THEPOWERCOMPANYLTD

Asset Management Plan 2016 - 2026

Publicly disclosed in March 2016

Contents

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0. Summary

0.1. Background and Objectives

The Power Company Limited (TPCL) is the disclosing entity for the electricity lines businesses that conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff), supplying approximately 35,208 customers.

TPCL's Asset Management Plan (AMP) provides an internal asset management framework for TPCL's network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination 2012 for the ten year planning period from 1 April 2016 to 31 March 2026. Other key asset management documents for TPCL are;

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

TPCL's business goals are driven by its stakeholders' interests, of which shareholder's expectations and meeting customer expectations have a primary influence. Aligned corporate and asset management strategies have been developed to guide TPCL's commercial operation, investment, risk management, business efficiency and customer satisfaction objectives.

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust and make the best use of their funds. This creates a primary driver for TPCL and formal accountabilities to the shareholder are in place for financial and network performance. Customers via the electricity retailers provide TPCL's revenue in return for the services provided by the TPCL network assets. Due to the importance TPCL places on meeting customer's expectations annual customer surveys are undertaken to monitor customer satisfaction with service level targets set aimed at ensuring standards are maintained or improved.

Stakeholder's interests are accommodated as far as possible while managing any conflicting interests by using a priority hierarchy considering safety, viability, pricing, supply quality and compliance in that order.

TPCL has a contract with PowerNet Limited which is owned by The Power Company Limited (TPCL) and Electricity Invercargill (EIL). The AMP is produced by PowerNet after extensive consultation throughout the business, with TPCL's Board, and with TPCL's customers. The AMP is approved by the TPCL's Board prior to 31 March of each year when it is publically disclosed.

0.2. Assets Covered

TPCL owns and operates an electrically contiguous networks which is supplied by Four Grid Exit Points (GXPs) at Invercargill, North Makarewa, Gore and Edendale and by up to 72MW of injected Generation from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station and Southern Generation Limited's Flat Hill wind farm. In total TPCL supplies 35,208 residential, commercial, and industrial customers across all network areas.

Key industries within TPCL's network area include sheep, beef and dairy farming, meat processing, black and brown coal mining, forestry, timber processing and tourism.

TPCL owns and operates 35 zone substations. The distribution network is predominantly overhead which is mainly meshed between substations with reasonable backup capability. Most distribution off this main distribution is radial with only some meshing.

0.3. Service Levels

TPCL sets and maintains a number of service levels on behalf of its stakeholders especially its customers. Two important metrics measuring network reliability are SAIFI and SAIDI:

- SAIFI is a measure of outage frequency which translates to the number of interruptions that the average customer can expect per annum. TPCL is forecasting a SAIFI of about 2.65 for the 2016/17 year.
- SAIDI is a measure of outage duration which translates to the number of minutes that the average customer can expect to be without power per annum. TPCL is forecasting SAIDI of about 158.96 for the 2016/17 year.

These projections are an average only, given the volatility in reliability statistics due to extreme weather events. TPCL's network reliability has been heavily influenced by extreme weather events in recent years, and its medium-term aim is to gradually reduce this average.

Secondary service levels are also set for customer satisfaction for those customers who have experienced an outage (both planned and unplanned) regarding their satisfaction with the amount of time they were without supply and communication received or available, about their outages. Independent surveys are undertaken annually to determine how customers perceive the service levels they receive from TPCL and generally responses are very positive.

Other service levels maintained are the compliance with safety legislation, amenity value legislation and regulations requiring certain performance standards for the business while avoiding interference with other parties.

In addition TPCL is required to set financial efficiency and energy efficiency service levels. For financial efficiency TPCL has adopted a set of six metrics from the current Information Disclosure format and aims to maintain or improve them from current levels. For efficiency of energy delivery TPCL is aiming to achieve an overall load factor of 65%, capacity utilisation of 31% and loss ratio of 7.0%.

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

0.4. Development

Development may be driven by the need to create additional network capacity for supplying increasing demand, or by the need to maintain or improve service levels. These drivers are monitored and trigger points set to identify when development projects are needed. When a development trigger is reached, several options are considered with the most cost efficient option selected as a solution. Standardisation is a valuable strategy in providing cost efficiencies in the delivery of capital projects.

Forecasts for demand growth are required to help TPCL predict when in future years the development triggers will be reached, thus enabling effective planning of future projects. Historical demand is trended and projected into future years while accounting for foreseeable future drivers that may cause a change to the current trend. Projections and associated planning are based on what is considered the most likely scenario, while TPCL's strategy of deferring capital expenditure until necessary, minimises the risk of overinvestment.

TPCL's work programme includes the following capital expenditure on network development for 2016/17:

- Consumer Connections – the provision of a connection point and additional network capacity as needed for new customers is budgeted at $3.4M.
- System Growth – Completion of upgrades to Waikiwi Substation budgeted at $1.6M. Construction of an upgraded substation at Centre Bush budgeted at $1.8M. Start of subtransmission line upgrade to 66kV from Centre Bush to Mossburn budgeted at $1.8M. Start of construction of an upgraded substation at Dipton budgeted at $0.9M. Design for upgrades at Riversdale and Lumsden substations budgeted at $0.3M each. Completion of 33kV circuit breaker installation at Edendale Substation budgeted at $0.1M. Upgrades of lines to 22kV in the Riversdale area to support load growth budgeted at $0.4M. Installation of Microwave radios to support the Oreti Valley Project budgeted at $0.5M
- Asset Relocations – a small budget of $54,000 is allowed for the relocation of miscellaneous poles or other assets as required.
- Quality of Supply – network upgrades to ensure sufficient voltage is delivered at customer connection points and automation of network equipment to allow faster location, isolation and supply restoration following a fault is budgeted at $750,000. Procurement of a mobile substation budgeted at $2.1M.
- Other Reliability, Safety and Environmental – a programme of Neutral Earth Resistor (NER) installations at TPCL substations budgeted at $0.8M, Retrofit of arc-flash protection on indoor 11kV switchboards budgeted at $0.2M. Installation of anti-climb devices on subtransmission towers budgeted at $0.3M

Total capital expenditure budget (including Asset Replacement and Renewal as described under "Lifecycle" below) is $25.02M for 2016/17, with budgets for the following two years set at $20.60M and $20.06M respectively.

0.5. Lifecycle

Once an asset has been installed it must be managed throughout its lifecycle to continue to fulfil its purpose for as long as required, and to minimise any adverse effects the asset might create. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service. At some point the asset will reach its end of life and will be retired from service. At that point the asset will be replaced (assuming the need remains) while the retired asset must be disposed of appropriately.

TPCL's work program includes the following capital expenditure on asset lifecycle management:

- Asset Replacement and Renewal – replacement of assets that are at the end of their economic life, or in some cases major refurbishment of assets to extend their expected life. The 2016/17 budget is $9.1M dominated heavily by line renewals and design for transformer renewals at Seaward Bush and Mataura Substations. The budgets for the following two years are set at $7.6M and $8.3M respectively, reflecting increased levels of line renewal work and the construction phase of transformer replacement at Seaward Bush and Mataura Substations.

The remainder of TPCL's works program is made up of the following operational expenditure on asset lifecycle management:

- Asset Replacement and Renewal – minor refurbishment work that doesn't impact on an asset's valuation is budgeted at $1.2M per annum ongoing.
- Vegetation Management – a budget of $1.32M is allowed yearly for the trimming of trees to prevent contact with overhead lines.
- Routine and Corrective Maintenance and Inspection – inspection, testing and investigation of network condition and resulting maintenance or repair as well as general routine asset maintenance and repairs budgeted at $3.4M each year ongoing.
- Service Interruptions and Emergencies – reactive work following network faults and customer outages to locate, isolate and repair faulty network assets budgeted at $2.9M each year ongoing.

Total network operational expenditure is budgeted at $8.8-8.9M each year ongoing. Additionally non-network operational expenditure will contribute $4.7-4.8M per annum.

0.6. Risk Management

TPCL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. Risks associated with TPCL's network are actively identified through regular reviews. Identified risks are then quantified in terms of the probability that an adverse occurrence will eventuate, and the scale of consequences of the occurrence for TPCL. A risk matrix is then used to systematically combine the probability and consequence into a resulting level of risk. Risk management looks at the most appropriate options for reducing risk to acceptable levels using the following general methods;

- Terminate – not proceeding with risky activity or eliminating a risk by choosing an alternative approach.
- Treat – reduce probability and/or consequence of an adverse occurrence
- Transfer – engage a more suitable party to effectively manage a certain risk
- Tolerate – accept a low level risk as tolerable (including residual risk after treatment of higher level risks)

TPCL's risk management framework recognises that resources for managing risk are finite. It may be appropriate to increase certain resources to manage risk appropriately however ultimately risk treatment measures identified need to prioritise using a philosophy of greatest risk reduction for the resources available. Many risks have been identified and are being managed under the following broad categories;

- Weather and Physical (including natural disasters and equipment failure)
- Safety and Environmental

- Human
- External Factors
- Corporate

For potential serious business interruptions TPCL has developed a Business Continuity Plan and has a Pandemic Action Plan for use in the outbreak of any highly infectious illness. TPCL also holds critical network spares and has contingency operating plans to support efficient restoration of supply following unexpected equipment failure as well as holding a range of business insurances.

0.7. Performance

For the financial year ending 31st March 2015 TPCL's performance in summarised as follows;

Capital expenditure was 16% over target due mainly to an unusually high level of consumer connection expenditure.

Operational expenditure was 16% over target due to major storms and rebuild of subtransmission line following failure of 13 poles.

Reliability performance on the overall network was above target given the high number of storms during the year with SAIFI 3% above target of 2.96 and SAIDI 33% over the target of 195.19 minutes.

Network efficiency performance was fair with the target of less than 7.0% for Loss Ratio achieved. The Capacity Utilisation target was not achieved, however the result was close to target.

Financial efficiency performance was slightly below than the targets set.

0.8. Capability to Deliver

TPCL has many systems, processes and tools to effectively and efficiently manage its network assets. The maintenance of these systems and the information that they contain requires dedicated staff. TPCL's information systems hold a great deal of data about its network assets including technical details, location, operational states and condition. This data is collated and displayed in various ways to help support efficient decision making for TPCL's asset management planning and activities.

TPCL's business is funded from the revenue received from customers via several electricity retailers and in return TPCL maintains a network for the conveyance of electricity to these customers within certain service levels. Significant expenditure is required each year to maintain network assets and to develop the network to meet increasing customer demand.

Staffing and contracting resources is an ongoing issue that TPCL is managing and TPCL's Annual Works Program recognises existing and future resourcing levels as constraints to be managed over time. With the internalising of PowerNet's field services in the eastern area of TPCL's network from 1st April 2016, TPCL will rely on internal field services to carry out much of the operational, maintenance and development work on its network, but it will also utilise local contractors where additional resources are required.

1. Background and Objectives

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 35,208 customer connections on behalf of twelve 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 Limited (EIL). 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.
- A 75.1% stake in OtagoNet. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of TPCL, EIL and ESL.
- A 25.9% stake in Peak Power Services Ltd, an electrical contracting company based in Frankton.
- A 25% stake in Southern Generation Ltd, a generation company with wind and hydro assets in New Zealand jointly owned with EIL and Pioneer Generation Ltd.

The 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.

1.1. Purpose Statement

The purpose of TPCL's Asset Management Plan (AMP) is to provide an internal governance and management framework for asset management practice on TPCL's network. Disclosure in this format is also intended to assist in meeting the requirements of Section 2.6, Attachment A and Schedules 11, 12 and 13 of the Electricity Distribution Information Disclosure Determination 2012.

1.2. Asset Management Objectives

TPCL's asset management objectives which this AMP endeavours to deliver are to:

- Set service levels of the electricity distribution services supplied by TPCL that will meet customer, community and regulatory requirements.
- Understand 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 an ever-increasing knowledge of TPCL's asset locations, ages and conditions as well as the assets' likely future behaviour as they age and may be required to perform at different levels.
- Have robust and transparent processes in place for managing all phases of the network life cycle from design, procurement and installation to disposal.
- Have adequate provision for funding all phases of the network lifecycle.
- Have adequately considered the classes of risk TPCL's network business faces and that there are systematic processes in place to manage identified risks.
- Make business decisions within systematic and structured frameworks.

This AMP is not intended to be a detailed description of TPCL's assets (these lie in other parts of the business), but rather 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. AMP Planning Period and Director Approval

TPCL's Asset Management Plan (AMP) is prepared annually by PowerNet however an "AMP update" is produced in place of a full AMP two years within each five year default price path period as allowed for by the Electricity Distribution Information Disclosure Determination 2012 (latest amendments incorporated). The AMP update which focusses on updates to the development and lifecycle works and expenditure is a cut down version of the full AMP represented by this document.

This latest edition was prepared during August 2015 to March 2016 and covers the ten year period from 1 April 2016 to 31 March 2026. It was approved by TPCL's Board on 31 March 2016 (see Appendix Directors Approval) and publicly disclosed at the end of March 2016.

There is a degree of uncertainty in any predictions of the future with the immediate future reasonably predictable and the longer term becoming more and more uncertain.

The first year of the AMP is considered reasonably certain. Planned capital works are generally well planned and only subject to minor variations. New customer connections are driven by turbulent commodity markets, public policy trends and possible generation opportunities so while trends are reasonably predictable, year to year variation around those trends can still be significant, especially with larger capacity connections that tend to have lower and more sporadic connection rates but have larger individual impact.

Maintenance works are relatively certain as most tasks tend to be ongoing, repeated year after year unless step changes are warranted due to age profiles or if new initiatives are introduced, but these changes are planned in advance. Reactive maintenance requirements are less predictable. Response to service interruptions is probabilistic by nature and due to the low number of faults on TPCL's network can be quite sporadic. Network faults on overhead parts of the network are even less predictable being heavily influenced by weather.

The two to four year timeframe has lower certainty. However customer connection rates, maintenance and response to service interruptions are expected to continue the current trend to a reasonable degree. Major projects are typically identified and scheduled however as detailed scope, design and costings are developed alternative options may be progressed influencing expenditure and timing. External influences tend to cause more minor projects to be considered within this timeframe each year especially the changing perceptions around health and safety.

The final five year period of the AMP's ten year planning horizon has little certainty if any. Projects for age based replacements can be proposed and growth trends can be used to predict when capacity triggers will be reached. However standards may change and new maintenance philosophies may be developed (and continual improvement in asset management practice means this is likely) potentially having a large impact on scope and timeframes for these projects. Experience shows these changes and other external influences are likely to introduce and reshape major and minor projects within this time frame but are very difficult to predict.

1.4. Drivers and Constraints

TPCL's business goals are driven by its stakeholder's interests, of which shareholder's expectations and meeting customer expectations have a primary influence. Also shaping business operation is the wider context in which the business operates which includes a number of drivers. These drivers range from governmental and regulatory strategies that may create incentives or impose constraints, to absolute issues such as the unpredictability of weather or the laws of physics.

This section describes the identification of TPCL's stakeholders, their interests in TPCL, how these interests are met and how conflicts between stakeholder's expectations are managed before identifying other influences that drive and shape TPCL's business.

Stakeholder Interests

The stakeholders TPCL has identified are listed in the following tables with the stakeholder's interests and how these interests are identified shown in Table 1 and Table 2 respectively. Table 3 then shows how stakeholder's interests are accommodated in TPCL's asset management practices. A stakeholder is identified as any person or organisation that does or may do any of the following:

- Have a financial interest in TPCL (be it equity or debt).
- Pay money to TPCL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to TPCL's network.
- Use TPCL's network for conveying electricity.
- Supply TPCL with goods or services (includes labour).
- Is affected by the existence, nature or condition of the network (especially if 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 or District Plan requirements).

Table 1: Key stakeholder interests

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

Interests:	Viability	Price	Quality	Safety	Compliance
Bankers	✓	✓		✓	✓

Table 2: Identifying stakeholder's interests

Stakeholder	How Interests are Identified
Southland Electric Power Supply (SEPS) Consumer Trust (Shareholder)	• By their approval or required amendment of the SOI • Regular meetings between the directors and executive
Connected Customers	• Regular discussions with large industrial customers as part of their on-going development needs • Customer consultation evenings (meetings open to public) • Annual customer surveys
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets monthly with Chief Executive and PNL Staff
Ministry of Business, Innovation & Employment	• Release of legislation, regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity Authority	• Weekly updates and briefing sessions • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity & Gas Complaints Commission	• Reviewing their decisions in regard to other lines companies
Councils (as regulators)	• Formally as necessary to discuss issues such as assets on Council land • Formally as District Plans are reviewed
Transport Agency	• Formally as required
Energy Safety	• Promulgated regulations and codes of practice • Audits of TPCL's activities • Audit reports from other lines businesses
Industry Representative Groups	• Informal contact with group representatives
Public (as distinct from customers)	• Word of mouth around the city • Feedback from public meetings
Mass-market Representative Groups	• Informal contact with group representatives
Staff & Contractors	• Regular staff briefings • Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Suppliers of Goods & Services	• Regular supply meetings • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet's CEO & CFO • By adhering to TPCL's treasury/borrowing policy • By adhering to banking covenants

Table 3: Accommodating Stakeholder's Interests

Interest	Description	How TPCL Accommodates Interests
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in TPCL.	Stakeholder's needs for long-term viability are accommodated by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital. In general terms this will need to be at least as good as the stakeholders could obtain from a term deposit at the bank plus a margin to reflect the ever-increasing risks to the capital in the business. Earnings are set by estimating the level of expenditure that will 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 what TPCL's customers want.	TPCL's total revenue is constrained by the price path threshold regime. Prices will be restrained to within the limits prescribed by the price path threshold, unless it comprises safety or viability. Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders. TPCL's pricing methodology is 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.	Stakeholder's needs for supply quality will be accommodated by focusing resources on continuity and restoration of supply. The most recent mass-market survey indicated a general satisfaction with the present supply quality but also with many customers indicating a willingness to accept a reduction in supply quality in return for lower line charges.
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 staff and contractors is ensured by providing all necessary equipment, improving safe work practices and ensuring that they are stood down in unsafe conditions. Motorists 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.
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.

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust and make the best use of their funds. This creates a primary driver for TPCL and formal accountabilities to the shareholder are in place for financial and network performance. See section Key Planning Docs (Statement of Intent).

Customers via the electricity retailers provide TPCL's revenue in return for the services provided by the TPCL network assets. Due to the importance TPCL places on meeting customer's expectations annual customer surveys are undertaken to monitor customer satisfaction with service level targets aimed at ensuring standards are maintained or improved. See sections Service levels and Performance for details of these surveys, customer feedback and performance targets TPCL sets.

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

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

Managing Conflicting Stakeholder Interests

When a conflict of stakeholder interests has been identified TPCL must arrive at an appropriate resolution. To achieve this outcome the following priority hierarchy is used to analyse the conflicting issues and options available:

1. **Safety**. Top priority is given to safety. The safety of staff, contractors and the public will not be compromised even if budgets are exceeded.
2. **Viability**. Second priority is viability (as defined above), because without it TPCL will cease to exist which makes supply quality and compliance pointless.
3. **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.
4. **Supply quality**. Supply quality is the fourth priority. Good supply quality makes customers, and therefore TPCL, successful.
5. **Compliance**. A lower priority is given to compliance that is not safety and supply quality related.

Once an appropriate resolution has been determined a recommendation will be presented to management. A decision may then be made by the management team or escalated to the TPCL Board if appropriate.

Other Influences

Other issues TPCL need to understand and around which strategies can be developed are as follows; these issues are not directly related to stakeholders but have a significant impact on TPCL's asset management practice.

- Competitive pressures from other lines companies which might try to supply TPCL customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with coal or oil at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, that could strand conventional wire utilities.
- Local, national and global economic cycles which effect growth and development.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- Interest rates which can influence the rate at which new customers connect to the network.

- Ensuring sufficient funds and skilled people are available long term to resource TPCL's service requirements.
- Technical regulations including such matters as limiting harmonics to specified levels.
- Safety requirements such as earthing of exposed metal and line clearances.
- Asset configuration, condition and deterioration. These parameters will significantly limit the rate at which TPCL can re-align their large and complex asset base to fit ever-changing strategic goals.
- The laws of physics which govern such fundamental issues as power flows, losses, 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 the transport agency required all poles to be moved back from the carriage way).

1.5. Strategy and Delivery

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

Vision Statement

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

Corporate Strategy

Key corporate drivers from TPCL's Strategic Plan are:

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

Asset Management Strategy

TPCL's asset management 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

Interaction of Goals/Strategies

TPCL’s vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 4.

Table 4: Corporate and Asset Management Strategy Linkage

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

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

Annual Works Programme

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

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

Annual Business Plan

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

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

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

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

Statement of Intent

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

The SOI includes financial performance projections for:

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

It also includes the quality performance projections for SAIFI and SAIDI which are set in the AMP Proposed Service Levels.

These projections are given over a three year period, 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.

1.7. Interaction between Objectives, Drivers, Strategies and Key Documents

The interaction between TPCL's corporate vision, asset management objectives, business drivers, strategies and key planning documents is shown in Figure 1 and is summarised as follows.

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

The asset management strategies are designed to provide guidance in achieving the asset management objectives while aligning with TPCL's vision and corporate strategies. Stakeholder interests and expectations as well as other external influences create business drivers which shape the strategies developed. They also shape the asset management objectives and even the corporate vision however these tend to remain relatively consistent whereas strategies tend to be more flexible and evolve as the driving factors change with time.

The asset management strategies are applied to the existing network assets to meet the asset management objectives including realising development opportunities as they arise. This involves the setting of performance targets which leads the AWP development.

The AMP incorporating (and especially) the AWP, which is prepared in a format assisting communication of key deliverables, sets and drives asset management works and expenditure to reshape network assets. Delivery of the AWP projects over time creates a network closely aligned with the asset management strategies, objectives and ultimately TPCL's corporate vision while meeting stakeholder expectations, especially the shareholder and network customers.

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

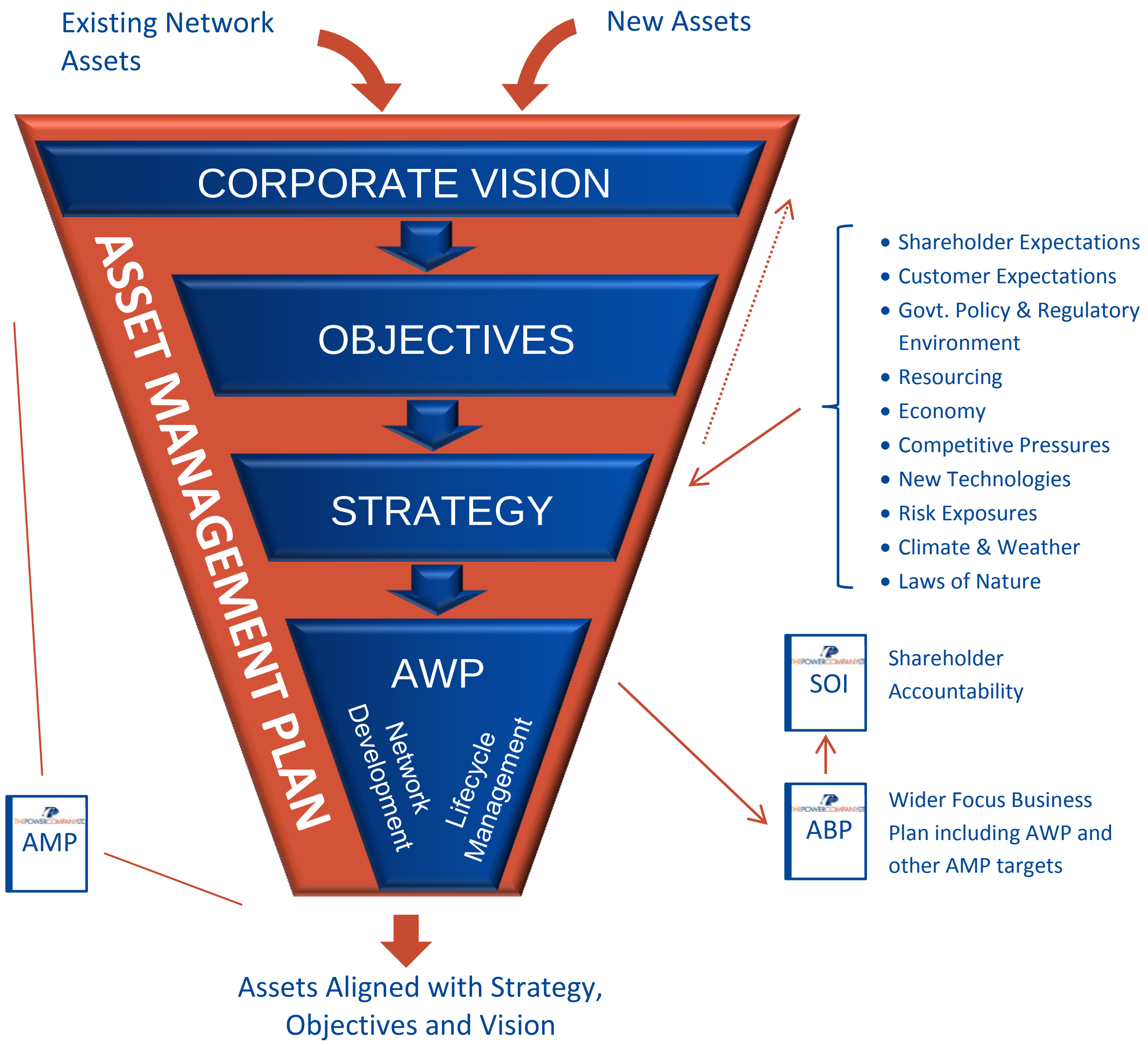

Figure 1: Interaction of Objective, Strategies and Key Plans

1.8. Accountabilities and Responsibilities

Accountability at Ownership Level

TPCL has a single shareholder – The SEPS Consumer Trust. The Trust currently have five trustees who collectively possess 68,165,402 shares in TPCL on behalf of the Trust:

- Jim Hargest (Chairman)
- Stuart Baird
- Carl Findlater
- Steve Canny
- 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.

Accountability at Governance Level

As TPCL uses PowerNet as their contracted management company to manage the assets there is effectively a two-tier governance structure. The first tier of governance accountability is between TPCL's Board and shareholder with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes TPCL's Board intimately accountable to TPCL's shareholder for these important asset management outcomes whilst the inclusion of financial targets in the statement makes TPCL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI. TPCL currently has five directors:

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

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

Accountability at Executive Level

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

Accountability at Management Level

There are 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 his responsibility for preparation of the AMP which will guide the nature and direction of the other managers' work.

Accountability at Operational Level

PowerNet's Network Assets and Major Projects Team (under the Chief Engineer), Technical and Network Performance Team and Customer, Metering and Distribution Services Team each manage their respective major projects, technical projects and distribution projects which make up the AWP. Their objectives are to deliver the AWP projects on time, to scope and to budget while also delivering to the AWP works category and overall CAPEX and OPEX budgets. Major projects typically utilise external consultants and contractors while technical and distribution projects utilise PowerNet's in-house field services.

Where 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 schedule.

Accountability at Work-face Level

PowerNet's internal field staff sit and are managed within PowerNet's Technical and Network Performance Team and Customer, Metering and Distribution Services Team to deliver work respectively divided into technical or distribution projects. External contractors are typically used to deliver major projects and occasionally when necessary to supplement workforce capacity or skillsets and include;

- DECOM Limited
- Broadspectrum Limited
- Electrix Limited
- Peak Power Services Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Asplundh Tree Expert (NZ) Limited
- Cory's Limited
- Consultants (Beca, Edison, Mitton Electronet, ProTechtion Consulting, Mitchell Partnerships)

The principal accountability mechanism when utilising these external contractors is through contracts that reflect the outcomes PowerNet must create for TPCL.

Key Reporting Lines

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

Figure 2:

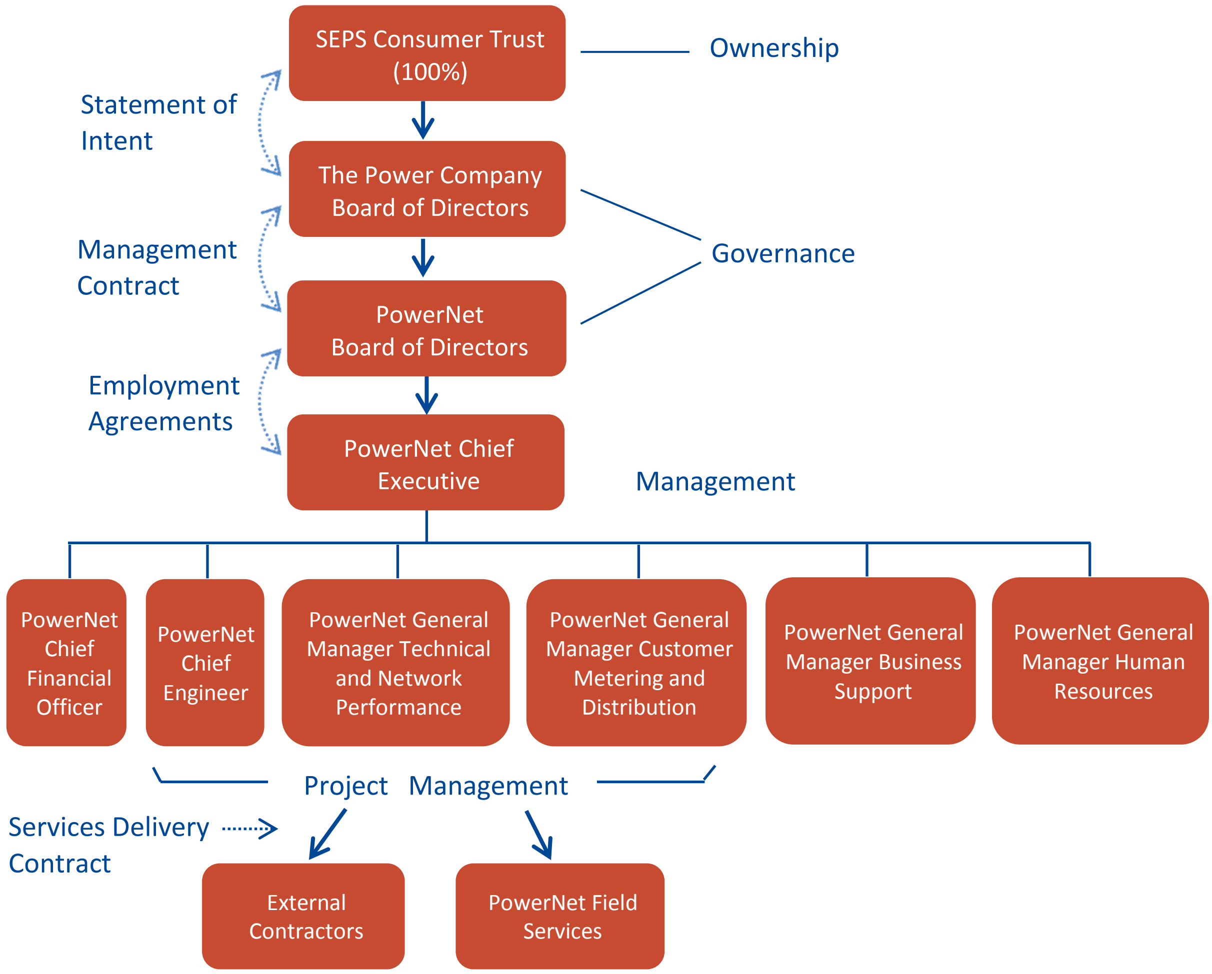

Figure 2: Governance and management accountabilities

The TPCL board receives monthly reports that cover 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 supply quality 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 line charges received
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network
- Works Programme – monthly, year-to-date (YTD) and project life expenditure actuals and forecasts on each works programme item, with notes on major variations

Any new project over $100,000 added or variation by more than +10% or -30% to the approved AWP will need to gain approval from the TPCL Board. Large projects with capital budgets exceeding $1,000,000 are required to be supported by a business case explaining the project scope and justification. The business case will generally include a detailed cost benefit analysis of the recommended scope over alternative options.

Each level of management has defined financial authority limits set out in the PowerNet Financial Authorities Policy. It includes general financial authority levels and increased levels specifically for project work previously approved in the AWP. Generally most projects in the AWP are approved by the TPCL Board as part of ABP process in the previous year.

1.9. AMP Communication and Participation Processes

A first draft of the AMP is generally created by November each year and is circulated around management for review and comment. The AWP is developed concurrently as part of the AMP process and has generally been through several revisions by the time it is circulated with the first AMP draft.

Customer perceptions and expectations gauged from surveys and customer consultation evenings are compared with the performance targets set in the previous year's AMP. Any improvements or changes deemed appropriate from this process will be incorporated into the AMP and AWP as necessary.

Management and Operations Participation

The planning team is in regular contact throughout the year with those responsible for implementing the current AWP to monitor progress and any variations as they arise with large capital projects covered in a formal monthly review meeting. Any changes are consolidated into the initial AWP revision and further revisions are developed in consultation with the management, project managers and field staff who will be involved in its implementation.

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

Governance Participation

The initial consolidated AWP is submitted to the TPCL Board supported by a presentation. Any business cases required for large capital projects or other papers covering any novel projects are submitted in advance and will be included in the AWP presentation. After their initial review the Board may request clarifications or changes which are then incorporated into the AWP. These changes tend to be more commercially motivated but will also recognise the need to address any identified health and safety related issues as a high priority. Any recommended changes to the wider AMP that the Board may need to consider, for example strategy updates, may be presented at this stage for review.

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

Post Disclosure Communication

Once the AMP has been finalised and publically disclosed project scopes are produced for non-routine projects that will be initiated in the next year. These scopes are passed to the relevant project managers to ensure that sufficient detail has been provided for each project in the AWP to proceed in line with the planner's expectation.

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

Again planners are in contact with the project managers throughout the year to monitor progression of the AWP and ensure agreement on any significant variations as design and implementation progresses.

1.10. Assumptions

Planning is based on the assumption that the scenario considered most likely will eventuate, except for ongoing but sporadic (typically reactive) work, where budgets reflect a longer term average. This philosophy is used to minimise variation to performance targets (especially financial) including average performance over the short to medium term. Exceptions are made where the consequences of this assumption are asymmetric, for example building additional capacity early results in a slight overinvestment whereas building additional capacity too late may have much greater consequences such as equipment damage or inability to supply customer load.

It is assumed that growth will continue to occur at an accelerated rate in the Northern Southland Area due to increased irrigation. Irrigation combined with more stringent requirements on dairy milk chilling will increase load across pastoral Southland.

Otherwise it is assumed that growth rates will be similar to historic trends. Developers rarely let TPCL know of their plans keeping large projects confidential until the last minute. Any major development could require significant new network to be built however planning for possibilities would inevitably lead to overinvestment. No major developments are anticipated in coal, gas, oil, mineral extraction, etc. or processing either in the region or off shore which might significantly increase electrical load in the network area. Similarly no material decline in meat or wool markets is anticipated.

No step changes in underlying growth are considered likely based on historical trending over a long period. Population growth for sizing of equipment is based on the high projection.

Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.

Distributed generation is assumed to develop slowly with little impact over the ten year planning horizon. The current rate of connection is quite manageable with the first adopters typically reducing load on network assets. A large increase in connections could lead to upgrade requirements to maintain supply quality which could come about through government incentives or unexpected technology breakthroughs.

It is assumed that plug-in electric vehicles will not penetrate the local vehicle fleets sufficiently to require investment in extra capacity within the planning period. At present electric vehicle uptake is concentrated in the main centres, and vehicle owners are encouraged to charge their vehicles during off-peak periods.

No changes are anticipated in present regulation. Any changes are likely to add additional cost. For example outages less than one minute aren't recorded against reliability KPIs; this allows a lower cost network automation solution which would be less appropriate if the one minute allowance were removed.

The standard life of assets is based on the ODV asset life, with actual replacement done on a condition basis. Equipment housed indoor will often exceed ODV life whereas the harsher coastal environment tends to shorten life for outdoor assets in these regions.

Abnormal price movements are difficult to predict and not allowed for in estimates.

Industry specific inflationary rates where available are used to account for increasing costs; otherwise adjustments are made according to CPI.

1.11. Potential Variation Factors

- Cost and time estimates
- Variation in inflation rates and/or exchange rates
- Staffing resource loss or inability to recruit as required
- Reactive work carrying from the estimated level – e.g. due extreme weather
- Equipment failure (especially large capital plant) which may influence future economic options
- New safety issues identified and initiatives created
- Reprioritisation as new work activities are identified
- Detailed analysis of the available options for projects commencing in the short term, which may indicate an alternative approach is preferable to that assumed for long-range forecasting
- Demand growth variation from anticipated levels, especially new large industry or customers or conversely loss of existing industry or customers

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2. Assets Covered

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. Service Areas

TPCL's distribution area broadly covers all of Southland as depicted in Figure 3 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. This broadly corresponds to the Southland and Gore District Council jurisdictions.

Figure 3: TPCL Distribution Area

Topography varies as follows:

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

- Uninhabited mountains and bush in the west and north-west of the area.

Key Industries

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

- Markets for basic and specialised meats such as beef, mutton and lamb.
- Markets for dairy products.
- Markets for processed timber.
- Markets for black and brown coal.
- Government policies on mining of coal.
- Government policies on forestry and nitrogen-based pastoral farming.
- Access to water for crop and stock irrigation, especially in northern Southland.

The impact of these issues is broadly discussed in Table 5.

Table 5: Impact of key issues

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 or expansion of demand by these industries.	Reduces / increases asset utilisation. Possible capacity stranding.
Shifting markets for timber.	May lead to a contraction in demand by these industries.	Reduces asset utilisation. Possible capacity stranding.
Shifting markets for coal.	May lead to a contraction in demand by these industries.	Reduces asset utilisation. Possible capacity stranding.
Government CO_2 Policy.	May lead to a contraction 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 - three 33kV cables each supplying an 11½/23MVA 33/11kV power transformer (N-1 requirement[1]).

- 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[2]).
- Open Country Dairy, at Awarua – supplied off local feeder.
- South Pacific Meats, at Awarua – supplied off local feeder.

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

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

- 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).
- Southern Generation Limited Partnership, windfarm at Flat Hill – exclusive 11kV feeder at Bluff.
- 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.

Load Characteristics

Domestic: Standard household demand peaks in the morning (8am) and evening (6:30pm). The use of heat pumps is increasing electricity usage, with no noticeable impact over the summer hot period yet. Peaks normally occur in the winter months as heating requirements increase. A typical daily domestic load profile and a typical annual domestic load profile are shown in Figure 4 and Figure 5 respectively.

Figure 4: Typical Domestic Daily Load Profile (09 July 2014, Waikiwi CB3)

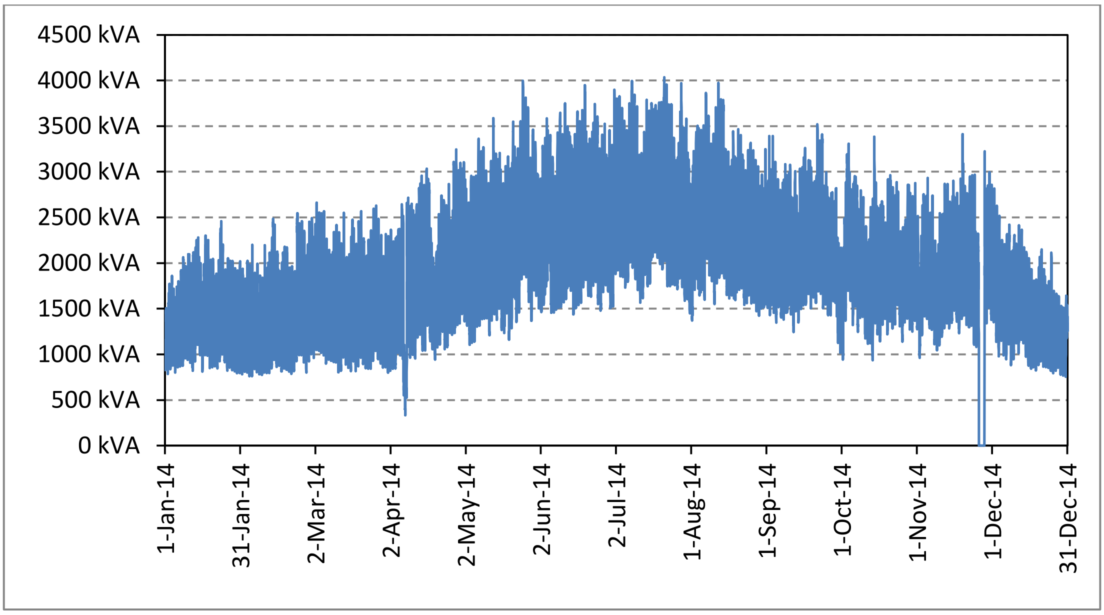

Figure 5: Typical Domestic Feeder Yearly Load Profile (Waikiwi CB3)

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. A typical daily milking load profile is shown in Figure 6

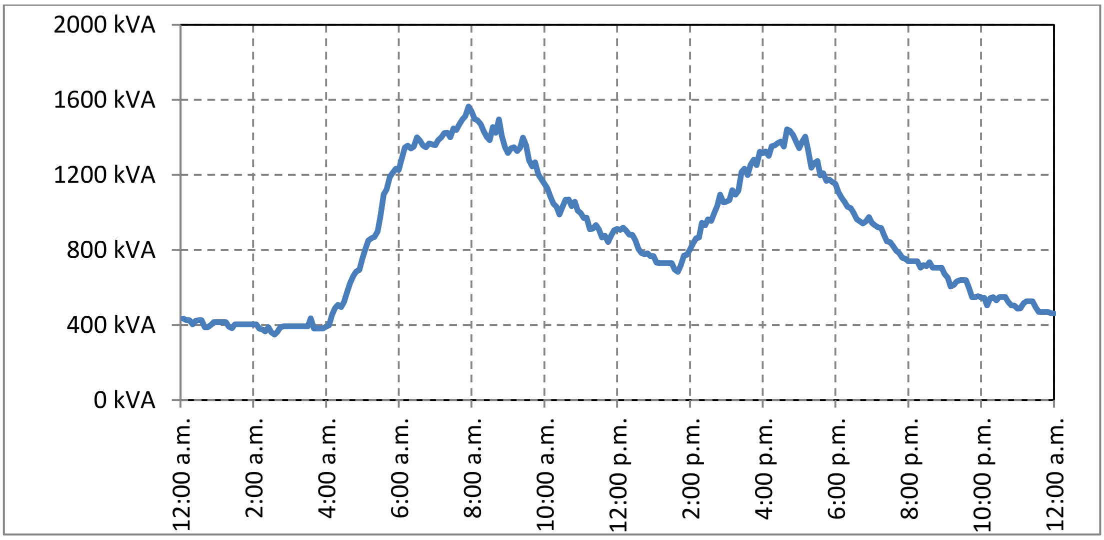

Figure 6: Typical Daily Milking Load Profile (01 October 2014, Centre Bush CB2)

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. A typical annual dairy processing plant profile is shown in Figure 7

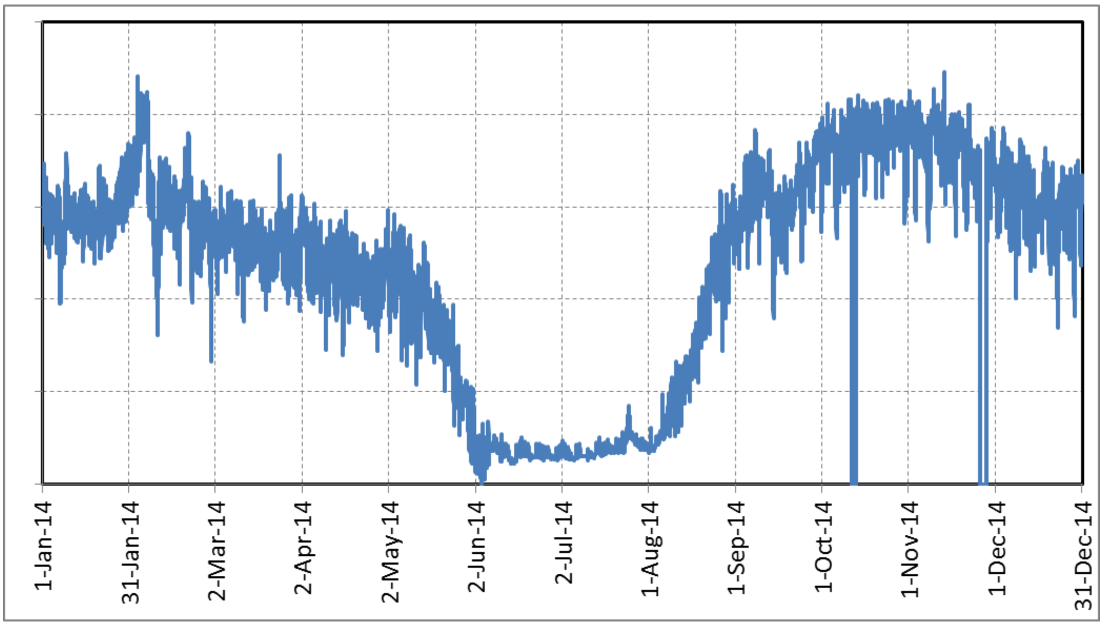

Figure 7: Dairy Processing Plant annual load profile

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

Energy and Demand Characteristics

Key energy and demand figures for the year ending 31 March 2015 are as shown in Table 6.

