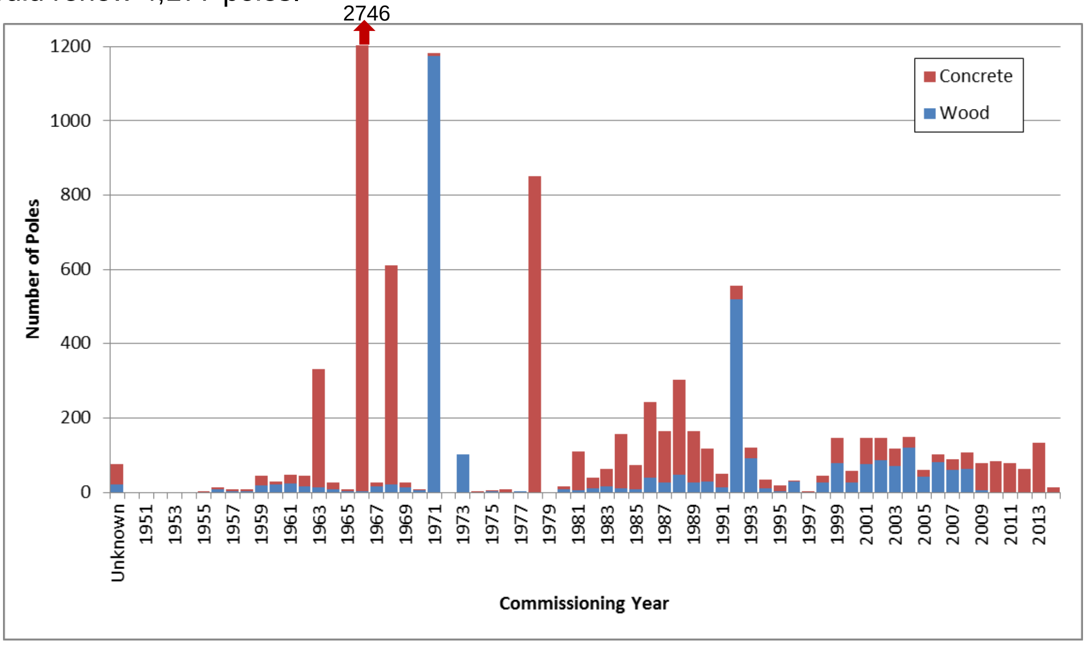

Figure 25 - Low Voltage Poles

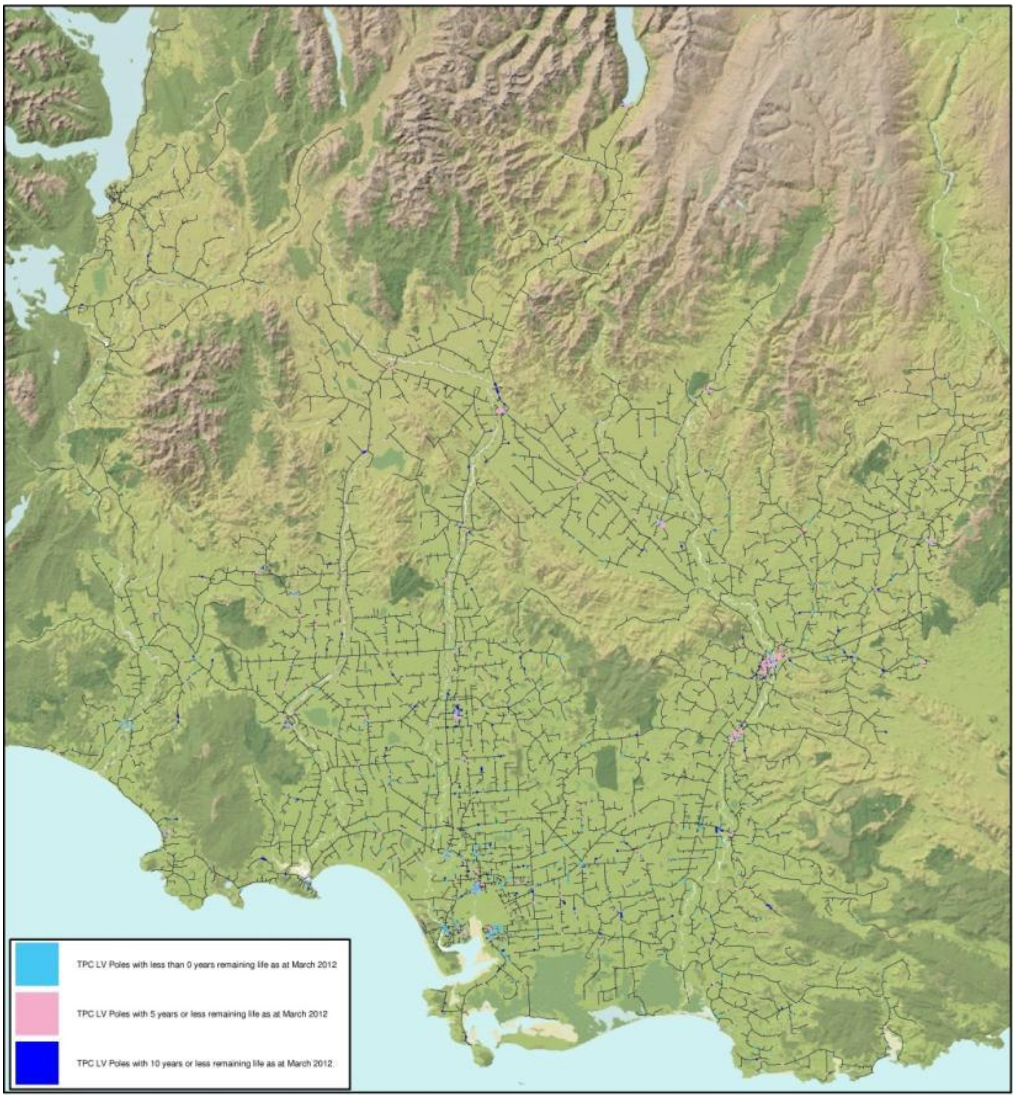

Figure 26 Low Voltage Poles with less than 10 years remaining life

2.3.8 LV cables [A.4.5.4.]

The age profile for low voltage cables is displayed below. Over the planning period an estimated 72.7km could be renewed, if it is found that the standard ODV life applies to these cables. The following 10 year period could is replacement of 24.0km.

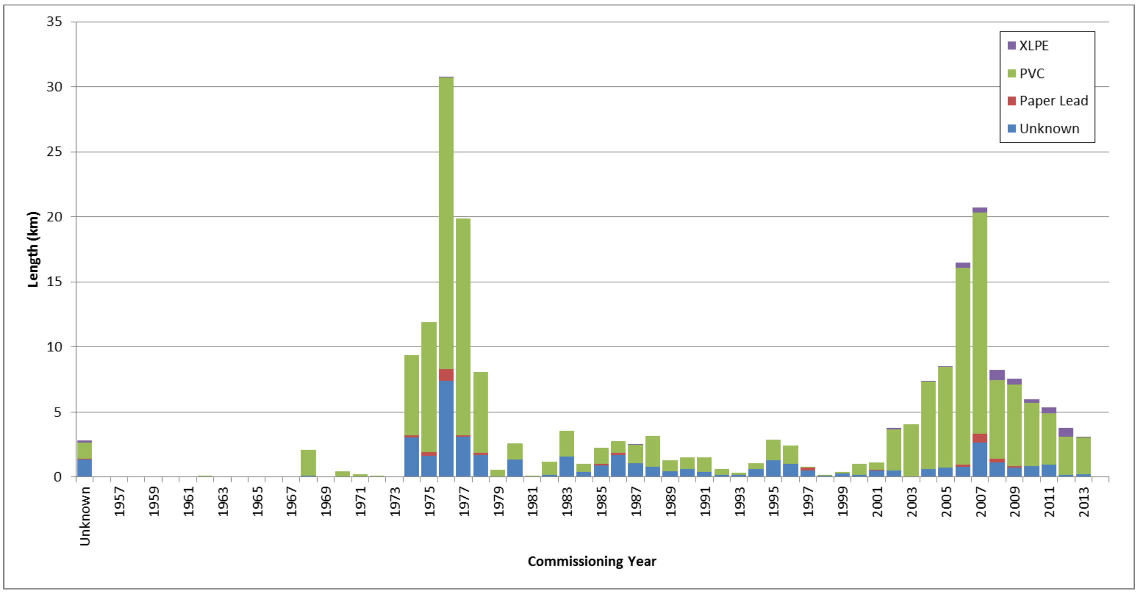

Figure 27 - Low Voltage Cables

2.3.9 Customer connection assets

No accurate age data exists for customer connection assets and generally these are renewed as they fail or are upgraded for increased customer requirements.

2.3.10 Load control assets

The installation of Load Control started with the injection plant at Invercargill in 1989 and finished at North Makarewa in 1994. Details are included with the GXP installed equipment. All 33kV plants are enclosed within buildings providing protection from the elements and therefore an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply units upgraded in 2005 after failures at other sites.

2.3.11 Distribution switchgear [A.4.5.6.]

Switches

The air break switchgear has the following age profile. The condition of these is generally poor with a proportion of older units. Additional evidence of this is the number of faulty units found each month when they fail to operate.

Fuses

There are 10,000+ drop-out fuses on the network protecting transformers and laterals. No known age profile exists but these have a relatively low failure rate.

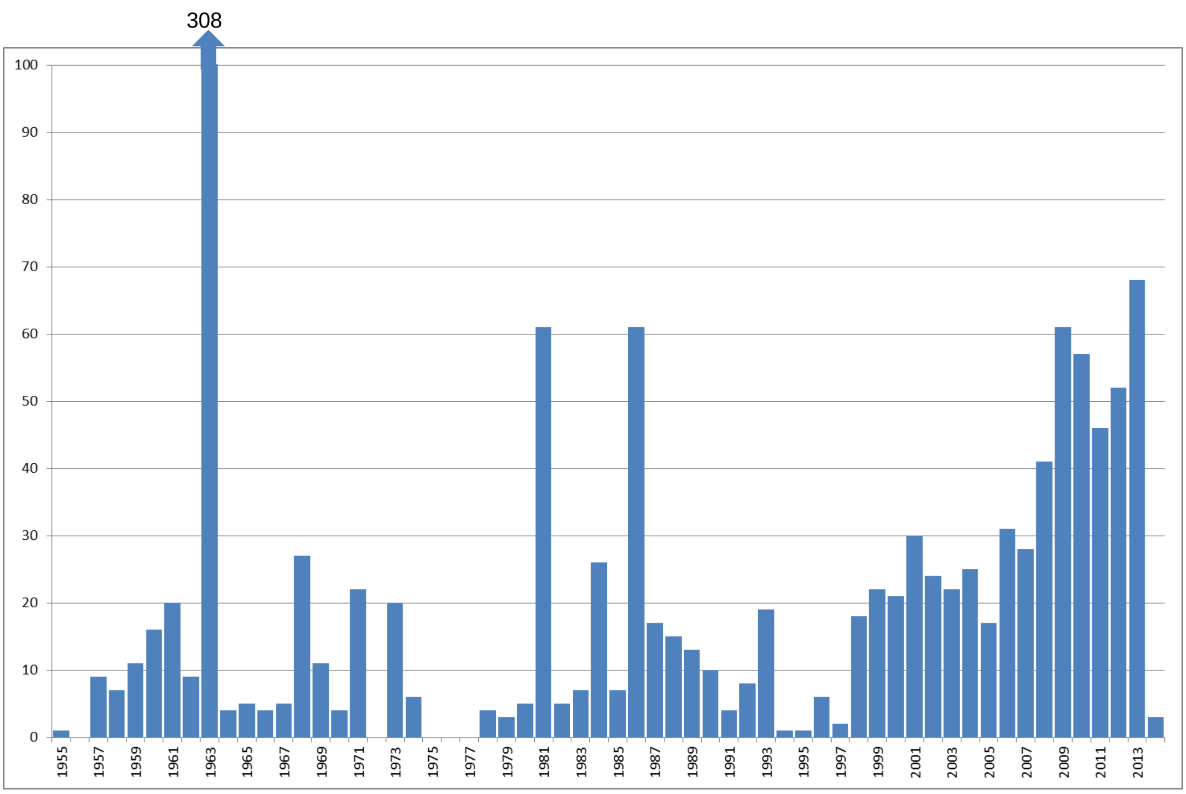

Figure 28 - Air Break Switches

2.3.12 Other assets [A.4.5.8.]

2.3.12.1 SCADA and Communications

(a) Master station

The initial system was commissioned in 1999 with a recent upgrade of the Server PC's in 2005. The software has been developed with the latest version being implemented with the new servers in 2005. Both operator stations now have LCD screens.

(b) Communications links

Standard life is 15 years and condition of older units is good. Manufacturer's support for all but Aprisa XE800 will end before 2018.

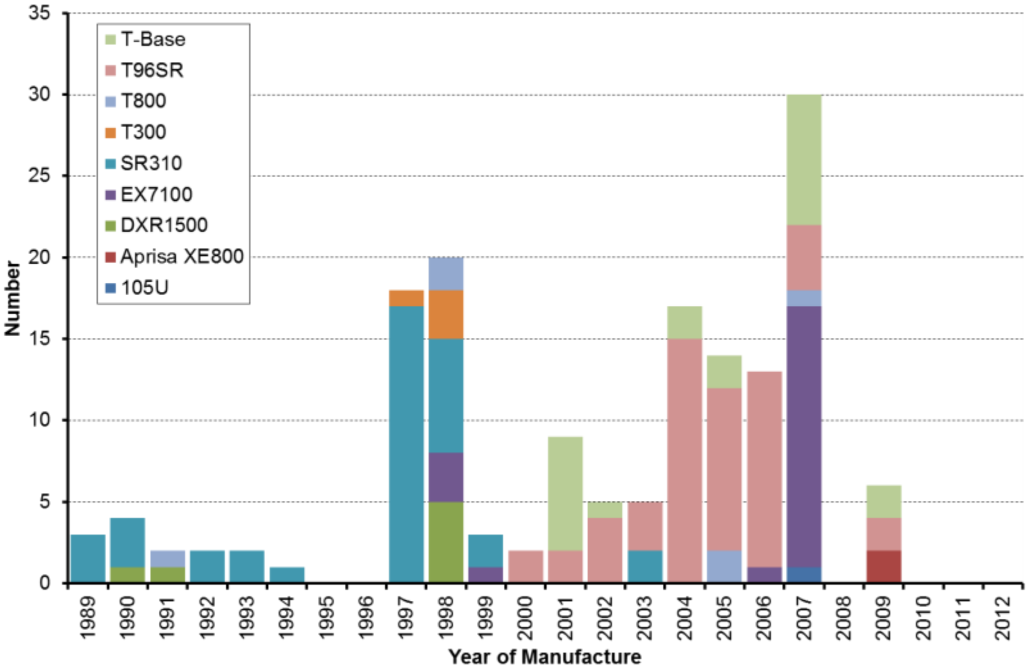

Figure 29 – Radios

2.3.12.2 Mobile generation

None.

2.3.12.3 Stand-by generators

None.

2.3.12.4 Power factor correction

None.

2.3.12.5 Mobile substations

One mobile 3MVA 11kV Regulator, on a heavy trailer. Condition of this unit is good with the trailer repainted and regulator maintained in during 2013.

2.3.13 Summary

TPCL's assets at the 2012 valuation are summarised in Table 8.

Table 8 - Summary of assets by category (as at 2012 Valuation)

Asset description	Quantity	Unit	Average remaining life as a percent of ODV Standard Life	Replacement Cost ($000)	Percent of RC
Ripple Injection	5	sites	15%	2,456	0.28%
66kV line	386	km	60%	49,974	5.69%
33kV line	454	km	39%	34,701	3.95%
33kV cable	7	km	80%	2,095	0.24%
Other zone substation assets		total	65%	16,211	1.85%
HV switchgear	360	units	64%	8,724	0.99%
MV switchgear	463	units	53%	10,861	1.24%
Power transformers	54	units	48%	31,553	3.59%

Asset description	Quantity	Unit	Average remaining life as a percent of ODV Standard Life	Replacement Cost ($000)	Percent of RC
Spares	348	units	44%	3,896	0.44%
MV line	6,732	km	39%	432,885	49.27%
MV cable	115	km	68%	20,302	2.31%
MV regulators	77	units	62%	2,656	0.30%
Distribution transformers	22,838	Units & sites	57%	102,795	11.70%
Distribution switchgear	13,310	units	34%	30,619	3.48%
LV lines	859	km	39%	61,898	7.05%
LV cable	208	km	54%	17,359	1.98%
LV switches, links etc.		units			0.00%
Street lighting circuits	271	km	37%	5,699	0.65%
SCADA and system control	495	units	59%	11,686	1.33%
Land and buildings	308	units	47%	16,561	1.88%
Connection assets	34,158	units	70%	15,674	1.78%
Total				**878,605**	

2.4 Justifying the assets

TPCL creates stakeholder service levels by carrying out a number of activities (described in section 5) on the assets, including the initial step of actually building assets such as lines and substations. Some of these assets need to deliver greater service levels than others e.g. TPCL's Waikiwi substation in north Invercargill has a higher capacity and security level than TPCL's Orawia substation in rural western Southland. Hence a greater level of investment will be required that will generally reflect the magnitude and nature of the demand.

Matching the level of investment in assets to the expected service levels requires the following issues to be considered:

- It requires understanding of how asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.
- It requires the asymmetric nature of under-investment and over-investment to be clearly understood i.e. over-investing creates service levels before they are needed but under-investing can lead to service interruptions (which typically cost about 10x to 100x, as much as over-investing as was discovered in Auckland in June 2006).
- It requires the discrete "sizes" of many classes of components to be recognised e.g. a 220kVA load will require a 300kVA transformer that is only 73% loaded. In some cases capacity can be staged through use of modular components.
- Recognition that TPCL's existing network has been built up over 80 years by a series of incremental investment decisions that were probably optimal at the time but when taken in aggregate at the present moment may well be sub-optimal.
- The need to accommodate future demand growth.

In theory an asset would be justified if the service level it creates is equal to the service level required. In a practical world of asymmetric risks, discrete component ratings, non-linear behaviour of materials and uncertain future growth rates, TPCL considers an asset to be justified if its resulting service level is not significantly greater than that required subject to allowing for demand growth and discrete component ratings.

A key practical measure of justification is the ratio of TPCL's optimised depreciated replacement cost (ODRC) to TPCL's depreciated replacement cost (DRC) which is 0.9916, with a ratio close to 1 indicating a high level of justification.

Assets that were optimised in the last ODV are listed in Table 9; together with a comment of changes since the 2004 ODV was completed.

Table 9 - Optimised Assets

Asset	Comment
Manapouri Substation	Retired from service.
Hillside to Manapouri 33kV line	Now operating at 11kV supplying south of Manapouri.
Waikaka to Pullar 33kV line	Disconnected, uneconomic to retire.
Pullar substation	All but civil works removed.
Underwood to Invercargill 33kV lines	Utilised to provide backup between North Makarewa and Invercargill GXP's.
North Makarewa to Invercargill 33kV (110kV)	Used as backup between GXP's.
Second 66kV Winton to Heddon Bush	Used as part of North Makarewa to Heddon Bush 66kV line.
Ohai substation	Extra 11kV circuit breakers are still in-service to provide quick change-over in event of power transformer failure.
Power transformer ratings.	Ratings are included in table 16, with Conical Hill transformers likely to be underutilised due to the closure of the Blue Mountain Lumber sawmill. Projected maximum demands are calculated in table 17.
Lines	ODV optimised 8.8km of heavy conductor to medium, 72.96km of medium to light and 52.97km of double circuit was optimised to single circuit.
Switchgear	68 ABS's were optimised and of these thirteen have been retired off the network.

3. Proposed service levels [A.5.]

This section describes how TPCL set its various service levels according to the following principles:

- What is most important to stakeholders (Section 1.7)
  - Safety
  - Viability
  - Price
  - Quality
  - Compliance
- How well is TPCL meeting those important objectives?
- What trade-offs exist between differing stakeholders? i.e.
  - Desire for ROI versus desire for low price with good reliability.
  - Safety at any cost?
  - Restoration ahead of compliance? (i.e. South Canterbury snow storm)

3.1 Creating service levels

TPCL creates a broad range of service levels for all stakeholders, ranging from capacity, continuity and restoration for connected customers (who pay for these service levels) to ground clearances, earthing, absence of interference, compliance with the District Plan and submitting regulatory disclosures (which are subsidised by connected customers), which are shown in Figure 30 below. This section describes those service levels in detail and how TPCL justifies the service levels delivered to its stakeholders.

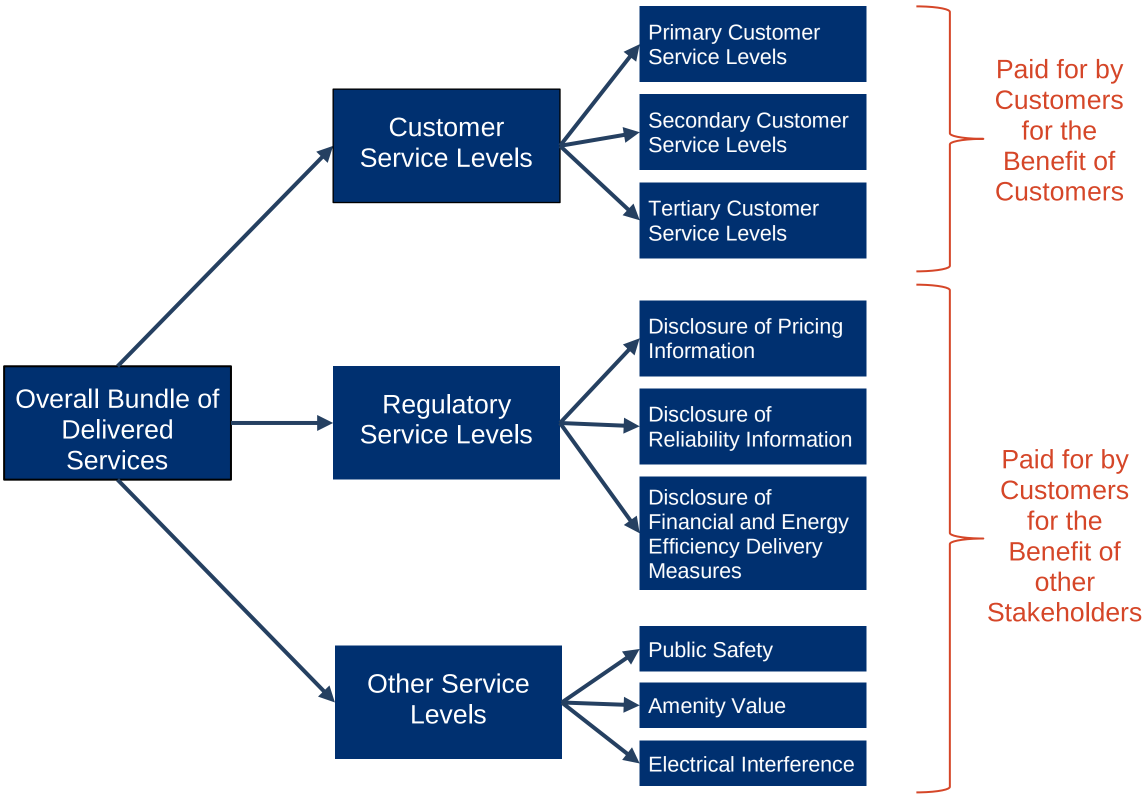

Figure 30 Types of service levels

3.2 Customer-oriented service levels

This section firstly describes the service levels TPCL expects to create for the customers, which are what they pay for and secondly the service levels TPCL expects to create for other key stakeholder groups which the customers are expected to subsidise.

Research indicates that customers value continuity and restoration of supply more highly than other attributes such as answering the phone quickly, quick processing of new connection applications etc. It has also become apparent from TPCL's research that there is an increasing value by customers placed on the absence of flicker, sags, surges and brown-outs. Other research however indicates that flicker is probably noticed more often than it is actually a problem.

The difficulty with these conclusions is that the service levels most valued by customers depend strongly on fixed assets and hence require capital expenditure solutions (as opposed to process solutions) to address which in itself raises the following three issues:

- Limited substitutability between service levels e.g. customers prefer TPCL to keep the power on rather than answer the phone quickly.
- Averaging effect i.e. all customers connected to an asset will receive about the same level of service.
- Free-rider effect i.e. customers who choose not to pay for improved service levels would still receive improved service due to their common connection[16].

3.2.1 Primary service levels

The surveyed customers have indicated that they value continuity and then restoration most highly; therefore TPCL's primary service levels are continuity and restoration. To measure performance in this area two internationally accepted indices have been adopted:

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

TPCL's targets for these measures for the next ten years ending 31 March 2025 are set out in Table 10 below.

	Normalised SAIDI			Normalised SAIFI		
	Class B (Planned)	Class C (Unplanned)	Total	Class B (Planned)	Class C (Unplanned)	Total
2015/16	35.74	120.25	155.99	0.178	2.499	2.680
2016/17	35.74	116.40	152.14	0.178	2.443	2.621
2017/18	35.74	113.84	149.58	0.178	2.388	2.566
2018/19	36.74	111.34	148.07	0.178	2.334	2.512
2019/20	36.74	109.67	146.40	0.178	2.322	2.500
2020/21	36.74	108.02	144.76	0.178	2.311	2.489
2021/22	36.74	107.48	144.22	0.178	2.299	2.477
2022/23	36.74	106.94	143.68	0.178	2.288	2.466
2023/24	36.74	106.41	143.15	0.178	2.276	2.454
2024/15	36.74	105.88	142.61	0.178	2.265	2.443

Table 10 - Primary Service Levels [A.6.

[16] This is the case with Invercargill and North Makarewa GXP's as they are more secure, due to the reliability required by the New Zealand Aluminium Smelter at Tiwai point.

In practical terms this means TPCL's customers can broadly expect the reliability below:

General location	Expected reliability[17]
Parts of Invercargill not supplied by EIL.	One outage per year of about 30 minutes duration
Large towns	Two outages per year of about 45 minutes duration
Small towns.	Three outages per year of about 60 minutes duration
Village	Four outages per year of about 120 minutes duration
Anywhere else	Five outages per year of about 240 minutes duration

Customers in all market segments surveyed indicated a preference for paying about the same line charges to receive about the same level of supply reliability.

3.2.2 Secondary service levels [A.7.1.]

Secondary service levels are the attributes of service that TPCL customers have ranked below the first and second most important attributes of supply continuity and restoration. The key point to note is that some of these service levels are process driven which has two implications:

- They tend to be cheaper than fixed asset solutions e.g. staff could work a few hours overtime to process a back log of new connection applications and could divert an over-loaded phone, or TPCL could improve the shut-down notification process.
- They are heterogeneous in nature i.e. they can be provided exclusively to customers who are willing to pay more in contrast to fixed asset solutions which will equally benefit all customers connected to an asset regardless of whether they pay.

These attributes include:

- How satisfied customers are after communication regarding:
    - Tree trimming
    - Connections
    - Faults.
- Time taken to respond to voltage complaints and time to remedy justified voltage complaints.
- Are customers given sufficient notice of planned shutdowns?

Table 11 below sets out the targets for these service levels for the next 3 years.

Table 11 - Secondary service levels

		Year Ending			
Attribute	**Measure**	**31/3/14**	**31/3/15**	**…**	**31/3/25**
Customer Satisfaction: New Connections	Phone: Friendliness and courtesy. {CSS: Q3(c)}[18]	>3.5[19]	>3.5	…	>3.5
	Phone: Time taken to answer call. {CSS: Q3(a)}	>3.5	>3.5	…	>3.5
	Overall level of service. {CSS: Q5(a)}	>3.5	>3.5	…	>3.5

[17] Except if directly connected to the faulty equipment….

[18] CSS = Customer Satisfaction Survey undertaken by sending questionnaire to customers with invoices.

[19] Where 1 = poor and 5 = excellent

		Year Ending			
Attribute	**Measure**	**31/3/14**	**31/3/15**	**…**	**31/3/25**
	Work done to a standard which meet your expectations. {CSS: Q4(b)}	>3.5	>3.5	…	>3.5
Customer Satisfaction: Faults	Power restored in a reasonable amount of time. {CES: Q4(b)}	>60%	>60%	…	>60%
	Information supplied was satisfactory. {CES: Q8(b)}	>60%	>60%	…	>70%
	PowerNet first choice to contact for faults. {CES: Q6}	>30%	>35%	…	>50%
Voltage Complaints {Reported in Network KPI report}	Number of customers who have made voltage complaints {NR}	<45	<45	…	<40
	Number of customers who have justified voltage complaints regarding power quality	<15	<15	…	<12
	Average days to complete investigation	<30	<30	…	<25
	Period taken to remedy justified complaints	<60	<60	…	<50
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>75%	>75%	…	>75%
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>75%	>75%	…	>75%
	Acceptance of maximum of one planned outage per year. {CES: Q1}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	>50%	>50%	…	>50%

{Where the information is collected / reported from.}

3.2.3 Other service levels

In addition to the service levels, that is of primary and secondary importance to customers and which they pay for there are a number of service levels that benefit other stakeholders such as safety, amenity value, absence of electrical interference and performance data. Some (in fact most) of these service levels are imposed on TPCL by statute and while they are for the public good, i.e. necessary for the proper functioning of a safe and orderly community, TPCL is expected to absorb the associated costs into its overall cost base.

3.2.3.1 Safety

Various legal requirements require TPCL's assets (and customers' plant) to adhere to certain safety standards which include earthing exposed metal and maintaining specified line clearances from trees and from the ground:

- Health and Safety In Employment Act 1992.
- Electricity (Safety) Regulations 2010.
- Electricity (Hazards From Trees) Regulations 2003.
- Maintaining safe clearances from live conductors (NZECP34:2001).
- EEA Guide to Power System Earthing Practice 2009 as a means of compliance with the Electricity (Safety) Regulations.

3.2.3.2 Amenity value

There are a number of Acts and other requirements that limit where TPCL can adopt overhead lines:

- The Resource Management Act 1991.
- The operative District Plans.
- Relevant parts of the operative Regional Plan.

- Land Transport requirements.
- Civil Aviation requirements.

3.2.3.3 Industry performance

Various statutes and regulations require TPCL to compile and disclose prescribed information to specified standards. These include:

- Electricity Distribution Information Disclosure Determination 2012.
- Commerce Act (Electricity Distribution Thresholds) Notice 2004.

3.2.3.4 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 TPCL's own equipment or TPCL's customers' plant. The following two codes impose service levels on us.

- Harmonic levels (NZECP36:1993).
- SWER load limitation to 8A (NZECP41:1993).

3.3 Regulatory service levels [A.7.2.]

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

- Ensure a wide degree of customer satisfaction with both pricing and reliability to avoid being placed under a restraining regime.
- Publicly disclose an AMP each year.
- Publicly disclose prescribed performance measures each year.

TPCL is also required to disclose a range of internal performance and efficiency measures as required by the Electricity Distribution Information Disclosure Determination 2012. However previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008 with the complete listing of these measures included in TPCL's disclosure to 31 March 20124 and with listing and analysis also on the Commerce Commission website

- http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

3.3.1 Financial efficiency measures

TPCL's projected financial efficiency measures are shown below. These measures are:

- Percentage of Operational Expenditure – [Operational Expenditure] / [Replacement cost of System Fixed Assets at year end]
- Indirect costs per ICP – [General Management, Administration and Overheads expenditure] / [Number of Connection Points (at year end)].
- All factors as defined in the Information Disclosure requirements.

Year ending	OPEX/RC %	Indirect costs/ICP
31/3/16	1.99%	$98.98
31/3/17	1.95%	$98.70
31/3/18	1.90%	$100.51
31/3/19	1.87%	$100.21
31/3/20	1.84%	$99.91
31/3/21	1.81%	$99.61
31/3/22	1.77%	$99.31
31/3/23	1.74%	$99.02
31/3/24	1.71%	$98.72
31/3/25	1.68%	$98.42

3.3.2 Energy delivery efficiency measures

Projected energy efficiency measures are shown below. These measures are:

- 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[20]].

Slight improvements are targeted but changes in peak management requirements have impacted the load factor. It may take a number of years for the Lower South Island (LSI) peak to settle down to a predictable level.

Loss ratio has varied due to reliance on annum sales quantities from retailers. As retailers are not reading the customers meter at midnight on the 31 December, some estimation methodology is required.

Year ending	Loss ratio	Load factor	Capacity utilisation
31/3/16	7.00%	65%	30%
31/3/17	7.00%	65%	31%
31/3/18	7.00%	65%	31%
31/3/19	7.00%	65%	31%
31/3/20	7.00%	65%	31%
31/3/21	7.00%	65%	31%
31/3/22	7.00%	65%	31%
31/3/23	7.00%	65%	31%
31/3/24	7.00%	65%	31%
31/3/25	7.00%	65%	31%

3.4 Justifying the service levels [A.8.]

TPCL's service levels are justified in five main ways:

- Positive cost benefit within revenue capability.
- By what is achievable in the face of skilled labour and technical shortages.
- By the physical characteristics and configuration of TPCL's assets which are expensive to significantly alter but which can be altered if a customer or group of customers agrees to pay for the alteration.
- By a customer's specific request and agreement to pay for a particular service level.
- When an external agency imposes a service level on TPCL or in some cases an unrelated condition or restriction that manifests as a service level such as requirement to place all new lines underground or a requirement to increase clearances.

Customer surveys over the last three years have indicated that customers' preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for increased supply reliability. However TPCL does note the following issues:

- The service level called 'Safety' may need to increase as the requirements of the amended Electricity Act 1992 become operative.
- Food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets, and in particular interruptions to cooling and chilling are less

[20] Capacity utilisation now includes an estimate of the capacity of customer owned distribution transformers.

acceptable. This requires TPCL's cold storage customers to have higher levels of continuity and restoration.

- Economic downturn may increase the instance of theft of materials and energy.

3.4.1 Basis for service level targets [A.9.]

Statistics for the last five years are listed below:

Measure	YE 31/3/10	YE 31/3/11	YE 31/3/12	YE 31/3/13	YE 31/3/14
SAIDI	214.4	209.06	238.10	191.4	177.8
SAIFI	3.16	3.21	3.04	2.59	2.87
Load factor	64%	63%	64%	64%	62%
Loss ratio	6.8%	6.8%	6.6%	7.2%	7.2%
Capacity utilisation	30.0%	29.5%	30.3%	29.5%	30.2%
OPEX % / RC	1.96%	1.84%	1.93%	2.16%	2.13%
Indirect/ICP	$70.57	$67.50	$79.46	$109.67	$69.05

3.4.1.1 Reliability

Industry results for the four years are shown in Figure 31 and 32. These show TPCL near the industry average but due to the low customer density and region covered the performance is considered good. This view is supported with the Customer survey result that 97% of people considered that faults were restored within a reasonable time.

We plan to normalise extreme events using the Commerce Commission DPP methodology. Target is calculated by averaging the normalised values, over the previous five years, and decreasing future years by 0.25% p.a. In addition, the distribution automation project is expected to provide increased reliability by reducing SAIFI by 7% and SAIDI by 8.8% after completion of the 4 year project – this has been estimated shown as annual reductions to SAIFI by 1.75% and SAIDI by 2.2%. Following completion of the automation project, the main focus will be to maintain similar reliability levels. These metrics are required to be reported for legislative monitoring.

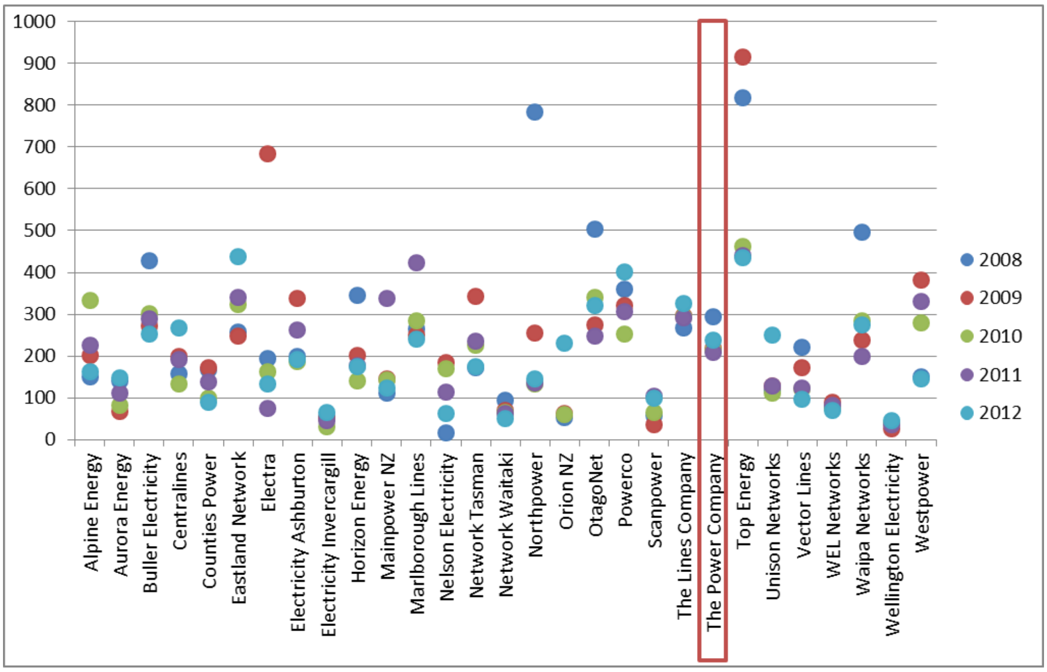

Figure 31 - Information disclosure data: SAIDI

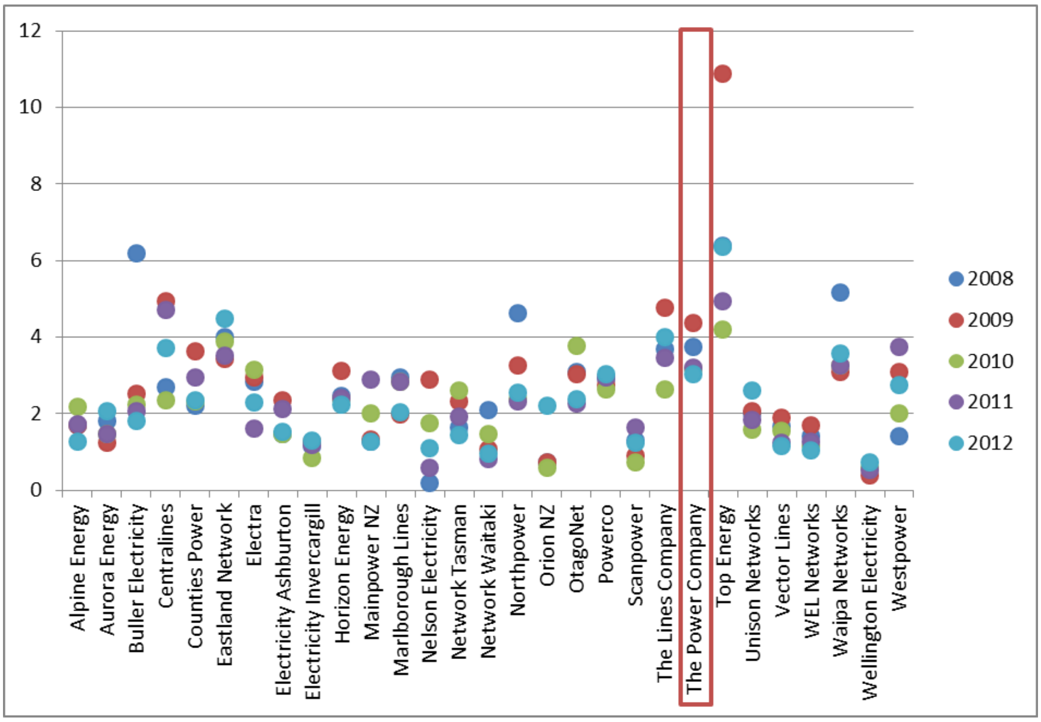

Figure 32 - Information disclosure data: SAIFI

3.4.1.2 Load Factor

LSI peak is due to New Zealand Aluminium Smelter (NZAS) and other network companies, with recent LSI peak occurring during winter due to demand in the cities and Dairy production beginning. This meant that peak load control was not required and results in a higher peak, as load control for peak reduction on each GXP was not needed.

TPCL's Load Factor is average with slight improvement due to transformer rationalisations planned. This metric is required to be reported for legislative monitoring.

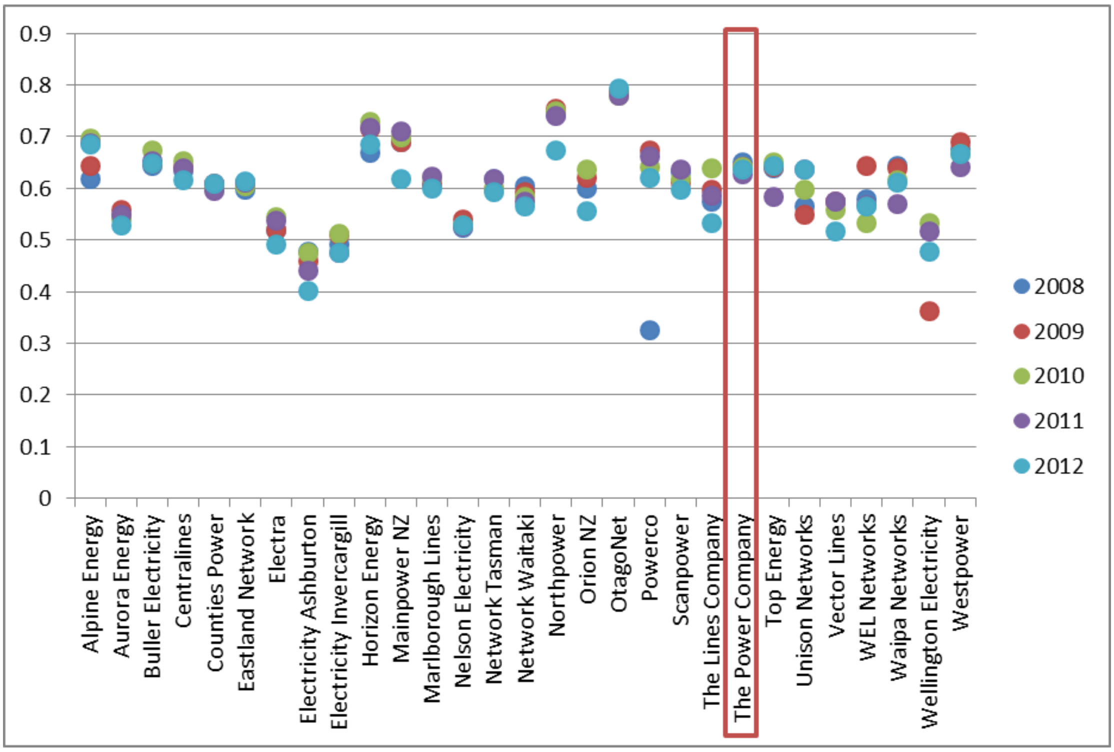

Figure 33 - Information disclosure data: Load Factor

3.4.1.3 Loss Ratio

Growth of Dairy Farms has increased loading on some feeders with the square-law impact on losses. i.e., a doubling of load would quadruple losses. Some minor reductions in losses due to poor voltage or current rating of equipment are remedied.

Comparison with others in the industry shows TPCL is on par with similar rural companies, therefore no change in target planned. This metric is required to be reported for legislative monitoring.

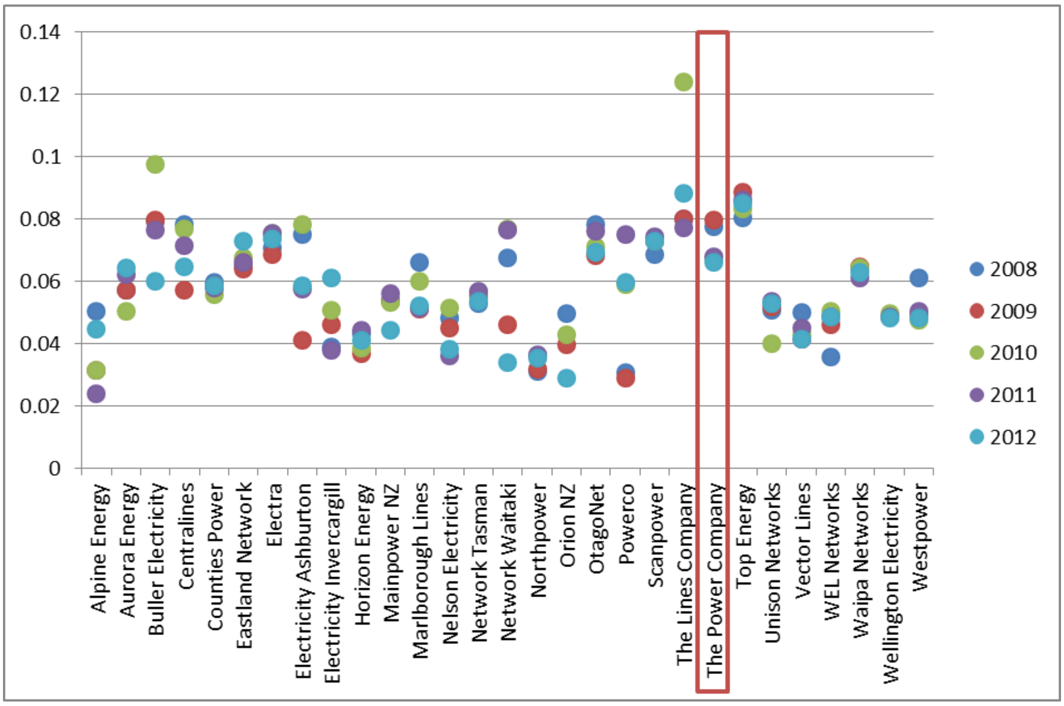

Figure 34 - Information disclosure data: Losses

3.4.1.4 Customer Survey

Target set at a level felt to be desirable as a good corporate citizen, due to historic trend and likely impact of targeted improvements.

For example: More Public Relations with newsletter and fridge-magnet should increase PowerNet as first point of contact for faults.

3.4.1.5 Capacity Utilisation

Impact of Dairy boom is likely to impact with a large number of larger capacity transformers installed to supply new farms. The load profile on these is very peaky with no rationalisation[21] of transformers, as dairy sheds are normally distant from existing farm house. Only very minor improvement expected. Compared to other electricity lines businesses TPCL is average, therefore no change in strategy is planned. This metric is required to be reported for legislative monitoring.

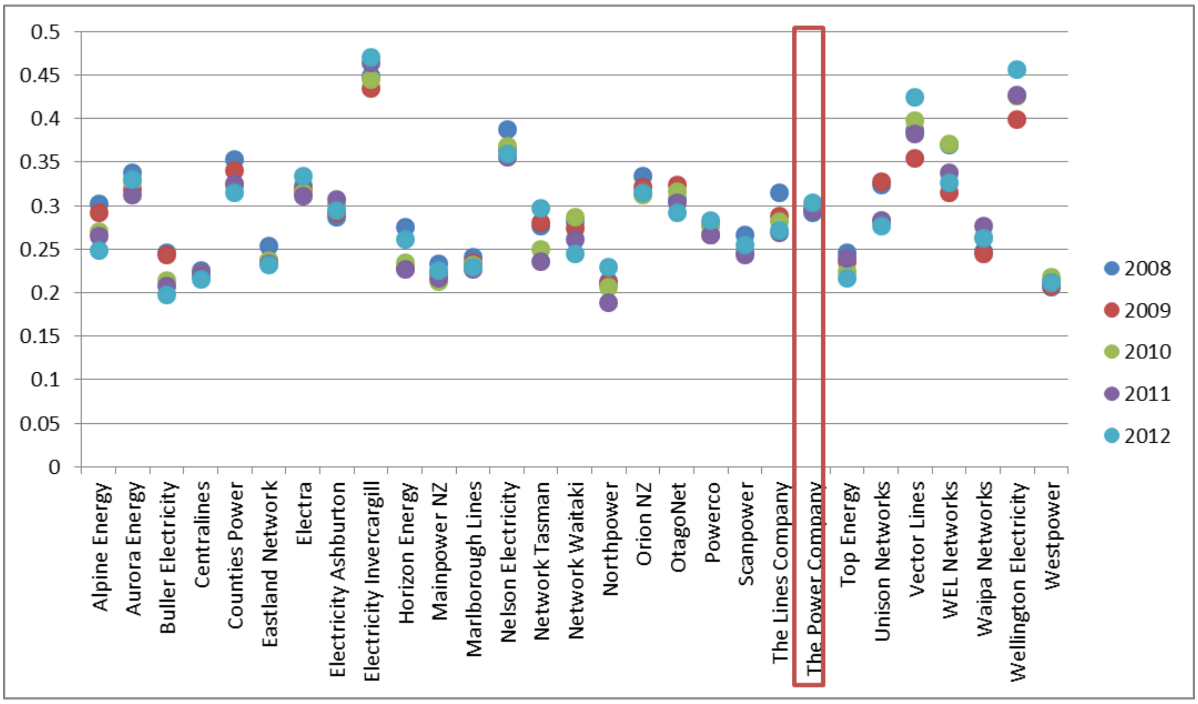

Figure 35 - Information disclosure 2011 data: Capacity Untilisation

3.4.1.6 Financial service levels

Due to TPCL having one of the lowest customer densities the financial service levels could be at the top end of New Zealand electricity lines businesses. Data from the 2011 Information Disclosure on Operational Expenditure Ratio (OPEX/RC) shows that TPCL is the second lowest as shown in Figure 36. The General management, administration and overheads cost (a.k.a. Indirect.) per connection is shown in Figure 37, with TPCL being the sixth lowest cost.

Based on the good ranking of TPCL in these measures the plan is to maintain these good results. The targets are set based on our projections, with budgeted costs, network growth and customer growth at 100 per year. Any higher growth or reduction in indirect costs will improve this efficiency measure.

These metrics are required to be reported for legislative monitoring.

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[21] Rationalisation is where one transformer is used to supply multiple customers, with peaks occurring at differing times a smaller installed capacity usually results. i.e. Dairy Shed transformer of 50kVA can normally supply the farm house, but due to distances usually requires its own 15kVA transformer.

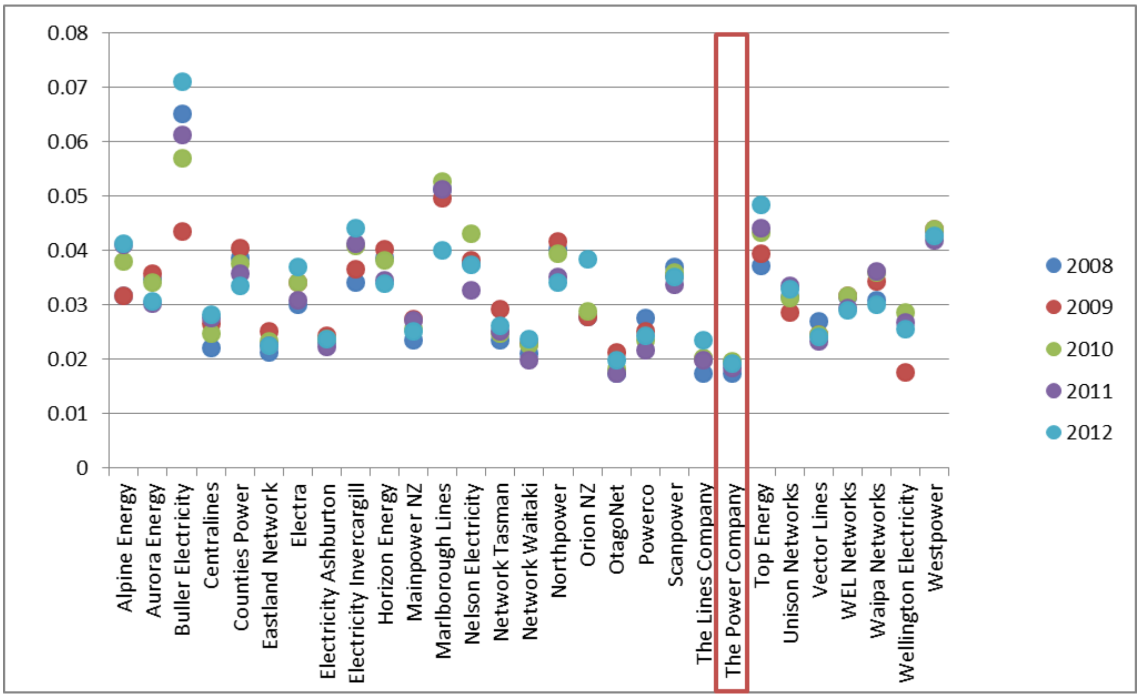


Figure 36 - Information disclosure data: OPEX/RC

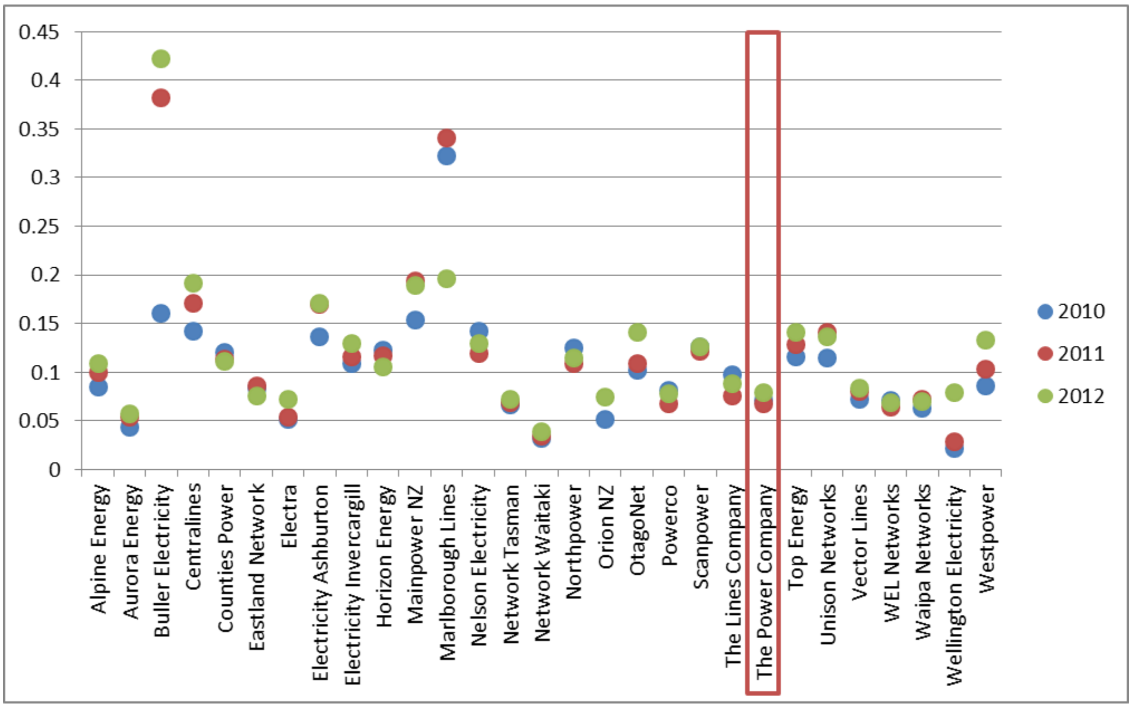


Figure 37 - Information disclosure data: General management, administration and overheads per Installation Connection Point

4. Development plans

Development plans are driven primarily by:

- Increasing customer demand, can be due to growth or generation
- Asset renewal requirements
- Statutory requirements to improve service levels (Security of supply, safety or environmental compliance)
- Internally generated initiatives to improve service levels

At its most fundamental level, demand is created by individual customers drawing (or injecting) energy across their individual connections. 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 a power station. Load diversity tends to favour better load factor and capacity utilisation more and more with this aggregation of load up the network.

4.1 Planning approach and criteria [A.3.13.2. & A.11.1.]

4.1.1 Planning unit

TPCL has adopted the 11kV feeder as TPCL's fundamental planning unit which typically represents one or perhaps two of the following combinations of customer connections:

- An aggregation of up to 1,000 urban domestic customer connections.
- An aggregation of up to 200 urban commercial customer connections.
- An aggregation of up to 30 urban light industrial customer connections.
- An aggregation of anywhere up to 500 rural domestic or farm customer connections.
- A single large industrial customer connection.
- Injection of generation.

Physically this planning unit will usually be based around the individual lines or cables emanating from a zone substation. For single load of more than 1MW (i.e., beyond what is considered incremental) TPCL's planning principles and methods still apply, but the likely outcome is new assets at 11kV or higher.

4.1.2 Planning approaches

TPCL plans its assets in three different ways; strategically, tactically and operationally as shown in Table 12 below:

Table 12- Planning approaches

Attribute	Strategic	Tactical	Operational
Asset description	Assets within GXP. Subtransmission lines and cables. Major zone substation assets. Load control injection plant. Central SCADA and telemetry. Distribution configuration e.g. decision to upgrade to 22kV.	Minor zone substation assets. All individual distribution lines (11kV). All distribution line hardware. All on-network telemetry and SCADA components. All distribution transformers and associated switches. All HV customer connections.	All 400V lines and cables. All 400V customer connections. All customer metering and load control assets.
Number of customers supplied	Anywhere from 500 upwards.	Anywhere from one to about 500.	Anywhere from one to about 50.

Attribute	Strategic	Tactical	Operational
Impact on balance sheet and asset valuation	Individual impact is high. Aggregate impact is moderate.	Individual impact is moderate. Aggregate impact is significant.	Individual impact is low. Aggregate impact is moderate.
Degree of specificity in plans	Likely to be included in very specific terms, probably accompanied by an extensive narrative.	Likely to be included in specific terms and accompanied by a paragraph or two.	Likely to be included in broad terms, with maybe a sentence describing each inclusion.
Level of approval required	Approved in principle in annual business plan. Individual approval by Board and possibly shareholder.	Approved in principle in annual business plan. Individual approval by Chief Executive.	Approved in principle in annual business plan. Individual approval by Chief Engineer.
Characteristics of analysis	Tends to use one-off models and analyses involving a significant number of parameters and extensive sensitivity analysis.	Tends to use established models with some depth, a moderate range of parameters and possibly one or two sensitivity scenarios.	Tends to use established models based on a few significant parameters that can often be embodied in a "rule of thumb".

TPCL has developed the following "investment strategy matrix" shown in Figure 38, which broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

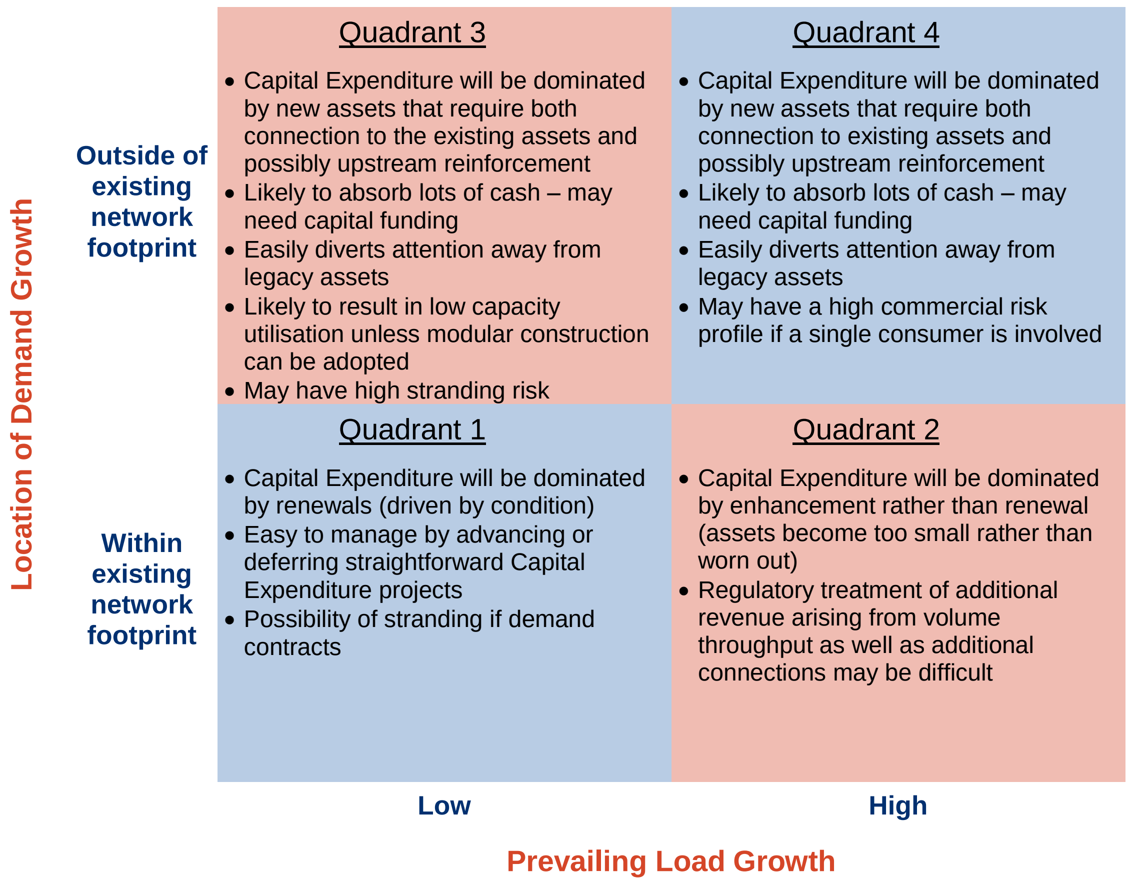


Figure 38 - Investment strategy matrix

Predominant capital expenditure (CAPEX) modes are:

- Large industrial loads such as a new factory, which involves firstly extension and then usually up-sizing, sit in Quadrant 4 which has desirable investment characteristics. This mode of investment does however carry the risk that if demand growth doesn't occur as planned, stranding can occur and the investment slips into Quadrant 3 which has less desirable investment characteristics.

- Dairy conversions involve extensions and then sometimes up-sizing but due to the lumpy nature of constructing line assets these may fall into Quadrant 3 which carries some risk of stranding or delayed recovery of investment.
- Declining cost of domestic heat pumps primarily requires urban up-sizing which fits mainly in Quadrant 2, which has reasonably desirable investment characteristics.
- Residential subdivisions around urban areas tend to have large up-front capital costs but recovery of costs through line charges often lags well behind. The size of the subdivision will dictate whether it falls in Quadrant 1 or 3, neither of which has particularly desirable investment characteristics. Hence some form of developer contribution is almost certain to be expected.

4.1.3 Trigger points for planning new capacity [A.11.2.]

As new capacity has valuation, balance sheet, depreciation and ROI implications for TPCL, endeavours will be made to meet demand by other less investment-intensive means. This discussion also links strongly to TPCL's discussion of asset life cycle in section 5.1.

The first step in meeting future demand is to determine if the projected demand will exceed any of TPCL's defined trigger points for asset location, capacity, reliability, security or voltage. These points are outlined for each asset class in Table 13.

If a trigger point is exceeded TPCL will then move to identify a range of options to bring the asset's operating parameters back to within the acceptable range of trigger points. These options are described in section 4.2 which also embodies an overall preference for avoiding new capital expenditure.

Table 13 - Summary of capacity "trigger points"

		Asset class		
Type	**Trigger**	**LV lines and cables**	**Distribution substations**	**Distribution lines and cables**
Extension	**Location**	Existing LV lines and cables don't reach the required location.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and substation.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and substation.
Up-sizing	**Capacity**	Tends to manifest as fuse blowing when current exceeds circuit rating.	Where fitted, MDI reading exceeds 90% of nameplate rating.	Analysis calculates that the peak current exceeds the thermal rating of the circuit segment.
	Reliability	Not applicable. Normally a Maintenance or Operational trigger, as no requirement for up-sizing.		
	Security	Excursion beyond triggers specified in section 3.2.1.		
	Voltage	Voltage at customers' boundary consistently drops below 0.94pu.	Voltage at customers' boundary consistently drops below 0.94pu that cannot be remedied by LV up-sizing.	Voltage at MV terminals of transformer consistently drops below 10.45kV and cannot be compensated by local tap setting.
Renewal	**Condition**	Asset deteriorated to an unsafe condition. Third party requests work. Neighbouring assets being replaced.		

		Asset Class		
Type	**Trigger**	**Zone substations**	**Subtransmission lines and cables**	**Network equipment within GXP**
Extension	**Location**	Load cannot be reasonably supplied by distribution configuration therefore requires new subtransmission lines or cables and zone substation.	Load cannot be reasonably supplied by distribution configuration therefore requires new subtransmission lines or cables and zone substation.	Load cannot be reasonably supplied by new or extended Subtransmission or substation therefore requires new GXP equipment.
Up-sizing	**Capacity**	Max demand consistently exceeds 100% of nameplate rating.	Analysis calculates that the peak current exceeds the thermal rating of the circuit segment.	Max demand consistently exceeds 80% of nameplate rating.
	Reliability	Not applicable. Normally a Maintenance or Operational trigger, as no requirement for up-sizing.		
	Security	Excursion beyond triggers specified in section 3.2.1.		
	Voltage	Voltage at MV terminals of transformer consistently drops below 10.45kV and cannot be compensated by OLTC.	Voltage at HV terminals of transformer consistently drops below 0.87pu and cannot be compensated by OLTC.	Not applicable.
Renewal	**Condition**	Asset deteriorated to an unsafe condition. Third party requests work.		

4.1.4 Quantifying new capacity [A.11.6.]

The two major issues surrounding constructing new capacity are:

- How much capacity to build? This comes back to the trade-off between cost and building in extra capacity for security and safety (risk-avoidance).
- When to build the new capacity? The obvious theoretical starting point for timing new capacity is to build just enough just in time, and then add a bit more over time.

However TPCL recognises the following practical issues which direct timeframes and mean that a certain degree of overbuild typically works out as the most economic option:

- The need to avoid risks associated with over-loading and catastrophic failure.
- The need to limit investment to what can be recovered to Shareholder requirements.
- The one-off costs of consenting, traffic management, access to land and reinstatement of sealed surfaces making it preferable to install large lumps of capacity to avoid multiple disruptions to a site.
- The standard size of many components (which makes investment lumpy).
- That while assets may be relocated, the often dominant construction and labour component of any installation cost cannot generally be recovered.

Selection of the right capacity to build is based on the following:

- Overhead lines:
    - MV routes between zone substations, a minimum of Helium conductor.
    - Usually set by voltage drop limits and strength requirements.
    - MV laterals Chlorine conductor.
    - LV: allow 20% growth.

- Cables:
  - Allow growth over expected lifetime when known or otherwise 100% growth.
- Distribution transformers:
  - Individual customers, size to customer capacity.
  - Domestic customers based on following diversity:

Customers	Transformer Size
2	15kVA
6	30kVA
10	50kVA
20	100kVA
50	200kVA
80	300kVA
150	500kVA

- Line equipment:
  - Use standard ratings (e.g. ABS 400A, Recloser 400A).
- Power transformers:
  - Allow expected area growth over 20 years.
- Substation equipment:
  - Use standard ratings.
- Subtransmission lines:
  - Allow expected area growth over 20 years.

TPCL's guiding principle is therefore to minimise the level of investment ahead of demand, while minimising the costs associated with doing the work.

4.2 Prioritisation methodology [A.11.7.]

4.2.1 Options for meeting demand

Table 13 defines the trigger points at which the capacity of each class of assets needs to be increased. In a broad order of preference, actions to increase the capacity of individual assets within these classes can take the following forms:

- 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 is unacceptably low for a short period at the height of the holiday season – the benefits of correcting such a constraint may be simply too low.
- 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.
- Influence customers to alter their consumption patterns so that assets perform at levels below the 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 dampened by the retailers' practice of repackaging fixed and variable charges.
- Construct distributed generation so that an adjacent asset's performance is restored to a level below its trigger points. Distributed generation 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 is essentially a subset of the above approach but will generally involve less expenditure. This approach is more suited to larger classes of assets such as power transformers.
- 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.
- Install new assets with a greater capacity that will increase the assets trigger point to a level at which it is not exceeded. An example would be to replace a 200kVA distribution transformer with a 300kVA so that the capacity criterion is not exceeded.

In identifying solutions for meeting future demands for capacity, reliability, security and satisfactory voltage levels TPCL considers options that cover the above range of categories. The benefit-cost ratio of each option is considered including estimates of the benefits of public safety and environmental compliance and the option yielding the greatest benefit is adopted. TPCL uses the model in figure 39 to broadly guide adoption of various approaches:

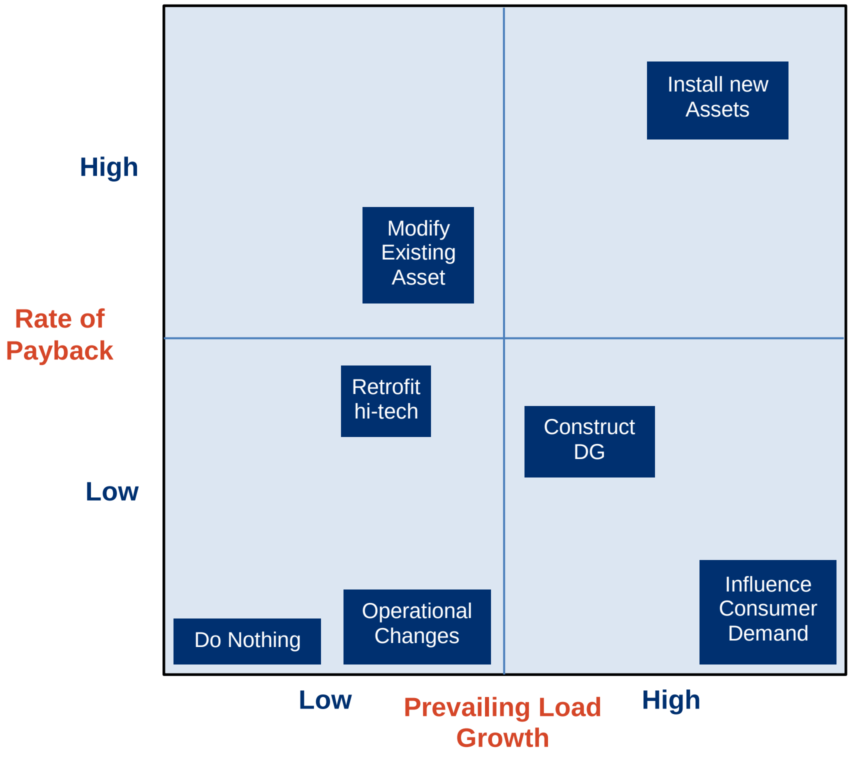


Figure 39 - Options for meeting demand

4.2.2 Meeting security requirements

A key component of security is the level of redundancy that enables supply to be restored independently of repairing or replacing a faulty component. Typical approaches to providing security to a zone substation include:

- Provision of an alternative substation-transmission circuit into the substation, preferably separated from the principal supply by a 66kV or 33kV switch.
- Provision to back-feed on the 11kV from adjacent substations where sufficient 11kV capacity and interconnection exists. This obviously requires those adjacent substations to maintain spare capacity.
- Use of local generation.
- Use of interruptible load (water heating, irrigation).

The most pressing issue with security is that it involves a level of investment beyond what is obviously required to meet demand and it can be easy to let demand growth erode this surplus capacity.

4.2.2.1 Prevailing security standards

The commonly adopted security standard in New Zealand is the EEA Guidelines which reflect the UK standard P2/5 that was developed by the Chief Engineers' Council in the late 1970's. P2/5 is a strictly deterministic standard i.e. it states that "this amount and nature of load will have this level of security" with no consideration of individual circumstances.

Deterministic standards are now beginning to give way to probabilistic standards in which the value of lost load and the failure rate of supply components is estimated to determine an upper limit of investment to avoid interruption.

4.2.2.2 Issues with deterministic standards

A key characteristic of deterministic standards such as P2/5 and the EEA Guidelines is that rigid adherence generally results in at least some degree of over investment. Accordingly the EEA Guidelines recommend that individual circumstances be considered.

4.2.2.3 Contribution of local generation to security

To be of any use from a security perspective, local generation would need to have 100% availability which is unlikely from a reliability perspective and even less likely from a primary energy perspective such as run-of-the-river hydro, wind or solar. For this reason, the emerging UK standard P2/6 provides for minimal contribution of such generation to security.

4.2.2.4 TPCL security standards

Table 14 below describes the security standards adopted by TPCL, whilst Table 15 lists the level of security at each zone substation, including any planned changes and justifies any shortfall. In setting target security levels the following guiding principles are used:

- Where a substation is for the predominant benefit of a single customer, their wish for security will over-ride prevailing industry guidelines.
- The preferred means of providing security to rural zone substations will be back-feeding on the 11kV subject to interconnection, line ratings and surplus capacity at adjacent substations.
- The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feeding on the 11kV providing a third tier of security.

Table 14 - Target security levels

Description	Load type	Security level
AAA	Greater than 12MW or 6,000 customers.	No loss of supply after the first contingent event.
AA	Between 5 and 12MW or 2,000 to 6,000 customers.	All load restored within 25 minutes of the first contingent event.
A(i)	Between 1 and 5MW	All load restored in time to isolate and back-feed following the first contingent event.
A(ii)	Less than 1MW	All load restored in time to repair after the first contingent event.

Table 15 - Substation security levels

Substation	Target 2025	Actual Now	Remarks
Athol (New)	A(i)		
Awarua		A(i)	
Colyer Road (New Awarua)	AA		Depends if new load occurs.
Awarua Chip Mill	A(ii)	A(ii)	Major voltage dip during motor start will affect other customers if alternative supply route used.

Substation	Target 2025	Actual Now	Remarks
Balfour (New)	A(i)		
Bluff	AA	AAA	
Centre Bush		A(i)	
Centre Bush (66/11kV)	AA		Subtransmission upgraded from 33kV to 66kV.
Conical Hill	A(i)	AAA	Sawmill closed/moth-balled.
Dipton		A(i)	
Dipton (66/11kV)	A(i)		Subtransmission upgraded from 33kV to 66kV.
Edendale Fonterra	AAA	AAA	
Edendale	AA	AAA	Fonterra down-stream plant supplied off this substation.
Glenham	A(i)	A(i)	
Gorge Road	A(i)	A(i)	
Hedgehope (New)	A(i)		
Hillside	A(i)	A(i)	
Isla Bank (New)	A(i)		
Kelso		A(i)	Depends if growth occurs.
Kelso (upgraded)	AA		
Kennington	AA	A(ii)	Need mobile regulator to restore full load. Needs alternate 33kV line to site.
Lumsden	A(i)	A(i)	Need mobile regulator to restore full load during peak load.
Makarewa	AA	AAA	
Mataura		AA	Can switch over onto Edendale GXP.
Mataura (Upgraded)	AA		
Monowai	A(ii)	A(ii)	
Mossburn	A(i)	AA	Backup 33/11kV will go when line moved over to 66kV.
North Gore	AAA	AAA	Gore hospital supplied off this substation.
North Makarewa	AAA	AAA	Spare supply transformer at Mossburn.
Ohai	A(i)	A(i)	
Orawia	A(i)	A(i)	
Otatara	AA	A(i)	Backup 11kV from EIL.
Otautau	A(i)	A(i)	New Isla Bank will limit demand to under 5MVA.
Racecourse Rd (EIL)	A(i)	A(i)	
Riversdale		A(i)	Low voltage if supplied from Lumsden, but will be okay when Lumsden 66/33kV is completed.
Riversdale (upgraded)	AA		Tee-off 33kV line has no alternative.
Riverton	AA	AAA	Spare 66/11kV 5/7.5MVA transformer in service at this site.
Seaward Bush		AAA	Southland base hospital supplied off this substation.
Seaward Bush (Upgraded)	AAA		
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(i)	

Substation	Target 2025	Actual Now	Remarks
Waikiwi		AA	Need to switch-over to alternate 33kV if supplying 33kV faults.
Waikiwi (Upgraded)	AAA		
White Hill (Wind)	A(ii)	A(ii)	
Winton	AAA	AAA	New Hedgehope and Isla Bank substations will limit demand to under 12MVA.

4.2.3 Choosing the best option to meet demand

Each of the possible approaches to meeting demand that are outlined in section 4.2.1 will contribute to strategic objectives in different ways. TPCL uses a number of decision tools to evaluate options depending on their cost:

Cost & nature of option	Decision tools	Organisational level of evaluation
Up to $50,000, commonly recurring, individual projects not tactically significant but collectively they do add up.	TPCL standard rules. Industry rules of thumb. Manufacturer's tables and recommendations. Simple spreadsheet model based on a few parameters.	GM Customer, Metering and Distribution Services
Up to $500,000, individual projects of tactical significance.	Spreadsheet model to calculate NPV that might consider 1 or 2 variation scenarios.	Chief Engineer
Up to $2,500,000 occurs maybe once every few years, likely to be strategically significant.	Extensive spreadsheet model to calculate NPV, Payback that will probably consider several variation scenarios. Use of optimisation tools. Business case presented to board for approval for projects >$1,000,000	Chief Executive
Over $2,500,000 occurs maybe once in a decade, likely to be strategically significant.	Extensive spreadsheet model to calculate NPV, Payback that will probably consider several variation scenarios. Use of optimisation tools.	Board approval

4.2.4 Project prioritisation

Designer and planners use the 'decision tools' on projects to enable prioritisation and rationing of our resources. Large projects have differing alternatives scored and the tools grade each with factors/weightings determined by the Board. Consideration is also given to the Risk Profile of each option and this is also useful in selecting projects.

The Manager in each area prioritises the work based on their need to meet service standards. Level of budget is adjusted due to trends in service levels; therefore if service levels are steady, expenditure would remain the same. Some abnormal situations[22] do distort results and these are considered in setting targets and expenditure.

[22] Abnormal situations: Major storms, significant planned outages, dry year rationing, external party major equipment failures.

4.3 TPCL's demand forecast [A.11.8.]

4.3.1 TPCL's current demand

TPCL's Transpower maximum demand (MD) of 135.1 MW on 16 October 2013 at 8am, did not occur at the same time as the Lower South Island (LSI) peak at 9am on the 10 July 2013. The individual maximum demands and the LSI coincident demands are shown in Figure 40. Note that for the other generators no export of energy into the network occurred at these times.

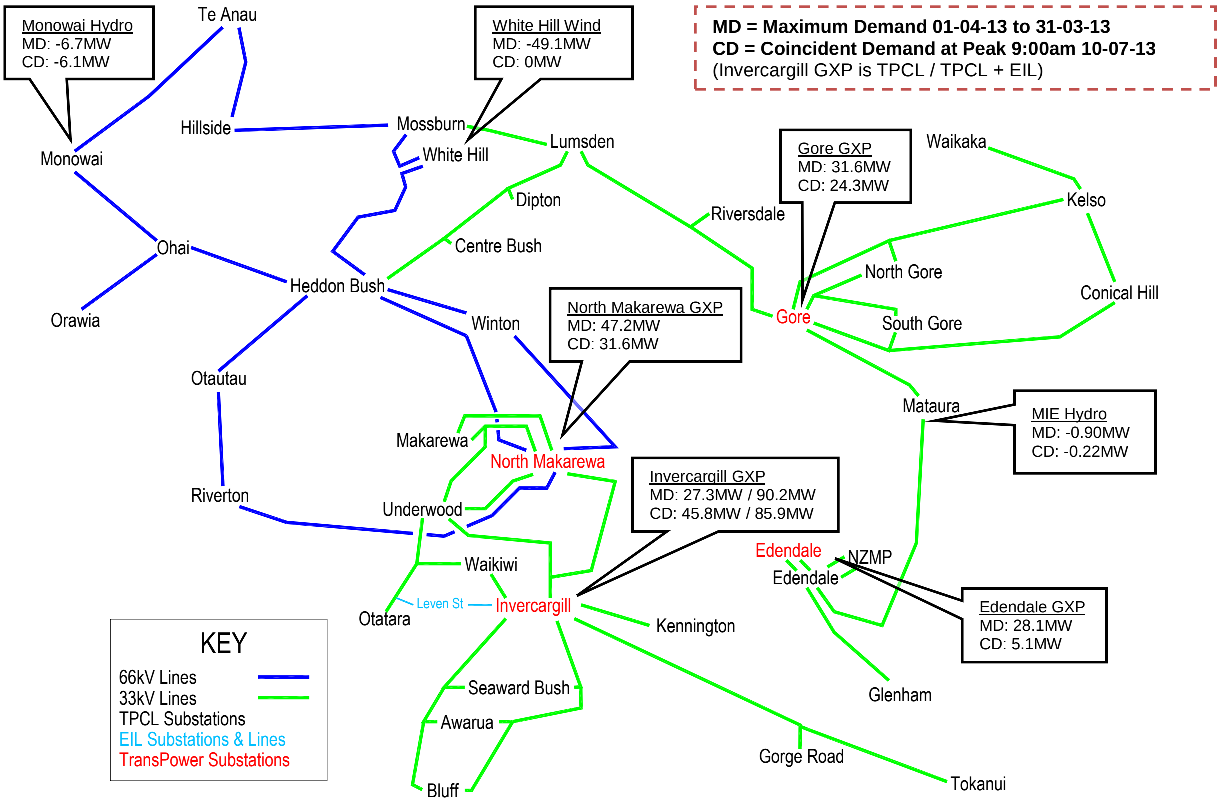


Figure 40 - GXP and Generation Demands

Each zone substation recorded the maximum demands as listed in Table 16. The 99.9 percentile demand is given to remove any short term load transfers and is more indicative of actual area maximum demand.

Table 16 substation demand

Zone substation	Firm Capacity (MVA)	2014 Maximum Demand (MVA)	99.90% 2014 (MVA)	99.90% 2013 (MVA)	99.90% 2012 (MVA)	99.90% 2011 (MVA)	99.90% 2010 (MVA)
Awarua	5.0	4.07	3.69	3.76	3.59	3.72	3.50
Awarua Chip Mill	5.0	0.90	0.77	2.74	0.74	0.70	3.53
Bluff	12.0	4.77	4.49	4.41	4.62	4.46	4.66
Centre Bush	5.0	4.35	3.97	4.43	4.25	3.71	3.61
Conical Hill	5.0	3.14	2.50	3.08	2.20	1.14	2.47
Dipton	1.5	**2.27**	**2.03**	**1.70**	**1.66**	**1.59**	**1.60**
Edendale Fonterra	23.0	**24.52**	22.36	**23.0**	22.91	21.47	21.31
Edendale	12.0	6.80	6.54	6.71	6.35	6.44	6.41
Glenham	1.5	1.40	1.10	1.14	1.28	1.06	1.09
Gorge Road	3.0	**3.19**	**3.02**	2.84	2.32	1.87	1.81
Heddon Bush	15.0	9.79	8.45	8.30	8.77	7.63	8.56
Hillside	2.3	0.69	0.65	0.62	0.62	0.62	0.63
Kelso	5.0	4.63	4.22	4.27	4.27	4.20	4.11

Zone substation	Firm Capacity (MVA)	2014 Maximum Demand (MVA)	99.90% 2014 (MVA)	99.90% 2013 (MVA)	99.90% 2012 (MVA)	99.90% 2011 (MVA)	99.90% 2010 (MVA)
Kennington	12.0	6.32	5.67	3.86	3.99	4.26	4.27
Lumsden	5.0	3.94	3.77	3.79	3.60	3.44	3.52
Makarewa	12.0	7.19	6.77	5.80	5.13	5.11	5.32
Mataura	10.0	9.65	6.99	8.55	8.24	7.91	8.00
Monowai	1.0	0.18	0.16	0.34	0.36	0.35	0.33
Mossburn	3.0	1.95	1.87	1.76	1.77	1.83	1.74
North Gore	15.0	8.85	7.72	9.66	7.86	9.13	7.88
North Makarewa	45.0	**46.97**	**45.06**	**45.73**	43.09	44.90	43.60
Ohai	5.0	2.83	2.54	2.60	2.22	2.33	2.11
Orawia	5.0	3.08	2.95	3.10	2.76	2.71	2.74
Otatara	5.0	3.94	3.70	3.91	3.91	3.80	3.70
Otautau	5.0	4.98	4.74	4.05	4.11	4.43	4.01
Riversdale	5.0	4.73	4.69	4.58	4.54	4.46	4.30
Riverton	7.5	5.07	4.69	5.16	4.76	4.71	4.32
Seaward Bush	10.0	7.58	7.31	8.28	8.76	8.62	8.40
South Gore	12.0	7.88	7.22	8.28	8.01	8.11	8.00
Te Anau	12.0	6.19	5.48	5.46	5.30	5.44	5.21
Tokanui	1.5	1.13	1.08	1.03	1.08	1.05	0.97
Underwood	20.0	12.03	11.73	11.79	11.79	11.95	12.47
Waikaka	1.5	0.86	0.73	0.79	1.16	0.94	0.96
Waikiwi	12.0	10.82	10.22	**12.08**	**12.25**	**12.42**	11.55
Winton	12.0	13.68	12.29	11.82	11.45	11.04	10.52
White Hill (Wind)		-57.07	-56.83	-56.84	-56.97	-56.93	-56.88
Monowai (Hydro)		-6.79	-6.59	-6.41	-6.47	-6.59	-6.63

Dipton, Edendale Fonterra, Gorge Road and North Makarewa substations peaked over the installed capacity. Projects are planned to upgrade to remedy.