Table 6: Energy and Demand

Parameter	Value	Long-term trend
Energy Conveyed	754.36 GWh	Steady Growth +1.0-1.2%
Maximum Demand[3]	132.815 MW	Steady
Load Factor	65%	Steady
Losses	6.8%	Steady

It is particularly hard to extract underlying growth rates from historical data as both maximum demands and total energy conveyed, as recorded for any year, are heavily dependent on the weather. This variation tends to swamp the effect of the relatively low growth rates. Mathematical treatment such as "best fit" curve application yields completely different results when applied to different time periods i.e. previous 5 years, 10 years, 20 years etc. Shorter time periods giving meaningless results due to huge variation between inclusion and exclusion of a particular year (say between 4 years trend or 5 years trend) and longer time periods do not account for recent trends. Growth rates therefore tend to reflect "gut feel" more than anything and accordingly certainty with the growth rates shown in Table 6 is low. Forecasting Demand and Constraints looks at the analysis, trending and forecast of growth for TPCL.

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

2.2. Network Configuration

To supply TPCL's 35,208 customers TPCL owns and operates an electrically contiguous networks which is supplied by Four Grid Exit Points (GXP) at Invercargill, North Makarewa, Gore and Edendale and by up to 72MW of injected Generation from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station and Southern Generation Limited's Flat Hill wind farm.

Bulk Supply Points and Embedded Generation

Invercargill GXP

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

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

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

North Makarewa GXP

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

TPCL owns the following assets within the GXP land area:

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

Edendale GXP

Edendale GXP is supplied by two 110kV single-circuit pole lines from Gore GXP via Brydone GXP and from Invercargill GXP. TPCL takes supply to its 33kV bus at Edendale by two incomers from two 30MVA transformers. 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.

Gore GXP

Gore GXP is supplied by three 110kV single circuit pole lines, from Roxburgh power station, Invercargill GXP via Edendale and Brydone and interconnected to Berwick and Halfway Bush GXP's. TPCL takes supply from the two 110/33kV 30MVA transformers at Gore to six 33kV feeders. 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.

Table 7: TPCL Bulk Supply Characteristics

	Voltage	Rating	Firm Rating	Maximum Demand 2014/15	LSI[4] Coincident Demand 2014/15
Invercargill GXP	220/33kV	240MVA	109MVA	88.20MW (13/08/2014 08:00)	79.72MW (10:30 26/05/2014)
TPCL	*(GXP assets shared with EIL)*			35.62MW (18/09/2014 08:00)	27.35MW (10:30 26/05/2014)
North Makarewa GXP	220/33kV	120MVA	67MVA	49.26MW (18/12/2014 08:30)	36.43MW (10:30 26/05/2014)
Gore GXP	110/33kV	60MVA	37MVA	28.14MW (08/08/2014 12:00)	26.90MW (10:30 26/05/2014)
Edendale GXP	110/33kV	60MVA	34MVA	26.73MW (13/11/2014 16:00)	11.73MW (10:30 26/05/2014)
White Hill Generation	66kV	56MVA	0MVA	49.56MW (17/04/2014 08:00)	2.33MW (10:30 26/05/2014)
Monowai Generation	66kV	7.5MVA	5MVA	6.63MW (30/11/2014 02:00)	4.56MW (10:30 26/05/2014)
Flat Hill Generation	11kV	6.8MVA	0MVA	-	-
Mataura Generation	11kV	0.9MVA	0MVA	0.83MW (11/06/2014 21:00)	0MW (10:30 26/05/2014)

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

Subtransmission

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.

[4] LSI = Lower South Island

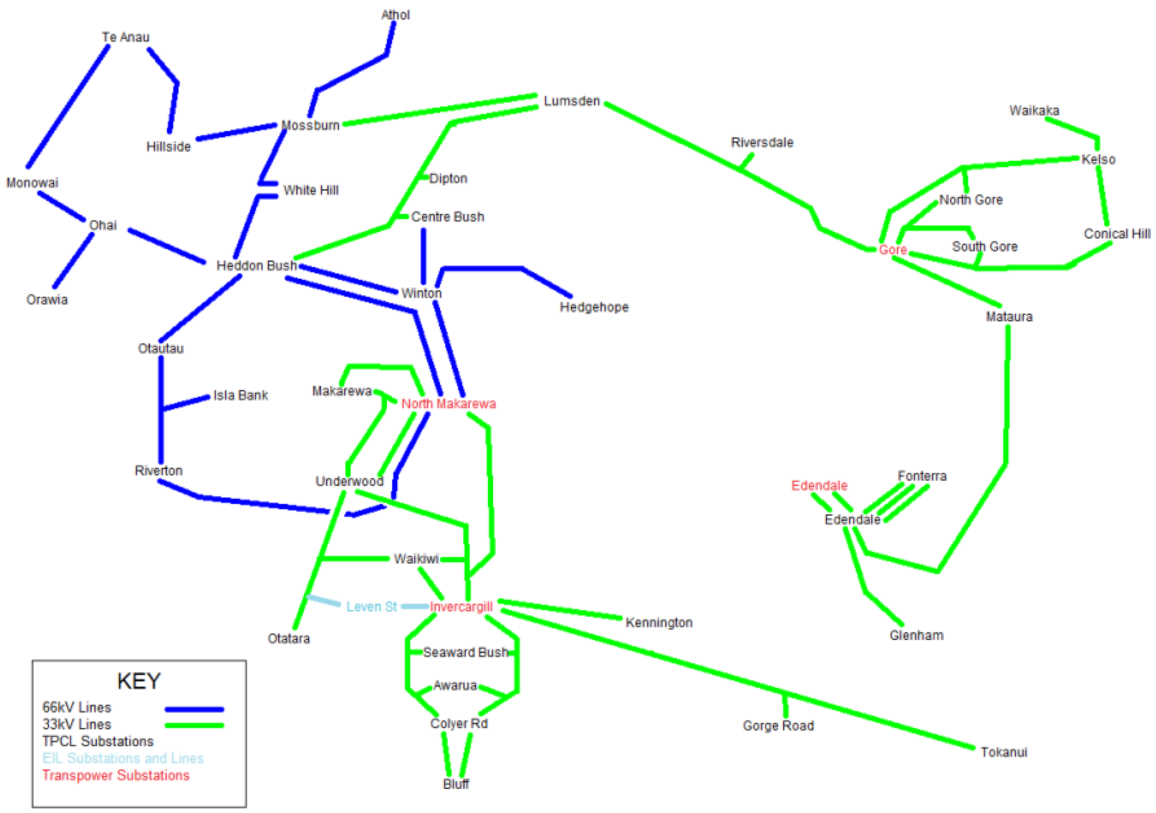

Figure 8: Subtransmission network

The subtransmission network comprises 444km of 66kV line, 449km of 33kV line, and 6km of 33kV cable 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.

Zone Substations

TPCL owns and operates the following 35 zone substations across Southland. TPCL also takes an 11kV supply for two feeders supplied from EIL's Racecourse Road substation to supply TPCL customers in areas at the eastern edge of Invercargill. Descriptions for TPCL's zone substations are given in Table 8

Table 8: TPCL's Zone Substations

Zone Substation	Nature of Load	Description of substation
Athol	Villages of Athol and Kingston, rural farms with summer irrigation.	66kV line from Mossburn onto a 66kV circuit breaker and 66/11+11kV 5MVA transformer supplying an indoor 22kV switchboard with two 11kV feeders.
Awarua	Single large industrial customer.	Simple outdoor site with two 33/11kV transformers and associated outdoor 33kV and 11kV circuit breakers.
Bluff	Predominantly urban domestic load in Bluff, but including one large and a few medium industrial customers. One large windfarm with exclusive 11kV feeder.	Medium complexity outdoor substation with two 33/11kV 6/12MVA transformers, these supply an indoor 11kV switchboard with four feeders.
Centre Bush	Predominantly rural load in the middle of the Southland Plains.	Simple tee connected 33/11kV 5MVA transformer with three outdoor 11kV feeders.
Colyer Road	Predominantly three large industrial customers with some minor rural load to the south-west.	Substantial two 33/11kV 6/12MVA transformer substation with (n-1) supply. Indoor 33kV switchboard with seven circuit breakers. Indoor 11kV switchboard with four feeders.
Conical Hill	Predominantly rural load. Old sawmill next to site, which has been moth-balled.	Large outdoor substation with 33kV circuit breakers on two incoming supplies from Gore via South Gore substation and also from Gore via Kelso substation. Two 33/11kV 5MVA transformers supply a full outdoor 11kV structure with incomer circuit breakers and four feeders.
Dipton	Predominantly rural load in the north of the Southland Plains.	Simple tee connected 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.	Triple 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, three to Edendale Fonterra, one to Glenham and one to Mataura. An indoor 11kV switchboard with seven feeders.
Glenham	Glenham village, rural farms.	33kV line from Edendale onto a 33kV circuit breaker and 33/11kV 1.5MVA transformer with two outdoor 11kV feeders.
Gorge Road	Gorge Road village, rural farms.	33kV line from Invercargill that continues on to supply Tokanui via a 33kV line circuit breaker. Substation has simple tee into single 33kV CB. 33kV bus branches into two motorised switches onto dual 33/11kV 1.5MVA transformers. Indoor 11kV switchboard with three 11kV feeders.
Heddon Bush	Step down from 66kV to 33kV.	Large outdoor 66kV switchyard with a single 66/33kV 10/15MVA transformer.

Zone Substation	Nature of Load	Description of substation
		Has three 66kV supply routes from North Makarewa and supplies two end of the North-western 66kV ring.
Hedgehope	Hedgehope Village, rural farms	66kV line from Winton onto a 66kV circuit breaker and 66/11+11kV 5MVA transformer supplying an indoor 22kV switchboard with three 11kV feeders.
Hillside	The Key village, rural farms.	Medium outdoor substation supplied by two 66kV lines with 66kV circuit breakers, a single 66/11kV 2.25MVA transformer, three single phase voltage regulators, and three outdoor 11kV feeders.
Kelso	Tapanui township, rural farms.	Medium outdoor 33kV structure with two supplying lines from Gore and a 33kV feeder to Waikaka. Single 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Kennington	Industrial area with various manufacturing process and few residences, Woodlands village, rural farms.	Medium outdoor 33kV structure with 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 five 66kV circuit breakers. A 66/33kV 30/40MVA transformer supplying load via a 3MVA 11kV tertiary winding. Backup via a 33/11kV 1.5MVA transformer and single 33kV backup line from Lumsden. Outdoor switchboard with incomer circuit breaker and four 11kV feeders. 66kV lines as part of North-western 66kV Ring. 66kV feeder to Athol and 66kV breaker for future 66kV supply to

Zone Substation	Nature of Load	Description of substation
		Lumsden.
North Gore	Town of Gore and rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV transformers (10MVA and 10/20MVA) supplying an indoor 11kV switchboard with four 11kV feeders.
Ohai	Town of Ohai and rural farms. Supplies one open-cast coal mine.	Large 66kV structure with lines from North Makarewa GXP, via Winton and Heddon Bush and to Monowai Power Station. Also supplies a 66kV feeder to Orawia. Each circuit is protected by a 66kV circuit breaker. One 66/11kV 5/7.5MVA 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 circuit breaker and four 11kV feeders.
Otatara	Town of Otatara and a few farms.	33kV line from Invercargill into simple outdoor substation with single 33/11kV 5MVA transformer supplying an outdoor 11kV structure with incomer circuit breaker and three 11kV feeders.
Otautau	Town of Otautau, rural farms.	Medium 66kV structure with lines from North Makarewa GXP via Heddon Bush and Riverton. These lines tee onto a single 66kV circuit breaker supplying one 66/11kV 5/7.5MVA transformer. Outdoor 11kV structure with incomer circuit breaker and five feeders.
Racecourse Road (EIL)	Eastern area next to Invercargill city, mix of urban, lifestyle blocks and rural. Includes major Hotel/Motel complex.	Two 11kV feeders from the indoor switchboard at Electricity Invercargill Ltd Racecourse Road substation.
Riversdale	Town of Riversdale, village of Waikaia and rural farms, some with summer irrigation.	Small outdoor 33kV structure with main supplying line from Gore, with a back line to Heddon Bush via Lumsden. Single 33kV circuit breaker and 33/11kV 5MVA transformer. Outdoor 11kV structure with incomer circuit breaker and four 11kV feeders.
Riverton	Town of Riverton, small fish processing, rural farms	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 5/7.5MVA transformers. Part of southern 66kV ring supplied from North Makarewa. Indoor 11kV switchboard with six feeders.
Seaward Bush	South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant, rural Farms.	Medium complexity outdoor substation with two 33/11kV 10MVA transformers, these supply an indoor 11kV switchboard with five feeders. 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.

Zone Substation	Nature of Load	Description of substation
		Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders. One 33kV line continues onto Conical Hill substation.
Te Anau	Towns of Te Anau and Manapouri, rural farms.	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 9/12MVA transformers. Part of northern 66kV ring supplied from Heddon Bush. Indoor 11kV switchboard with five feeders.
Tokanui	Villages of Waikawa, Fortrose, Curio Bay and Tokanui, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer. Outdoor 11kV structure incomer circuit breaker and two 11kV feeders. 33kV line from Invercargill via Gorge Road.
Underwood	Major Meat processing plant, town of Wallacetown, rural farms.	Large 33kV structure with three 33kV circuit breakers, supplying two 10/20MVA transformers. An indoor 11kV switchboard with four feeders. 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. Indoor 11kV switchboard has four feeders.
Winton	Town of Winton, Villages of Lochiel and Browns, Large Sawmill, Limeworks, rural farms.	Winton is on the southern 66kV ring supplied from North Makarewa, with two lines from North Makarewa and Heddon Bush. Two 66/11kV 6/12MVA transformers supplying a full indoor 11kV switchboard with seven feeders.

Distribution Network

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).

The 11kV distribution network construction is 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[5] or XLPE[6] cable.
- CBD areas tend to be PILC cable unless this has been replaced, which will almost always be with XLPE cable.

TPCL's split of 11kV distribution network on a per substation basis is presented in Table 9. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Table 9: 11kV Distribution network per substation

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	123.9	6.4	207	1.6
Awarua	11.8	2.0	39	2.83
Bluff (TPCL)	34.1	0.5	149	4.3
Centre Bush	237.3	0.0	576	2.4
Conical Hill	164.7	0.3	297	1.8
Dipton	188.4	0.2	379	2.0
Edendale Fonterra	0.0	0.0	1	
Edendale	295.9	4.0	1385	4.6
Glenham	192.0	0.0	399	1.9
Gorge Road	164.6	0.0	391	2.4
Hedgehope	139.9	0.5	315	2.2
Hillside	226.9	2.3	354	1.5
Kelso	427.1	0.4	1309	3.1
Kennington	171.1	3.0	736	4.2
Lumsden	249.5	4.1	968	3.8
Makarewa	278.1	2.4	1154	4.1
Mataura	231.7	5.2	1278	5.4
Monowai	47.2	0.3	100	2.1
Mossburn	240.8	2.8	523	2.1
North Gore	263.1	3.7	2676	10.0
Ohai	315.9	3.0	779	3.7
Orawia	61.7	4.9	950	3.0
Otatara	211.9	1.0	1221	18.3
Otautau	27.9	2.8	890	4.2
Racecourse Road (TPCL)	405.7	2.5	453	14.7
Riversdale	312.9	6.9	1305	3.2
Riverton	152.7	6.0	2050	6.4
Seaward Bush	187.4	5.9	2378	15.0
South Gore	175.0	39.1	2421	12.5
Te Anau	229.6	0.6	2262	10.6
Tokanui	64.0	1.9	568	2.5
Underwood	405.7	2.5	580	8.8
Waikaka	108.0	0.2	257	2.4

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

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

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Waikiwi	95.1	13.5	3280	30.2
Winton	465.3	8.0	2624	5.5
Unallocated	0.4	0.6	0	
			Average	**5.1/km**

Distribution Substations

Just as zone substation transformers form the interface between the subtransmission and the 11kV distribution networks, distribution substations form the interface between the 11kV distribution and 400V distribution networks. The distribution substations range from 1-phase 0.5kVA pole-mounted transformers to 3-phase 1,500kVA ground-mounted transformers supplied via circuit breaker ring main units. These larger substations typically supply special customers, like the Open Country Dairy processing plant at Awarua. Table 10 shows distribution transformer numbers by rating.

Table 10: Number of distribution substations

Rating	Pole	Ground
1-phase up to 15kVA	4427	24
1-phase 30kVA	611	11
1-phase 50kVA	5	1
3-phase up to 15kVA	1564	6
3-phase 30kVA	2204	38
3-phase 50kVA	1000	35
3-phase 75kVA	254	10
3-phase 100kVA	187	78
3-phase 200kVA	116	188
3-phase 300kVA	47	100
3-phase 500kVA	2	39
3-phase 750kVA	-	22
3-phase 1,000kVA	-	12
3-phase 1,500kVA	-	2
Total	**10417**	**566**

Each distribution transformer has medium voltage (MV) protection generally provided by fuses but some larger units by circuit breakers controlled by basic overcurrent and earth fault relays. This is generally applied as individual protection for each site. Group protection is used where a single fuse is located at the take-off from the main feeder 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[7] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

[7] 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.

Low Voltage Network

The 230/400V Low Voltage (LV) network is predominantly clustered around each distribution transformer. The coverage of each individual distribution transformer tends to be limited by volt-drop to about a 200m radius.

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

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

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

TPCL's split of LV network on a per substation basis is presented in Table 11. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Table 11 Low Voltage network per substation

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	8.12	2.08	207	20.29
Awarua	0.42	0.01	39	89.56
Bluff	6.17	0.09	149	23.77
Centre Bush	14.50	0.73	576	37.83
Conical Hill	8.93	0.27	297	32.29
Dipton	10.50	0.44	379	3.47
Edendale Fonterra	0.00	0.00	1	
Edendale	45.21	2.62	1385	28.96
Glenham	12.82	0.47	359	27.02
Gorge Road	13.94	0.44	391	27.18
Hedgehope	11.29	1.00	315	25.63
Hillside	3.63	0.60	354	83.81
Kelso	31.74	1.63	1309	39.22
Kennington	3.52	0.12	736	201.87
Lumsden	16.61	2.88	968	49.68
Makarewa	44.69	2.43	1154	24.49
Mataura	31.04	1.83	1273	38.72
Monowai	1.07	0.71	100	56.18
Mossburn	9.18	1.52	523	48.86
North Gore	54.58	10.99	2676	40.81
Ohai	25.39	0.33	779	30.29
Orawia	28.37	2.91	950	30.37
Otatara	28.10	10.07	1221	31.98
Otautau	24.02	3.83	890	31.96
Racecourse Road (TPCL)	9.49	7.64	453	26.44
Riversdale	33.26	1.32	1305	37.73
Riverton	63.64	6.82	2050	29.09

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Seaward Bush	49.08	24.81	2378	32.18
South Gore	44.88	14.96	2421	40.46
Te Anau	12.67	54.51	2262	33.67
Tokanui	26.14	1.54	568	20.52
Underwood	16.51	2.20	580	31.01
Waikaka	6.93	0.13	257	36.38
Waikiwi	75.11	28.06	3280	31.79
Winton	59.10	19.20	2624	33.51
Unallocated	9.72	8.39	0	0.00
			Average	**33.28/km**

Customer Connection Assets

TPCL has 35,208 customer connections - for which revenue is earned for providing a connection to the network via the twelve retailers which convey electricity over the network. All of the "other assets" convey energy to these customer connections and essentially are a cost to TPCL that has to be matched by the revenue derived from the customer connections. These customer connections generally involve assets ranging in size from a simple fuse on a pole or in a suburban distribution pillar to dedicated lines and transformer installations supplying single large customers. The number and changes over the year are shown in

Table 12.

Table 12: Classes of Customer Connections

	Small (≤ 20kVA)			Medium (21 – 99kVA)			Large (≥100kVA)			
	8kVA 1ph	10% Fixed Option	20kVA 1ph	15kVA 3ph	30kVA 3ph	50kVA 3ph	75kVA 3ph	100kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	Total
Apr-14	1764	6236	21249	391	3097	1523	221	51	81	167	34780
May-14	1768	6465	21267	390	3090	1528	220	52	81	169	35030
Jun-14	1770	6447	21276	391	3089	1527	218	52	80	175	35025
Jul-14	1774	6477	21262	391	3082	1532	220	51	79	176	35044
Aug-14	1779	6440	21317	390	3081	1536	219	53	79	176	35070
Sep-14	1776	6513	21283	390	3077	1536	220	53	79	177	35104
Oct-14	1781	6512	21311	392	3073	1536	221	53	80	178	35137
Nov-14	1786	6508	21312	394	3072	1538	222	54	79	178	35143
Dec-14	1787	6513	21342	396	3071	1542	223	54	78	179	35185
Jan-15	1782	6938	20912	396	3063	1543	225	54	79	181	35173
Feb-15	1777	7112	20754	395	3061	1544	222	56	79	182	35182
Mar-15	1781	7185	20701	395	3050	1550	228	56	79	183	35208

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.

TPCL has a range of other assets to provide control or other auxiliary functions as described in Table 13.

Table 13: TPCL's Other Assets

Load Control Assets	
Ripple Injection Plant and Receivers	TPCL currently owns and operates four main 33kV 216⅔Hz 125kVA ripple injection plants at Invercargill, North Makarewa, Gore and Edendale along with a backup 66kV 216⅔Hz 125kVA ripple injection plant at Winton. At Invercargill, EIL has the same size ripple plant as TPCL and each can act as a backup for the other. Ripple relays at customer's premises respond to the injected ripple signal and switch controllable load (such as hot water cylinders and night-store heaters) providing effective load control for the network.
Protection and Control	
Circuit Breakers	Circuit breakers provide switching and isolation points on the network and generally work with protection relays, to provide automatic detection, operation and isolation of faults. They are usually charged spring or DC coil operated and able to break full load current as well as interruption of all faults.
Protection Relays	Protection relays have always included over-current and earth-fault functions but more recent equipment also includes voltage, frequency, directional and circuit breaker fail functionality in addition to the basic functions. Other relays or sensors may drive circuit breaker operation. Examples include transformer and tap changer temperature sensors, gas accumulation and surge relays, arc flash fibre and point sensors, explosion vents or oil level sensors.
Fuses	Fuses provide fault current interruption of some faults and may be utilised by manual operation to provide isolation at low loading levels. As fuses are a simple over-current device they do not provide a reliable earth fault operation, or any other protection function.
Switches	Switches provide no protection function but allow simple manual operation to provide control or isolation. Switches may be able to break considerable load (e.g. ring-main unit load break switches) but others such as air break switches may only be suitable for operation under low levels of load. Switches may be motorised to provide remote operation for control/isolation. Links generally require operation when de-energised so provide economic but less convenient switch points.
Batteries and Chargers	Batteries, battery chargers and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions and allow continued operation of plant throughout any power outage.
Voltage Regulating Relays	Voltage Regulating Relays (VRR's) provide automatic control of the 'Tap Change On Load' (TCOL) equipment integral to power transformers and regulate the outgoing voltage to within set limits.
SCADA and Communications	
SCADA Master Station	SCADA (Supervisory Control And Data Acquisition) is used for control and monitoring of zone substations and remote switching devices and for activating load control plant TPCL's SCADA master station is located at PowerNet's System Control centre at the Findlay Road GXP, Invercargill. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide full Power Industry functions.
Communication Media	TPCL currently owns and operates a number of different radio systems. These systems transmit protection, SCADA, load control and voice traffic. Most traffic is between zone substations and field devices, and the SCADA master station at System Control. However, in the case of protection traffic, signals are sent directly between the protection devices - generally zone substation to zone substation, or zone substation to field device. The radio system is comprised of • Digital microwave radio links which simultaneously convey multiple types of traffic including protection signals, SCADA, and voice. • UHF radio links which generally convey a single type of traffic, but modern systems may convey multiple types of traffic (although at a lower speed than microwave radio links). These are used for protection signals, SCADA, load control and voice.

- Point-to-multipoint UHF channels for SCADA.
- VHF land mobile channels for voice.

Remote Terminal Units

TPCL owns RTUs at both zone substations and field substations. The table below gives the RTU at each zone substation. Field substations generally use the circuit breaker protection relay or regulator controller as the RTU.

Zone Substation	RTU
Athol	SEL 3530 over 9600 baud modem
Awarua	Harris D25 over 9600 baud modem
Bluff	Kingfisher CP-11 over 9600 baud modem
Centre Bush	Siemens C68 over 300 baud modem
Colyer Road	SEL 3530 over Ethernet
Conical Hill	Kingfisher CP-11 over 9600 baud modem
Dipton	Siemens mini RTU over 1200 baud modem
Edendale	SEL3530 & Harris D20C over 9600 baud modem
Glenham	Kingfisher CP-11 over 9600 baud modem
Gore Injection Plant	Kingfisher CP-11 over 9600 baud modem
Gorge Road	Kingfisher CP-11 over 9600 baud modem
Heddon Bush	Harris D20 over 9600 baud modem
Hedgehope	SEL 3530 over 9600 baud modem
Hillside	Kingfisher CP-11 over 9600 baud modem
Invercargill Injection Plant	Siemens C68 over 300 baud modem
Kelso	SEL 3530 over 9600 baud modem
Kennington	SEL 3530 over 9600 baud modem
Lumsden	Kingfisher CP-11 over 9600 baud modem
Makarewa	SEL 3530 over 9600 baud modem
Mataura	Kingfisher CP-11 over 9600 baud modem
Monowai	Kingfisher CP-11 over 9600 baud modem
Mossburn	Kingfisher CP-11 over 9600 baud modem
North Gore	Kingfisher CP-11 over 9600 baud modem
North Makarewa	Harris D20M++ over 9600 baud modem
Ohai	Harris D20C over 9600 baud modem
Orawia	Kingfisher CP-11 over 9600 baud modem
Otatara	Kingfisher CP-11 over 9600 baud modem
Otautau	Kingfisher CP-11 over 9600 baud modem
Riversdale	Kingfisher CP-11 over 9600 baud modem
Riverton	SEL3530 & Kingfisher CP-11 over 9600 baud modem
Seaward Bush	Harris D20ME over 9600 baud modem
South Gore	SEL 3530 over 9600 baud modem
Te Anau	Kingfisher CP-11 over 9600 baud modem
Tokanui	Kingfisher CP-11 over 9600 baud modem
Underwood	Kingfisher CP-11 over 9600 baud modem
Waikaka	SEL351 relay over 9600 baud modem
Waikiwi	Harris D20ME over 9600 baud modem
White Hill	Kingfisher CP-11 over 9600 baud modem
Winton	SEL3530 & Harris D20ME over 9600 baud modem

	Winton Injection Plant	Siemens C68 over 300 baud modem

Other Assets	
Generation	TPCL do not own any mobile generation plant but may utilise three diesel generators owned by PowerNet. These are rated at 500kW, 350kW and at 275kW. There are no stand-by generators owned or able to be utilised by TPCL.
Power Factor Correction	TPCL owns and operates two 2.5VA 66kV capacitors at Heddon Bush and four 5MVA 66kV capacitors at North Makarewa. These were installed during the construction of Meridian Energy Limited's White Hill wind farm to cover the VAR requirements of the generators. Other than the above, customers are required to draw load from connection points with sufficiently good power factor so as to avoid the need for network scale power factor correction
Mobile Substations	TPCL can utilise a TPCL owned trailer mounted 3MVA 11kV regulator and circuit breaker with cable connections.
Metering	Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

2.3. Network Asset Details

Bulk Supply Assets and Embedded Generation

TPCL owns the following assets within the GXPs

Asset	Location	Quantity	Manufactured	Condition
66kV Circuit Breaker	North Makarewa	5	2007 (RL = 37yrs)	Good
66kV Circuit Breaker	North Makarewa	4	2000 (RL = 30yrs)	Good
33kV Circuit Breaker	North Makarewa	1	1967 (RL = -2yrs)	Average
33kV Circuit Breaker	North Makarewa	1	1981 (RL = 11yrs)	Average
33kV Circuit Breaker	North Makarewa	2	1983 (RL = 13yrs)	Average
33kV Circuit Breaker	North Makarewa	2	1984 (RL = 14yrs)	Average
33kV Circuit Breaker	Edendale	7	2002 (RL = 32yrs)	Good
11kV Circuit Breaker	Edendale	5	1994 (RL = 24yrs)	Good
11kV Circuit Breaker	Edendale	1	1995 (RL = 25yrs)	Good
11kV Circuit Breaker	Edendale	1	1996 (RL = 26yrs)	Good
11kV Circuit Breaker	Edendale	1	1998 (RL = 28yrs)	Good
11kV Circuit Breaker	Edendale	2	1999 (RL = 29yrs)	Good
66kV Bus	North Makarewa	1	2000 (RL = 30yrs)	Good
33kV Bus	Edendale	1	2002 (RL = 33yrs)	Good, Indoor switchboard
66kV Capacitor	North Makarewa	4	2007 (RL = 37yrs)	Good
66kV NER	North Makarewa	1	2000 (RL = 30yrs)	Good

Injection Plants

Voltage	Location	Quantity	Manufactured	Condition
66kV	Winton	1	1992 (RL = -3yrs)	Average, coupling cell and capacitors are outdoor
33kV	Invercargill 1	1	1988 (RL = -7yrs)	Good, all gear is indoor
33kV	Gore	1	1990 (RL = -5yrs)	Good, all gear is indoor
33kV	Edendale	1	1988 (RL = -7yrs)	Good, all gear is indoor
33kV	North Makarewa	1	1994 (RL = -1yrs)	Good, all gear is indoor

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 there is an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply units upgraded in 2005 after failures at other sites. These plants will be made redundant with the roll out of smart meters over the next few years.

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

Subtransmission Network

Figure 9 below summarises the subtransmission lines constructed each year:

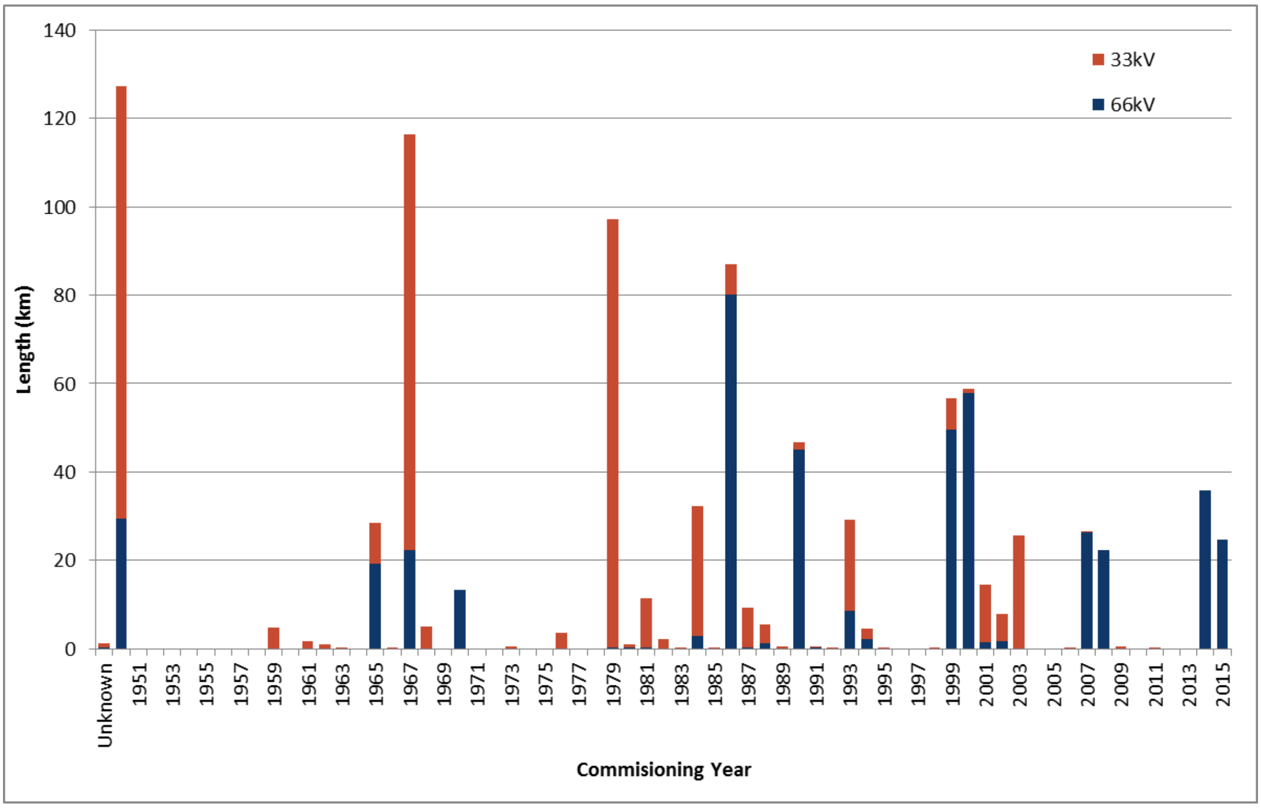

Figure 9: Subtransmission line construction

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. Figure 10 shows the ages of poles on the subtransmission network.

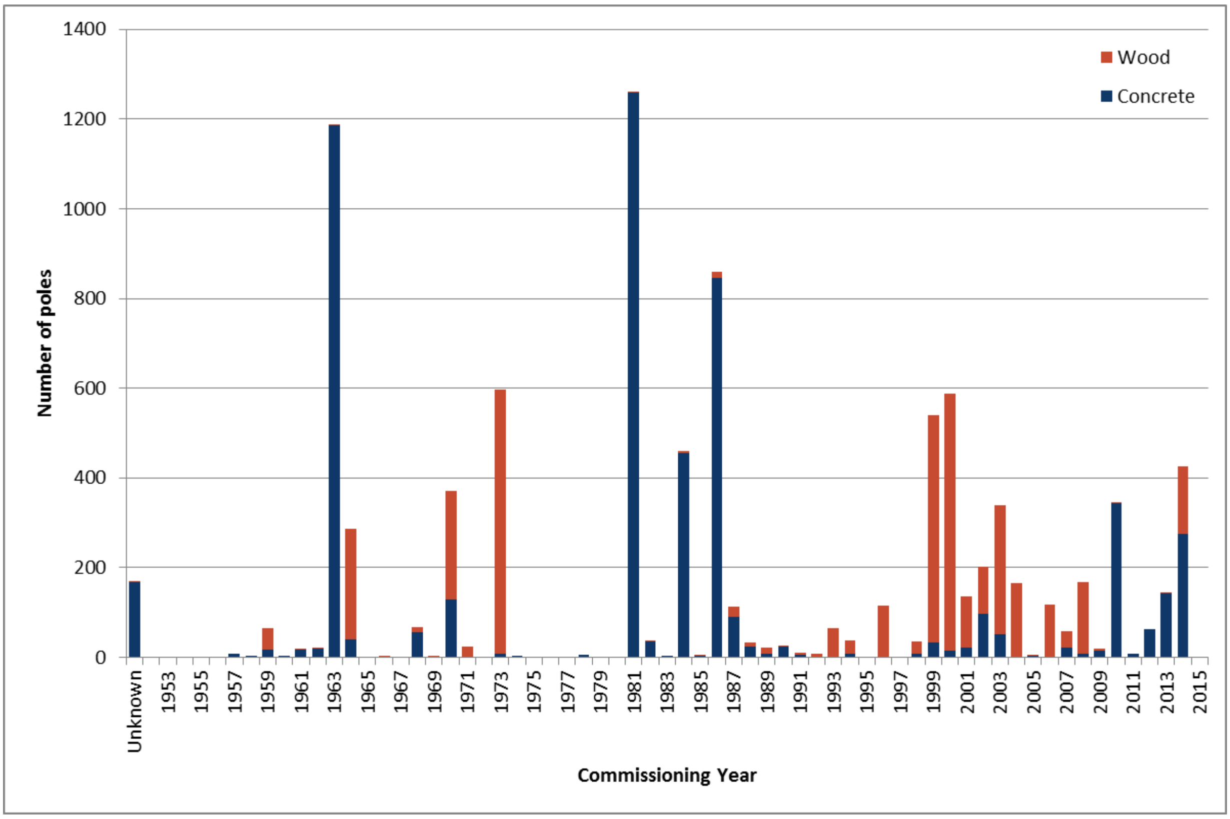

Figure 10: Subtransmission Poles

In theory, for wooden poles, all lines built prior to 1981 should be replaced before the end of 2026. Similarly, for concrete poles, all lines built prior to 1966 should be replaced before the end of 2026 Annual aerial and five-yearly walking condition inspections are made of all subtransmission lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

Subtransmission Cables

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

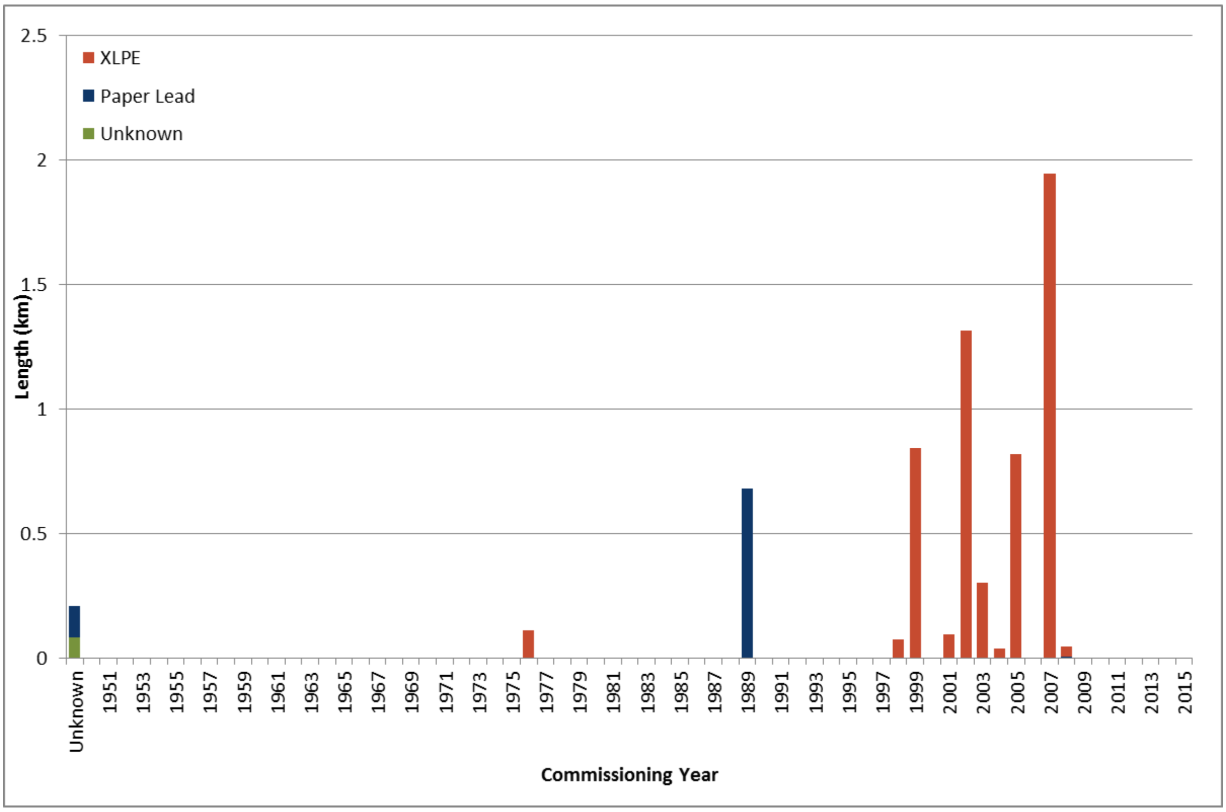

Figure 11: Subtransmission Cables

Zone Substations

Subtransmission Voltage Switchgear

TPCL has two indoor 33kV switchboards at Waikiwi and Edendale. All other 33kV circuit breakers are outdoor units. All 66kV circuit breakers are installed outdoors and all units installed after 1992 are SF6 insulated. The three remaining oil 66kV circuit breakers are in good condition and the oldest breaker (which is in service at Heddon Bush) is expected to be decommissioned during the 10 year planning period. Three 33kV oil circuit breakers will reach their standard lives during the 10 year planning. Renewals of these will be planned when condition inspections determine that they are no longer fit for service.

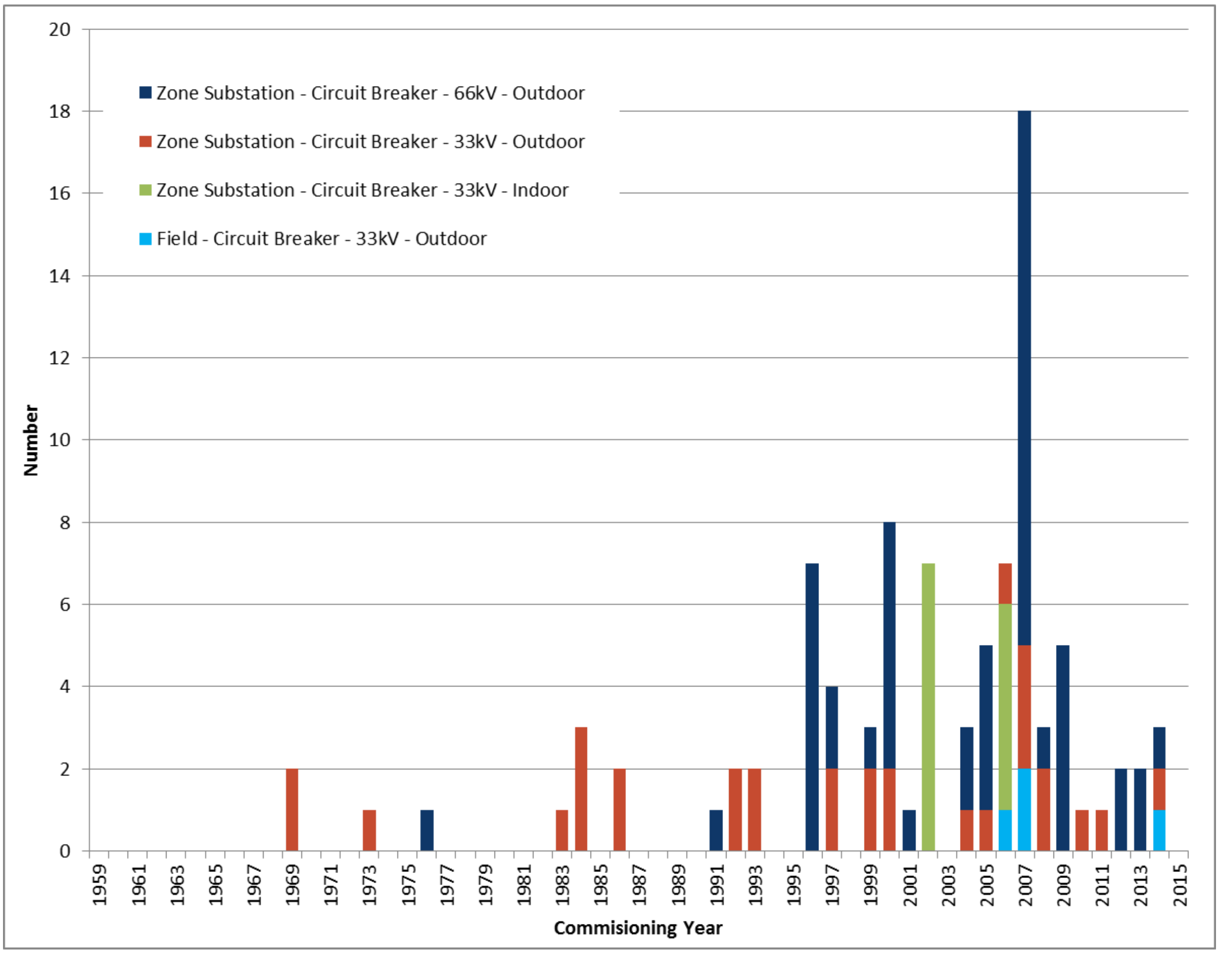

Figure 12: Subtransmission Voltage Circuit Breakers

Power Transformers

The Power Transformers on the network are generally in good condition. Fifteen units are expected to exceed the standard service life of 55 years within the 10 year planning period. A plan is being developed for the renewal of the oldest transformers on the network which are single phase units in service at Hillside. However this work will likely be deferred until condition indicates failure is imminent or the spare single phase unit stored at Hillside is needed to be utilised due to failure.

Seven power transformers are planned to be replaced with either new or refurbished units from other sites during the next five years.