4.3.2 Drivers of future demand

Key drivers of demand growth (and contraction) are likely to include the issues depicted in Figure 41.

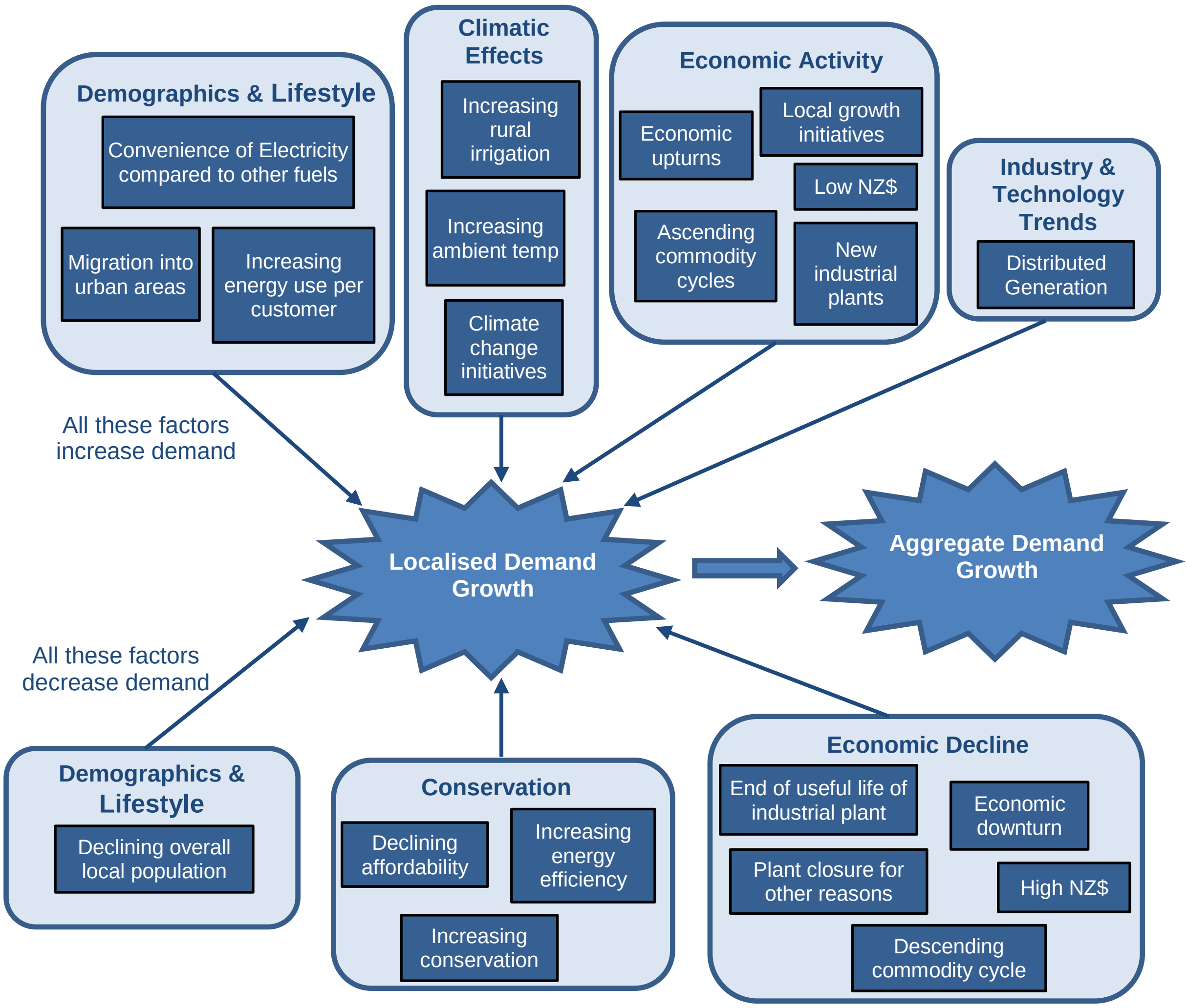


Figure 41 - Drivers of demand

At residential and light commercial feeder level, three or four of these issues may predominate and be predictable and manageable on a statistical basis; however experience is that large customers give little if any warning of increases or decreases in demand. The residential and light commercial demand projections can be aggregated into a reasonably reliable zone substation demand forecast but heavy industrial demand will always remain more unpredictable. TPCL's estimates of future demand are described in section 4.3.4 below.

Historically, TPCL has experienced an average annual demand growth of about 3.0% for the last 10 years. This growth has been distorted with Transpower's introduction of TPM[23] where individual ELB peaks have been replaced by a regional grouping. This has allowed TPCL to relax load control during the year due to the increased summer loading due to Dairying. Whilst the company expects this average rate not to continue and to influence the revenue aspects of TPCL's business, such as pricing, it must be acknowledged that actual demand growth at localised levels (which will influence costs) can vary anywhere from negative to highly positive. The following sections examine in detail the predicted significant drivers of TPCL's network configuration over the next 10 to 15 years.

[23] Transmission Pricing Methodology: Allocation of Transpower costs are based on the share of the average of the top 100 peaks for all loads in the Lower South Island (LSI) region. See http://www.ea.govt.nz/industry/transmission/transmission-pricing/transmission-pricing-methodology/ for more details.

4.3.2.1 Construction of wind-farms

One large wind farm is presently under operation at White Hill. This is connected to the 66kV network and has taken most of the spare capacity on the lines between White Hill and North Makarewa when at full generation. Meridian has consents for six additional machines and desire network upgrades to allow installation of these additional units.

An application to connect a windfarm at Flat Hill into the Bluff substation at 11kV has been received. The proposed windfarm has 8 machines and is proposed to connect into a new 11kV circuit breaker at the Bluff substation. First generation from the windfarm is expected in 2015.

Inquiry from TrustPower regarding the Kaiwera Downs wind farm and options for connecting into the 33kV network off Gore GXP.

Other inquiries from numerous developers and land owners highlight the present interest in wind generation. Wind generation up to 2MW can be connected to some 11kV feeders. Above this level or, if a number are installed in an area, will require connection to the subtransmission network.

Distributed Generation (DG) of under 10kW is occurring at a noticeable rate on the network, and these are normally connected on existing installations, so no additional capacity is required. No other significant Wind Generation is planned to be connected over the next ten years.

Larger farms will need to connect to the Transpower Transmission network at 110kV or 220kV.

Timing	Injection Point	Expected injection	Required provision for injection
unknown	North Makarewa	12MW	Completion of Oreti Valley project to upgrade 33kV between Mossburn and Winton to 66kV.
unknown	Gore	10 to 30MW	Still under investigation.
2015-16	Bluff Substation	6-8MW	New 11kV circuit breaker at Bluff Substation
unknown	All	< 0.01MW x 100 p.a.	Normally can connect onto existing equipment or connection onto MV network.

4.3.2.2 Milling of local forests

This could involve expansion of existing mills (Figure 38 Quadrant 2), or could involve new mills (Figure 38 Quadrant 2 or 4 depending on location). Key drivers of investment will include global timber prices, the eventual outcome of the Kyoto Protocol, the strength of the NZ dollar and any decisions to process locally as opposed to export.

No expected new mills in the next ten years, with the closure of the mill at Conical Hill and slow-down at Otautau.

4.3.2.3 Irrigation

Dry areas in northern Southland such as Athol, Riversdale and Mossburn have a reasonably predictable demand for irrigation which is already occurring. However there are wetter areas that may also install irrigation.

Project a 2% demand increase on substations in Northern Southland.

4.3.2.4 Dairy conversions

Data from Fonterra indicates that dairy conversions to date represent only about 15% of possible conversions based on land area, suggesting no end is in sight for concentrated 50-100kVA loads appearing throughout TPCL's entire network footprint. This will have the knock-on effect of another dairy factory or expansion of the existing Edendale plant which will mean about 8MW of additional load within the next 1-2 years.

Further to this is the faster milk chilling requirements from the Ministry of Primary Industries (MPI) which is currently under draft[24]. MPI have stated that any changes to the chilling requirements will not come into force until after March 2016. TPCL has already seen some farmers proactively installing snap chilling which requires an additional 30-50kVA per shed. Whilst not all dairy sheds will require snap chilling to meet the new requirements, there will be some increase in load at some dairy sheds.

Project a 1% demand increase in rural areas due to Dairy conversions, an on-going 1% p.a. growth at Fonterra Edendale and a 2MW step change at Colyer Road for the second stage of the Open Country Dairy Plant, with an on-going 2.5% p.a. growth.

No allowance has been made for the Mataura Valley Milk plant at McNab, and should this occur would require a new zone substation and subtransmission line upgrades. Impact on Transpower is likely to be delayed until they undertake the second stage, as the present GXP load is mainly a winter profile.

4.3.2.5 Coal mining

The whole of Southland sits on at least 100 years of black and brown coal. The precise end use of this coal is not clear other than that the coal industry has undertaken not to supply the domestic market, so coal will not substitute for domestic electricity.

L&M have investigated Coal Seam Gas extraction with a pilot at Ohai; with poor gas extraction means this project is unlikely to progress.

4.3.2.6 Oil exploration

Prospecting for petroleum reserves is currently occurring onshore with extensive offshore exploration planned for the next four years. Likely impact for TPCL is increased residential growth and new or expanded support industries.

Allowed for in the 1% p.a. general growth allowance.

4.3.2.7 Expanding tourism

Continued interest in the Fiordland and Stewart Island World Heritage Parks, with the flow-on support infrastructure of hotels, restaurants, cafés etc.

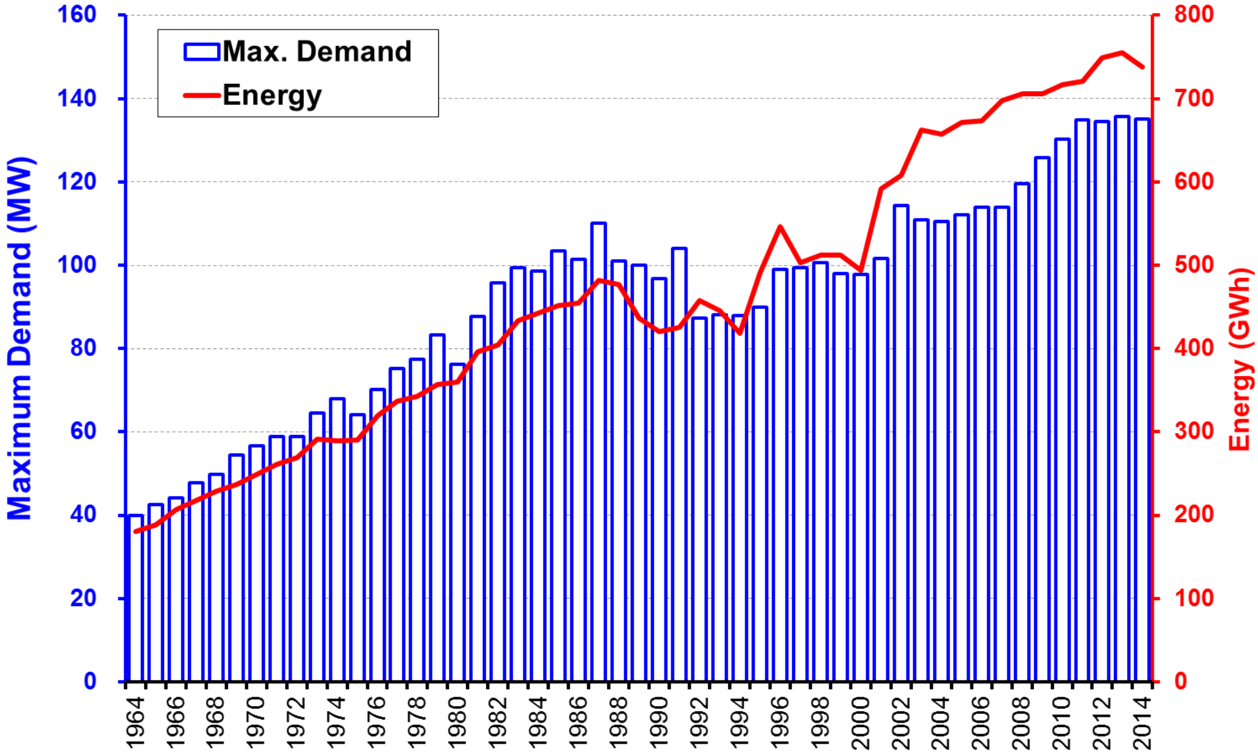
We have allowed a 1.5% p.a. increase in demand for the Te Anau Substation.

4.3.3 Load forecast trend

Analysis of historic demand and energy usage over the last 10 years gives demand growth of 2.1% and energy growth of 1.2%. The chart following shows the data since 1964 and the drop in demand in the early 1990's when load control was introduced.

The step in demand in the last five years is due to the Transmission Pricing Methodology impact.

[24] See NZCP1: Code of Practice for the Design and Operation of Farm Dairies (Version 5 Amendment 2)



4.3.4 Estimated zone substation demands [A.11.8.2.]

As outlined in detail in the remainder of section 4, TPCL's demand is expected to increase from that described in section 4.3.1 as follows:

- Standard natural growth of 1.0%, with some decline of small rural communities.
- Irrigation growth in Northern Southland of 2%.
- Tourism related growth in Te Anau of 1.5%.
- Continued Dairy conversions across pastoral Southland 1.0%, with related growth at Edendale Fonterra at 0.5% and Colyer Road at 2.5%.
- Load Management shedding to control regional and local peaks is estimated at existing levels. The amount of this may decrease if price incentives are not passed on by retailers, or taken up by customers.

Experience strongly indicates that it would be rare to ever get more than a few months confirmation, sufficient to justify significant investment, of definite changes in an existing or a new major customer's demand. This is because most of these customers operate in fast-moving customer markets and often make capital investment decisions quickly themselves and they generally keep such decisions confidential until the latest possible moment. Probably the best that TPCL can do is to identify in advance where TPCL's network has sufficient surplus capacity to supply a large chunk of load but, as experience shows, industrial siting decisions rarely, if ever, consider the location of energy supply – they tend to be driven more by land-use restrictions, raw material supply and transport infrastructure.

Table 17 following identifies the rate of growth projected to zone substation level for a 10 year horizon, along with the provision expected to be made for future growth. Expanded data is included in Appendix C.

Growth is also calculated using the average energy growth for the last 10 years which was 1.2% pa.

Table 17 Substation demand growth rates

Zone Substation	Proposed Annual Growth	2013 Demand	2023 Demand	2023 Maximum Demand at 2.1 %	Planned actions
Awarua	2.5%	4.8 MVA		6.0 MVA	▼ see below ▼
Colyer Road (New Awarua)	2.5%		9.1 MVA		New 2 x 6/12 MVA 33/11kV
Awarua Chip Mill	0.0%	0.8 MVA	0.8 MVA	1.0 MVA	Customer driven
Athol (New)	2.5%		1.0 MVA		New 1 x 3/5 MVA 66/11kV
Bluff	1.0%	4.9 MVA	5.4 MVA	6.1 MVA	Monitor
Centre Bush	3.0%	5.0 MVA		6.3 MVA	▼ see below ▼
Centre Bush (66/11kV)	3.0%		6.7 MVA		ex Ohai 5/7½ MVA 66/11kV
Conical Hill	0.5%	1.2 MVA	1.3 MVA	1.5 MVA	ex Mossburn or Dipton 1½ MVA 33/11kV
Dipton	2.5%	1.6 MVA		2.0 MVA	▼ see below ▼
Dipton (66/11kV)	2.5%		2.1 MVA		New 1 x 3/5 MVA 66/11kV
Edendale Fonterra	0.5%	24.6 MVA	30.0 MVA	31.0 MVA	Customer driven
Edendale	1.5%	6.7 MVA	7.7 MVA	8.4 MVA	Monitor
Glenham	2.0%	1.3 MVA	1.6 MVA	1.7 MVA	Spare or new 3 MVA 33/11kV
Gorge Road	3.0%	2.1 MVA	2.8 MVA	2.6 MVA	Monitor
Heddon Bush	2.0%	10.2 MVA		12.9 MVA	Remove 33kV plant
Lumsden (New 66/33kV)	2.0%		10.1 MVA		Additional ex Heddon Bush 10/15 MVA 66/33kV
Hedgehope (New)	1.5%		2.3 MVA		New 1 x 3/5 MVA 66/11kV
Hillside	1.0%	0.7 MVA	0.7 MVA	0.8 MVA	Monitor
Isla Bank (New)	2.5%		3.0 MVA		New 1 x 3/5 MVA 66/11kV
Kelso	2.0%	4.6 MVA		5.8 MVA	▼ see below ▼
Kelso (Upgraded)	2.0%		5.6 MVA		New 5/7½ MVA or ex Waikiwi 6/12MVA 33/11kV
Kennington	1.5%				▼ see below ▼
Kennington (New)	1.5%	7.0 MVA	8.2 MVA	8.8 MVA	New 2 x 6/12 MVA 33/11kV
Lumsden	3.0%	4.1 MVA	4.4 MVA	5.1 MVA	Monitor
Makarewa	1.0%	5.3 MVA	5.9 MVA	6.7 MVA	Monitor
Mataura	1.0%	8.6 MVA		10.9 MVA	▼ see below ▼
Mataura (Upgraded)	1.0%		9.5 MVA		New 2 x 6/12 MVA 33/11kV
Monowai	2.5%				▼ see below ▼
Monowai (Upgraded)	2.5%	0.4 MVA	0.6 MVA	0.6 MVA	New 1 x 0.5 MVA 66/11kV
Mossburn	3.0%	1.9 MVA	2.6 MVA	2.0 MVA	Monitor
North Gore	1.0%	8.4 MVA	9.2 MVA	10.5 MVA	Monitor
North Makarewa	1.5%	45.6 MVA	53.0 MVA	57.4 MVA	▼ see below ▼
North Makarewa 33kV	1.5%	50.6 MVA	58.7 MVA	63.6 MVA	Request Transpower to add 220/66kV
Ohai	1.0%	2.4 MVA	2.6 MVA	3.0 MVA	New 1 x 3/5 MVA 66/11kV
Orawia	1.5%	3.0 MVA	3.5 MVA	3.8 MVA	Monitor
Otatara	2.0%	4.1 MVA	5.1 MVA	5.2 MVA	Monitor

Zone Substation	Proposed Annual Growth	2013 Demand	2023 Demand	2023 Maximum Demand at 2.1 %	Planned actions
Otautau	2.5%	4.0 MVA	3.6 MVA	5.0 MVA	Monitor
Riversdale	3.0%	4.7 MVA		**5.9 MVA**	▼ see below ▼
Riversdale (Upgraded)	3.0%		6.3 MVA		ex Waikiwi 1 x 6/12 MVA 33/11kV
Riverton	2.5%	4.9 MVA	5.3 MVA	6.1 MVA	Monitor
Seaward Bush	0.5%	9.4 MVA		**11.9 MVA**	▼ see below ▼
Seaward Bush (Upgraded)	0.5%		9.4 MVA		New 2 x 6/12 MVA 33/11kV
South Gore	1.5%	8.5 MVA	9.9 MVA	10.7 MVA	Monitor
Te Anau	1.0%	5.8 MVA	6.4 MVA	7.2 MVA	Monitor
Tokanui	1.0%	1.2 MVA	1.3 MVA	1.5 MVA	Monitor
Underwood	0.0%	12.2 MVA	12.2 MVA	15.3 MVA	Monitor
Waikaka	2.5%	0.8 MVA	1.1 MVA	1.1 MVA	Monitor
Waikiwi	2.5%	11.7 MVA		**14.7 MVA**	▼ see below ▼
Waikiwi (Upgraded)	2.5%		15.0 MVA		New 2 x 11½/23 MVA 33/11kV
Winton	2.0%	12.6 MVA	12.4 MVA	**15.8 MVA**	Load transfer to Hedgehope and Makarewa
White Hill (Wind)	0.0%	-57.2 MVA	-69.9 MVA	-58.0 MVA	Customer driven
Monowai (Hydro)	0.0%	-6.6 MVA	-6.6 MVA	-7.8 MVA	Customer driven

The red highlighted values indicate when the initial trigger point for capacity is exceeded based on the present equipment and configuration.

4.3.4.1 Demand model assumptions [A.3.8.]

The impact of Distributed Generation (DG) has been ignored due to the estimated low connection rate of DG and the probability that only a small percentage of the capacity will be available during peaks, e.g. White Hill only contributed 31.6MW during the network peak (Figure 40).

Load Management is used when substation equipment is nearing overload, and during load transfers for maintenance, and hasn't been considered in the projected demands above. Load shifting can also be done at the Retailer's request or during Dry-year rationing.

Increased monitoring of heavily loaded sites if data indicates capacity will be extended.

Annual preparation of this data will highlight sites that vary from the above model and the planned works adapted for each situation, with some upgrades delayed or brought forward.

4.3.5 Estimated demand aggregated to GXP level

Table 18 shows the aggregated effect of substation demand growth for a 10 year horizon at the four GXP's, Monowai and White Hill.

It is interesting to consider that any additional generation connected onto the North Makarewa GXP may be limited due to the network being fully loaded when White Hill and Monowai are at peak generation and the local area load is low.

Table 18 GXP demand growth

GXP	Rate of growth	2025 MD	Provision for growth
Edendale	1.90%	32.7MVA	Possible Transpower project to allow full 36.6/38.7 MVA (summer/winter) capacity with upgrades.

GXP	Rate of growth	2025 MD	Provision for growth
Gore	1.54%	31.6MVA	Load is under firm capacity of 36.6/37.9 MVA (summer/winter) and load control will be used to keep under this limit. Mataura is able to be transferred onto Edendale GXP during Dairy off-season. Any major new loads will require additional capacity at Transpower or an agreement to drop new load if Transpower loses one supply transformer.
Invercargill	2.15%	122.5MVA Incl. EIL @ 87.0MVA LM[25] = 34MVA	Two 120MVA banks, allows 20MVA of additional load. Presently limited to 104MVA. Possible Transpower project to allow full 144.8/151.3 MVA (summer/winter) capacity with small upgrades.
North Makarewa	1.66%	55.3MVA	As generation is likely to make this a normally exporting GXP. Possible Transpower project to allow full 76.1/79.4 MVA (summer/winter) capacity with 33kV cable upgrade.
Monowai	0%	- 7.1MVA	66kV lines able to export all expected generation.
White Hill	6 × 2MVA	- 70MVA	Needs additional 66kV lines.
Total	**1.79%**	**208.0MVA**	Including EIL and less load management

4.3.6 Issues arising from estimated demand

The significant issues arising from the estimated demand in section 4.3.4 are:

- Short term trigger is reached at Dipton, Edendale Fonterra, North Makarewa, Riversdale and Waikiwi.
- Medium term trigger is reached at Kelso.
- Long term trigger may be reached at Glenham, Otatara and Winton.

4.4 Where are TPCL's network constraints [A.8.3.]

TPCL's network includes the following constraints:

Constraint	Description	Intended remedy
Limited extra capacity.	Substations close to maximum capacity. (Dipton, Edendale Fonterra, Glenham, Kelso, North Makarewa, Otatara, Riversdale, Waikiwi, Winton)	Up-size as required. Review annually. Addition of new substations will transfer load off some heavily loaded substations.
Invercargill GXP.	104.0 MVA limitation in 'Other Equipment' ratings. Additional load likely.	Transpower project to upgrade 'Other Equipment' to allow 144.8/151.3MVA. Up-size when load control cannot keep under this limit.

[25] LM = Load Management; an estimate of the controllable load on this GXP that could be off during system peaks.

Constraint	Description	Intended remedy
Gore GXP.	Close to firm capacity of 36.6 / 37.9 MVA (Summer/Winter) Additional load likely.	Up-size when load control cannot keep load under this limit.
North Makarewa GXP.	Firm capacity 62.3MVA, limited by 33kV cable and protection.	Transpower project to upgrade cables and protection to allow 76.1/79.4MVA. Up-size when load control cannot keep load under this limit.
Edendale Fonterra substation.	Additional load likely.	Up-size transformers when customer request received.
Subdivisions.	Possible large developments in Athol, Garston and Kingston.	Extend subtransmission to Athol and Kingston.
Environmental – Oil.	Expectation that no significant oil spills from substations.	Install oil bunding, blocking and separation systems.
Voltage at Riversdale and Centre Bush.	When the first 33kV line supplying northern Southland is out-of-service the voltage at the end substation is marginal.	Upgrade some lines to 66kV.
Export capability from White Hill.	Export of energy limited to 58MVA.	Upgrade 33kV lines to 66kV down the Oreti Valley, Mossburn to Winton.
11kV voltage low due to Dairy milking.	Conversion of farms to dairying may cause feeder voltage to drop below 0.94pu.	Install 11kV regulators to improve voltage. Install new substations if growth continues.
Undergrounding.	District / Regional Plan requirements on the location / position of lines.	Alternative routes. Undergrounding of lines.
Coastal marine.	Salt pollution reducing insulation effectiveness.	Over insulate lines. Use high pollution type equipment.
Coastal marine.	Increase corrosion.	Enclose substation equipment inside buildings. Increased renewals of outdoor equipment.

4.5 Policies for distributed generation [A.11.11.]

The value of distributed generation can contribute in the following ways:

- Reduction of peak demand at Transpower GXP's.
- 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.

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and TPCL is actively encouraged.

The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings, with a guideline and application forms available on the web at http://www.powernet.co.nz/dg-guide.

4.5.1 Connection terms and conditions (commercial)

- Connection of up to 10kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10kW 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 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 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.

4.5.2 Safety standards

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

4.5.3 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 10kW 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.

4.6 Use of non-asset solutions [A.11.12.]

As discussed in section 4.2.1 the company routinely considers a range of non-asset solutions and indeed TPCL's preference is for solutions that avoid or defer new investment as part of the planning process for issues. Process is described in section 4.7.

Effectiveness of tariff incentives is lessened with Retailers repackaging line charges that sometimes removes the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels.

Load control is utilised to control:

- The amount of Transpower charges by controlling the network load during the LSI peaks.
- The load on individual GXP's when they exceed the capacity of that GXP.
- The load on feeders during outage situations.
- Load shedding is used by some customers where they accept a drop of their load / generation instead of investing in additional network assets. i.e., White Hill wind farm will limit generation to under 20MW, if the 66kV line from White Hill to Heddon Bush is out.

Consideration is also given to local generation options. One situation is the supply to Kingston, which is presently a long radial fed from Lumsden. With growth this feeder is likely to cross the trigger level for reliability and require an alternate supply. Evaluation of options will consider the cost of 60km of new line verses the on-going cost of a diesel generator to provide this alternative.

If an Engineer considers that adoption of non-asset options may be sufficient to overcome a constraint, a business case would be prepared to get approval from the Chief Engineer or Chief Executive, to proceed.

The approval would be given if the likelihood of success is acceptable compared to the cost / benefit ratio.

Suggestions of non-asset options can come from other staff and external parties with these allocated to an Engineer to investigate.

4.7 Network development options [A.11.2.]

4.7.1 Identifying options

When faced with increased demand, reliability, security or safety requirements, TPCL considers the broad range of options described in Section 4.2.1. The range of options for each issue varies due to:

- Stakeholder interests

Section 1.7 lists stakeholder interests and the Engineer considers these areas in planning and ranking an option.

- Size of the project

Different issues have differing resource requirements. The level of analysis and the breadth of options vary with size. A simple issue like connecting a new customer next to an existing low voltage pillar box would only have a single option analysed, whereas a new industrial plant would have multiple options considered.

- Creativity and knowledge of the Engineer

Breadth of options is also dependent on the Engineer undertaking the planning. Options are developed by the Engineer and critiqued by the Chief Engineer. Use of standard construction and existing designs mainly, but support for innovation.

- Resource

The other higher priority projects may limit the resources available for each option. This could be a limitation of finances (uneconomic), workforce (to plan, design, manage, build or operate), materials (unavailability or long lead-time of equipment) or legal (need Resource Consent or Easements.)

- Standardisation [A.11.3. & A.11.4.]

Standards that apply to the network are given in the PowerNet Network Design standard.

Some of the standardisation is listed below:

Component	Standard	Justification
Conductor	All Aluminium Alloy Conductor (AAAC): Chlorine, Helium, Iodine, Neon, Oxygen.	Low corrosion and improved impedance
Conductor	Aluminium Conductor Steel Reinforced (ACSR): Magpie, Squirrel, Flounder, Snipe.	Higher strength for long spans or snow loading
Low Voltage	Aerial Bundled Cable (ABC): 35, 50 & 95mm² Al / two & four core.	Safety, visual impact, lower cost.
Cable	Cross-linked Polyethylene (XLPE)	Rating, ease of use.
Suppliers	Normally one or two suppliers for each component	Reduce spare requirements. Improved contractor familiarity.
Poles	Busck pre-stressed concrete	Long life, good strength

Component	Standard	Justification
Crossarms	Solid hardwood	Long life, good strength

Standardised design is used for line construction with a Construction Manual and standard drawings in use by Contractors.

Standardised designs have been used for the Hedgehope, Athol and Isla Bank substation projects, with the following components the same:

- Transformer
- 66kV structure components and switchgear
- Port-a-com building
- 22kV switchgear
- Protection and controls

4.7.2 Identifying the best option

Once the best broad option has been identified using the principles embodied in figure 39, TPCL will use a range of analytical approaches to determine which option best meets TPCL's investment criteria. As set out in Section 4.2.3, TPCL uses increasingly detailed and comprehensive analytical methods for evaluating more expensive options.

- Simple Spreadsheet: Cost calculation with standardised economic benefit values.
- Risk analysis: More comprehensive and complexity for larger projects.
- Net Present Value (NPV) model: Time series model of future costs and benefits. The analysis also considers change in losses to promote energy efficiency. [A.11.5.]
- Payback calculation: Financial calculation of the time estimated to recover cost of undertaking that option.
- Optimisation Tools: Multiple parameter models used to optimise stakeholder objectives.
- Customer consultation: If solution impacts on a customer and changes the service level provided, the customer must be consulted to obtain their support. i.e. disconnecting remote customers by replacing connection with a RAPS[26].

4.7.3 Implementing the best option

Having determined that a fixed asset (CAPEX) solution best meets TPCL's requirements and that TPCL's investment criteria will be met (and if they won't be met, ensuring that a customer contribution or some other form of subsidy will be forthcoming), a project will proceed through the following broad steps:

- Perform detail costing and re-run cost-benefit analysis if detail costs exceed those used for investment analysis.
- Address resource consent, land owner and any Transpower issues.
- Perform detailed design and prepare drawings, construction specifications and if necessary tender documents.
- Tender out or assign construction.
- Close out and de-brief project after construction.
- Ensure that contractors pass all necessary information back to TPCL including as-builts and commissioning records.
- Ensure that learning experiences are examined, captured and embedded into PowerNet's knowledge base, standards, or culture.

[26] RAPS = Remote Area Power System: A stand-alone energy network of alternative energy sources (Solar, Photovoltaic, Wind turbine, Micro-hydro, LPG, Diesel, etc…) so that a connection to the TPCL electricity network is not required.

4.8 Development programme [A.11.9. & A.11.10.]

General individual estimates are only given as work is tendered and disclosure of estimates would negate the benefit of tendering.

4.8.1 Current material projects

Expected projects for year one (YE 31 March 2016) are as follows. These projects have a high certainty.

4.8.1.1 Oreti Valley Project (OVP)

(a) Description

The long term plan is to extend the 66kV network so it includes Centre Bush, Dipton, Lumsden and Mossburn substations. The southern connection is proposed at Winton to avoid all 66kV lines going through Heddon Bush substation.

The initial connection out of Winton substation is planned to be a new 66kV crossing the Oreti River to the west of the substation.

Over a number of years sections of the 33kV network will be upsized to 66kV but initially will operate at 33kV. At a date when load growth makes the 33kV unable to meet the service levels in the region, these sites can be upsized to 66/11kV transformers with the present 66/33kV transformer at Heddon Bush relocated to Lumsden.

Work on this project may be accelerated in consultation with Meridian Energy to lower the losses occurring in transporting its generation output to the national grid.

Work planned includes:

- Add an additional 66kV bay off the Winton Substation to supply the new 66kV line up the Oreti Valley.
- New 66kV line out of Winton to the west across the Oreti River and north to Centre Bush substation.
- Upgrade Centre Bush with a new 66/11+11kV 5/7.5MVA transformer[27] and add one additional 11kV feeder to supply along the now free 33kV line back to Heddon Bush area. Feeder upgrading to 22kV will be possible.
- Incorporate dual protection on the lines to maintain less than 200mS clearance of faults, as required for the White Hill Wind Turbines.
- Reinsulate the 33kV lines from Centre Bush to Mossburn to 66kV.
- Upgrade Dipton by replacing the transformer with a new 66/11+11kV 3MVA unit and upgrade protection on the 66kV by having digital differential on the two sides of the substation but no 66kV Circuit Breakers.
- Construct a step down at Lumsden utilising the relocated 66/33kV 10/15MVA transformer and 33kV circuit breaker from Heddon Bush to supply the 33kV bus at Lumsden.
- The reinsulated 66kV line to connect into Mossburn substation by the spare 66kV bay.

[27] 66/11+11kV transformer can be connected to provide 11kV or 22kV output by parallel or series connecting the two 11kV windings.

Figure 42 - Winton 66kV Substation

(b) **Issues**

Load growth has made the existing back-ups to Riversdale, Lumsden, Dipton and Centre Bush marginal.

Losses occurring on the 66kV lines are significant when White Hill generation is high.

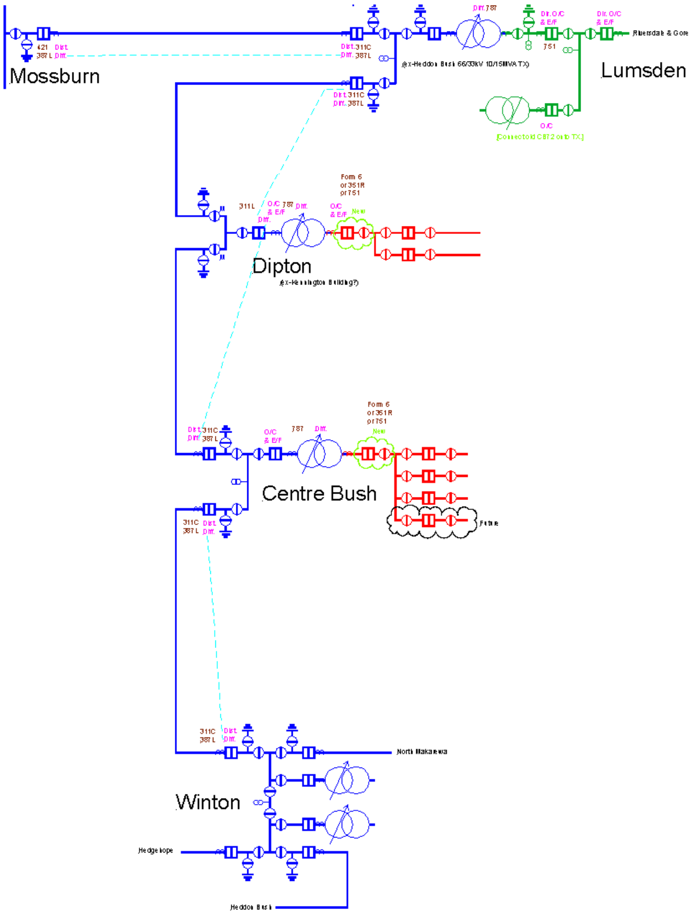
Desire by Meridian to increase generation at White Hill to the consented levels.

(c) **Options**

- Upgrade to 66kV from Mossburn to Winton. [Selected option that provides the greatest benefits.]
- Conversion to 110kV. [Too expensive.]
- 33kV regulators. [Increased losses and increase system impedance.]
- Up-sizing of components (Conductor, Transformer).[Limited future capacity.]

(d) **Details**

Planned outcome is shown in the diagram below:



(e) **Cost and type**

$0.5M - $7.5M p.a. 2015 to 2019, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Migrate from a 33kV network to 66kV.

4.8.1.2 Isla Bank Project (IBP)

(a) **Description**

Final completion of the Isla Bank substation project is to occur during the first quarter of 2015/16. Detail on the project can be found in the 2014-2024 AMP Update

(b) **Cost and type**

<$0.5M 2015/16, System Growth.

4.8.1.3 Waikiwi Project

(a) **Description**

Replacement of outdoor 6/12MVA 33/11kV transformers with new indoor 11.5/23MVA 33/11kV transformers with external radiators. A new transformer room is required for the new transformers and will be built as part of the project. Other works which will be completed as part of the project include installation of an 11kV NER and replacement of the Harris RTU.

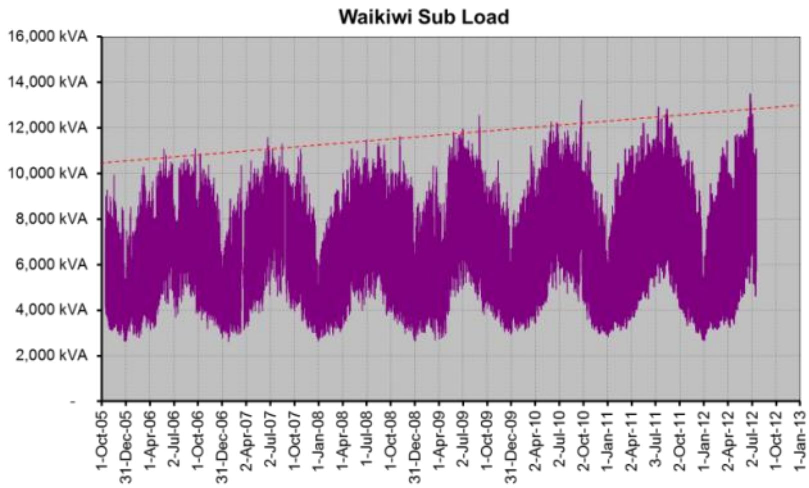
Figure 43 – Aerial view of Waikiwi Substation

(b) **Issues**

Load growth has reached the capacity trigger point of 12MW.

Site has been in-built with residences now on three side of the site.

Noise levels on boundary exceed District Plan requirements.



(c) **Options**

- Upgrade 33/11kV transformers. [Selected option as provides the most benefits.]
- Conversion to 66kV. [More expensive.]
- Transfer loads to other substations. [Some planned to go to Kennington.]

- Move equipment indoor to reduce noise level. [Most likely only option to achieve noise level requirements.]

(d) **Details**

Consultants are designing the substation upgrade based on indoor transformer rooms with external radiators.

The existing Harris RTU has become uneconomic to support so is being replaced with an SEL 3530.

(e) **Cost and type**

$0.5 - $2.5M 2013 - 2017, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.1.4 Riversdale Transformer

(a) **Description**

Add extra capacity at Riversdale.

Figure 44 - Present Riversdale substation

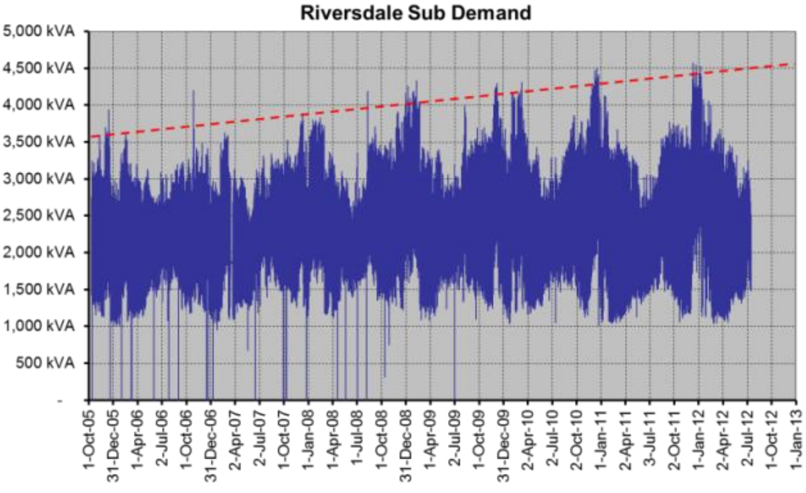
(b) **Issues**

Nearing capacity trigger.

Risk with a single power transformer on-site.

Limitation of 11kV to supply new irrigation in the area.

Reliability issue with 11/22kV autotransformers. (Energising forces stress the coils, and impedance requires downstream regulation.)