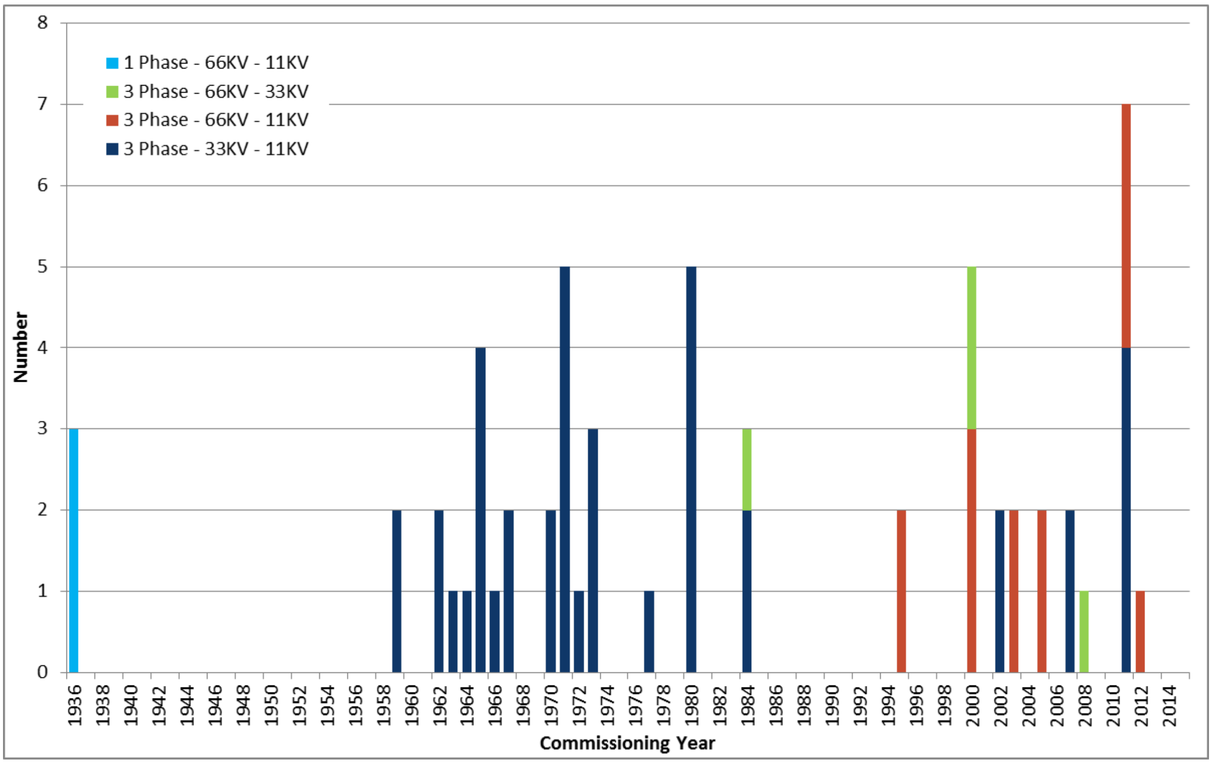

Figure 13: Power Transformers

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. No batteries are more than twelve years old.

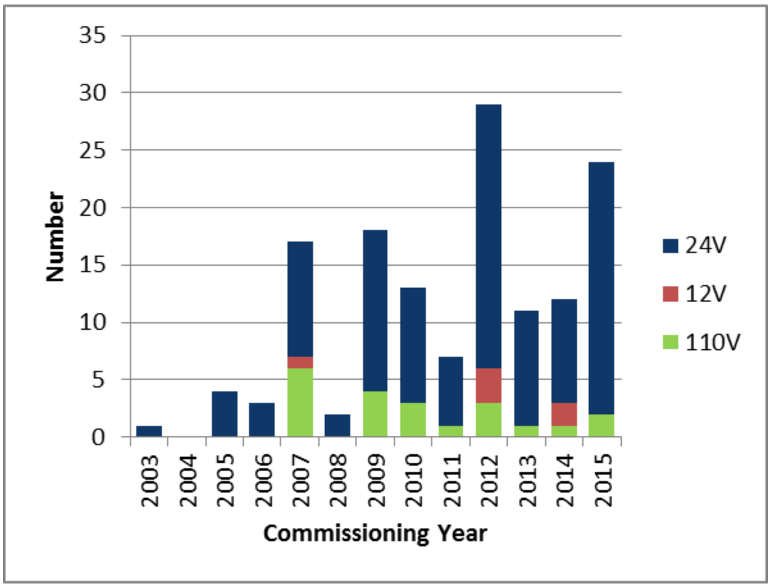

Figure 14: DC Batteries

Tap Changer Controls

104 voltage regulating relays (VRR) are in operation and most have been installed with the associated transformer or voltage regulator. 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. The two oldest VRRs on the network are at Awarua and Riversdale. The VRR at

Riversdale is planned to be replaced in the next 5 years and the VRR at Awarua is on the T2 transformer which is currently energised but not on load following transfer or load to the recently commissioned Colyer Road substation.

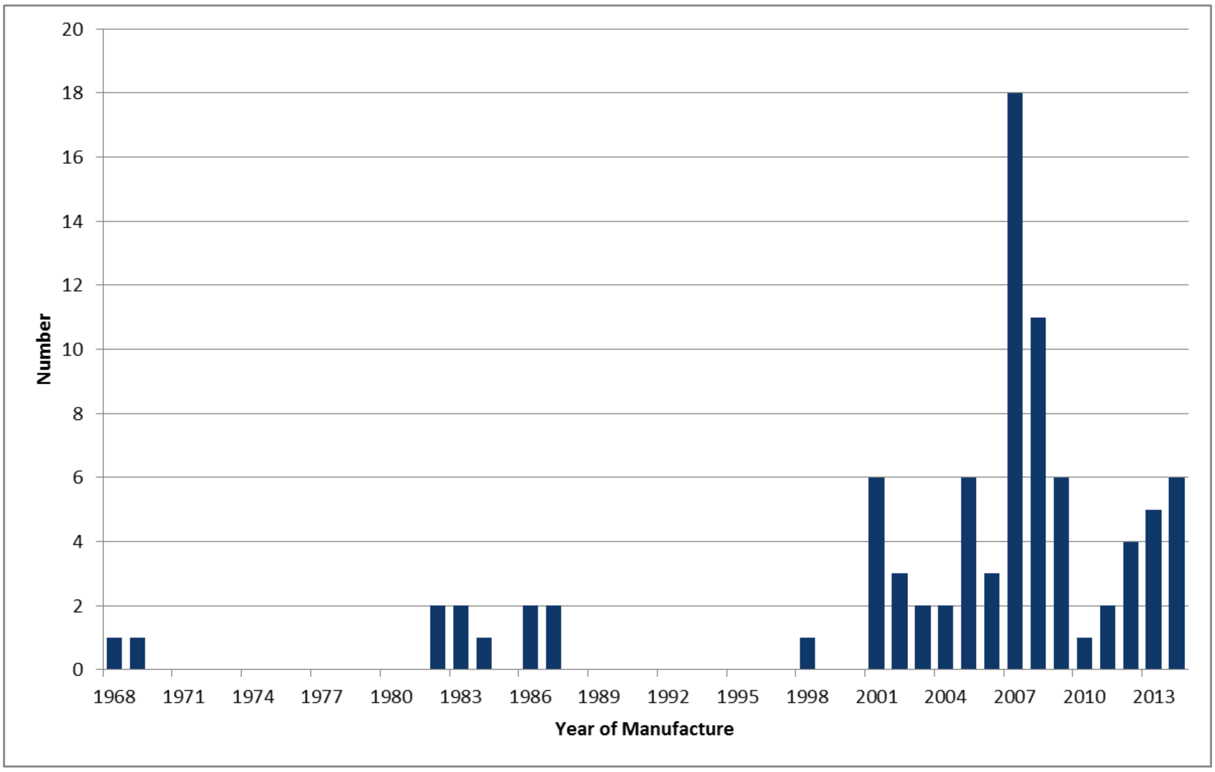

Figure 15: Voltage Regulating Relays

Distribution Network

Circuit Breakers

TPCL has a mix of outdoor and indoor distribution circuit breakers. Older circuit breakers are 11kV to match the operating voltage of the network. 22kV circuit breakers have been installed as part of new substation construction as it provides for future voltage conversion and aligns with a long term plan to convert to 22kV within the lifetime of the equipment.

Indoor circuit breakers have an extra 5 years standard life over outdoor units, therefore outdoor units installed before 1986, and indoor installed before 1981, should be refurbished or replaced by 2026. 23 indoor circuit breakers, and 12 outdoor, will be due for replacement before 2025. The indoor switchboard at Riverton is being replaced in 2015/16. Bluff and Makarewa indoor switchboards are planned for replacement at the end of their standard life in 2025/26.

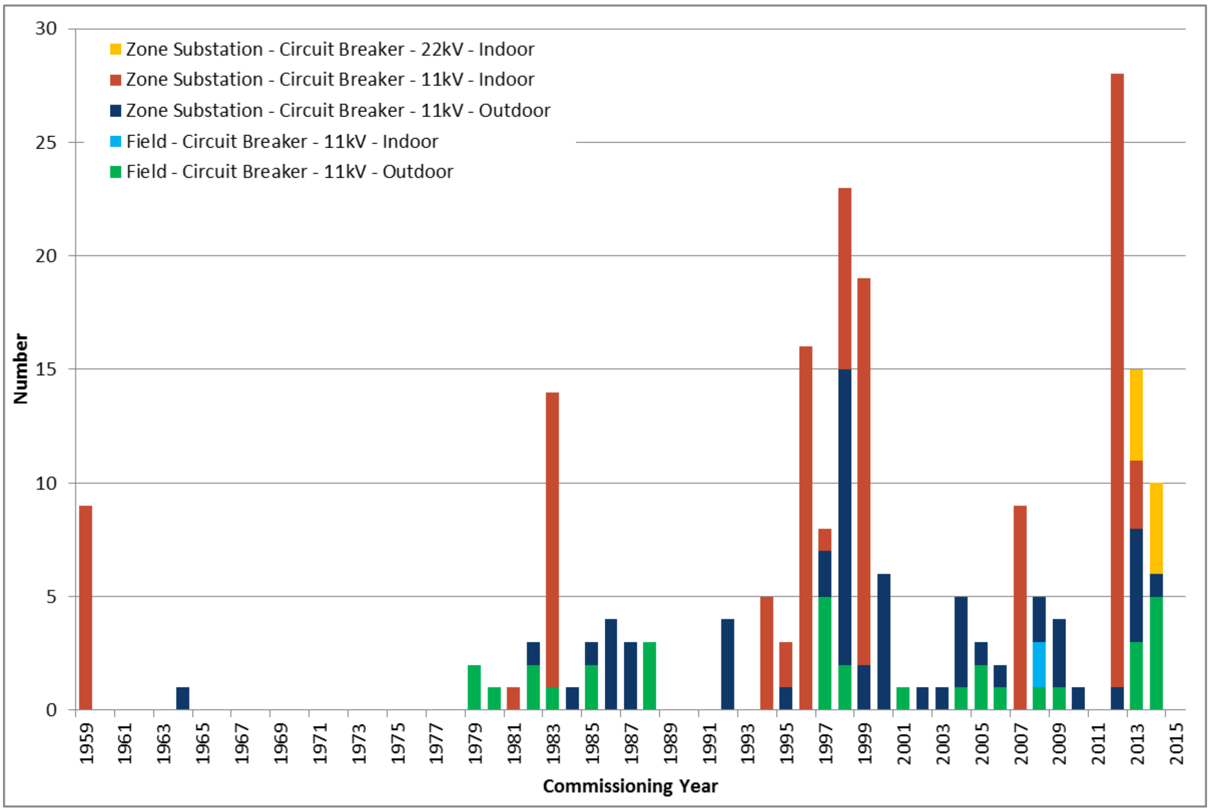

Figure 16: Distribution Circuit Breakers

Air Break 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.

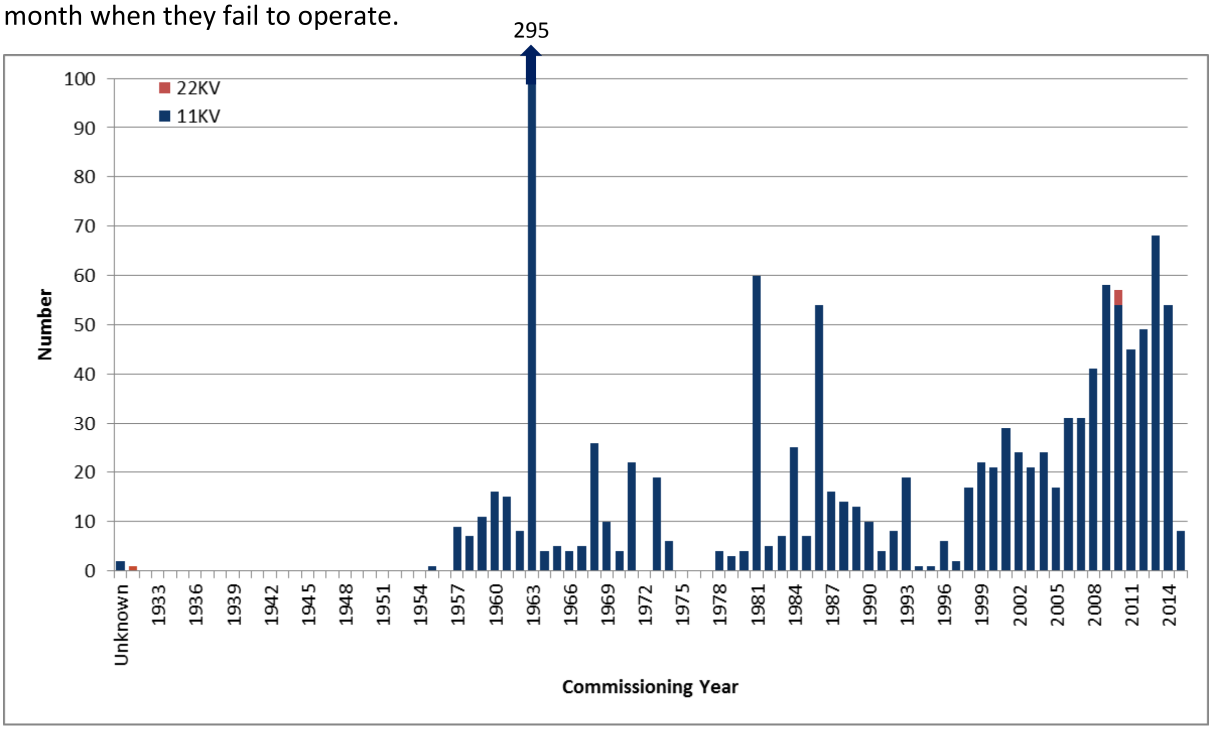

Figure 17: Air Break Switches

Fuses

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

Ring Main Units

Ring Main Units (RMU) have the following age profile. As these are relatively recent additions, only the oldest 4 RMUs will be at the end of their standard life in the final few years of the 10-year planning period. Condition inspections will determine requirements for replacement but in general condition is good.

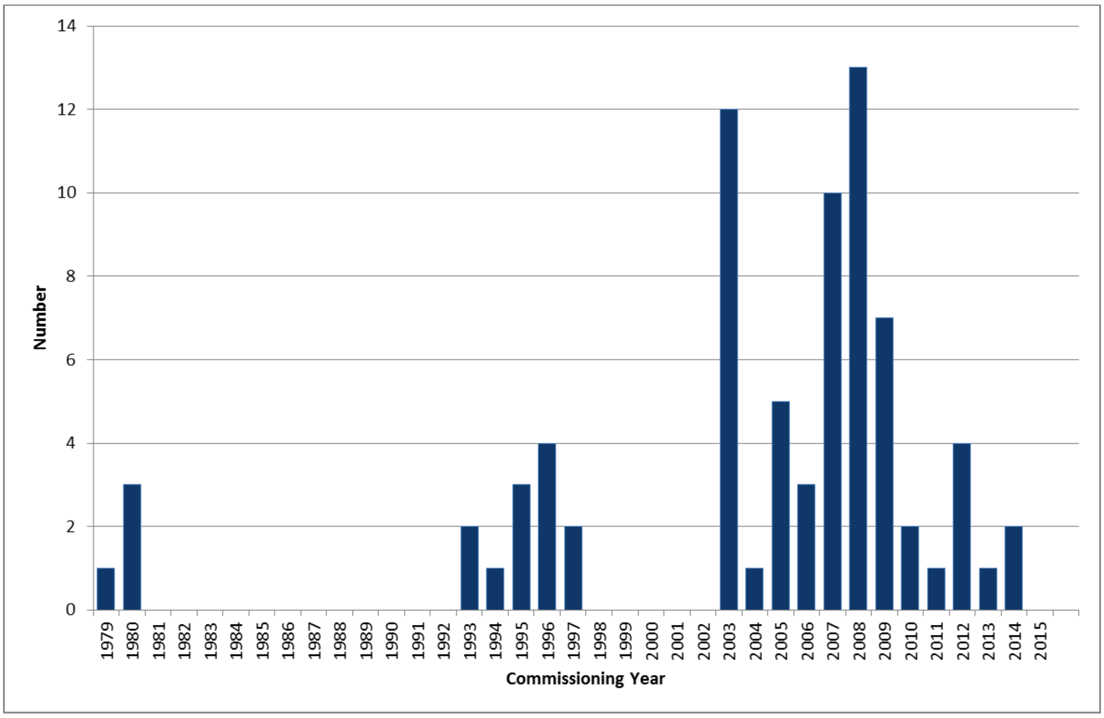

Figure 18: Ring Main Units

Overhead Lines

Distribution network poles have an age profile as shown in Figure 19.

In theory, for wooden poles, all lines built prior to 1981 should be replaced before the end of 2026. Similarly, for concrete poles, all lines built prior to 1966 should be replaced before the end of 2026. Based on this 6,700 wooden poles and 18,806 concrete poles should be renewed by 2026. Over the following 10 year period (2027-2036), these numbers drop to 647 wooden poles and 16,195 concrete poles. These numbers imply that an average of over 2,100 poles should be replaced per annum over the next 20 years.

Five-yearly walking condition inspections are made of all distribution lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection. Good pole lives as proven by inspection and non-destructive testing (NDT) will hopefully allow up to 30% to remain in service for an additional ten years.

To smooth the number of poles likely to require renewal, TPCL 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 (Non-Destructive Testing) and fault incidences.

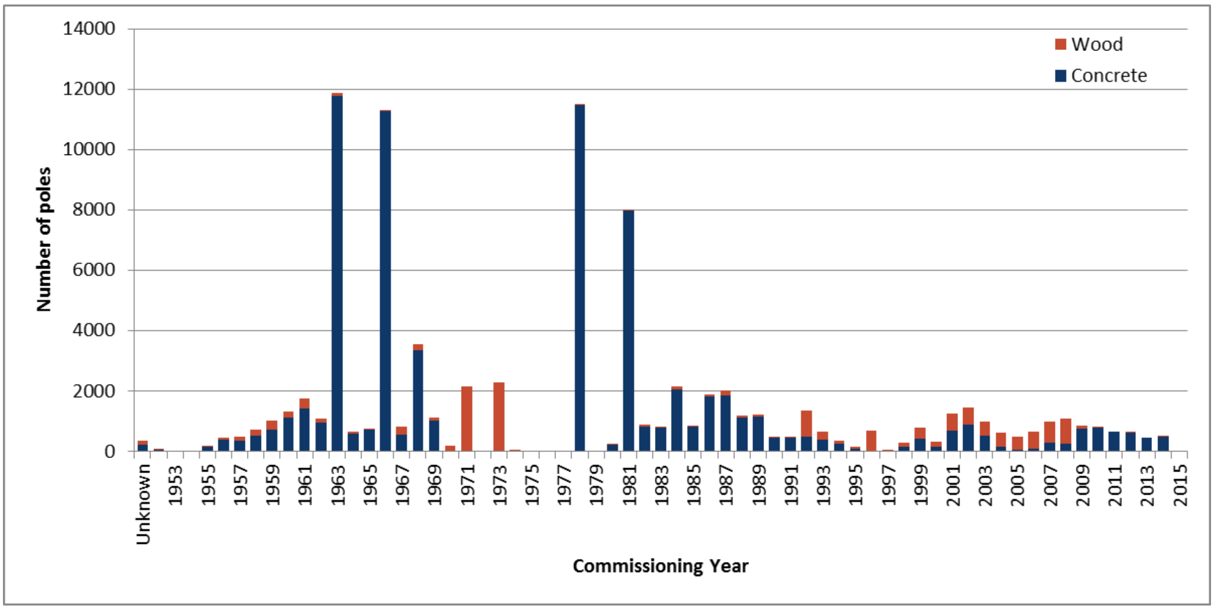

Figure 19: Distribution Poles

Underground Cables

Figure 20 below displays the age of the Distribution cables on the network. The age profile of 11kV cables shows that some XLPE cables may need renewal within the planning period (XLPE cables installed before 1985). These will be monitored and replacement done if failures are predicted. Actual practical life for any cable is likely to be greater than the ODV standard life and on-going monitoring of actual performance will be utilised in planning. Most cables are lightly loaded and in sound condition however there have been termination and joint failures.

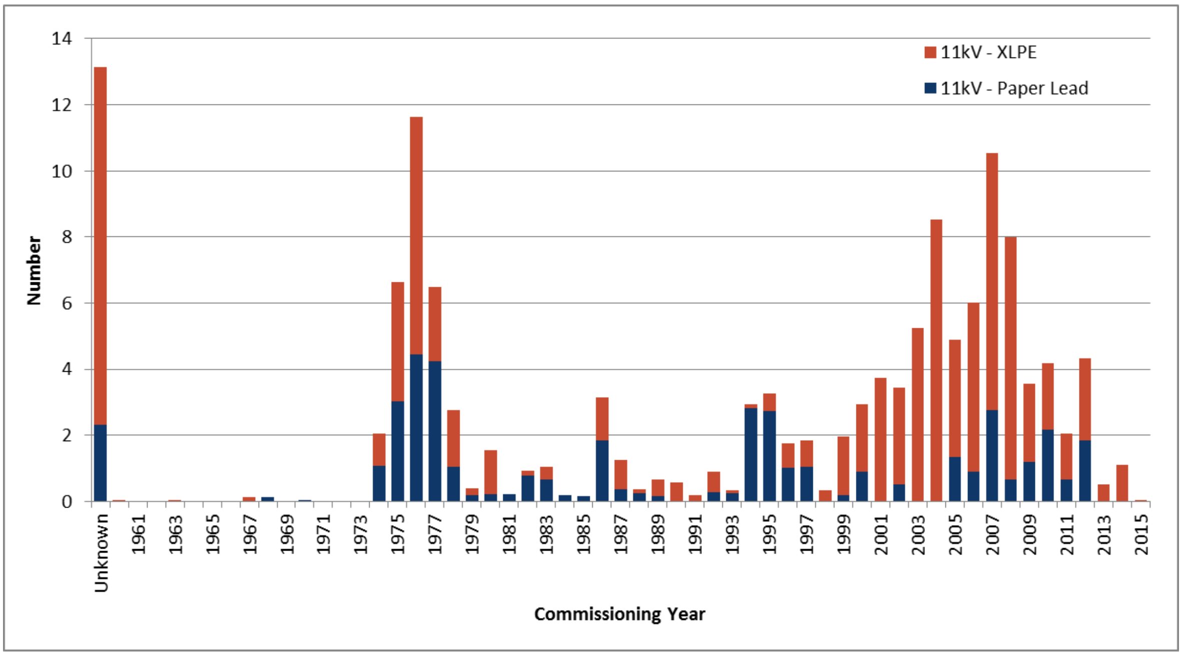

Figure 20: Distribution Cables

Voltage Regulators

The age profile for voltage regulators is shown in Figure 21. Voltage regulators exist on TPCL's network for voltage improvement and to allow for 11kV backups between zone substations. Replacements of older 3 phase regulators have largely been completed over the last decade. Only two regulators are older than 15 years. One of these (Bushy Park Regulator) has been replaced in 2015/16 with the other (Wyndham Ridges Regulator) planned for 2016/17.

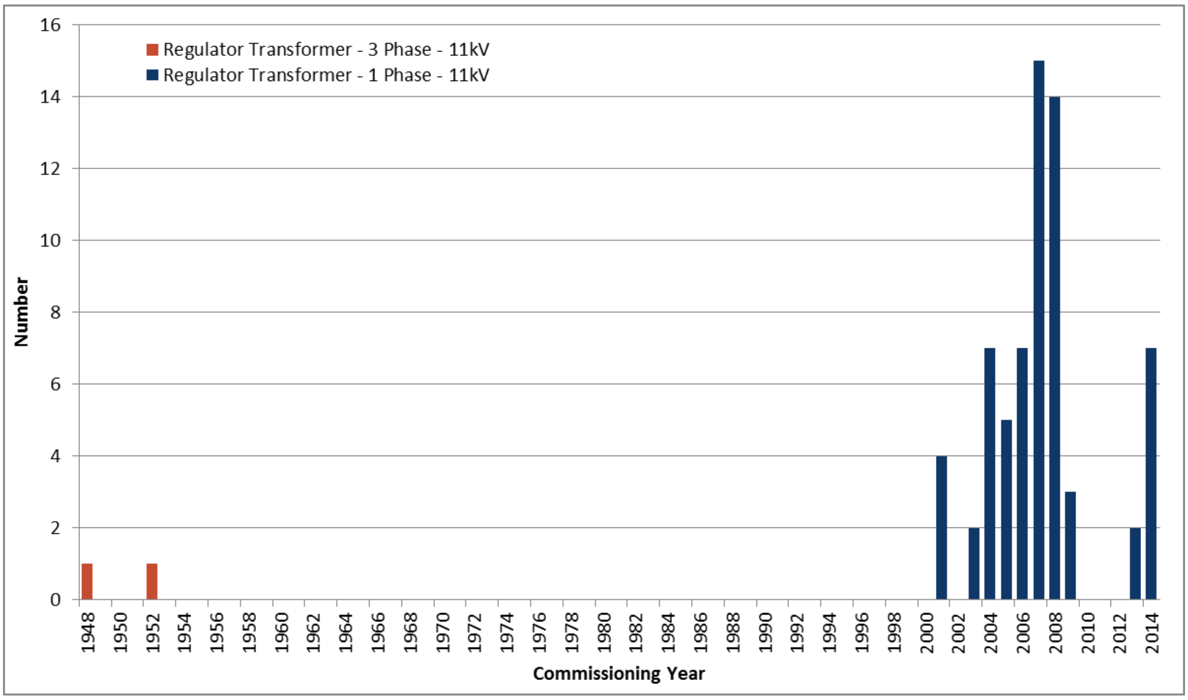

Figure 21: Voltage Regulators

Distribution Substations

Transformers

Table 14 shows the numbers of the various sized distribution transformers on TPCL's network and their age profile is displayed in Figure 22. Two spikes occur at 1970 and 1986 where estimated ages have been used, as the actual manufacturing year was not able to be found.

Most of TPCL's transformers are pole mounted with a much smaller number of ground mounted transformers – generally in larger urban townships or at individual larger customer's premises.

Rating	Pole	Ground
1-phase up to 15kVA	4427	24
1-phase 30kVA	611	11
1-phase 50kVA	5	1
3-phase up to 15kVA	1564	6
3-phase 30kVA	2204	38
3-phase 50kVA	1000	35
3-phase 75kVA	254	10
3-phase 100kVA	187	78
3-phase 200kVA	116	188
3-phase 300kVA	47	100
3-phase 500kVA	2	39

Rating	Pole	Ground
3-phase 750kVA	-	22
3-phase 1,000kVA	-	12
3-phase 1,500kVA	-	2
Total	**10417**	**566**

Table 14: Distribution Transformers

Transformers found to be in poor condition after five yearly inspections may be replaced with units removed from service refurbished for reuse, if economic. Condition varies generally due to proximity to the coast and if the unit has been heavily loaded.

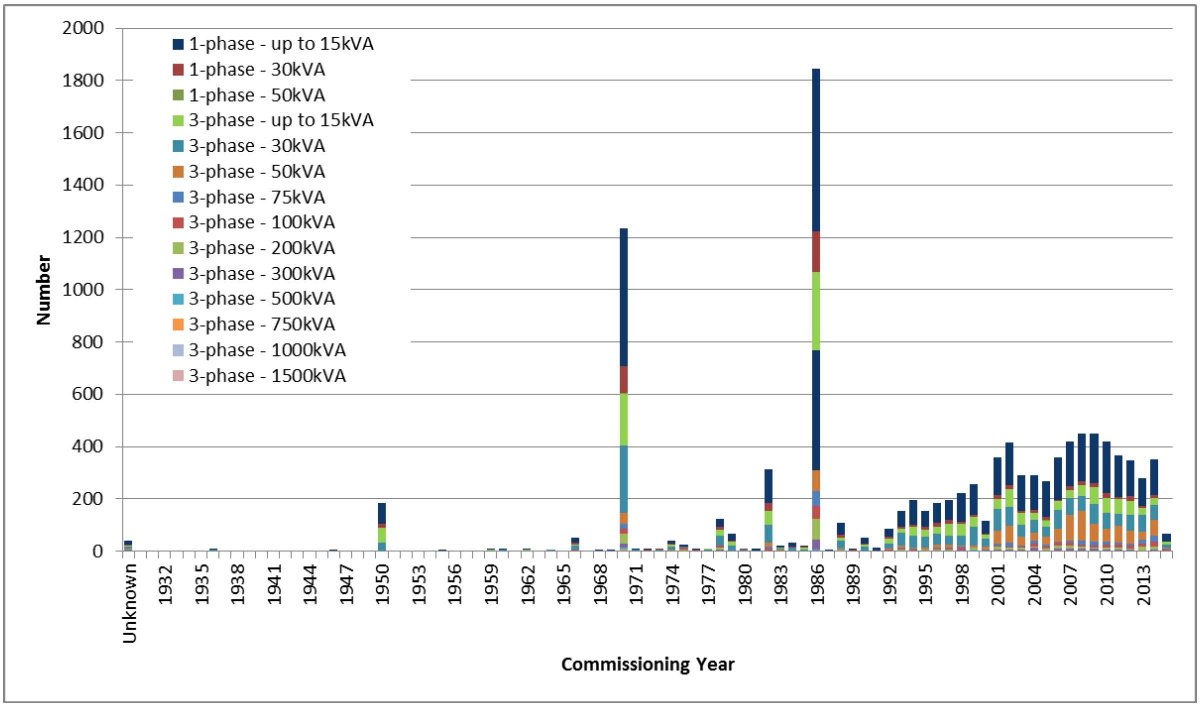

Figure 22: Distribution Transformers

Remote Terminal Units

Age profile of Remote Terminal Units (RTU) is shown in Figure 23. Standard age is 15 years and condition is average. The older Siemens units starting to become difficult to maintain and are planned to be replaced over the next 2 years. The Harris RTUs are becoming harder to maintain due to difficulties in finding personnel who can reprogram these units when changes are required. In some cases a new SEL 3530 RTU connected to new equipment is installed in parallel with the existing Harris RTU, which remains connected to older equipment. Over the next 5 years the older equipment will be migrated to the SEL 3530 RTU. All other Harris RTUs will be replaced in the next 5 years.

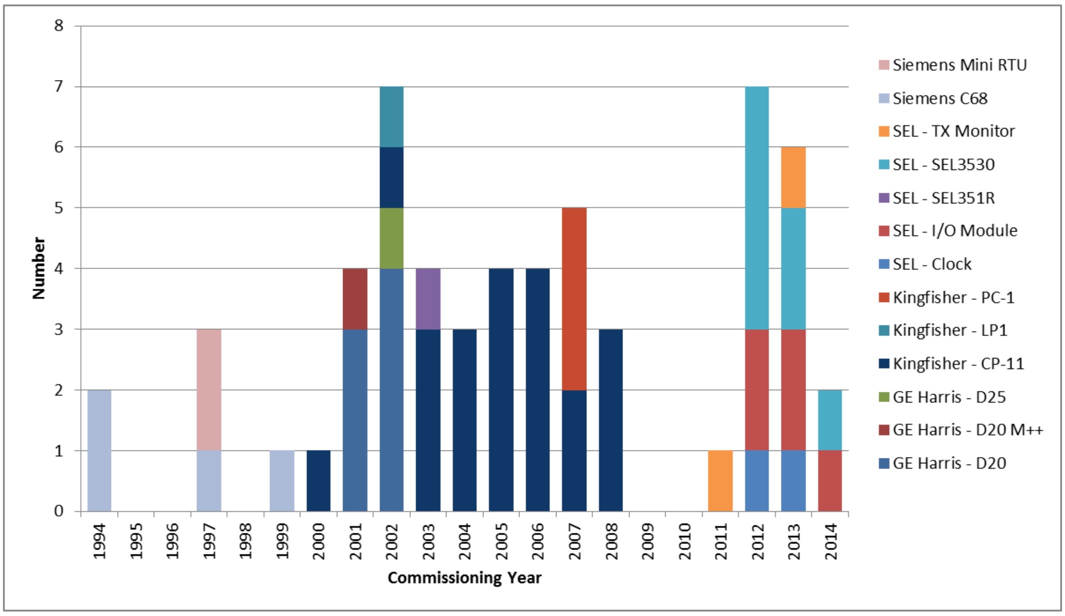

Figure 23: Remote Terminal Unit Assets

LV Network

Overhead

The age profile of the 400 volt poles is shown in Figure 24. Conditions of these are average, with a large number of poles due for renewal this planning period based on age. Five-yearly walking condition inspections are made of all LV lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

New overhead line is being installed as ABC (Aerial Bundled Conductor) which does not require cross arms and insulators and has PVC insulation improving line safety.

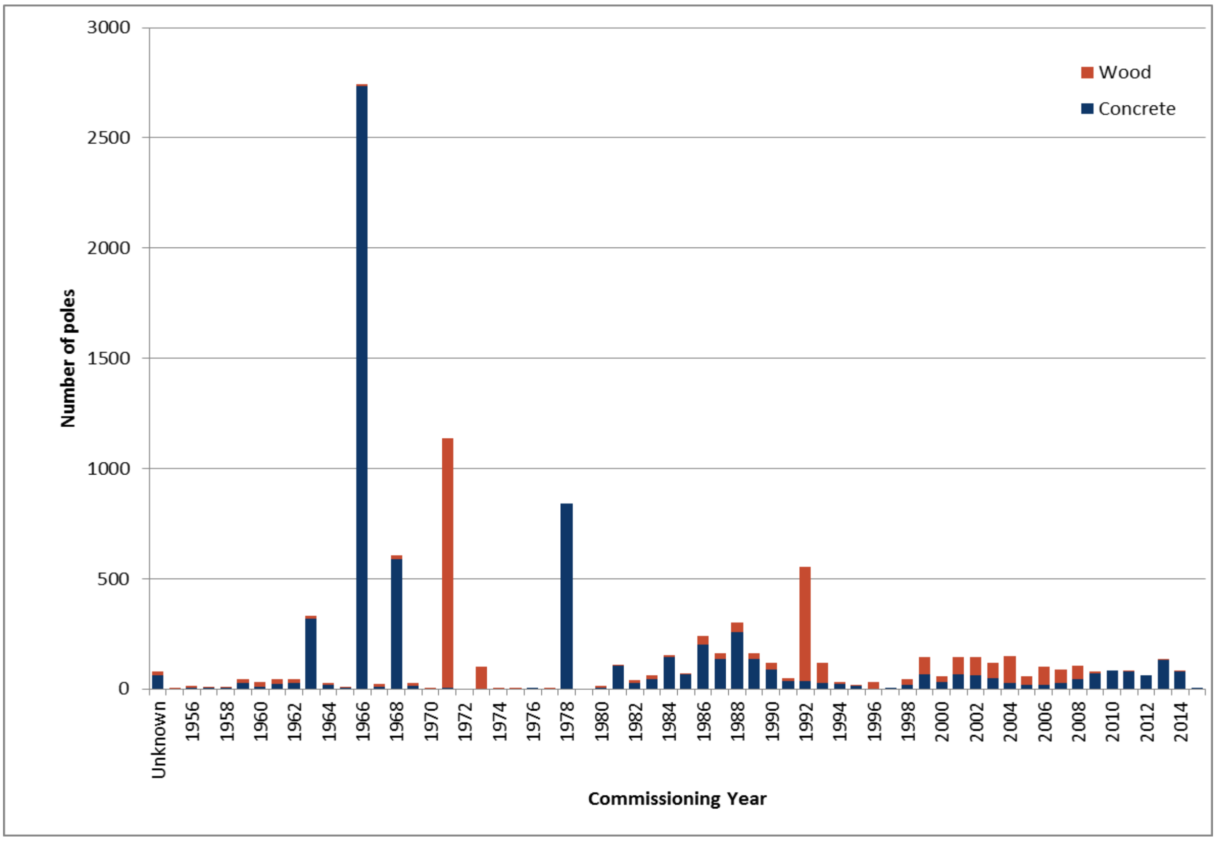

Figure 24: LV Lines

Underground

The LV cable commissioning year profile is shown in Figure 25 and highlights that based on age, a number of assets should be renewed. In practice cables are left in service until performance deteriorates impacting on service levels.

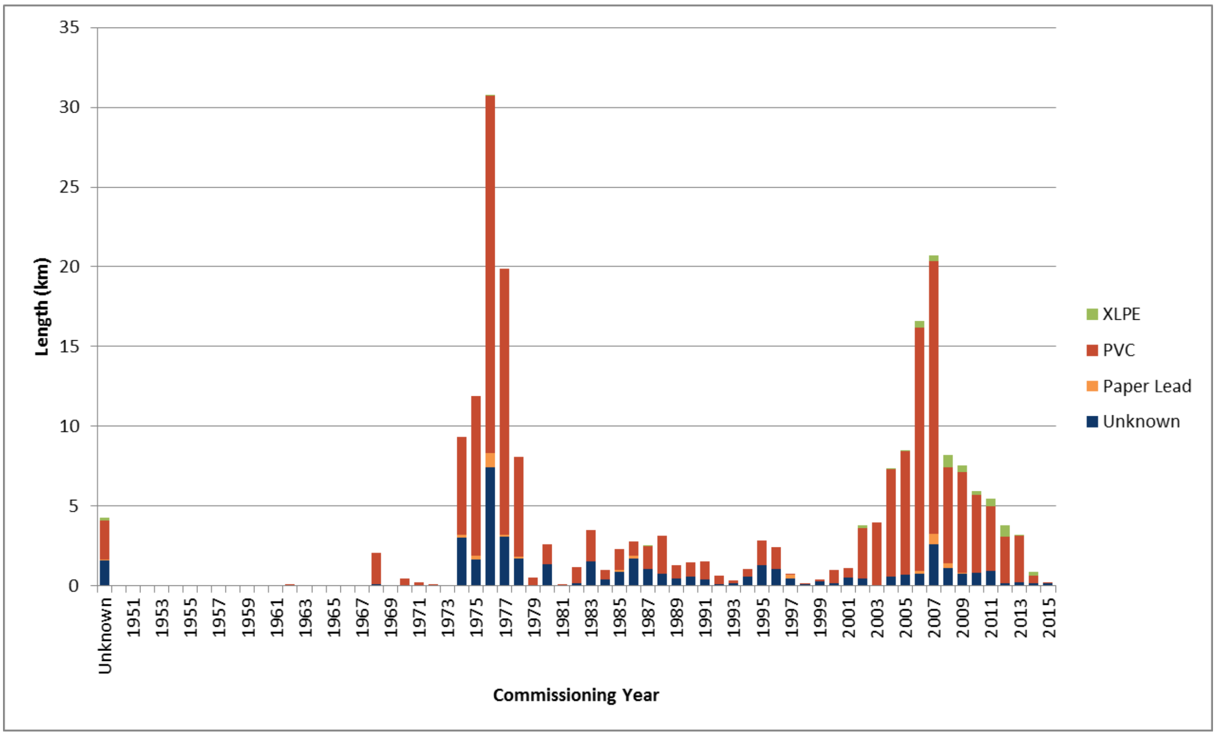

Figure 25: LV Cables

Other Assets

SCADA and Communications

The initial SCADA master station was commissioned in 1999 with a further upgrade of the Server PC's in 2005. These SCADA servers have now reached end of life. The software has been developed with the latest version being implemented with the new servers in 2005. Both operator stations now have LCD screens.

The age profile of radios used for communications is given in Figure 26. Manufacture support has ended for many of MAS DXR1500 microwaves and these will be renewed over the next three years. Manufacturer support has ended for the Exicom EX7100 due to the business being liquidated. TPCL has a spare unit but due to the criticality of the protection links operating on these radios, they will be replaced as required over the next few years to ensure a spare is always available if needed.

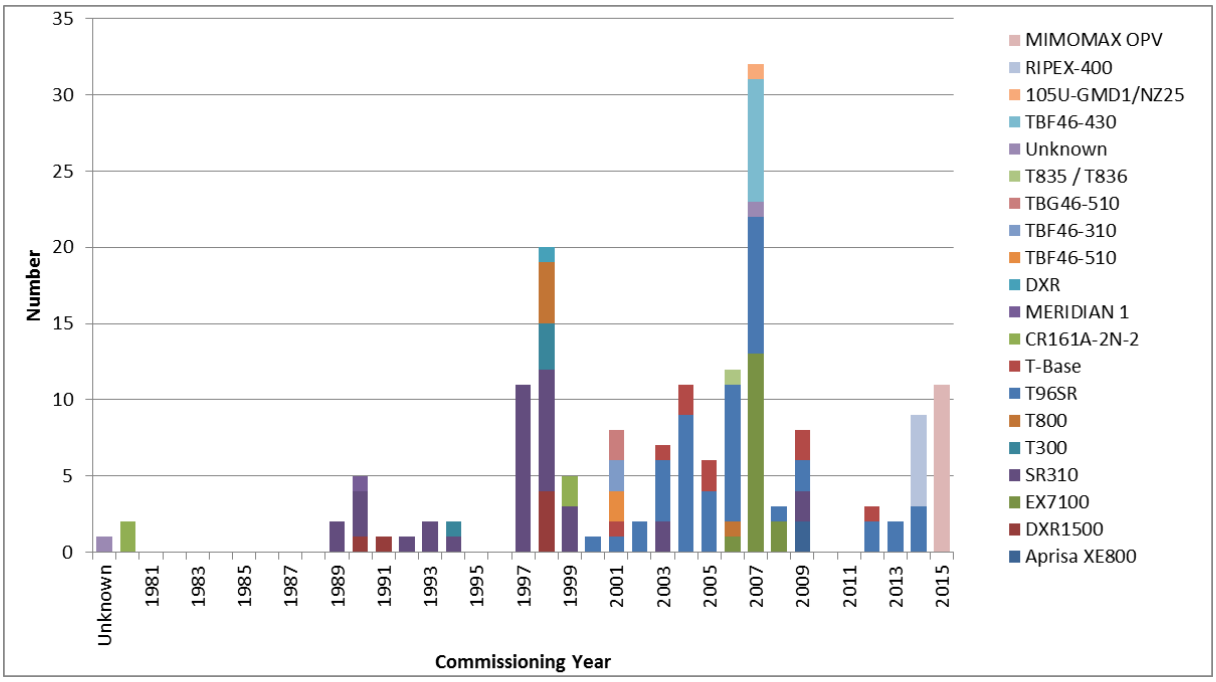

Figure 26: Radios

Metering

TPCL has 'Time Of Use' (TOU) meters on its incoming circuit breakers to provide accurate loading information on each zone substation. There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these is shown in Figure 27.

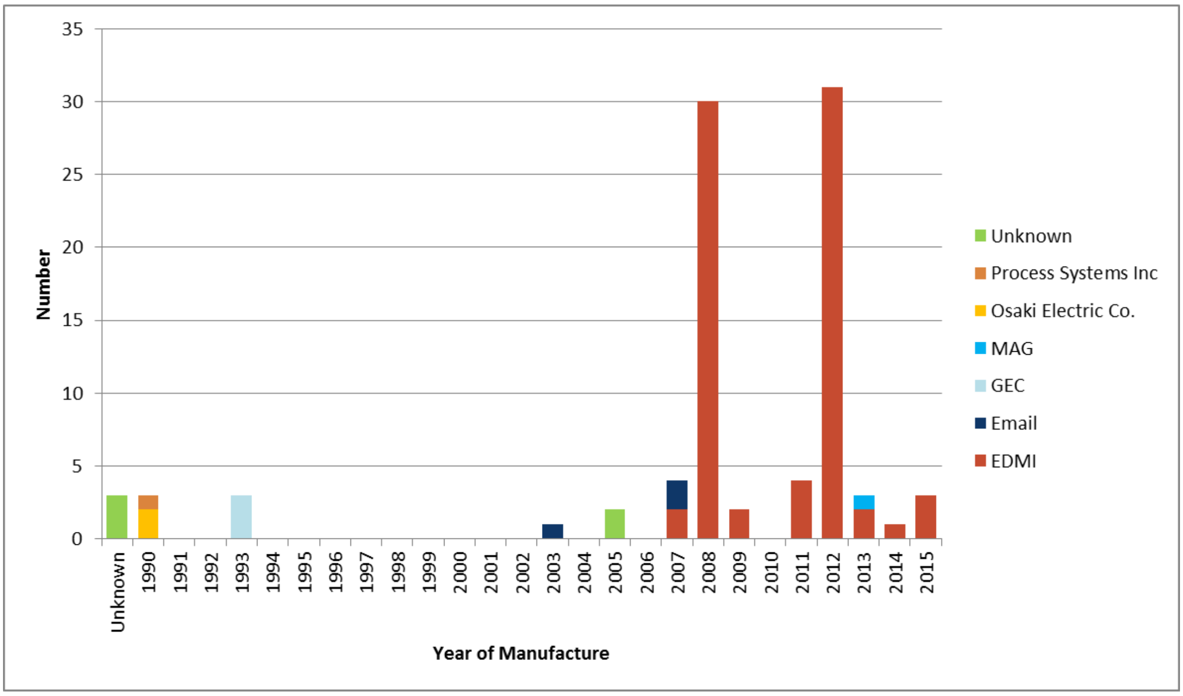

Figure 27: Metering Assets

Mobile Plant/ Load Correction/ Generation

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

TPCL does not own any mobile substations, power factor correction plant, mobile generation or standby generation plant however PowerNet own three mobile diesel generators rated at 500kW, 350kW and 275kW which TPCL can utilise.

3. Service Levels

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

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

3.1. Customer Oriented Service Levels

Customer engagement surveys are completed annually to measure customer perceptions around a range of service levels. This involves contacting a large sample of customers by phone and asking a predetermined set of questions; the full questionnaire used is detailed in Appendix 2. This is carried out independently by engaging Gary Nicol Associates who collate the results into a customer satisfaction report for presentation. Face to face interviews are also held directly with major customers to help understand individual service level requirements and satisfaction with current service levels.

Statistics around voltage complaints are kept to measure how often voltage quality issues are experienced by customers. Issues are dealt with at the time but these statistics give an indication of how voltage quality and the response services are trending over time. In addition, following the completion of customer connection work a survey form is sent to the customer to measure satisfaction with the connections service. Results are monitored and any comments given are reviewed and responded to.

Targeted improvement initiatives could result from dissatisfaction being expressed by customers; however survey results show that for the most part customers are happy with the current level of service. Customer engagement telephone surveys indicate 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 also appears that there is an increasing value by customers placed on the absence of flicker, sags, surges and brown-outs although other research 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 to address and hence require capital expenditure solutions (as opposed to process solutions) which 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 (or chain of assets) 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[8].

Primary Customer Service Levels

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 TPCL has adopted two internationally accepted indices:

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

This aligns with the Commerce Commission's use of SAIFI and SAIDI (and determine their calculation methodology) in their regulation of local EDBs (noting that TPCL is exempt from price-quality regulation due to its consumer controlled status). TPCL's projections for these measures over the next ten year period ending 31 March 2026 are shown in Table 15. These projections take into account the recently updated default price quality path calculation methodology including new (lower) extreme event normalising boundaries and a 50% weighting for planned outages. TPCL's reliability targets are set equivalent to these projections.

These projections are an average only, given the volatility in reliability statistics due to their dependence on extreme weather events. TPCL's medium-term aim is to reduce this average.

Table 15: TPCL Reliability Projections

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	…	2025/26
SAIDI	B (Planned)	36.02	36.02	37.02	37.02	37.02	…	37.02
	C (Unplanned)	122.94	120.23	117.59	117.00	116.42	…	113.53
	Total	**158.96**	**156.25**	**154.61**	**154.02**	**153.43**	**…**	**150.55**
SAIFI	B (Planned)	0.176	0.176	0.176	0.176	0.176	…	0.176
	C (Unplanned)	2.653	2.597	2.543	2.531	2.519	…	2.461
	Total	**2.829**	**2.774**	**2.719**	**2.707**	**2.696**	**…**	**2.638**

In practical terms this means TPCL's customers can broadly expect the reliability shown in Table 16.

Table 16: Expected fault frequency and restoration time

General location	Expected reliability[9]
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

[8] 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.

[9] Except if supplied directly off the faulty substation, or section of line or cable.

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.

Table 17 shows the theoretical thresholds which would apply to TPCL's reliability performance if it were regulated. The boundary values represent the threshold for normalising extreme events where if SAIDI or SAIFI in any day exceeds the respective boundary the contribution to the overall annual SAIDI or SAIFI is capped at that boundary value. The limit represents the upper limits of acceptable reliability for network performance after normalising out extreme events and must not be breached more than once in any three year period. It is worth noting that whilst TPCL is not regulated, and none of these calculated values apply to TPCL, TPCL calculates its performance in alignment with these measures in order to allow for benchmarking against other EDBs.

Table 17: TPCL Theoretical Reliability Thresholds

	Target	Limit	Boundary
SAIDI	149.82	165.459	6.20
SAIFI	2.844	3.157	0.111

Secondary Customer Service Levels

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 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 with communication regarding tree trimming, connections or faults, the time taken to respond to and remedy justified voltage complaints and the amount of notice before planned shutdowns. Table 18 sets out targets for these service levels for the next ten years (either as a percentage or on a scale of 1 to 5, where 1 is poor and 5 is excellent).

The use of Customer Satisfaction Surveys (questionnaires sent to customers with invoices for new connections) has been discontinued due to an extremely poor response rate. TPCL is investigating alternative methods of gathering this information, including the possibility of adding similar questions to the existing Customer Engagement Survey (phone survey carried out by an independent consultant).

Table 18: Secondary service levels

Attribute	Measure	2016/17	2017/18	…	2025/26
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>80%	>80%	…	>80%
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>80%	>80%	…	>80%
	Acceptance of maximum of one planned outage per year. {CES: Q1}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting four hours on average. {CES:	>50%	>50%	…	>50%

Attribute	Measure	2016/17	2017/18	…	2025/26
	Q1}				
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES: Q4(b)}	>80%	>80%	…	>80%
	Information supplied was satisfactory. {CES: Q8(b)}	>80%	>80%	…	>80%
	PowerNet first choice to contact for faults. {CES: Q6}	>30%	>35%	…	>50%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<10	<10	…	<10
	Number of customers who have justified voltage complaints regarding supply quality {IK}	<4	<3	…	<2

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

Other Service Levels

In addition to the service levels that are 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.

Table 19: Other Service Levels

Service Level	Description
Safety	Various legal requirements require TPCL's assets (and customer's 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 at Work Act 2015. • Electricity (Safety) Regulations 2010 • Electricity (Hazards from Trees) Regulations 2003. • Maintaining safe clearances from live conductors (NZECP34 or AS2067). • EEA Guide to Power System Earthing Practice 2009 as a means of compliance with the Electricity (Safety) Regulations.
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. • Land Transfer Act 1952 (easements)
Industry Performance	Various statues 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
Electrical Interference	Under certain operational conditions TPCL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or TPCL's own equipment. The following publications are used to prevent issues from interference:

Service Level	Description
	• Harmonic levels (NZECP36:1993). • Single wire earth return limitations (EEA High Voltage SWER Systems Guide). • NZCCPTS: coordination of power and telecommunications (several guides).

3.2. Regulatory Service Levels

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

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

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 2012 and with listing and analysis also on the Commerce Commission website http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

Financial Efficiency Measures

TPCL has redefined its financial efficiency measures to take advantage of the benchmarking opportunities available under the current Information Disclosure format. The new measures fall into two groups:

- Network OPEX metrics
- Non-Network OPEX metrics

to capture the level of efficiency in both sides of the business. However for effective benchmarking this OPEX must be measured against the relative size of the EDBs in question. As there is no single fair measure of the "size" of an EDB, TPCL has adopted the most consistent (and therefore predictable) measures from Information Disclosure Schedule 1:

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

TPCL therefore has six financial efficiency targets as shown in Table 20:

Table 20: Financial Efficiency Targets

Measure	Network OPEX			Non-Network OPEX		
	/ICP	/km	/MVA	/ICP	/km	/MVA
2015/16	250	1000	21,500	150	600	12,900
2016/17	250	1000	21,500	150	600	12,900
2017/18	250	1000	21,500	150	600	12,900
2018/19	250	1000	21,500	150	600	12,900

Measure	Network OPEX			Non-Network OPEX		
	/ICP	/km	/MVA	/ICP	/km	/MVA
2019/20	250	1000	21,500	150	600	12,900
2020/21	250	1000	21,500	150	600	12,900
2021/22	250	1000	21,500	150	600	12,900
2022/23	250	1000	21,500	150	600	12,900
2023/24	250	1000	21,500	150	600	12,900
2024/25	250	1000	21,500	150	600	12,900

Comparative benchmarking as discussed in **Benchmarking** shows these service levels to be in line with peers once allowance is made for network size measures, therefore continuation at current levels is justified.

Energy Delivery Efficiency Measures

Projected energy efficiency forecasts and targets are shown in Table 20. 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].

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 annual sales quantities from retailers. As retailers are not reading the customers meter at midnight of the 31 December, some estimation methodology is required.

Table 20: Energy Efficiency Targets

Measure	2015/16	2016/17	…	2023/25
Load Factor	65%	65%	…	65%
Loss Ratio	7.0%	7.0%	…	7.0%
Capacity Utilisation	30%	31%	…	31%

3.3. Service Level Justification

TPCL's service levels are justified when:

- Improvements provide positive cost benefit within revenue capability.
- Customer contributions fund uneconomic portions of upgrade or alteration expenses to achieve a desired service level for an individual or group of customers.
- Skilled labour and technical shortages constrain what can be achieved.

- External agencies impose service levels either directly or indirectly where an unrelated condition or restriction manifests as a service level e.g. a requirement to place all new lines underground or a requirement to increase clearances.

Customer surveys over the last four 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" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- TPCL's cold storage customers require higher levels of continuity and restoration with interruptions to cooling and chilling being less acceptable as food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets.
- Economic downturn may increase the incidence of theft of materials and energy.

3.4. Basis for Service Level Targets

Historical Trends

When setting TPCL's service level targets the recent history of these service level measures are taken into account and it is recognised that these measures will be difficult and typically slow to change. Historical results are trended and projected to forecast future service levels and then adjusted to account for any particular initiatives or other issues that are anticipated to affect service levels.

Targets for network reliability and for financial and energy efficiency targets are generally set at the forecast levels to help drive the completion of performance enhancement initiatives. Targets for customer satisfaction are set based on the desired outcome of achieving positive customer experiences while accepting that targeting 100% satisfaction would be unrealistic.

Results over the last five years for the key reliability and energy efficiency service levels for which TPCL sets service level targets are listed in Table 21 and customer satisfaction as indicated from past surveys are shown in Table 22.

SAIDI and SAIFI for future years (starting with the 2015/16 disclosure year) will be calculated using the new methodology including new (lower) extreme event normalising boundaries and a 50% weighting for planned outages. Previously disclosed reliability results are shown however a recalculation of TPCL's SAIDI and SAIFI using the new default price-quality path method have been completed and are also shown as these are the more relevant figures used in TPCL's trending and forecasting.

Table 21: Reliability and Energy Efficiency History

Measure		2010/11	2011/12	2012/13	2013/14	2014/15
SAIDI	Previous Disclosure Method	209.06	238.10	191.40	177.77	259.12
	New DPP method	165.79	166.87	148.99	142.78	190.67
SAIFI	Previous Disclosure Method	3.21	3.04	2.59	2.87	3.04
	New DPP method	2.98	2.65	2.38	2.65	2.88
Load Factor		63%	64%	64%	62%	64%
Loss Ratio		6.8%	6.6%	7.2%	7.2%	6.8%
Capacity Utilisation		29.5%	30.3%	29.5%	30.6%	29.7%
Network OPEX / ICP		193	208	205	253	294

Measure	2010/11	2011/12	2012/13	2013/14	2014/15
Network OPEX / km	771	832	816	994	1172
Network OPEX / MVA	17350	18710	17612	21554	24995
Non-Network OPEX / ICP	136	146	184	137	117
Non-Network OPEX / km	541	581	733	539	464
Non-Network OPEX / MVA	12168	13065	15826	11686	9897

Table 22: Customer Satisfaction History

Attribute	Measure	2010/11	2011/12	2012/13	2013/14	2014/15
New Connections	Phone: Friendliness and courtesy. {CSS: Q3c}	4.9	4.0	4.8	4.5	-
	Phone: Time taken to answer call. {CSS: Q3a}	4.8	4.2	3.8	3.0	-
	Overall level of service. {CSS: Q5}	4.5	4.3	4.4	4.3	-
	Work done to a standard which met your expectations. {CSS: Q4b}	4.6	4.2	4.6	4.3	-
Planned Outages	Provided sufficient information. {CES: Q3a}	91%	100%	97%	100%	96%
	Satisfaction regarding amount of notice. {CES: Q3c}	87%	98%	97%	100%	98%
	Acceptance of maximum of three planned outages every year. {CES: Q1}	99%	98%	98%	97%	99%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	91%	91%	87%	96%	91%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES: Q4b}	72%	98%	85%	92%	96%
	Information supplied was satisfactory. {CES: Q8b}	92%	91%	96%	86%	92%
	PowerNet first choice to contact for faults. {CES: Q6}	17%	31%	33%	44%	45%
Voltage Complaints	Number of customers who have made voltage complaints {IK}	30	16	31	21	13
	Number of customers who have justified voltage complaints regarding power quality {IK}	16	0	12	14	9

{ } indicates information source; CSS = Customer satisfaction survey undertaken by sending questionnaire to customers with invoices, CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs

Benchmarking

In addition to trending of these results, benchmarking against other local distribution networks, as shown in Figure 28 to Figure 32, helps identify where TPCL might look to improve from current service levels. Any year to year changes predicted are expected to be small and need to be backed up by planned projects or initiatives which would impact service levels.

SAIFI – available EDB reliability results since 2013 show TPCL near the industry average but due to the low customer density and region covered the performance is considered good.

TPCL plans 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% after completion of the 4 year project – this has been estimated as annual reductions to SAIFI by 1.75%. Following completion of the automation project, the main focus will be to maintain similar reliability levels.

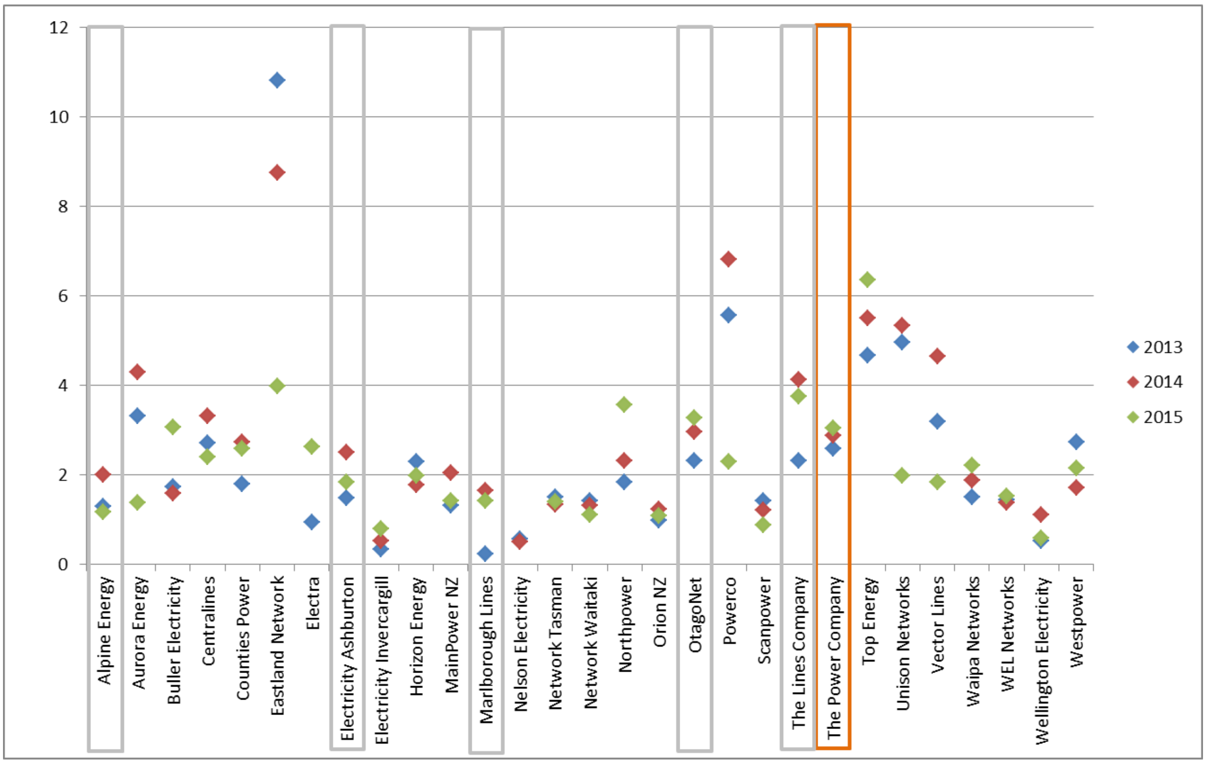

Figure 28: TPCL SAIFI Comparison with Local EDBs

SAIDI – available EDB reliability results since 2013 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 96% of people considered that faults were restored within a reasonable time.

TPCL plans 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 0.5% p.a. In addition, the distribution automation project is expected to provide increased reliability by reducing SAIDI by 8.8% after completion of the 4 year project – this has been estimated as annual reductions to SAIDI by 2.2%. Following completion of the automation project, the main focus will be to maintain similar reliability levels.

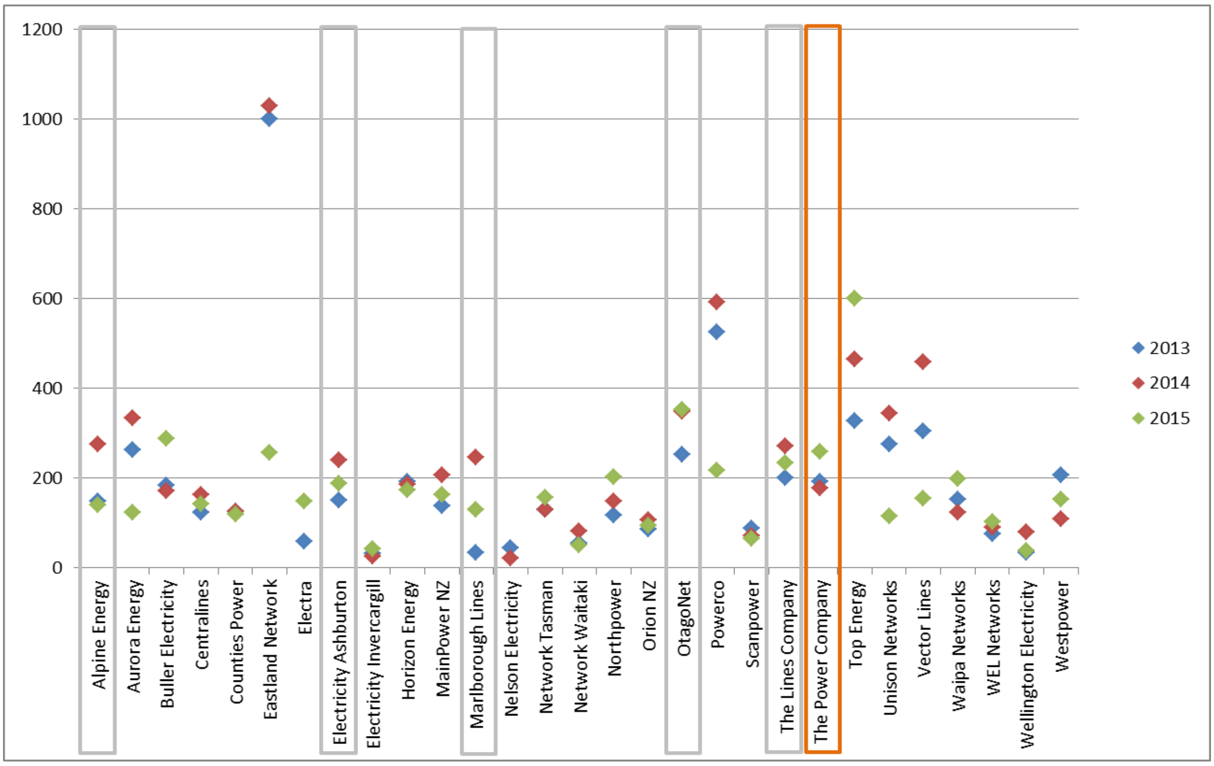

Figure 29: TPCL SAIDI Comparison with Local EDBs

Load Factor - LSI peak is due to New Zealand Aluminium Smelter (NZAS) and other network companies, with the most recent LSI peak occurring during early winter due to demand in the cities. Load control will have been used as the LSI peak is expected during the winter months.

Comparison with other networks shows that TPCL's load factor is average. TPCL is forecasting slight improvement due to transformer rationalisations planned.

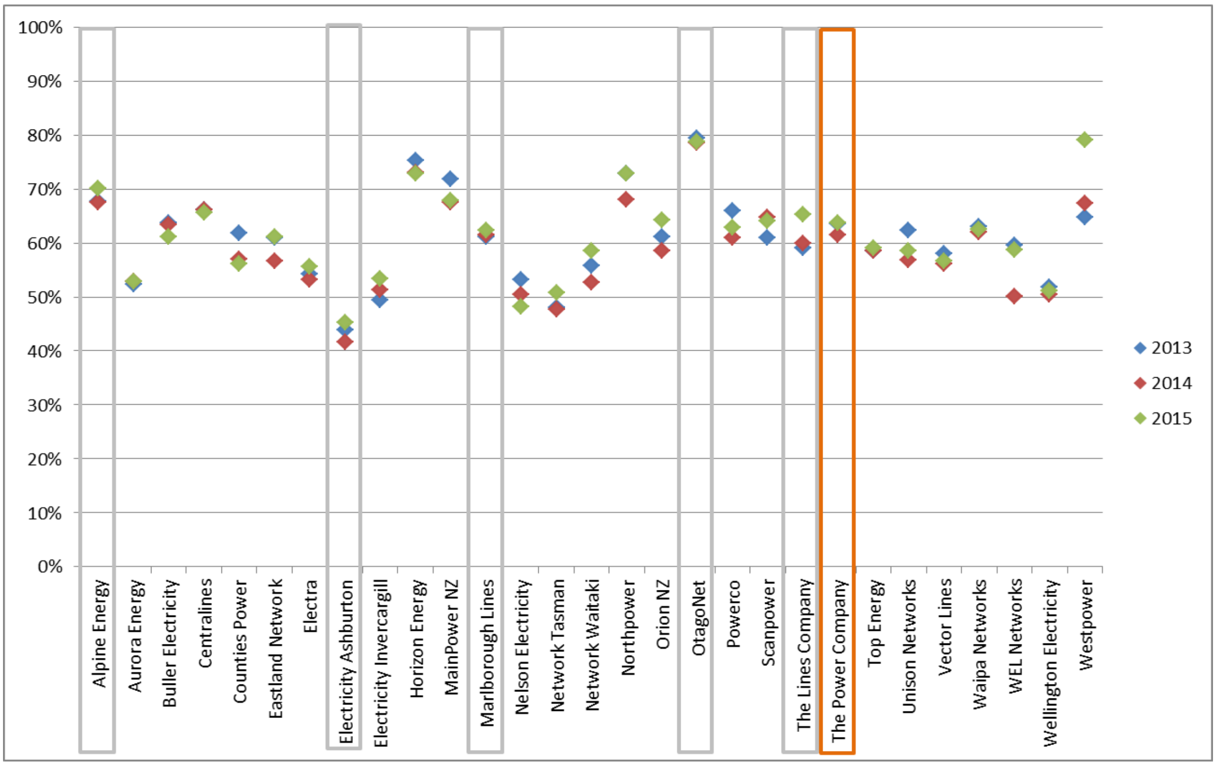

Figure 30: TPCL Load Factor Comparison with Local EDBs

Loss Ratio - Despite energy efficiency getting increasing focus it is generally uneconomic to improve the efficiency of primary assets to improve losses. Also as losses are paid for by retailers, there is no financial incentive for the network company to reduce them apart from other technical issues such as poor voltage or current rating of equipment. Upgrading network equipment as growth occurs is expected to maintain losses at approximately present levels.

Comparison with other network companies shows TPCL's network is average. Trending over a five year period shows network losses are flat. TPCL can expect a long term average of about 7% to be maintained however year to year results can vary due to retailer estimations.

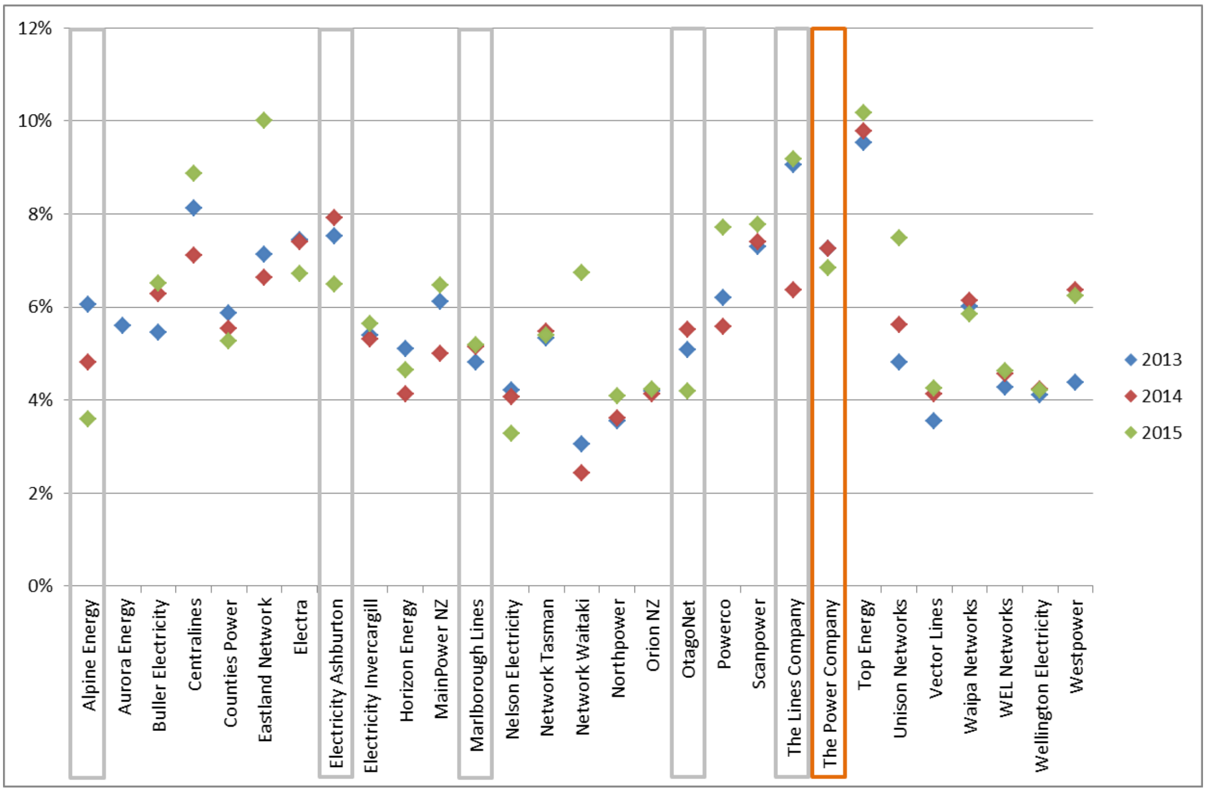

Figure 31: TPCL Loss Ratio Comparison with Local EDBs

Capacity Utilisation - Impact of expanding dairy industry 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[10] 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.

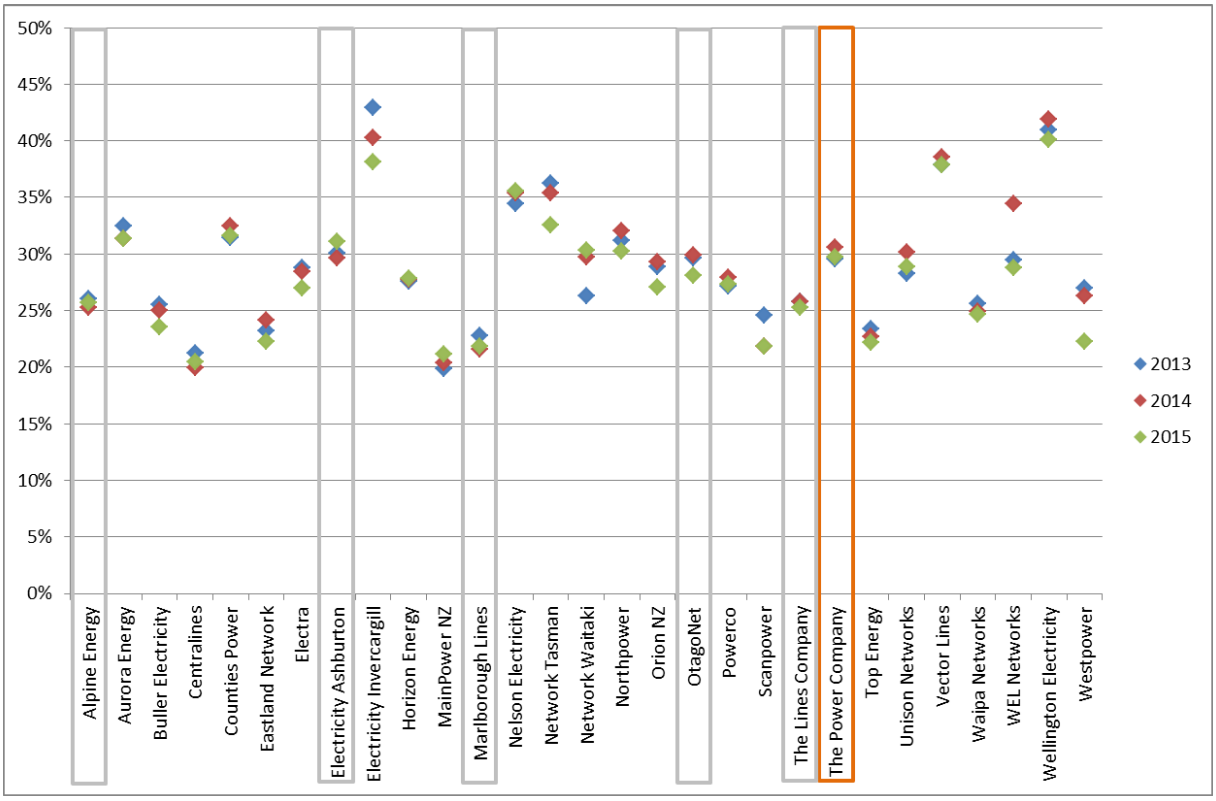

Figure 32: TPCL Capacity Utilisation Comparison with Local EDBs

Financial service levels – TPCL has redefined its financial service levels as discussed in section 3.2, comparison with similar lines companies must be made cautiously. When compared to the EDB's in its peer group, TPCL has the highest customer count, the second lowest connection density, and the middle level of connected distribution transformer capacity. This places upward pressure on the /km measures.

Examination of Figure 33 to Figure 38 shows that both Network OPEX and Non-Network OPEX are in line with or ahead of peers once adjustment is made for distortion of the /km metrics as described above.

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

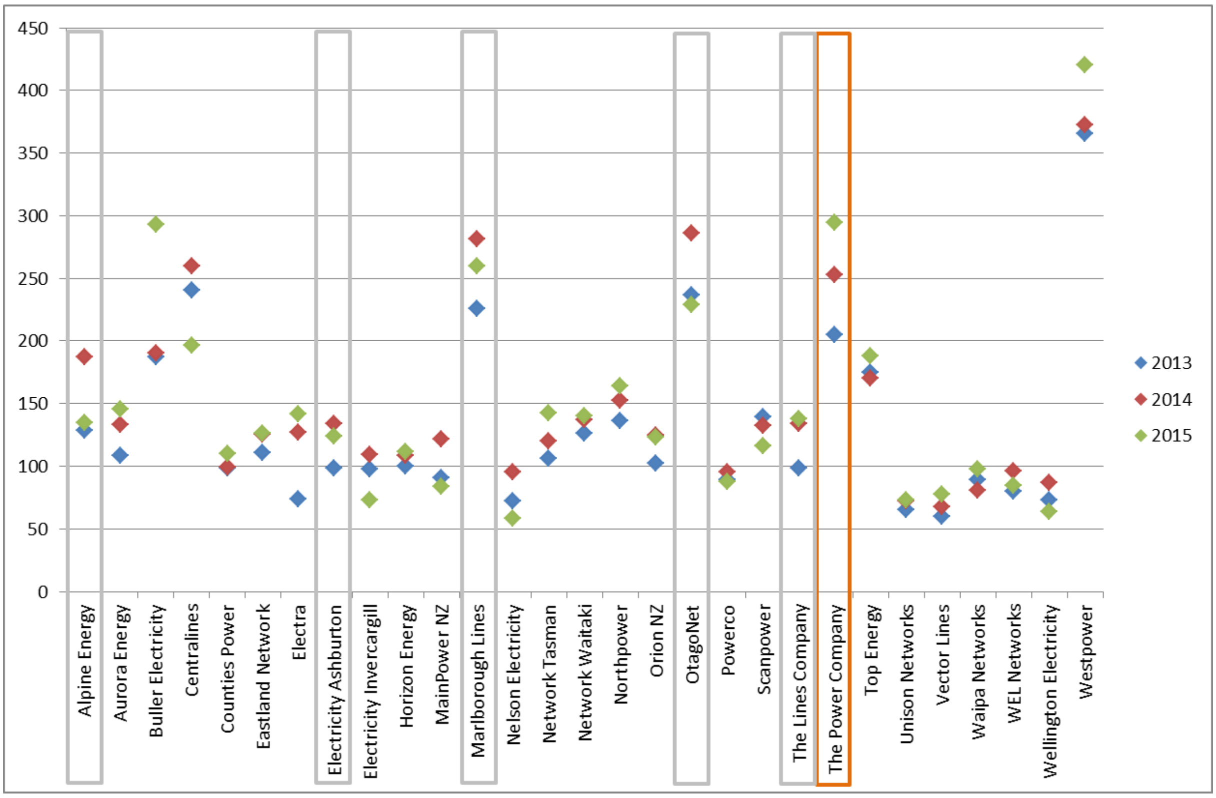

Figure 33: TPCL Network OPEX/ICP Comparison with Local EDBs

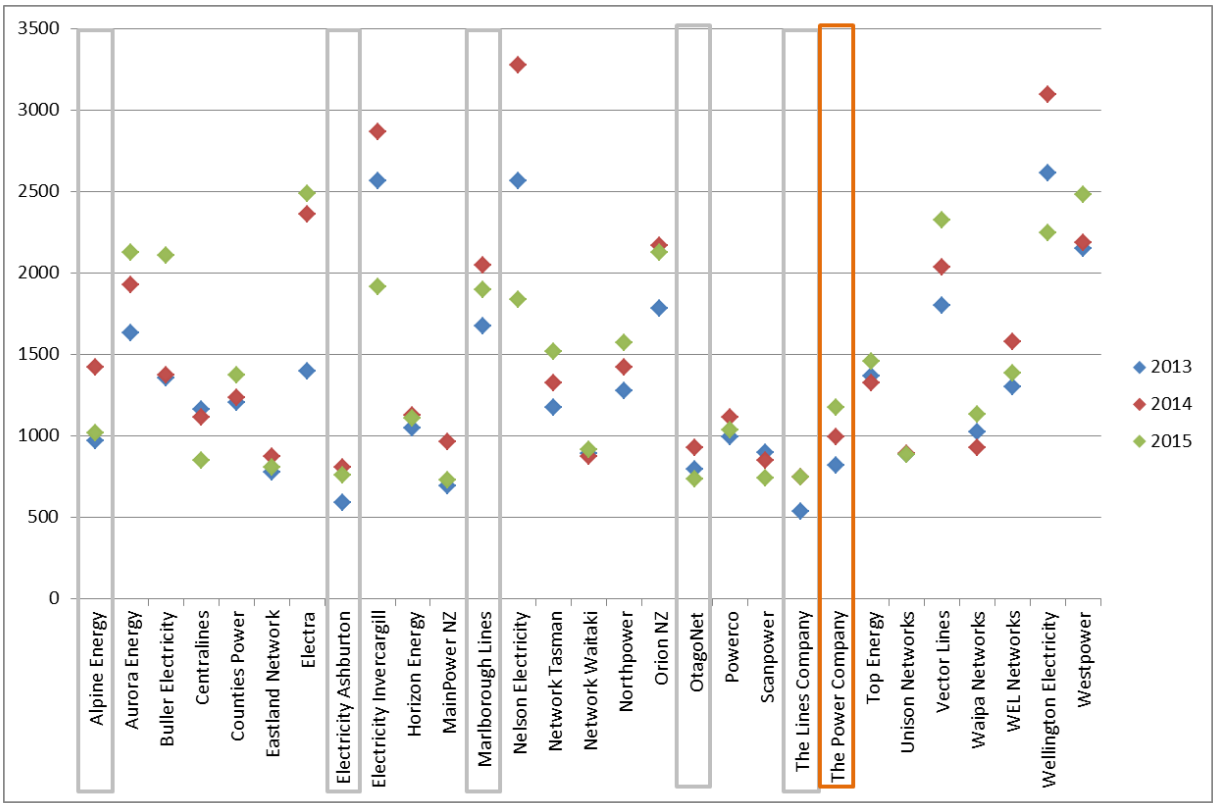

Figure 34: TPCL Network OPEX/km Comparison with Local EDBs

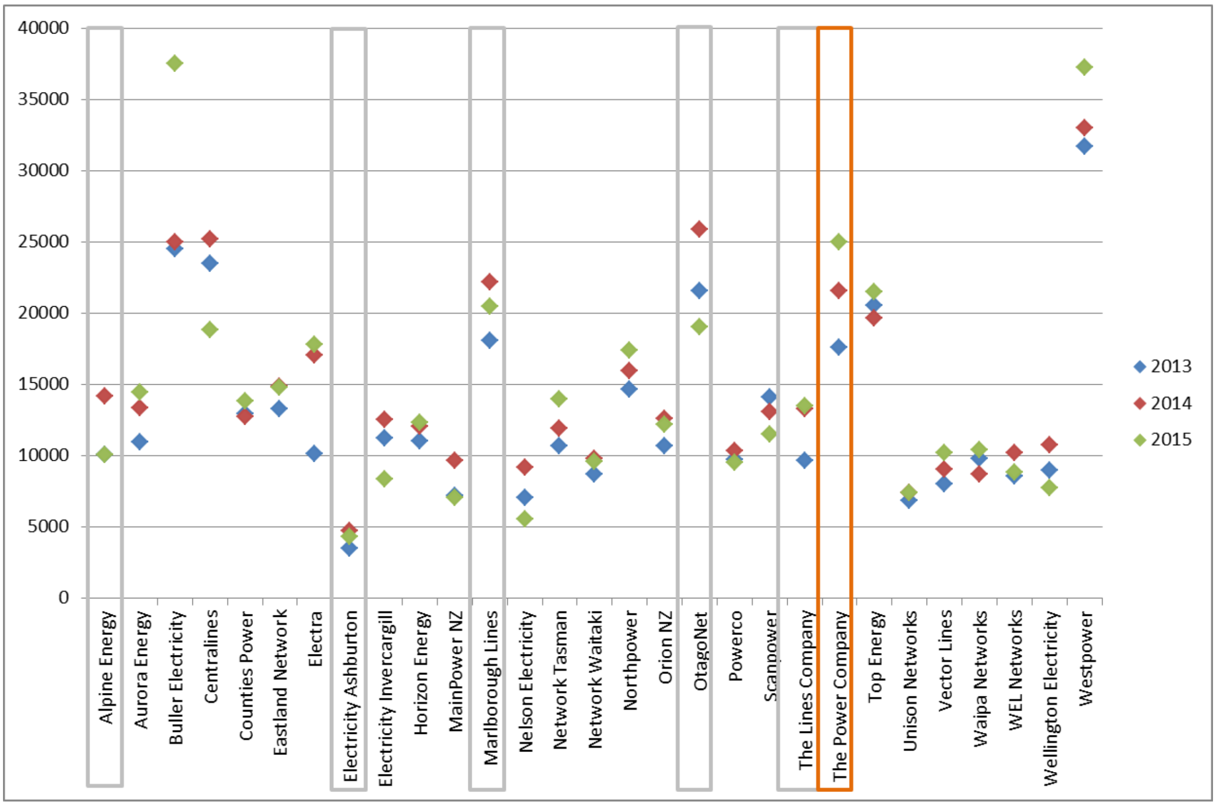

Figure 35: TPCL Network OPEX/MVA Comparison with Local EDBs

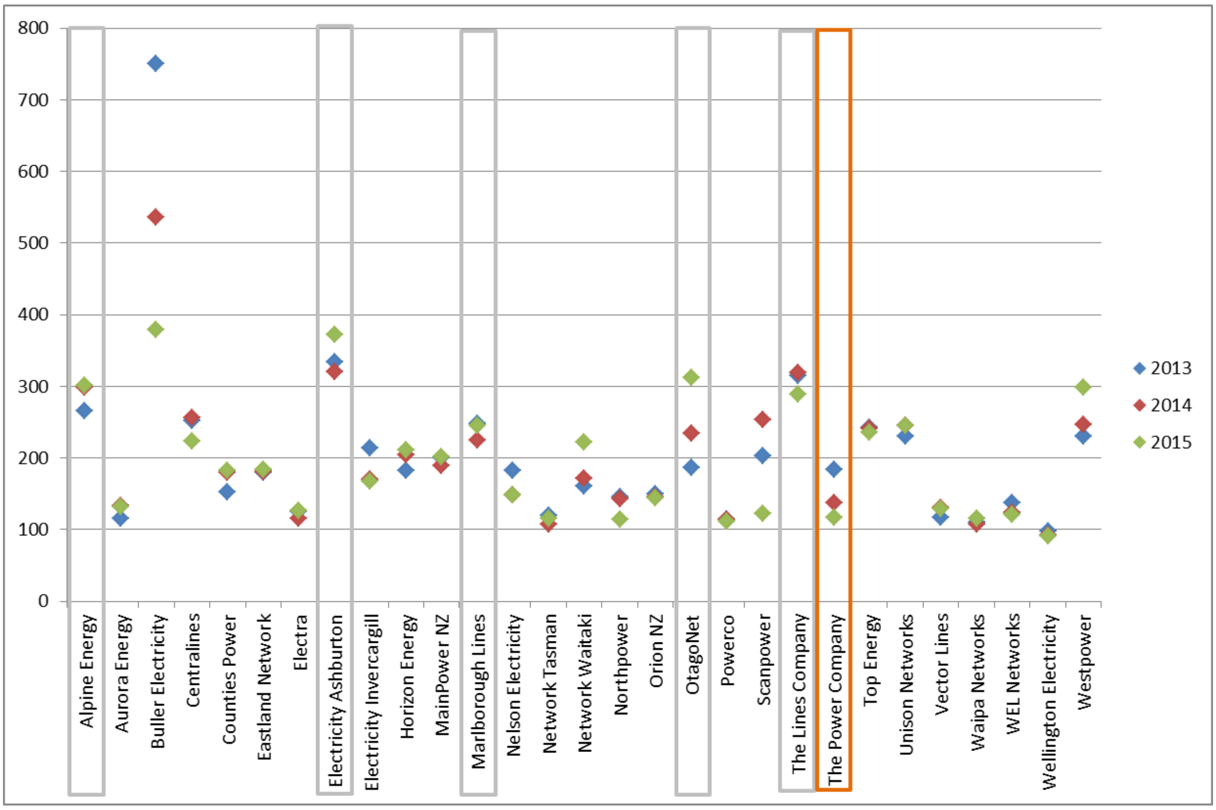

Figure 36: TPCL Non-Network OPEX/ICP Comparison with Local EDBs

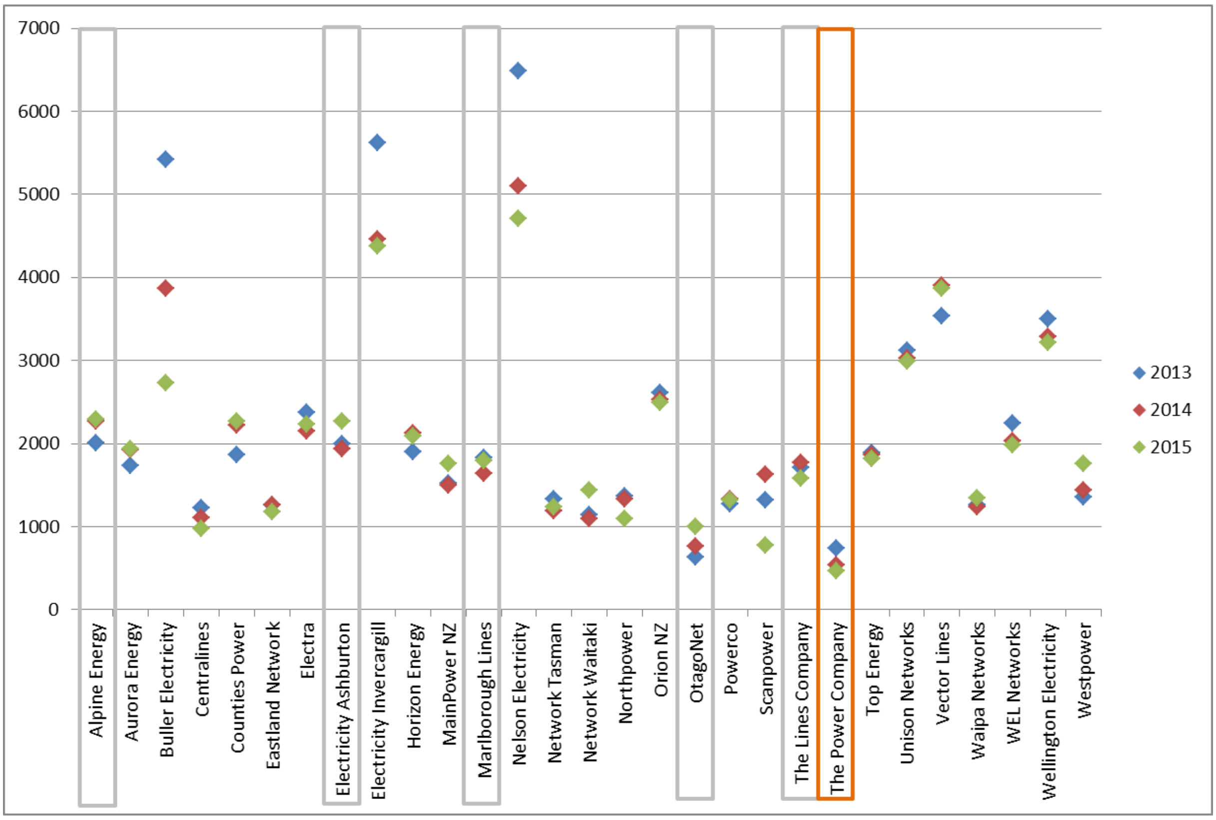

Figure 37: TPCL Non-Network OPEX/km Comparison with Local EDBs

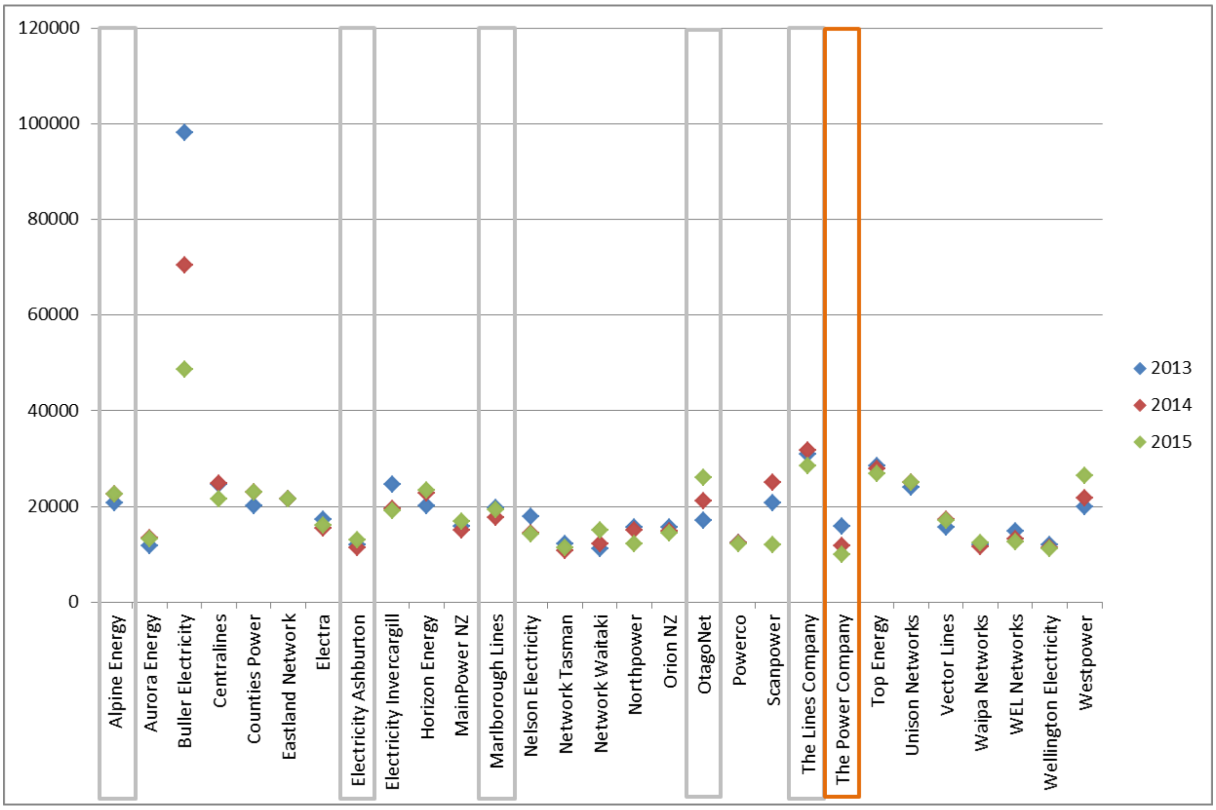

Figure 38: TPCL Non-Network OPEX/MVA Comparison with Local EDBs

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4. Development Planning

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

4.1. Development Criteria

Network development is primarily associated with creating additional network capacity for supplying increasing demand (customer load). Large generation or an aggregation of many small generators may also become the dominant driver for increased capacity on some areas of the network. Requirements for maintaining or improving service levels, whether driven by statute, customer and other stakeholders' desire or internal strategic initiatives, also create development drivers. While asset renewal is generally a lifecycle management requirement it may present an opportunity as the most economic time for development initiatives such as additional capacity, the introduction of new technology or more efficient alternative solutions.