(c) **Options**

- Replace 33/11kV 5MVA power transformer with a 6/12MVA unit. [Selected option as least cost but needs backup option of mobile sub or generator to be developed.]
- Add a second 33/11kV power transformer on-site. [Limited space.]
- Add a 33/11+11kV power transformer on-site. [Existing unit has remaining life.]
- Transfer some load to new substation, Balfour and/or Mandeville. [Higher cost as would require a fully new site.]

(d) **Details**

Design work has been completed to detail the installation of a 33/11kV 6/12MVA transformer that is planned to be removed from Waikiwi in 2015/16.

(e) **Cost and type**

$0.5M - $1M 2013 to 2018, System Growth.

(f) **Goal / Strategy**

Strive to become an efficient and effective operation.

4.8.1.5 New Colyer Road Substation

(a) **Description**

The Invercargill City Council has purchased an area of land southeast of the present substation for industrial zoning, but has yet to attract any customers.

It is proposed to begin planning and design to build a new substation to supply most existing industrial customers and have provision for expansion. The new site will be developed and incorporate indoor 33kV and 11kV switchgear and space for up to three 11.5/23MVA transformers, giving a firm capacity of 46MVA. Note that if load did grow an additional 33kV heavy line could be added from Invercargill.

First stage will purchase the two 33/11kV transformers and store these until customer demand requires the extra capacity.

Open Country Dairy are doubling their plant at Awarua, which requires that Colyer Road substation is operational before August 2016.

The existing Awarua substation is to be retained to continue supply to the South Wood Exports 1500kVA chipper motor.

Construction of the substation is underway with completion expected in December 2015

(b) **Issues**

The present substation is not close to the likely load centre, is limited in expansion and is a very damp site.

Short timeframe for new industrial customers wanting supply.

Marine / Coastal location, with high salt pollution.

(c) **Options**

- New substation on the 33kV network. [Selected as provides the greatest benefits.]
- Expansion of the present site. [Limited space and prone to liquefaction.]
- Upsize of the old 33/11kV 5MVA transformer. [Would not provide reliability level desired.]

(d) **Cost and type**

$2.5M - $5M 2014 to 2016, System Growth.

(e) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.1.6 Edendale Supply Transformers and Substation Upgrade

(a) **Description**

Fonterra have committed to increased capacity at their Edendale dairy factory. A third 33/11kV, 11½/23MVA power transformer is to be added to allow full N-1 supply of the increased load.

(b) **Issues**

Possible load growth may exceed the firm capacity of the substation.

(c) **Options**

- Replace the two power transformers with 33/11kV, 18/36MVA units. [Limited capacity of 33kV Cables and 11kV equipment.]
- Add third 33/11kV, 11½/23MVA power transformer. [Planned option that will provide good future capacity and allows a separate site to be used to achieve diversity.]
- Supersede the Ripple Injection system with Smart Meters. [This is expected.]

(d) **Detail**

Add third 33/11kV 11½/23MVA transformer on Fonterra site, supplied by a new 33kV cable.

Upgrade the existing voltage regulation scheme to a modern system to allow integration of third transformer.

Arrange for Transpower to upgrade the 110/33kV supply transformers.

(e) **Cost and type**

$0.5 - $2.5M p.a. 2015/16, System Growth.

Additional operational expenditure for Transpower new investment and metering.

(f) **Goal / Strategy**

Provide its customers with above average levels of service.

4.8.1.7 New Balfour Substation

(a) **Description**

Growth in the Waimea Plains between Gore and Lumsden is estimated to reach the level where an additional zone substation is required.

Planning and design work for the construction of a new 33/11kV zone substation in the Balfour area with supply sourced from the 33kV line between Riversdale and Lumsden

Work planned for the project:

- Construct a 33kV over line tee-off from the existing 33kV line between Riversdale and Lumsden. The line will be constructed at 66kV to allow for future upgrade.
- Construct a new zone substation with a single refurbished 33/11kV 5MVA or 6/12MVA transformer with four 11kV feeders supplied via an indoor switchboard
- 66kV and 22kV switchgear will be utilised to allow for future upgrades.

(b) **Issues**

Due to dairy conversions and increased irrigation load the network in this area has been calculated to be at the limit of acceptable voltage and the installation of additional 11kV regulators is considered not optimal. The projected peak load occurring at Riversdale is also nearing the firm capacity so a transfer of load is also desirable.

Need to obtain land next to the Riversdale to Lumsden 33kV line.

(c) **Options**

- New substation on the 33kV network. [Selected option as provides the most benefits.]
- Conversion to 22kV. [More expensive.]
- 11kV regulators. [Increased losses.]

- Demand-side management (Tariff? Dairying loads…)[Limited capability from farmers.]

(d) **Details**

Consultants are to design the substation in 2015/16 once a suitable land parcel has been obtained. The design will be based on a port-a-com transportable building with equipment installed prior to transport to site similar to Isla Bank and Athol solution.

Design of the 33kV tee-off from the Lumsden-Riversdale line will be done in 2015/16 and major equipment ordered for delivery in 2016/17 with construction planned for 2017/18.

Final construction details will be defined when designs are completed.

(e) **Cost and type**

$0.5 - $2.5M p.a. 2015 to 2018, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.1.8 Mobile Substation

(a) **Description**

With multiple single transformer substations and reducing back-up capability from neighbouring substations the option of building a mobile substation was investigated. Cost varied between options from Alstom, Australia and ABB, Italy and local design-build from Mitton Electronet / Electronet Services.

Finalising of the detail is planned with the mobile substation operational during 2016/17.

Design of the mobile substation has been completed and construction is planned for 2015/16.

(b) **Issues**

Single transformer substations with little or no periods where backup from neighbouring substations can be used.

Significant periods to move spare transformers into sites where the transformer has failed.

Differing vector angles between the 66kV, 33kV, 22kV and 11kV.

(c) **Options**

- Mobile Substation(s). [Selected option.]
- Mobile Generator(s). [Requires fuel to run that is not recoverable.]
- Add second transformer to single transformer substations. [Expensive.]
- Add extra substations to restore backup capability. [Expensive.]

(d) **Details**

Finalise solution to develop the best solution for TPCL.

(e) **Cost and type**

$0.5 - $2.5M 2014-16 Supply of Quality.

4.8.1.9 Neutral Earthing Resistor (NER) project

(a) **Description**

As part of compliance with the new EEA Guide to Power System Earthing Practice 2009, Neutral Earthing Resistors (NERs) are being installed at each zone substation to limit earth fault currents on the 11kV network. While NERs alone will not ensure network safety they will generally significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs. TPCL considers NERs to be effectively a requirement of the EEA guide as when cost is considered to be distributed over all affected earth sites downstream of the zone substation this per site cost is quite low.

(b) **Issues**

Safety of the public due to earth faults is reducing the earth potential rise (EPR) at the site under acceptable limits. This is achieved by either reducing the earth resistance, clearing the fault quicker or limiting the fault current.

Historic practice was to have an earth resistance under 10Ω (ohms) and protection operation of under 5 seconds. As some locations having poor ground resistivity achieving under 10Ω was found to be impractical and the level of EPR with 10Ω was still not low enough to mitigate the hazard.

This project plans to install a resistance in the neutral point that will greatly reduce the earth fault current and limit the EPR to acceptable levels. All zone substations will have an NER installed to limit the current to under 200A.

(c) **Options**

- Larger earth systems at each distribution site. [Expensive.]
- Fault current neutralisation. [Worst hazard when a second fault occurs.]
- Faster protection clearing. [At practical limits of mechanical devices. Wish to maintain discrimination between protection devices.]

(d) **Details**

Install a NER on each neutral at each zone substation.

(e) **Cost and type**

Under $1.0M p.a. 2014 to 2018. Other Reliability, Safety and Environmental.

(f) **Goal / Strategy**

Risk Management.

4.8.1.10 Distribution Automation

(a) **Description**

To improve reliability it is planned to continue automating and remotely controlling field circuit breakers, increasing the number of these and integrating with an Outage Management System.

(b) **Issues**

Manual reclosing is longer than the one minute trigger level for outages.

Number of control devices is low based on network size.

Greater Operator knowledge needed to manually operate.

(c) **Options**

- Automate existing equipment. [Not always reliable, based on past experiences.]
- Install earth-fault neutralisation methods. [Would reduce fault impact but could create extra safety issues. High cost.]
- Increased inspections and maintenance. [Possibly beyond point of demising returns.]
- Add extra substations to add more feeders. [Expensive.]

(d) **Details**

Install new field reclosers on worst performing feeders.

Install additional field reclosers, and remote operable vacuum load break switches, to allow automatic restoration and reduce average length of medium voltage per device to one per 25km. (about 75 extra devices.)

(e) **Cost and type**

$0.5 - $2.5M 2013 to 2018. Supply of Quality.

(f) **Goal / Strategy**

Improve reliability by sectionalising poorly performing feeders.

Expand remote controllability of the distribution.

4.8.1.11 Substation Safety

(a) **Description**

Arc flash hazards have been identified around MV switchgear at zone substations, presenting a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

Makarewa and Bluff substations designs completed in 201/4/15 and installation is planned for completion in 2015/16. It is planned that Ohai Substation will have designed and installation completed in 2015/16.

(b) **Issues**

Harm to personnel

Damage to network equipment and buildings

4.8.1.12 Options

- Additional PPE requirements [Bulky PPE considered suboptimal as it can create additional hazards for personnel]
- Operation controls [Relies on human intervention for safety of personnel]
- Protection improvements including retrofit of arc flash detection [Chosen option. Improves safety for personnel and provides improved fault detection through modern protection relays]

(a) **Cost and type**

$205k p.a. 2015 to 2017

(b) **Goal / Strategy**

CAPEX – Other Reliability, Safety and Environmental.

4.8.2 Current routine and non-material projects

Expected routine and non-material projects for year one (YE 31 March 2016) are as follows.

4.8.2.1 Quality Remedies

(a) **Description**

Projects to remedy poor power quality.

Voltage is measured (or calculated to vary) outside of regulatory limits.

(b) **Alternatives**

Each of the below options / situations are considered and an appropriate solution implemented.

- Installation of 11kV regulators.
- Up-sizing of components (Conductor, Transformer).
- Demand side management. (Planning an Irrigation ripple control channel.)
- Power factor improvements. (Ensuring customer loads are operating effectively.)
- Harmonic filtering / blocking. (Ensuring customers are not injecting harmonics.)
- Motor starter faults / settings remedied. (Ensuring customer equipment is working and configured appropriately.)

Cost is budgeted at $170k p.a. on-going, Quality of Supply.

(c) **Goal / Strategy**

Achieve 100% regulatory compliance. Migrate from a 33kV subtransmission network to 66kV.

4.8.2.2 New connections

(a) Description

Allowance for new connections to the network. Each specific solution will depend on location and customer requirements.

Some subdivision developments are occurring but we receive little or no prior notification of these. Request to Developers and Regional Authorities provided only minor subdivisions occurring, or no firm commitments. An estimated allowance based on past experience and projected development has been included in the plan.

An allowance has been made to connect Distributed Generation to the network as the proposed regulations have this as a TPCL's cost.

(b) Alternatives

Vary due to customer type and location.

Cost is budgeted at $3.3M p.a. on-going, Consumer Connection.

(c) Goal / Strategy

Undertake new investments, which are 'core business', acceptable return for risk involved.

4.8.2.3 Earth upgrades

(a) Description

Regular testing of earths across the network is still locating sites with earths that are not sufficient. This programme is to upgrade these to an acceptable level and ensure that missing or stolen components are replaced.

Resistance to earth and earthing systems on equipment needs to be sufficient to maintain a safe environment for staff and the public.

(b) Alternatives

- Upgrade and/or extension of electrodes in the ground.
- Limit earth fault current by installing NER's.
- Isolate equipment for contact.
- Separate HV / MV and LV / MEN earths.

Cost is budgeted at around $580k for the next three years. Then reducing for following years, once NER's are installed. Other Reliability, Safety and Environmental.

(c) Goal / Strategy

Undertake safety and environmental improvements. Achieve 100% regulatory compliance.

(d) Goal / Strategy

Strive to become an efficient and effective operation.

4.8.2.4 Line Relocation

(a) Description

Works to move lines around trees or for roadway realignments.

Needed to achieve clearances between lines and trees, due to high tree value to community or individuals.

(b) Alternatives

- Move line to other side of road.
- Underground line next to the trees.
- Insulate the line next to the trees.
- Remove or trim the trees.
- Move line to a long-side new alignment.

Cost budgeted at $52k pa, Asset Relocations.

(c) **Goal / Strategy**

Undertake safety and environmental improvements. Achieve 100% regulatory compliance.

4.8.2.5 Lumsden Oil Bunding

(a) **Description**

Install a refurbished 33/11kV 5MVA transformer on the existing bunded pad at Lumsden and remove the existing 33/11kV 5MVA from the unbunded pad for refurbishment.

(b) **Issues**

Existing transformer has no bund – oil spill will have negative environmental consequences

Existing transformer due for refurbishment

(c) **Options**

Add bund to existing unbunded transformer pad [Transformer due for refurbishment, other existing pad already has bund constructed]

Shift refurbished transformer to empty bunded pad and remove existing transformer from unbunded pad for refurbishment [Planned option. Allows utilisation of empty bunded pad and allows for refurbishment of transformer currently in service at Lumsden]

(d) **Cost and type**

<$0.5M 2015/16

(e) **Goal / Strategy**

Minimise environmental harm. Undertake power transformer refurbishments to extend useful service life.

4.8.3 Planned projects [A.11.10.2.]

Expected projects for year two to five (YE 31 March 2017 to 2020) are as follows. These projects have some certainty.

Note some projects are planned to start in year one and continue over following years, these are not repeated in following sections.

4.8.3.1 Gore Supply Transformers upgrade

(a) **Description**

Transpower is likely to upgrade the 110/33kV supply transformers and may have some impact on TPCL's assets around Gore GXP.

As an alternate to upgrading the ripple injection plant it is proposed to install 'Smart' meters on each consumers premise. A separate Metering business will install the 'smart' meters and provide control and information to TPCL.

(b) **Issues**

Existing Ripple Injection plant overloaded.

Network electrical parameters changing.

(c) **Options**

- Replace with a higher rated plant. [Likely to be superseded by 'smart' meters.]
- Change to another methodology. [Radio]
- 'Smart' meters. [Could be provided by Smart Meters if bulk replacement occurs.]

(d) **Details**

Estimate is assuming that 'smart' meters are installed.

Transpower new investment agreement if supply transformer upgraded.

(e) **Cost and type**

No capital expenditure but would have additional Transpower and metering charges.

(f) **Goal / Strategy**

Strive to become an efficient and effective operation.

4.8.3.2 New Invercargill to Colyer Rd 33kV Line

(a) **Description**

Should development occur in the Awarua industrial zone additional capacity will likely be required.

It is proposed to begin planning and design to build a new heavy 33kV line from Invercargill to the new Colyer Road substation.

Construction is estimated to occur during 2017/18.

(b) **Issues**

A new line route from Invercargill to Awarua will be difficult to obtain with early consultation with affect parties desired.

Marine / Coastal location, with high salt pollution.

(c) **Options**

- New 33kV line.
- Upgrade existing 33kV lines.
- Upgrade lines to 66kV. [Would require a 66kV source from Transpower.]
- New Transpower supply substation.]Could be required if customer demand is expected to exceed 60MW.]
- New 33kV Cable. [Can be considered if no line route available, but likely more expensive.]

(d) **Cost and type**

$65k landowner consultation in 2014/15.

<$0.5M in 2016/17 Design

$1M - $5M in 2017/18, System Growth.

(e) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.3.3 Gore to Mataura 33kV Line Upgrade

(a) **Description**

Upgrade the existing 33kV line between Gore and Mataura to reduce losses and improve backup capability between Gore GXP and Edendale substation

(b) **Issues**

High losses due to medium construction of existing 33kV line

Line can have voltage drop which is unable to be corrected at load end when providing backup supply to Edendale substation

(c) **Options**

- New 33kV line.
- Upgrade existing 33kV lines.
- Upgrade lines to 66kV. [Would require a 66kV source from Transpower and 66kV to 33kV transformer at Mataura]

(d) **Cost and type**

$1M - $2.5M 2019/20 System Growth.

(e) **Goal / Strategy**

Provide its customers with above average levels of service. Strive to become an efficient and effective operation.

4.8.3.4 Kelso Transformer Upgrade

(a) **Description**

Load growth is forecast to exceed the capacity of the transformer at Kelso Substation in 2017. Planning is to design for the replacement of the single 33/11kV 5MVA power transformer at Kelso substation with a 33/11kV 6/12MVA transformer.

(b) **Issues**

Possible load growth may exceed the firm capacity of the substation.

Backup capability on 11kV from neighbouring substations is limited by voltage drop so load transfer is not practical

(c) **Options**

Load transfer [Not achievable due to voltage drop when fed from neighbouring substations]

Replace transformer with larger unit [Planned option – refurbished 6/12MVA 33/11kV transformer ex Waikiwi should be available depending on timing]

Add second transformer [Requires new switchgear and changes to existing spare transformer pad. Security standard does not require 2 transformers. Likely to be more expensive]

(d) **Cost and type**

$0.5 - $1.0Mpa 2018 to 2020, System Growth.

(e) **Goal / Strategy**

Provide its customers with above average levels of service. Strive to become an efficient and effective operation.

4.8.3.5 New Tuturau Substation

Growth in the Tuturau area between Mataura and Edendale is estimated to reach the level where an additional zone substation is required.

Planning and design work for the construction of a new 33/11kV zone substation in the Tuturau area with supply sourced from the 33kV line between Mataura and Edendale

Work planned for the project:

- Construct a 33kV line tee-off from the existing 33kV line between Mataura and Edendale.
- Construct a new zone substation with a single refurbished (or new) 33/11kV 5MVA or with three or four 11kV feeders supplied via an indoor switchboard

(a) **Issues**

Due to dairy conversions the network in this area has been calculated to be at the limit of acceptable voltage and the installation of additional 11kV regulators is considered not optimal.

Need to obtain land next to the Edendale to Mataura 33kV line.

(b) **Options**

- New substation on the 33kV network. [Selected option as provides the most benefits.]
- Conversion to 22kV. [More expensive.]
- 11kV regulators. [Increased losses.]
- Demand-side management (Tariff? Dairying loads…)[Limited capability from farmers.]

(c) **Details**

Consultants are to design the substation based on a port-a-com transportable building with equipment installed prior to transport to site similar to Isla Bank and Athol solution.

Final construction details will be defined when designs are completed.

(d) **Cost and type**

$0.5 - $2.5M p.a. 2017 to 2019, System Growth.

(e) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.3.6 New 33kV Line to Kennington

(a) **Description**

Load growth is forecast to exceed the ability of the 11kV network to provide backup to Kennington should a fault affect the single 33kV line from Invercargill to Kennington.

Kennington was upgraded to a dual transformer site in 2013 and load on the site has increased after planned transfers from neighbouring substations.

A tee off from the Invercargill to Gorge Road 33kV line is proposed. The tee off will be constructed as 33kV over existing 11kV line routes in the road corridor

(b) **Issues**

Limited 11kV backup from neighbouring substations

(c) **Options**

- New 33kV Cable. [Can be considered if no line route available, but likely more expensive.]
- Transfer load to neighbouring substations on 11kV. [Lines close to limit of voltage drop at peak times. Additional 11kV regulators considered suboptimal]

(d) **Cost and type**

$0.1-0.5M 2017 to 2019, System Growth

(e) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.3.7 Glenham Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Glenhma Substation in 2018. Planning is to design for the replacement of the single 33/11kV 1.5MVA power transformer at Kelso substation with a new 33/11kV 3MVA transformer or refurbished 5MVA transformer.

(a) **Issues**

Possible load growth may exceed the firm capacity of the substation.

Backup capability on 11kV from neighbouring substations is limited by voltage drop so load transfer is not practical.

Limited space at Glenham substation.

(b) **Options**

Load transfer [Not achievable due to voltage drop when fed from neighbouring substations]

Replace transformer with larger unit [Planned option – refurbished 5MVA 33/11kV transformer ex Conical Hill should be available depending on timing]

Add second transformer [Requires new switchgear and new transformer pad. Security standard does not require 2 transformers. Likely to be more expensive]

(c) Cost and type

$0.5 - $1.0M 2018 to 2020, System Growth.

4.8.4 Considered projects [A.11.10.3.]

Expected projects for year six to ten (YE 31 March 2021 to 2025 are as follows. These projects have little if any certainty.

Note some projects that are on-going throughout this period are detailed above.

4.8.4.1 Township Undergrounding

Underground conversion of the 11kV and 400V lines in the townships. Mostly driven and funded by the local community.

4.8.4.2 North Makarewa Supply Transformers

Load growth is likely to require an upgrade at North Makarewa. The suggested upgrade would add one or two 220/66kV supply transformers.

4.8.5 Contingent projects

The following projects are contingent on uncertain events. These have been excluded from TPCL's spend plans until they become certain.

4.8.5.1 Mataura Valley Milk

Possible additional Milk Powder plant at the old saleyards site in McNab. Will require a new substation and reinforcement of the 33kV network.

4.8.5.2 Additional Milk Processing

Possible additional Milk Processing plants at existing or new sites.

4.8.5.3 Solid Energy Briquette Plant

Possible production of Lignite Briquettes in the Mataura area. Depending on the location, may require a new substation and subtransmission lines to supply or a step increase in capacity at an existing substation.

4.8.5.4 Coal to Liquid Plants

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

4.8.5.5 Mines

Possible mineral extraction with power required to operate the mine and/or process the material. Possible resources include coal, lignite, silicon, gold, platinum…

4.8.5.6 Oil Refineries

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

4.8.6 Proposed network configuration

The proposed network configuration at the end of the planning period is shown in figure 45.

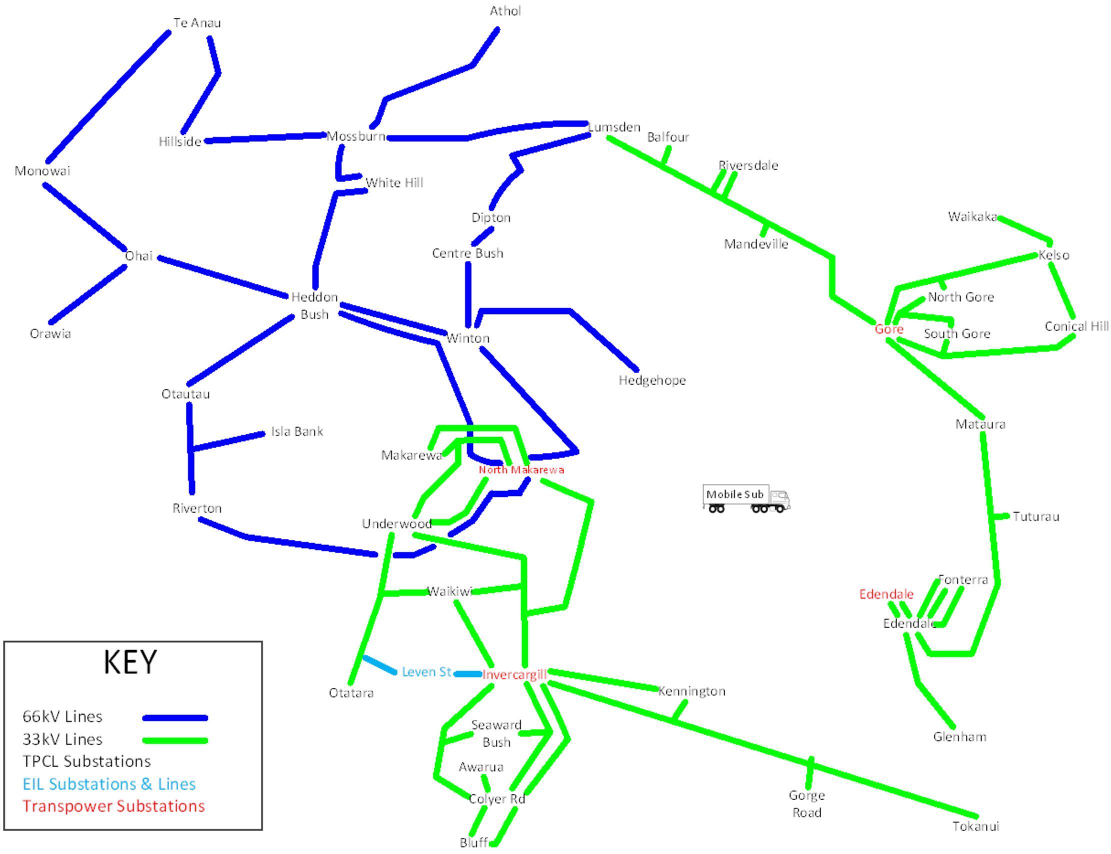


Figure 45 2025 proposed network configuration

4.8.7 Capital Budget

The estimated capital budget for TPCL is given in Figure 46. Note the actual cost of some projects are not shown so as not to compromise the contractors' estimating and tendering processes.

CAPEX: System Growth	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
New Mossburn to Athol 66kV Line	[redacted]	-	-	-	-	-	-	-	-	
New Isla Bank Substation	[redacted]	-	-	-	-	-	-	-	-	-
Waikiwi Substation Upgrade	[redacted]	[redacted]	-	-	-	-	-	-	-	-
OVP-Design	[redacted]	-	-	-	-	-	-	-	-	-
OVP-Winton to Centre Bush 66kV Line	[redacted]	-	-	-	-	-	-	-	-	-
OVP-Centre Bush to Mossburn 66kV Line	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-
OVP-Dipton Substation Upgrade	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
OVP-Centre Bush Substation Upgrade	[redacted]	[redacted]	-	-	-	-	-	-	-	-
OVP-Lumsden Substation Upgrade	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-
Riversdale Substation Upgrade	[redacted]	-	[redacted]	-	-	-	-	-	-	-
New Colyer Road Substation	[redacted]	-	-	-	-	-	-	-	-	-
TPNZ Edendale 110kV Transformer Upgrade	-	0	-	-	-	-	-	-	-	-
Edendale Substation Upgrade	[redacted]	-	-	-	-	-	-	-	-	-
New Invercargill to Colyer Rd 33kV Line	-	[redacted]	[redacted]	-	-	-	-	-	-	-
New Balfour Substation	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Gore to Mataura 33kV Line	-	-	-	-	[redacted]	-	-	-	-	-
TPNZ North Makarewa 220/66kV Transformer	-	-	-	-	-	0	-	-	-	-
Kelso Transformer Upgrade	-	-	[redacted]	[redacted]	-	-	-	-	-	-
New Tuturau Substation	-	-	[redacted]	[redacted]	-	-	-	-	-	-
Kennington 2nd 33kV Line	-	-	[redacted]	[redacted]	-	-	-	-	-	-
Glenham Transformer Upgrade	-	-	-	[redacted]	[redacted]	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	3,471,400	3,471,400	3,471,400	3,471,400	3,471,400
-	**12,958,173**	**4,848,030**	**8,169,984**	**3,993,958**	**1,391,353**	**3,471,400**	**3,471,400**	**3,471,400**	**3,471,400**	**3471400.1**

CAPEX: Consumer Connection	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Customer Connections (≤ 20kVA)	1,133,695	1,133,695	1,133,695	1,133,695	1,133,695	1,123,100	1,123,100	1,123,100	1,123,100	1,123,100
Customer Connections (21 to 99kVA)	1,339,822	1,339,822	1,339,822	1,339,822	1,339,822	1,327,300	1,327,300	1,327,300	1,327,300	1,327,300
Customer Connections (≥ 100kVA)	762,668	762,668	762,668	762,668	762,668	755,540	755,540	755,540	755,540	755,540
Distributed Generation Connection	5,153	5,153	5,153	5,153	5,153	5,105	5,105	5,105	5,105	5,105
New Subdivisions	103,063	103,063	103,063	103,063	103,063	102,100	102,100	102,100	102,100	102,100
	3,344,401	**3,344,401**	**3,344,401**	**3,344,401**	**3,344,401**	**3,313,145**	**3,313,145**	**3,313,145**	**3,313,145**	**3,313,145**

CAPEX: Asset Replacement and Renewal	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
General Distribution Replacement-West	720,735	720,735	720,735	720,735	720,735	714,000	714,000	714,000	714,000	714,000
General Distribution Replacement-East	401,939	401,939	401,939	401,939	401,939	398,183	398,183	398,183	398,183	398,183
General Technical Replacement	27,252	27,252	27,252	27,252	27,252	26,997	26,997	26,997	26,997	26,997
Transformer Replacement - West	895,332	895,332	895,332	895,332	895,332	886,964	886,964	886,964	886,964	886,964
Transformer Replacement - East	441,010	441,010	441,010	441,010	441,010	436,888	436,888	436,888	436,888	436,888
11kV Line Replacement - West	2,408,917	2,408,917	2,408,917	2,408,917	2,408,917	2,386,404	2,386,404	2,386,404	2,386,404	2,386,404
11kV Line Replacement - East	1,042,912	1,042,912	1,042,912	1,042,912	1,042,912	1,033,165	1,033,165	1,033,165	1,033,165	1,033,165
Subtransmission Lines Replacement - West	0	0	0	0	57,715	57,176	57,176	57,176	57,176	57,176
Subtransmission Lines Replacement - East	32,465	32,465	32,465	32,465	32,465	32,162	32,162	32,162	32,162	32,162
Zone Substation Minor Replacement	87,395	86,347	60,667	62,889	62,889	62,301	62,301	62,301	62,301	62,301
RTU Replacement	128,829	153,686	153,686	157,223	157,223	155,754	155,754	155,754	155,754	155,754
Regulator Replacement	153,030	425,362	167,704	-	167,704	-	166,137	-	166,137	166,137
Relay Replacement	25,615	25,615	25,615	41,926	41,926	41,534	41,534	41,534	41,534	41,534
Communications Replacement	204,914	204,914	104,815	-	-	-	-	-	-	-
Seismic Remedial Zone Substations	206,126	206,126	-	-	-	-	-	-	-	-
Seismic Remedial Distribution	52,408	-	-	-	-	-	-	-	-	-
Power Transformer Refurbishment	419,261	272,520	267,279	267,279	220,112	264,781	280,356	280,356	311,507	311,507
Riversdale to Lumsden 33kV Replacement	[redacted]	-	-	-	-	-	-	-	-	-
Riverton Switchboard Replacement	[redacted]	-	-	-	-	-	-	-	-	-
Seaward Bush Transformer Replacement	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Mataura Substation Transformer Upgrade	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Counsel Rd Nth - Winton 66kV Replacement	[redacted]	-	-	-	-	-	-	-	-	-
Counsel Rd Sth - Ingill 33kV Replacement	-	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-
Hillside to Te Anau 66kV Replacement	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Lumsden 11kV Switchgear renewal	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	2,042,000	2,042,000	2,042,000	2,042,000	2,042,000
	10,632,201	**10,275,644**	**10,838,229**	**7,320,227**	**6,678,132**	**8,538,309**	**8,720,021**	**8,553,884**	**8,751,172**	**8,751,172**

CAPEX: Other Reliability, Safety and Environmen	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Earth Upgrades	528,268	209,631	104,815	104,815	104,815	103,836	103,836	103,836	103,836	103,836
NER Installation	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Substation Safety	206,126	206,126	-	-	-	-	-	-	-	-
Lumsden Oil Bunding	118,523	-	-	-	-	-	-	-	-	-
Township Undergrounding	-	-	-	257,658	257,658	255,250	255,250	255,250	255,250	255,250
	1,419,765	**982,605**	**671,663**	**362,473**	**362,473**	**359,086**	**359,086**	**359,086**	**359,086**	**359,086**

CAPEX: Asset Relocations	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Line Relocations	52,084	52,408	52,408	52,408	52,408	51,918	51,918	51,918	51,918	51,918
	52,084	**52,408**	**52,408**	**52,408**	**52,408**	**51,918**	**51,918**	**51,918**	**51,918**	**51,918**

CAPEX: Quality of Supply	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Supply Quality Upgrades	262,038	262,038	262,038	262,038	262,038	259,589	259,589	259,589	259,589	259,589
Mobile Substation	1,978,484	-	-	-	-	-	-		-	-
Distribution Automation	463,784	463,784	463,784	-	-	-	-	-	-	-
Network Improvement Projects	-	-	-	104,815	104,815	103,836	103,836	103,836	103,836	103,836
	2,704,306	**725,823**	**725,823**	**366,853**	**366,853**	**363,425**	**363,425**	**363,425**	**363,425**	**363,425**

CAPEX: Legislative and Regulatory	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
	-	-	-	-	-	-	-	-	-	
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

CAPEX Grand Total	31,110,931	20,228,909	23,802,507	15,440,321	12,195,621	16,097,282	16,278,995	16,112,857	16,310,145	16,310,145

Figure 46 - Capital Budget

4.9 Non-network assets

4.9.1 Non-network asset description and treatment [A.13.1. & A.13.2.]

TPCL owns none of the following assets that are non-network, as these are owned by PowerNet:

- Information and technology systems.
- Asset management systems.
- Office furniture and equipment.
- Motor vehicles.
- Tools, plant and machinery.

Future upgrades include:

- System Control upgrades incl. new Outage Management System

The PowerNet costs of providing and servicing these are incorporated into charges to TPCL.

5. Managing the assets' lifecycle [A.12.]

All physical assets have a lifecycle. This section describes how TPCL manages assets over their entire lifecycle from "commissioning" to "retirement".

5.1 Lifecycle of the assets

The lifecycle of TPCL's existing assets is outlined in Figure 47 below:

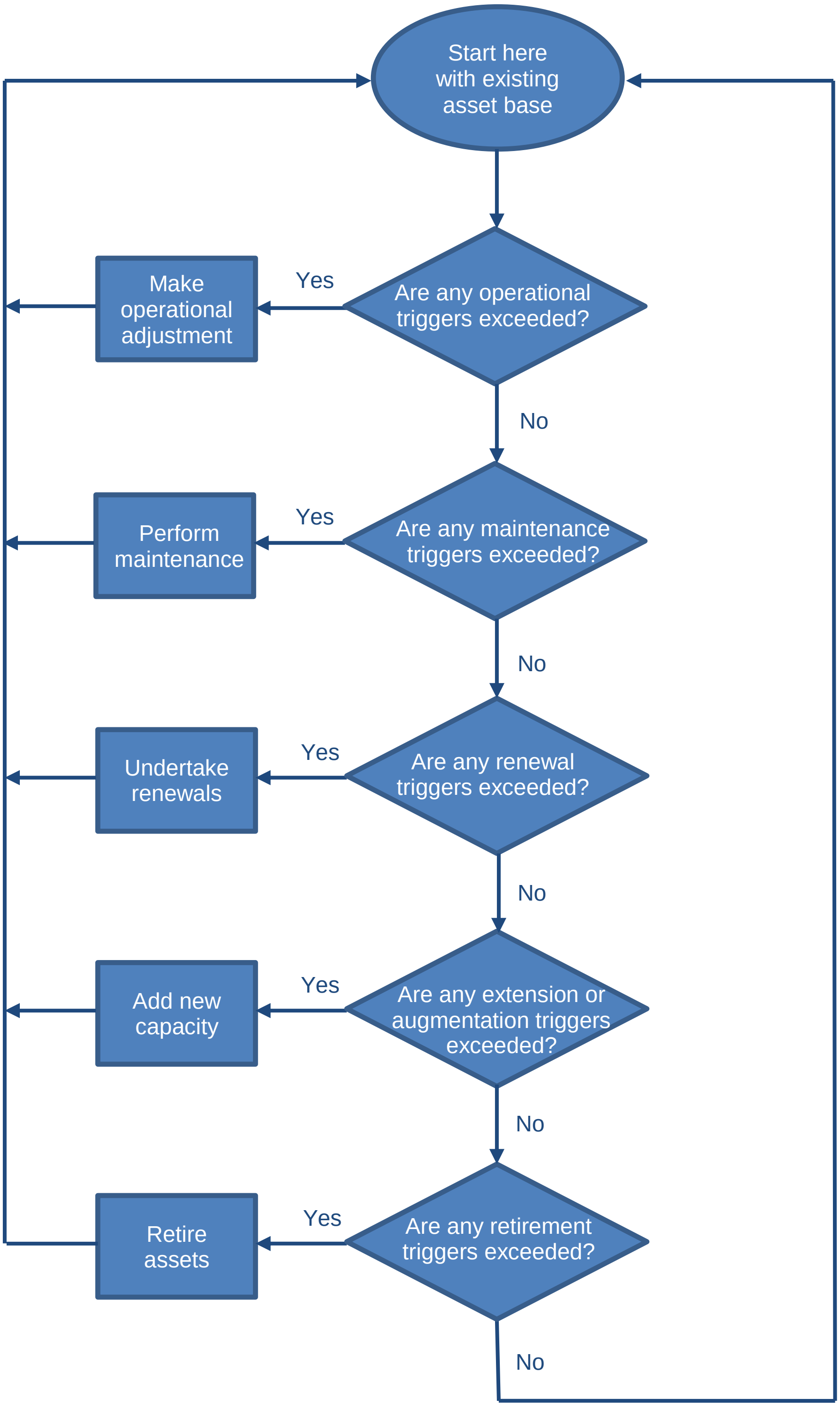


Figure 47 - Asset lifecycle

Table 19 provides some definitions for key lifecycle activities:

Table 19 – Definition of key lifecycle activities

Activity	Detailed definition
Operations	Involves altering the operating parameters of an asset such as closing a switch or altering a voltage setting. Doesn't involve any physical change to the asset, simply a change to the asset's configuration that it was designed for. In the case of electrical assets it will often involve doing nothing and just letting the electricity flow.
Maintenance	Involves replacing consumable components like the seals in a pump, the oil in a transformer or the contacts in a circuit breaker. Generally these components will be designed to wear out many times over the asset's design lifecycle and continued operation of the asset will require such replacement. There may be a significant asymmetry associated with consumables such as lubricants in that replacing a lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the asset's life.
Renewal	Generally involves replacing a non-consumable item like the housing of a pump with a replacement item of identical functionality (usually capacity). Such replacement is generally regarded as a significant mile-stone in the life of the asset and may significantly extend the life of the asset (a bit like "Grandpa's axe"). Renewal tends to dominate the Capital expenditure in low growth areas (Quadrant 1 of Figure 38) because assets will generally wear out before they become too small. The most typical criteria for renewal will be when the capitalised costs of operation and maintenance exceed the cost of renewal. A key issue with renewal is technological advances that generally make it impossible to replace assets such as SCADA with equivalent functionality.
Up-sizing	Generally involves replacing a non-consumable item like a conductor, busbar or transformer with a similar item of greater capacity but which does not increase the network footprint i.e. restricted to Quadrants 1 and 2 in Figure 38.
Extensions	Involves building a new asset where none previously existed because a location trigger in Table 13 has been exceeded e.g. building several spans of line to connect a new factory to an existing line. This activity falls within Quadrants 3 and 4 of Figure 38. Notwithstanding any surplus capacity in upstream assets, extensions will ultimately require up-sizing of upstream assets.
Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement will be when an asset is no longer required, creates an unacceptable risk exposure or when its costs exceed its revenue.

5.2 Operating TPCL's assets

As outlined in Table 19 operations predominantly involves doing nothing and simply letting the electricity flow from the GXP's to customers' 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). As outlined in Figure 47 the first efforts to relieve excursions beyond trigger points are operational activities with typical activities listed in Table 20.

Table 20 Typical responses to operational triggers

Asset class	Trigger event	Response to event	Approach
GXP	Voltage is too high or low on 33kV or 11kV.	Automatic operation of tap changer.	Reactive
	Demand exceeds allocated Transpower limit.	Activate ripple injection plant to switch off load control relays.	Reactive
		Move Zone Substations between GXP's to relieve load from highly loaded GXP.	Reactive
	Transition from day to night.	Activate ripple injection plant to switch street lights on or off.	Proactive
	On-set of off-peak tariff periods.	Activate ripple injection plant to switch controlled loads on or off.	Proactive
Zone substation transformers	Voltage is too high or low on 11kV.	Automatic operation of tap changer.	Reactive
	Demand exceeds rating.	Move tie points to relieve load from zone sub.	Reactive
Distribution reclosers	Fault current exceeds threshold.	Automatic operation of recloser.	Reactive
Distribution ABS's	Component current rating exceeded.	Open & close ABS's to shift load.	Proactive or reactive
	Fault has occurred.	Open & close ABS's to restore supply.	Reactive
Distribution transformers	Voltage is too high or low on LV.	Manually raise or lower tap where fitted.	Reactive
	Fuses keep blowing.	Shift load to other transformers by cutting and reconnecting LV jumpers.	Reactive
LV distribution	Voltage is too low at customers' board.	Supply from closer transformer if possibly by cutting and reconnecting LV jumpers.	Reactive

Table 21 outlines the key operational triggers for each class of TPCL's assets. Note that whilst temperature triggers will usually follow demand triggers, they may not always e.g. an overhead conductor joint might get hot because it is loose or rusty rather than overloaded.

Table 21 - Operational triggers

Asset category	Voltage trigger	Demand trigger	Temperature trigger
LV lines and cables	Voltage routinely drops too low to maintain at least 0.94pu at customers switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at customers switchboards.	Customers' pole or pillar fuse blows repeatedly.	Infra-red survey reveals hot joint.
Distribution substations	Voltage routinely drops too low to maintain at least 0.94pu at customers switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at customers switchboards.	Load routinely exceeds rating where MDI's are fitted. LV fuse blows repeatedly. Short term loading exceeds guidelines in IEC 354.	Infra-red survey reveals hot connections.

Asset category	Voltage trigger	Demand trigger	Temperature trigger
Distribution lines and cables		Alarm from SCADA that current has exceeded a set point.	Infra-red survey reveals hot joint.
Zone substations	Voltage drops below level at which OLTC can automatically raise or lower taps.	Load exceeds guidelines in IEC 354.	Top oil temperature exceeds manufacturers' recommendations. Core hot-spot temperature exceeds manufacturers' recommendations.
Subtransmission lines and cables	Alarm from SCADA that voltage is outside of allowable set points.	Alarm from SCADA that current is over allowable set point.	Infra-red survey reveals hot joint.
TPCL equipment within GXP	Alarm from SCADA that voltage is outside of allowable set points.	Alarm from SCADA that current is over allowable set point.	Infra-red survey reveals hot joint.