Network developments are triggered by events that necessitate changes to network capacity or service levels. These trigger events may directly dictate a development requirement for example a connection request from an intending customer requires an increase in network capacity to match their additional load requirements. They may also be less direct such as when load growth exceeds a threshold for increased security; the security trigger threshold being predetermined based on a strategic "line in the sand" designed to provide particular service levels when applied consistently across the network. Identified development triggers and the thresholds at which they are set form the key criteria for TPCL's network development planning.

Growth Based Development Triggers

At its most fundamental level, demand is created by individual customers drawing (or injecting) energy through their individual connection points. The demand at each connection aggregates "up the network" through LV reticulation to the distribution transformer, then through the distribution network, the zone substation, the subtransmission network to the GXP and ultimately through the grid to the power stations. Load diversity tends to favour better load factor and capacity utilisation more and more with this aggregation of load up the network.

Demand growth creates the predominant driver for network development and therefore growth triggers have been identified and where appropriate corresponding thresholds have been set to achieve desired service levels. These development triggers provide simple scenario based indicators for development requirements although reliability incorporates probabilistic considerations. In meeting future demand while maintaining service levels, the first step 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 23.

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 later in this section (see Cost Efficiency) which also embodies an overall preference for avoiding new capital expenditure. As new capacity has 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 Lifecycle Planning.

Table 23: Development Triggers and Typical Network Solutions

Development	Trigger Point	Typical Network Solution
Extension	New customer requests a connection outside of the existing network footprint; often within network area but not immediately adjacent to existing infrastructure.	New assets are required to extend the network to the new customer. Additional capacity may also be need to be built into the nearest existing network and upstream assets depending on customer size.
Capacity	Load exceeds capacity rating of network assets (or encroaches on spare capacity required to be maintained) or voltage drops below acceptable levels; i.e. below 0.94pu at customer's premises. Proactively identified through network modelling and monitoring load data from meters or MDIs but may occasionally manifest as overload protection operation, temperature alarms or voltage complaints. The current roll out of smart meters will vastly improve ability to estimate loading and utilisation of asset capacity.	Replace assets with greater capacity assets. May utilise greater current ratings or increase voltage level (extension of higher voltage network, use of voltage regulators to correct sagging voltage or introduction of new voltage levels). Alternative options are considered prior to these capital intensive solutions but generally provide a means to delay investment; may be network based such as adding cooling fans to a zone substation transformer or non-network e.g. controlling peak demand with ripple control.
Security and Reliability	Load reaches the threshold for increased security as defined in TPCL's security standard set out later in this section (see Security Standards). Customers especially large businesses may request (and be willing to provide a capital contribution for) increased security.	Duplicating assets to provide redundancy and continued supply after asset failures. Increase meshing/interconnection to provide alternative supply paths (backups). Additional switching points to increase sectionalising i.e. limit amount of load which cannot have supply reinstated by switching alone after fault occurrence. Automation of switching points for automatic or remote sectionalising or restoration.

Service Level Changes

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

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

Relationship with Lifecycle Maintenance

It is important to understand the relationship between network development, lifecycle management practices and the network service levels discussed in section Service Levels. Demand growth on fixed network assets erodes supply reliability over time as a greater number of customers or level of demand is affected when a supply interruption occurs. Using increased network maintenance to preserve network reliability against demand growth requires a shift away from the most economic asset age profiles (generally about 50% average life) which then must be sustained so this approach is uneconomic as well as inherently limited. Essentially with a long term view, lifecycle maintenance counteracts declining reliability in the face of network aging and deterioration while network development counteracts declining reliability in the face of demand growth.

Cost Efficiency

In the interests of cost efficiency, TPCL aims to minimise capital expenditure when determining the most appropriate development option for the network. Being cost efficient with network development requires a "just enough, just in time" approach for the determination of appropriate new capacity as well as an appropriate level of standardisation and these strategies will be discussed later in this section. Before capital intensive upgrades are required the following actions, in a broad order of preference, are considered as solutions when development triggers have been reached.

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

power transformers. Installation of voltage regulating transformers may be economic where voltage drops below acceptable levels but current capacity is not fully utilised.

- Retrofitting high-technology devices that can exploit the features of existing assets including the generous design margins of old equipment. An example might include using advanced software to thermally re-rate heavily-loaded lines, using remotely switched air-break switches to improve reliability or retrofit core temperature sensors on large transformers to allow them to operate closer to temperature limits.

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

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

Standardisation

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

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

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

Virtually all of the TPCL network assets are standardised to some degree either by being an approved network material or asset type or by selection and installation in line with network standards. Examples of standardisation are listed in Table 24:

Table 24: Equipment Standardisation

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

Security Standard

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

Provision of alternative supplies: achieved by providing one or more inter-feeder tie switches (interconnection points). Urban areas can naturally achieve a high level of meshing with many tie points between feeders whereas rural area feeders may need significant line extension to meet adjacent feeders. The number of switches effectively dividing up a feeder also contributes to security, with the greater the number, the smaller the section which must be isolated after a fault for the duration of the repair. This requires those adjacent feeders to maintain spare capacity.

Duplication of assets: so that in normal service both sets of assets share the load. Then when a duplicated asset malfunctions it can be isolated and all load is transferred to the remaining asset. This approach generally provides the greatest security as there is typically no interruption to supply though duplication of assets tends to be more expensive than merely allowing greater capacity in existing adjacent assets.

Use of generation: may be used to either provide an alternate supply or at least supplement supply and reduce capacity requirements for backup assets. To be of any use from a security perspective, generation would need to have close to 100% availability. Diesel generation has good availability so is practically able to be used occasionally to manage network constraints though it is too expensive to run for extended periods. Other forms of generation such as run-of-the-river hydro, wind or solar, do not provide the needed availability due to lack of energy storage so cannot be relied on to respond to varying load or provide sufficient generation during peak demand periods.

Use of demand management: (interruptible load) can be used to avoid security triggers based on load level or avoid capacity of backup assets being exceeded.

The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feeding on the 11kV providing a third tier of security. Table 25 summarises the security standards adopted by TPCL. Where a substation is for the predominant benefit of a single customer, their wish for security will over-ride this standard.

Table 25: 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 by isolation and back-feeding. Isolated section restored after time to repair.
A(ii)	Less than 1MW	All load restored after time to repair.

Determining Capacity

When new or increased capacity has been determined as necessary the amount of new capacity must be quantified. Appropriate asset sizing is balanced to fit within TPCL's guiding principle of minimising the long term cost of service of sufficient quality ahead of demand.

Sizing network equipment carries a cost efficiency risk for assets being underutilised if not done correctly. While sizing a particular asset for the present time is relatively straight forward, load growth makes appropriately sizing an asset more difficult, especially for asset lifetimes over periods of high growth and growth unpredictability. Installing assets with too much spare capacity means an over investment however if assets are undersized the asset will need to be replaced early before their natural end of life. In many cases standardisation will limit the options available to assist in the selection of capacity.

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

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

Examples of criteria to determine capacity of equipment in line with the above considerations are as shown in Table 26. Clearly understanding load growth into the future is crucial to making sound investment decisions. The method and considerations for forecasting network demand is discussed later in this section.

Table 26: Capacity Selection Criteria

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

Energy Efficiency

TPCL strives to make decisions based on the best outcome for its customers and as customers pay for losses on the network in their energy bills, cost benefits are considered in delivering energy as efficiently as possible. However selection of more efficient assets rarely is justified as a cost benefit to customers. In the few cases where there is an economic justification to reduce losses in this way TPCL will use these solutions, for example specifying low loss cores used in the magnetic circuits of transformers. Otherwise power consumed by TPCL and its organisational partners is used responsibly with heating of substation buildings and PowerNet’s office buildings heated using efficient heat pump technology, insulation and draft control etc. where appropriate.

Additionally TPCL formed the Southland Warm Homes Trust (SWHT) in 2008 with EIL. The SWHT works in partnership with government, the Energy Efficiency and Conservation Authority (EECA) and local funders to provide subsidies for insulation and heating assessments and retrofits for warmer, healthier homes across the Deep South region. PowerNet provides administration and financial reporting services on behalf of the (SWHT).

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

Identifying the Best Option

Of the many possible development options that may be identified for meeting demand and service levels, the option which best meets TPCL's investment criteria is determined using a range of analytical approaches. Each of the possible approaches to meeting demand will contribute to strategic objectives in different ways. Increasingly detailed and comprehensive analytical methods are used for evaluating more expensive options. Table 27 summarises the decision tools used to evaluate options depending on their cost.

Table 27: Decision Tools Used Based on Cost

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

Prioritising Development Projects

Development projects are prioritised in line with the principles set out in Drivers and Constraints – Managing Conflicting Stakeholder Interests when competition for resources exists. Safety, viability, pricing, supply quality and compliance is the order of priority for manging these conflicts. These factors cannot be applied absolutely as each project will have its own combination of these factors presenting in various degrees. Instead a weighting approach is used recognising the relative severity of these factors between projects and their importance relative to each other. Each factor also implicitly recognises risk however this may need to be rationalised as it affects the AWP as a whole. The resulting prioritised AWP is presented to the TPCL Board for approval with supporting justification in the updated AMP.

4.2. Forecasting Demand and Constraints

As development projects can take many months or even years to complete, understanding when trigger points may be exceeded in the future is necessary to ensure capacity can be made available by the time it is needed. This involves demand forecasting based on trends taken from historical data as well factoring in the many demand drivers which may cause future deviation from status quo trends.

TPCL's Current Demand

TPCL's maximum demand (MD) of 132.815 MW did not occur at the same time as the Lower South Island (LSI) peak which occurred at 10:30 on the 26th of May 2014. All of the GXPs which provide supply to TPCL had maximum demands which occurred at a different time to both the overall TPCL MD and the LSI peak. The TPCL coincident demand at the time of the LSI peak was 106.88 MW. The individual maximum demands are shown in Figure 39.

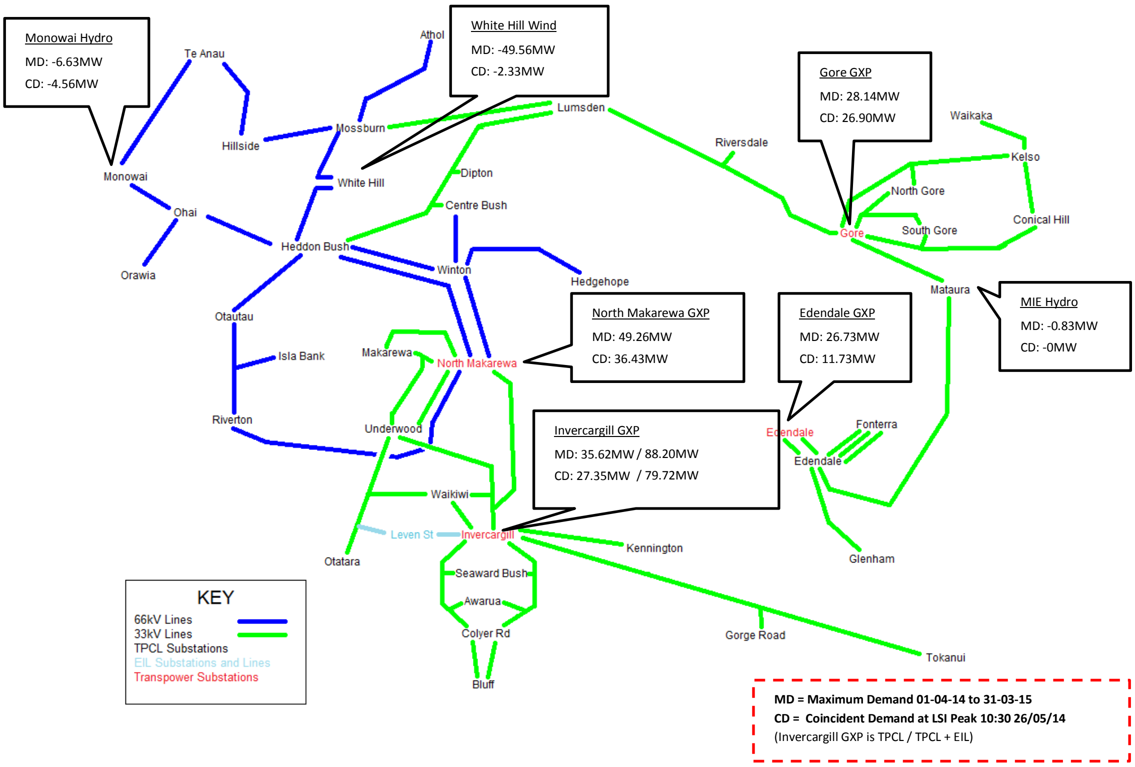

Figure 39: GXP and Generation Demands

Demand History and Trend

Growth trends are difficult to establish as there is somewhat random variation on top of underlying growth. Generally the trend taken over the latest ten year period will be quite different year to year as the most recent years' data is included and data beyond ten years is excluded. This is again quite different to a 20 year trend. Longer term trends tend to "average" out the random variations but lose sight of recent changes to underlying growth. Some causes may be identified with hindsight but are typically difficult to predict, for example a drought initiating increasing irrigation load. Growth is plotted and trend lines over various time periods are considered along with known events effecting consumption patterns before arriving at a reasonable estimate of growth which can be used for forecasting future demand and consumption.

Figure 40 shows the overall TPCL data since 1960 and highlights the flattening out since the late '80s. Recent flattening of maximum demand has been affected by changes in Transpower's pricing methodology; these changes are not apparent in energy growth.

Analysis of historic demand and energy usage over the last 10 years or so gives maximum demand growth of between 0.5-2.0% and energy consumption growth of about 1.2%. The overall effect of drivers of future demand mentioned in Drivers of Future Demand is not expected to significantly alter these growth trends in future years. Historically, TPCL has experienced an average annual demand growth of about 2.0% for the last 20 years. This growth has been distorted with Transpower's introduction of TPM[11] where individual ELB peaks have been replaced by a regional grouping. This has allowed some relaxing of winter load control during the year due to the increased summer loading (due to increased dairy farming on the TPCL network). 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. No reductions are foreseen due to the removal of the requirement to supply in 2013, as the few sections that could be considered uneconomic do not contribute significant load. The following sections examine in detail the most significant drivers of the network demand over the next 10 to 15 years.

[11] 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.electricitycommission.govt.nz/rulesandregs/rules Part F, Section IV for more details.

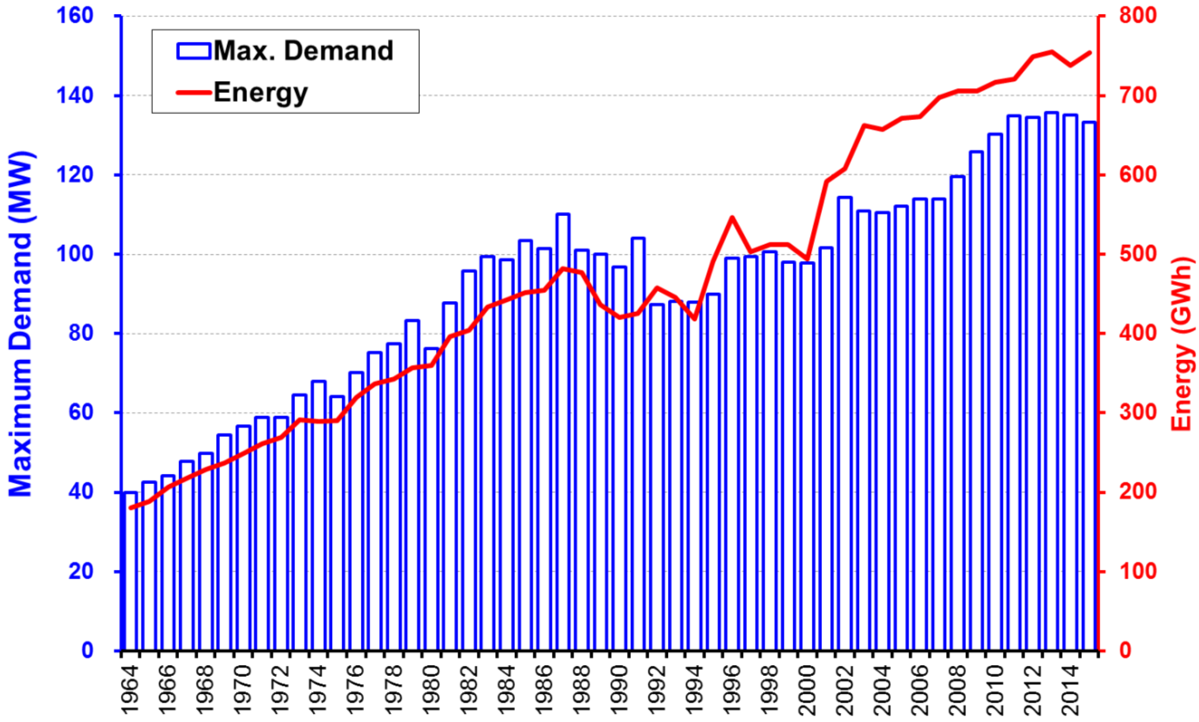

Figure 40: Maximum Demand and Energy Transmitted

Each zone substation recorded the maximum demands as listed in Table 28. The 99.9 percentile demand is given to remove any short term load transfers and is more indicative of actual area maximum demand.

Table 28: Substation Demand

Zone Substation	Firm Capacity (MVA)	Max Demand (MVA) 2014/15	99.9% Percentile Demand (MVA) 2014/15	2013/14	2012/13	2011/12	2010/11	2009/10
Athol	5.0	0.95	0.61	-	-	-	-	-
Awarua Chip Mill	5.0	1.04	0.76	3.69	3.76	3.59	3.72	3.50
Bluff	12.0	4.75	4.53	4.49	4.41	4.62	4.46	4.66
Centre Bush	5.0	4.15	3.97	3.97	4.43	4.25	3.71	3.61
Colyer Road	12.0	-	-	-	-	-	-	-
Conical Hill	5.0	2.23	1.10	2.50	3.08	2.20	1.14	2.47
Dipton	1.5	1.85	1.73	2.03	1.70	1.66	1.59	1.60
Edendale Fonterra	46.0	24.23	23.35	22.36	23.00	22.91	21.47	21.31
Edendale	12	6.77	6.40	6.54	6.71	6.35	6.44	6.41
Glenham	1.5	1.73	1.18	1.1	1.14	1.28	1.06	1.09
Gorge Road	1.5	3.09	2.66	3.02	2.84	2.32	1.87	1.81
Heddon Bush	15.0	8.22	7.60	8.45	8.30	8.77	7.63	8.56
Hedgehope	5.0	-	-	-	-	-	-	-
Hillside	2.25	0.75	0.68	0.65	0.62	0.62	0.62	0.63
Kelso	5.0	4.58	4.32	4.22	4.27	4.27	4.20	4.11
Kennington	12.0	5.81	5.76	5.67	3.86	3.99	4.26	4.27
Lumsden	5.0	3.41	3.22	3.77	3.79	3.60	3.44	3.52
Makarewa	12.0	6.5	6.29	6.77	5.80	5.13	5.11	5.32
Mataura	10.0	6.35	5.99	6.99	8.55	8.24	7.91	8.00
Monowai	1.0	0.18	0.16	0.16	0.34	0.36	0.35	0.33
Mossburn	3.0	2.08	1.96	1.87	1.76	1.77	1.83	1.74

Zone Substation	Firm Capacity (MVA)	Max Demand (MVA) 2014/15	99.9% Percentile Demand (MVA) 2014/15	2013/14	2012/13	2011/12	2010/11	2009/10
North Gore	10.0	8.6	7.68	7.72	9.66	7.86	9.13	7.88
North Makarewa	45.0	49.71	45.7	45.06	45.73	43.09	44.90	43.60
Ohai	5.0	2.7	2.57	2.54	2.60	2.22	2.33	2.11
Orawia	5.0	3.1	2.99	2.95	3.10	2.76	2.71	2.74
Otatara	5.0	4.16	3.65	3.70	3.91	3.91	3.80	3.70
Otautau	7.5	5.22	4.22	4.74	4.05	4.11	4.43	4.01
Racecourse Road (EIL)	23.0	10.90	9.20	9.40	12.70	10.10	9.40	10.10
Riversdale	5.0	5.11	5.07	4.69	4.58	4.54	4.46	4.30
Riverton	7.5	4.79	4.56	4.69	5.16	4.76	4.71	4.32
Seaward Bush	10.0	8.52	8.03	7.31	8.28	8.76	8.62	8.40
South Gore	12.0	11.36	8.09	7.22	8.28	8.01	8.11	8.00
Te Anau	12.0	5.67	5.11	5.48	5.46	5.30	5.44	5.21
Tokanui	1.5	1.16	1.06	1.08	1.03	1.08	1.05	0.97
Underwood	20.0	12.93	12.48	11.73	11.79	11.79	11.95	12.47
Waikaka	1.5	1.31	0.75	0.73	0.79	1.16	0.94	0.96
Waikiwi	12.0	10.42	10.03	10.22	12.08	12.25	12.42	11.55
Winton	12.0	12.45	11.8	12.29	11.82	11.45	11.04	10.52
White Hill (Wind)		-57.09	-56.81	-56.83	-56.84	-56.97	-56.93	-56.88
Monowai (Hydro)		-6.88	-6.56	-6.59	-6.41	-6.47	-6.59	-6.63

Drivers of Future Demand

Future demand is forecast by understanding historical trends, projecting these trends into the future and altering these projections by factors which cause deviation of demand away from the current trends.

Figure 41 shows population projections for TPCL's network area as estimated by Statistics New Zealand from 2013 Census data. As well as total population the group 65 years and older is shown highlighting the predicted significant aging of the population.

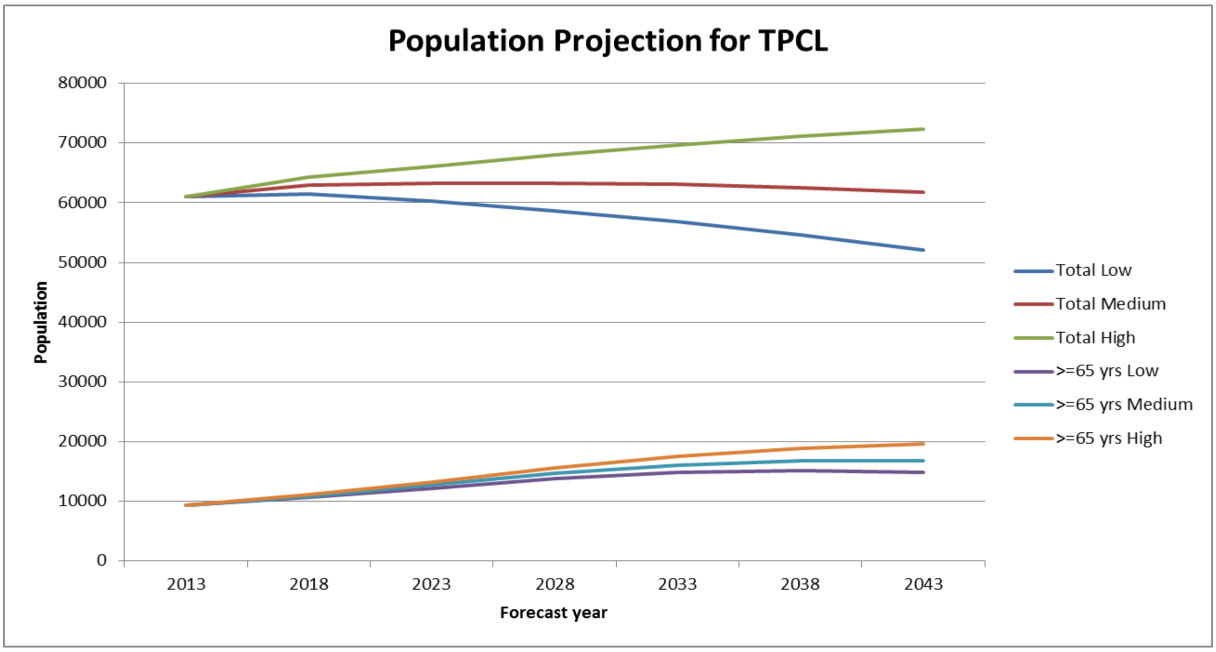

Figure 41: TPCL Population Projections

Table 29: Drivers of Future Demand

Demographics & Lifecycle	
Population Growth and Decline	**Effect:** Population static initially but increasing in future years to approx. 10% above 2016 levels by 2025. This corresponds to a similar increase in demand of 10% assuming similar housing and living arrangements and employment is available from a similar business profile.
Description: The population of TPCL's distribution area is approximately 61,000. Census population projections for TPCL's distribution area are shown in Figure 41. The high projection shows population increasing by 10% by 2026, medium projection increasing by 4%, and low projection showing a 3% decline out to 2026. Population trends have been noticed with concern by Southlanders and in response the Southland Regional Development Strategy has as its main target an increase in population to 105,000 by 2025 for the Southland region. This represents an average increase of about 1000 people per year from now and if achieved would be expected to happen gradually at first and gain momentum in future years. It is expected that the vast majority of growth would occur in urban areas of which Invercargill is Southland's largest metropolitan area. Further, Southland Institute of Technology as a tertiary education provider is seen as an important attractor for potential migrants located within central Invercargill. Invercargill would attract the majority of potential migrants however the Invercargill area is supplied by both EIL and TPCL. TPCL supplies the outer regions of the city and as such expansion of Invercargill for additional housing would therefore often likely fall within TPCL's network boundary. EIL does have some undeveloped land suitable for housing and there is further potential for in-build with subdivided sections which if increased demand eventuates would be utilised to some extent. Business expansion is also a target for the Southland Regional Development Plan and the majority of industrial expansion would expect to be within TPCL's network area.	
Housing Density and Utilisation	**Effect:** Housing density increases allow and are expected to create growth in TPCL's domestic supply demand. Increasing utilisation (more people per household) has the opposite effect
Description: Housing density can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand. Expansion into new subdivisions at the edge of Invercargill would see growth on TPCL's network. The gradual trend toward smaller family size is expected to continue and this may counteract some of the growth caused by increased density	
Rural Migration to Urban Areas	**Effect:** Especially retirees (baby boomers)
Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has been seen in Southland also. Farming has been shedding jobs for some time as improved technology means fewer people are required per unit of production. This supports the above assumption that Southland's urban areas, particularly Invercargill is likely to see the vast majority of population growth if the population growth strategy is successful. Figure 41 shows the number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2026. The impact of farmers retiring to urban areas increases demand for townhouses in desirable locations. This is not a new effect and therefore there is no increase in growth expected above trending of previous years.	
Increasing Energy use per Customer	**Effect:** Growth minimal and included in existing demand trends.
Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months. Consumer goods including appliances and electronic technology are generally becoming more affordable however while the numbers of these goods per household may be increasing they are often not used at the same time. Energy efficiency is also improving for many of these items offsetting any increases in household demand.	

Demographics & Lifecycle	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for TPCL over the next ten years. Incorporates growth anticipated from Table 30; council fuel burner constraints.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. Around 8% of energy consumption comes from gas and solid fuel based space heating and has the potential to be replaced by electrical heating. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. Heat pump installation cost is a barrier for many people and some prefer the ambience of other heat sources. Therefore complete conversion to electrical heating cannot be expected and further conversions will occur over an extended period of time. The additional demand that arises will be partly offset by increased use of heat pumps over other traditional electric heaters which can use three to four times the power to run. Conversion will be both driven and constrained by the Breathe Easy clean air initiative discussed in Table 31	
Electricity Affordability	**Effect:** Reduction of customer numbers and load
Description: Line charges in the Southland regions reflect TPCL's high cost of transporting energy over large distances to limited numbers of customers. These costs make alternative technologies such as solar and photovoltaic more attractive to customers. While these alternative technologies are not yet competitive with traditional supply, their gradually declining costs may make them more competitive toward the end of the planning period.	
Irrigation & Dairy	**Effect:** Accelerated growth for dairy conversions in pastoral areas of Southland and additional irrigation in the Northern Southland
Description: Irrigation is becoming more common in the drier climate of Northern Southland. TPCL substations most likely to be affected are Dipton, Lumsden, Riversdale, Mossburn and Athol. Environment Southland has placed more stringent restrictions on the use of water which encourage the use of spray irrigators; which are both more water-efficient and more electrically demanding than the pre-existing irrigation schemes. The Ministry of Primary Industries has also placed more stringent requirements on the chilling of milk on dairy farms, which is expected to increase load in areas with a substantial dairy population. This affects most of TPCL's rural zone substations.	

Table 30: Drivers of Future Demand

Environment and Climate	
Removal of Coal as Heating	**Effect:** Continuation of existing trends towards electrical space heating
Description: Solid Energy had previously advised it would withdraw from supplying coal to the household market by the beginning of 2013 in line with the National Environmental Standards for air quality but has since been revised to 2016. This would likely result in an increase in use of alternative sources of heating including heat pumps with resulting growth expected to affect residential areas. Heat pump usage has naturally continued to increase as a convenient and efficient form of heating and the impact on demand has been less than earlier anticipated, therefore existing growth has been assumed to continue.	
Council Fuel Burner Constraints	**Effect:** Continuation of existing trends towards electrical space heating
Description: Proposed updates to the Regional Air Quality Plan have been advised and include prohibition of open fires from September 2015 and prohibition of non-approved burner/boilers installed; • before January 2001 from January 2016, • between January 2001 and September 2005 from January 2021, • between September 2005 and January 2010 from January 2025, • after January 2010 from January 2029. Approved boilers and burners are those which meet the national environmental Standards for emissions and thermal efficiency. This phase-out of inefficient heating will require replacement and some degree of conversion to electrical heating with heat pumps is to be expected.	

Conversion with be both driven and constrained by the Breathe Easy clean initiative. Often heat pumps will be selected as replacement for prohibited burners as they are phased-out however those opting for efficient burners as replacements are less likely to install heat pumps for a significant period afterward.

Energy Conservation Initiatives	**Effect:** Customers are responding to marketing, strategies and the availability of energy efficient products to reduce their consumption. Considered a significant driver of demand contraction however is mostly recognised within existing trends. Energy savings are likely to increase to some degree estimated at 0.5% (demand contraction) over the next ten years.

Description: Energy efficiency in consumer appliances is increasingly popular due the combination of government or local council drivers, marketing and consumer demand. Replacement of appliances with improved energy efficiency provides customers with the same benefits or standard of living while requiring less power consumed and so reduces power bills. Similar drivers are contributing to further installations of insulation which also assists in reduced power requirements for heating (see above section Energy Efficiency).

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

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

Table 31: Drivers of Future Demand

Economy

Major Industry Continuance or Growth	**Effect:** Assumption that existing industries will continue and major new industries will eventuate

Description: Tiwai aluminium smelter takes supply directly from the transmission grid however it helps support many businesses and individuals both directly and indirectly and loss of this business could have a major impact on the local economy and therefore growth on TPCL's network particularly in the Invercargill area.

It is considered most likely Tiwai will continue to be viable in the short to medium term at least and therefore no change to growth forecasts has been made.

The Great Southern Basin is a potentially viable location for deep water oil drilling. Possible flow on effects if a deposit is developed could create infrastructure and demand at the Bluff port however Dunedin port could be favoured over Bluff. The likelihood and level of growth from this effect is quite uncertain and has therefore not been included in forecasted growth.

$NZD variation & commodity cycles	**Effect:** The improving economy will support the growth initiatives discussed in population growth and lifestyle.

Description: Economic downturn and recovery affects investment by customers and therefore the rate of growth. The global financial crisis affected the rate of growth causing a temporary stalling of new connections. A gradual recovery with growth increasing slowly has been evident.

Table 32: Drivers of Future Demand

Technology

Electric Vehicles	**Effect:** Negligible over planning period

Description: With significant penetration into the transport sector, electric vehicles have the potential to have a large impact on network demand. It is expected that the majority of this load should be able to be

Technology	
managed so that it is consumed at off-peak times (especially overnight) and therefore would have much less impact on peak demand and even improve load factor. Some demand increase is expected in the long term but is likely to be beyond the ten year planning horizon so has not been included in growth forecasts.	
Distributed Generation	**Effect:** Generation tends not to coincide with network peak demand therefore the effect on network peak demand is expected to be negligible.
Description: The vast majority of the distributed generation seen so far has been solar installations and this trend is expected to continue for the foreseeable future. Relatively low numbers of new solar connections have been seen on TPCL's network to date although the trend is gradually increasing as economics improve for solar installations. However the overall generation connection density is very low and not expected to increase enough over the ten year planning horizon to affect peak demand. Without energy storage solar generation is only able to offset load during available sunshine hours which don't typically coincide with peak demand; especially with shorter days over the colder winter months when the greatest demand occurs on the network. Additionally variation in the weather means solar generation cannot be relied on at any time including peak load periods. Total energy consumption is likely to be reduced to some extend by solar installations within the planning period however energy does not tend effect planning which focusses on providing capacity for peak demand periods.	
Energy Storage	**Effect:** Not expected to be economic for customers within the ten year planning horizon and therefore negligible effect on network demand.
Description: Energy storage is one technology that could have a large impact on network demand especially if used in combination with distributed generation installations. Storage could make it feasible for customers to go "off-grid" with a sufficiently sized solar system or other generation source. However this technology is not expected to be economic for some time and so is not considered likely to impact on peak network demand in the next ten years.	
Energy Efficiency	**Effect:** Negative growth driver accounted a part of the above discussed driver Energy conservation initiatives.
Description: Improving energy efficiency has been a government strategy for several years as discussed in Table 30 - Energy Conservation Initiatives. It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.	
On-line shopping	**Effect:** Likely to negatively affect the business sector in TPCL's network area however the overall effect on demand is expected to be relatively insignificant.
Description: Shopping online continues to become more and more popular with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within TPCL's network area. However there is also some opportunity for local businesses to connect with customers outside of Invercargill or even worldwide and this will somewhat offset the potential loss of business. It is expected the overall effect will be a loss for the business sector in TPCL's area.	
Internet of Things	**Effect:** It is not considered likely that this technology will be extensively used in the near future and has therefore not affected demand forecasts. In the case that it does eventuate in the next ten years the uptake of this technology is likely to be gradual and so plans would be able to react sufficiently quickly.
Description: The internet of things refers to the interconnection of the internet and many electronic enabled devices. In particular smart appliances may enable centrally controlled management of a dwelling's or business's consumption so that maximum demand may be minimised by staggering load to make the most of potential load diversity. This could enable customers to reduce line charges in line with a reduced network capacity requirement for their supply.	

Demand Forecasts

The overall impact of the drivers explained above is a slow growth rate for maximum demand on TPCL's network of 1.4% per annum. TPCL's total maximum demand is forecast to increase from about

139.99MW in 2016/17 to about 156.46MW in 2025/26. TPCL's demand (at a zone substation level) is expected to increase over the planning period by the following factors

- Standard natural growth of 1.0%, with some decline of small rural communities.
- Irrigation growth in Northern Southland of 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. Table 33 shows this growth on a per substation basis as the most appropriate network level for identifying constraints on the network.

Table 33: Existing Substations Growth Projection

Zone Substation	Proposed Annual Growth	Maximum Demand 2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Athol	2.5%	0.63	0.65	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79
Awarua Chip Mill	0.0%	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Bluff	1.0%	4.62	4.67	4.71	4.76	4.81	4.86	4.91	4.95	5.00	5.05
Centre Bush	1.5%	4.09	4.15	4.21	4.28	4.34	4.41	4.47	4.54	4.61	4.68
Colyer Road	2.5%	5.02	5.15	5.28	5.41	5.54	5.68	5.82	5.97	6.12	6.27
Conical Hill	0.5%	1.11	1.12	1.12	1.13	1.13	1.14	1.14	1.15	1.16	1.16
Dipton	2.5%	1.82	2.36	2.42	2.48	2.54	2.61	2.67	2.74	2.81	2.88
Edendale Fonterra	0.5%	31.66	31.82	31.97	32.13	32.30	32.46	32.62	32.78	32.95	33.11
Edendale	1.5%	6.59	6.69	6.79	6.89	7.00	7.10	7.21	7.32	7.43	7.54
Glenham	2.0%	1.23	1.25	1.28	1.30	1.33	1.36	1.38	1.41	1.44	1.47
Gorge Road	3.0%	2.82	2.91	2.99	3.08	3.18	3.27	3.37	3.47	3.57	3.68
Heddon Bush	2.0%	7.91	8.07	8.23	8.39	8.56	8.73	8.90	9.08	9.26	9.45
Hedgehope	2.0%	1.43	1.46	1.49	1.52	1.55	1.58	1.61	1.64	1.67	1.71
Hillside	1.0%	0.69	0.70	0.71	0.71	0.72	0.73	0.74	0.74	0.75	0.76
Isla Bank	2.5%	1.50	1.54	1.58	1.62	1.66	1.70	1.74	1.78	1.83	1.87
Kelso	2.0%	4.49	4.58	4.68	4.77	4.87	4.96	5.06	5.16	5.27	5.37
Kennington	1.5%	5.93	6.02	6.11	6.21	6.30	6.39	6.49	6.59	6.68	6.78
Lumsden	3.0%	3.42	3.52	3.62	3.73	3.84	3.96	4.08	4.20	4.33	4.46
Makarewa	1.0%	6.42	6.48	6.55	6.61	6.68	6.74	6.81	6.88	6.95	7.02
Mataura	0.0%	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99
Monowai	0.5%	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.17
Mossburn	3.0%	2.08	2.14	2.21	2.27	2.34	2.41	2.48	2.56	2.63	2.71
North Gore	1.0%	7.83	7.91	7.99	8.07	8.15	8.23	8.32	8.40	8.48	8.57
Ohai	1.0%	2.62	2.65	2.67	2.70	2.73	2.76	2.78	2.81	2.84	2.87
Orawia	1.5%	3.08	3.13	3.17	3.22	3.27	3.32	3.37	3.42	3.47	3.52
Otatara	2.0%	3.80	3.87	3.95	4.03	4.11	4.19	4.28	4.36	4.45	4.54
Otautau	2.5%	4.43	4.54	4.66	4.77	4.89	5.02	5.14	5.27	5.40	5.54
Riversdale	3.0%	5.38	5.54	5.71	5.88	6.05	6.24	6.42	6.62	6.81	7.02
Riverton	2.5%	4.79	4.91	5.03	5.16	5.29	5.42	5.56	5.69	5.84	5.98
Seaward Bush	0.5%	8.11	8.15	8.19	8.23	8.27	8.32	8.36	8.40	8.44	8.48
South Gore	1.0%	8.25	8.34	8.42	8.50	8.59	8.67	8.76	8.85	8.94	9.03
Te Anau	1.5%	5.26	5.34	5.42	5.50	5.59	5.67	5.76	5.84	5.93	6.02
Tokanui	1.0%	1.08	1.09	1.10	1.11	1.13	1.14	1.15	1.16	1.17	1.18
Underwood	0.0%	12.48	12.48	12.48	12.48	12.48	12.48	12.48	12.48	12.48	12.48
Waikaka	2.5%	0.79	0.81	0.83	0.85	0.87	0.89	0.91	0.94	0.96	0.98
Waikiwi	2.5%	10.54	10.80	11.07	11.35	11.63	11.92	12.22	12.53	12.84	13.16
Winton	2.0%	12.28	12.52	12.77	13.03	13.29	13.55	13.83	14.10	14.38	14.67
White Hill (Wind)	0.0%	-56.81	-56.81	-56.81	-56.81	-56.81	-56.81	-56.81	-56.81	-56.81	-56.81
Monowai (Hydro)	0.0%	-6.56	-6.56	-6.56	-6.56	-6.56	-6.56	-6.56	-6.56	-6.56	-6.56
Flat Hill (Wind)	0.0%	-6.50	-6.50	-6.50	-6.50	-6.50	-6.50	-6.50	-6.50	-6.50	-6.50

These projected substation demands are considered the most likely outlook and are the basis for TPCL's network development planning. It is accepted that there is significant uncertainty in these forecasts and actual future demands may depart significantly from these levels. Forecasts are updated annually to ensure plans are able to react quickly to any changes from previous assumptions.

If growth rates decline, schedules for projects to address capacity constraints are correspondingly delayed so as to minimise the risk of over investing. Ultimately TPCL seeks to realise growth opportunities as they arise which means developing the network to alleviate constraints as required accepting, as with any investment that some risk is involved. Risk of stranding of new assets is managed where appropriate through capacity guarantee contracts with new customers. Otherwise risk is minimised by avoiding investment by utilising whatever options are available to defer investment until absolutely necessary while maintaining desired service levels.

Higher growth rates are also possible and present a risk of missed opportunity for growth for both TPCL and TPCL's customers. Growth affecting the entire network is most likely to come with sufficient warning to allow resources to be adjusted as required. Any large scale developments are likely to be largely funded by external investors through capital contributions and TPCL generally has the ability to respond quickly to unforeseen large scale one off developments. Naturally there are limits to this capability and negotiation may be required around timing of project delivery. Unfortunately experience shows that while endeavours are made to warn customers of potential lead times around providing additional network capacity requests for supply tend to come relatively late in their planning processes due to commercial sensitivities.

Table 34 shows the aggregated effect of substation demand growth for a 10 year horizon at the four GXPs which provide supply TPCL.

Table 34: GXP Demand Growth

GXP	Rate and nature of growth	Provision for growth to 2026
Invercargill	0.0% Maximum Demand Load will be controlled using load management to stay at present levels.	Transpower have recently upgraded the two 220/33kV banks to 120MVA. This will allow over 20MVA of additional load.
North Makarewa	1.66% Increased load from irrigation in Northern Southland and continued dairy growth across Northern and Western Southland.	Load forecast is under firm capacity of 67MVA. Any substantial embedded generation is likely to make this a normally exporting GXP. Possible Transpower project to allow 76.1/79.4 MVA (summer/winter) capacity with 33kV cable upgrade.
Gore	1.54% Increased load from continued dairy growth across Eastern Southland.	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.
Edendale	1.90% Growth from Fonterra Edendale and TPCL Edendale and Glenham substations.	Current forecast shows exceeding of summer capacity of 34MVA during planning period. Discussions have begun with Transpower to look at project project to allow full 36.6/38.7 MVA (summer/winter) capacity with upgrades.

Constraints Arising from Estimated Demand

The significant issues arising from the estimated demand are the capacity at a number of zone substations. Most of these are covered by upgrade projects which are discussed in full in section Development Programme.

A summary of TPCL's network constraints is shown in Table 35:

Table 35: TPCL Network Constraints and Intended Remedy

Constraint	Description	Intended remedy
Capacity at Zone Substations	Substations close to (or exceeding) maximum capacity. Dipton, Glenham, Gorge Road, Kelso, Riversdale, Waikiwi, Winton	Load will be reviewed annually to ensure timing of projects is kept just ahead of load. Upgrades planned for Dipton, Glenham, Gorge Road, Kelso, Riversdale, and Waikiwi during the planning period. Load transfers will be used to keep Winton load under the firm capacity of 12MVA.
Invercargill GXP	109.0 MVA limitation in 'Other Equipment' ratings	Transpower project to upgrade 'Other Equipment' to allow 144.8/151.3MVA. Up-size when load control cannot keep load under this limit.
Gore GXP	Close to firm capacity of 36.6/37.9 MVA (Summer/Winter)	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.
Subdivisions	Possible large developments in Athol, Garston and Kingston	Extend subtransmission to 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 or convert lines and supply to 22kV if growth continues.
Undergrounding	District 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.
MV Transformers	Some transformers are near full capacity.	Maximum Demand Indicators (MDIs) are monitored and transformers will be upsized or

Constraint	Description	Intended remedy
		supplemented with additional units as appropriate. Underutilised transformers may be relocated before purchasing new.

Table 36 and Table 37 show the substation demands and proposed changes to keep demand within the capacity of zone substations. Proposed changes show new substations, upgrades to existing substations, and load transfers to and from substations to maintain capacity ahead of demand. New substations and upgrades to existing substations are discussed fully in section Development Programme

Table 36: Substation Demands with Proposed Developments 2016 - 2021

Zone Substation	*2015/16 Changes*	2015/16 Demand	*2016/17 Changes*	2016/17 Demand	*2017/18 Changes*	2017/18 Demand	*2018/19 Changes*	2018/19 Demand	*2019/20 Changes*	2019/20 Demand	*2020/21 Changes*	2020/21 Demand
Athol		0		0		0		0		0		0
Awarua (Chip Mill)		0.76		0.76		0.76		0.76		0.76		0.76
Bluff		4.58		4.62		4.67		4.71		4.76		4.81
Centre Bush		4.03	*-4.09*	0.00		0.00		0.00		0.00		0.00
Centre Bush (66/11kV)			*+4.09*	4.09		4.15		4.21		4.28		4.34
Colyer Road	*+4.90*	4.90		5.02		5.15		5.28		5.41		5.54
Conical Hill		1.11		1.11		1.12		1.12		1.13		1.13
Dipton		1.77		1.82	*-1.88*	0.00		0.00		0.00		0.00
Dipton (66/11kV)					*+2.38*	2.38		2.43		2.50		2.56
Edendale Fonterra		31.50		31.66		31.82		31.97		32.13		32.30
Edendale		6.50		6.59		6.69		6.79		6.89		7.00
Glenham		1.20		1.23		1.25		1.28	*-1.30*	0.00		0.00
Glenham (Upgraded)									*+1.30*	1.30		1.33
Gorge Road		2.74		2.82		2.91		2.99	*-3.08*	0.00		0.00
Gorge Road (Upgraded)									*+3.08*	3.08		3.18
Heddon Bush		7.75		7.91		8.07		8.23		8.39		8.56
Hedgehope	*+1.4*	1.40		1.43		1.46		1.49		1.52		1.55
Hillside		0.69		0.69		0.70		0.71		0.71		0.72
Isla Bank			*+1.50*	1.50		1.54		1.58		1.62		1.66
Kelso		4.41		4.49		4.58		4.68	*-4.77*	0.00		0.00
Kelso (Upgraded)									*+4.77*	4.77		4.87
Kennington	*-0.2*	5.65		5.73		5.82		5.90		5.99		6.08
Lumsden		3.32		3.42	*-0.30*	3.22	*-3.32*	0.00		0.00		0.00
Lumsden (66/11kV)							*+3.32*	3.32		3.41		3.52
Makarewa		6.35		6.42		6.48		6.55		6.61		6.68
Mataura	*-0.4*	5.62		5.65		5.68	*-5.70*	0.00		0.00		0.00
Mataura (Upgraded)							*+5.70*	5.70		5.73		5.76
Monowai		0.16		0.16		0.16		0.16		0.16		0.16
Mossburn		2.02		2.08		2.14		2.21		2.27		2.34
North Gore		7.76		7.83		7.91		7.99		8.07		8.15
Ohai		2.60		2.62		2.65		2.67		2.70		2.73
Orawia		3.03		3.08		3.13		3.17		3.22		3.27
Otatara		3.72		3.80		3.87		3.95		4.03		4.11
Otautau		4.30	*-0.40*	3.99		4.07		4.15		4.23		4.32

Zone Substation	2015/16 Changes	2015/16 Demand	2016/17 Changes	2016/17 Demand	2017/18 Changes	2017/18 Demand	2018/19 Changes	2018/19 Demand	2019/20 Changes	2019/20 Demand	2020/21 Changes	2020/21 Demand
Riversdale		5.22		5.38		5.54	*-5.71*	0.00		0.00		0.00
Riversdale (Upgraded)							*+5.71*	5.71		5.88		6.05
Riverton		4.67	*-0.25*	4.54		4.65		4.77		4.89		5.01
Seaward Bush		8.07		8.11		8.15	*-8.19*	0.00		0.00		0.00
Seaward Bush (Upgraded)							*+8.19*	8.19		8.23		8.27
South Gore		8.17		8.25		8.34		8.42		8.50		8.59
Te Anau		5.19		5.26		5.34		5.42		5.50		5.59
Tokanui		1.07		1.08		1.09		1.10		1.11		1.13
Underwood		12.48		12.48		12.48		12.48		12.48		12.48
Waikaka		0.77		0.79		0.81		0.83		0.85		0.87
Waikiwi		10.28	*-10.54*	0.00		0.00		0.00		0.00		0.00
Waikiwi (Upgraded)			*+10.54*	10.54		10.80		11.07		11.35		11.63
Winton		11.54	*-0.85*	10.92		11.14		11.36		11.58		11.82
White Hill (Wind)		-56.81		-56.81		-56.81		-56.81		-56.81		-56.81
Monowai (Hydro)		-6.56		-6.56		-6.56		-6.56		-6.56		-6.56
Flat Hill (Wind)		-6.50		-6.50		-6.50		-6.50		-6.50		-6.50

Table 37: Substation Demands with Proposed Developments 2021 – 2026

Zone Substation	2021/22 Changes	2021/22 Demand	2022/23 Changes	2022/23 Demand	2023/24 Changes	2023/24 Demand	2024/25 Changes	2024/25 Demand	2025/26 Changes	2025/26 Demand
Athol		0.71		0.73		0.75		0.77		0.79
Awarua (Chip Mill)		0.76		0.76		0.76		0.76		0.76
Bluff		4.86		4.91		4.95		5.00		5.05
Centre Bush		0.00		0.00		0.00		0.00		0.00
Centre Bush (66/11kV)		4.41		4.47		4.54		4.61		4.68
Colyer Road		5.68		5.82		5.97		6.12		6.27
Conical Hill		1.14		1.14		1.15		1.16		1.16
Dipton		0.00		0.00		0.00		0.00		0.00
Dipton (66/11kV)		2.62		2.69		2.75		2.82		2.89
Edendale Fonterra		32.46		32.62		32.78		32.95		33.11
Edendale		7.10		7.21		7.32		7.43		7.54
Glenham		0.00		0.00		0.00		0.00		0.00
Glenham (Upgraded)		1.36		1.38		1.41		1.44		1.47
Gorge Road		0.00		0.00		0.00		0.00		0.00
Gorge Road (Upgraded)		3.27		3.37		3.47		3.57		3.68
Heddon Bush		8.73		8.90		9.08		9.26		9.45
Hedgehope		1.58		1.61	*+0.3*	1.94		1.98		2.02
Hillside		0.73		0.74		0.74		0.75		0.76
Isla Bank		1.70		1.74	*+0.3*	2.08		2.14		2.19
Kelso		0.00		0.00		0.00		0.00		0.00
Kelso (Upgraded)		4.96		5.06		5.16		5.27		5.37
Kennington		6.17		6.27		6.36		6.46		6.55
Lumsden		0.00		0.00		0.00		0.00		0.00
Lumsden (66/11kV)		3.62		3.73		3.84		3.96		4.08
Makarewa		6.74		6.81		6.88		6.95		7.02

Zone Substation	2021/22 Changes	2021/22 Demand	2022/23 Changes	2022/23 Demand	2023/24 Changes	2023/24 Demand	2024/25 Changes	2024/25 Demand	2025/26 Changes	2025/26 Demand
Mataura		0.00		0.00		0.00		0.00		0.00
Mataura (Upgraded)		5.79		5.82		5.85		5.88		5.91
Monowai		0.17		0.17		0.17		0.17		0.17
Mossburn		2.41		2.48		2.56		2.63		2.71
North Gore		8.23		8.32		8.40		8.48		8.57
Ohai		2.76		2.78		2.81		2.84		2.87
Orawia		3.32		3.37		3.42		3.47		3.52
Otatara		4.19		4.28		4.36		4.45		4.54
Otautau		4.41		4.49		4.58		4.68		4.77
Riversdale		0.00		0.00		0.00		0.00		0.00
Riversdale (Upgraded)		6.24		6.42		6.62		6.81		7.02
Riverton		5.14		5.27		5.40		5.53		5.67
Seaward Bush		0.00		0.00		0.00		0.00		0.00
Seaward Bush (Upgraded)		8.32		8.36		8.40		8.44		8.48
South Gore		8.67		8.76		8.85		8.94		9.03
Te Anau		5.67		5.76		5.84		5.93		6.02
Tokanui		1.14		1.15		1.16		1.17		1.18
Underwood		12.48		12.48		12.48		12.48		12.48
Waikaka		0.89		0.91		0.94		0.96		0.98
Waikiwi		0.00		0.00		0.00		0.00		0.00
Waikiwi (Upgraded)		11.92		12.22		12.53		12.84		13.16
Winton		11.72		11.95	*-0.60*	11.59		11.82		12.06
White Hill (Wind)		-56.81		-56.81		-56.81		-56.81		-56.81
Monowai (Hydro)		-6.56		-6.56		-6.56		-6.56		-6.56
Flat Hill (Wind)		-6.50		-6.50		-6.50		-6.50		-6.50

4.3. Development Programme

Expected projects for year one (YE 31 March 2017) are as follows. These projects have a high certainty.

New Connections

This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements.

Planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance.

Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer’s location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer’s property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised.

Distributed generation as a network alternative tends to be intermittent so cannot be relied on without energy storage which would make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the upfront cost is generally not attractive to most customers and generally a connection to the network is still desired as backup, supplementation and sometimes the ability to sell surplus energy. Customers may be encouraged to better manage diversity of load within their facilities where details are known and there is perceived benefit to the customer or network.

Cost $2.5M - $5.0M per annum on-going; CAPEX - Consumer Connections.

Oreti Valley Project (OVP)

Load growth has made the existing 33kV subtransmission backups to Centre Bush, Dipton, Lumsden and Riversdale marginal. The network is constrained by the amount of load and the length of 33kV line from Heddon Bush (for backup to Riversdale) or Gore GXP (for backups to Centre Bush, Dipton and Lumsden) under backup scenarios. A further constraint exists in that the capacity of the 15MVA 66/33kV transformer at Heddon Bush is exceeded when supplying Riversdale at peak times.

To resolve the above issues consideration was given to the use of 33kV voltage regulators to improve voltage for backup scenarios. However, given the transformer constraint at Heddon Bush, increased losses and higher system impedances caused by use of 33kV regulators, this option was discounted. The chosen solution to resolve the backup issues and provide for future load growth is to extend the 66kV network along the Oreti valley 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 and heading north along Riverside Road to Centre Bush Substation. This line has been completed and the upgrade of Centre Bush Substation to 66kV has commenced.

Starting in 2016/17 the 33kV lines between Centre Bush and Mossburn will be upsized to 66kV. The first section to be completed will be Centre Bush to Dipton. Once this section is completed, work will commence on the upgrade of Dipton Substation to 66kV. The lines between Dipton and Lumsden and Lumsden and Mossburn will then be upgraded. The upgrade to 66kV at Lumsden will be timed to align with the completion of the 66kV lines into Lumsden from both Mossburn and Centre Bush.

Once the upgrade of Dipton Substation is completed, the 66/33kV transformer at Heddon Bush will become surplus and will be moved to spares. At this stage of the project, Lumsden will be supplied at 33kV by a single subtransmisison line from Gore GXP until the remainder of the project is completed. This risk is acceptable as 11kV backups from Athol, Mossburn and Riversdale can supply all load normally supplied by Lumsden.

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[12] and new 22kV indoor switchboard with 4 feeder CBs. The additional feeder will 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. This protection requires redundant communications paths, the design has been completed and will use digital microwave radios operating in a ring configuration.
- Reinsulate the 33kV lines from Centre Bush to Mossburn to 66kV.
- Upgrade Dipton by replacing the transformer with a new 66/11+11kV 5MVA unit and upgrade protection on the 66kV by having digital differential on the two sides of the substation but no 66kV line circuit breakers.
- Upgrade Lumsden by replacing the transformer with a 66/11+11kV 5MVA unit (ex Ohai) and replace the existing outdoor 11kV switchgear with a new 22kV indoor switchboard.
- The reinsulated 66kV line to Lumsden will connect into Mossburn substation by the spare 66kV bay.

Cost $1.5M - $7.5M per annum 2016/17 to 2018/19; CAPEX – System Growth

Planned outcome is shown in the diagram below**:**

[12] 66/11+11kV transformer can be connected to provide 11kV or 22kV output by parallel or series connecting the two 11kV windings.

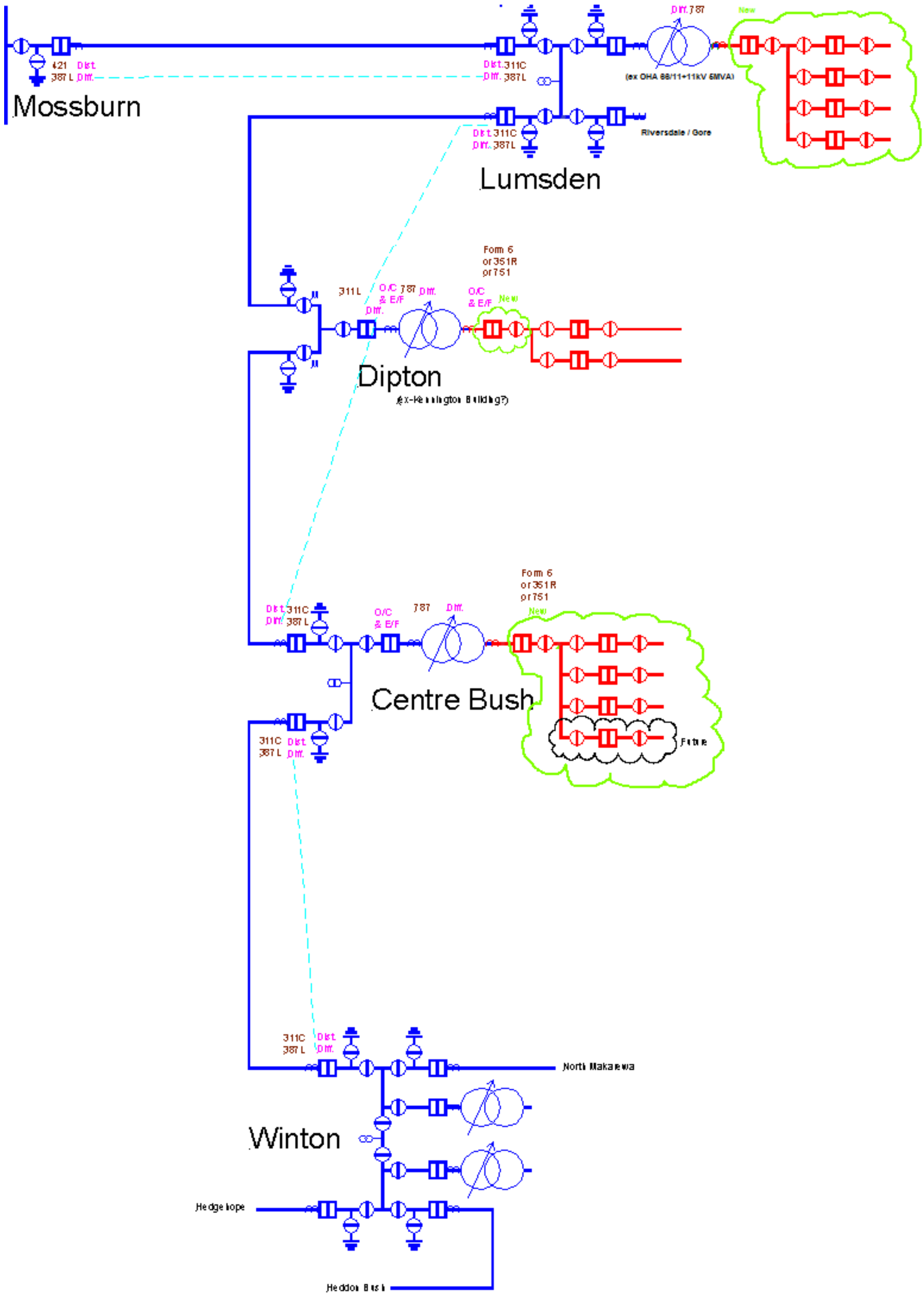

Figure 42 - Completed Oreti Valley Project Single Line Diagram

Waikiwi Substation Upgrade

Load growth at Waikiwi Substation has reached the capacity trigger point of 12MVA. There is limited ability to shift additional load to neighbouring substations following the shift of some load to Kennington.

Figure 43 – Aerial view of Waikiwi Substation

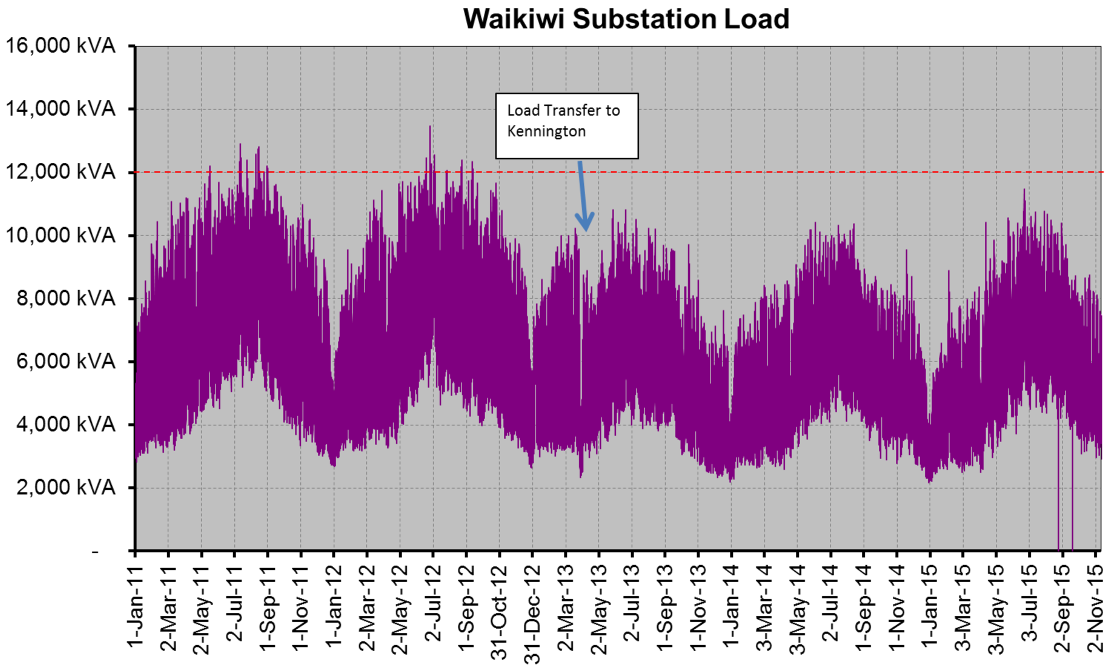

Figure 44 - Waikiwi Substation Load Profile

Given the above this project will replace the outdoor 6/12MVA 33/11kV transformers with new 11.5/23MVA 33/11kV transformers. Current noise levels on the boundary exceed District Plan requirements. The new transformers will be installed indoors in a purpose-built transformer room (to be built as part of the project) and utilise external radiators to reduce noise levels at the boundary. This has been determined to be the only economic option to reduce noise levels to comply with the requirements of the District Plan.

The larger transformers require upgraded local service supplies and a larger 24V DC system to support them so these systems will be updated as part of the project. The existing Harris RTU is now unsupported and is becoming difficult to maintain and interface with new equipment so will be replaced as part of the project. An 11kV Neutral Earthing Resistor (NER) will also be installed as this work was already planned and it is considered more cost effective to complete this work during the Waikiwi Project.

Cost $0.5M - $2.5M 2016/17; CAPEX – System Growth

Riversdale Substation Upgrade

Load growth has exceeded the capacity trigger point of 5MVA which aligns with the existing single 33/11kV 5MVA transformer. This growth has also eroded the 11kV backups between Lumsden and Riversdale Substations. The bulk of the growth on Riversdale had come from increased irrigation in the Waipounamu and Freshford areas. This irrigation growth is forecast to exceed the capacity of the existing 11kV network to deliver acceptable voltage. There are 2 existing 11kV regulators installed on the feeder already and one approaching its 3MVA capacity. Additional or larger regulators in conjunction with reconductoring to a larger sized conductor was considered as an option, however was determined to be not optimal due to increased losses and the limited gains achieved by reconductor. A new 11kV feeder heading into the affected area was also considered, however difficulty in obtaining a new line route due to the geography of the area and the length of line to be constructed (>6km) has meant that this option was discounted.

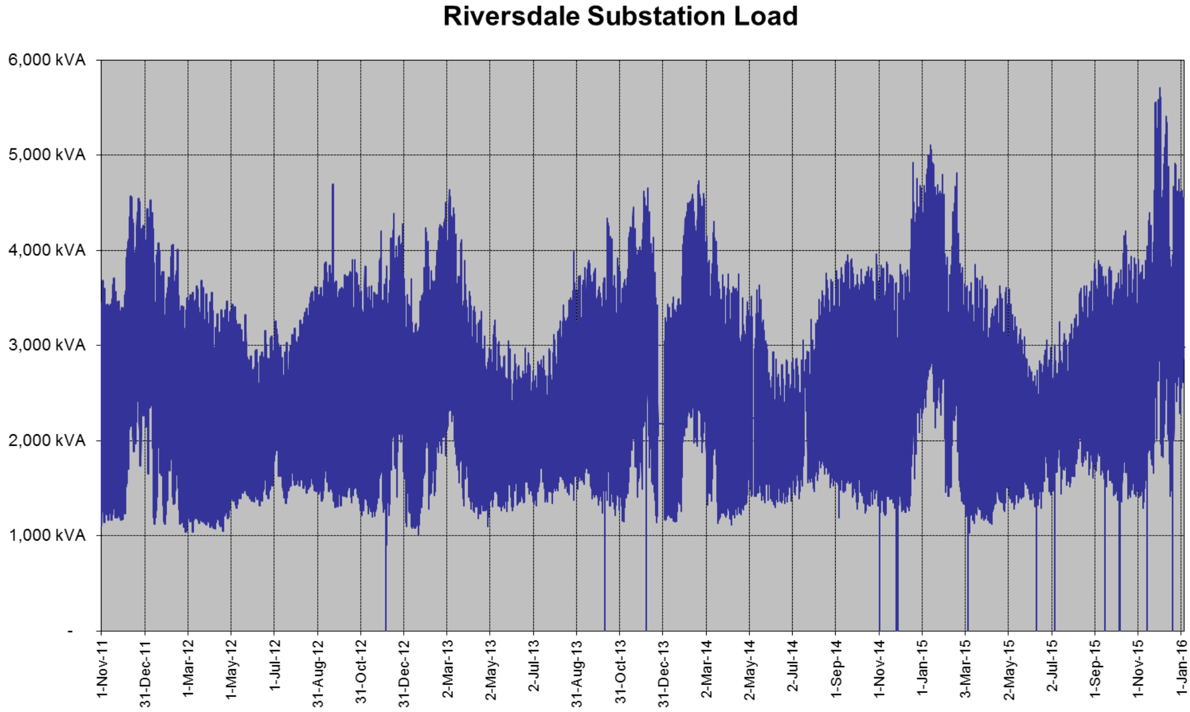

Figure 45 - Riversdale Substation Load Profile

Transfer of load to a new substation around Balfour (which is approximately halfway between Riversdale and Lumsden) would alleviate the transformer capacity trigger and improve the 11kV backups between Riversdale and Lumsden. However, the new substation at Balfour would not provide a solution to the load growth being experienced north of Riversdale in the Waipounamu and Freshford areas and as such has been removed as a project.

Figure 46 - Present Riversdale substation

The proposed solution is to install a new 66/22kV 6/12MVA unit and 22kV indoor switchboard with four feeders, two incomers and a bus coupler. The new transformer would operate in parallel with the existing 33/11kV 5MVA unit. The new switchboard would have 2 feeders operating at 11kV and 2 operating at 22kV with the bus coupler remaining open. Backup between the 2 transformers will be achieved by the use of 11/22kV autotransformers installed at tie-points between the 11kV and 22kV feeders. A diagram of the proposed solution is shown in Figure 47.

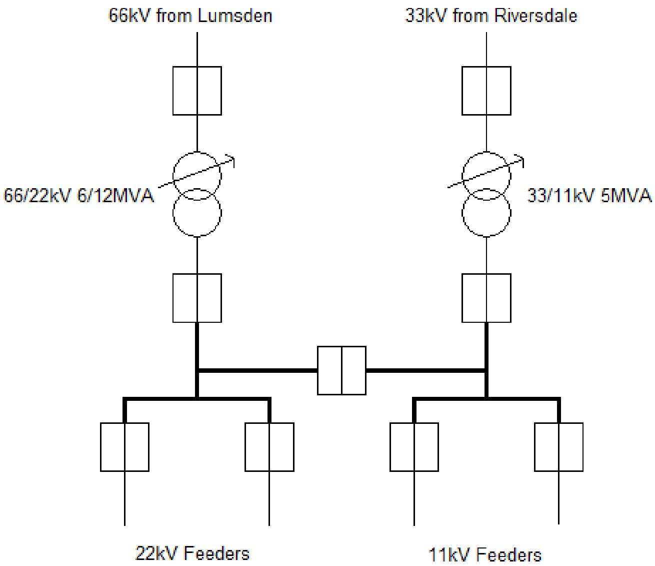

Figure 47 - Proposed Riversdale Single Line Diagram

A separate project will upgrade the two feeders heading north of Riversdale to 22kV in preparation for supply at 22kV from the upgraded Riversdale substation. Autotransformers will be used to reduce the voltage from 22kV to 11kV at the end of the upgraded sections to allow 11kV supply to the remainder of the feeder. If growth occurs before the upgrade is completed, 11/22kV autotransformers may be installed to allow operation of sections at 22kV as required as an interim measure.

The upgraded substation will be future-proofed by modifying the foundation for the existing transformer so a second 66/22kV 6/12MVA unit can be installed at a later date once conversion to 22kV has progressed on all four feeders.

Concept design has been completed. Detailed design will be completed in 2016/17 with construction to occur in 2017-2019.

Cost $0.5M - $5.0M per annum 2016/17 to 2018/19; CAPEX – System Growth

Riversdale 22kV Line Upgrades

Load growth north of Riversdale is forecast to exceed the capacity of the existing 3MVA 11kV voltage regulator at Elders Corner. A larger regulator is considered not optimal as the existing conductor upstream and downstream of the regulator would also need to be upgraded to allow for additional load.

It is planned to supply 2 feeders out of Riversdale substation at 22kV following the proposed upgrade. These feeders will have 11kV insulators replaced with 22kV insulators ahead of supply conversion to 22kV. Autotransformers will be used to reduce the voltage from 22kV to 11kV at the end of the upgraded sections. This allows for 11kV supply to continue to the remainder of the feeder. If growth occurs before the Riversdale substation upgrade is completed, 11/22kV autotransformers may be installed at the start of the feeders to allow operation of sections at 22kV if required as an interim measure.

Cost Under $0.5M 2016/17; CAPEX – System Growth

Edendale Supply Transformers and Substation Upgrade

This project has carried over due to receiving a damaged 33kV circuit breaker from the manufacturer. The project will involve installation of the repaired circuit breaker during the dairy off-season (June-July 2016) and connecting the 33kV cable to the new circuit breaker. See 2015-2025 Asset Management Plan for full details of this project.

Cost Under $0.5M 2016/17; CAPEX – System Growth

Mobile Substation

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.

Mitton Electronet / Electronet Services have been selected to provide the mobile substation. Design has largely been completed and long-lead materials ordered. Delivery of the mobile substation is expected during the 2016/17 financial year.

The mobile substation will provide for maintenance and capital upgrades of single transformer substations with little or no periods where backup from neighbouring substations can be used. In the event of a transformer failure, the mobile substation will be quick to deploy. This will allow for coverage of the significant periods to move spare transformers into sites where the transformer has failed.

Consideration was given to the purchase of a mobile generator or generators but these require fuel to run and this is a cost that is not recoverable. Single transformer sites could have a second transformer added, but given the large number of single transformer substations this was considered cost prohibitive. Converting lines and supply to 22kV or adding additional substations to restore backup capability was considered both cost prohibitive and time prohibitive (would take a substantial number of years - greater than the 10-year planning period)

Cost \$0.5-2.5M 2016/17; CAPEX – Quality of Supply

Neutral Earthing Resistor (NER) project

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.

The aim of the project is to achieve safety of the public under earth fault conditions by 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.

Cost \$0.5-2.5M per annum 2016/17 to 2018/19; CAPEX – Other Reliability, Safety and Environmental

Distribution Automation

To improve reliability it is planned to continue automating and remotely controlling field circuit breakers and load break switches. The project will increase the number of these and integrate with an Outage Management System to achieve automated fault detection, isolation and restoration. This will minimise the number of customers affected by a fault.

The project will target the installation of new field reclosers and remote operable vacuum load break switches on worst performing feeders from a SAIDI and SAIFI perspective. The aim is to allow automatic restoration and reduce average length of 11kV distribution network to one device per 75km.

Cost Under \$0.5M per annum 2016/17 and 2017/18; CAPEX – Quality of Supply

Substation Safety

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

The project will retrofit arc flash detection through the use of modern protection relays to all indoor switchboards. This will reduce the hazard for personnel to under the levels provided by 8cal/cm^2

overalls required to be worn by all staff when entering zone substations. Additional PPE was considered as an alternative, but was determined to be suboptimal as each employee would require a full 40cal/cm^2 suit and the bulky PPE to achieve this level of protection creates additional hazards for personnel.

Cost Under $0.5M per annum 2016/17 and 2017/18; CAPEX – Other Reliability, Safety and Environmental

Tower Anti-Climb Guards

A recent public safety management system audit highlighted the need for anti-climb guards are to be installed on any subtranmission towers within 500m of a road or residential dwelling. 54 towers have been identified as requiring anti-climb guards. 10 sites have been completed with 44 to be completed in 2016/17.

Cost Under $0.5M 2016/17; CAPEX – Other Reliability, Safety and Environmental.

Asset Relocation Projects

This budget captures costs for general minor relocation works required such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive and typically above or below budget in any year.

Cost Under $0.5M per annum on-going; CAPEX – Asset Relocations

Supply Quality Upgrades

This covers projects to remedy poor power quality. Most cases of poor power quality on TPCL's network are reports or measurements of low voltage. Voltage is either then measured (or calculated to vary) outside of regulatory limits.

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.)

Costs budgeted represent a long term average with actual spend being reactive typically being above or below in any year. The years 2016/17 through 2020/21 have increased budget to manage an increase in upgrades foreseen as the rollout of smart meters on the TPCL network progresses and identifies voltage constraints.

Cost Under $0.5M per annum on-going; CAPEX – Quality of Supply.

Network Improvement Projects

Projects to improve reliability through installation of remotely controlled field circuit breakers and load break switches or closing short gaps between adjacent 11kV circuits..

Cost Under $0.5M per annum on-going from 2018/19; CAPEX – Quality of Supply

New Invercargill to Colyer Rd 33kV Line

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 from 2019/20 (subject to development in the Awarua industrial zone)

Cost $1.5-3.0M per annum 2019/20 to 2021/22; CAPEX -System Growth.

Kelso Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Kelso Substation in 2022. 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.

Consideration was given to load transfers to keep load under 5MVA however backup capability on 11kV from neighbouring substations is limited by voltage drop so load transfer is not practical.

Consideration was also given to adding a second transformer. However, this would require new switchgear and changes to existing spare transformer pad. The security standard does not require 2 transformers and the mobile substation can be deployed to allow maintenance or upgrade. This was considered likely to be more expensive and not an efficient use of capital

Cost $0.2 - $1.0M per annum 2018 to 2020, System Growth.

Kennington 2nd 33kV line

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

Cost $0.1-1.0M 2017/18 and 2018/19; CAPEX - System Growth

Glenham Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Glenham Substation in 2026. However, as the substation provides 11kV backup to the adjacent Gorge Road and Tokanui substations, the project will occur ahead of load growth to ensure some backup capacity is retained. Planning is to design for the replacement of the single 33/11kV 1.5MVA power transformer at Glenham substation with a new 33/11kV 3MVA transformer or refurbished 5MVA transformer.

Cost $0.2 - $1.0M 2018/19 and 2019/20; CAPEX - System Growth.

Lumsden/Riversdale 22kV Line Upgrades

Load growth has eroded backup capability between Lumsden and Riversdale substations. Both substations are being upgraded to be able to supply 22kV and this project intends to upgrade key sections of line between the two substations to improve MV backups.

Autotransformers will be used to change the voltage between 22kV and 11kV at the ends of the upgraded sections.

Cost Under $0.5M per annum 2017/18 to 2020/21; CAPEX – System Growth

Gorge Road Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Glenham Substation in 2019. Planning is to design for the replacement of the dual 33/11kV 1.5MVA power transformers at Gorge Road substation with new 33/11kV 3MVA transformers or refurbished 5MVA transformers.

Cost Under $0.5M per annum 2018/19 and 2019/20; CAPEX – System Growth

Unspecified Projects

The unspecified projects budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term (six to ten year time frame). Certainty for these estimates is obviously quite low.

$2.5M - $5.0M per annum 2021/22 onwards; System Growth.

4.4. Contingent projects

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

Mataura Valley Milk

New milk processing plant at the old saleyards site in McNab. This will likely require a new substation and reinforcement of the 33kV network.

Additional Milk Processing

Additional Milk Processing plants at existing or new sites.

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.

Mines

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

Oil Refineries

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

Wind farms

Possible large (>5MW) wind farms that may require new subtransmission lines and/or zone substations.

4.5. Distributed Generation Policy

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

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

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

- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an asset's capacity.
- Raising voltage above regulated levels to enable export of electricity

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.

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 administration fee will be payable by the connecting party.
- Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.
- Any benefits of distributed generation that arise from reducing TPCL's costs, such as transmission costs or deferred investment in the network, and, provided the distributed generation is of sufficient size (greater than 10kW) 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.

Safety Standards

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

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-Network Solutions

As discussed in section Cost Efficiency the company routinely considers a range of non-asset solutions and indeed TPCL's preference is for solutions that avoid or defer new investment.

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:

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

Load shedding may be used by some customers where they accept a reduction of their load instead of investing in additional network assets.

Generators (owned by PowerNet) are sometimes used to minimise the impact of significant planned outages on the TPCL network.

The acquisition of a mobile substation (as part of a current project – expected delivery late 2016) raises the threshold at which TPCL justifies converting a single-transformer substation to a dual-transformer site; resulting in significantly deferred growth-related investment on the larger single-transformer substations.

Where the nature of the load and network permit, stand-by generators and network storage solutions (batteries) are considered as an alternative to line upgrades.

4.7. TPCL's Forecast Capital Expenditure

The forecast capital expenditure for TPCL is shown in Table 38. These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 38: TPCL's Forecast Capital Expenditure

CAPEX: Consumer Connection	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Customer Connections (≤ 20kVA)	1,171,054	1,171,054	1,171,054	1,171,054	1,171,054	1,171,054	1,171,054	1,171,054	1,171,054	1,171,054
Customer Connections (21 to 99kVA)	1,383,974	1,383,974	1,383,974	1,383,974	1,383,974	1,383,974	1,383,974	1,383,974	1,383,974	1,383,974
Customer Connections (≥ 100kVA)	787,801	787,801	787,801	787,801	787,801	787,801	787,801	787,801	787,801	787,801
Distributed Generation Connection	5,323	5,323	5,323	5,323	5,323	5,323	5,323	5,323	5,323	5,323
New Subdivisions	106,459	106,459	106,459	106,459	106,459	106,459	106,459	106,459	106,459	106,459
	3,454,611	**3,454,611**	**3,454,611**	**3,454,611**	**3,454,611**	**3,454,611**	**3,454,611**	**3,454,611**	**3,454,611**	**3,454,611**
CAPEX: System Growth	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Waikiwi Substation Upgrade	1,595,915	-	-	-	-	-	-	-	-	-
OVP-Centre Bush to Mossburn 66kV Line	1,844,572	1,229,716	-	-	-	-	-	-	-	-
OVP-Dipton Substation Upgrade	901,189	600,793	-	-	-	-	-	-	-	-
OVP-Centre Bush Substation Upgrade	1,774,069	-	-	-	-	-	-	-	-	-
OVP-Lumsden Substation Upgrade	298,420	2,949,187	1,702,089	-	-	-	-	-	-	-
Riversdale Substation Upgrade	358,104	2,408,360	3,674,876	-	-	-	-	-	-	-
TPNZ Edendale 110kV Transformer Upgrade	-	-	-	0	0	-	-	-	-	-
Edendale Substation Upgrade	118,705	-	-	-	-	-	-	-	-	-
New Invercargill to Colyer Rd 33kV Line	-	-	-	2,572,493	1,885,850	1,885,850	-	-	-	-
TPNZ North Makarewa 220/66kV Transformer	-	-	-	-	-	-	0	0	-	-
Kelso Transformer Upgrade	-	-	159,489	875,333	-	-	-	-	-	-
Kennington 2nd 33kV Line	-	89,526	839,763	-	-	-	-	-	-	-
Glenham Transformer Upgrade	-	-	147,884	770,886	-	-	-	-	-	-
Riversdale 22kV Line Upgrade	450,062	-	-	-	-	-	-	-	-	-
Lumsden / Riversdale 22kV Line Upgrades	-	342,631	342,631	342,631	342,631	-	-	-	-	-
Gorge Road Transformer Upgrade	-	-	77,589	177,228	-	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	3,585,794	3,585,794	3,585,794	3,585,794	3,585,794
OVP-Microwave Radio Ring Scheme	546,407									
	7,887,444	**7,620,212**	**6,944,321**	**4,738,570**	**2,228,481**	**5,471,644**	**3,585,794**	**3,585,794**	**3,585,794**	**3,585,794**
CAPEX: Asset Replacement and Renewal	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
General Distribution Replacement	1,221,179	1,221,179	1,221,179	1,221,179	1,221,179	1,221,179	1,221,179	1,221,179	1,221,179	1,221,179
Transformer Replacment	1,414,121	1,414,121	1,414,121	1,414,121	1,414,121	1,414,121	1,414,121	1,414,121	1,414,121	1,414,121
11kV Line Replacement	3,741,136	3,741,136	3,741,136	3,741,136	3,741,136	3,741,136	3,741,136	3,741,136	3,741,136	3,741,136
Subtransmission Line Replacement	38,502	38,502	38,502	98,121	98,121	98,121	98,121	98,121	98,121	98,121
Zone Substation Minor Replacement	90,276	90,276	90,276	90,276	90,276	90,276	90,276	90,276	90,276	90,276
RTU Replacement	133,074	133,074	133,074	133,074	133,074	133,074	133,074	133,074	133,074	133,074
Regulator Replacement	225,652	-	-	-	316,144	-	-	-	-	-
Relay Replacement	98,521	26,458	26,458	26,458	26,458	26,458	26,458	26,458	26,458	26,458
Communications Replacement	211,666	211,666	211,666	-	-	-	-	-	-	-
General Technical Replacement	27,762	27,762	27,762	27,762	27,762	27,762	27,762	27,762	27,762	27,762
Seismic Remedial Zone Substations	212,919	-	-	-	-	-	-	-	-	-
Seismic Remedial Distribution	53,388	53,388	53,388	53,388	53,388	-	-	-	-	-
Power Transformer Refurbishment	-	202,926	202,926	-	322,294	167,115	202,926	220,831	322,294	220,831
Riversdale to Lumsden 33kV Replacement	333,789	-	-	-	-	-	-	-	-	-
Seaward Bush Transfomer Replacement	257,968	-	492,567	611,231	-	-	-	-	-	-
Mataura Transformer Replacement	257,968	492,567	611,231	-	-	-	-	-	-	-
Ohai Substation Upgrade	347,274	-	-							
Counsell Rd Sth - Ingill 33kV Replacement	295,434	-	-	-	-	-	-	-	-	-
Hillside to Te Anau 66kV Replacement	172,951	-	-	-	-	-	-	-	-	-
Makarewa Switchboard Replacement	-	-	-	-	-	-	-	-	179,052	1,522,893
Bluff Switchboard Replacement	-	-	-	-	-	-	-	-	179,052	1,122,800
Hillside Transformer Replacement	-	-	-	199,942	712,992	-	-	-	-	-
	9,133,580	**7,653,056**	**8,264,287**	**7,616,688**	**8,156,946**	**6,919,243**	**6,955,053**	**6,972,958**	**7,432,525**	**9,618,651**
CAPEX: Asset Relocations	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Line Relocations	53,800	53,800	53,800	53,800	53,800	53,800	53,800	53,800	53,800	53,800
	53,800	**53,800**	**53,800**	**53,800**	**53,800**	**53,800**	**53,800**	**53,800**	**53,800**	**53,800**
CAPEX: Quality of Supply	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Supply Quality Upgrades	270,673	270,673	270,673	270,673	270,673	135,336	135,336	135,336	135,336	135,336
Mobile Substation	2,138,563	-	-	-	-	-	-	-	-	-
Distribution Automation	479,069	479,069	-	-	-	-	-	-	-	-
Network Improvement Projects	-	-	108,269	108,269	108,269	108,269	108,269	108,269	108,269	108,269
	2,888,305	**749,742**	**378,942**	**378,942**	**378,942**	**243,605**	**243,605**	**243,605**	**243,605**	**243,605**
CAPEX: Legislative and Regulatory	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
-	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
CAPEX: Other Reliability, Safety and Environment	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Earth Upgrades	267,866	133,933	133,933	133,933	133,933	133,933	133,933	133,933	133,933	133,933
NER Installations	827,210	827,210	827,210	-	-	-	-	-	-	-
Substation Safety	212,920	106,461	-	-	-	-	-	-	-	-
Township Undergrounding	-	-	-	-	-	-	-	-	-	-
Tower Anti-Climb Guards	297,352	-	-							
	1,605,348	**1,067,605**	**961,143**	**133,933**	**133,933**	**133,933**	**133,933**	**133,933**	**133,933**	**133,933**
Network Capital Expenditure Total	**25,023,088**	**20,599,026**	**20,057,103**	**16,376,544**	**14,406,712**	**16,276,835**	**14,426,795**	**14,444,700**	**14,904,267**	**17,090,393**

5. Lifecycle Planning

Development criteria, the subject of the previous section, determine the need for particular assets. Once this need has been established each asset must be managed throughout its lifecycle to create and maintain the fulfilment of the assets purpose as long as it is required and to minimise any adverse effects the asset might create.

5.1. Lifecycle Asset Management Processes

Following procurement of equipment and materials, assets are constructed or installed as per a design or network standard and commissioned through a process to ensure the asset is capable of operating as intended. The asset then enters its useful service life where it will often be operated over a considerable time period. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service for as long as it is economic to do so. At some point the asset will reach its end of life and is retired from service. Assuming the need remains the asset will be replaced while the retired asset must be disposed of appropriately. This process is outlined in Figure 48 below.

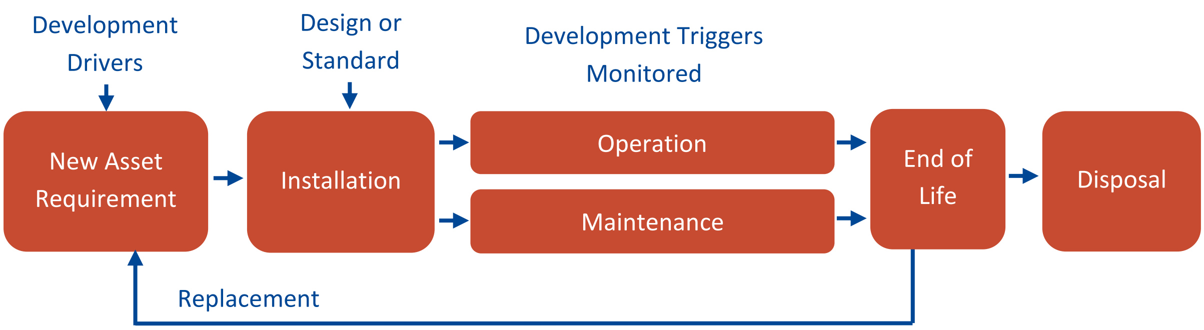

Figure 48: Asset Lifecycle

TPCL follows several asset management procedures to manage network assets throughout these lifecycle stages as referenced in Appendix 1.