5.3 Maintaining TPCL's assets [A.3.13.1. & A.12.1.]

As described in Table 19 maintenance is primarily about replacing consumable components. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts and wearing of pump seals. Continued operation of such components will eventually lead to failure as indicated in Figure 48 below. Failure of such components is usually based on physical characteristics and 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 – note that the horizontal axis in Figure 48 is not simply labelled "time".

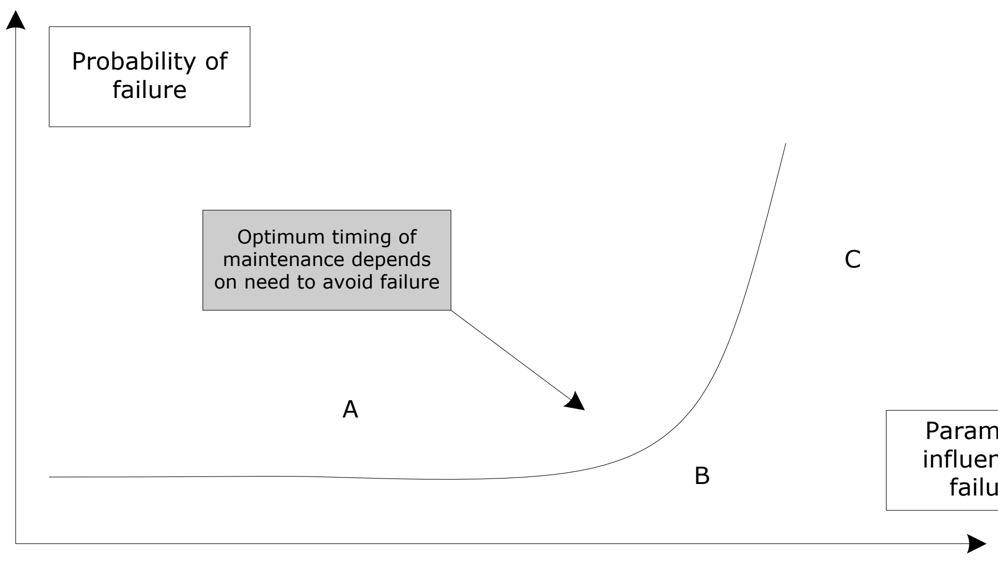


Figure 48 - Component failure

Exactly when maintenance is performed will be determined by the need to avoid failure. For instance the need to avoid failure of a 10kVA transformer supplying a single customer is low; hence it might be operated out to point C in Figure 48 whilst a 66/11kV substation transformer may only be operated to point B due to a higher need to avoid failure. In the extreme case of, say, a transformer supplying a critical process plant or facility, it would be desirable to avoid even the slightest probability of failure hence the supply transformer may only be operated to point A. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the asset's lifecycle along with the cost of discarding unused component life.

Like all TPCL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoiding supply interruption. The practical effect of this is that assets supplying large customers or numbers of customers will be extensively condition monitored to avoid supply interruption whilst assets supplying only a few customers such as a 10kVA transformer will more than likely be run to breakdown. The maintenance strategy map in Figure 49 broadly identifies the maintenance strategy adopted for various ratios of costs and benefits.

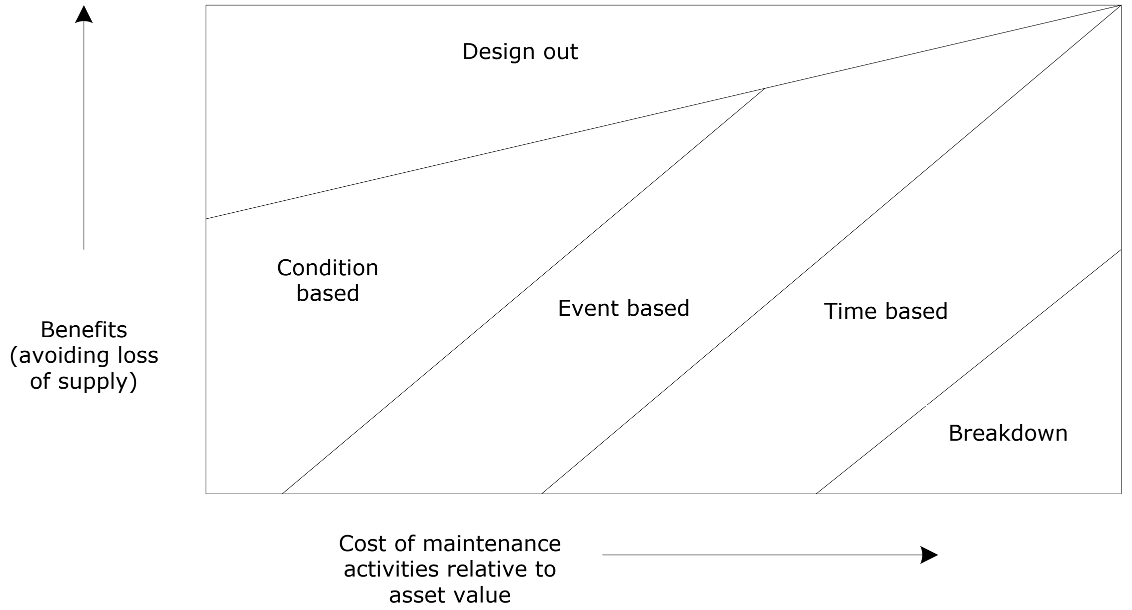


Figure 49 - Maintenance strategy map

This map indicates that where the benefits are low (principally there is little need to avoid loss of supply) and the costs of maintenance are relatively high, an asset should be run to breakdown. As the value of an asset and the need to avoid loss of supply both 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 actual component condition (through such means as DGA[28] for transformer oil).

Component condition is the key trigger for maintenance; however the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 22 describes the maintenance triggers adopted:

Table 22 - Maintenance triggers [A.12.2.1.]

Asset category	Components	Maintenance trigger
LV lines and cables • Five yearly inspection • Ten yearly scan of wooden poles	Poles, arms, stays and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Pins, insulators and binders	• Obviously loose pins. • Visibly chipped or broken insulators. • Visibly loose binder.
	Conductor	• Visibly splaying or broken conductor.

[28] DGA = Dissolved Gas Analysis, where the type and quantity of gas dissolved in the oil is measured. This usually gives an early indication of failure.

Asset category	Components	Maintenance trigger
Distribution substations • Five yearly inspection • Six monthly for sites >150kVA	Poles, arms and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Enclosures	• Visible rust. • Cracked or broken masonry.
	Transformer	• Excessive oil acidity (500kVA or greater). • Visible signs of oil leaks. • Excessive moisture in breather. • Visibly chipped or broken bushings.
	Switches and fuses	• Visible rust. • Oil colour. • Visible signs of oil leak.
Distribution lines and cables • Five yearly inspection • Ten yearly scan of wooden poles	Poles, arms, stays and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Pins, insulators and binders	• Loose tie wire. • Chipped or cracked insulator.
	Conductor	• Loose or pitted strands. • Visible rust. • Low clearance.
	Ground-mounted switches	• Visible rust. • Oil colour. • Visible signs of oil leak.
	Regulators	• Visible rust. • Oil colour. • Visible signs of oil leak. • Excessive moisture in breather. • High Dissolved Gas Analysis results.
Zone substations • Monthly checks	Fences and enclosures	• Weeds. • Visible rust. • Gaps in fence.
	Buildings	• Flaking paint. • Timber rot. • Cracked or broken masonry.
	Bus work and conductors	• Hot spot detected by Infrared detector. • Corrosion of metal or fittings.
	33kV switchgear	• Visible rust. • Operational count exceeded. • Low oil breakdown.
	Transformer	• Visible rust. • High Dissolved Gas Analysis results (Annual test). • Low oil breakdown. • High oil acidity. • Chipped or cracked bushing. • Visible signs of oil leak.
	11kV switchgear	• Visible rust. • Operational count exceeded. • Low oil breakdown.
	Instrumentation/protection • Electromechanical three yearly • Electronic five yearly	• Maintenance period exceeded. • Possible mal-operation of device.
	Batteries • Six monthly test	• Discharge test or Impedance test.
Substation-transmission lines and cables • Five yearly inspection • Ten yearly scan of wooden poles	Poles, arms, stays and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Pins, insulators and binders	• Loose tie wire. • Chipped or cracked insulator.
	Conductor	• Loose or pitted strands. • Visible rust. • Low clearance.
	Cable • Annual check	• High Partial discharge detected. • Sheath insulation short. • Oil pressure declining.

Asset category	Components	Maintenance trigger
Our equipment within GXP • Monthly check	Injection plant	• Alarm from failure ripple generation. • Period exceed for checks.

Typical maintenance policy responses to these trigger points are described in Table 23.

Table 23 Typical responses to maintenance triggers

Asset class	Trigger point	Response to trigger	Approach
Subtransmission lines	Loose or displaced components	Tighten or replace	Condition as revealed by annual inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by annual inspection or ten yearly scan
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by annual inspection
	Low clearance	Resag conductor	As revealed by inspections
GXP and zone substation transformers	Oil acidity	Filter oil	Condition as revealed by annual test
	Excessive moisture in breather	Filter oil	Condition as revealed by monthly inspection
	Weighted number of through faults	Filter oil, possibly de-tank and refurbish	Event driven
	General condition of external components	Repair or replace as required	Condition as revealed by monthly inspection
Distribution lines	Loose or displaced components	Tighten or replace	Condition as revealed by five yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by five yearly inspection or ten yearly scan
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by five yearly inspection
	Low clearance	Resag conductor	As revealed by inspections
Distribution reclosers	Weighted number of light and heavy faults	Repair or replace contacts, filter oil if applicable	Event driven
Distribution ABS's	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by five yearly inspection
	Seized or tight	Lubricate or replace components as required	Breakdown
Distribution transformers	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by five yearly inspection
	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by five yearly inspection
	Oil acidity	Filter oil	Remove from service for full overhaul every 15 years
	Excessive moisture in breather where fitted	Filter oil	Condition as revealed by three yearly inspection

Asset class	Trigger point	Response to trigger	Approach
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by five yearly inspection
	Chipped or broken bushings	Replace	Breakdown or condition as revealed by five yearly inspection
LV lines	Loose or displaced components	Tighten or replace	Breakdown unless revealed by five yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Five yearly inspection or ten yearly scan
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by five yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by five yearly inspection
	Low clearance	Resag conductor	As revealed by inspections

The frequency and nature of the response to each of the above triggers are embodied in TPCL's policies and work plans.

5.3.1 Systemic faults [A.12.2.2.]

Analysis of incidents over the last year has been done, with the resulting map shown in Figure 53. From this analysis no additional concerns have been highlighted.

Examples of past investigations and outcomes:

- 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
- Snow loading leading to cascade failure of pre-stressed poles: Installation of stayed poles to limit extent of cascade.

5.3.2 Routine and corrective maintenance and inspection [A.3.13.1. & A.12.2.]

Each maintenance trigger has a related inspection period listed in Table 22. i.e. Zone substations are checked each month.

Monitoring of assets includes the following areas:

- Protection relay testing / checks.
- Earthing checks.
- DGA of transformer oil.
- Partial discharge and Infrared survey of substations and major distribution equipment.
- Injection plant tuning checks.
- Supply quality checks.
- Line surveys and testing.
- Radio checks.

The on-going maintenance of assets is also covered by this budget. Items covered include:

- Lubrication of ABS's.
- Cleaning of air insulated switchgear.
- Battery replacements.
- Rust repairs and painting.
- TCOL and CB service.

- Minor customer connections.

OPEX on this is budgeted at $2.7 to $2.8 million per annum.

5.3.3 Service interruptions and emergencies

Fault and emergency maintenance provides for the provision of staff, plant and resources to be ready for faults and/or emergencies. This resource attends and makes the area safe, then may isolate the faulty section so other customers are restored or undertake quick repairs to restore supply to all customers.

OPEX on this is budgeted at $2.6 million per annum.

5.3.4 Vegetation Management

Electricity (Hazards from Trees) Regulations 2003, put the requirement on TPCL to undertake the first trim of trees free, and this budget is the on-going actioning of this. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation.

OPEX on this is budgeted at $1.2 million per annum.

5.4 TPCL's maintenance policies [A.12.2.1.]

TPCL's maintenance policies are embodied in the PowerNet standards PNM-99, PNM-105 and PNM-97 which broadly follow manufacturers' recommendations but tend to be modified by industry experience.

5.5 Renewing TPCL's assets [A.12.3.]

Work is classified as renewal if there is no change (and such change would usually be an increase) in functionality i.e. the output of any asset doesn't change. TPCL's key criterion for renewing an asset is when the capitalised operations and maintenance costs exceed the renewal cost and this can occur in a number of ways:

- Operating costs become excessive e.g. addition of inputs to a SCADA system requires an increasing level of manning.
- Maintenance costs begin to accelerate away e.g. a transformer needs more frequent oil changes as the seals and gaskets perish.
- Supply interruptions due to component failure become excessive; what constitutes "excessive" will be a matter of judgment which will include the number and nature of customers affected.
- Renewal costs decline, particular where costs of new technologies for assets like SCADA decrease by several fold.

Table 24 below lists TPCL's renewal triggers for key asset classes.

Table 24 – Renewal triggers

Asset category	Components	Renewal trigger
LV lines and cables	Poles	• Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Done with pole renewal.
	Conductor	• Excessive failures. • Multiple joints in a segment.
Distribution substations	Poles	• Failure due to pole test. • Failure due to external force.
	Enclosures	• Uneconomic to maintain.
	Transformer	• Excessive rust. • Old technology, pre-1970 core. • Uneconomic to maintain.
	Switches and fuses	• Uneconomic to maintain.
Distribution lines and cables	Poles	• Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Done with pole renewal.

Asset category	Components	Renewal trigger
	Conductor	• Excessive failures. • Multiple joints in a segment.
	Ground-mounted switches	• Uneconomic to maintain. • No source of spare parts. • If not able to be remote controlled.
	Regulators	• Uneconomic to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
Zone substations	Fences and enclosures	• Uneconomic to maintain.
	Buildings	• Uneconomic to maintain.
	Bus work and conductors	• Uneconomic to maintain.
	33kV switchgear	• Uneconomic to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Transformer	• Uneconomic to maintain. • No spare parts. • Greater than 1.2 Standard Life and maintenance required.
	11kV switchgear	• Uneconomic to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Bus work and conductors	• Uneconomic to maintain.
	Instrumentation/Protection	• Uneconomic to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Batteries	• Prior to manufacturers' stated life. • On failure of testing.
Subtransmission lines and cables	Poles	• Uneconomic to maintain. • Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Uneconomic to maintain.
	Conductor	• Uneconomic to maintain. • Excessive joints in a segment
	Cables	• Uneconomic to maintain.
Our equipment within GXP		• Uneconomic to maintain.

Broad polices for renewing all classes of assets are:

- When an asset is likely to create an operational or public safety hazard.
- When the capitalised operations and maintenance costs exceed the likely renewal costs.
- When continued maintenance is unlikely to result in the required service levels.

5.5.1 Current Renewal projects [A.12.3.3.]

Renewal projects planned to year end 31 March 2016.

5.5.1.1 General replacement

This covers the on-going operation of the network and covers the following items / areas:

- Red tagged pole replacement
- Increasing road crossing height
- Minor distribution renewals and upgrades.

Cost: $0.4M to $1.1M per annum, CAPEX Renewals.

5.5.1.2 Transformer replacement

On-going renewals of distribution transformers. Most are identified during distribution inspections with projects grouping like work in an area.

Some removed units are refurbished.

Cost: $1.3M per annum, CAPEX Renewals.

5.5.1.3 Line replacement

Work discovered during previous years inspections are combined by feeders into projects. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's. Distribution transformers are covered by the previous item.

Cost: $2.4M - $3.5M per annum, CAPEX Renewals.

5.5.1.4 Zone Substation replacement

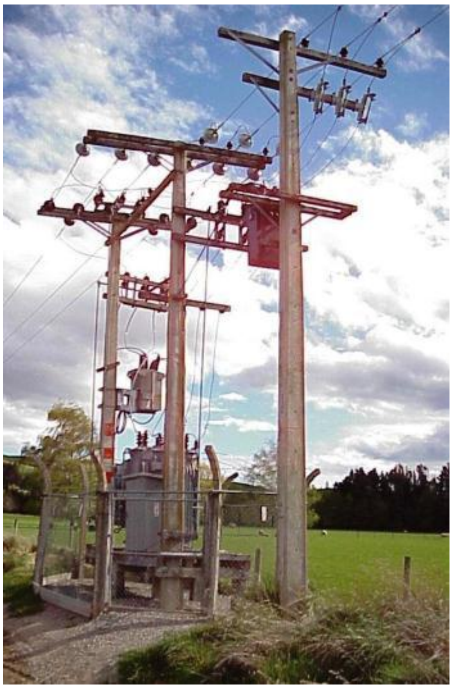
Minor work discovered during previous years inspections are combined by sites into projects. Allows for renewal of equipment and minor upgrades.

Cost: Under $0.1M per annum, CAPEX Renewals.

5.5.1.5 Regulator replacement

Replacement of voltage regulators as they reach the condition where maintenance and repair become uneconomic.

Cost: About $160k per site with one every two years. CAPEX Renewals.



Old Dunrobin Regulator

New Browns Regulator

5.5.1.6 Seismic remedial work

After the earthquakes in Christchurch a review of substations and the network is planned and some strengthening works will be undertaken.

Liquefaction and high horizontal forces damaged equipment in Christchurch, beyond what was expected. Calibre have reviewed each substation and have highlighted equipment that is likely to be damaged due to current learnings on earthquakes. Next stage is to detail reinforcement works and get the strengthening work done.

Cost: Under $0.5M p.a. 2013 to 2016, CAPEX Renewal.

5.5.1.7 Riversdale to Lumsden 33kV replacement

The 33kV line from Riversdale to Lumsden will reach its Standard Life in 2010 and limitations exist in transporting power though this line. The age of the poles on this line can be seen on Figure 11. Consideration was given to upgrading this line to 66kV but the need for this capacity is not expected until after 2018. Initial works will consider the condition of each pole and replace if the expected life is less than five years or the strength of the pole is not sufficient for upsizing to neon conductor. Neon AAAC[29] is selected to match the capacity of the Wolf ACSR[30] Riversdale to Gore 33kV section of this route. Design has been completed and construction is underway with completion expected in 2015/16.

Cost: Completion is estimated at $1.3 million and will occur in 2015/16. CAPEX Renewal.

5.5.1.8 Counsel Rd Nth to Winton 66kV replacement

The line is nearing its Standard Life and renewal is expected during 2015/16. Line was purchased from Transpower and full refurbishment or renewal of all components is desired to maintain service levels in Western and Northern Southland. The age of the poles on this line can be seen on Figure 11. Some poles have been replaced and these will be reviewed and maintained. This line was expected for renewal in 2014/15 however after the design was completed, the cost of rebuild was more than 50% over budget. In light of this information a new design was completed in 2014/15 and the renewal will occur in 2015/16

Cost: Rebuild construction cost is estimated at $1.5 million and is scheduled for 2015/16. CAPEX Renewal.

5.5.1.9 Power transformer refurbishment

A budget to allow refurbishment work on large power transformers. Generally this work only insures that the power transformer will achieve its expected life.

Cost: Varies but generally $250k per annum, CAPEX Renewals.

5.5.1.10 Distribution refurbishment

A budget to allow refurbishment work that doesn't impact on the valuation of the distribution asset. This covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

Cost: $1.0M per annum, OPEX Renewals.

5.5.1.11 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.

Cost: $71k per annum, OPEX Renewals.

5.5.1.12 Substation refurbishment

A budget to allow refurbishment work that doesn't impact on the valuation of the substation assets. This covers items like power transformers, earth sticks, safety equipment, buildings, battery systems etc.

Cost: $37k per annum, OPEX Renewals.

5.5.1.13 Communications replacements

[29] AAAC = All Aluminium Alloy Conductor

[30] ACSR = Aluminium Conductor Steel Reinforced.

Equipment is becoming obsolete with manufactures ending support. This project will replace the total communications network with a modern scheme to provide the required communication for TPCL.

Cost: $700k from 2015 to 2018, CAPEX Renewals.

5.5.1.14 Transformer refurbishment

A budget to allow refurbishment work that doesn't impact on the valuation of the distribution assets.

Cost: $38k per annum, OPEX Renewals.

5.5.1.15 Seaward Bush Transformer

The two 33/11kV 10MVA power transformers at Seaward Bush are nearing their 'end-of-life' and additional refurbishments are not considered desirable due to insulation degradation, corrosion of main tank, corrosion of radiators and TCOL[31] mechanism wear. Due to the impact that failure of these would do to service levels and the strategy of "Replace critical assets near to their technical end-of-life", these units are programmed for replacement. The old units are planned to be retained until newer spares are obtained.

Cost: $0.5M - $2.5M 2015 to 2018, CAPEX renewal.

5.5.1.16 Mataura Transformer Upgrade

(a) Description

The two 33/11kV 10MVA power transformers at Mataura are nearing their 'end-of-life' and additional refurbishments are not considered desirable due to insulation degradation, corrosion of main tank, corrosion of radiators and TCOL[32] mechanism wear. Due to the impact that failure of these would do to service levels and the strategy of "Replace critical assets near to their technical end-of-life", these units are programmed for replacement. The old units are planned to be retained until newer spares are obtained.

Cost: $0.5 - $2.5M p.a. 2015 to 2018, System Growth.

5.5.1.17 North Makarewa to Invercargill renewal

The line is nearing its Standard Life and renewal is expected during 2016 to 2018.

Cost: $0.5 - $2.5M 2015 to 2018, CAPEX renewal.

5.5.1.18 Hillside to Te Anau renewal

The 66kV line is nearing its Standard Life and renewal is expected during 2016 to 2018, with design work during 2015/16.

Cost: $0.5 - $2.5M 2016 to 2018, CAPEX renewal.

5.5.2 Planned renewal projects [A.12.3.4.]

Project planned for year two to five, YE 2017 to YE 2020.

5.5.2.1 SCADA RTU replacements

This project will replace an average of two sites each year. The GPT RTU's have now been replaced (or will be replaced as part of other projects) so focus is now on the Harris RTU's. Some substation projects will include the RTU replacement and have costs included. i.e. Waikiwi, Centre Bush, Dipton and Lumsden.

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[31] TCOL = Tap Change On-Load

[32] TCOL = Tap Change On-Load

This was chosen as the present units are becoming unreliable and full remote operation is required to meet the service levels. Rate of renewal could be increased if unreliability reaches unacceptable levels.

Cost: Under $0.25M per annum from 2015/16, CAPEX Renewals.

5.5.2.2 Relay replacements

On-going testing and fault investigation sometimes highlight protection and control relays that are not performing as desired; this programme allows renewal of these with modern protection and control relays. (Includes Voltage Regulating Relays)

Some replacements will occur with other replacement projects, i.e. Switchboard replacement projects.

Cost: Under $50k per annum from 2015/16, CAPEX Renewals.

Cost: $0.5 - $2.5M 2015 to 2018, CAPEX renewal.

5.5.3 Future renewal projects [A.12.3.5.]

Projects planned for year five to ten, YE 2021 to YE 2025.

5.5.3.1 Subtransmission Line replacement

Work discovered during previous years' inspections are combined by circuits into projects. Allows for renewal of equipment and minor upgrades.

Budgeted at $100k per annum from 2018/19, CAPEX Renewals.

5.5.4 Renewal/replacement budget

CAPEX renewals are budgeted in the capital budget, see section 4.8.7.

5.6 Up-sizing or extending TPCL's assets

If any of the capacity triggers in Table 13 are exceeded consideration is given to either up-sizing or extending TPCL's network. These two modes of investment are however, quite different as described in Table 25 below.

Table 25 - Distinguishing between up-sizing and extension

Characteristic	Up-sizing	Extension
Location	Within or close to existing network footprint (within a span or so).	Outside of existing network footprint (more than a couple of spans).
Load	Can involve supply to a new connection within the network footprint or increasing the capacity to an existing connection.	Almost always involves supply to a new connection.
Upstream reinforcement	Generally forms the focus of up-sizing.	May not be required unless upstream capacity is constrained.
Visible presence	Generally invisible.	Obviously visible.
Quadrant in Figure 38	Either 1 or 2 depending on rate of growth.	Either 3 or 4 depending on rate of growth.
Necessity	Possible to avoid if sufficient surplus capacity exists. Possible to avoid or defer using tactical approaches described in section 4.2.1.	Generally can't be avoided – a physical connection is required.
Impact on revenue	Difficult to attribute revenue from increased connection number or capacity to augmented components.	Generally results in direct contribution to revenue from the new connection at the end of the extension.

Characteristic	Up-sizing	Extension
Impact on costs	Cost and timing can vary and be staged.	Likely to be significant and over a short time.
Impact on ODV	Could be anywhere from minimal to high.	Could be significant depending on length of extension and any consequent up-sizing required.
Impact on profit	Could be anywhere from minimal to high.	Could be minimal depending on level of customer contribution.
Means of cost recovery	Most likely to be spread across all customers as part of on-going line charges.	Could be recovered from customers connected to that extension by way of capital contribution.
Nature of work carried out	Replacement of components with greater capacity items.	Construction of new assets.

Despite the different nature of up-sizing and extension work, similar design and build principles are used as described in sections 5.6.1 and 5.6.2.

5.6.1 Designing new assets

TPCL uses a range of technical and engineering standards to achieve an optimal mix of the following outcomes:

- Meet likely demand growth for a reasonable time horizon including such issues as modularity and scalability.
- Minimise over-investment.
- Minimise risk of long-term stranding.
- Minimise corporate risk exposure commensurate with other goals.
- Maximise operational flexibility.
- Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with sensible environmental and public safety requirements.

Given the fairly simple nature of TPCL's network standardised designs are adopted for all asset classes with minor site-specific alterations. These designs, however, will embody the wisdom and experience of current standards, industry guidelines and manufacturers recommendations.

5.6.2 Building new assets

TPCL uses external contractors to augment or extend assets. As part of the building and commissioning process TPCL's information records will be "as-built" and all testing documented.

5.7 Enhancing reliability

Although enhancing reliability does not neatly fit into the life-cycle model, TPCL believes that enhancing reliability is strategically significant enough in reshaping the business platform to merit inclusion in the AMP. As described in Section 3.2.1 customers prefer to receive about the same reliability in return for paying about the same line charges, so it is acknowledged that there is no mandate to go improving reliability just because it can be improved, even if TPCL doesn't need to increase line charges to do it. However there are many factors that will lead to a decline in reliability over time:

- Tree re-growth.
- Declining asset condition (especially in coastal marine areas).
- Extensions to the network that increase its exposure to trees and weather.
- Increased customer numbers that increase the lost customer-minutes for a given fault.
- Installation of customer requested asset alterations that can reduce reliability (e.g. needing to lock out reclosers on feeders that have embedded generation).

TPCL believes it is necessary to offset these impacts in order to maintain reliability; hence a reliability enhancement program using an approach that embodies the following steps has been developed:

- Identifying the customer-minutes lost for each asset by cause.
- Identifying the scope and likely cost of reducing those lost customer-minutes.
- Estimating the likely reduction in lost customer-minutes if the work scope was to be implemented.
- Calculating the cost per customer-minute of each enhancement opportunity.
- Prioritising the enhancement opportunities from lowest cost to highest. TPCL expects the incremental cost of regaining lost customer-minutes will accelerate away at some point which will set an obvious limit to implementing opportunities.

5.8 Converting overhead to underground

Conversion of overhead lines to underground cable is also an activity that doesn't fit neatly within the asset life-cycle because it tends to be driven more by the need to beautify areas rather than for asset-related reasons (which doesn't really fit the renewal or up-sizing triggers). As such, conversion tends to rely on other utilities cost sharing or local communities funding the work.

5.9 Retiring of TPCL's assets

Retiring assets generally involves doing most or all of the following activities:

- De-energising the asset.
- Physically disconnecting it from other live assets.
- Curtailing the assets revenue stream.
- Removing it from the ODV.
- Either physical removal of the asset from location or abandoning in-situ (typically for underground cables).
- Disposal of the asset in an acceptable manner particularly if it contains SF_6, oil, lead or asbestos.

Key criteria for retiring an asset include:

- Its physical presence 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.
- Where better options exist to create similar outcomes (e.g. replacing lubricated bearings with high-impact nylon bushes) and there are no suitable opportunities for re-deployment.
- Where an asset has been augmented and no suitable opportunities exist for re-deployment.

5.10 TPCL's Maintenance Budget [A.12.2.3.]

Estimated expenditure on maintaining the assets are given below. Target is maintaining the ratio of maintenance to under 2% of the total network replacement cost. This budget covers both Operation and Maintenance areas.

OPEX: Routine and Corrective Maintenance and Inspection	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Routine Dist Insp Check & Mtce - West	597,387	597,387	597,387	597,387	597,387	597,387	597,387	597,387	597,387	597,387
Routine Dist Insp Check & Mtce - East	305,727	305,727	305,727	305,727	305,727	305,727	305,727	305,727	305,727	305,727
Minor Work Dist Insp Check & Mtce - West	202,480	202,480	202,480	202,480	202,480	202,480	202,480	202,480	202,480	202,480
Minor Work Dist Insp Check & Mtce - East	91,374	91,374	91,374	91,374	91,374	91,374	91,374	91,374	91,374	91,374
Condition and Data Assessment - West	-	-	-	-	-	-	-	-	-	-
Pole Scanning - East	-	-	-	-	-	-	-	-	-	-
Distribution Earthing Maintenance	443,378	443,378	443,378	443,378	443,378	443,378	443,378	443,378	443,378	443,378
TSL Communications Routine Inspection and Ch	73,437	73,437	73,437	73,437	73,437	73,347	73,347	73,347	73,347	73,348
Technical Routine Inspections and Checks	541,130	541,130	541,130	541,130	541,130	541,130	541,130	541,130	541,130	541,130
Technical Planned Maintenance	816,800	816,800	816,800	816,800	816,800	816,800	816,800	816,800	816,800	816,800
Minor Work Tech Insp Check & Mtce	-	-	-	-	-	-	-	-	-	-
Infrared Survey	15,652	15,652	15,652	15,652	15,652	15,652	15,652	15,652	15,652	15,652
Partial Discharge Survey	26,530	26,530	26,530	26,530	26,530	26,530	26,530	26,530	26,530	26,530
Supply Quality Checks	15,918	15,918	15,918	15,918	15,918	15,918	15,918	15,918	15,918	15,918
Spares Checks and Minor Maintenance	31,836	31,836	31,836	31,836	31,836	31,836	31,836	31,836	31,836	31,836
Seismic Checks - Distribution	61,260	61,260	61,260	61,260	61,260	61,260	61,260	61,260	61,260	61,260
Seismic Checks - Zone Substations	-	-	-	-	-	-	-	-	-	-
Customer Connections	91,890	91,890	91,890	91,890	91,890	91,890	91,890	91,890	91,890	91,890
	3,314,800	**3,314,800**	**3,314,800**	**3,314,800**	**3,314,800**	**3,314,710**	**3,314,710**	**3,314,710**	**3,314,710**	**3,314,711**

OPEX: Asset Replacement and Renewal	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
General Dist Refurbishment - West	650,344	650,344	650,344	650,344	650,344	650,344	650,344	650,344	650,344	650,344
General Dist Refurbishment - East	342,652	342,652	342,652	342,652	342,652	342,652	342,652	342,652	342,652	342,652
Subtransmission Refurbishment - West	56,071	56,071	56,071	56,071	56,071	56,071	56,071	56,071	56,071	56,071
Subtransmission Refurbishment - East	15,575	15,575	15,575	15,575	15,575	15,575	15,575	15,575	15,575	15,575
Overhead Line Design TPCL	-	-	-	-	-	-	-	-	-	-
Zone Substation Refurbishment	37,142	37,142	37,142	37,142	37,142	37,142	37,142	37,142	37,142	37,142
Power Transformer Refurbishment	-	-	-	-	-	-	-	-	-	1
Transformer Refurbishment	38,458	38,458	38,458	38,458	38,458	38,458	38,458	38,458	38,458	38,458
	1,140,243	**1,140,243**	**1,140,243**	**1,140,243**	**1,140,243**	**1,140,243**	**1,140,243**	**1,140,243**	**1,140,243**	**1,140,244**

OPEX: Service Interruptions and Emergencies	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Incident Response Dist - West	1,626,402	1,626,402	1,626,402	1,626,402	1,626,402	1,626,402	1,626,402	1,626,402	1,626,402	1,626,402
Incident Response Dist - East	512,221	512,221	512,221	512,221	512,221	512,221	512,221	512,221	512,221	512,221
Incident Additional Time Dist - West	207,671	207,671	207,671	207,671	207,671	207,671	207,671	207,671	207,671	207,671
Incident Additional Time Dist - East	25,958	25,958	25,958	25,958	25,958	25,958	25,958	25,958	25,958	25,958
Incident Response - TSL Comms (FA)	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,001
Incident Response - Faults Availability	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000
Faults Response Technical (includes TSL Comm	315,013	315,013	315,013	315,013	315,013	315,013	315,013	315,013	315,013	315,013
Incident Additional Time Technical	-	-	-	-	-	-	-	-	-	-
	2,827,266	**2,827,266**	**2,827,266**	**2,827,266**	**2,827,266**	**2,827,266**	**2,827,266**	**2,827,266**	**2,827,266**	**2,827,267**

OPEX: Vegetation Management	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Vegetation Management	1,303,138	1,303,138	1,303,138	1,303,138	1,303,138	1,303,138	1,303,138	1,303,138	1,303,138	1,303,138
	1,303,138	**1,303,138**	**1,303,138**	**1,303,138**	**1,303,138**	**1,303,138**	**1,303,138**	**1,303,138**	**1,303,138**	**1,303,138**

Operational Expenditure Total	**8,585,446**	**8,585,446**	**8,585,446**	**8,585,446**	**8,585,446**	**8,585,356**	**8,585,356**	**8,585,356**	**8,585,356**	**8,585,359**
System Management and Operations	1,598,535	1,633,702	1,666,523	1,666,523	1,666,523	1,666,523	1,666,523	1,666,523	1,666,523	1,666,523
Business Suport	3,492,006	3,492,562	3,567,142	3,567,142	3,567,142	3,567,142	3,567,142	3,567,142	3,567,142	3,567,142
AMP OPEX Total	**13,675,987**	**13,711,710**	**13,819,111**	**13,819,111**	**13,819,111**	**13,819,021**	**13,819,021**	**13,819,021**	**13,819,021**	**13,819,024**

6. Risk management [A.14.]

The business is exposed to a wide range of risks. This section examines TPCL's risk exposures, describes what it has done and will do about these exposures and what it will do when disaster strikes.

Risk management is used to bring risk within acceptable levels.

6.1 Risk methods [A.14.1., A.14.2]

The risk management process as it applies to the electricity network business is intended to assess exposure and prioritise mitigating actions. The risk on the network is analysed at a high level, reviewing major network components and systems to see if possible events could lead to undesirable situations.

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

Depending on the magnitude of risk identified a large scale programme may be initiated to quickly reduce risk. Generally identified risks will have mitigating solutions which become a part of design standards used on the network.

Each risk identified is graded in terms of its likelihood and potential consequences, and responses are developed to minimise the risk as low as reasonably possible. The criteria used to grade the risks are shown below.

LIKELIHOOD	Probability of Occurrence
High	Greater than once per year
Medium	Once every 1-10 years
Low	Once every 10-100 years
Very Low	Less than once per 100 years

CONSEQUENCE	Very Low	Low	Medium	High
CAPEX ($M)	< 0.5	0.5 to 5	5 to 20	> 20
Reliability	KPI Breach	Marginal repeat breaches	Repeat breaches	Repeat breaches over long term
Workplace H&S	Less than minor injury	Minor injury (med treatment reqd.)	Serious injury (LTI)	Fatality / multiple serious injury
Public Safety	Reversible health effects	Reversible health effects of concern	Irreversible health effects of concern	Life threatening or disabling event
Environmental	Single on-site event, negligible harm	Immediately recoverable on-site harm	Recoverable localised off-site harm	Severe localised or widespread off-site harm
Community	Negligible impact on social benefits or developments	Minor impact on social benefits or developments	Moderate impact on social benefits or developments	Extensive impact on social benefits or developments

6.1.1 Guiding principles

TPCL's behaviour and decision making is guided by the following principles:

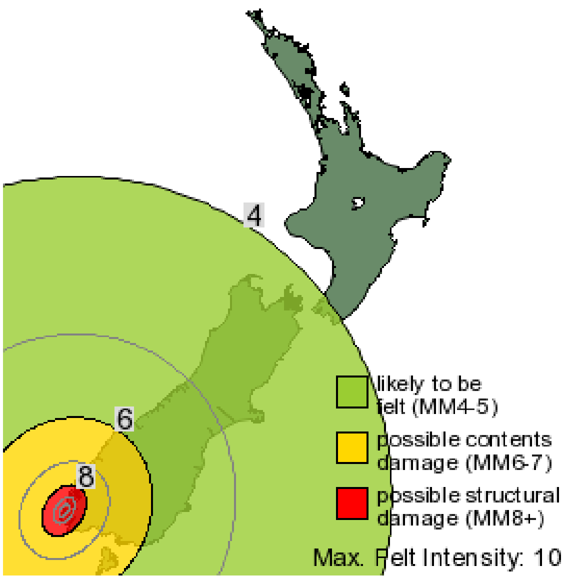
- Safety of the public and staff is paramount.
- Essential services are the second priority.
- Large impact work takes priority over smaller impact work.
- Switching to restore supplies prior to repair work.
- Plans will generally only handle one major event at a time.

- Risks will be removed, mitigated, or otherwise lessened, as appropriate to reduce risk as low as reasonably practicable.+

6.1.2 Risk categories

Risks are classified against the following categories:

- Safety & Environmental
  - 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, that is capable of causing electric shock
  - Arc flash – potential for significant injury to staff from a fault on or near equipment they are using/working on
  - Underground – safety risks amplified by the close proximities and contained space around underground assets
  - Oil spills from transformers or oil circuit breakers
  - Staff error causing worksite safety risk
  - Historical assets not meeting modern safety requirements
  - Site security – unauthorised persons approaching live components through unlocked gate etc.
- Weather
  - 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 the 1984 floods has caused Environment Southland to install flood protection works, but still need to consider if similar water levels do occur again.
- Physical
  - Earthquake – no recent history of major damage. Large events may occur and impact the network. The 15 July 2009 7.8 Richter scale quake 100 km south-west of Te Anau, caused no damage to the network. (*Ref. number 3124785/G*)
  - Liquefaction – post Christchurch 22 February 2011 6.3 quake, the hazard of liquefaction has become a risk to be considered.
  - Tsunami – The TPCL network services coastal areas that are potentially vulnerable to inundation due to a tsunami.



  - Fire – transformers are insulated with mineral oil that is flammable and buildings have flammable materials so fire will affect the supply of electricity. Source of fire could be internal or from external sources.
  - Asset Failures – equipment failures can interrupt supply or negate systems from operating correctly.
- Human/Animal
  - Pandemic – impact depends on the virility of the disease. Could impact on staff work as they try to avoid infection or become unable to work.
  - Third party accidental damage to network – e.g. car versus pole, overheight 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.

  - Terrorism/Vandalism – range varies from malicious damage to copper theft to 'tagging' of buildings or equipment.
  - Cyber attack – low risk at present, but vulnerability increases as the network becomes "smarter"
  - Animals either physically bridging overhead conductors – e.g. birds, possums – or causing conductor clashing – e.g. cattle against stays.
- Corporate
  - Investment – providing business processes that ensure appropriate contracts and guarantees are agreed prior to undertaking large investments.
  - Loss of revenue – loss of customers through by-pass or economic downturn could reduce revenue.
  - Management contract – failure of PowerNet as TPCL's asset manager.
  - Regulatory – failure to meet regulatory requirements.
  - Resource – field staff to undertake operation, maintenance, renewal, up-sizing, expansion and retirement of network assets.

6.2 Risk tactics

The following tactics are used to manage risk under the following broad categories:

- Operate a 24hr Control centre.
- Provide redundancy of supply to large customer groups.
- Remove assets from risk zone.
- Involvement with the local Civil Defence.
- Regular inspections to detect vulnerabilities and potential failures.
- Align asset design with Good Electrical Industry practice.

6.3 Risk details [A.14.1, A.14.2 & A.14.3.]

6.3.1 Safety & Environmental

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

Event	Likelihood	Consequence	Responses
Oil spill (zone sub)	Low	Medium	Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. Bunding is installed in the remaining substations as the opportunity arises. Regular checks of tank condition
Oil spill (dist. transformer)	Medium	Low	Distribution transformers located away from waterways, etc. Installations designed to protect against ground water accumulation
Staff Error	Medium	High	Standardised procedures Training Worksite audits Certification reqd for sub entry, live-line work, etc. Monitor incidents and investigate root causes
Historical Assets	Medium	Medium to High	Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, depending on risk
Site Security	Very Low	High	Monthly checks of restricted sites Alarms on underground sub hatches Standardised exit procedures in 3rd party bldg Above ground sub clearances to AS2067 s5 Design to avoid climbing aids etc.

6.3.2 Weather

Event	Likelihood	Consequence	Responses
Wind	Medium	Low	Impact is reduced by undergrounding of lines. Network design standard specifies level for design. If damage occurs on lines this is remedied by repairing the failed equipment.
Snow	Low	Low	Impact is reduced by undergrounding of lines. If damage occurs on lines this is remedied by repairing the failed equipment. If access is limited then external plant is hired to clear access or substitute.
Flood	Low	Low	Impact is reduced by undergrounding of lines. Transformers and switchgear in high risk areas to be mounted above the flood level. Zone substations to be sited in areas of very low flood risk.