5.2. Routine Corrective Maintenance & Inspection

Network assets are inspected routinely with the frequency dependant on the criticality of the assets and the outcome focussing on failure avoidance. Recognising that some deterioration is acceptable, inspections are intended to identify components which could lead to failure or deteriorate beyond economic repair within the period until the next inspection.

Deterioration is noted and may trigger corrective maintenance if economic, especially where deterioration can be “nipped in the bud”, for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved) for example pole cracks or rotting and noting these issues may become a trigger for replacement or renewal depending on the extent of deterioration i.e. loss of structural integrity.

Inspections are not able to cover all assets such as cables buried underground and may be limited by the availability of outages or the added effort (labour cost) required to remove covers. Therefore for the most part routine inspections are limited to what can be viewed from a walkover of the assets.

Testing supplements network inspections and although it typically requires additional time and skilled staff, testing has strong advantages over visual inspection if cost effective. It is generally possible to gain greater detail around asset condition and often allows collection of condition data without the need to remove covers for inspection. Testing may be destructive or non-destructive. For example insulation resistance (IR) testing gives an ohmic value for insulation under test whereas very low frequency (VLF) testing is "pass-fail" where a pass proves integrity of insulation but a fail will cause a fault which needs to be repaired.

TPCL's Maintenance Approach

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

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

As cables are underground they are unable to be inspected and testing is generally not cost effective and difficult to obtain accurate results to predict time to failure. Cables are therefore often run to failure however as the relatively young cable network ages and fault frequency begins to increase a more preventive strategy will be employed based on testing to determine condition for critical cables.

In terms of cost efficiency, failures are relatively acceptable for lines and cables compared to the more technical assets. Significant serviceable life can be restored by repairing a fault due to the distributed nature of these assets and the relatively minor (i.e. localised) effect of faults. Asset criticality must allow for the occurrence of outages however increased security (redundancy) is often applied as more effective than attempting to determine time to failure and performing preventative maintenance.

Table 39 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 39: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Sheath insulation IR tested. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during	Annual

Asset Category	Sub Category	Maintenance Approach	Frequency
		other inspections or work; may use IR, PI, TR, PD, VLF.	
	Distributed Sub Transmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Lubrication of moving parts.	5 yearly
Zone Substations	Sub Transmission Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or failed indications and general condition. Testing; Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, Cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly
	Power Transformers	Condition monitoring through periodic inspections. Winding resistances, Insulation resistance, Function checks on auxiliary devices (Buchholz, pressure relief, thermometers). Tap changer servicing; mechanism and contacts inspected – replacements as necessary, DC resistance across winding each tap, diverter resistors resistances Predictive maintenance - oil analysis (dissolved gasses, furan) to estimate age and identify internal issues arising or trends; frequency increased if issues and trends warrant. Oil processed as necessary. Clean up and repair of corrosion, leaks etc and replacement of deteriorated or damaged components. Replacement of breathers when saturated. Paper sample may be taken to estimate age for aged transformers in critical locations at Engineers instruction or otherwise during major refurbishment work at unit's half-life. Swept frequency test at start of life and after significant events such as relocation, repaired fault, refurbishment done to check for internal movement of components.	Monthly Annual Operation Count Bi-Annual Non-periodic
	Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or failed indications and general condition. Testing; Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, Cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly Non-periodic
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures, buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Relays recertified by external technicians as regulations require. Otherwise any other equipment visually inspected for anything untoward.	Monthly 5 yearly Non-periodic
Distribution	O/H	Condition Monitoring through periodic visual inspection.	5 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
Network		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if visible
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500kVA and larger. Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated. Winding resistances, Insulation resistance for older units if shut down allows. DGA for critical end of life units.	6 monthly or if <150kVA 5 yearly Opportunistic Non-Periodic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge. Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	6 monthly 5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. O/H structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting sinking etc. Internal components run to failure and repair. Some opportunistic inspections when opened for other work.	5 yearly
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 40 and forecasts are provided in Table 44 at the end of this section. These budgets tend to be ongoing at similar levels year after year but may be adjusted from time to time to allow for improvements in maintenance practice.

Table 40: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Routine Distribution Inspections, Checks & Maintenance	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.	Cost Under $1.0M on-going; OPEX
Minor Work Distribution Inspections, Checks & Maintenance	Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.	Cost Under $0.5M on-going; OPEX
Routine Technical Inspections, Checks & Maintenance	Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.	Cost Under $1.0M on-going; OPEX
Technical Planned Maintenance	Routine maintenance at zone substations such as grounds, fence and building maintenance, rust repair and paint touch-ups. Routine maintenance at distribution substation assets such as cleaning, paint touch-ups and enclosure repairs. Routine maintenance for Ring Main Units such as cleaning, paint touch-ups and enclosure repairs. Includes reactive work undertaken to correct issues found during the routine technical inspection. Also a general budget for all minor technical work.	Cost Under $1.0M on-going; OPEX
Partial Discharge Survey	Routine partial discharge condition monitoring surveying of subtransmission cables, terminations and equipment to identify abnormal discharge levels before failure occurs.	Cost Under $0.5M on-going; OPEX
Infra-Red Survey	Routine Infra-Red condition monitoring survey of bus-work, connections, contacts etc for abnormal heating as indication of poor electrical contact between current carrying components which may lead to voltage quality issues and/or failure of equipment.	Cost Under $0.5M on-going; OPEX
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	Cost Under $0.5M on-going; OPEX
Spare Checks and Minor Maintenance	A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.	Cost Under $0.5M on-going; OPEX
Seismic Checks	A one off budget to complete checks to determine what remedial strengthening work is required to ensure seismic resilience for network equipment generally at distribution substations.	Cost Under $0.5M on-going; OPEX

Budget	Description	Expenditure Range/Type
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	Cost Under $0.5M on-going; OPEX
Earth Testing	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed for all earths on a five yearly basis.	Cost Under $0.5M on-going; OPEX

Systemic Issues

There are no systemic issues presently being investigated. Examples of past investigations and outcomes are shown below. Some of these examples represent learnings from issues found on other networks managed by PowerNet but which are common to the TPCL network.

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

5.3. Asset Replacement and Renewal

The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to their economic end of life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

Inspection and testing programmes identify assets that are reaching the end of their economic life while critical assets may be replaced on a fixed time basis. For example 11kV switchboards at zone substations are replaced at the end of their expected 45 year life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole of lifecycle cost analysis there are several additional drivers for replacement (though they can often be reduced to a cost analysis) including operational or public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions. Replacement of assets may also be heavily influence by the development drivers discussed in section Development Criteria.

Table 41 sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 41: Replacement and Renewal Decisions by Asset Category

Asset Category	Sub Category	Replacement and Renewal Decision Approach
Subtransmission	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic. Oil cables may be damaged beyond economic repair depending on nature of failure.
	Distributed Sub Transmission Voltage Switchgear (ABSs)	When inspection indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Sub Transmission Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers & Regulator Transformers	After failure causing significant damage that is not economic to repair. Paper, Furan or DGA analysis indicating insulation at end of life. Tank and fittings deteriorating, lack of spare parts and not economic to maintain for aged units. Not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors when not economic to maintain. Greater than Standard Life and maintenance required.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Often replaced if rusting is advanced or other deterioration/damage is significant and maintenance becomes uneconomic. Otherwise units generally run to failure but transformers supplying critical loads may be replaced early based age or as part of other replacements at site. Units removed from service <100kVA and older than 20yrs are scrapped otherwise tested and if satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Enclosures not economic to maintain after significant accumulating deterioration or seismic resilience concerns.
LV Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally run to failure. Replaced when condition declines to an unreliable level e.g. embrittlement of insulation.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure but security provided by backup plant.

Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not ongoing are described in Table 42 and often represent one-off replacement or renewal of significant assets that have reached end of life or a significant miles stone in its life. Other projects may target a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

Table 42: Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
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. This line will be insulated at 66kV for future voltage upgrade. This project is largely complete, with the final sections being completed after crop harvest early in 2016/17.	CAPEX Cost Under $0.5M 2016/17
Counsel Rd Sth to Invercargill 33kV Replacement: The line is nearing its Standard Life and renewal is expected during 2016/17. This full line runs from Invercargill to Winton and was purchased from Transpower. It is insulated at 110kV and based on inspection and forecast renewals in the section from Counsel Rd Nth to Winton only 10 percent of the poles in this section are expected to need renewal.	CAPEX Under $0.5M 2016/17
Hillside to Te Anau 66KV Replacement: Line condition inspection has been completed. Of 109 poles, 18 have been assessed as needing renewal within 2 years. 2 red tagged poles have been replaced with 4 more planned before the end of 2015/16. This leaves 12 poles to be replaced in 2016/17.	CAPEX Under $0.5M 2016/17
Mataura Transformer Replacement: The two 33/11kV 10MVA power transformers at Mataura are nearing their 'end-of-life' (50 years at 2015). Oil testing has shown that paper age is currently sufficient for a few more years service but will be monitored annually. Project will plan for replacement of these units with 33/11kV 6/12MVA transformers – one new and one refurbished (ex Waikiwi). Design and refurbishment of ex Waikiwi transformer to be completed in 2016/17 to cover urgent replacement in case of transformer fault. Transformer replacements forecast for 2017/18 and 2018/19 but may be deferred based on ongoing condition monitoring.	$0.25-$0.75M per annum 2016/17 to 2018/19
Seaward Bush Transformer Replacement: The two 33/11kV 10MVA power transformers at Seaward Bush are nearing their 'end-of-life' (50 years at 2015). Oil testing has shown that paper age is currently sufficient for a few more years' service but will be monitored annually. Project will plan for replacement of these units with 33/11kV 6/12MVA transformers – one new and one refurbished (ex Waikiwi). Design and refurbishment of ex Waikiwi transformer to be completed in 2016/17 to cover urgent replacement in case of transformer fault. Transformer replacements forecast for 2018/19 and 2019/20 but may be deferred based on ongoing condition monitoring.	$0.25-$0.75M per annum 2016/17 to 2019/20
Hillside Transformer Replacement: The three single phase transformers at Hillside reach end of life (60 years) in 2017. Project will design for a replacement 3 phase 66/11+11kV 3MVA transformer. The replacement of the transformers may be deferred until condition indicates end of life or one transformer fails and spare single phase transformer is utilised.	$0.25-$0.75M per annum 2019/20 to 2020/21
Makarewa Switchboard Replacement: The Makarewa 11kV Switchboard reaches its expected life of 45 years in 2025/26. Design to be completed in 2024/25 ahead of replacement in 2025/26.	CAPEX $0.1-$2.0M per annum 2024/25-2025/26
Bluff Switchboard Replacement: The Bluff 11kV Switchboard reaches its expected life of 45 years in 2025/26. Design to be completed in 2024/25 ahead of replacement in 2025/26. The new CB6 (installed in 2015) for connection of Flat Hill wind farm will be retained.	CAPEX $0.1-$1.5M per annum 2024/25-2025/26
Ohai Substation Upgrade: This project is to upgrade and renew multiple secondary	CAPEX

Project and Description	Cost and Timing
systems at Ohai Substation. Work to be completed includes • Renewal of voltage regulation relays • Renewal of RTU • Upgrade of incomer protection relays • Installation of arc flash protection of 11kV switchboard • Installation of NER Design has been completed in 2015/16 with construction to occur in 2016/17.	Under $0.5M 2016/17
Seismic Remedial - Zone Substations: Ongoing project completing seismic strengthening following inspections of zone substations. Most work is now complete and this project is in its final year	CAPEX Under $0.5M 2016/17
Seismic Remedial Distribution: This project will implement seismic remedial solutions at TPCL's distribution substations following seismic assessments. Various options will be available depending on the site characteristics and include strengthening of buildings, enclosures or structures or replacement with self-contained freestanding equipment. There are a limited number of distribution substations in TPCL's network so work will also consider the strength of overhead structures with large distribution transformers. Remedial work will be spread across five years to manage workload; beginning in 2016/17 and being completed in the 2020/21 year.	CAPEX Cost Under $0.1M per annum 2016/17 to 2020/21
Communications Replacement: Equipment is becoming obsolete with manufacturers' ending support. This project will replace the total communications network with a modern scheme to provide the required communication for TPCL. The chosen scheme will be a combination of higher speed digital microwave radio (DMR) to replace the existing microwave links, and high speed point-to-multipoint broadband radio to zone substations. The overall aim is to achieve a minimum of 1Mbps (Megabit-per-second) speed over Internet Protocol to all of TPCL's zone substations.	CAPEX Cost Under $0.25M per annum 2016/17 to 2018/19

Ongoing Replacement and Renewal Programmes

The remaining replacement and renewal budgets are for ongoing work that tends to require about the same expenditure year after year. These budgets are listed and described in Table 43 and expenditure forecasts are provided in Table 38 (CAPEX) and Table 44 (OPEX)

Table 43: Replacement and Renewal Programmes

Budget	Description	Expenditure
General Distribution Replacement	On-going replacements of distribution assets. These are identified through routine inspection. Covers the following: • Red tagged pole replacement • Increasing road crossing height • Minor distribution renewals and upgrades	Annual CAPEX Cost Under $1.5M
Transformer Replacement	On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished.	Annual CAPEX Cost Under $1.5M
11kV Line Replacement	On-going replacements of 11kV line assets. These are identified through routine inspection. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's.	Annual CAPEX Cost Under $4.0M
Subtransmission Line Replacement	On-going replacements of subtransmission line assets. These are identified through routine inspection.	Annual CAPEX Cost Under $0.1M
Zone Substation Minor Replacement	Minor work discovered during previous years inspections are combined by sites into projects. Covers on-going replacement	Annual CAPEX

Budget	Description	Expenditure
	of minor components at zone substations such as LTAC panels and battery banks.	Cost Under $0.1M
RTU Replacements	This project will replace an average of three sites over each 2 year period. The Siemens 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, Lumsden and Riversdale. 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.	Annual CAPEX Cost Under $0.25M
Regulator Replacement	Replacement of voltage regulators as they reach the condition where maintenance and repair become uneconomic. This project will have replaced all end-of-life phase regulators with modern single phase regulators in 2016/17. The mobile regulator will be renewed in 2020/21.	CAPEX Cost Under $0.25M 2016/17 Under $0.5M 2020/21
Relay Replacement	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	Annual CAPEX Cost Under $0.1M
General Technical Replacement	General replacement of technical items at Zone Substations such as DC systems and batteries.	Annual CAPEX Cost Under $0.1M
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.	Annual CAPEX Cost varies but generally $0.2-0.35M per annum
General Distribution Refurbishment	Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	Annual OPEX Cost Under $1.5M
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.	Annual OPEX Cost Under $0.1M
Zone Substation Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the substation assets. Covers items like earth sticks, safety equipment, buildings, battery systems etc.	Annual OPEX Cost Under $0.1M
Power Transformer Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the power transformers. Covers items like painting.	Annual OPEX Cost Under $0.1M
Transformer Refurbishment	Refurbishment of distribution transformers such as rust repairs, paint touch-up, oil renewal, replacement of minor parts such as bushings, seals etc.	Annual OPEX Cost Under $0.1M

5.4. TPCL’s Forecast Operation Expenditure

The forecast operational expenditure for TPCL is shown in Table 44. These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Two further categories not described earlier complete TPCL’s forecasted operational expenditure budget as follows.

Vegetation Management

Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at TPCL’s expense as required under the Electricity (Hazards from Trees) Regulations 2003. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. As TPCL’s network is mostly overhead, tree issues are substantial and therefore costs are considerable. This OPEX cost is budgeted at $1.32M per annum ongoing.

Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. This OPEX cost is budgeted at $2.87 million per annum.

Table 44: TPCL’s Forecast Operational Expenditure

OPEX: Routine and Corrective Maintenance and Inspection	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Routine Dist Insp Check & Mtce	915,757	915,757	915,757	915,757	915,757	915,757	915,757	915,757	915,757	915,757
Minor Work Dist Insp Check & Mtce	297,968	297,968	297,968	297,968	297,968	297,968	297,968	297,968	297,968	297,968
Distribution Earthing Maintenance	449,586	449,586	449,586	449,586	449,586	449,586	449,586	449,586	449,586	449,586
TSL Communications Routine Inspection and Checks	74,465	74,465	74,465	74,465	74,465	74,465	74,465	74,465	74,465	74,465
Technical Routine Inspections and Checks	605,489	605,489	605,489	605,489	605,489	605,489	605,489	605,489	605,489	605,489
Technical Planned Maintenance	828,235	828,235	828,235	828,235	828,235	828,235	828,235	828,235	828,235	828,235
Infrared Survey	15,871	15,871	15,871	15,871	15,871	15,871	15,871	15,871	15,871	15,871
Partial Discharge Survey	53,802	53,802	53,802	53,802	53,802	53,802	53,802	53,802	53,802	53,802
Supply Quality Checks	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141
Spares Checks and Minor Maintenance	32,282	32,282	32,282	32,282	32,282	32,282	32,282	32,282	32,282	32,282
Seismic Checks - Distribution	62,118	62,118	62,118	62,118	62,118	62,118	62,118	62,118	62,118	62,118
Customer Connections	93,176	93,176	93,176	93,176	93,176	93,176	93,176	93,176	93,176	93,176
	3,444,890	**3,444,890**	**3,444,890**	**3,444,890**	**3,444,890**	**3,444,890**	**3,444,890**	**3,444,890**	**3,444,890**	**3,444,890**
OPEX: Asset Replacement and Renewal	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
General Distribution Refurbishment	1,006,898	1,006,898	1,006,898	1,006,898	1,006,898	1,006,898	1,006,898	1,006,898	1,006,898	1,006,898
Subtransmission Refurbishment	89,556	89,556	89,556	89,556	89,556	89,556	89,556	89,556	89,556	89,556
Zone Substation Refurbishment	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663
Power Transformer Refurbishment	64,490	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147	25,147
Transformer Refurbishment	38,996	38,996	38,996	38,996	38,996	38,996	38,996	38,996	38,996	38,996
	1,237,604	**1,198,261**	**1,198,261**	**1,198,261**	**1,198,261**	**1,198,261**	**1,198,261**	**1,198,261**	**1,198,261**	**1,198,261**
OPEX: Service Interruptions and Emergencies	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Incident Response Distribution	2,168,564	2,168,564	2,168,564	2,168,564	2,168,564	2,168,564	2,168,564	2,168,564	2,168,564	2,168,564
Incident Additional Time Distribution	236,901	236,901	236,901	236,901	236,901	236,901	236,901	236,901	236,901	236,901
Incident Response - TSL Comms (FA)	30,420	30,420	30,420	30,420	30,420	30,420	30,420	30,420	30,420	30,420
Incident Response - Faults Availability	111,539	111,539	111,539	111,539	111,539	111,539	111,539	111,539	111,539	111,539
Faults Response Technical (includes TSL Comms)	319,424	319,424	319,424	319,424	319,424	319,424	319,424	319,424	319,424	319,424
	2,866,848	**2,866,848**	**2,866,848**	**2,866,848**	**2,866,848**	**2,866,848**	**2,866,848**	**2,866,848**	**2,866,848**	**2,866,848**
OPEX: Vegetation Management	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Vegetation Management	1,321,382	1,321,382	1,321,382	1,321,382	1,321,382	1,321,382	1,321,382	1,321,382	1,321,382	1,321,382
	1,321,382	**1,321,382**	**1,321,382**	**1,321,382**	**1,321,382**	**1,321,382**	**1,321,382**	**1,321,382**	**1,321,382**	**1,321,382**
Network Operational Expenditure Total	**8,870,724**	**8,831,380**	**8,831,380**	**8,831,380**	**8,831,380**	**8,831,380**	**8,831,380**	**8,831,380**	**8,831,380**	**8,831,380**
System Operations and Network Support	1,653,869	1,688,149	1,789,767	1,789,767	1,789,767	1,789,767	1,789,767	1,789,767	1,789,767	1,789,767
Business Support	3,040,128	3,059,772	3,058,536	3,058,536	3,058,536	3,058,536	3,058,536	3,058,536	3,058,536	3,058,536
Non-Network Operational Expenditure Total	**4,693,997**	**4,747,921**	**4,848,303**	**4,848,303**	**4,848,303**	**4,848,303**	**4,848,303**	**4,848,303**	**4,848,303**	**4,848,303**
Operational Expenditure Total	**13,564,721**	**13,579,301**	**13,679,683**	**13,679,683**	**13,679,683**	**13,679,683**	**13,679,683**	**13,679,683**	**13,679,683**	**13,679,683**

6. Risk Management

Risk is seen as any potential but uncertain occurrence that may impact the achievement of objectives and ultimately the value of TPCL's business. TPCL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. This section examines TPCL's risk exposures, describes what it has done and will do about these exposures and what it will do to reinstate service levels should disaster strike.

6.1. Risk Strategy and Policy

TPCL embraces risk management as a critical business task with a key corporate strategy being to "Understand and Effectively Manage Appreciable Business Risk" while each of TPCL's asset management strategies also, directly or indirectly, incorporate risk management (see Strategy and Delivery).

PowerNet has developed a risk management framework which is required by PowerNet's risk management policy and requires the framework to be consistent with the ISO 31000:2009 Standard: Risk Management - Principles and Guidelines. The framework aims to formalise the practices that are and have been used to effectively manage the risks that TPCL's business faces. This will ensure greater consistency in the quantification of various risks and correct prioritisation of their mitigation as well as ensuring the regularity of review.

6.2. Risk Management Methods

PowerNet's risk management methods are used to manage TPCL's risk to acceptable levels with decision making around TPCL's asset management related risks 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

Risk Identification

To mitigate risks they must first be identified. While many risks may be obvious, identifying others requires experience and insight into the many factors that could have an appreciable impact on business objectives. The following risk categories have been created as a prompt for ensuring the various risk types are considered during risk identification and so that responsibility for review can be allocated to the applicable manager:

- Procurement
- Health & Safety
- Network, Management, Field Operations and Environment
- Stakeholders, Community and Customers
- Strategic Commercial and Other
- Human Resources
- Finance

- Business Systems, Business Integrity and Technology
- Compliance
- Infrastructure, Plant and Vehicles
- Business Continuity

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

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.

Risk Quantification

Once a risk has been identified it must be quantified. This is done by determining the following two factors:

- Consequence severity associated with the risk that may eventuate
- Probability the consequences will be encountered

These factors are categorised using relative terms as set out in Table 45 and Table 46 to allow an intuitive assessment of consequence and probability. At the same time this categorisation allows for the use of more robust calculations for these factors where this is practical (especially regarding probability).

Table 45: Event Consequence Categorisation

Consequence:	Very Low	Low	Moderate	High
Safety	First Aid injuries only.	Individual serious injury or recurring minor injuries or health issues.	Fatality(ies) &/or multiple serious injuries for any reason due to PowerNet operations.	Fatality(ies) &/or multiple serious injuries due to criminal negligence.
Performance	Insignificant budget or time over run(s) on work activity.	Budget and time over runs on a significant work activity.	Inability to achieve agreed works within budget and time over 12 month period.	Consistent inability to achieve agreed works within budget and time over several years.
Network Reliability	Marginal breach(es) of a reliability KPIs due to matters under PowerNet's control.	Significant breaches of an important reliability KPIs due to matters under PowerNet's control.	Repeat breaches of reliability KPIs due to matters under PowerNet's control (or perceived by stakeholders to be under PowerNet's control).	Repeat long term breaches of reliability KPIs due to matters under PowerNet's control (or perceived by stakeholders to be under PowerNet's control).
Network Disruption	Network disruption up to 6 hours.	Disruptions - up to 2 days - of a major network.	Repeat disruptions - up to 2 days per event of a major network.	Extended (10 days +) disruption of a major network.
Reputation	Local press attention - short-term impact on public memory.	Local press attention (not front page) and/or regulator inquiry.	Local TV news and/or regulator investigation - medium-term impact on public memory.	International TV news headlines and/or government investigation - long-term impact on public

Consequence:	Very Low	Low	Moderate	High
				memory.
Financial	Loss of assets/revenue or unbudgeted costs less than: < 1% p.a.	Loss of assets/revenue or unbudgeted costs less than: 1-5% p.a.	Loss of assets/revenue or unbudgeted costs less than: 5-10% p.a.	Loss of assets/revenue or unbudgeted costs less than: >10% p.a.
Governance	Shareholder awareness.	Perception of systemic underperformance, shareholder concern.	Shareholder dissatisfaction.	Dysfunctional governance - major conflicting interests or fundamental change in governing board direction.
Compliance	Prosecution / improvement notice.	Prosecution of business / prohibition notice.	Prosecution of Director or other employees.	Breach resulting in Imprisonment of Directors or other employees, or appointment of statutory board to a network due to matters under PowerNet control.
Environmental	Transient environmental harm.	Significant release of pollutants with mid-term recovery.	Significant long term environmental harm.	Catastrophic, long term environmental harm.

Table 46: Event Probability Categorisation

Probability Ranking	Descriptor	Expected Occurrence Interval
4	Highly Likely	Greater than once per year
3	Possible	Once every 1-10 years
2	Unlikely	Once every 10-100 years
1	Very Unlikely	Less than 100 years

Risk Ranking

Together consequence and probability give an overall measure of a risk. Table 47, commonly known as a risk matrix, shows how these factors are combined to give a relative risk level so that risks can be ranked. The risk matrix inherently recognises HILP (high impact low probability) events and gives them a high risk level ranking so that they receive appropriate attention.

Table 47: Risk Ranking Matrix

Consequence:	Very Low	Low	Moderate	High
Highly Likely	Level 3	Level 5	Level 6	Level 7
Possible	Level 3	Level 4	Level 5	Level 6
Unlikely	Level 2	Level 3	Level 4	Level 6
Very Unlikely	Level 1	Level 2	Level 3	Level 5

Risk Treatment and Mitigation Prioritisation

With finite resources risk can never be completely eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment measures. Often a number of options are available for the treatment of any risk with each treatment option likely to come at various levels of cost, effort and time to implement. At the same time, each treatment option may be more or less effective than another option. Treatment options are not necessarily mutually exclusive and may be used in combination where appropriate. Table 48 summarises the types of treatment options that should be considered for any risk, ordered by effectiveness for the control of risk.

Table 48: Options for Treatment of Risk

Treatment Options	
Terminate	Deciding not to proceed with the activity that introduced the unacceptable risk, choosing an alternative more acceptable activity that meets business objectives, or choosing an alternative less risky approach or process.
Treat	Implementing a strategy that is designed to reduce the likelihood or consequence of the risk to an acceptable level, where elimination is considered to be excessive in terms of time or expense.
Transfer	Implementing a strategy that shares or transfers the risk to another party or parties, such as outsourcing the management of physical assets, developing contracts with service providers or insuring against the risk. The third-party accepting the risk should be aware of and agree to accept this obligation.
Tolerate	Making an informed decision that the risk rating is at an acceptable level or that the cost of the treatment outweighs the benefit. This option may also be relevant in situations where a residual risk remains after other treatment options have been put in place. No further action is taken to treat the risk, however, ongoing monitoring is recommended.

Deciding on the most appropriate treatment option may be obvious, for example a low cost option providing very effective mitigation compared with a higher cost option providing less effective mitigation, however deciding between high cost effective treatments and low cost but less effective treatments may be difficult. Choosing the least “cost” option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe is the desired outcome and requires careful judgement of all the factors involved.

Good risk management recognises that limited resources are available meaning that risks cannot be effectively mitigated immediately. Therefore effective risk management also requires prioritisation of the many risk reduction actions identified and to do this the “greatest risk reduction for the resource available” is used as a guiding principle. Appropriate resourcing also needs to be considered as adjusting available resources may be necessary to control risk appropriately. This is explicitly recognised as part of the new Health and Safety at Work Act where sufficient resource to reduce hazards “as far as reasonably practicable” must be provided. This represents an example where adjustment of the cost/staffing balance may be required.

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

6.3. TPCL’s Asset Management Risk

Asset management related risks that have been identified for TPCL have been classified under the categories; physical, safety and environmental, human, external, weather, and corporate; with a summary of the risk assessment under each of these categories is as follows.

Physical

The following physical risks have been identified with Table 49 and Table 50 summarising their quantification and treatment responses:

- Earthquake – no recent history of major damage. The November 2004 7.2 Richter scale quake 240 km south-west of Te Anau caused no damage to the network. Although recent earthquakes in Christchurch have proven that large and unexpected events may occur and have significant impact on the network.
- Tsunami – maybe triggered by large off shore earthquake.
- Liquefaction – post Christchurch's 22 February 2011 6.3 magnitude earthquake, the hazard of liquefaction has become a risk to be considered.
- 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. i.e. failure of a padlock could allow public access to restricted areas.

Table 49: Risk Associated with Physical Events and Responses

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Very Unlikely	High	• Disaster recovery event. • Projects underway to investigate and improve survivability through large seismic events.
Earthquake (6 to 7)	Very Unlikely	Low to High	• Specify so buildings and equipment will survive. • Review existing buildings and equipment and reinforce if necessary.
Tsunami	Very Unlikely	Low to Medium	• Review equipment in coastal areas and protect or reinforce as necessary.
Liquefaction	Very Unlikely	Low to Medium	• Specify buildings and equipment foundations to minimise impact.
Fire	Very Unlikely	High	• Supply customers from neighbouring substations. • Maintain fire alarms in buildings.

Table 50: Risk Associated with Equipment Failures and Responses

Event	Likelihood	Consequence	Responses
33kV & 66kV Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by ringed subtransmission or through the distribution network. • All new lines designed to AS/NZS 7000:2010
Power Transformer	Unlikely	Low to medium	• At dual power transformer sites, one unit can be removed from service due to fault or maintenance without interrupting supply. • Continue to undertake annual DGA to allow early detection of failures. • Relocate spare power transformer to site while damaged unit is repaired or replaced.
11kV	Unlikely	Medium	• Annual testing including PD[13] and IR[14].

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

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

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

As the impact of equipment failure 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.

Safety & Environmental

The following safety and environmental risks have been identified with Table 51 summarising their quantification and treatment responses:

- 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.

Table 51: Risk Associated with Safety and Environmental Events and Responses

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Possible	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	Unlikely	High	• Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2010
Arc Flash	Very Unlikely	High	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations • De-energise installation before switching where PPE inadequate
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met

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

Human

The following human related risks have been identified with Table 52 summarising their quantification and treatment responses:

- 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.
- Terrorism/Vandalism – range varies from malicious damage to copper theft to 'tagging' of buildings or equipment. Cyber-attack could also occur; considered low risk at present but vulnerability increases as the network becomes "smarter"

Table 52: Human Event Risks and Responses

Event	Likelihood	Consequence	Responses
Pandemic	Unlikely	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.
Vandalism	Possible	Low to High	• Six monthly checks of all ground-mounted equipment. • Faults contractor to report all vandalism and repair depending on safety then economics. i.e. Tagging/graffiti would depend on the location and content. • Any safety problems will be made safe as soon as they are discovered.
Terrorism	Very Unlikely	High	• Ensure security of restricted sites. • Use alternative routes and equipment to restore supply, similar to equipment failures below.
Cyber Attack	Very Unlikely	High	• Secure communications links • Analyse and remove vulnerabilities • Review and apply industry best practice

External Factors

The following external factor risks have been identified with Table 53 summarising their quantification and treatment responses:

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

Table 53: External Factor Event Risks and Responses

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

Weather

The following weather related risks have been identified with Table 54 summarising their quantification and treatment responses:

- Wind – strong winds that either cause pole failures or blow debris into lines.
- Snow – impact can be by causing failure of lines or limiting access around the network.
- Flood – experience of 1984 floods has caused Environment Southland to install flood protection works, but still need to consider if similar water levels do occur again.

Table 54: Risk Associated with Weather Events and Responses

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

Corporate

The following corporate risks have been identified with Table 55 summarising their quantification and treatment responses:

- 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.

Table 55: Corporate Risks and Responses

Event	Likelihood	Consequence	Responses
Investment	Unlikely	Low	• New larger contracts require Shareholder Guarantee before supply is provided.
Loss of Revenue	Very Unlikely	High	• Continue to have Use of System Agreements with retailers. • New large investments for individual customers to have a guarantee.
Management Contract	Very Unlikely	High	• Continue management contract with PowerNet noting that it operates a Business Continuity Plan
Regulatory	Very Unlikely	High	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to a Business Continuity Plan.
Resource	Unlikely	High	• PowerNet utilises internal staff allowing effective planning and management of recruitment training and retention of skilled staff. • Endeavour to provide a reasonably constant stream of work for key external contractors to assist in their continued viability.

6.4. Emergency Response and Contingency

The following tactics have been or are being implemented to manage risk for TPCL (especially for HILP events):

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

Additionally TPCL has the following specific contingencies in place through its management company PowerNet.

PowerNet Business Continuity Plan

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

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

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

PowerNet Pandemic Action Plan

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

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

Critical Network Spares

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

Network Operating Plans

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

Insurance

TPCL holds the following insurances:

- Material damage and business interruption over Substations and Buildings.
- Contracts works.
- Directors and officers liability.
- Utilities Industry Liability Programme (UILP) that covers Public, Forest & Rural Fires and Products liability.
- Statutory liability.
- Employee and fidelity/crime.

Contractors working on the network hold their own liability insurance.

7. Evaluation of Performance

Details of asset management performance measurement, evaluation, improvement;

7.1. Progress against Plan

Capital Expenditure

Table 56: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2014/15 ($k)	Actual 2014/15 ($k)	Variance
Consumer Connection	2,778	4,720	70%
System Growth	11,329	10,937	-3%
Asset Replacement and Renewal	11,433	8,430	-26%
Asset Relocations	59	194	228%
Quality of Supply	2,881	449	-84%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	1,300	396	-70%
Capital Expenditure on Network Assets	19,467	22,503	16%

Capital works was under budget due to;

- Customer Connections – 70% more customer connections than was forecast. Actuals depend on regional growth and development.
- System Growth – While financial spend is close to budget, physical achievement was poor and actual spend on some projects significantly exceeded budgets. Details of significant projects expanded below in Table 57.

Asset Replacement and Renewal – 26% underspent due to deferral of some projects. Details of significant projects expanded below in Table 58.

- Asset Relocations – 228% overspend due to more projects than anticipated.
- Quality of Supply – 84% underspend due to design completion delays on Mobile Substation and subsequent carryover into future years.
- Other Reliability, Safety and Environment – 70% underspend due to design completion delays on NER installations and subsequent carryover into future years.

Table 57: System growth project expenditure details

Project	Planned Completion	Actual Completion	Reason
Hedgehope Substation	100%	100% Physical 131% Financial	Planned contractor lost local Transpower contract and alternatives allocated to other works.
Athol Substation	100%	100% Physical 94% Financial	Achieved completion slightly ahead of budget
Mossburn to Athol 66kV line	100%	99% Physical 310% Financial	Scope change as reuse of existing poles not feasible. Extra time and resource required.
Winton to Centre Bush 66kV line	100%	50% Physical 76% Financial	All poles installed. Conductor stringing not started due to insufficient resource.
Colyer Road Substation	100%	67% Physical 70% Financial	Customer driven project – was planned for completion but delays due to contractor resource.
Isla Bank Substation	100%	75% Physical 81% Financial Forecasting 114% of budget	Project deferred to completed customer driven project of Colyer Road Substation
OVP - Design	100%	50% Physical 86% Financial	Changes in overall scope of OVP to include Lumsden
Fairfax to Isla Bank 66kV Line	100%	88% Physical 127% Financial Forecasting 155% of budget	Delays in receiving some materials
Waikiwi Substation Upgrade	100%	0% Physical 35% Financial	Transformers and other major materials have arrived and are being stored Project deferred to completed customer driven project of Colyer Road Substation
Riversdale Substation Upgrade	12%	0% Physical 100% Financial	Design completed. However major change in scope now requires complete redesign.
Edendale Substation Upgrade	0%	0% Physical 6% Financial	Customer driven project – was planned for 2017/18 but brought forward at customer request. Design started.
Centre Bush Substation	0% Physical 16% Financial	0% Physical 5% Financial	Plan for transformer procurement (16% financial completion), however only down payment made due to design delays
Dipton Substation	0% Physical 4% Financial	0% Physical 2% Financial	Planned to complete more of design

Table 58: Asset replacement and renewal project expenditure details

Project	Planned Completion	Actual Completion	Reason
Winton Switchboard Replacement	100%	100% Physical 170% Financial	Additional costs to maintain supply while replacing equipment.
Riverton Switchboard Replacement	100%	39% Physical 58% Financial Forecasting 150% of budget	Design not completed as expected and contractor resource availability led to delays

Project	Planned Completion	Actual Completion	Reason
Riversdale to Lumsden 33kV renewal	50%	30% Physical 50% Financial	Materials all ordered and arrived. Contractor resource availability lower than planned
Counsell Rd Nth-Winton 66kV Replacement	100%	0% Physical 43% Financial	Re-design required to achieve a more cost effective option. Some materials ordered and received

Operation Expenditure

Table 59: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2014/15 ($k)	Actual 2014/15 ($k)	% Variance
Service Interruptions and Emergencies	3,002	4,346	45%
Vegetation Management	1,404	1,541	10%
Routine and Corrective Maintenance and Inspection	3,095	3,152	2%
Asset Replacement and Renewal	1,393	1,286	-8%
Operational Expenditure on Network Assets	**8,894**	**10,325**	**16%**

Maintenance was over budget due to;

- Vegetation Management – Overall OPEX managed in line with budget.
- Routine and Corrective Maintenance and Inspection – Overall OPEX managed in line with budget.
- Service Interruptions and Emergencies – 45% above budget due to major storms and rebuild of subtransmission line following failure of 13 poles.
- Asset Replacement and Renewal – Overall OPEX managed in line with budget.

7.2. Service Level Performance

Customer Consultation

A face to face survey using a survey company was undertaken with seven key clients. It was found businesses had a very positive view of PowerNet as a professional company and were generally happy with the current level of reliability. Customers appreciate the notification of planned outages and the ability to negotiate timing to minimise impacts on their businesses. While most customers seemed happy with the restoration times after unplanned outages, there was a wide range of preferred timeframes indicated from six hours to ten minutes. On the whole communication with PowerNet regarding network issues or progress restoring supply during unexpected interruptions was seen positively however a couple of comments were received that this communication could have been more timely or more helpful and informative.

PowerNet is perceived to have a good public profile regarding community support. Some businesses expressed a desire for more proactive and regularly initiated contact from PowerNet staff to make them more aware of pricing and reliability options while others commented that they would prefer to initiate contact with PowerNet themselves.

Individual customers are also consulted as they undertake connection to the network. For example, the connection of the show grounds subdivision where options and negotiations occurred before the supply was agreed on.

Reliability

Table 60 displays the target versus actual reliability performance on the network. For the 2014/15 year the overall network performance was poor, with SAIFI 103% of target and SAIDI 133% of target.

Table 60: Performance against Primary Service Targets

	2014/15 AMP Target	2014/15 Actual
SAIFI	2.96	3.04
SAIDI	195.19	259.1

Targets are based on averages over the previous five years and due to the reliability of the network have been set at a level which typically excludes major storms. This, however, means major storm events have the potential to have a significant impact on reliability performance.

Customer Satisfaction

Results for 2014/15 are shown in Table 61:

Table 61: Performance against Secondary Service Targets

Attribute	Measure	Target 2014/15	Actual 2014/15
Customer Satisfaction on Faults	Power restored in a reasonable amount of time {CES: Q4(b)}	>90%	96%
	Information supplied was satisfactory {CES: Q8(b)}	>90%	92%
	PowerNet first choice to contact for faults {CES: Q6}	>35%	45%
Voltage Complaints	Number of customers who have made voltage complaints {IK}	<45	13
	Number of customers having justified voltage quality complaints {IK}	<15	9
Planned Outages	Provide sufficient information {CES: Q3(a)}	>75%	96%
	Satisfaction regarding amount of notice {CES: Q3(c)}	>75%	98%
	Acceptance of max of one planned outage every year {CES: Q1}	>50%	99%
	Acceptance of planned outages lasting four hrs on average {CES: Q2}	>50%	91%

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

The 2015 AMP set targets for Customer Satisfaction Surveys (questionnaires sent to customers with invoices for new connections), however the use of these surveys has been discontinued due to an extremely poor response rate. PowerNet is investigating alternative methods of gathering this information, including the possibility of adding similar questions to the existing Customer Engagement Survey (phone survey carried out by an independent consultant).

The percentage of customers who were satisfied that their supply was restored within a reasonable amount of time following an unexpected outage was 96% which was above the target of 90%. Only 3% indicated that the restoration time was unacceptable.

Performance against all other secondary service levels matched or performed better than the targets set for 2014/15.

Network Efficiency

Table 62: Performance against Efficiency Targets

Measure	2014/15 Target	2014/15 Actual	Comment
Load factor	> 65%	64%	Reduced load control required
Loss ratio	< 7.0%	6.8%	Variable - dependant on Retailer accruals
Capacity utilisation	> 30%	29.7%	Influenced by load factor

The growth seen at the GXP level has been distorted with Transpower's introduction of the TPM[15] where individual EDB peaks have been replaced by a regional grouping. This has allowed TPCL to relax load control during the year but has had a negative impact on load factor.

Losses tend to vary from year to year more than would be expected due to changes in operation and network assets. This variation can mostly be attributed to the retailer accrual process. Therefore a longer term average is more likely to be indicative of actual loss ratio. New smart meters will allow better analysis and monitoring.

While it is desirable to have a capacity utilisation factor as high as possible, standardisation of transformer sizing, allowance for growth and the unpredictable consumption patterns of some customers means there is a practical and economic limit to how much this factor can be improved. TPCL's capacity utilisation compares well with other similar distribution businesses.

Financial Efficiency

Table 63: Performance against Financial Targets

Measure	2014/15 Target	2014/15 Actual
OPEX/RC	1.99%	1.56%
Indirect Cost per Customer	$98.98	$117

OPEX to RC ratio performance was okay as actual was less than target and Indirect Costs per Customer performance was poor as actual was greater than the target set.

7.3. AMMAT Performance

TPCL understands the foundations of good asset management practice and generally looks to implement each aspect, however often implementation is not systematic and therefore may not always be consistent or applied to all potential areas of benefit. In scoring TPCL's asset management practice against the Asset Management Maturity Assessment Tool (AMMAT) this results scores from '1' to '3' but with a typical score of '2' as shown in Figure 42.

[15] 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.electricitycommission.govt.nz/rulesandregs/rules Part F, Section IV for more details.

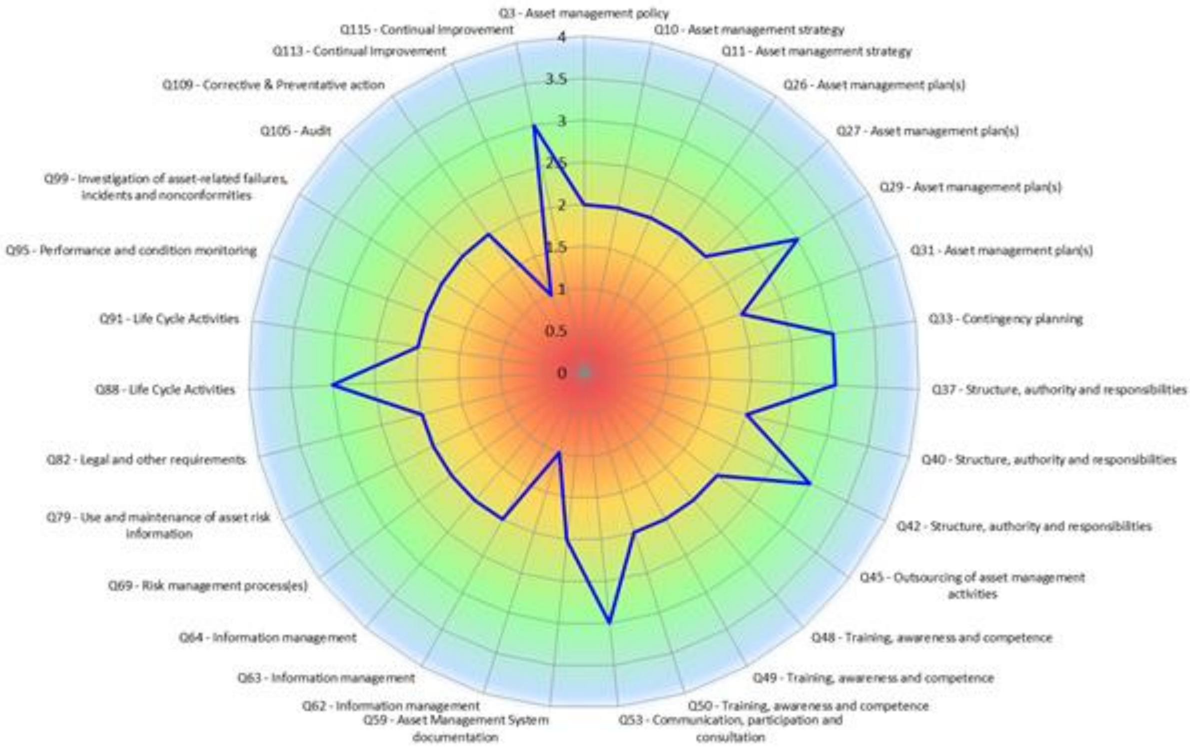

Figure 49: Figure 42: TPCL's Asset Management Maturity Assessment Tool Scores

The AMMAT is based on a selection of the questions asked in PAS-55 intended to prompt consideration of performance against a number of facets of asset management practice. Each question can be scored from ‘0’ to ‘4’ and each question has a series of answers to describe what is required to achieve each scoring level. Appendix 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

7.4. Gap Analysis and Planned Improvements

AMMAT

For a distribution company of TPCL’s size a score of ‘2’ for many of the asset management functions is considered appropriate. However as PowerNet provides TPCL’s asset management services as well as providing this service across other networks, TPCL believes that some improvements are realisable and appropriate. TPCL therefore believes a score of ‘3’ is desirable as a long term goal for each of the AMMAT functions and that improvements made over time would be generally in line with TPCL’s asset management and corporate strategies, ultimately supporting the achievement of TPCL’s asset management objectives.