6.3.3 Physical

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Extremely Low	Major	Disaster recovery event. Need to determine actual likely level of survivability of existing assets.
Earthquake (6 to 7)	Very Low	Low to High	Specify so buildings and equipment will survive. Review existing buildings and equipment and reinforce if necessary.

Event	Likelihood	Consequence	Responses
Tsunami	Very Low	Low to Medium	Review equipment in coastal areas and protect or reinforce as necessary.
Liquefaction	Very Low	Low to High	Specify buildings and equipment foundations to minimise impact.
Fire	Low	High	Supply customers from neighbouring substations. Maintain fire alarms in buildings.
Vegetation	High	Low	Vegetation monitoring & tree trimming Public awareness program

A seismic upgrade program for substation buildings and switchyard equipment is currently underway.

6.3.4 Equipment Failures

As the impact of this is variable, a central control room is provided, which is manned 24 hours a day by PowerNet staff. Engineering staff are on standby at any time to provide backup assistance for network issues. Faults contractors provide onsite action and minor failure repairs with contractors 'on-call' for medium to large failures or storms.

Event	Likelihood	Consequence	Responses
33kV & 66kV Lines and Cables	Medium	Low	Regular inspections and maintain contacts with experienced faults contractors. Provide alternative supply by ringed subtransmission or through the distribution network. All new works to Southern Power Contractors Line Design Standard.
Power Transformer	y Low	Low to medium	At dual power transformer sites, one unit can be removed from service due 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. Longer term plan to procure mobile substation.
11kV Switchboard	Low	Medium	Annual testing including PD[33] and IR[34]. Replacement at end of life and continue to provide sectionalised boards. Able to reconfigure network to bypass each switchboard with use of mobile regulators.
11kV & 400V Lines and Cables	Medium	Low	Regular inspections and maintain contacts with experienced faults contractors. Provide alternative supply by meshed distribution network.
Oil Spill	Very Low	Medium	Oil spill kits located at a few substations for the faults contractor to use in event of an oil leak or spill. Most zone substations have oil bunding and regular checks that the separator system is functioning correctly.

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

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

Event	Likelihood	Consequence	Responses
Security measures	Very Low	Medium	Monthly checks of each restricted site. Remote monitoring of access doors by SCADA.
Batteries	Low	Medium	Continue monthly check and six-monthly testing. Dual battery banks for the most critical assets.
Circuit breaker Protection	Low	Medium	Continue regular operational checks. Design protection scheme for upstream relay(s) to operate in event of relay failure Regular protection reviews Mal-operations investigated
Circuit Breakers	Low	Low	Backup provided by upstream circuit breaker. Continue regular maintenance and testing.
SCADA RTU	Low	Low	Monitor response of each RTU at the Master Station and alarm if no response after five minutes. If failure then send faults contractor to restore, if critical events then roster a contractor onsite.
SCADA Masterstation	Very low	Low	Continue to operate as a Dual Redundant configuration, with two 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	Low	Medium	Provide backup to and from EIL Invercargill 2 Ripple Injection Plant for Invercargill, Winton backs up North Makarewa and Gore and Edendale backup each other. Manually operate plant with test set if SCADA controller fails.

6.3.5 Human/Animal

Event	Likelihood	Consequence	Responses
Pandemic	Low	Low to High	Work to the PowerNet Pandemic plan. Includes details such as working from home, only critical faults work and provide emergency kits for offices etc.
Third party accidental	Medium	High (Safety) Low (Network)	Design (assets, protection settings) to minimise electrical safety consequences of failure Underground particularly vulnerable areas Approval process for railway crossings, etc. Regular inspections for sag etc. Resource to bypass and repair.
Vandalism	Medium	Low to High	Six monthly checks of all ground-mounted equipment. Faults contractor to report all vandalism and repair depending on safety then economics: for example tagging/graffiti would depend on the location and content. Any safety problems will be made safe as soon as they are discovered.
Terrorism	Very Low	High	Design restricted sites to prevent unauthorised entry. Use alternative routes and equipment to restore supply, similar to equipment failures above.

Cyber Attack	Very Low	High	Secure communications links. Analyse and remove vulnerabilities. Review and apply industry best practice.
Animal	High	Low	Possum guards all poles. Cattle guards, bird spikes as required.

6.3.6 Corporate

Event	Likelihood	Consequence	Responses
Investment	Low	Low	New larger contracts require Shareholder Guarantee before supply is provided.
Loss of Revenue	Very Low	High	Continue to have Use of System Agreements with retailers. New large investments for individual customers to have a guarantee.
Management Contract	Extremely low	High	Maintain a contract with PowerNet. Ensure PowerNet has and operates to a Business Continuity Plan.
Regulatory	Extremely low	High	Continue to contract PowerNet to meet regulatory requirements. Ensure PowerNet has and operates to a Business Continuity Plan.
Resource	Low	High	Continue to enhance Alliance contractor relationship with present contractors. Provide a long term commitment and support, for the contractor to be sufficiently resourced to achieve the contract service levels on the network.

6.4 Contingency plans [A.14.4.]

TPCL has the following contingency plans through its management company PowerNet:

6.4.1 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.

The principal objectives of the Business Continuity Plan are to:

- 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.

6.4.2 PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause staff to be unable to function in their job.

The plan aims to manage the impact of an influenza pandemic on PowerNet's staff, the business and services through two main strategies:

1. Containment of the disease by reducing spread within PowerNet. This is achieved by such measures as; 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.

2. Maintenance of essential services if containment is not possible. This is 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.

6.4.3 Network Operating Plans

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

6.5 Insurance

TPCL holds the following insurances:

- Material damage and business interruption over Substations and Buildings.
- Contract works
- Directors and officers liability
- Utilities Industry Liability Programme (UILP) that covers Public, Forest & Rural Fires and Products liability.
- Statutory liability
- Marine Cargo.

Contractors working on the network are required to hold Liability Insurance.

7. Funding the business

Everything discussed in TPCL's AMP so far has been (indirectly) about costs. This section discusses how TPCL's business is funded.

7.1 Business model

TPCL's business model is based around the right-hand side of Figure 50.

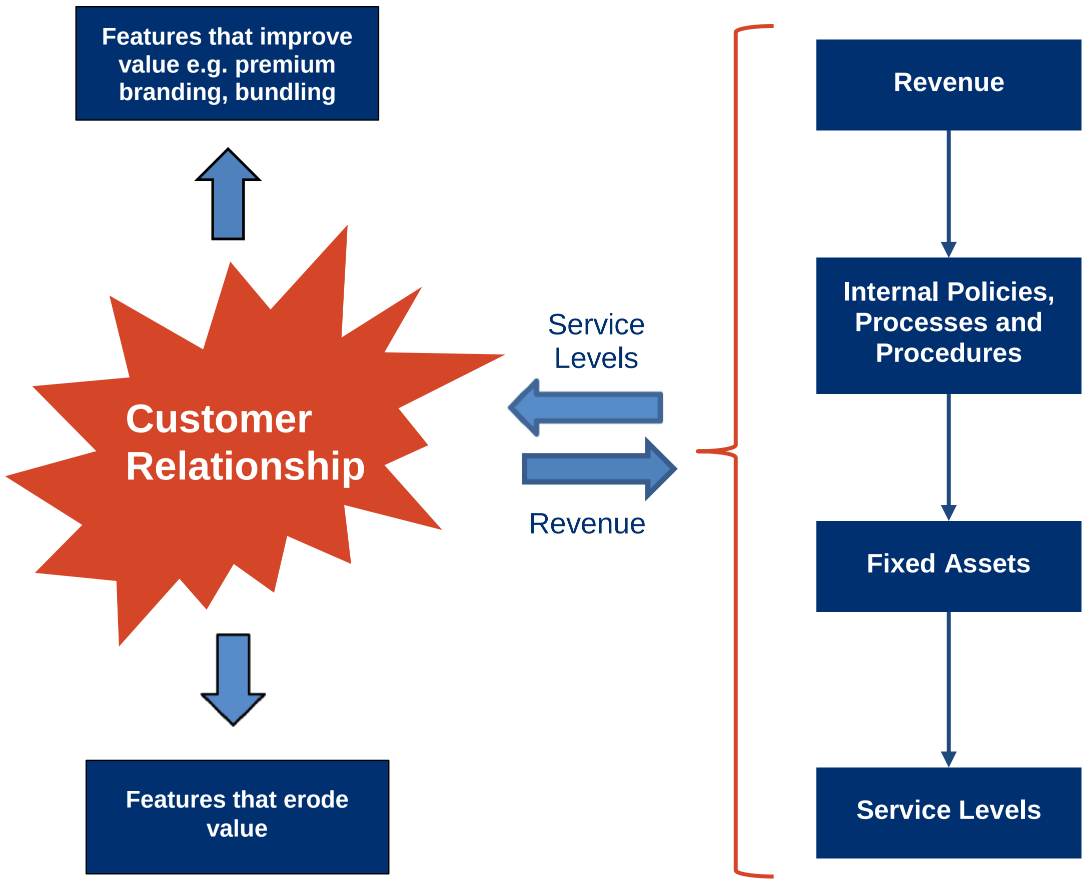


Figure 50 - Customer interface model

This model clearly shows that the company receives cash from TPCL's customers (via the retailers who operate on TPCL's network) and then, through a wide range of internal processes, policies and plans, the company converts that cash into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and voltage stability that customers want.

7.2 Revenue

TPCL's money comes primarily from the retailers who pay TPCL for conveying energy over TPCL's lines or by customer contributions for the uneconomic part of works. In regard to funding new assets (i.e. beyond the immediate financial year) TPCL has considered the following approaches:

- 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 ODV and its balance sheet.

7.3 Expenditure

Work is done to maintain the asset value of the network and to expand or up-size to meet customer demands.

7.4 Changes in the value of assets

Given the preferences expressed by TPCL's customers for the following price-quality trade-offs in the 'Customer engagement telephone survey' undertaken by Gary Nicol Associates in January - February 2014 (2013 score):

- 7% (9%) of rural customers are willing to pay $10 more each month for improved reliability.
- 6% (5%) or rural customers don't know or are unsure of price-quality trade-offs.
- 4% (6%) of urban customers are willing to pay $10 more each month for improved reliability.
- 5% (13%) of urban customers don't know or are unsure of price-quality trade-offs.

This presents TPCL with the dilemma of responding to customers wishes for lower supply quality in the face of a "no material decline in SAIDI requirement". Factors that will influence TPCL's asset value are shown in Table 26 below:

Table 26– 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. Need to confirm exactly when asset value can be added to valuation base under ODV rules.	Removal of assets from the network. Need to confirm when asset value can be removed from valuation base under ODV rules.
Renewal of existing assets. Note definition of renewal as being restoration of original functionality – no increase in service potential beyond original functionality.	On-going depreciation of assets.
Increase of standard component values implicit in the regulatory valuation methodology.	Reduction of standard component values implicit in the regulatory 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.

7.5 Depreciating the assets

As outlined in section 7.4 above, the accounting treatment of depreciation doesn't strictly model the decline in service potential of an asset - sure it probably does quite accurately model the underlying physical processes of rust, rot, acidification, erosion etc. – but an asset often tends to remain 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 worn out assets. This will be particularly important as the "bow wave" of asset renewals approaches.

8. Processes and systems [A.3.11. & A.3.12.]

The core of TPCL's asset management activities lie with the detailed processes and systems that reflect TPCL's thinking, manifest in TPCL's policies, strategies and processes and ultimately shape the nature and configuration of TPCL's fixed assets. The hierarchy of data model shown in Figure 51 describes the typical sorts of information residing within TPCL's business (including in TPCL's employees' brains).

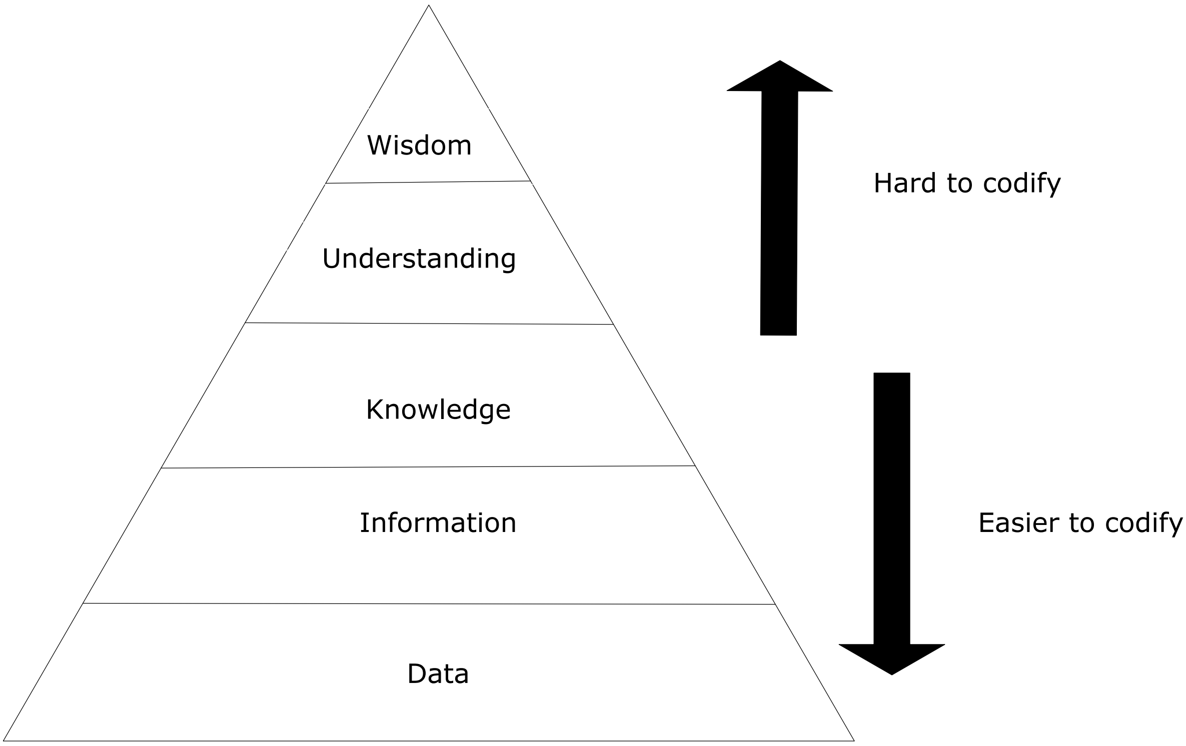


Figure 51 - Hierarchy of data

The bottom two layers of the hierarchy tend to relate strongly to TPCL's asset and operational data which reside in the GIS and SCADA respectively and the summaries of this data that form one part of TPCL's decision making.

The third layer – knowledge – tends to be more broad and general in nature and may include such things as technical standards that codify accumulated knowledge into a single useful document.

The top two layers tend to be very broad and often quite fuzzy. It is at this level that key organisational strategies and processes reside at. As indicated in Figure 51 it is generally hard to codify these things, hence correct application is heavily dependent on skilled people.

8.1 Asset knowledge [A.3.12.]

TPCL knows a great deal about almost all of the assets – their location, what they are made of, generally how old they are and how well they can perform.

TPCL's asset data resides in three key locations:

- Asset description, location, age and condition information of line, cables and field devices resides in the Geographical Information System (GIS).
- Asset descriptions, details, age and condition information of serial numbered components resides in Asset Management System (AMS)[35].

[35] The current AMS is Maximo

- Asset operational data such as loadings, voltages, temperatures and switch positions reside in the Supervisory Control and Data Acquisition (SCADA).

An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history.

Table 27 Knowledge Accuracy

System	Parameter	Completeness	Notes
GIS	Description	Excellent	Some delays between job completion and updating into the GIS
GIS	Location	Excellent	
GIS	Age	Poor	Pole ages not available for 58%
GIS	Condition	Poor	No recent information
AMS	Description	Okay	Some delays between job completion and updating into Maximo
AMS	Details	Okay	
AMS	Age	Okay	Missing age on old components
AMS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Okay	Some sites monitored

8.2 Improving the quality of the data [A.8.12.]

8.2.1 GIS data improvement

TPCL's original data capture emphasised asset location and configuration and was used to populate the GIS, but didn't include a high level of asset condition. 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 apply an age but 63% of poles had no supporting information. Due to old poles not having a manufacture date affixed, it is very difficult to obtain the actual age to update GIS. We are considering options to get ages measured, for the un-dated poles, but no economic methodology has been found. Recent pole replacements have superseded 5% of these unknowns.

About 20% of the network (by length) each year is condition assessed to update asset condition data (noting that that asset condition is continually varying), and any discovered details are updated.

Key process improvements will include more timely as-builts with PowerNet staff GPS-ing[36] poles and use of scan-able forms for data input (Teleform system).

8.2.2 AMS data improvement

Data for the AMS is collected by the Network Equipmeny Movement Notice 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.

8.3 Use of the data

All data will be used for either making decisions within TPCL's own business or assisting external entities to make decisions. This data is almost always aggregated into information (the second level of the pyramid) in order to make decisions e.g. a decision to replace a zone substation transformer will be based on an aggregation of loading data.

[36] GPS = Global Positioning System, a device that uses satellites and accurate clocks, to measure the location of a point.

8.4 Decision making

The decision making process also involves the top two levels of the hierarchy – understanding and wisdom – which tend to be broad and enduring in nature. Although true understanding and wisdom are difficult to codify, it is possible to capture discrete pieces of understanding and wisdom and then codify them into such documents as technical standards, policies, processes, operating instructions, spreadsheet models etc. This is called knowledge and probably represents the upper limit of what can be reasonably codified.

Accurate decision making therefore 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 source, roles and interaction of each component of the hierarchy are shown below in Figure 52.

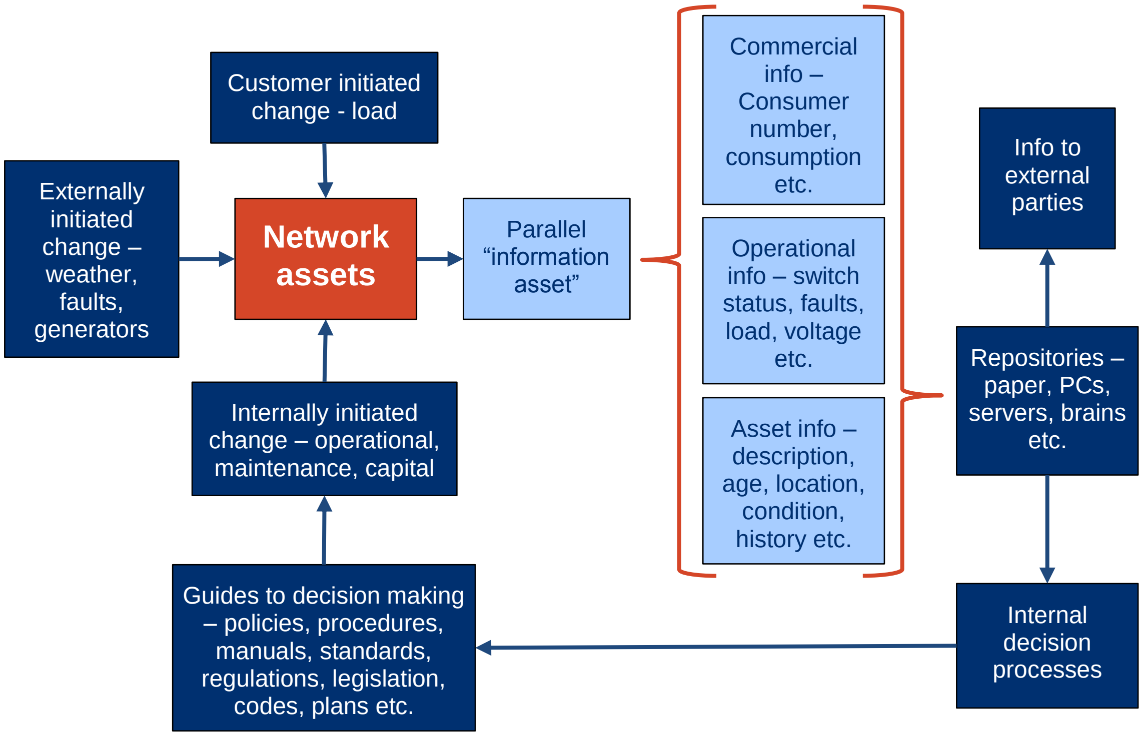


Figure 52 - Key information systems and processes

8.5 Key processes and systems [A.3.11.]

TPCL's key processes and systems are based around the key lifecycle activities defined in Figure 47, based around the AS/NZS9001:2001 Quality System and are described in the following sections. These processes are not intended to be bureaucratic or burdensome, but are rather intended to guide TPCL's decisions toward ways that have proved successful in the past (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.

8.5.1 Operating processes and systems

Commissioning Network Equipment	PNM-61
Network Equipment Movements	PNM-63
Security of Supply - Participant Outage Plan	PNM-64
Planned Outages	PNM-65
Network Faults, Defects and Supply Complaints	PNM-67
Major Network Disruptions	PNM-69
Use of Operating Orders (O/O)	PNM-71
Replacement of HV Network Fuses	PNM-72
Control of Tags	PNM-73

Access to Substations and Switchyards	PNM-75
Operational Requirements for Confined Space Entry	PNM-76
Operating Authorisations	PNM-77
Radio Telephone Communications	PNM-79
Operational Requirements for Live Line Work	PNM-81
Control of SCADA Computers	PNM-83
Machinery Near Electrical Works	PNM-85
Customer Fault Calls/Retail Matters	PNM-87
Site Safety Management Audits	PNM-88
Drawing Control	PNM-89
Network Operational Diagram/GIS Control	PNM-91
Meter/Ripple Receiver Control	PNM-121

8.5.2 Maintenance processes and systems

Control of Network Spares	PNM-97
Transformer Maintenance	PNM-99
Maintenance Planning	PNM-105
Network Overhead Lines Equipment Replacement	PNM-106

Other maintenance is to manufacturers' recommendations or updated industry practise.

8.5.3 Renewal processes and systems

Network Development	PNM-113
Design and Development	PNM-114

8.5.4 Up-sizing or extension processes and systems

Network Development	PNM-113
Design and Development	PNM-114
Processing Installation Connection Applications	PNM-123
Easements	PNM-131

8.5.5 Retirement processes and systems

Disconnected And/Or Discontinued Supplies	PNM-125

8.5.6 Performance measuring processes and systems [A.3.13.3.]

8.5.6.1 Faults

All faults are entered into the 'Faults' database and reported monthly to the board, together with details of all the planned outages.

8.5.6.2 Financial

Monthly reports out of the Finance One (F1) financial system provide measurement of revenues and expenses for the TPCL line business unit. Project costs are managed in PowerNet with project managers managing costs in Maximo. Interfaces between F1 and Maximo track estimates and costs against assets.

8.5.6.3 Customer

Customer statistics are monitored by a Customer Database system developed by ACE computers. 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.

8.5.6.4 Service levels

Customers that have had work done are sent a survey form at the end of the job. Results are monitored and any comments given are reviewed and responded to.

8.5.7 Other business processes

In addition to the above processes that are specific to life cycle activities, TPCL has a range of general business processes that guide activities such as evaluating tenders and closing out contracts:

Flowchart of Contract Administration Process	PNM-05
Setting Up the Contract	PNM-10
Tender Evaluation	PNM-15
Contract Formation	PNM-20
Construction Approval	PNM-25
Materials Management	PNM-30
Contract Control	PNM-35
Contract Close Out	PNM-40
Customer Satisfaction	PNM-50
Internal Quality Audits	PNM-55
External Contracting	PNM-60
Control of Operating and Maintenance Manuals	PNM-93
Control of External Standards	PNM-95
Control of Power Quality Recorders	PNM-103
Quality Plans	PNM-107
Health and Safety	PNM-109
Accidents and Incidents	PNM-111
Network Purchasing	PNM-115
Network Pricing	PNM-117
Customer Service Performance	PNM-119
Incoming and Outgoing Mail Correspondence	PNM-129

8.6 Asset management tools

A variety of tools and procedures are utilised by PowerNet to best manage the assets of the various networks. GIS and AMS software packages are used to store and evaluate assets data. Quality system procedures are in place to highlight and focus on various management techniques. The outputs of these systems produce 1 year and 10 year AMP's, together with data for on-going day to day planning and control.

8.6.1 GIS

An Intergraph based Geographic Information System is utilised to store and map data on individual components of distributed networks. This focuses primarily on cables, conductors, poles, transformers, switches, fuses and similar items. Large composite items such as substations are managed by more traditional techniques such as drawings and individual test reports.

Equipment capacity, age and condition are listed by segment. The data is used to provide base maps of existing equipment, for extensions to the network, for maintenance scheduling and similar functions.

8.6.2 AMS

Our present Asset Management System is Maximo, which provides work scheduling and asset management tool. It is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling.

Most day to day operations are managed using Maximo. Maintenance regimes, field inspections and customers produce tasks and/or estimates that are sometimes grouped and a 'work order' issued from Maximo.

The MAXIMO software package is a replacement for the predecessor AMS system WASP and is more up to date and better suited to TPCL's needs. It provides greater functionality and helps streamline administration of TPCL's maintenance practices. As part of the transfer of data to the new system data was checked for accuracy and completeness and updated where possible to provide better information about TPCL's assets to facilitate better maintenance management decisions.

8.6.3 Faults Database

All outages are logged into a database, which is used to provide regulatory information and statistics on network's performance. Reports from this system are used to highlight poorly performing feeders. These are then analysed to determine if it is a maintenance issue or if reliability may be enhanced by other methods. An analysis of one year's fault data is shown in Figure 53; and indicates no areas of concern.

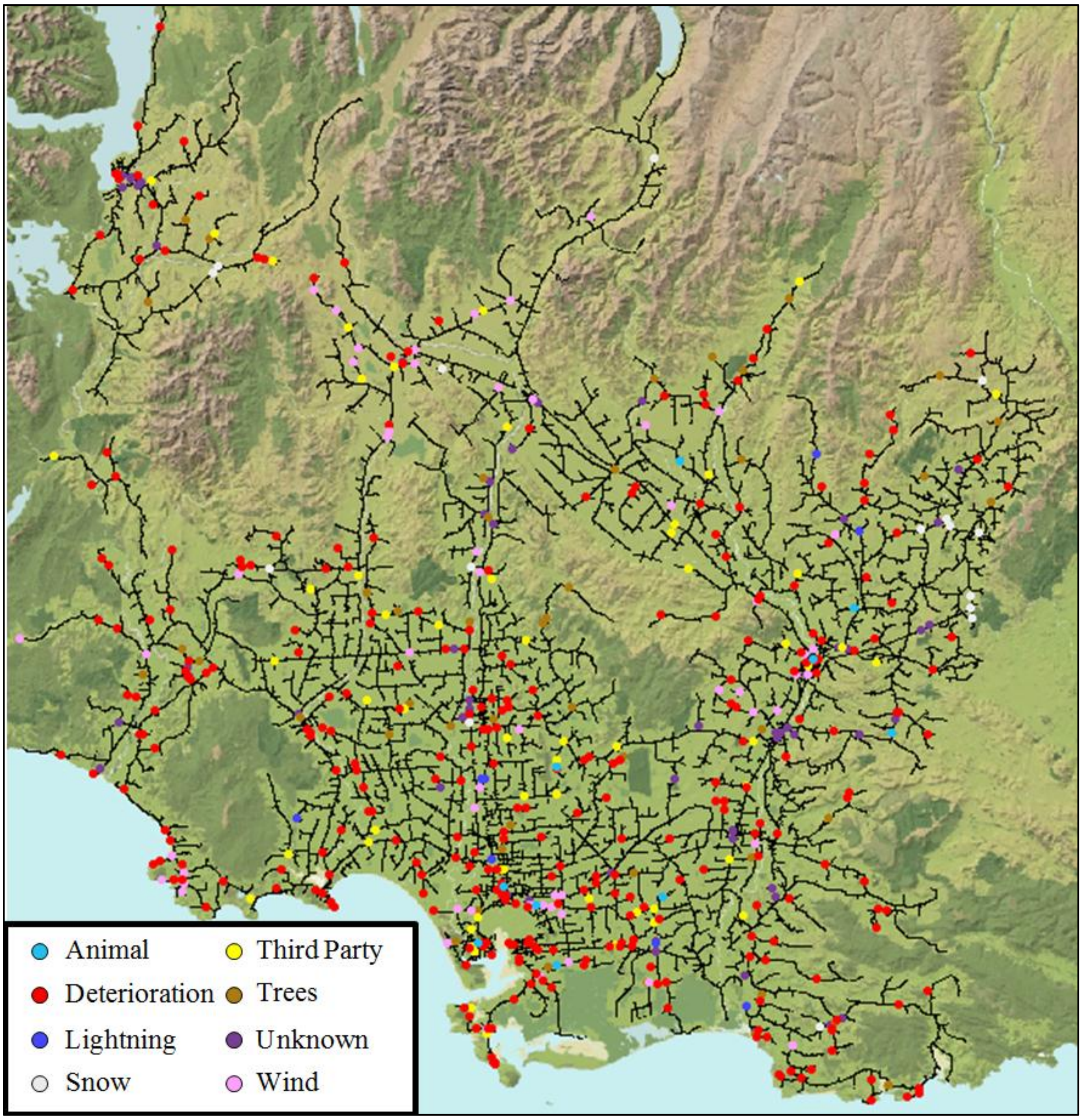


Figure 53 Faults 1 April 2011 to 31 March 2012

8.6.4 PNM-105 Maintenance Planning

The quality system procedure PNM-105 drives maintenance planning. It is the procedure used to drive this document to completion. The flowchart from this quality system document is shown in Figure 54.

Relevant inputs into the plan include:

- Maixmo Records
- Surveys (field, CDM)
- Analysis of faults database
- GIS database
- System network loading data
- Major customers
- Growth (domestic, commercial, industrial) in geographic areas
- Legislation
- Cyclic maintenance on major plant items
- Current AMP.

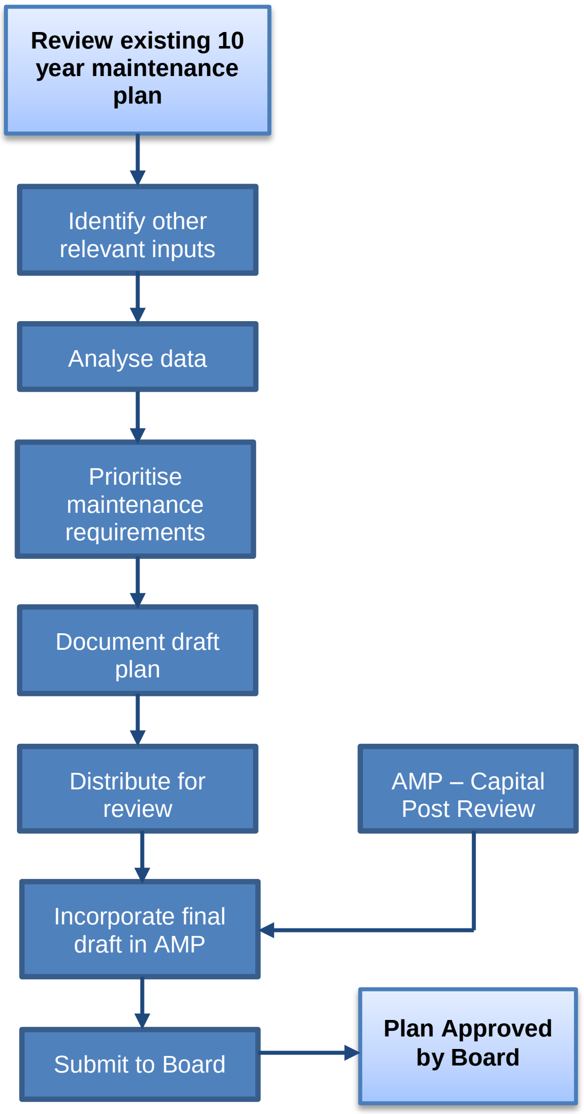


Figure 54 PNM-105 Maintenance Planning Flowchart

9. Performance and improvement

This section firstly evaluates TPCL's performance over the 2013/14 year and secondly identifies areas where TPCL believes it could improve its business.

9.1 Outcomes against plans [A.15.1.]

9.1.1 Capital

	Forecast 2013/14 ($000)	Actual 2013/14 ($000)	% Variance
Customer Connection	2,720	3,263	20.0%
System Growth	9,888	10,183	3.0%
Reliability, Safety and Environment	1,187	1,099	-7.4%
Asset Replacement and Renewal	5,614	7,915	41.0%
Asset Relocations	58	43	-25.9%
Capital Expenditure	**19,467**	**22,503**	**15.6%**

9.1.1.1 Customer Connection

20% more customer connections than was forecast. Actuals depend on regional growth and development.

9.1.1.2 System Growth

While financial spend is close to budget, actual financial and physical achievement was poor. Details of significant projects expanded below.

Project	Plan	Actual	Reason
Hedgehope Substation	100%	75% Ground works and major substation equipment all delivered to site. Forecast 170% of budget.	Planned contractor lost local Transpower contract and alternatives allocated to other works.
Athol Substation	100%	97% Substation complete – excluding commissioning Forecast 128% of budget.	Awaiting completion of Mossburn-Athol 66kV line to enable commissioning
Mossburn to Athol 66kV line	100%	97% (Stage 1 & 2 completed and stage 3 90% complete) Forecast 310% of budget.	Scope change as reuse of existing poles not feasible. Extra time and resource required.
Winton to Centre Bush 66kV line	50%	20% complete. Installation of CB at Winton largely complete.	Line work not started due to insufficient resource.
Kennington Substation	100%	Completed. 325% of budget	Scope change with two new transformers required. Switchboard and a transformer damaged during delivery.
Monowai Transformer	100%	Completed 180% of budget.	Scope change due to limited space in proposed location.

Project	Plan	Actual	Reason
OVP - Design	100%	40% completed Concept design completed	Changes in Project Management staff.
Fairfax to Isla Bank 66kV Line	58%	44% completed Material procurement only – some long lead time items not delivered Forecast 125% of budget	Delays in receiving some materials
Waikiwi Substation Upgrade	100%	50% Transformers have arrived and being stored	Project deferred to completed customer driven project of Colyer Road Substation
Colyer Road Substation	0%	27% Completed	Customer driven project – was planned for construction to start in 2015/16
Riversdale Substation Upgrade	12%	4% Preliminary design completed – detailed design underway	Changes in Project Management staff.

9.1.1.3 Reliability, Safety and Environment

Earth upgrades behind schedule with a forecast that only 80% of work will be completed but work is 11% under budget. Supply quality upgrades were 5% over budget.

9.1.1.4 Asset Replacement and Renewal

41% overspend due to unexpected safety issues, timing issues and unforeseen poor condition of some equipment.

Project	Plan	Actual	Reason
Winton Switchboard Replacement	100%	80% 130% of budget Expect 170% of budget at completion	Additional costs to maintain supply while replacing equipment.
Riverton Switchboard Replacement	10%	5% - Design started but not completed	Changes in Project Management staff.
Kelso RTU, Oil, CB's replacement	100%	Completed. 290% of budget.	Additional costs to maintain supply while replacing equipment. Tidy-up costs to ensure safe clearances

9.1.1.5 Asset Relocations

Reactive work; fewer projects than anticipated.

9.1.2 Maintenance

	Forecast 2013/14 ($000)	Actual 2013/14 ($000)	% Variance
Service Interruptions and Emergencies	2,573	2,920	13.5%
Vegetation Management	1,255	1,379	9.9%
Routine and Corrective Maintenance and Inspection	2,796	3,431	22.7%
Asset Replacement and Renewal	930	1,022	9.9%
Operational Expenditure	**7,554**	**8,752**	**15.9%**

9.1.2.1 Service Interruptions and Emergencies

13% above budget due to contractor charging error found.

9.1.2.2 Vegetation Management

Overall expenditure managed in line with budget

9.1.2.3 Routine and Corrective Maintenance and Inspection

23% over budget due to increased safety and seismic inspections.

9.1.2.4 Asset Replacement and Renewal

Overall expenditure managed in line with budget

9.2 Performance against targets [A.15.2.]

9.2.1 Primary service levels

The table below displays the target versus actual reliability performance on the network.

	2013/14 Target	2013/14 Actual
SAIFI	3.21	2.87
SAIDI	161.75	177.8

Based on historic results the actual 2013/14 SAIFI is close to the average, whilst the actual 2013/14 SAIDI is below average.

9.2.2 Secondary service levels

Results for 2013/14 are shown below:

Attribute	Measure	Target	Feb14
Customer Satisfaction: New Connections	Phone: Friendliness and courtesy. {CSS: Q3(c)}[37]	>3.5[38]	4.5
	Phone: Time taken to answer call. {CSS: Q3(a)}	>3.5	3.0
	Overall level of service. {CSS: Q5(a)}	>3.5	4.3

[37] CSS = Customer Satisfaction Survey undertaken by sending questionnaire to customers with invoices.

[38] Where 1 = poor and 5 = excellent

Attribute	Measure	Target	Feb14
	Work done to a standard which meet your expectations. {CSS: Q4(b)}	>3.5	4.3
Customer Satisfaction: Faults	Power restored in a reasonable amount of time. {CES: Q4(b)}	>60%	92%
	Information supplied was satisfactory. {CES: Q8(b)}	>60%	86%
	PowerNet first choice to contact for faults. {CES: Q6}	>30%	44%
Voltage Complaints {Reported in Network KPI report}	Number of customers who have made voltage complaints {NR}	<45	7
	Number of customers who have justified voltage complaints regarding power quality	<15	7
	Average days to complete investigation	<30	64
	Period taken to remedy justified complaints	<60	64
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>75%	100%
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>75%	100%
	Acceptance of maximum of one planned outage per year. {CES: Q1}	>50%	97%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	>50%	96%

PowerNet as first contact for faults has reduced likely due to Retailer switching campaigns that has increased their profile.

High justified voltage complaints are due to the extra load that dairy farm conversions have put on the network, and neighbouring customers seeing a decline in quality.

9.2.3 Other service levels

9.2.3.1 Efficiency

Measure	2013/14 Target	2013/14 Actual
Load factor	65%	62.4%
Loss ratio	7.0%	7.2%
Capacity utilisation	30%	30.2%

Load factor impacted with change to TPM relaxing individual GXP peaks caused system peak to increase.

9.2.3.2 Financial

Measure	2013/14 Target	2013/14 Actual
OPEX/RC %	2.05%	2.13%
Indirect costs	$98.22	$69.05

9.3 Improvement Areas and Strategies [A.15.4.]

The following areas are highlighted as gaps in performance that could be improved, and the strategies proposed to achieve improvements.

TPCL plans to improve its AMP in the future not simply by writing a better document but by improving the asset management processes, systems and activities that it uses / undertakes.

9.3.1 Capital Works

Gaps:

Completion of the planned projects and initiatives.

Discussion:

Planned work has not been completed that can lead to delays in future projects.

Strategies:

We plan to create a long term relationship with contractors so they can build their resources and personnel. This will allow more work to be completed and ensure a resource for future years.

We will increase our Project Management team and management, and structure them with clear areas of responsibility.

We will continue to forward plan projects so that resource requirements are better defined and works can be effectively scheduled.

9.3.2 Efficiency

Gaps:

Low transformer capacity utilisation.

Reduce loss to improve efficiency.

Discussion:

Network growth occurs at an unknown rate and equipment is chosen to meet expectations or customer requests. Unfortunately the customer requests for capacity can require a larger unit because of standard sizes. Eg. Customer requests 350kVA so a 500kVA transformer is installed, as a 300kVA is too small.

Actual monitoring of loadings or maximum demands of equipment is done to ensure that equipment can safety supply the load, or if expectations have not been met.

Some loads have a very poor load factor but still require an appropriate sized transformer. E.g. Fire pumps at a factory may need 300kVA to operate but will hopefully never use any energy.

A new requirement has transformers not owned by TPCL included in this parameter and we may need to encourage the owners of these to rationalise the rating of their transformers.

Overloaded and highly loaded equipment normally has higher then optimal losses.

Strategies:

We will check as new transformers are added to the network, with a rationalisation of capacities. Underutilised units will be relocated to match loads. Overloaded transformers will also be rationalised and this has a negative impact on this indicator.

We will review the demand of customers that own their own transformers and contact them if we believe that there is a concern.

Analysis of highly loaded lines and cables has highlighted sections that have high losses, up-sizing of these to larger conductor or a higher voltage will improve the loss ratio of the network. The level of losses normally doesn't initiate the change but is used when selecting sizes when work is done on the equipment.

A. Appendix - Customer Engagement Survey

PowerNet Consumer Engagement Telephone Survey: TPCL

Phone	Date	Interviewer

Good afternoon/evening my name is _____. I am conducting a brief customer survey on behalf of PowerNet.

May I please speak to a person in your home who is responsible for paying the electricity account?

(Reintroduce if necessary) May I trouble you for a few minutes of your time?

A1: Do you know who PowerNet is?	Yes	**1**	*Go to A2*
	No	**2**	*Go to A4*

A2: Where did you most recently hear about PowerNet?	Newsletter	**1**
	Billboard	**2**
	Other	**3**
	DK/NS	**4**

A3: Using a 1 to 5 rating scale where 1 is Poor and 5 is Excellent can you rate the performance of PowerNet over the last 12 months for:	Caring for customers	**1**	**2**	**3**	**4**	**5**	**X**
	Reliable	**1**	**2**	**3**	**4**	**5**	**X**
	Supporting the community	**1**	**2**	**3**	**4**	**5**	**X**
	Safety conscious	**1**	**2**	**3**	**4**	**5**	**X**
Go to D1	Efficient	**1**	**2**	**3**	**4**	**5**	**X**

A4: PowerNet maintains the local electricity lines and substations that supply power to your premises.