Of the 30 questions posed in the AMMAT, seven scores of ‘3’ have been determined across the areas of Asset Management Policy, Asset Management Plans, Contingency Planning, Structure Authority and Responsibilities, and Communication, Participation and Consultation. For the remaining questions there is room for improvement, especially with two questions assessed as ‘1’ in the areas of Continual Improvement and Information Management.

While there have been no changes in score since the previous AMP, the following improvements have been made:

- This latest version of TPCL's AMP (Q26-31) has been largely rewritten to better comply with the Electricity Distribution Information Disclosure Determination 2012. Improvements have also been made to aid the AMP in being further embedded in TPCL's internal asset management planning and to support continuous improvement (Q69) especially in the area of communication.
- The overhead lines inspection process has been an area of recent focus for PowerNet. Objective criteria have been set out in an inspection standard (Q95), for inspectors to use when determining how quickly a defect must be rectified to minimise the chances of failure. A mobile application is being developed that will allow inspectors to record the results of their inspections in a structured format (Q62). This format is designed to allow comprehensive bulk analysis of inspection data to promote continuous improvement (Q113) of the inherent trade-off between repair cost and asset performance in the inspection standard.
- Responsibility for investigation of asset-related failures (Q99) has been codified in the PowerNet standard PNM-067; this standard also prescribes defect elimination measures (Q113) where a systemic defect is found. PowerNet has joined the National Equipment Defect Reporting System (NEDeRS) scheme (Q115); standard PNM-066 sets out the process for promulgating details of identified systemic defects via NEDeRS where appropriate.
- TPCL has adopted the Incident Cause Analysis Methodology (ICAM) approach to investigating safety incidents but has been utilised where other significant incidents have occurred. A roster of trained staff (Q50) is rotated through for the investigation of eligible incidents (Q99) with the ICAM to be given priority over routine work.
- TPCL is initiating a Safety by Design system and has developed an interim policy and procedure to ensure a systematic process for identifying and effectively managing risks (Q69) associated with each lifecycle stage of any new assets designed. Future work will also look to extend this systematic risk management approach across its existing assets to ensure regular comprehensive reviews are undertaken.
- A programme of Lean Management implementation has been initiated. This is a long-term approach to business processes that systematically seeks to achieve small, incremental changes in processes in order to improve efficiency through the elimination of wastage. Lean management is an approach to running an organization that supports the concept of continuous improvement (Q113).
- Improvements to TPCL's AMS are being implemented including;
  - Work Scheduling to more systematically and efficiently schedule and track asset maintenance activities.
  - Compatible Units to allow standardisation common asset types including cost by materials and labour to enable efficient costing and scheduling of future work.
  - Integration of TPCL's financial management system to efficiently track costs supporting compatible units and understanding whole of lifecycle costs for these assets.
  - Electronic purchase orders are also being implemented to support these improvements.

TPCL recognises this organisation of information (Q62) as important for managing its assets efficiently and effectively by improving ability to estimate costs for future similar work and evaluating whole lifecycle costs.

Capital and Maintenance Works

The initiatives above will improve efficiency for capital and maintenance project delivery and support consistent performance against delivery TPCL's AWP.

In addition TPCL's Amalgamation of TPCL's network management company PowerNet and its previous field service contracting companies has improved relationships and communication between planning and field staff. More efficient work practices are being realised and expected to continue. The amalgamated company PowerNet has also employed additional technical field staff to extend the in-house field services concept to further realise efficiencies. This should help increase productivity and with some additional resource TPCL should be better placed to deliver the planned projects.

Long term relationships with external contractors are being maintained so they can more confidently manage their resources and personnel. This will allow more work to be completed and ensure a resource for future years.

Reliability

On the whole reliability of the TPCL network is average and the SAIDI and SAIFI results for 2014/15 were above targets set. TPCL will look to control the impact of events that might incur large customer-minute totals primarily by increasing the number of remotely controlled devices on the network to speed isolation of faulty sections and restoration of supply to healthy sections. The completion of the network automation project will achieve a significant improvement in the network's reliability.

TPCL's network management company PowerNet will work to retain experienced field services staff and maintain long term relationships with external contractors so quality personnel with sufficient network familiarity are available for efficient restoration of supply.

Regular network inspections will be continued and critical items will be acted on as they are identified. Also data capture and condition assessment will be increased above reactive maintenance practices to increase knowledge of the assets and their condition to enable better planning based on more accurate and comprehensive asset data. Again the initiatives noted as improvements under the AMMAT will assist with the improvement of reliability by enhancing TPCL's maintenance practices.

Efficiency

Load factor is average compared to other similar EDB's and no specific improvements are targeted. The introduction of smart meters in future years is expected to provide some additional leverage to influence customer's consumption behaviour.

Losses and capacity utilisation are not specifically being targeted for improvement except for selecting efficient and optimally sized assets when required for network development or replacements.

8. Capability to Deliver

TPCL succeeds in delivering when the network development and maintenance plans are achieved on time and to budget while achieving service level targets from the present time to the long term. To achieve successful delivery TPCL must have sufficient staffing (planning, management, field services) and financial resources available along with having appropriate systems and processes in place.

8.1. Systems and Processes

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 50 describes the typical sorts of information residing within TPCL's business (including in PowerNet employees brains).

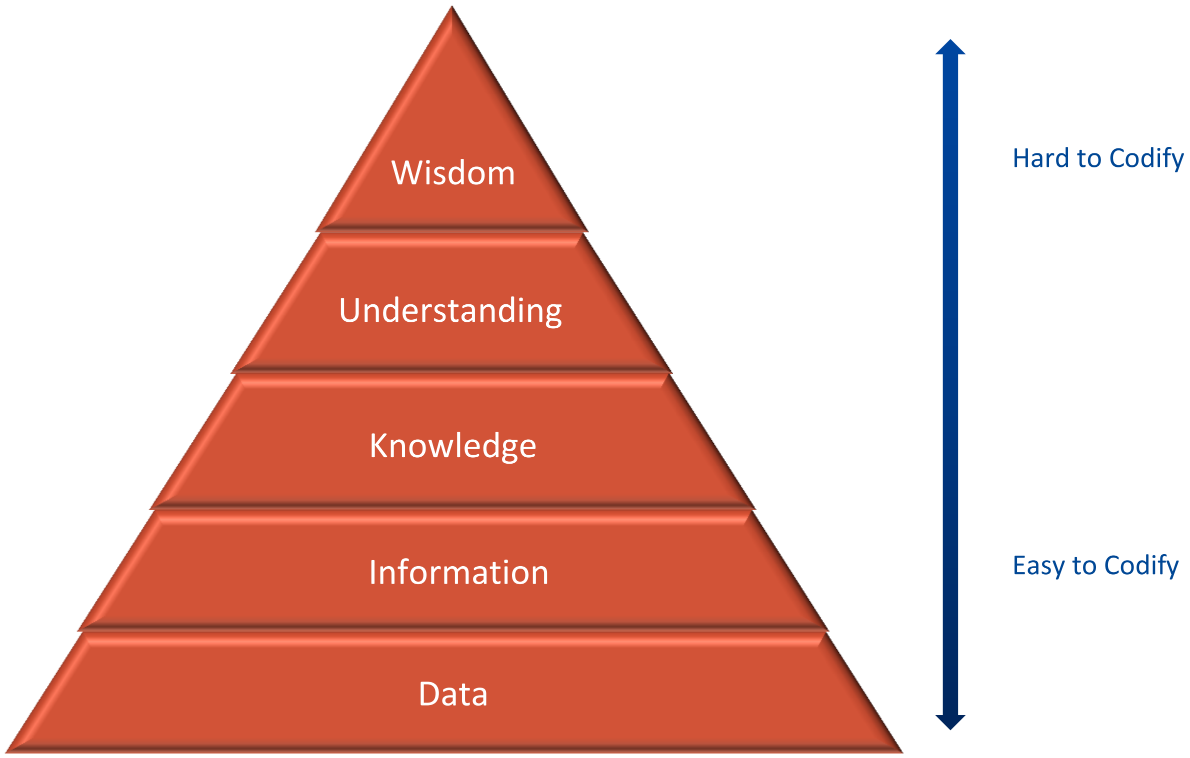

Figure 50: Hierarchy of Data

- The bottom two layers 'Data' and 'Information' of the hierarchy tend to relate strongly to TPCL's asset and operational data and the summaries of this data that form one part of TPCL's decision making.
- The middle 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 'Understanding' and 'Wisdom' tend to be very broad and often quite fuzzy. It is at this level that key organisational strategies and processes reside. As indicated in Figure 50 it is generally hard to codify these things, hence correct application is heavily dependent on skilled and experienced people.

Asset Management Systems

TPCL has a variety of information management tools which capture asset data and can be used to aggregate this data into summary information. From this information TPCL has a great deal of knowledge about almost all of the assets; their location, what they are made of, generally how old they are and how well they can perform. This knowledge will be used for either making decisions within TPCL's own business or assisting external entities to make decisions.

The decision making process 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 roles and interaction of each component of the hierarchy are incorporated in Figure 51 which provides a high level summary of TPCL's asset management processes and systems.

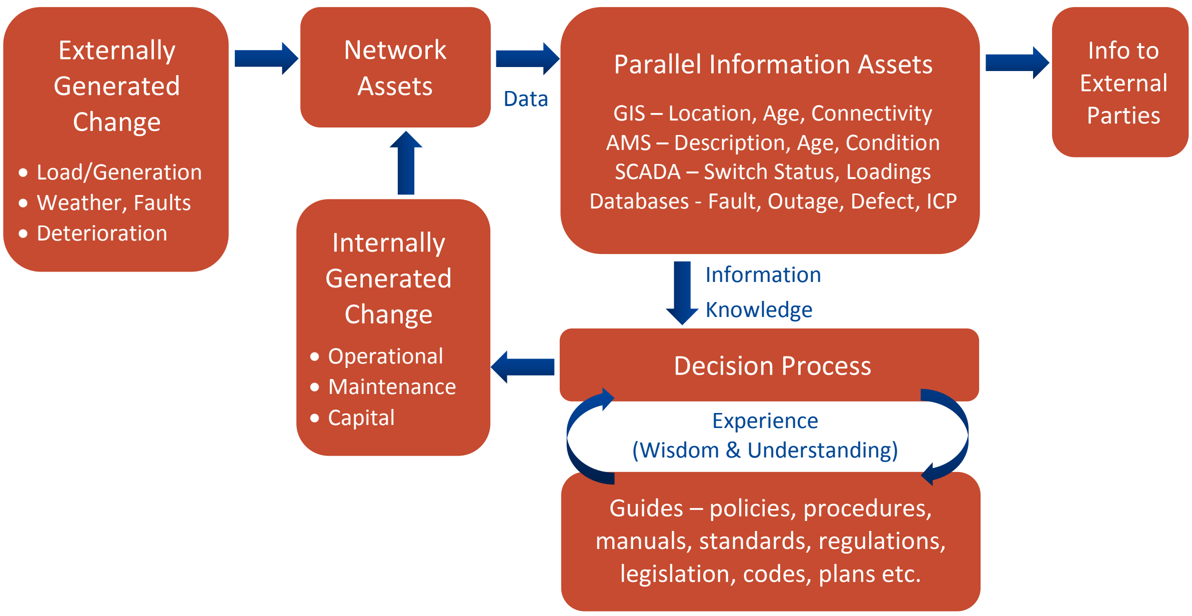

Figure 51: Key information systems and processes

Processes and Documentation

TPCL's key processes and systems are based around the key lifecycle activities defined in Figure 51, which are based around the AS/NZS9001 Quality Management System. The 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.

The asset management processes are documented and grouped in the following categories with a complete list provided in Appendix 1:

- Operating Processes and Systems

- Maintenance Processes and Systems
- Renewal Processes and Systems
- Up-sizing or Extension Processes and Systems
- Retirement Processes and Systems
- Performance Measuring Processes
- Other Business Processes

Some processes are prescribed in external documents (such as the information disclosure determination which this AMP is required to comply with) and as such they are not copied onto internal documentation. Processes are often embedded within asset management tools including external requirements such as the need to produce network reliability statistics for disclosure being embedded within the outage management database.

Documents and Control Reviews

Each document is controlled by an owner at management level who is given responsibility for the documents review and update. The documents are reviewed periodically (which includes review of the underlying processes that have been documented) to ensure they are kept up to date and incorporate any changes that have been identified as necessary. Lean Management practices have recently been introduced to refine business and asset management processes with the changes identified ultimately reflected in documented procedures.

Once updates have been finalised they are approved by the controlling manager and all staff are notified by email and where necessary by placement on notice board and direct training and communication to individuals affected.

Asset Management Tools

PowerNet maintain and utilise a number of software based tools to efficiently and effectively manage data and knowledge for TPCL's network assets.

The **Asset Management System (AMS)** stores TPCL's assets descriptions, details, ages and condition information for serial numbered components. It also provides work scheduling and asset management tools with most day to day operations being managed through the AMS. Maintenance regimes, field inspections and customers produce tasks and/or estimates, that are sometimes grouped and a 'work order' issued from the AMS which is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling. The individual assets that make up large composite items such as substations are managed through the AMS in conjunction with other more traditional techniques such as drawings and individual test reports. The Maximo software package is utilised as TPCL's AMS. Maximo is considered suited to TPCL's needs, providing sufficient functionality and helping streamline administration of TPCL's maintenance practices.

An Intergraph based **Geographic Information System (GIS)** is utilised to store and map data on individual components of distributed networks. The GIS focuses primarily on geographically distributed assets such as cables, conductors, poles, transformers, switches, fuses and similar items and provides asset description, location and age information for each asset. Locational data is used to provide mapping type displays of existing equipment for planning network upgrades, extensions and maintenance scheduling. It allows these plans to account for distance and travel time and any other factors influenced by the geographic distribution of the assets. Electrical connectivity, capacity and ratings also form a crucial data set stored in the GIS which assists the analysis of the networks ability to supply increasing customer load or determine contingency plans.

Export of data from the GIS into **Load Flow and Fault Analysis Software** allows modelling of the network. This helps predict network capability in the existing arrangement and in future “what if” scenarios considered as planning options as well as determining fault levels to assess safety and effectiveness of protection and earthing systems. Two software packages PSS Adept and Cyme are used to perform this analysis for TPCL.

The **Supervisory Control and Data Acquisition (SCADA)** system provides real time operational data such as loadings, voltages, temperatures and switch positions. It also provides the interface through which PowerNet’s System Control staff can view the data through a variety of display formats and remotely operate SCADA connected switchgear and other assets. Historical data is stored and provides a reference for planning. For example network loading can be downloaded over several years allowing growth trends to be determined and extended to forecast future loading levels.

Monthly reports out of the **Finance One (F1)** financial system provide recording of revenues and expenses for the TPCL line business unit. Project costs are managed in PowerNet with project managers managing costs through the AMS system. Interfaces between F1 and the AMS track estimates and costs against assets.

Outage, Fault and Defect Databases are populated by the System Control staff as information is reported by field staff or via the faults call centre to ensure efficient tracking of operational issues affecting network service levels.

- The faults database logs all customer initiated calls reporting power cuts or part power to store reported information and contact details. Calls are therefore able to be tracked to ensure effective response and restoration.
- The outage database logs outage data used to provide regulatory information and statistics on network performance. As such data capture is in line with regulatory focuses so therfore excludes LV network outages. Reports from this system are used to highlight poorly performing feeders which can then be analysed to determine maintenance requirements or if reliability may be enhanced by other methods. Monthly reports are provided to the TPCL board for monitoring, together with details of planned outages.
- Asset defects are captured in another database for technical asset issues which don’t have an immediate impact on service levels but have the potential to if not responded to. Defects are tracked in this database and scheduled for remediation.

The **Condition Assessment Database** tracks the results of routine overhead line inspection rounds and is used as a basis for assigning line repair/renewal work. Severely deteriorated structures are marked as red-tagged and are prioritised for repair, and low conductor spans are also marked for a heightened priority. The Condition Assessment Database is being replaced as part of an overhaul of line inspections on all PowerNet-managed networks; the replacement database will permit the recording of repairs and will allow more precision in reliability analysis.

An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history resides in an **ICP/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.

Data Control, Improvement and Limitations

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 56% 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. Options have been considered to get ages measured for the un-dated poles but no economic methodology has been found, and condition data is considered to be more useful in determining replacement timeframes.

Almost all GIS data entered for assets is standardised and selected from lists to ensure quality of data entry and for all other data, for example electrical connectivity, thorough processes, peer reviews and well trained staff are used to ensure data entry quality is very good. Key process improvements will include more timely as-builts with PowerNet staff taking GPS[16] coordinates for poles and use of scan-able forms for data input (Teleform system).

Data for the AMS is collected by the Network Equipment Movement (NEM) form that records every movement of serial numbered assets. Some updating of data is obtained when sites are checked with a barcode label put on equipment to confirm data capture, and highlight missed assets. About 20 percent of the network (by length) is condition assessed each year to update asset condition data (noting that asset condition is continually varying), and any discovered details are corrected.

As the AMS system has recently been replaced the opportunity was taken during transfer of data to the new system to check for accuracy and completeness with some data improvements achieved through update where issues were found. Further improvements to the AMS are continually being undertaken to allow additional asset details to be captured which were historically captured in spreadsheets; especially the addition of condition based indicators to assist in making better asset management decisions. Data validation and completeness controls are also being added over time to prevent new assets being created without all required data being captured.

Assets are assigned a unique reference common to both the GIS and AMS. Where asset data is common to both systems it will be input into one system (deemed the master for that data) and automatically copied to the other to ensure consistency. Other systems also have some degree of interface for copying across common data such as customer data residing in both the ICP database and in GIS and referenced by the common ICP number. However apart from these data copying interfaces and for the most part, these tools do not interact directly, with staff pulling together information from the necessary tools for their use as part of their asset management activities.

The SCADA system and monitoring completeness and accuracy is excellent at zone substations as it is critical for both safety and reliability of the network as it is used for the day to day operation of the network. More field devices are be being added to SCADA for remote monitoring and operation.

Other data repositories have very good data quality with these database systems controlling data entry through drop down lists and validation controls. Modifications may be made from time to time to better align with maintenance processes as they evolve.

[16] GPS = Global Positioning System, a device that uses satellites and accurate clocks, to measure the location of a point.

Table 64 provides a summary for the completeness of TPCL's data.

Table 64: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion & GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion & GIS update
GIS	Age	Poor	Pole ages not available for 63%
Condition Assessment Database	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMS	Description	Okay	Some delays between job completion & Maximo Update
AMS	Details	Okay	Some delays between job completion & Maximo Update
AMS	Age	Okay	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

8.2. Funding the Business

TPCL's business is funded from the revenue received from their customers. And through a wide range of internal processes, policies and plans, the company converts that funding into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and supply quality that customers want. This business model is shown in Figure 52.

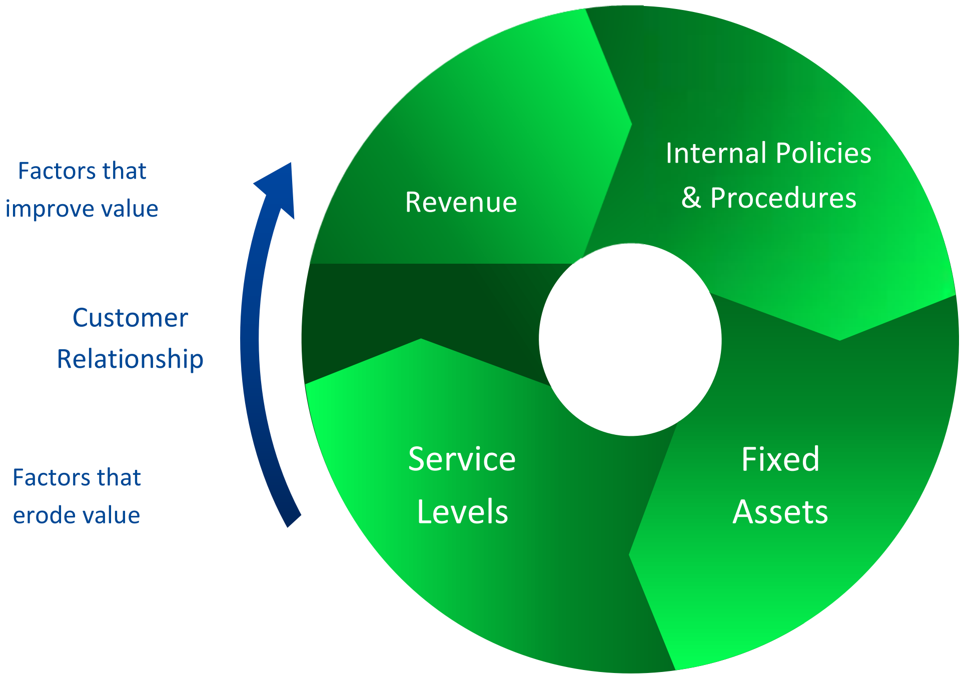

Figure 52: Customer Interface Model

Revenue

TPCL's money comes primarily from the retailers who pay for the conveyance of energy over TPCL's network but also from customers providing contributions for the uneconomic part of works. Revenue is closely tied to the value of assets as set out in a "price path" determined by the commerce commission.

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 balance sheet, but perhaps more importantly also allows TPCL to treat any increased Transpower charges as a pass-through cost

Expenditure

Work is done to maintain the asset value of the network and to expand or augment to meet customer demands.

Influences on the Value of Assets

An annual independent telephone 'Customer Engagement Survey' is undertaken in September each year and consistently indicates TPCL's customer's price-quality trade-off preferences are as follows:

- A large majority are not willing to pay $10 per month more in order to reduce interruptions
- A small minority are willing to pay $10 per month more in order to reduce interruptions
- A small minority feel they don't know or are unsure of price-quality trade-offs

In response TPCL's asset value should either remain about the same or be allowed to decline in a controlled manner (and knowing how to do this is obviously a complex issue). However this presents TPCL with the dilemma of responding to customers wishes for lower cost supply in the face of a "no material decline in SAIDI" requirement and in fact revenue incentives to improve reliability. Factors that will influence TPCL's asset value are shown in Table 65 below:

Table 65: Factors influencing TPCL's asset value

Factors that increase TPCL's asset value	Factors that decrease TPCL's asset value
Addition of new assets to the network	Removal of assets from the network
Renewal of existing assets	On-going depreciation of assets
Increase of standard component values implicit in valuation methodology	Reduction of standard component values implicit in valuation methodology

At a practical level TPCL's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

Depreciating the Assets

The accounting treatment of using straight-line depreciation doesn't strictly model the decline in service potential of an asset. It may well 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.

8.3. Staff and Contracting Resources

The greatest issue presently facing TPCL is staff and contracting resources. Each item or project making up the AWP is carefully considered as to the man hours required using the experience gained over many years of network management. The works plan as a whole is then considered to ensure that it is realistic with the resources expected to be available and any adjustments can be made. Low priority work may be delayed short term where a commitment to increase staff or contractor numbers has been made such that the necessary works plan will not fall behind. It is important that the AWP "smooths" the year to year work volumes required (to the extent possible acknowledging appropriate risk controls) to provide a relatively constant work stream.

PowerNet's internal field services is a great benefit in ensuring a longer term approach may be taken to resourcing. This means staff numbers can be increased with added confidence that they will be fully utilised in future years given the long term plans developed. Working closely with TPCL's contractors is also an important part of the AWP development process, carefully communicating the detailed works plan and getting commitment that sufficient resources will be available for the year ahead. The future works plan is also communicated so that contractors can confidently commit to hiring extra staff where appropriate, recognising that TPCL's development and maintenance requirements are on-going into the future.

Appendix 1 – Policies, Standards and Procedures

Operating Processes and Systems

Commissioning Network Equipment	PNM-061
Network Equipment Movements	PNM-063
Planned Outages	PNM-065
Network Faults, Defects and Supply Complaints	PNM-067
Major Network Disruptions	PNM-069
Use of Operating Orders (O/O)	PNM-071
Control of Tags	PNM-073
Access to substations and Switchyards	PNM-075
Operating Authorisations	NMPR-040
Radio Telephone Communications	PNM-079
Operational Requirements for Live Line Work	PNM-081
Control of SCADA Computers	PNM-083
Operating Near Electrical Works	PNM-085
Customer Fault Calls/Retail Matters	PNM-087
Site Audits	PNM-088
Meter/Ripple Receiver Control	NMPR-005

Maintenance Processes and Systems

Transformer Maintenance	NMPR-030
Defect Submission & Retrieval from the NEDeRS Database	PNM-066
Control of Network Spares	PNM-097
Maintenance Planning	PNM-105
Network Overhead Lines Equipment Replacement	PNM-106
Earth Tests	PNM-133

Other maintenance is to manufacturers' recommendations or updated industry practise.

Renewal Processes and Systems

Network Development	PNM-113
Design and Development	PNM-114

Up-sizing or Extension Processes and Systems

Processing Installation Connection Applications	PNM-123
Network Development	PNM-113
Design and Development	PNM-114
Easements	PNM-131

Retirement Processes and Systems

Disconnected and/or Discontinued Supplies	PNM-125

Performance Measuring Processes

These processes are embedded within, and controlled by, the outage, faults and defects databases.

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:

Setting Up the Project	PNM-010
Tendering	NMPR-045
Progressing the Project	PNM-020
Construction Approval	PNM-025
Materials Management	PNM-030
Project Control	PNM-035
Project Close Out	PNM-040
Customer Satisfaction	PNM-050
Internal Quality Audits	PNM-055
Drawing Control	PNM-089
Network Operational Diagram/GIS Control	PNM-091
Control of Operating and Maintenance Manuals	PNM-093
Control of External Standards	QYPR-005
Control of Power Quality Recorders	PNM-103
Quality Plans	PNM-107
Contractor Health and Safety	PNM-109
Network Accidents and Incidents	PNM-111
Design and Development	PNM-114
Network Purchasing	PNM-115
Network Pricing	PNM-117
Customer Service Performance	PNM-119
Incoming and Outgoing Mail Correspondence	PNM-129
Setting Up the Project	PNM-010

Appendix 2 – Customer Engagement Questionnaire

PowerNet Consumer Engagement
Telephone Questionnaire 2014
The Power Company Limited

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**
	Don't know/unsure	**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 electricity supply was restored within a reasonable amount of time?	Yes **1**	*Go to Q 5*
	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

Appendix 3 – Disclosure Schedules

Company Name: **The Power Company Limited**
AMP Planning Period: **1 April 2016 – 31 March 2026**

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
8	for year ended	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	31 Mar 26
9	**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10	Consumer connection	2,408	3,455	3,527	3,594	3,670	3,750	3,825	3,902	3,980	4,060	4,141
11	System growth	10,750	7,887	7,780	7,225	5,034	2,419	6,059	4,050	4,131	4,214	4,298
12	Asset replacement and renewal	9,788	9,134	7,814	8,598	8,091	8,855	7,662	7,856	8,033	8,734	11,529
13	Asset relocations	15	54	55	56	57	58	60	61	62	63	64
14	Reliability, safety and environment:											
15	Quality of supply	1,125	2,888	765	394	403	411	270	275	281	286	292
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	662	1,605	1,090	1,000	142	145	148	151	154	157	161
18	**Total reliability, safety and environment**	1,787	4,494	1,856	1,394	545	557	418	426	435	444	453
19	**Expenditure on network assets**	24,748	25,023	21,032	20,867	17,396	15,640	18,024	16,295	16,641	17,514	20,485
20	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	24,748	25,023	21,032	20,867	17,396	15,640	18,024	16,295	16,641	17,514	20,485
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	1,445	2,073	2,116	2,157	2,202	2,250	2,295	2,341	2,388	2,436	2,484
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	23,303	22,950	18,915	18,711	15,194	13,390	15,729	13,954	14,253	15,078	18,000
28												
29	Assets commissioned	30,963	23,573	14,944	24,017	12,004	10,767	18,810	12,533	12,582	12,715	15,650

30		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31	for year ended	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	31 Mar 26
32		$000 (in constant prices)										
33	Consumer connection	2,408	3,455	3,455	3,455	3,455	3,455	3,455	3,455	3,455	3,455	3,455
34	System growth	10,750	7,887	7,620	6,944	4,739	2,228	5,472	3,586	3,586	3,586	3,586
35	Asset replacement and renewal	9,788	9,134	7,653	8,264	7,617	8,157	6,919	6,955	6,973	7,433	9,619
36	Asset relocations	15	54	54	54	54	54	54	54	54	54	54
37	Reliability, safety and environment:											
38	Quality of supply	1,125	2,888	750	379	379	379	244	244	244	244	244
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	662	1,605	1,068	961	134	134	134	134	134	134	134
41	**Total reliability, safety and environment**	1,787	4,494	1,817	1,340	513	513	378	378	378	378	378
42	**Expenditure on network assets**	24,748	25,023	20,599	20,057	16,377	14,407	16,277	14,427	14,445	14,904	17,090
43	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	24,748	25,023	20,599	20,057	16,377	14,407	16,277	14,427	14,445	14,904	17,090
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											
50												

51		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	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	31 Mar 26
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	-	73	140	215	296	371	447	525	605	686
55	System growth	-	-	160	281	295	191	587	464	545	628	712
56	Asset replacement and renewal	-	-	161	334	474	698	743	901	1,060	1,301	1,910
57	Asset relocations	-	-	1	2	3	5	6	7	8	9	11
58	Reliability, safety and environment:											
59	Quality of supply	-	-	16	15	24	32	26	32	37	43	48
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	22	39	8	11	14	17	20	23	27
62	**Total reliability, safety and environment**	-	-	38	54	32	44	41	49	57	66	75
63	**Expenditure on network assets**	-	-	433	810	1,019	1,233	1,747	1,868	2,197	2,610	3,394
64	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
65	**Expenditure on assets**	-	-	433	810	1,019	1,233	1,747	1,868	2,197	2,610	3,394
66												

67		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	$000 (in constant prices)					
70	Customer Connections (≤ 20kVA)	1,124	1,171	1,171	1,171	1,171	1,171
71	Customer Connections (21 to 99kVA)	749	1,384	1,384	1,384	1,384	1,384
72	Customer Connections (≥ 100kVA)	321	788	788	788	788	788
73	Distributed Generation Connection	54	5	5	5	5	5
74	New Subdivisions	161	106	106	106	106	106
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	2,408	3,455	3,455	3,455	3,455	3,455
77	*less* Capital contributions funding consumer connection	1,445	2,073	2,073	2,073	2,073	2,073
78	**Consumer connection less capital contributions**	963	1,382	1,382	1,382	1,382	1,382
79	**11a(iii): System Growth**						
80	Subtransmission	1,679	1,845	1,306	714	2,058	1,509
81	Zone substations	9,072	5,046	5,972	5,888	2,338	377
82	Distribution and LV lines	-	450	223	223	223	223
83	Distribution and LV cables	-	-	-	-	-	-
84	Distribution substations and transformers	-	-	86	86	86	86
85	Distribution switchgear	-	-	34	34	34	34
86	Other network assets	-	546	-	-	-	-
87	**System growth expenditure**	10,750	7,887	7,620	6,944	4,739	2,228
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	10,750	7,887	7,620	6,944	4,739	2,228
90							

91		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
93	**11a(iv): Asset Replacement and Renewal**	$000 (in constant prices)					
94	Subtransmission	2,304	841	39	39	98	98
95	Zone substations	1,532	1,651	973	1,584	1,089	1,629
96	Distribution and LV lines	3,258	3,416	3,416	3,416	3,416	3,416
97	Distribution and LV cables	445	305	305	305	305	305
98	Distribution substations and transformers	961	1,468	1,468	1,468	1,468	1,468
99	Distribution switchgear	1,234	1,241	1,241	1,241	1,241	1,241
100	Other network assets	54	212	212	212	-	-
101	**Asset replacement and renewal expenditure**	9,788	9,134	7,653	8,264	7,617	8,157
102	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**	9,788	9,134	7,653	8,264	7,617	8,157
104							

105		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
107	**11a(v):Asset Relocations**						
108	*Project or programme**	$000 (in constant prices)					
109	Line Relocations	15	54	54	54	54	54
110	[Description of material project or programme]						
111	[Description of material project or programme]						
112	[Description of material project or programme]						
113	[Description of material project or programme]						
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations						
116	**Asset relocations expenditure**	15	54	54	54	54	54
117	*less* Capital contributions funding asset relocations						
118	**Asset relocations less capital contributions**	15	54	54	54	54	54
119							

120		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
122	**11a(vi):Quality of Supply**						
123	*Project or programme**	$000 (in constant prices)					
124	Supply Quality Upgrades	364	271	271	271	271	271
125	Mobile Substation	297	2,139	-	-	-	-
126	Distribution Automation	464	479	479	-	-	-
127	Network Improvement Projects	-	-	-	108	108	108
128	[Description of material project or programme]						
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply						
131	**Quality of supply expenditure**	1,125	2,888	750	379	379	379
132	*less* Capital contributions funding quality of supply		-	-	-	-	-
133	**Quality of supply less capital contributions**	1,125	2,888	750	379	379	379
134							

135		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	$000 (in constant prices)					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

150		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	$000 (in constant prices)					
153	Earth Upgrades	139	268	134	134	134	134
154	NER Installations	317	827	827	827	-	-
155	Substation Safety	206	213	106	-	-	-
156	Township Undergrounding	-	-	-	-	-	-
157	Tower Anti-Climb Guards	-	297	-	-	-	-
	Lumsden Oil Bundingin	117	-	-	-	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	662	1,605	1,068	961	134	134
161	*less* Capital contributions funding other reliability, safety and environment		-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	662	1,605	1,068	961	134	134
163							

164		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	$000 (in constant prices)					
169	[Description of material project or programme]						
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	[Description of material project or programme]						
173	[Description of material project or programme]						
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	-	-	-	-	-	-
177	**Atypical expenditure**						
178	*Project or programme**						
179	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	[Description of material project or programme]						
183	[Description of material project or programme]						
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	-	-	-	-	-	-

Company Name: **The Power Company Limited**
AMP Planning Period: **1 April 2016 – 31 March 2026**

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 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	31 Mar 26
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	4,235	2,867	2,927	2,983	3,045	3,112	3,175	3,238	3,303	3,369	3,436
11	Vegetation management	1,390	1,321	1,349	1,375	1,404	1,435	1,463	1,492	1,522	1,553	1,584
12	Routine and corrective maintenance and inspection	2,673	3,445	3,517	3,584	3,659	3,740	3,815	3,891	3,969	4,048	4,129
13	Asset replacement and renewal	1,448	1,238	1,223	1,247	1,273	1,301	1,327	1,353	1,380	1,408	1,436
14	**Network Opex**	9,746	8,871	9,017	9,188	9,381	9,587	9,779	9,975	10,174	10,378	10,585
15	System operations and network support	1,528	1,654	1,724	1,862	1,901	1,943	1,982	2,021	2,062	2,103	2,145
16	Business support	2,975	3,040	3,124	3,182	3,249	3,320	3,387	3,455	3,524	3,594	3,666
17	**Non-network opex**	4,503	4,694	4,848	5,044	5,150	5,263	5,369	5,476	5,586	5,697	5,811
18	**Operational expenditure**	14,249	13,565	13,864	14,232	14,531	14,851	15,148	15,451	15,760	16,075	16,397
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 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	31 Mar 26
21		$000 (in constant prices)										
22	Service interruptions and emergencies	4,235	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
23	Vegetation management	1,390	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321
24	Routine and corrective maintenance and inspection	2,673	3,445	3,445	3,445	3,445	3,445	3,445	3,445	3,445	3,445	3,445
25	Asset replacement and renewal	1,448	1,238	1,198	1,198	1,198	1,198	1,198	1,198	1,198	1,198	1,198
26	**Network Opex**	9,746	8,871	8,831	8,831	8,831	8,831	8,831	8,831	8,831	8,831	8,831
27	System operations and network support	1,528	1,654	1,688	1,790	1,790	1,790	1,790	1,790	1,790	1,790	1,790
28	Business support	2,975	3,040	3,060	3,059	3,059	3,059	3,059	3,059	3,059	3,059	3,059
29	**Non-network opex**	4,503	4,694	4,748	4,848	4,848	4,848	4,848	4,848	4,848	4,848	4,848
30	**Operational expenditure**	14,249	13,565	13,579	13,680	13,680	13,680	13,680	13,680	13,680	13,680	13,680
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	125	125	125	125	125	125	125	125	125	125	125
34	Direct billing*											
35	Research and Development											
36	Insurance	303	303	303	303	303	303	303	303	303	303	303
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 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	31 Mar 26
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	60	116	178	245	308	371	436	502	569
43	Vegetation management	-	-	28	53	82	113	142	171	201	231	262
44	Routine and corrective maintenance and inspection	-	-	72	139	214	295	370	446	524	603	684
45	Asset replacement and renewal	-	-	25	48	75	103	129	155	182	210	238
46	**Network Opex**	-	-	185	357	550	756	948	1,143	1,343	1,546	1,754
47	System operations and network support	-	-	35	72	111	153	192	232	272	313	355
48	Business support	-	-	64	124	190	262	328	396	465	536	607
49	**Non-network opex**	-	-	100	196	302	415	520	628	737	849	963
50	**Operational expenditure**	-	-	285	553	852	1,171	1,468	1,771	2,080	2,395	2,717

THEPOWERCOMPANYLTD

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2016 – 31 March 2026**

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											
9	**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**
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%
35											
36					**Asset condition at start of planning period (percentage of units by grade)**						
37											
38	**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**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.		8.00%	90.00%	2.00%	-	3	10.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	10.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	10.00%
42	HV	Distribution Line	SWER conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	75.00%	5.00%	20.00%	1	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	2.00%	73.00%	5.00%	20.00%	1	2.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A					N/A	
46	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%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A					N/A	
48	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%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A					N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	3.00%	94.00%	3.00%	-	1	5.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	3.00%	74.00%	3.00%	20.00%	1	10.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	1.00%	96.00%	3.00%	-	1	10.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	5.00%	90.00%	5.00%	-	1	5.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	N/A	-	-	-	-	N/A	
55	LV	LV Line	LV OH Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
56	LV	LV Cable	LV UG Cable	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.00%	4.00%	70.00%	5.00%	20.00%	1	5.00%
58	LV	Connections	OH/UG consumer service connections	No.	1.00%	4.00%	70.00%	5.00%	20.00%	1	10.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	2.00%	94.00%	4.00%	-	1	10.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	2.00%	94.00%	4.00%	-	1	10.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	100.00%	-	-	1	-
62	All	Load Control	Centralised plant	Lot	-	20.00%	80.00%	-	-	1	20.00%
63	All	Load Control	Relays	No.	-	-	18.00%	2.00%	80.00%	1	50.00%
64	All	Civils	Cable Tunnels	km	N/A					N/A	

	Company Name	**The Power Company Limited**
	AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref										
7	**12b(i): System Growth - Zone Substations**									
8	*Existing Zone Substations*	**Current Peak Load (MVA)**	**Installed Firm Capacity (MVA)**	**Security of Supply Classification (type)**	**Transfer Capacity (MVA)**	**Utilisation of Installed Firm Capacity %**	**Installed Firm Capacity +5 years (MVA)**	**Utilisation of Installed Firm Capacity + 5yrs %**	**Installed Firm Capacity Constraint +5 years (cause)**	**Explanation**
9	Athol	1	-	N	1	-	-	-	No constraint within +5 years	
10	Awarua	5	-	N	1	-	12	67%	No constraint within +5 years	
11	Awarua Chip Mill	1	-	N	1	-	-	-	No constraint within +5 years	
12	Bluff	5	13	N-1	1	37%	13	42%	No constraint within +5 years	
13	Centre Bush	4	-	N	2	-	-	-	No constraint within +5 years	
14	Conical Hill	2	5	N-1	2	45%	-	-	No constraint within +5 years	
15	Dipton	2	-	N	1	-	-	-	No constraint within +5 years	
16	Edendale Fonterra	24	46	N-1	-	53%	46	74%	No constraint within +5 years	
17	Edendale	7	12	N	1	56%	12	60%	No constraint within +5 years	
18	Glenham	2	-	N	1	-	-	-	No constraint within +5 years	Upgrade planned
19	Gorge Road	3	2	N-1 switched	1	206%	-	-	Transformer	Upgrade planned
20	Heddon Bush	8	-	N	6	-	N/A	-	No constraint within +5 years	Removed to spares
21	Hedgehope	-	-	N	1	-	-	-	No constraint within +5 years	
22	Hillside	1	-	N	1	-	-	-	No constraint within +5 years	
23	Kelso	5	-	N	2	-	-	-	Transformer	Upgrade planned
24	Kennington	6	12	N-1 switched	2	48%	12	40%	No constraint within +5 years	
25	Lumsden	3	-	N	2	-	-	-	No constraint within +5 years	
26	Makarewa	7	12	N-1 switched	2	54%	12		No constraint within +5 years	
27	Mataura	6	10	N-1	2	64%	12	50%	No constraint within +5 years	
28	Monowai	0	-	N	-	-	-	-	No constraint within +5 years	
	Mossburn	2	2	N-1 switched	2	139%	-	-	No constraint within +5 years	
	North Gore	9	10	N-1	8	86%	10	77%	No constraint within +5 years	
	North Makarewa	50	45	N-1	-	110%	45	110%	Transformer	Expect some additional DG in Area
	Ohai	3	5	N-1 switched	1	54%	-	-	No constraint within +5 years	
	Orawia	3	-	N	2	-	-	-	No constraint within +5 years	
	Otatara	0	-	N	4	-	-	-	No constraint within +5 years	
	Otautau	5	-	N	3	-	-	-	No constraint within +5 years	
	Riversdale	5	-	N	3	-	5	118%	No constraint within +5 years	Upgrade planned
	Riverton	5	8	N-1	2	64%	8	70%	No constraint within +5 years	
	Seaward Bush	9	10	N-1 switched	1	85%	12	67%	No constraint within +5 years	Upgrade planned
	South Gore	11	12	N-1	8	95%	12	77%	No constraint within +5 years	
	Te Anau	6	12	N-1	1	47%	12	51%	No constraint within +5 years	
	Tokanui	1	-	N	1	-	-	-	No constraint within +5 years	
	Underwood	13	20	N-1	4	65%	20	61%	No constraint within +5 years	
	Waikaka	1	-	N	1	-	-	-	No constraint within +5 years	
	Waikiwi	10	12	N-1	2	87%	23	58%	No constraint within +5 years	Upgrade in progress
	Winton	12	12	N-1	3	104%	12	90%	No constraint within +5 years	Load transfer to new Isla Bank Substation

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

Company Name: **The Power Company Limited**

AMP Planning Period: **1 April 2016 – 31 March 2026**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected 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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**							
12	Customer Connections (≤ 20kVA)		203	250	250	250	250	250
13	Customer Connections (21 to 99kVA)		70	50	50	50	50	50
14	Customer Connections (≥ 100kVA)		6	5	5	5	5	5
15	Subdivsions		-	5	5	5	5	5
16								
17	**Connections total**		279	310	310	310	310	310
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		31	30	30	30	30	30
21	Capacity of distributed generation installed in year (MVA)		7	0	0	0	0	0
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25	GXP demand		81	82	83	84	84	85
26	*plus* Distributed generation output at HV and above		56	56	56	56	56	56
27	**Maximum coincident system demand**		137	138	139	139	140	141
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**		135	136	137	137	138	139
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		611	603	606	609	612	615
32	*less* Electricity exports to GXPs		48	50	50	50	50	50
33	*plus* Electricity supplied from distributed generation		229	240	240	240	240	240
34	*less* Net electricity supplied to (from) other EDBs		18	18	18	18	18	18
35	**Electricity entering system for supply to ICPs**		775	775	778	781	784	787
36	*less* Total energy delivered to ICPs		725	725	728	731	734	737
37	**Losses**		50	50	50	50	50	50
38								
39	**Load factor**		65%	65%	65%	65%	65%	65%
40	**Loss ratio**		6.4%	6.4%	6.4%	6.4%	6.3%	6.3%

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	81.2	72.0	72.0	74.0	74.0	74.0
12	Class C (unplanned interruptions on the network)	187.8	122.9	120.2	117.6	117.0	116.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.33	0.35	0.35	0.35	0.35	0.35
15	Class C (unplanned interruptions on the network)	3.23	2.48	2.42	2.37	2.36	2.34

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.

Appendix 4 - Directors Approval

Certification for Year-beginning Disclosures

We, Douglas William Fraser 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.

D W Fraser

M L Macpherson

Date: 30/03/2016