D1: Do you live in a mainly rural or urban area?	Urban	**5**
	Rural	**6**

D2: Are you a commercial or residential customer?	Commercial	**1**
	Residential	**2**

Question 1: PowerNet is proposing a maximum of one planned interruption to your power supply, on average, every year in order to carry out maintenance or upgrade work on its electricity network. Do you consider this number of planned interruptions to be reasonable?	Yes	**1**	*Go to Q 2*
	No	**2**	*Go to Q 1(a)*
	Don't know/unsure	**3**	*Go to Q 2*

Question 1(a): How many years between planned interruptions do you consider to be more reasonable?	2 years	**1**
	3 years	**2**
	4 years	**3**

Question 2: PowerNet expects such planned interruptions will on average last up to four hours each. Do you consider this amount of time to be reasonable?	Yes	**1**	*Go to Q 3*
	No	**2**	*Go to Q 2(a)*
	Don't know/unsure	**3**	*Go to Q 3*

Question 2(a): What length of time would you consider to be more reasonable? *(Specify hours)*	1 hour	**1**
	2 hours	**2**
	3 hours	**3**

Question 3: Have you received advice of a planned electricity interruption during the last 6 months?	Yes	**1**	*Go to Q 3(a)*
	No	**2**	*Go to Q 3(e)*
	Don't know/unsure	**3**	*Go to Q 3(e)*

Question 3(a): Were you satisfied with the amount of information given to you about this planned interruption?	Yes	**1**	*Go to Q 3(c)*
	No	**2**	*Go to Q 3(b)*
	Unable to recall	**3**	*Go to Q 3(c)*

Question 3 (b): What additional information would you have liked?

Question 3(c): Do you feel that you were given enough notice of this planned interruption?	Yes	**1**	*Go to Q 3(e)*
	No	**2**	*Go to Q 3(d)*
	Don't know/unsure	**3**	*Go to Q 3(e)*

Question 3(d): How much notice of planned interruptions would you prefer to be given? *(Specify days/weeks)* *(Do not prompt)*	1 day	**1**	1 week	**4**
	3 days	**2**	2 weeks	**5**
	5 days	**3**	Other	**6**

Question 3(e): Do you have a preferred day and time(s) for a planned interruptions?	Yes	**1**	*Go to Q 3(f)*
	No	**2**	*Go to Q 4*

Question 3 (f): What is your preferred day and time(s)?

Question 4: Have you had an unexpected interruption to your power supply during the last 6 months?	Yes	**1**	*Go to Q 4(a)*
	No	**2**	*Go to Q 5*
	Unable to recall	**3**	*Go to Q 5*

Question 4(a): Thinking about the most recent unexpected interruption to your electricity supply, how long did it take for your supply to be restored? *(Specify hours/days)* *(Do not prompt)*	Within 45 min	**1**	3 hours	**5**
	1 hour	**2**	4 hours	**6**
	$1^1/_2$ hours	**3**	12 hours	**7**
	2 hours	**4**	Don't know	**8**
			Other	**9**

Question 4(b): Do you consider your	Yes	**1**	*Go to Q 5*

electricity supply was restored within a reasonable amount of time?	No	**2**	*Go to Q 4(c)*
	Unable to recall	**3**	*Go to Q 5*

Question 4(c): What do you consider would have been a more reasonable amount of time? *(Specify hours/days)* *(Do not prompt)* ***Go to Q5(a)***	30 minutes	**1**	$1^1/_2$ hours	**4**
	45 minutes	**2**	2 hours	**5**
	1 hour	**3**	Other	**6**

Question 5: In the event of an unexpected interruption to your electricity supply, what do you consider would be a reasonable amount of time before electricity supply is restored to your home? *(Specify hours/days)* *(Do not prompt)*	5 minutes	**1**	2 hours	**10**
	10 minutes	**2**	3 hours	**11**
	15 minutes	**3**	4 hours	**12**
	20 minutes	**4**	5 hours	**13**
	30 minutes	**5**	6 hours	**14**
	40 minutes	**6**	12 hours	**15**
	45 minutes	**7**	1 day	**16**
	1 hour	**8**	Unsure	**17**
	$1^1/_2$ hours	**9**	Other	**18**

Question 5(a): PowerNet is reviewing the level of reliability provided to its customers and options include increasing spending. Presently there is an average of three interruptions each year. If this was reduced to two interruptions per year would you be happy to pay an additional $10 per month on your electricity bill?	Yes	**1**
	No	**2**
	Don't know/unsure	**3**

Question 5(b): If PowerNet were to reduce your bill by $10 per month, would you be happy that the number of interruptions increased to four per year?	Yes	**1**
	No	**2**
	Don't know/unsure	**3**

Question 6: Who would you telephone in the event of the power supply to your home being unexpectedly interrupted? *(Do not prompt)*	Meridian Energy	**1**
	Contact Energy	**2**
	Mighty River Power	**3**
	TrustPower	**4**
	PowerNet	**5**
	Genesis Energy	**6**
	Other	**7**

Question 7: Have you made such a call within the last 6 months?	Yes	**1**	*Go to Q 8*
	No	**2**	*Go to Q 8(d)*
	Unable to recall	**3**	*Go to Q 8(d)*

Question 8: Were you satisfied that the system worked in getting you enough information about the supply interruption?	Yes	**1**	*Go to Q 8(b)*
	No	**2**	*Go to Q 8(a)*
	Don't know/unsure	**3**	*Go to Q 8(b)*

Question 8 (a): What, if anything, do you feel could be done to improve this system?

Question 8 (b): Were you satisfied with the information that you received?	Yes	**1**	*Go to Q 8(d)*
	No	**2**	*Go to Q 8(c)*
	Don't know/unsure	**3**	*Go to Q 8(d)*

Question 8 (c): What, if anything, do you feel could be done to improve this information or the way in which it is delivered?

Question 8 (d): What is the most important information you wish to receive when you experience an unplanned supply interruption? *(Do not prompt)*	Accurate time when power will be restored	**1**
	Reason for fault	**2**
	Other	**3**
	Specify	

Question 8(e): Are you aware of PowerNet's 0800 faults number?	Yes	**1**	No	**2**

Question 9: Finally, do you have any comments or suggestions about anything to do with PowerNet which we haven't covered in our interview today?	
Happy with things as they are/no comments/nothing to add, etc.	**1**
Comment(s):	

This concludes our survey - Thank you for your time

B. Appendix - Description of TPCL's assets

This appendix extends the descriptions of TPCL's assets.

B.1 Subtransmission

The natural split of this group is into overhead tower circuits, overhead pole line circuits and cable circuits. Any particular circuit from A to B may be a mixture of these forms. Overhead lines may be multi circuit or be common with lower voltage circuits. Maintenance planning differences are more a function of circuit form than circuit voltage.

Subtransmission includes all circuits "upstream" of a zone substation. Effectively these circuits bring electricity to whole communities of interest and are therefore more critical than distribution circuits. The arrangement of these circuits is very much dependent on geography and history. The required reliability varies according to the security available with the associated network configuration. Supply security and reliability are defined in the Network Design Standard

TPCL's subtransmission is largely ringed or parallel fed with few common mode failure points. Consequently the inherent circuit reliability of TPCL's network can be relaxed while still providing overall supply reliability.

Figure 55 The Power Company Limited Area

B.1.1 Tower circuits

B.1.1.1 Description and capacity

Generally these are limited to critical areas or such locations as river crossings. Individual drawings, profiles and route plans are kept for these lines that provide invaluable information for maintenance and development purposes.

Tower lines tend to be dual circuit. Conductor is Wolf ACSR. Sagging is based on 75°C giving a current rating of 500A. Generally the lines are rated for voltage drop and loss considerations, such that the load is well below the 500A limit. The tower circuits are well utilised. Voltage drop and losses are quite significant. In some operating conditions the voltage drop increases to the allowable maximum.

Most towers are located on the 66kV circuit between Mossburn and Hillside, Northern Southland. These towers were constructed for 110kV use, but are only insulated to 66kV.

B.1.1.2 Condition, age and performance

Most towers were installed around 1983 to New Zealand Electricity (NZE) 110kV standard. Strain insulators are 110kV ceramic type. Other insulation is 66kV glass disk suspension format. Generally the condition of the tower circuits remains very good. Unfortunately the performance of the main Winton to Hillside 66kV circuit has generally been poor. Fault causes have largely been classified as lightning and trees. Maintenance to date has primarily focused on improving reliability to design levels.

B.1.1.3 Monitoring and procedures

Deterioration of the tower circuits is very slow. All towers are of galvanised steel lattice construction mounted on concrete cage foundations. Maintenance programming has been limited to intermittent field surveys by experienced personnel.

Dominant failure modes are corrosion and insulator cracking. Galvanising thickness provides a suitable indicator for anticorrosion protection and can readily be measured by non-destructive testing (NDT) techniques. Cracked insulators are typically located by visual inspection. Monitoring consists of:

- Visual inspection at five yearly intervals. This includes checks of foundation condition, location of any rust, faulty hardware and insulator condition.
- Galvanising thickness is inspected on a 10 year cycle.
- Fault data is used for abnormal problems.

B.1.1.4 Maintenance plan

A program to install vibration dampers on conductor has been implemented.

Bird deterrent fixtures are being installed in specific areas where birds are causing faults.

Very little routine maintenance is required.

B.1.1.5 Renewal plan

There are no plans for renewal of towers or associated conductor in the next 10 years.

B.1.1.6 Retirement plan

There are no plans for any retirement of tower circuit assets.

B.1.2 Pole line circuits

B.1.2.1 Description and capacity

Pole lines form the majority of subtransmission circuits within rural Southland and Otago. 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 with current loading generally always being well below capacity. Voltage drop is a problem due to small conductor and long circuit lengths. On a voltage and loss basis most circuits operate between 80% and 150% of optimum level.

Most subtransmission line circuits are routed cross-country to minimise cost and length. More recent circuits tend to be constructed along road reserve due to land access issues. Poles are a mixture of concrete, hardwood and softwood, chosen by the relative costs at the time of construction. Rural lines are typically sagged to a maximum operating temperature of 75°C to maximize capacity and minimise cost.

Some of the circuits have substantial design drawings and route plans, a reflection of their importance. The poles and conductors are listed within the GIS system in the same fashion as lower voltage circuits.

B.1.2.2 Condition, age and performance

Little of the original subtransmission network remains. Upgrading, rebuilding and piecewise maintenance has largely replaced circuits originally installed between 1928 and 1950.

The age profile of transmission circuits is shown in Figure 9. Since most transmission circuits are of overhead line construction this graph gives a good indication of overall circuit age. Note however that many circuits have poles and other hardware replaced when and where needed. Consequently the age of circuits is difficult to precisely state.

The subtransmission pole age distribution is provided in Figure 10 for wood and concrete. This data is contained within the GIS database. Again the data should be treated carefully. The data generally refers to installation date. Many poles may be second hand when installed, although generally of good quality.

The 33kV subtransmission fault rate was 3.49 faults/100km/per annum and the 66kV was 0.52 faults/100km/per annum. Since overhead lines form the majority of subtransmission, these figures effectively relate to pole lines. These rates provide suitable overall system performance as measured by SAIDI etc.

B.1.2.3 Monitoring and procedures

Dominant failure modes are pole and crossarm deterioration, tree contact, conductor corrosion, ties/clamps, joints and insulator cracking.

Visual inspection is conducted annually to locate obvious problems. These are rectified dependent on the urgency.

Defect inspection is conducted at five yearly intervals on a rolling basis. This includes checks of foundation, pole integrity, crossarm condition, faulty hardware and insulator condition. Part of the inspection includes the diagnostic techniques of scanning and thermal imaging and a ten yearly x-ray of wooden poles. This inspection is the prime driver for maintenance planning.

Fault data is used for abnormal problems. Protection relay data (distance to fault) is used where available to help locate faults and subsequently identify fault cause. Detailed analysis of outages and their cause using root cause analysis (RCA) identifies target areas for maintenance programs.

B.1.2.4 Maintenance plan

Repair of items identified from inspections or analysis.

B.1.2.5 Renewal plan

See the capital works plan for details of subtransmission circuit renewal.

B.1.2.6 Retirement plan

There are no plans for any retirement of any circuit assets.

B.1.3 Cable circuits

B.1.3.1 Description and capacity

Subtransmission cables are limited to special locations in rural areas. Cable circuits are listed in Figure 12.

Subtransmission cables are a mixture of types, sizes and configurations, largely determined by age and network.

The present standard generally consists of aluminium conductor, XLPE insulation, single cores and copper screens.

Generally the smallest cable size used is 120mm^2, a size suitable for typical fault levels. Selected thermal backfill is used where required.

B.1.3.2 Condition, age and performance

The installation date of the cable circuits is shown in Figure 12. Generally there are no known problems associated with the cables. The cable sizes match the associated lines and substations to which they connect, so are well utilised.

B.1.3.3 Monitoring and procedures

Dominant failure modes for cables are joint or termination faults, sheath damage, overheating and external mechanical damage. Generally the cables are very stable and require little attention.

On line partial discharge testing is conducted on a five year basis to check for insulation integrity. Time domain spectrometry and screen insulation resistance tests are conducted when cables are available unenergised and at installation. These tests indicate significant discontinuities or sheath failure that may require further investigation or corrective action. Five yearly thermal inspections of terminations are conducted to check for excessive heating or overload. Fibre cable has been installed on recent circuits to allow for real time temperature profiles to be undertaken should the need arise.

B.1.3.4 Maintenance plan

There are no plans for any significant cable maintenance other than monitoring.

B.1.3.5 Renewal plan

There are no plans for any renewal of subtransmission cables.

B.1.3.6 Retirement plan

There are no plans for any retirement of cables.

B.2 Zone substations

B.2.1 Substations general

B.2.1.1 Description and capacity

There are 33 zone (district) substations in the network. These are listed in section 2.2.3.

These stations vary considerably from installations with indoor switchgear and transformers to small roadside stations with no buildings.

The prime general functions of the stations are to house the transformers, switchgear and associated control.

B.2.1.2 Monitoring and procedures

The stations consist of buildings, fences, yards and similar exposed items similar to other industrial sites. Monitoring consists of monthly checks to identify obvious problems such as broken windows, weeds, and damaged security fencing. Routine maintenance such as spraying is conducted in conjunction with monitoring.

Yearly inspections are undertaken for forward planning, at which time such activities as painting, spouting, rusting problems are identified. The standard required is as would be expected for domestic or industrial buildings.

Station batteries have their resistance checked yearly and are replaced before the manufacturer's recommended useful life on the assumption that failure rates increase significantly at this age.

Electromechanical protection relays are tested on a five yearly basis due to general drift and wear of the mechanical bearings etc. They are also being replaced with electronic relays in conjunction with circuit breaker renewal. The preferred relays are the Schweitzer Engineering Laboratories range chosen on a reliability, flexibility and functional basis. Electronic relays are checked on an eight yearly cycle.

SCADA is generally maintained on a repair basis due to the random basis of failure. The original GPT Remote Terminal Units (RTU) are being replaced because of the high overall failure rate and non-availability of parts.

Outdoor structures are checked as part of the monthly inspections. Yearly visual inspections are undertaken to assess overall condition and list any action required. Yearly ultrasonic and thermal imaging tests are done to identify failed insulation or high contact resistance.

B.2.1.3 Maintenance and renewal plans

Maintenance is of a routine nature with no significant activity expected. There are no plans to replace any existing sites. The Centre Bush Building is planned to be replaced during the period.

B.2.2 Transformers

B.2.2.1 Description and capacity

These vary significantly in both size and detail. Transformers within the network consist of two 11.5/23MVA 33/11kV Yyn0 three phase units

complete with on load tap changers (OLTC). The remainder of the TPCL transformers vary from 10/20MVA ONAN/OFAF capacity down to 1.5MVA, all with OLTC.

The zone substation transformers have two main purposes. Firstly they are required to "transform" the higher subtransmission voltages to more usable distribution voltage. And secondly they are required to regulate the highly variable higher voltages to a more stable voltage at distribution levels.

Several issues should be noted. The rating is obviously important. The transformers must be suitable to withstand the load imposed upon them. This is generally stated as the ONAN (Oil Natural, Air Natural) level at which losses are optimised and no special cooling is required. To allow for maintenance or faults transformers are often installed in pairs. Typically they share the load and operate within their economic ONAN level. Should one transformer not be in service then the remaining transformer can carry the total load. Fans and pumps are needed to dissipate heat and the life may be reduced. The rating at this level is called OFAF and may be twice the ONAN rating. Transformers are often relocated to optimise use as load varies at the various sites. Consequently the transformers are well utilised.

Phasing of the transformers is important to allow paralleling of the network. Most of the transformers therefore have Dyn3 vector for 66/33kV or 66/11kV, Yyn0 or Dzn0 for 33/22kV or 33/11kV.

OLTC provide a less expensive regulation method than separate regulators.

The high cost of the larger transformers has driven the installation of comprehensive protection systems for the transformers.

The TPCL transformers are less utilised generally because of transformer availability and historic lack of dual rated transformers.

B.2.2.2 Monitoring and procedures

Most transformer deterioration is assumed to be time based, with the exception that tap changing equipment wears proportionately to the number of operations. Monthly visual inspection is undertaken to check for obvious problems such as oil leaks. Yearly inspections are done to check fan control operation, paint condition and obtain oil samples for Dissolved Gas Analysis (DGA) testing.

Routine transformer maintenance is done on a five yearly basis. This covers protection relay operation, insulation levels and instrumentation checks.

Tap Changer maintenance is done on a time and/or operation basis as per manufacturers' recommendations.

DGA results are checked for trend changes and against industry standard absolute levels. Action is taken as recommended by the testing agency. Insulation trend is used to trigger further more specific action.

Transformers are sometimes moved as part of utilisation planning.

B.2.2.3 Maintenance plan

There are no plans for any significant transformer maintenance. All work consists of routine inspection and maintenance.

B.2.2.4 Renewal plan

The Mataura and Seaward Bush transformers are to be replaced due to age and capacity limits.

B.2.2.5 Retirement plan

The Mataura and Seaward Bush transformers will be evaluated for major refurbishment but are likely to be sold as scrap or retained as-is for emergency use.

B.2.3 Switchgear

B.2.3.1 Description and capacity

Four general group types of switchgear are in use in the network:

- The majority of 33kV and 66kV circuit breakers are outdoor units mounted on stands in conjunction with associated current transformers. Many types and ratings are in use. This equipment is purchased on a case-by-case basis, generally on a lowest price tender basis. Minimum oil, vacuum and SF_6 units are in use. Ratings vary from 200A to 2000A, although load is typically in the range of 20A to 630A. Most operating mechanisms are dc motor wound spring to allow operation de-energised. There are a number of "recloser: type units in service although these are limited in number because of the directional limits of solenoid closing.
- 33kV ABB Unisafe switchgear has been installed at Edendale and Waikiwi. These were installed on a price and limited space basis.
- 50% of 11kV circuit breakers are Reyrolle indoor panels of various vintages.
- 50% of 11kV circuit breakers consist of pole mounted outdoor units with integral current transformers. Many of these are solenoid operated reclosers.

Note that current transformers are generally assumed to form part of the switchgear, but outdoor isolators etc. are lumped in with the general structure.

The dominant circuit breaker rating is 630A continuous and 12kA or 13kA fault break capacity. Few circuit breakers are loaded over 200A due to the nature of the networks.

The main purpose of a circuit breaker is to allow switching of high energy circuits and more specifically to switch open (i.e. break) faulted circuits automatically by the use of associated protection devices. A few circuit breakers at the source ends of lines would be adequate to protect the lines from a safety point of view.

Unfortunately faults are bound to occur on lines no matter how well maintained the lines are. If a large length of line were protected by a very limited number of circuit breakers then the reliability at any particular installation would be completely unacceptable. To achieve reasonable reliability on the network TPCL have adopted a guideline such that no more than 40km of line is connected between circuit breakers for circuits near the coast. This figure increases to 100km inland where fault density is less. The large length of lowly loaded line circuits in the Otago and Southland hinterland has resulted in a large number of lightly loaded field circuit breakers being installed. These are included together with substation circuit breakers as a single logical grouping.

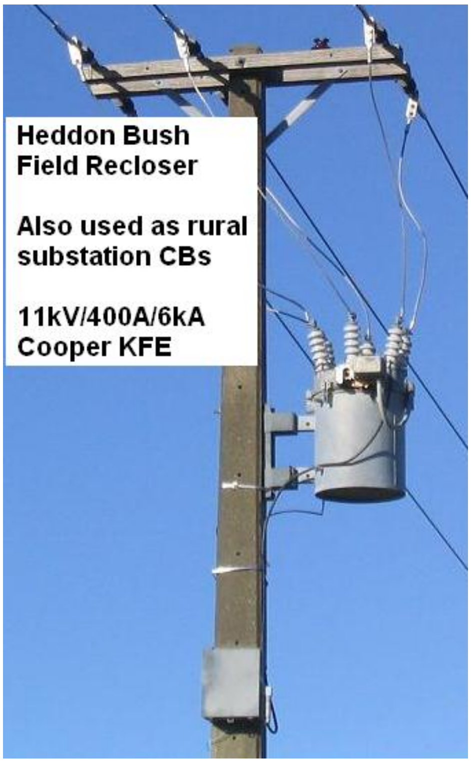
Based on load capacity the circuit breakers are very much underutilized. Based on the more important safety and reliability parameters there is no doubt that more circuit breakers should be installed in specific areas.

B.2.3.2 Monitoring and procedures

Circuit breakers are assumed to deteriorate in a time based fashion with regard to general corrosion and mechanical faults. Experienced has indicated that circuit breakers with oil based arc quenching require significant maintenance following relatively few fault clearing operations. Literature and manufacturer recommendations suggest that vacuum and SF_6 devices have longer maintenance cycles and generally provide service levels based on fault breaking current.

PowerNet does not have significant data on current breaking levels for individual switching operations. Consequently routine maintenance is carried out at two yearly intervals for oil base circuit breakers and five years for vacuum and SF6. Some circuit breakers are maintained following a specific number of operations.

Routine substation inspections are used to check for corrosion, external damage and the like.



Maintenance is specific to the requirements. Outdoor units may require sand blasting and painting as determined from inspections. Time based maintenance generally covers correct operation, timing tests, insulation levels and determination of contact life. Contacts or vacuum bottles are replaced as per the manufacturers' recommendations.

B.2.3.3 Maintenance plan

There are no plans for any significant circuit breaker maintenance. All work consists of routine inspection and maintenance.

B.2.3.4 Renewal plan

Kelso 11kV feeder circuit breakers are being replaced. The existing outdoor SF6 units have become unreliable and parts are not readily available.

B.2.3.5 Retirement plan

Oil and SF_6 gas are reclaimed. Useful spare parts are retained. The contractor scraps the remainder.

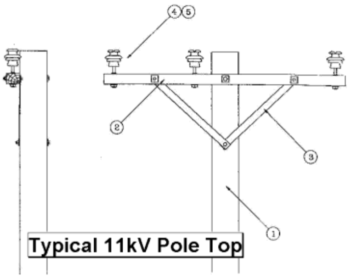
B.3 Distribution circuits

B.3.1 Overhead lines

B.3.1.1 Description and capacity

Overhead lines form the backbone of the rural networks. These form the basis of getting the centralised bulk generation to the multitude of individual customers. The lines account for the largest proportion of rural network costs and interference to customer supply.

Most lines are rated at 11kV phase to phase. This is the most common voltage utilised for distribution within New Zealand and has been the standard used in Southland and most of Otago since the inception of reticulated electrical supply. A few circuits have been built at 22kV. This voltage has four times the capacity of 11kV and greatly reduces voltage drop and losses. There is generally a 15% cost penalty in using this voltage over 11kV, so implementation is limited. There are a few other



Typical 11kV Pole Top

voltages used specifically in conjunction with Single Wire Earth Return (SWER).

The majority of feeder lines are three wire three phase with all connections phase to phase. A significant length of the Southland lines reduces to two wire single phase circuits. SWER is used a little bit within remote parts of the Southland system.

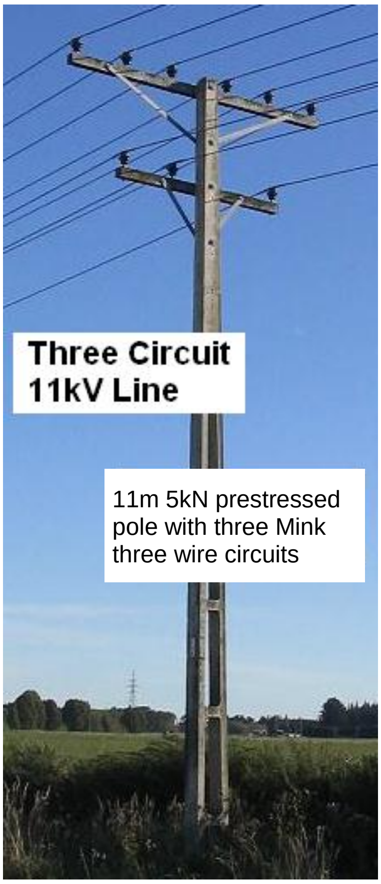
SWER system consists of one phase wire and the earth as a return path. Voltages to earth vary, typically being 6.35kV, 6.6kV and 11kV. Special transformer systems are generally required to create the SWER voltage. The main advantage of SWER is that the number of poles and length of conductor can be significantly reduced from the standard 11kV requirements. Cost is significantly reduced at the expense of very limited capacity.

A typical concrete pole is 11m long with a transverse top load capacity of 5kN. A typical softwood pole is 11m 9kN symmetric top load capacity. 12m, 6kN and 12kN poles are also relatively common. Common conductors previously used are relative small such as: Squirrel, Dog, Mink, Dog and Cockroach. The present AAAC standard allows for five conductors for most situations:

Conductor Name	Current Rating	Resistance
Chlorine	150A	0.86Ω/km
Helium	250A	0.38Ω/km
Iodine	350A	0.24Ω/km
Neon	500A	0.12Ω/km
Oxygen	700A	0.09Ω/km

B.3.1.2 Condition, age and performance

Bulk electrical distribution within Otago and Southland generally commenced around 1930. Lines are up to 70 years old. Most construction was undertaken in the 1930's, 1950's and 1960's. The 1970's and 1980's expansions were generally to transmit larger levels of energy into the existing reticulated areas. Present construction levels are very low.



Consequently there is quite a range of material and construction types. Hardwood poles gave way firstly to concrete, then largely softwood and now returning to concrete. Copper conductor was very common. This was generally replaced by AAC and ACSR conductor (All Aluminium Conductor and Aluminium Conductor Steel Reinforced) based on a lesser cost. The present standard is AAAC1120 (All Aluminium Alloy Conductor) based on price and resistance to corrosion. Maintenance requirements vary by material.

Poles are the critical and most expensive component of line support. Most construction in the 1930's utilised hardwood poles because of availability and strength. Hardwood poles cannot be effectively treated and are therefore prone to rot. Rot is worst in the biologically active ground area. Rot is often not visible, such that many poles that appeared healthy were in fact very prone to failure. Typical life expectance of hardwood poles varies from 30 years to 70 years. Around 20% of poles are hardwood. Structurally the poles are very good, but cost and life expectancy limit hardwood pole usefulness.

Concrete poles became prevalent in the 1950's. The strength of these poles is very limited and failure from abnormal overload such as snow loading can be a problem. They do not suffer from significant deterioration so maintenance requirements tend to be limited.

More recently softwood poles have been introduced based on cost and strength. These are treated timber with a minimum life expectancy of 50 years. Long term durability has yet to be confirmed.

New concrete poles became the standard from 2008. The new design provides improved strength and expected long life.

Cross arms are generally hardwood and suffer from significant deterioration. Life expectancy varies, but since they are not in contact with the ground a minimum life of 20 years is expected. Recent crossarms have the top surface painted to extend their life to 30 years. A few lines have been constructed in armless format, but generally this form does not have acceptable mid span clearance. For most distribution lines hardwood crossarms remain the preferred form.

Conductor life is limited by vibration (excessive tension) and corrosion. Copper conductor is robust, but very expensive. ACSR conductor is prone to corrosion especially in coastal areas. All Aluminium Alloy Conductor has been chosen as a standard conductor that is expected to limit maintenance requirements of line conductor.

The age profile of poles is shown in Figure 21.

B.3.1.3 Monitoring and procedures

Overhead distribution lines are the dominant feature of rural networks. With poles numbering over 100,000 and conductor length over 1,000,000m the largest proportion of capital is tied up in these assets. Consequently cost effective procedures have been introduced to optimise the balance between cost, safety and reliability. The PowerNet inspection and maintenance regime is aimed at the identification and rectification of defects which have the potential to cause outages or which threaten safety. The following specific procedures are extracted from the Lines Services Contracts Scope of Works.

Strategies

Focus should be on:

- Higher priority will be given to those 33/66kV and 11kV circuits that have a greater potential to adversely affect SAIDI figures.
- Factors adversely affecting SAIFI and the number of faults per kilometre of line to allow subsequent appropriate targeting of maintenance using RCM strategies on areas that significantly impact reliability indices.
- Issues affecting public safety and the safety of employees working on the network using CDM strategies.
- Meeting legislative requirements for test and inspection criteria.

Inspection regime

General

The Scope of Work generally describes the requirements for inspections of the subtransmission and distribution networks using visual and diagnostic techniques (i.e. x-ray scanning, thermal imaging) and includes:

Inspections of all the equipment listed, including five yearly circuit inspections, six monthly transformer inspections/MDI recording and earth testing and ten yearly scanning of wooden pole by x-ray. Upgrading of earths is not included in the scope but may be added at a later date.

Annual inspections of certain circuits selected due to their low reliability and/or high importance.

The contractor will include in its response its proposed methodology in implementing the required strategies and any enhancements that may be beneficial. PowerNet and the Contractor(s) will jointly review the inspection regime and the annual program to ensure best practice is being employed.

Methodology

The PowerNet inspection and maintenance regime is aimed at the identification and rectification of defects which have the potential to cause outages or which threaten safety.

The SAIFI and SAIDI performance of each 11kV feeder and 33/66kV circuit will be analysed quarterly and classified as being either Level 1, 2 or 3. Those in Level 1 will be passed to a team consisting of PowerNet and Contractor's staff for a detailed root cause analysis and to establish an inspection and maintenance strategy. Those in Level 2 will be discussed by the team to reach an agreed maintenance strategy and will then be closely monitored by PowerNet System Control.

Level 1 represents the worst performance.

The table following provides an indication of the inspection and maintenance regime.

- Defect Inspection

This is a detailed route and equipment inspection, generally conducted from ground level and includes an ultra-sound inspection. For the five yearly inspection cycle 20% of the feeders/circuits in the contract area are inspected every year as part of the cycle and included as part of the lump sum cost.

- Targeted Inspections

Selected feeders/circuits, including those in Level 1 and those supplying important CBD and industrial areas, may require more frequent inspections. The frequency of these inspections will be decided on a reliability basis and completed as a reimbursable cost. Use of a helicopter may be approved in some rural situations.

- Annual Inspections

These are rapid patrol generally achieved by a drive-by, although CBD cable routes may require a walk-by to identify any recent works that may affect cable performance. The object is to identify any obvious defects that may impact network reliability in the short term (Two years). For example: leaning/damaged poles; unbalanced/excessive sags; leaning insulators; loose ties and/or hardware; excavations near poles; clearances from ground, buildings, trees; damaged crossarms, lightning arrestors, insulators; ground mounted equipment: cable protection and terminations; and similar items. Included as part of the lump sum cost.

- Thermal Inspections

Generally carried out at times of peak load on the network in order to identify hot connections. A thermal inspection of connections on CBD, industrial and urban feeders may be required within three days of a heavy fault near a substation. Unit rates per kilometre of overhead line and per site for ground mounted equipment are to be provided. Inspections are to be grouped for efficiency and an estimate of costs prepared prior to commencement.

- Ultra-Sound Inspections

To be carried out in conjunction with Defect Inspections and Thermal Inspections.

- Wood pole tests

PowerNet owns an 'X-Ray' scanner equipment that will be made available to the Contractor(s) for the purpose of testing wood (hardwood and softwood) poles. The use of this equipment will be subject to a lease agreement between the Contractor(s) and PowerNet. The Contractor(s) must have at least two staff trained in the use of the equipment.
The criteria for selecting poles to be tested are wood poles over ten years old that have not been tested in the previous ten years, or any pole the Contractor(s) believe to be in danger of imminent failure.

A unit rate per test is to be provided on the basis of a specific agreed number of poles.

- Pole Top Inspections

This inspection is to identify any defects in the pole head, crossarm, insulators, tie wire and associated hardware, connections and terminations, as required. A unit rate per kilometre of overhead line is to be provided. Inspections are to be grouped for efficiency and a cost estimate prepared prior to commencement."

	Level 1	Level 2	Level 3
CBD and Major Industrial	Thermal inspection on fault route < seven day response and correction of urgent defects < three month correction of non-urgent defects No loss of 11kV supply	All incidents Level 1	Annual thermal inspection at peak loads, including link boxes Annual cable route inspection Five yearly defect inspection < six month correction of non-urgent defects No loss of 11kV supply
Industrial	Thermal, ultra sound and defect inspection < one month response and correction of urgent defects live line < three month correction of non-urgent defects No loss of 11kV supply	All incidents Level 1	Annual thermal inspection at peak loads Five yearly defect inspection, live line pole top inspection and ten yearly pole test < six month correction of non-urgent defects
Urban	Thermal, x-ray and defect inspection < one month response and correction of urgent defects live line < three month correction of non-urgent defects	Thermal inspection following heavy fault Defect inspection Defect correction live line. < six month correction of non-urgent defects	Annual Inspection Five yearly thermal and defect inspection and ten yearly pole test 10 year live line pole top inspection 12 month correction of non-urgent defects
Rural	Defect inspection < two month response and correction of urgent defects live line < six month correction of non-urgent defects	Defect inspection < two month response and correction of urgent defects live line < six month correction of non-urgent defects	Annual Inspection five yearly defect inspection and ten yearly pole test 12 month correction of non-urgent defects

B.3.1.4 Maintenance plan

A significant volume of maintenance is planned, too numerous to detail within this document.

B.3.1.5 Renewal plan

Few lines are replaced in entirety solely based on maintenance requirements. Most lines are like the proverbial axe that was two hundred years old. It had its head replaced twice and the handle replaced ten times. In theory it was 200 years old. In practice it was much less. Lines, in common with most network equipment, consist of many components of varying age. Complete renewal is usually triggered by capacity upgrade requirements or similar. Significant capital works are listed elsewhere.

B.3.1.6 Retirement plan

Since no lines are being replaced under maintenance, there are no lines that require retirement. However a significant amount of material does become redundant. This typically has little value and is not suitable for reuse, since it is component level material that has deteriorated beyond use.

B.3.2 Distribution cables

B.3.2.1 Description and capacity

Most cables in TPCL network tend to be 1 or 3 core aluminium conductor, XLPE insulated, medium duty copper screen and HDPE sheath. This is the present cable standard used in all of the PowerNet networks. Because of the very short circuit lengths generally associated with cable supply, voltage drop is seldom a problem. So design limits tend to be that of the cable current rating. XLPE cables operate acceptably at significantly higher temperatures to paper insulated cables. Therefore the current rating is higher with XLPE giving a more economic cable form.

The standard sizes and typical ratings of cables are listed below.

Cable type	Current Rating	Resistance
1 x 3C 35mm^2 Al XLPE	135A	0.868Ω/km
1 x 3C 95mm^2 Al XLPE	240A	0.320Ω/km
1 x 3C 185mm^2 Al XLPE	320A	0.164Ω/km
3 x 1C 300mm^2 Al XLPE	420A	0.100Ω/km

Rating is very much affected by the thermal parameters of the surrounding media. Most distribution cables are direct buried to limit temperature rise associated with ducts. Backfill material is almost always the removed material, so no control is available over thermal resistivity. Most backfill tested appears to have similar characteristics to the standard quoted figures.

Lightning protection (surge divertors) is fitted where cables terminate to overhead lines. Over-voltage stress due to lightning is a dominant cause of cable failure.

B.3.2.2 Condition, age and performance

The southern networks basically utilised overhead distribution until 1958 when the Invercargill network started to install 11kV cable. A significant amount of urban development in the TPCL network utilised 11kV cable in the 1970's. The age profile is shown in Figure 23.

Failure of cable is very rare. The most common failure modes are joints, terminations, lightning and external mechanical damage. Consequently little proactive maintenance is deemed necessary on the cables themselves.

B.3.2.3 Monitoring and procedures

Little monitoring is conducted on cables. Most processes involving cable is involved with loading and circuit arrangement. Failure analysis is the prime tool utilised to identify possible maintenance or remedial action.

B.3.2.4 Maintenance plan

Several types of cable termination have been identified as a common cause of failure. The breakout arrangements on these terminations are being replaced.

B.3.2.5 Renewal plan

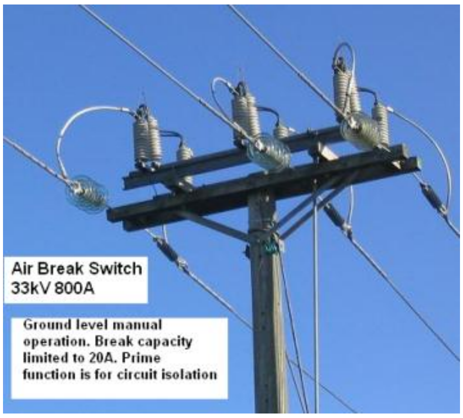
There are no plans to replace existing cables.

B.3.2.6 Retirement plan

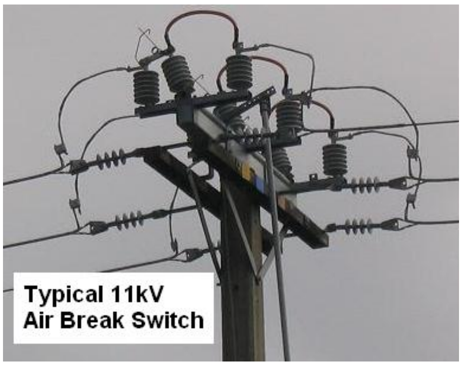
No cables have been identified for retirement.

B.3.3 Distribution switchgear

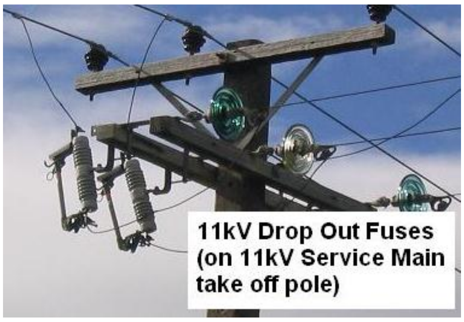
B.3.3.1 Description and capacity



Distribution switchgear used in the Southern region can be classified into four forms. The most common switch is in fact a fuse that can be used to switch, isolate and protect equipment. Around 30,000 HV fuses are in service in sets of 1, 2 or 3. The most common fuse is the drop out fuse rated up to 100A. These are the preferred type because of fault rating and clearly visible break point. A number of glass fuses and sand filled porcelain are still in use, but are generally replaced during significant maintenance work. Fuses are fitted at transformers, on HV service mains and quite a number of lateral circuits.



The majority of true switches, generally in rural areas, are pole mounted air break switches (ABS). There are approximately 1500 switches in service. They are generally rated 200A continuous capacity or 400A. Most are in fact more correctly called isolators because their load breaking capacity is in the range of 10A to 20A. 10% of these switches have load break heads that allow the switch to break rated load. A few enclosed units are being trialled.



Approximately 200 outdoor ring main unit switches are in service with most being manufactured by ABB (SDAF series). These are often associated with transformers and located on the road berm.

There are a significant number of indoor polymer construction switches such as Krone and Magnefix. These are mounted within the few LV substation buildings, or more generally within transformer kiosk enclosures.

B.3.3.2 Monitoring and procedures

Experience has shown that the ABB and indoor Ring Main Units require little maintenance. Routine visual inspections are conducted in conjunction with line surveys. The dominant maintenance requirement is protective painting of outdoor equipment.

Outdoor air break switches are also visually assessed. Major switchgear is periodically inspected with Infrared thermal cameras, which are the main method of identifying joint or contact heating problems. Unfortunately, for the majority of switchgear, failure during operation is the first indication of a maintenance requirement.

B.3.3.3 Maintenance plan

There are no plans for any specific switchgear maintenance. All work consists of routine inspection and maintenance.

B.3.3.4 Renewal plan

General renewal as part of works identified in five yearly inspections.

B.3.3.5 Retirement plan

Most switchgear removed from service is overhauled and made available for reuse. The contractor scraps the remainder.

B.3.4 Distribution transformers

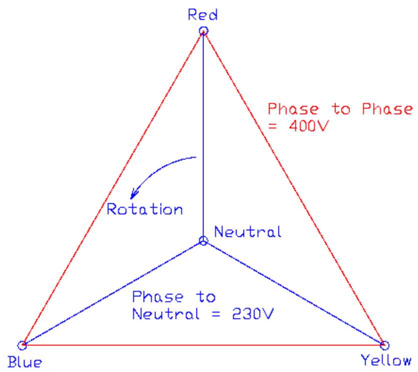
B.3.4.1 Description and capacity

The concept of electrical transformers was central to the development of the present integrated electricity systems found throughout the world. Previous centralised generation systems were extremely inhibited due to the limits imposed by low voltage direct current utilisation. Transformers provide a relatively economic means to convert voltage and allow distribution of electricity over large areas. Distribution transformers are the present devices used to convert distribution level voltages to reticulation level voltages directly usable by customers.

The majority of rural transformers supply one or two customers in close proximity. Since many rural properties are spaced kilometres apart there are a great number of customers with their own individual transformer. The most common rural transformer size is 10kVA to 30kVA. Urban customers tend to have section frontages of 20m, meaning they are in close proximity. The most economic electrical supply arrangement tends to have around 50 domestic customers connected to a single transformer. Consequently the most common urban transformer ratings are 200kVA to 300kVA.

The primary side voltage ratings must match the distribution voltages. Consequently most distribution transformers have a primary rating of 6.6kV, 11kV or 22kV phase to phase. A few connect directly to 33kV subtransmission and are therefore rated at 33kV. There are a few single wire earth return (SWER) transformers in the systems. These are generally rated at 6.35kV, 6.6kV or 11kV phase to ground.

The secondary side voltage must be suitable for typical reticulation voltages. The secondary rating is almost always 240V phase to neutral which is equivalent to 415V phase to phase. An important point to note is that the standard New Zealand nominal LV voltage is 230V, yet 240V transformers are used. 230V is the nominal voltage with an allowable deviation of ±6%. As load is applied to a transformer the voltage always drops. Transformers are rated at the upper limit of the allowable voltage range. As load increases the voltage falls through the nominal system voltage towards the minimum allowable limit. This fine distinction has created problems, even with experts.



Another item of significance that is best explained in terms of transformers is that of polyphase systems. Polyphase systems generally utilise three phases, usually being the most economic form. Two important differences exist between single phase (or direct current) and three phase systems. The three phase system has two voltage levels available. 230V is the voltage between any one of the tree phases and the common neutral point. But 400V is the voltage between any pair of the three phases. The standard vector arrangement of distribution transformers is Dyn11. It is difficult to connect some transformers in a standard fashion. Consequently the actual 400V system vector varies.

The other significant advantage of three phase supply is that the system has a sense of rotation. Motors will rotate in a direction defined by their electrical connection. Originally many rural properties utilised motors, so three phase supply was prevalent. Typical domestic requirements are met by single phase supply. Groups of urban customers are most economically supplied by connecting single phase customers to three phase transformers.

Consequently there are a great variety of transformer configurations and ratings. This has significant implications for stocking levels and renewal availability. Most transformers are purchased with off load tap change (OLTC) systems to allow adjustment of voltage. The dynamic nature of voltage variation and correct specification generally means that the tap setting must remain on neutral, so OLTC is in fact not particularly practical or useful.

There are four general forms of transformers. Most rural transformers in the range of 15kVA to 50kVA are pole hanger mounted. These have brackets that allow easy installation of the transformer near the pole top, giving a very economic installation. Some large outdoor transformers are still in service, mounted on heavy specially made pole structures. This arrangement is rather messy. Most of these units are replaced or rearranged to some form of ground mount system.

A third form of transformer is the kiosk unit. These are freestanding ground mount transformers that have cubicles included to enclose associated switches and terminations. These are the most common form of urban transformer. A similar form is a cable entry transformer that has no cubicles for switchgear. Cables are terminated in small termination boxes.

None of the above forms require additional housing. There are a limited number of open bushing transformers houses in specially built structures. These are commonly called distribution substations. The cost and land requirements mean these are quite rare within the southern systems.

Transformers are one of the few network assets that can be readily and uniquely tracked as individual items. Most other named items are formed of combinations of minor parts that are replaced as needed. Consequently the age of lines, for example, is in reality not really definable. With transformers, however, at least the nameplate has a manufacture date. The tank and cores may have been replaced, but a date can still be associated with each transformer. Transformers are fairly robust devices. It is economic to overhaul many units for reuse on the system. Consequently there are quite a number of old units still in use as shown in the age profile graph in Figure 24.

Care is required in interpretation of transformer age. In many cases the age refers to the site installation date. The age in that case will in reality be that of the transformer site including miscellaneous equipment associated with transformation. The actual transformer may be older still.

Transformers have for many years been purchased on a total cost economic basis. This includes capitalization of losses. Losses now form part of the MIPS legislation that specifies maximum allowable equipment losses. Generally there is little difference between old and new transformers

B.3.4.2 Monitoring and procedures

As equipment failure is not a major cause of outages most maintenance is based on inspections. Age of assets is deemed to have greater impact on maintenance requirements and inspection strategies are adjusted to allow for this. Small rural transformers are inspected together with line circuits on a five year basis. Urban transformers and large rural transformers are inspected on a six monthly basis and Maximum Demand Indicators are read where fitted.

The typical maintenance requirement is for tank and bushing repair or refurbishment. This can usually be determined from the visually inspection. A five year cycle of inspection is well within typical deterioration rates. Catastrophic failure is very random in nature and no economic means are available to determine risk of failure. The six monthly inspections are largely to check for overload and problems with miscellaneous equipment such as fuse heating.

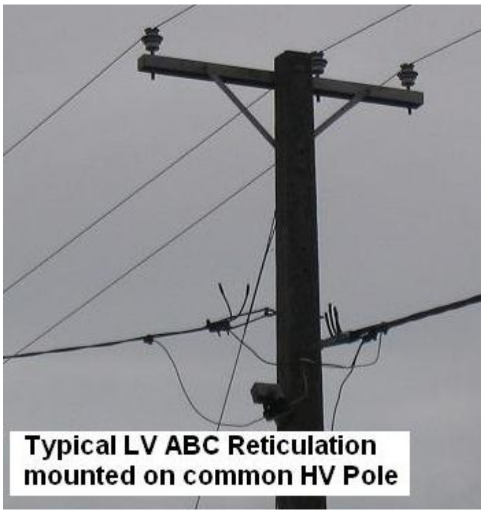
Transformers are replaced on site with new or refurbished transformers. Removed transformers are individually assessed for repair or retirement.

B.3.4.3 Maintenance plan

There are no plans for any large scale maintenance of transformers. All work consists of routine inspection and maintenance.

B.3.4.4 Renewal plan

A number of transformers are being replaced as part of renewal programs, or due to load requirements. These changes are part of the capital plans.


Typical LV ABC Reticulation mounted on common HV Pole

B.3.4.5 Retirement plan

Oil is removed from scrapped transformers and the remainder of the transformer sold as scrap metal. Bushings are sometimes kept where these may prove useful to replace damaged insulation. High loss and nonstandard transformers removed from service are invariably scrapped.

B.4 Reticulation

B.4.1 Overhead lines

B.4.1.1 Description and capacity

The majority of original reticulation circuits were in overhead construction, similar to 11kv distribution circuits. Most were of a flat top construction with 2 to 5 wires. Copper was the dominant conductor. The conductor size was relatively small due to the typical loading of the time.

Underground reticulation became dominant in the 1960's especially in urban areas, but overhead reticulation has remained in some areas until this day. The main change in overhead construction has been the use of aerial bundled conductor (ABC) since around 1990. This eliminated the need for crossarms, uses covered conductor and is generally a more reliable and aesthetically pleasing overhead format.


Typical LV Overhead Reticulation arrangement

The dominant bare wire conductor sizes range from 14mm^2 (7/16 Cu) to 40mm^2 (19/16Cu). ABC uses aluminium conductor of 35mm^2, 50mm^2 and 95mm^2 area. Some bare aluminium conductor was used prior to the introduction of ABC.

Many LV reticulation circuits are attached to 11kV poles.

B.4.1.2 Condition, age and performance

Most overhead reticulation is relatively old, because little of this construction is used now days. Age profiles are provided in Figure 25.

LV systems are more tolerant of ambient conditions than HV systems due to the much lower voltage stress imposed.

B.4.1.3 Maintenance plan

There are no plans for any large scale maintenance. All work consists of routine inspection and maintenance. LV overhead reticulation is managed on a similar basis to the HV distribution, although with a lesser priority.

B.4.1.4 Renewal plan

Renewals are done as reticulation is checked as part of the on-going inspections.

B.4.1.5 Retirement plan

See overhead distribution.

B.4.2 Reticulation cables

B.4.2.1 Description and capacity

The majority of reticulation is now undertaken using cable circuits. Cable is generally aluminium conductor with a copper neutral screen. Standard sizes are 95mm^2, 185mm^2 with a small amount of 300mm^2 as the maximum size. The dominant selection criterion is to limit voltage drop. Typically cables are loaded to 30% of their current capacity.

The combination of aluminium cable and copper based switchgear requires rigid adherence to proper termination procedures, generally utilising bimetal compression joints.

B.4.2.2 Condition, age and performance

Few problems are experienced with underground cable. Most faults are due to joints and external mechanical damage. The cable network is relatively young as shown in Figure 27**.**

B.4.2.3 Monitoring and procedures

Little monitoring is conducted on cables. Most processes involving cable is involved with loading and circuit arrangement. Failure analysis is the prime tool utilised to identify possible maintenance or remedial action.

B.4.2.4 Maintenance plan

Minor works only.

B.4.2.5 Renewal plan

No renewal is planned for.

B.4.2.6 Retirement plan

No cables have been identified for retirement.

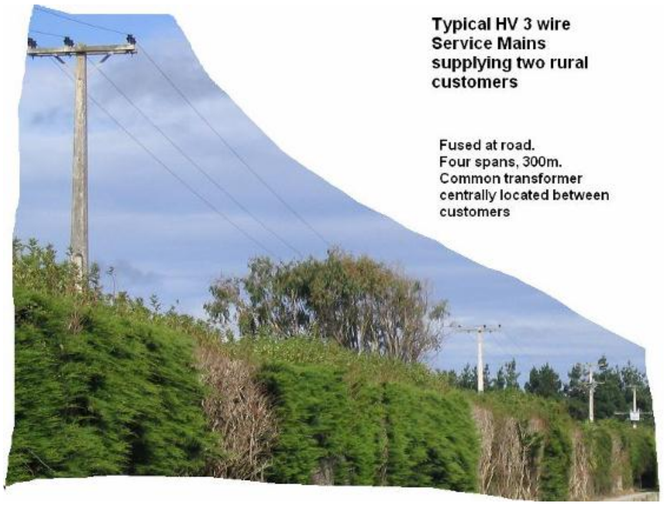
B.4.3 Service mains

B.4.3.1 Description and capacity

Service mains are generally the responsibility of individual customers with the demarcation point at the local pillar box. But a large proportion of rural service mains are MV. MV circuits are generally not a specialty of customers or their electricians. Consequently ownership of most MV service mains now resides with the associated network.

Typical MV service mains will be of 2 or 3 wire squirrel conductor, possibly 2 to 5 spans long. In many cases there will be drop out fuses protecting both the line and the transformer.

B.4.3.2 Condition, age and performance



Not a lot of information is available on service mains due to past ownership changes.

B.4.3.3 Monitoring and procedures

A five yearly inspection regime is in place, as required for safety and forward planning. Similar methods are used as with the distribution circuits. This inspection is limited to circuits identified as owned by the various networks.

B.4.3.4 Maintenance, renewal and retirement

Little maintenance is planned. Retirement is at the whim of the individual customers.

B.5 Earthing

B.5.1.1 Description and capacity

Earthing is a very importance safety system that is often overlooked. Earthing costs are significant. Earthing comes in two general forms. In urban areas with close proximity between transformers the prime format is to ensure interconnection of earth systems to create a large equipotential grid. In rural areas the main purpose is to create a connection to earth that has a reasonable resistance and will ensure that protection will operate to clear any fault.

Urban design targets limiting EPR to 650V and ensuring Touch Voltages are acceptable. 70mm^2 earth conductor is used to allow for the relatively large fault currents.

Rural design attempts to achieve a 10Ω earth resistance. 25mm^2 conductor is used, suitable for the lower fault currents.

B.5.1.2 Condition, age and performance

The age profile of earth system is similar to that of transformers. Unfortunately earth systems, by definition, are in close proximity to the ground. Corrosion is an on-going problem.

B.5.1.3 Monitoring and procedures

A five yearly inspection regime is in place. Generally a site is inspected, tested and maintained as a single process. Sites are chosen from the GIS system based on last inspection.

B.6 Ripple control

B.6.1.1 Description and capacity

"Ripple Control" controls a large proportion of demand side load directly or indirectly. This is a form of communication that has the highest probability of reaching all electrical sites. Ripple control is a very slow speed communication signal superimposed on the network. Where 50Hz power flows, so does the ripple signal.

Modern systems utilise 216⅔Hz as the carrier signal. Older systems used 500Hz to 1000Hz, which had problems due to electrical resonance. The signals propagate similar to telephone signals. Communications theory is required to understand and analyse the operation of ripple control.

Ripple systems consist of three basic sections. Firstly the load must be monitored such that appropriate control actions can be undertaken. This is done with separate SCADA equipment.

Secondly a signal must be injected onto the 50Hz network. This is done with Injection Plants. And finally the signal must be detected by a Receiver that undertakes control at the individual installations. It is similar to a radio receiver that receives its signal not from an antenna, but from the mains wiring. One, two or three relays control equipment such as hot water heating, night store heaters and meters. The maintenance and control of receivers is intricately tied to meters.

The central part of ripple control that is discussed here is injection plant. They all consist of a generator and a coupling cell. The generator was traditionally a motor/generator set. Modern generators use electronic components to convert 50Hz firstly to direct current and secondly to the required frequency. A typical rating is 100kVA at around 200V.

The coupling cells vary. Those in use in the PowerNet controlled networks consist of: (a) LV side inductor/capacitor tuning, (b) coupling transformer and (c) EHV capacitors. These operate well under a large range of network configurations.

Many traditional systems injected onto the 11kV busbar of each zone substation. This required a lot of injection plants. The systems within PowerNet all inject at or near to

Transpower Grid Exit Points. The signal propagates quite satisfactorily down to the zone substations on to individual LV installations.

Injection plants are located at the sites below.

- Edendale 33kV 125kVA (a backup coupling connects to the 11kV)
- Gore 33kV 125kVA
- Invercargill 1 33kV 125kVA
- Invercargill 2 (EIL) 33kV 125kVA (Designed to operate in parallel with plant 1)
- North Makarewa 33kV 125kVA
- Winton 66kV 125kVA

The typical signal level is 2%. The system works adequately at injection levels down to 1.4%.

Ripple control has been instrumental in increasing load factor from around 45% to the present 65%. Effectively 70MW of load is controlled by ripple control.

B.6.1.2 Monitoring and procedures

Most of the plants are located indoors and utilise electronic components. There is little that can deteriorate. Inspection is limited to locating obvious signs of failure. Spare parts or duplicate systems are available as backup in the case of faults. Most work involves tuning and signal level investigation that is largely influence by the network, not the injection plant.

B.6.1.3 Maintenance, renewal and retirement

No maintenance is planned other than routine inspection.

Renewal of plants is envisaged in the later part of the ten years, due to electronics failures and Transpower network upgrades.

B.7 Trees

B.7.1.1 Description and capacity

The networks do not own trees. However they are the single most common cause of faults on the network. Consequently a lot of effort is spent on tree control and maintenance.

B.7.1.2 Monitoring and procedures

Trees and similar vegetation are listed within the GIS system. Procedures are in place for proper monitoring within the bounds of recent legislation.

A significant amount of tree trimming is being undertaken at the expense of the networks. Once trees have been confirmed as being within specified clearances from the lines, the responsibility is placed on the tree owner for future maintenance. At that stage procedures will change to a monitoring and policing role.

C. Appendix – Assumptions [A.3.8.]

When developing this plan we have made the following assumptions:

- No major developments in the region, unless specifically listed.
    - Developers don't always let TPCL know of their plans with large projects kept confidential until the last minute.
- Transpower will upgrade the 110kV network by reinforcing Gore with a 220/110kV interconnecting transformer.
- Growth trends will be similar to historic trends.
    - No step changes considered as none are certain.
    - History supports actual outcomes over a long period.
- No change in present regulation.
    - Any changes likely to add additional costs.
    - Regulation change seems to be driving at improved reliability. TPCL remains unregulated in this aspect but prudent asset management to follow industry / regulator trend so as to continue to be unregulated.
- Distributed generation will develop slowly with little impact until after five years.
    - Based on current connections onto the network.
- The standard life of assets is based on the ODV asset life, with actual replacement done on a condition basis.
    - Some areas greatly exceed standard lives (Inland North Otago) and others fail to reach standard lives (Coastal).
- Population for sizing of equipment is based on the high projection.
    - Sizing of equipment step changes are minor with labour cost being a large proportion of works.
- No decline in meat and wool markets.
    - So no closures of the meat processing plants.
    - TPCL notes the reduction in load at Mataura as Alliance Group shifted all lamb processing to Lorneville plant (≈2.5MVA peak reduction)
- Increase in dairy markets.
    - Growth in dairy farm conversions being similar to recent years.
- Recovery in the timber market.
    - Some additional production occurring at Brightwood, Otautau.
- No major development in coal extraction and/or processing.
    - Any new mine or process could add or subtract load and require new network to be built.
- No major development in mineral extraction and/or processing.
    - Any new mine or process could add or subtract load and require new network to be built.
- Material and Labour costs only increasing by CPI.
    - Any abnormal price movements are difficult to predict and not allowed for in estimates.

D. Appendix – Schedule 11a

Company Name	**The Power Company Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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).

This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		4,690	3,344	3,418	3,501	3,584	3,640	3,712	3,787	3,862	3,940	4,018
11	System growth		11,055	12,958	4,955	8,552	4,281	1,514	3,853	3,930	4,009	4,089	4,171
12	Asset replacement and renewal		8,882	10,632	10,502	11,345	7,845	7,267	9,478	9,873	9,879	10,308	10,515
13	Asset relocations		201	52	53	54	56	56	58	59	60	61	62
14	Reliability, safety and environment:												
15	Quality of supply		684	2,704	742	760	393	399	403	411	420	428	437
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		408	1,420	1,004	703	388	394	399	407	415	423	431
18	**Total reliability, safety and environment**		1,092	4,124	1,746	1,463	782	794	802	818	834	851	868
19	**Expenditure on network assets**		25,920	31,111	20,673	24,914	16,548	13,271	17,903	18,467	18,644	19,249	19,634
20	Non-network assets												
21	**Expenditure on assets**		25,920	31,111	20,673	24,914	16,548	13,271	17,903	18,467	18,644	19,249	19,634
22													
23	*plus* Cost of financing												
24	*less* Value of capital contributions		2,345	2,747	2,051	2,100	2,151	2,184	2,227	2,272	2,317	2,364	2,411
25	*plus* Value of vested assets												
26													
27	**Capital expenditure forecast**		23,575	28,364	18,623	22,814	14,397	11,088	15,676	16,195	16,327	16,886	17,223
28													
29	Value of commissioned assets		18,562	17,400	8,033	11,182	8,582	3,361	5,338	5,445	5,554	5,665	5,778
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
32			**$000 (in constant prices)**										
33	Consumer connection		4,690	3,344	3,344	3,344	3,344	3,344	3,344	3,344	3,344	3,344	3,344
34	System growth		11,055	12,958	4,848	8,170	3,994	1,391	3,471	3,471	3,471	3,471	3,471
35	Asset replacement and renewal		8,882	10,632	10,276	10,838	7,320	6,678	8,538	8,720	8,554	8,751	8,751
36	Asset relocations		201	52	52	52	52	52	52	52	52	52	52
37	Reliability, safety and environment:												
38	Quality of supply		684	2,704	726	726	367	367	363	363	363	363	363
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		408	1,420	983	672	362	362	359	359	359	359	359
41	**Total reliability, safety and environment**		1,092	4,124	1,708	1,397	729	729	723	723	723	723	723
42	**Expenditure on network assets**		25,920	31,111	20,228	23,802	15,440	12,195	16,129	16,310	16,144	16,341	16,341
43	Non-network assets		-	-	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**		25,920	31,111	20,228	23,802	15,440	12,195	16,129	16,310	16,144	16,341	16,341
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses												
48	Overhead to underground conversion												
49	Research and development												
57			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
58		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
59	**Difference between nominal and constant price forecasts**		**$000**										
60	Consumer connection		-	-	74	156	240	295	368	442	518	595	674
61	System growth		-	-	107	382	287	123	382	459	538	618	700
62	Asset replacement and renewal		-	-	226	506	525	589	939	1,153	1,325	1,557	1,763
63	Asset relocations		-	-	1	2	4	5	6	7	8	9	10
64	Reliability, safety and environment:												
65	Quality of supply		-	-	16	34	26	32	40	48	56	65	73
66	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	-	22	31	26	32	40	47	56	64	72
68	**Total reliability, safety and environment**		-	-	38	65	52	64	79	96	112	129	146
69	**Expenditure on network assets**		-	-	445	1,112	1,108	1,076	1,774	2,156	2,500	2,908	3,293
70	Non-network assets		-	-	-	-	-	-	-	-	-	-	-
71	**Expenditure on assets**		-	-	445	1,112	1,108	1,076	1,774	2,156	2,500	2,908	3,293
72													

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
73			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
74	**11a(ii): Consumer Connection**							
75	*Consumer types defined by EDB**		**$000 (in constant prices)**					
76	Customer Connections (≤ 20kVA)		1,500	1,134	1,134	1,134	1,134	1,134
77	Customer Connections (21 to 99kVA)		1,800	1,340	1,340	1,340	1,340	1,340
78	Customer Connections (≥ 100kVA)		1,200	763	763	763	763	763
79	Distributed Generation		150	5	5	5	5	5
80	Subdivsions		40	103	103	103	103	103
81	**include additional rows if needed*							
82	**Consumer connection expenditure**		4,690	3,344	3,344	3,344	3,344	3,344
83	*less* Capital contributions funding consumer connection		2,345	2,007	2,007	2,007	2,007	2,007
84	**Consumer connection less capital contributions**		2,345	1,338	1,338	1,338	1,338	1,338
85	**11a(iii): System Growth**							
86	Subtransmission		3,101	2,391	1,165	3,286	703	1,031
87	Zone substations		7,954	10,568	3,683	4,884	3,291	361
88	Distribution and LV lines		-	-	-	-	-	-
89	Distribution and LV cables		-	-	-	-	-	-
90	Distribution substations and transformers		-	-	-	-	-	-
91	Distribution switchgear		-	-	-	-	-	-
92	Other network assets		-	-	-	-	-	-
93	**System growth expenditure**		11,055	12,958	4,848	8,170	3,994	1,391
94	*less* Capital contributions funding system growth		-	740	-	-	-	-
95	**System growth less capital contributions**		11,055	12,218	4,848	8,170	3,994	1,391
103			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
104		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
105	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
106	Subtransmission		1,263	2,934	609	1,268	645	90
107	Zone substations		2,572	1,530	3,551	3,554	765	677
108	Distribution and LV lines		2,332	3,150	3,150	3,150	3,150	3,150
109	Distribution and LV cables		331	281	281	281	281	281
110	Distribution substations and transformers		1,437	1,389	1,336	1,336	1,336	1,336
111	Distribution switchgear		888	1,144	1,144	1,144	1,144	1,144
112	Other network assets		59	205	205	105	-	-
113	**Asset replacement and renewal expenditure**		8,882	10,632	10,276	10,838	7,320	6,678
114	*less* Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
115	**Asset replacement and renewal less capital contributions**		8,882	10,632	10,276	10,838	7,320	6,678
116	**11a(v):Asset Relocations**							
117	*Project or programme**							
118	[Description of material project or programme]							
119	[Description of material project or programme]							
120	[Description of material project or programme]							
121	[Description of material project or programme]							
122	[Description of material project or programme]							
123	**include additional rows if needed*							
124	All other asset relocations projects or programmes		201	52	52	52	52	52
125	**Asset relocations expenditure**		201	52	52	52	52	52
126	*less* Capital contributions funding asset relocations		-	-	-	-	-	-
127	**Asset relocations less capital contributions**		201	52	52	52	52	52
128								
129	**11a(vi):Quality of Supply**							
130	*Project or programme**							
131	Supply Quality Upgrades		106	262	262	262	262	262
132	Mobile Substation		53	1,978	-	-	-	
133	Distribution Automation		525	464	464	464	-	-
134	[Description of material project or programme]							
135	[Description of material project or programme]							
136	**include additional rows if needed*							
137	All other quality of supply projects or programmes		-	-	-	-	105	105
138	**Quality of supply expenditure**		684	2,704	726	726	367	367
139	*less* Capital contributions funding quality of supply		-	-	-	-	-	-
140	**Quality of supply less capital contributions**		684	2,704	726	726	367	367
141								
142	**11a(vii): Legislative and Regulatory**							
143	*Project or programme**							
144	[Description of material project or programme]							
145	[Description of material project or programme]							
146	[Description of material project or programme]							
147	[Description of material project or programme]							
148	[Description of material project or programme]							
149	**include additional rows if needed*							
150	All other legislative and regulatory projects or programmes							
151	**Legislative and regulatory expenditure**		-	-	-	-	-	-
152	*less* Capital contributions funding legislative and regulatory							
153	**Legislative and regulatory less capital contributions**		-	-	-	-	-	-
161								
162			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
163	**11a(viii): Other Reliability, Safety and Environment**							
164	*Project or programme**		**$000 (in constant prices)**					
165	Earth Upgrades		307	528	210	105	105	105
166	NER Installation		32	567	567	567	-	-
167	Substation Safety		69	206	206	-	-	-
168	Lumsden Oil Bunding		-	119	-	-	-	-
169	Township Undergrounding		-	-	-	-	258	258
170	**include additional rows if needed*							
171	All other reliability, safety and environment projects or programmes		-	-	-	-	-	-
172	**Other reliability, safety and environment expenditure**		408	1,420	983	672	362	362
173	*less* Capital contributions funding other reliability, safety and environment		-	-	-	-	-	-
174	**Other reliability, safety and environment less capital contributions**		408	1,420	983	672	362	362
175								
176								
177								
178	**11a(ix): Non-Network Assets**							
179	**Routine expenditure**							
180	*Project or programme**							
181								
182	[Description of material project or programme]							
183	[Description of material project or programme]							
184	[Description of material project or programme]							
185	[Description of material project or programme]							
186	**include additional rows if needed*							
187	All other routine expenditure projects or programmes							
188	**Routine expenditure**		-	-	-	-	-	-
189	**Atypical expenditure**							
190	*Project or programme**							
191	[Description of material project or programme]							
192	[Description of material project or programme]							
193	[Description of material project or programme]							
194	[Description of material project or programme]							
195	[Description of material project or programme]							
196	**include additional rows if needed*							
197	All other atypical projects or programmes							
198	**Atypical expenditure**		-	-	-	-	-	-
199								
200	**Non-network assets expenditure**		-	-	-	-	-	-

E. Appendix – Schedule 11b

Company Name: **The Power Company Ltd**
AMP Planning Period: **1 April 2015 – 31 March 2025**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
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	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	4,330	2,827	2,903	2,970	3,038	3,096	3,157	3,221	3,285	3,351	3,418
11	Vegetation management	1,404	1,303	1,338	1,369	1,400	1,427	1,455	1,484	1,514	1,544	1,575
12	Routine and corrective maintenance and inspection	2,971	3,315	3,404	3,482	3,562	3,629	3,702	3,776	3,851	3,928	4,007
13	Asset replacement and renewal	1,300	1,140	1,171	1,198	1,225	1,248	1,273	1,299	1,325	1,351	1,378
14	**Network Opex**	10,005	8,585	8,816	9,018	9,225	9,400	9,588	9,780	9,975	10,175	10,378
15	System operations and network support	1,452	1,599	1,678	1,751	1,791	1,825	1,861	1,898	1,936	1,975	2,015
16	Business support	1,610	3,492	3,586	3,747	3,833	3,906	3,984	4,063	4,145	4,228	4,312
17	**Non-network opex**	3,062	5,091	5,264	5,498	5,624	5,730	5,845	5,962	6,081	6,203	6,327
18	**Operational expenditure**	13,067	13,676	14,079	14,516	14,849	15,131	15,433	15,742	16,057	16,378	16,705
19		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
21		$000 (in constant prices)										
22	Service interruptions and emergencies	4,330	2,827	2,827	2,827	2,827	2,827	2,827	2,827	2,827	2,827	2,827
23	Vegetation management	1,404	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303
24	Routine and corrective maintenance and inspection	2,971	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315
25	Asset replacement and renewal	1,300	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,140
26	**Network Opex**	10,005	8,585	8,585	8,585	8,585	8,585	8,585	8,585	8,585	8,585	8,585
27	System operations and network support	1,452	1,599	1,634	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667
28	Business support	1,610	3,492	3,493	3,567	3,567	3,567	3,567	3,567	3,567	3,567	3,567
29	**Non-network opex**	3,062	5,091	5,126	5,234	5,234	5,234	5,234	5,234	5,234	5,234	5,234
30	**Operational expenditure**	13,067	13,676	13,712	13,819	13,819	13,819	13,819	13,819	13,819	13,819	13,819
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	125	125	125	125	125	125	125	125	125	125	125
34	Direct billing*											
35	Research and Development											
	Insurance	306	296	296	296	296	296	296	296	296	296	296
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	76	143	211	268	330	393	458	523	590
43	Vegetation management	-	-	35	66	97	124	152	181	211	241	272
44	Routine and corrective maintenance and inspection	-	-	89	167	247	315	387	461	537	614	692
45	Asset replacement and renewal	-	-	31	58	85	108	133	159	185	211	238
46	**Network Opex**	-	-	230	433	640	815	1,003	1,195	1,390	1,590	1,793
47	System operations and network support	-	-	44	84	124	158	195	232	270	309	348
48	Business support	-	-	94	180	266	339	417	496	578	660	745
49	**Non-network opex**	-	-	137	264	390	497	611	728	847	969	1,093
50	**Operational expenditure**	-	-	368	697	1,030	1,311	1,614	1,923	2,238	2,559	2,886

F. Appendix – Schedule 12a

Company Name	The Power Company Ltd
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

7					Asset condition at start of planning period (percentage of units by grade)						
8	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	-	5.00%	70.00%	5.00%	20.00%	1	5.00%
11	All	Overhead Line	Wood poles	No.	-	5.00%	70.00%	5.00%	20.00%	1	15.00%
12	All	Overhead Line	Other pole types	No.	-	5.00%	70.00%	5.00%	20.00%	1	5.00%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	5.00%	70.00%	5.00%	20.00%	1	5.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	-	-	-	-	N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km		-	100.00%	-	-	1	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	-	-	-	-	N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	-	-	-	-	N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		-	100.00%	-	-	1	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	-	-	-	-	N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	-	-	-	-	N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	-	-	-	-	N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	-	-	-	-	N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	-	-	-	-	N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	5.00%	90.00%	5.00%	-	1	5.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	-	-	-	-	N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.		-	100.00%	-	-	1	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		5.00%	90.00%	5.00%	-	1	5.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	-	-	-	-	N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.		2.00%	90.00%	8.00%	-	1	2.00%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	-	-	-	-	N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	-	-	-	-	N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	2.00%	90.00%	8.00%	-	1	2.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	7.00%	86.00%	7.00%	-	1	7.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	100.00%	-	-	1	10.00%

42					Asset condition at start of planning period (percentage of units by grade)						
43	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.		8.00%	90.00%	2.00%	-	3	10.00%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	10.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	10.00%
48	HV	Distribution Line	SWER conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	75.00%	5.00%	20.00%	1	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	2.00%	73.00%	5.00%	20.00%	1	2.00%
51	HV	Distribution Cable	Distribution Submarine Cable	km	N/A					N/A	
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	3.00%	92.00%	5.00%	-	1	3.00%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A					N/A	
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.00%	6.00%	67.00%	6.00%	20.00%	1	7.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A					N/A	
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	3.00%	94.00%	3.00%	-	1	5.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	3.00%	74.00%	3.00%	20.00%	1	10.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	1.00%	96.00%	3.00%	-	1	10.00%
59	HV	Distribution Transformer	Voltage regulators	No.	-	5.00%	90.00%	5.00%	-	1	5.00%
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	N/A	-	-	-	-	N/A	
61	LV	LV Line	LV OH Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
62	LV	LV Cable	LV UG Cable	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
64	LV	Connections	OH/UG consumer service connections	No.	1.00%	4.00%	70.00%	5.00%	20.00%	1	10.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	2.00%	94.00%	4.00%	-	1	10.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	2.00%	94.00%	4.00%	-	1	10.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	100.00%	-	-	1	-
68	All	Load Control	Centralised plant	Lot	-	20.00%	80.00%	-	-	1	20.00%
69	All	Load Control	Relays	No.	-	-	18.00%	2.00%	80.00%	1	50.00%
70	All	Civils	Cable Tunnels	km	N/A					N/A	

G. Appendix – Schedule 12b

Company Name	The Power Company Ltd
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Awarua	4	-	N	1	-	12	67%	No constraint within +5 years	
10	Awarua Chip Mill	1	-	N	1	-	-	-	No constraint within +5 years	
11	Bluff	5	12	N-1	1	40%	12	42%	No constraint within +5 years	
12	Centre Bush	4	-	N	2	-	-	-	No constraint within +5 years	
13	Conical Hill	3	5	N-1	2	63%	2	-	No constraint within +5 years	
14	Dipton	2	-	N	1	-	-	-	No constraint within +5 years	
15	Edendale Fonterra	25	23	N-1	-	107%	46	74%	No constraint within +5 years	Single Customer so their call when to upgrade
16	Edendale	7	12	N-1	1	57%	12	60%	No constraint within +5 years	
17	Glenham	1	-	N	1	-	-	-	No constraint within +5 years	
18	Gorge Road	3	2	N-1 switched	1	213%	2	161%	Transformer	Dual 1.5MVA TX so under our N-1 limit
19	Heddon Bush	10	-	N	6	-	N/A	-	No constraint within +5 years	Relocated to Lumsden
20	Hillside	1	-	N	1	-	-	-	No constraint within +5 years	
21	Kelso	5	-	N	2	-	-	-	No constraint within +5 years	
22	Kennington	6	12	N-1 switched	2	53%	12	40%	No constraint within +5 years	
23	Lumsden	4	-	N	2	-	-	-	No constraint within +5 years	
24	Makarewa	7	12	N-1 switched	2	60%	12	47%	No constraint within +5 years	
25	Mataura	10	10	N-1	2	97%	12	75%	No constraint within +5 years	Upgrade planned
26	Monowai	0	-	N	-	-	-	-	No constraint within +5 years	
27	Mossburn	2	2	N-1 switched	2	130%	-	-	No constraint within +5 years	
28	North Gore	9	10	N-1	8	89%	10	88%	No constraint within +5 years	
	North Makarewa	47	45	N-1	-	104%	45	109%	Transformer	Expect some DG from Monowai or White Hill
	Ohai	3	5	N	1	57%	5	50%	No constraint within +5 years	
	Orawia	3	-	N	2	-	-	-	No constraint within +5 years	
	Otatara	4	-	N	4	-	-	-	No constraint within +5 years	
	Otautau	5	-	N	3	-	-	-	No constraint within +5 years	
	Riversdale	5	-	N	3	-	-	-	No constraint within +5 years	
	Riverton	5	8	N-1	2	68%	8	70%	No constraint within +5 years	
	Seaward Bush	8	10	N-1 switched	1	76%	12	67%	No constraint within +5 years	Upgrade planned
	South Gore	8	12	N-1	8	66%	12	77%	No constraint within +5 years	
	Te Anau	5	12	N-1	1	44%	12	51%	No constraint within +5 years	
	Tokanui	1	-	N	1	-	-	-	No constraint within +5 years	
	Underwood	12	20	N-1	4	60%	20	61%	No constraint within +5 years	
	Waikaka	1	-	N	1	-	-	-	No constraint within +5 years	
	Waikiwi	11	12	N-1	2	90%	23	58%	No constraint within +5 years	Upgrade planned
	Winton	14	12	N-1	3	114%	12	85%	No constraint within +5 years	Load transferred onto new Hegehope and Isla Bank substations

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

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
31		
32	Distribution transformer capacity (EDB owned)	N/A
33	Distribution transformer capacity (Non-EDB owned)	N/A
34	**Total distribution transformer capacity**	#VALUE!
35		
36	**Zone substation transformer capacity**	N/A

H. Appendix – Schedule 12c

Company Name	The Power Company Ltd
AMP Planning Period	1 April 2015 – 31 March 2025

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 in year by consumer type*				Number of connections			
9			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
10		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
11	*Consumer types defined by EDB**							
12	Customer Connections (≤ 20kVA)		247	250	250	250	250	250
13	Customer Connections (21 to 99kVA)		58	50	50	50	50	50
14	Customer Connections (≥ 100kVA)		10	5	5	5	5	5
15	Subdivsions		5	5	5	5	5	5
16								
17	**Connections total**		320	310	310	310	310	310
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		110	125	140	160	180	180
21	Installed connection capacity of distributed generation (MVA)		1	8	1	1	13	1
22	**12c(ii) System Demand**							
23			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
24	**Maximum coincident system demand (MW)**	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
25	GXP demand		81	84	86	88	78	80
26	*plus* Distributed generation output at HV and above		54	61	61	61	73	73
27	**Maximum coincident system demand**		135	145	147	149	151	153
28	*less* Net transfers to (from) other EDBs at HV and above		2	2	2	2	2	2
29	**Demand on system for supply to consumers' connection points**		133	143	145	147	149	151
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		607	587	590	594	598	602
32	*less* Electricity exports to GXPs		50	50	50	50	50	50
33	*plus* Electricity supplied from distributed generation		220	244	244	244	244	244
34	*less* Net electricity supplied to (from) other EDBs		20	20	21	21	21	21
35	**Electricity entering system for supply to ICPs**		757	761	763	767	771	775
36	*less* Total energy delivered to ICPs		710	714	718	722	727	731
37	**Losses**		47	47	45	45	44	44
38								
39	**Load factor**		65%	61%	60%	60%	59%	59%
40	**Loss ratio**		6.2%	6.2%	5.9%	5.9%	5.7%	5.7%

I. Appendix – Schedule 12d

Company Name	**The Power Company Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Network / Sub-network Name	**The Power Company Ltd**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	72.9	35.7	35.7	35.7	36.7	36.7
12	Class C (unplanned interruptions on the network)	175.0	120.2	116.4	113.8	111.3	109.7
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.30	0.18	0.18	0.18	0.18	0.18
15	Class C (unplanned interruptions on the network)	2.72	2.50	2.44	2.39	2.33	2.32

J. Appendix – Schedule 13

Summary of Asset Management Maturity Assessment Tool.

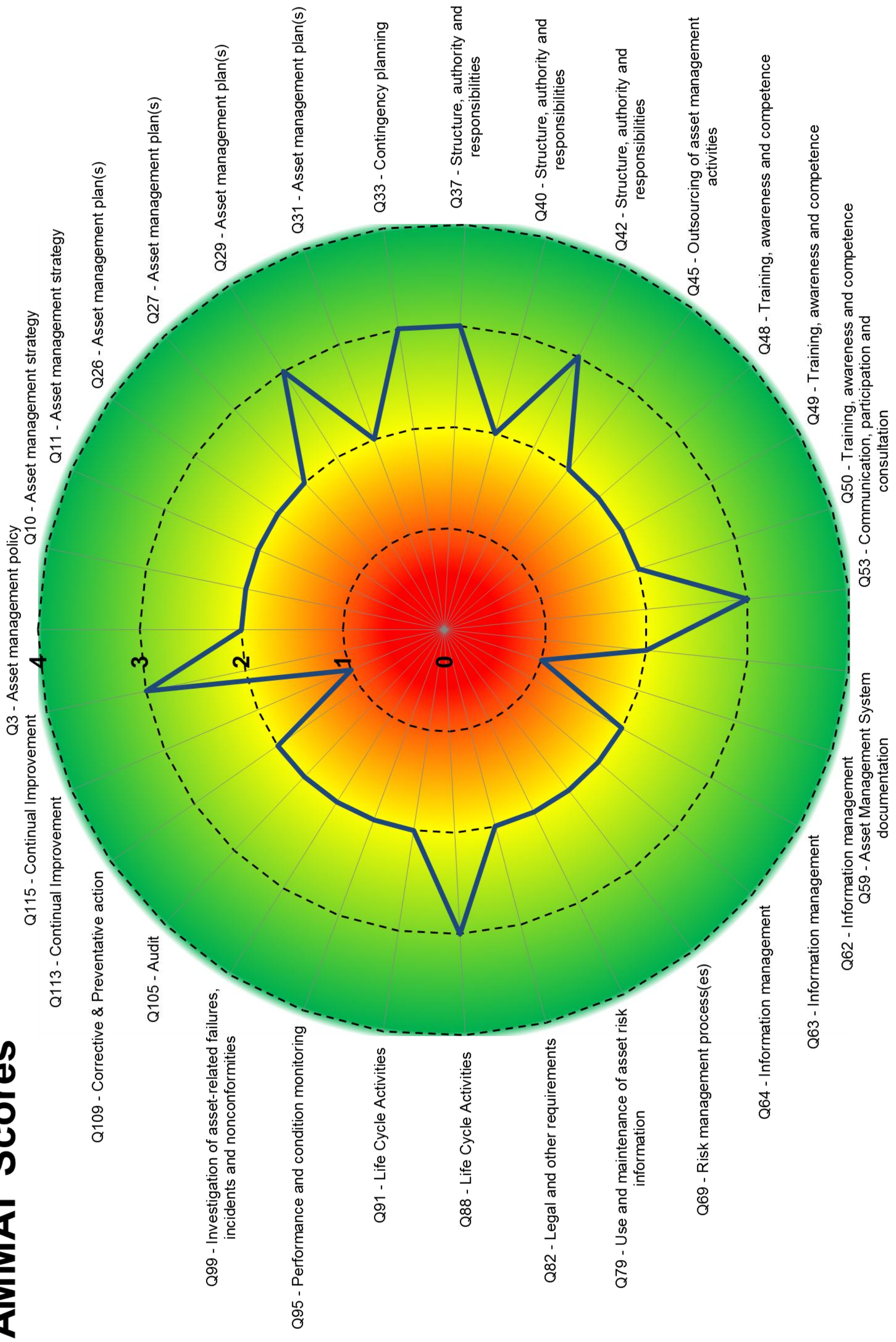
Company Name	The Power Company Ltd
AMP Planning Period	1 April 2015 – 31 March 2025
Asset Management Standard Applied	PAS 55: 2008

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	Maturity Level Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the	2	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	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)?	2	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the	3	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and	2	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	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.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite	2	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.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.
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	2	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across	3	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are	2	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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	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?	2	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and	2	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of	1	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

AMMAT Scores



10. Approval by Board of Directors

Certification for Year-beginning Disclosures

We, Alan Bertram Harper and, Maryann Louise Macpherson being Directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of The Power Company Limited prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) 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 and 12c are based on objective and reasonable assumptions which both align with The Power Company Limited's corporate vision and strategy and are documented in retained records.

A B Harper

M L Macpherson

Date: 25 March 2015